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TECHNICAL NOTE

Labrador – Island HVdc Link
and
Island Interconnected System Reliability

Date: October 30, 2011

System Planning Department

newfoundland labrador hydro
a nalcor energy company

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INTRODUCTION

The addition of a 900 MW HVdc transmission line between Muskrat Falls in Labrador and Soldiers Pond on the Island portion of the Province has raised concerns regarding the impact that such a significant change will have on the reliability of the Island Interconnected System. The purpose of this technical note is to provide an overview of the system reliability, the interrelationships between the areas which affect system reliability and finally the impact that the proposed HVdc transmission line addition will have on system reliability.

SYSTEM RELIABILITY INTERRELATIONSHIPS

To understand the concept of system reliability and overall impact the addition of a 900 MW HVdc transmission link between Labrador and Newfoundland will have on the Island Interconnected Transmission System, it is beneficial to understand the interrelationships between System Planning, Transmission Line Design and System Operations. To this end a brief explanation of each is provided so that the reader may more fully understand the issue of system reliability as it relates to the transmission system on the Island portion of the Province and the impact the Labrador – Island HVdc Link will have on said system reliability.

System Planning Components

Least cost reliable planning of the Island Interconnected Transmission System is comprised of two main components: generation planning and transmission planning.

Generation Planning

Generation planning for the Island Interconnected System ensures that there is sufficient generation, both capacity (MW) and energy (MWh) to supply the load as provided in load forecasts for future years. NLH uses an industry recognized computer program, *Strategist®*, to complete the generation planning exercise. As general rules to guide NLH's generation planning activities, the following criteria have been adopted:

> **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[1].
>
> **Energy**: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[2].

At a very high level, when there is an energy deficiency *Strategist®* will add energy source(s) to restore the balance. When there is a capacity shortfall, but sufficient energy to supply the load *Strategist®* will add low cost combustion turbines. Iterations are used to provide the overall least cost expansion plan for the load forecast.

[1] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For NLH, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

[2] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood Thermal Generating Station) is based on energy capability adjusted for maintenance and forced outages.

The generation planning exercise considers the forced outage rates of all available generators to determine the LOLH. However, the forced outage rates for the interconnected transmission network, or grid, is not included in the LOLH calculation.

Transmission Planning

Transmission planning at NLH follows traditional transmission planning practices similar to, but less stringent than, that found in North American Electric Reliability Corporation (NERC) Transmission Planning Standards.

Transmission planning is deterministic in nature. That is the power system must remain stable with no loss of load for certain equipment contingencies for all system loading conditions.

Typically the system peak and light load conditions are considered as these loading conditions stress the system in opposite directions (i.e. peak load resulting in low voltage and light load resulting in high voltages for a given contingency). Based upon the knowledge of the system, the transmission planner may select other loading conditions which have significant impacts (i.e. a 15 ˚C ambient day with limited thermal ratings on certain lines and relatively high line flows).

The established transmission planning criteria includes the requirement that for loss of a transmission line[3] or power transformer that there be no loss of load. Unlike the NERC planning criterion which requires no loss of load for loss of generation, the NLH transmission planning criterion for the Island System permits under frequency load shedding for loss of a generator[4]. The rationale for this deviation is the fact that that the Island Interconnected Transmission System is electrically isolated from the North American grid and operation of sufficient spinning reserve and increased system inertia for the loss of generation contingency would be cost prohibitive for the relatively small rate base. While the loss of the generator results in temporary loss of load through the under frequency load shedding scheme, the transmission planning exercise for the Island Interconnected System considers the fact that the generator outage may be long term, requiring the start up of standby generation including the combustion turbines added by the generation planning exercise to meet the LOLH target. With the permanent generator outage and start up of stand by generation, the transmission planning exercise must ensure that there is sufficient transmission capacity to supply all load including that load temporarily shed during the initial generator contingency.

[3] This applies for bulk system transmission lines; loss of a radial transmission line will result in loss of load.
[4] The under frequency load shedding targets for the Island Interconnected System are no more than five operations for Newfoundland Power customers and no more than six operations for NLH customers per year.

Transmission Line Design

In Canada, transmission line design practices can be found in at least two CSA standards (CSA C22.3 No. 1-06 and CAN/CSA C22.3 No. 60826:06). A brief description of each is warranted.

CSA Standard C22.3 No. 1-06 Overhead Systems

CSA Standard C22.3 No. 1-06 Overhead systems provides the transmission line designer with a choice between deterministic and reliability-based design methods. CSA C22.3 No. 1-06 covers the deterministic-based design method, while CSA C22.3 No. 60826 covers the reliability-based design method.

With respect to weather loads (i.e. ice and wind), Section 7.2 of C22.3 No. 1-06 states:

> *For purposes of this Standard, four deterministic load conditions are recognized: severe, heavy, medium loading A, and medium loading B (see Table 30).*
> *Load classification shall be based on local experience and weather records. Annex C provides maps for guidance; the loads for the areas shown are considered the minimum, and local experience and information might permit the adjustment of these loads.*

Reference to Annex C indicates that:

- The area surrounding the Churchill River is considered to have a loading condition of medium loading B;
- The area traversed by the proposed HVdc line from Muskrat Falls to the Strait of Belle Isle is considered to have a loading condition of heavy;
- The Bonavista and Avalon Peninsulas on the Island portion of the Province are considered to have a loading of severe; and
- The remainder of the Island is considered to have a loading condition of heavy.

Reference to Table 30 indicates the following radial ice thicknesses:

- Medium loading B – 12.5 mm (~ 0.5 inch);
- Heavy loading – 12.5 mm (~0.5 inch); and
- Severe loading – 19 mm (~0.75 inch).

Section 10 of C22.3 No. 1-06 states:

> *The reliability-based method should be used for supply lines greater than 70 kV phase-to-phase, in areas where significant amounts of meteorological data are readily available. This method may also be used for lines designed for specific climatic loads in accordance with previous experience or calibration with existing lines having a long history of satisfactory performance.*

CAN/CSA C22.3 No. 60826:06

International Standard CEI/IEC 60826:2003 (third edition, 2003-10) has been adopted as CAN/CSA C22.3 No. 60826:06 Design criteria of overhead transmission lines with Canadian deviations and has been approved as a National Standard of Canada.

Section 4.1 states the objective of this standard. Subsection a) states:

> *It provides design criteria for overhead lines based upon reliability concepts. The reliability based method is particularly useful in areas where significant amounts of meteorological and strength data are readily available. This method may however be used for lines designed to withstand specific climatic loads, either derived from experience or through calibration with existing lines that had a long history of satisfactory performance. In these cases, design consistency between strengths of line components will be achieved, but actual reliability levels may not be known, particularly if there has been no evidence or experience with previous line failures.*

Section 4.3 goes on to state:

> *The objective of the design criteria described in this standard is to provide for reliable and safe lines. The reliability of lines is achieved by providing strength requirements of the line components larger than the quantifiable effects of weather related loads. These climatic loads are identified in this standard as well as means to calculate their effects on transmission lines. However, it has to be recognized that other conditions, not dealt with in the design process, can occur and lead to line failure such as impact of objects, defects in material, etc. Some measures, entitled security requirements, included in this standard provide lines with enough strength to reduce damage and its propagation, should it occur.*

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

Annex A.1.2.5 provides guidance for the selection of the appropriate reliability level characterized by the return period of the climatic load. The section stipulates that in any case transmission lines should at least be designed to the 1:50 year return period load levels. The section goes on to state:

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

> *Finally, it is suggested to use a reliability level characterized by return periods of 500 years for lines, mainly above 230 kV which constitute the principal or perhaps the only source of supply to a particular load. Their failure would have serious consequences to the power supply.*
>
> *The applications of the reliability for overhead lines, including corresponding voltage levels, may be set differently in individual countries depending upon the structure of the grid and the consequences of the line failures.*

It is worth noting at this point that the standard suggests reliability levels characterized by return periods of the weather loads based upon the impact of failure, and recognizes that individual countries may set different limits.

Considering the Canadian deviations, Figure CA.2 provides the reference radial ice thickness for a 1:50 year return period at a 10 m elevation above ground and provides a spatial factor of 1.5 to account for the fact that the ice maps were developed from a limited number of meteorological station across the country, potentially remote from the transmission line route and also that transmission line conductors are located at elevations on the order of 30 m above the ground. With reference to the Avalon Peninsula Figure CA.2 indicates a radial ice thickness of 40 mm at 10 m which translates into a 1:50 year return period ice thickness of 60 mm (2.4 inches) at the line conductor elevation. The method for calculating increase return period loads indicates a 1:100 year ice thickness of 66 mm, a 1:150 year ice thickness of 69 mm (2.7 inches) and a 1:500 year ice thickness of 78 mm (3.1 inches).

NLH Line Design

At this point it is worth describing how each of the above noted standards has impacted transmission line design within the Island Interconnected System. The 230 kV transmission lines on the Avalon Peninsula are used to discuss application.

The original 230 kV transmission lines on the Island Interconnected System were designed beginning in 1963 using the deterministic-based approach similar to that outlined in the latest CSA C22.3 No. 1-06 Standard. While the CSA Code of the day specified 13 mm (0.5 inch) radial ice, transmission line design engineers selected a radial ice thickness of 25 mm (1 inch) for normal load zones and 38 mm (1 ½ inches) for ice zone areas. It was noted that a 27 km section to the southeast of the Sunnyside Terminal Station was known for severe ice storms and so lines in this area were designed for 50 mm (2 inches) of radial ice. Note that the total weather load includes the combined wind and ice load. For discussion purposes the wind load has been removed for clarity.

With respect to the Avalon Peninsula subsequent to construction in the mid to late 1960's ice storms resulted in line failures in 1970, 1984, 1988, 1990 and 1994. Observations following the failures indicated radial ice thicknesses varying from 44 mm (1 ¾ inches) to 50 mm (2 inches) with one extreme occurrence of 150 mm (6 inches)[5]. In essence the failure for each storm event indicated that the combined ice and wind loads had exceeded the original design loads. Investigations by NLH following the 1994 ice storm revealed that the original design ice loads of 25 mm to 38 mm (1 to 1.5 inches) have a return period of approximately one in ten years (1:10). Based upon the location of the transmission line on the Avalon Peninsula the 1 in 25 year return period (1:25) was determined to be between 48 mm and 66 mm (1.9 and 2.6 inches) of radial ice and the 1 in 50 year return period (1:50) between 60 mm and 75 mm (2.35 and 3 inches) of radial ice. Consequently reinforcement of the 230 kV steel lines on the Avalon Peninsula between 1998 and 2002 utilizing a radial ice thickness of between 66 mm and 75 mm (2.6 and 3.0 inches) resulted in improved reliability of the 230 kV transmission system with a return period between 1:25 and 1:50 years based upon line and location.

Based upon the work completed as part of the transmission line upgrades on the Avalon Peninsula, NLH has adopted a 1:50 year return period for new 230 kV transmission line design.

[5] Observed ice loads and known failure rates for 230 kV transmission lines were used by Haldar [4] to determine future ice loads in terms of various return periods.

System Operations

With all equipment available and in service the Island Interconnected System operates at its most reliable level as the generation planning exercise ensures there is sufficient generation to meet the load even for loss of a single generating unit, the transmission planning exercise ensures there is sufficient transmission line and transformer capacity to supply the load for loss of any single element, and prudent transmission line design ensures that the transmission lines fail only under extreme weather conditions. Unfortunately forced outages will occur as moving parts in generators may fail, lightning or a tree may cause damage to a transmission line. In addition, equipment must be taken out of service so that it can be maintained. For these events System Operations must reconfigure the system so that a second equipment loss results in no loss of supply to customers. To this end System Operations schedules generator and transmission line maintenance so that there is sufficient stand by generator and transmission capacity for a sudden, unplanned loss of an element during the maintenance period.

IMPACT OF THE LABRADOR – ISLAND HVdc LINK ON ISLAND SYSTEM RELIABILITY

The Labrador – Island HVdc Link has the following nominal ratings:

- ±320 kV operating voltage (bipole);
- 2 x 450 MW, 1406 A per pole;
- 900 MW at Muskrat Falls;
- 92.1 MW peak losses; and
- 807.9 MW at Soldiers Pond.

The impact of a 900 MW HVdc transmission line between Labrador and Newfoundland on the reliability of the Island Interconnected System can only be considered in the context of all of the components discussed above if one is to understand the full impact.

The generation planning process models the HVdc deliveries to the Island Interconnected System as if it were a generator connected to the system. Similar to other generators connected to the Island Interconnected System, the HVdc model in *Strategist®* incorporates a forced outage rate that is important in calculating the system LOLH on an annual basis. Consequently in the Island Interconnected Scenario one notes the addition of 50 MW combustion turbines at regular intervals following the addition of the HVdc line to maintain the LOLH below the 2.8 hours per year (i.e. the capacity requirement criteria).

In considering the quantity of energy available over the Labrador – Island HVdc Link, the energy balance in the generation planning exercise indicates that there will be sufficient generating capability to supply all of its firm energy requirements with firm system capability to the year 2036, at which time additional energy sources are required (i.e. Portland Creek, wind, combined cycle combustion turbine, etc).

The generation planning process to date incorporates the impacts of the HVdc transmission line along with appropriate capacity and energy source additions to meet the generation planning criteria.

While the existing transmission planning criteria does not specifically state the reliability requirements for an HVdc interconnection, the existing criteria provides the fundamentals to plan a reliable integration of the proposed HVdc line in the Island Interconnected System (i.e. loss of a generator, loss of a line, etc.).

Pole Outages

CIGRE 2010 paper B4_209_2010 "A survey of the Reliability of HVdc Systems Throughout the World During 2007 – 2008" provides the latest available outage statistics for HVdc transmission systems worldwide. It must be noted that the statistics provides very good insight into converter equipment outages but purposefully neglects significant detail on overhead and cable portions of the HVdc transmission system. The average data for reporting HVdc systems is based upon data from 1988 to 2008, and therefore includes some of the older technology issues (i.e. controls and mercury arc valves) which have been corrected over time. The statistics for two terminal systems with one converter per pole, as per the proposed Labrador – Island HVdc Link, indicate that, on average, one can expect between 0.38 and 4.90 pole outages per year (permanent and temporary), with average durations ranging from 2.6 to 484.2 hours. For a bipole system such as the Labrador – Island Link this results in the potential for between 0.76 (~ 1 outage every 4 years) to 9.8 pole outages per year. Alternatively, a rough rule of thumb is to consider approximately one pole outage per 100 km per year. In the context of approximately 1100 km of overhead transmission, one could consider 11 pole outages per year.

Given an existing under frequency load shedding target of no more than six operations per year, sudden loss of a pole of the HVdc line would result in under frequency load shedding operations well in excess of the established targets. Further, the largest unit on the Island Isolated System today is a 175 MW generator. By comparison each pole of the HVdc line will deliver approximately 404 MW (net of losses) to the Island in bi-pole mode of operation. Consequently, loss of a pole could have a severe impact on system frequency and potential system collapse. Clearly, loss of a pole requires additional attention to ensure that system reliability is not negatively impacted. This issue has been recognized for quite some time. As part of the transmission planning process the HVdc transmission line is required to have a temporary rating of twice rated power (2 p.u.) for ten minutes to ensure that following the loss of a pole, the healthy pole ramps to twice rated output or 900 MW so that there is no load loss on the Island Interconnected System. The ten minute window provides time for NLH system operators to start standby generation on the Island and reduce the loading on the remaining pole to one and one half times rated power (1.5 p.u.) or 675 MW, the continuous rating in monopolar mode.

The rating of the Labrador – Island Link to prevent unacceptable under frequency load shedding events is:

- 320 kV operating voltage;
- Bipole operation
    - 2 x 450 MW, 1406 A per pole;
    - 900 MW at Muskrat Falls;
    - 92.1 MW peak losses;
    - 807.9 MW at Soldiers Pond
- Monopolar operation – ten minutes
    - 1 x 900 MW, 2812 A;
    - 900 MW at Muskrat Falls
    - 272.8 MW peak losses;
    - 627.2 MW at Soldiers Pond
- Monopolar operation – continuous
    - 1 x 675 MW, 2109 A;
    - 675 MW at Muskrat Falls;
    - 144.4 MW peak losses;
    - 530.6 MW at Soldiers Pond

Pole Outages – Maritime Link In Service

Of the 807.9 MW delivered to Soldiers Pond, 162.2 MW is assigned to supply the Emera block, leaving 645.7 MW as the peak deliveries to the Island Interconnected System. For loss of a pole the Emera block will be curtailed leaving the 627.2 MW capacity in the ten minute monopolar operation mode to supply the Island Interconnected System demand. In the peak case there is a 27.5 MW shortfall (627.2 MW monopolar supply and 645.7 MW peak Island demand). However, the 27.5 MW shortfall in monopolar mode will not lead to under frequency load shedding on the Island. Given that the bipole is loaded to maximum at the time of the pole outage, there will be spinning reserve carried on the Island Interconnected System generators. Operating experience with the existing system indicates that there will be no under frequency load shedding for a sudden loss of 27.5 MW.[6] Further, with the start of up to 150 MW of combustion turbine in the ten minute window, the continuous monopolar rating of 530.6 MW at Soldiers Pond is capable of supplying the Island Interconnected System demand[7].

[6] Hydro successfully performs 25 MW load rejection tests on its hydroelectric generators as part of major overhauls to assess governor/generator response without initiating under frequency load shedding action. Therefore it is expected that the 27.5 MW shortfall following loss of a pole will be made up by governor action on Island hydro units without initiation of under frequency load shedding.
[7] The continuous monopolar rating of 552.6 MWplus start up of three 50 MW combustion turbines (Stephenville, Hardwoods and the new unit scheduled for 2014) results in a capacity of 702.6 MW, which exceeds the 645.7 MW Island Interconnected System block thereby eliminating any shortfall.

Pole Outages – No Maritime Link

Should the Maritime Link component of Phase I of the Lower Churchill Project not proceed, operation of the Labrador – Island Link would be somewhat modified. Under the Maritime Link scenario, System Operations has the opportunity to call upon spinning reserve in Nova Scotia. Recall that with the Labrador – Island Link fully loaded, loss of a pole resulted in the curtailment of the Emera block to Nova Scotia in order to maintain the Island Interconnected System whole with no under frequency load shedding. In other words, the Nova Scotia spinning reserve was used to cover the curtailment of the 162.2 MW import from Newfoundland. Without the Maritime Link, spinning reserve to avoid under frequency load shedding must be carried between the Island Interconnected and Labrador Interconnected Systems. If all Island Interconnected System generation is on line and at maximum output, then there must be a minimum of 154 MW of reserve carried on the Labrador – Island Link (maximum delivery of 653.9 MW) to cover the sudden loss of the largest unit on the Island (i.e. Bay d'Espoir Unit 7 at 154 MW). Conversely, 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[8]. 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.

While NLH is not a member of any reliability organization as a transmission owner or operator at this time, reference to these organizations provides some perspective of what is deemed acceptable in the industry at large. The North American Electric Reliability Corporation (NERC) has the mandate for reliability of the interconnected transmission systems in the United States. Given the interties between Canadian Provinces and US States, Canadian utilities must abide by NERC reliability criteria and the criteria of the regional reliability organization (i.e. Northeast Power Coordinating Council Inc – NPCC for Ontario, Québec, New Brunswick and Nova Scotia). The NERC transmission planning standards with respect to system reliability stipulate that there be no loss of load for loss of a single pole of an HVdc bipole system. This is the criterion to which NLH is planning the Labrador – Island Link as described above – curtailment of the Emera Block and twice rated power on the healthy pole to avoid under frequency load shedding on the Island Interconnected System.

[8] For loss of a pole at maximum delivery there is a 180.7 MW deficiency (807.9 – 627.2 = 180.7 MW). Recall for loss of a pole the monopolar 10 minute rating equals 627.2 MW, and continuous monopole rating equals 530.6 MW.

Bipole Outages

The CIGRE statistics for bipole outages of two terminal HVdc systems with one converter per pole are summarized in Table 1. The data indicates an average bipole outage rate varying from zero per year to a high of 0.42 outages per year (1 every 2.4 years). The average duration of the bipole outage ranges from 1.03 hours to 2.27 hours. As noted earlier, the CIGRE statistics deal predominantly with the converter equipment and not the overhead transmission lines. In the context of the Labrador – Island HVdc Link failure of a bipole is intended to result in a curtailment of exports via the Maritime Link and operation of a special protection scheme (SPS) to trip load on the eastern portion of the Island Interconnected System (i.e. Avalon Peninsula) to restore generation and load balance between NLH hydroelectric generation in central and western Newfoundland with the remaining load on the Island Interconnect System and subsequently prevent a total Island blackout. Under this scenario, an average restoration time of the bipole of less than 3 hours for a converter station forced outage is not viewed as overly severe. Given the time required to start all stand by generation and schedule imports from Nova Scotia via the Maritime Link coupled with the load restoration process for the lost Island Interconnected System load, the Labrador – Island HVdc Link will be restarted and the system returned to normal in under 2 hours following a bipole outage as the result of a converter station issue.

Table 1
Summary of Frequency and Duration of Forced Bipole Outages
2 Terminal Systems – 1 Converter per Pole
Average 1988 – 2008

System	Years	Frequency	Duration – hours
Skagerrak 1 & 2	20	0.13	1.03
Square Butte	18	0.42	2.27
CU	20	0.28	1.66
Gotland 2 & 3	20	0.20	1.49
Kii Channel	8	0.00	0.00

Source: CIGRE 2010 paper B4_209_2010 "A survey of the Reliability of HVdc Systems Throughout the World During 2007 – 2008" – Table V (B)

Forced outages to the HVdc overhead transmission line is of more concern in the context of the Labrador – Island HVdc Link given the length, environmental conditions and mean time to repair. The CIGRE statistics do not provide long term average forced outage rates and durations for overhead or cable systems. Similarly, there is no HVdc system in operation that is a one for one comparison to the Labrador – Island HVdc Link. The CIGRE statistics do provide the number of forced outages and durations for the previous two reporting years. Unfortunately, the causes are not reported. Table 2 provides the 2007 – 2008 data for several HVdc transmission line projects of interest.

Table 2 Summary of Forced Outages and Durations for Overhead Transmission Lines				
Project	**2007**		**2008**	
	Number	**Duration**	**Number**	**Duration**
Skagerrak 1 & 2	0	0.0	0	0.0
Square Butte	2	194.6	1	64.5
CU	1	0.1	0	0.0
New Zealand Pole 2	1	0.3	5	9.3
Nelson River BP1	0	0.0	2	2.1
Nelson River BP2	1	0.2	4	0.6
Source: CIGRE 2010 paper B4_209_2010 “A survey of the Reliability of HVdc Systems Throughout the World During 2007 – 2008” – Tables II A and II B				

Without supporting data, one can only surmise that the outages of short duration were more temporary in nature (i.e. lightning), while the outages of longer duration on the Square Butte system were due to tower failures requiring repair.

The available outage data suggests that forced outages to the bipole attributed to converter station problems will occur between once every 2 years to once in 8 years. The duration of these outages are less than three hours, and as such should not have a significant impact on overall Island Interconnected System reliability. It is worth noting that the newest of the reporting systems has not suffered a forced bipole outage due to converter station issues. Continued long term reporting of the system is required to confirm that the lack of forced bipole outages is due to improvements in technology.

Bipole Outages – Maritime Link In Service

For loss of the bipole, NERC transmission planning standards permit planned and controlled load loss in order to maintain system stability. In the context of the Labrador – Island Link loss of the bipole will result in curtailment of the exports via the Maritime Link. As part of the detailed design phase a special protection scheme is contemplated to trip the Avalon Peninsula load so that the on line Island generation will remain on and stable with a balanced load. In this situation the Labrador, Island and Nova Scotia systems become isolated from one another but each will be stable. Once the Island Interconnected System has stabilized, standby generation on the Island is started and imports from Nova Scotia are scheduled to permit the restoration of the Avalon Peninsula load tripped during the bipole event.

The NPCC transmission planning criteria requires that members be able to withstand the loss of the complete bipole without loss of load. Consequently, Nova Scotia must plan for the loss of the full 500 MW rating of the Maritime Link without loss of load and maintain a stable system. Not being members of NPCC, NLH must only demonstrate that the loss of the Labrador – Island Link has no adverse impact on its neighbours – Québec and Nova Scotia in this situation. A 900 MW swing in Labrador attributed to the loss of the Labrador – Island Link is within the Hydro Québec TransÉnergie 1500 MW spinning reserve criteria and Nova Scotia is planning for the loss of the 500 MW import loss. Therefore the sudden loss of the Labrador – Island Link has no adverse impact on our neighbours and should be of little consequence to NPCC south of the border.

Table 3 summarizes the generation supply available on the Island Interconnected System following the loss of the Labrador – Island Link.

Table 3
Island Interconnected System Generation Supply for Loss of Labrador – Island Link
Maritime Link In Service

Owner	**Type**	**Capacity – MW**
NLH	hydroelectric	927.3
	stand by diesel	14.7
	combustion turbine[1]	150.0
Newfoundland Power	hydroelectric	96.6
	stand by diesel	7.0
	combustion turbine	36.5
Corner Brook Pulp & Paper	hydroelectric	121.4
Non-Utility Generators	mixed less wind	115.0
Import from Nova Scotia	thermal	300.0
Total Island Generation Supply		**1768.5**

Notes:
1: New 50 MW CT on Avalon Peninsula in 2014 brings total to 150 MW, Hardwoods and Stephenville 50 MW CTs to retire in 2022 and 2024 respectively

By comparison the 2017 peak load forecast for the Island Interconnected System equals 1704 MW. Based upon the load forecast the Island Interconnected System load is expected to exceed the total Island Generation Supply in 2022 when the forecast indicates a peak load of 1775.8 MW. Based upon the probability of a bipole outage occurring during the peak load period, the duration of the outage and the cost of such an outage, a decision can be made as to when additional combustion turbine generation should be added.

Bipole Outages – No Maritime Link

Without the Maritime Link, the available generation to supply the Island Interconnected System following a bipole outage to the Labrador – Island Link equal 1468.5 MW. Given that the 2017 load forecast for the Island Interconnected System equals 1704 MW, there is an apparent capacity shortfall of 235.5 MW.

To demonstrate the level of exposure a typical annual load shape for the Island Interconnected System was developed using the NLH Energy Management System (EMS) historical hourly load data. The load shape was then scaled to the year 2017. Figure 1 provides the expected 2017 annual load shape and denotes the 1468.5 MW generation supply limit. Clearly, the figure indicates that there will be a significant number of hours during the year, particularly between late fall and early spring, when the forecast load will exceed the available generation should there be a loss of the bipole during that time period. In addition, the figure also indicates that if there were a bipole failure anytime between early spring and late fall there is sufficient generation to supply all Island Interconnected load.

Figure 2 provides the load duration curve for the 2017 Island Interconnected System load. For an available generating capacity of 1468.5 MW with no Maritime Link one finds that the 2017 load will exceed the generating capacity for 7.3% of the year. In other words, there is an exposure for a total of 637 hours should a bipole outage occur in 2017. Considering a 1:50 year design, there is a 2% probability that the design load condition will occur in any one year. The probability of unsupplied energy in 2017 is calculated as 0.02 * 0.073 = 0.00146 or 0.14%. Expressed in terms of availability, energy availability in 2017 is calculated as 1 – 0.00146 = 0.99854 or 99.85% availability.

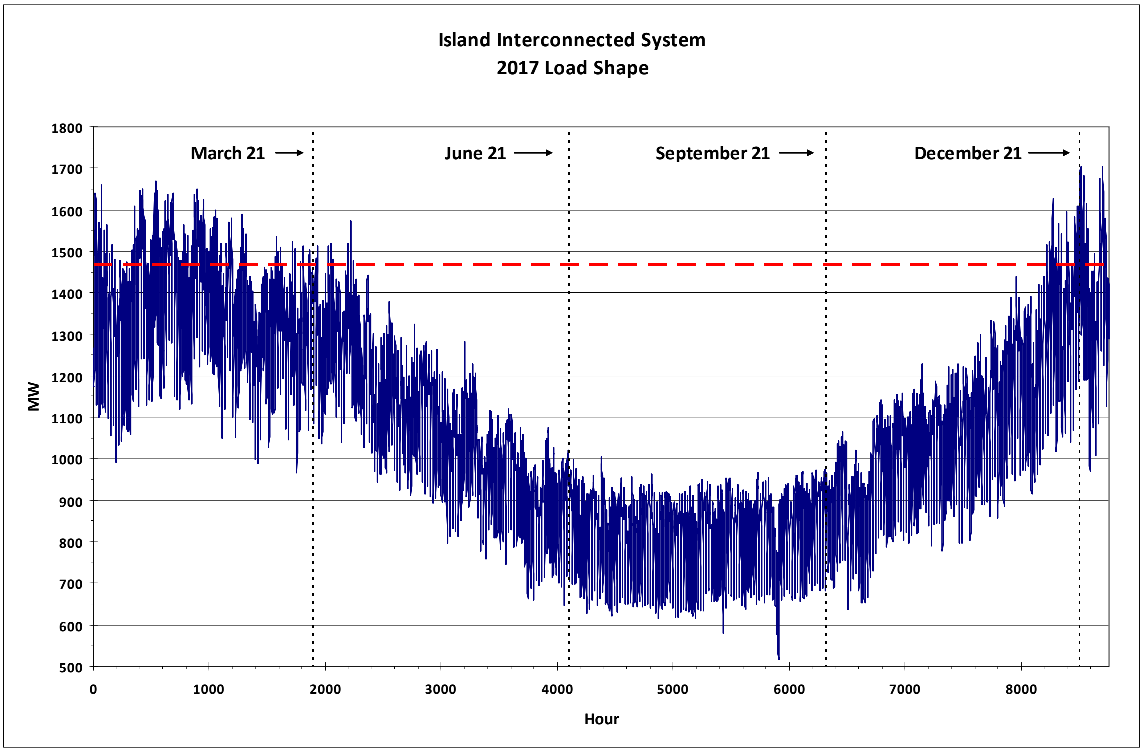

Figure 1 – 2017 Load Shape

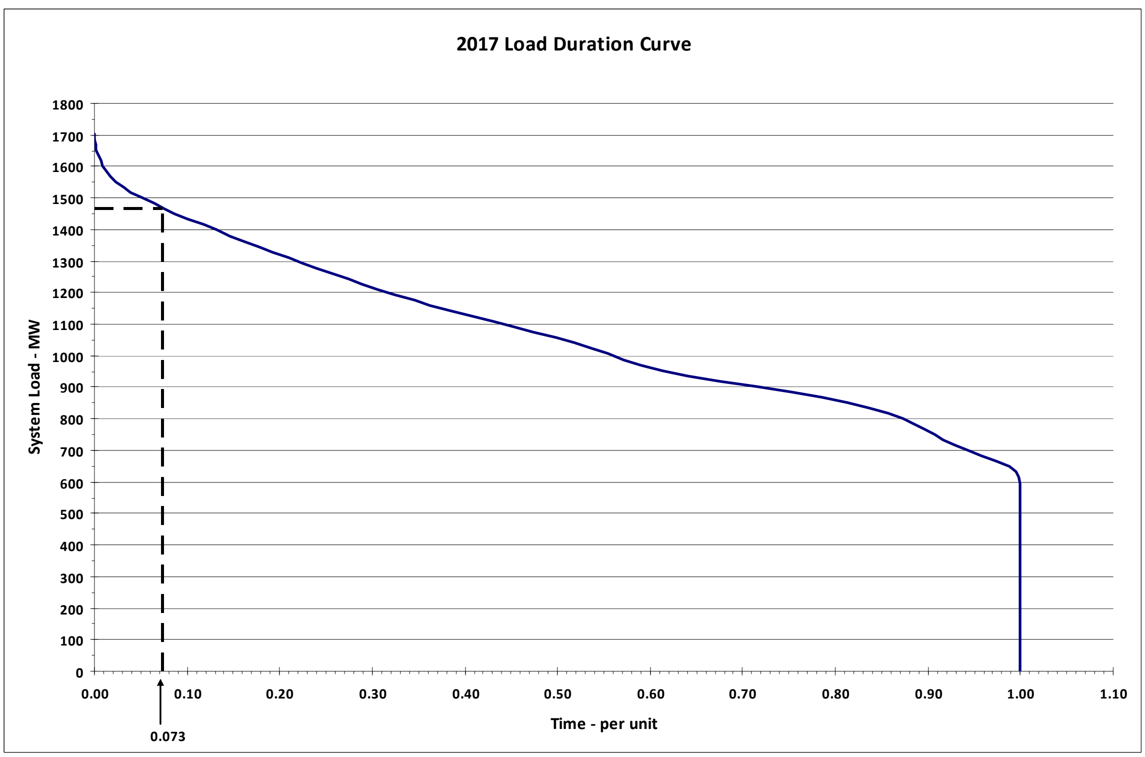

Figure 2 – 2017 Load Duration Curve

In comparison, for the existing Island Isolated System the design loads for TL202 and TL206 between Bay d'Espoir and Sunnyside are between 1:10 and 1:25 year return periods. It is difficult to determine the exact return period due to the lack of meteorological data along the line corridor, loading data on the transmission lines, and actual line failures to TL202 and TL206. Based upon the analysis completed for the Avalon Upgrades and the lack of a structural failure on either TL202 or TL206, it is assumed that the design for each line is on the order of 1:25 years. That being said, the probability of the design load condition occurring on the TL202/206 corridor is 4% per year. The probability of a common mode weather based failure of both TL202 and TL206 failing in a given year is therefore approximately 4%. Assuming the simultaneous failure of both TL202 and TL206, the generation capacity east of Sunnyside is the only capacity available to supply the Avalon and Burin Peninsulas in the Isolated Island Scenario. The load east of Bay d'Espoir is approximately 67% of the total peak load. In 2012 the load to be supplied east of Bay d'Espoir equals 1052 MW. The generating capacity east of Bay d'Espoir is summarized in Table 4. For an available generating capacity of 635.1 MW east of Bay d'Espoir in 2012, one finds that the 2012 load east of Bay d'Espoir will exceed the generating capacity for 49.29% of the year. In other words, there is an exposure of a total of 4318 hours should both TL202 and TL206 fail in 2012. Considering the 1:25 year design for TL202 and TL206, the probability of unsupplied energy in 2012 for the Isolated Island Scenario is 0.4929 * 0.04 = 0.01972 or 1.97%. The resultant energy availability in 2012 is 98.0%.

Table 4
Isolated Island Interconnected System Generation
Generation Capacity East of Bay d'Espoir
TL202 and TL206 Outage

Owner	Type	Capacity – MW
NLH	hydroelectric	8.0
	Thermal[1]	465.5
	stand by diesel	0.0
	combustion turbine[2]	50.0
Newfoundland Power	hydroelectric	75.1
	stand by diesel	0.0
	combustion turbine	36.5
Corner Brook Pulp & Paper	hydroelectric	0.0
Non-Utility Generators	mixed less wind	0.0
Total Island Generation Supply		635.1[3]

Notes:
1: Isolated Island Alternative includes a new 170 MW CCCT in 2022 bringing 465.5 MW Thermal to 635.5 MW
2: Hardwoods 50 MW CT to retire in 2022
3: For BDE – WAV 230 kV transmission line transfer capability add 328 MW

In essence the 2017 loss of the Labrador – Island Link in the Interconnected Scenario provides a higher level of energy availability than the simultaneous loss of TL202 and TL206 in the Isolated Scenario today. Given both situations involve steel transmission line structures, one would argue that the repair time in each situation would be very similar. That being said, calculations have shown that for a worst case two week repair period, the unsupplied energy for loss of TL202 and TL206 is 5.6 times greater than the unsupplied energy for the loss of the Labrador – Island Link during the same two weeks.

In 2017 the load to be supplied east of Bay d'Espoir equals 1142 MW. The generating capacity east of Bay d'Espoir increases to 965.2 MW given the additional transfer capacity provided by the new 230 kV transmission line between Bay d'Espoir and Western Avalon. For an available generating capacity of 965.2 MW east of Bay d'Espoir, one finds that the 2017 load east of Bay d'Espoir will exceed the generating capacity for 9.87% of the year. In other words, there is an exposure of a total of 865 hours should both TL202 and TL206 fail in 2017. Considering the 1:25 year design for TL202 and TL206, the probability of unsupplied energy in 2017 for the Isolated Island Scenario is 0.0987 * 0.04 = 0.00394 or 0.39%. The resultant availability equals 99.6%[9].

Table 5 summarizes the exposure levels and unsupplied energy for the Isolated Island, Interconnected and Interconnected with Maritime Link Scenario. A review of the results indicate that for the Island Interconnected Scenario the level of exposure for the period 2017 to 2037 does not exceed the level of exposure faced by the Isolated Island Scenario in 2012 for the simultaneous loss of TL202 and TL206. Analysis of the Isolated Island results demonstrate the improvements that will be realized with the net increase in capacity with the retirement of the 50 MW Hardwoods CT in 2022 and construction of a 170 MW CCCT on the Avalon Peninsula in that same year. The Isolated Island Scenario additions of 50 MW CTs in 2024 and 2027 also demonstrate substantial reductions in the level of exposure over the study period.

By comparison, in the Island Interconnected Scenario there are no capacity additions to augment the retirement of the Hardwoods and Stephenville 50 MW CTs in 2022 and 2024 respectively until the 23 MW Portland Creek facility is added in 2036 and a 170 MW CCCT is added in 2037 to meet the generation planning criteria in *Strategist®*. The impact on the level of exposure is a continual increase in annual hours of exposure, a corresponding reduction in the availability values and increases in unsupplied energy for a two week maintenance window until 2037. It must be noted that the annual hours of exposure do not, at any time, exceed that in the Island Isolated Scenario today. In turn the availability values for the Island Interconnected Scenario are greater than the availability value today for loss of TL202 and TL206.

[9] Assumes 230 kV transmission line constructed between Bay d'Espoir and Western Avalon built to a 1:50 year design load.

Finally, if one considers the addition of the Maritime Link import capabilities during a Labrador – Island Link bipole outage, substantial improvements can be expected in the level of exposure for the period 2017 to 2027.

Table 5
Level of Exposure and Unsupplied Energy

Year	Load Forecast		Island Standby Generation	Level of Exposure Load Exceeds Generation		Availability %	Unsupplied Energy Worst 2 wk Window	
	MW	GWh	MW	Annual Hours	Annual %		MWh	% of Annual
Isolated Island – TL202/206 Outage								
2012	1571	7850	635.1	4318	49.29	98.02	79,969	1.02
2017	1704	8666	965.2[1]	865	9.87	99.605	13,435	0.16
2021	1757	8967	965.2	1206	13.67	99.449	19,838	0.22
2022	1776	9065	1085.2[2]	200	2.28	99.909	2,622	0.029
2027	1856	9464	1185.2[3]	50	0.57	99.977	553	0.006
2032	1934	9860	1235.2[4]	0	0	100.0	0	0
2037	2006	10228	1277.7[5]	58	0.66	99.974	649	0.006
Island Interconnected – Bipole Outage								
2017	1704	8666	1468.5	637	7.27	99.854	14,384	0.16
2022	1776	9065	1418.5[6]	1431	16.34	99.673	37,019	0.40
2027	1856	9464	1368.5[7]	2279	26.02	99.480	66,883	0.70
2032	1934	9860	1368.5	2691	30.72	99.386	85,888	0.87
2036	1992	10157	1391.5[8]	2831	32.32	99.354	93,744	0.92
2037	2006	10228	1561.5[9]	1683	19.21	99.616	50,900	0.498
Island Interconnected – Bipole Outage – Maritime Link In Service								
2017	1704	8666	1768.5	0	0	100.0	0	0
2022	1776	9065	1718.5[6]	19	0.22	99.996	389	0.004
2027	1856	9464	1668.5[7]	281	3.20	99.936	6,019	0.064
2032	1934	9860	1668.5	626	7.14	99.986	15,765	0.160
2037	2006	10228	1861.5[8,9]	118	1.34	99.973	2,342	0.022

Notes
1: 230 kV transmission line Bay d’Espoir to Western Avalon is built prior to 2017 increasing transfer to east coast for loss of TL202 and TL206.
2: 170 MW CCCT in 2022 at Holyrood and Hardwoods 50 MW CT retired in 2022
3: 50 MW CT in 2024 and 50 MW CT in 2027 both assumed on Avalon Peninsula
4: 50 MW CT in 2030
5: Holyrood units replaced with 170 MW CCCT (1&2 in 2033 + 3 in 2036)
6: Hardwoods 50 MW CT retired in 2022
7: Stephenville 50 MW CT retired in 2024
8: 23 MW Portland Creek in 2036
9: 170 MW CCCT in 2037

In selecting the appropriate level of exposure to unsupplied load following a forced outage of the bipole one must consider the probability of the event. The LOLH calculations in *Strategist®* provide a statistical assessment of the risk of not being able to supply the firm load of the system. It considers the forced outage rate of the bipole in conjunction with the forced outage rates of all other generating units to derive the LOLH expectation target. Based upon the *Strategist®* analysis, the LOLH target is not exceeded until 2036 requiring additional capacity in 2036-2037.

To eliminate the hours of exposure to zero for a permanent outage of the bipole, one would have to carry sufficient stand by generation on the Island Interconnected System to cover the loss of the bipole. In the long term this would translate to 807.9 MW of stand by generation. Installation of in excess of 16 x 50 MW combustion turbines to coincide with the Labrador – Island Link 2017 in service date would be costly. The results in Table 6 indicate that a more gradual addition of combustion turbines may be desirable to reduce the exposure to unsupplied load in the event of a permanent bipole outage. For example, the addition of 4 x 50 MW combustion turbines in 2017 reduces the level of exposure to 9 hours or 0.1% of the year. The total unsupplied energy during the two week repair outage would be 19 MWh or 0.002% of the annual load. With 4 x 50 MW combustion turbines in stand by the level of exposure in 2022 is 193 hours or 2.20% of the year and the unsupplied energy during the two week repair window equals 3,904 MWh or 0.043% of the annual load. Adding a fifth combustion turbine in 2022 to replace the retired Hardwoods 50 MW CT reduces the level of exposure to 83 hours or 0.94% of the year and the unsupplied energy to 1,278 MWh or 0.014% of the annual load during a two week repair outage. As one can see, the level of exposure can be managed to a preset level by incremental additions of 50 MW combustion turbines over time rather than applying a wholesale 800 MW combustion turbine plant in stand by on day one. Similarly, the incremental additions provide for a more attractive cumulative present worth cost alternative over the single 800 MW up front stand by plant.

By comparison, Table 7 provides the impact of combustion turbine additions on hours of exposure to permanent loss of the bipole with the Maritime Link included. The results indicate a significant reduction in the number of combustion turbines to provide the same level of exposure when the Maritime Link in included.

Table 6
Level of Exposure and Unsupplied Energy
No Maritime Link
50 MW Combustion Turbines Added

Year	Load Forecast		Island Standby Generation MW	Level of Exposure Load Exceeds Generation		Availability %	Unsupplied Energy Worst 2 wk Window	
	MW	GWh		Annual Hours	Annual %		MWh	% of Annual
2017	1704	8666	1468.5	637	7.27	99.854	14,384	0.166
			1518.5[1]	331	3.78	99.924	7,003	0.080
			1568.5[2]	151	1.72	99.966	2,742	0.032
			1618.5[3]	59	0.67	99.986	497	0.006
			1668.5[4]	9	0.10	99.998	19	0.002
			1718.5[5]	0	0	100.0	0	0
2022	1776	9065	1418.5[6]	1431	16.34	99.673	37,019	0.408
			1468.5[1]	1065	12.16	99.756	26,420	0.291
			1518.5[2]	700	7.99	99.840	16,967	0.187
			1568.5[3]	413	4.71	99.906	8,985	0.099
			1618.5[4]	193	2.20	99.956	3,904	0.043
			1668.5[5]	83	0.94	99.981	1,278	0.014
			1718.5[7]	19	0.22	99.996	389	0.004
			1768.5[8]	2	0.02	99.999	14	0.0002
2027	1856	9464	1368.5[6,9]	2279	26.02	99.480	66,883	0.706
			1418.5[1]	1900	21.68	99.566	53,821	0.568
			1468.5[2]	1533	17.50	99.650	41,809	0.442
			1518.5[3]	1170	13.36	99.732	30,930	0.326
			1568.5[4]	806	9.20	99.816	21,027	0.222
			1618.5[5]	543	6.20	99.876	12,405	0.131
			1668.5[7]	281	3.20	99.936	6,019	0.063
			1718.5[8]	130	1.48	99.970	2,404	0.025
			1768.5[10]	48	0.54	99.989	820	0.008
			1818.5[11]	9	0.10	99.998	187	0.002
2032	1934	9860	1368.5[6,9]	2691	30.72	99.386	85,888	0.871
			1418.5[1]	2324	26.52	99.469	71,508	0.725
			1468.5[2]	1953	22.29	99.554	58,269	0.591
			1518.5[3]	1607	18.34	99.633	46,068	0.467
			1568.5[4]	1251	14.28	99.714	34,968	0.354
			1618.5[5]	908	10.36	99.792	24,770	0.251
			1668.5[7]	626	7.14	99.857	15,765	0.160
			1718.5[8]	349	3.98	99.920	8,377	0.084
			1768.5[10]	175	2.00	99.960	3,789	0.038
			1818.5[11]	79	0.90	99.981	1,345	0.014
			1868.5[13]	23	0.26	99.994	461	0.004
			1918.5[14]	4	0.04	99.999	38	0.0004
2037	2006	10228	1561.5[6,9,10]	1683	19.21	99.616	50,900	0.498
			1611.5[1]	1356	15.48	99.690	39,510	0.386
			1661.5[2]	1038	11.84	99.763	29,040	0.284
			1711.5[3]	709	8.09	99.838	19,622	0.191
			1761.5[4]	462	5.27	99.894	11,416	0.112
			1811.5[5]	236	2.69	99.946	5,688	0.056
			1861.5[7]	118	1.34	99.973	2,342	0.022
			1911.5[8]	48	0.54	99.989	875	0.008
			1961.5[10]	10	0.11	99.998	233	0.002
			2011.5[11]	0	0.00	100.0	0	0.00

Notes
1: 1 x 50 MW CT added
2: 2 x 50 MW CT added
3: 3 x 50 MW CT added
4: 4 x 50 MW CT added
5: 5 x 50 MW CT added
6: Hardwoods 50 MW CT retired in 2022

7: 6 x 50 MW CT added
8: 7 x 50 MW CT added
9: Stephenville 50 MW CT retired in 2024
10: 8 x 50 MW CT added
11: 9 x 50 MW CT added
12: Portland Creek at 23 MW and new CCCT at 170 MW Added
13: 10 x 50 MW CT added
14: 11 x 50 MW CT added

Table 7
Level of Exposure and Unsupplied Energy
With Maritime Link
50 MW Combustion Turbines Added

Year	Load Forecast		Island Standby Generation MW	Level of Exposure Load Exceeds Generation		Availability %	Unsupplied Energy Worst 2 wk Window	
	MW	GWh		Annual Hours	Annual %		MWh	% of Annual
2017	1704	8666	1768.5	0	0.00	100.00	0	0.000
2022	1776	9065	1718.5[1]	19	0.22	99.996	389	0.004
			1768.5[2]	2	0.02	99.999	14	0.0002
2027	1856	9464	1668.5[1,3]	281	3.20	99.936	6,019	0.064
			1718.5[2]	130	1.48	99.970	2,404	0.025
			1768.5[4]	48	0.54	99.989	820	0.008
			1818.5[5]	9	0.10	99.998	187	0.002
			1868.5[6]	0	0.00	100.00	0	0.000
2032	1934	9860	1668.5[1,3]	626	7.14	99.986	15,765	0.160
			1718.5[2]	349	3.98	99.920	8,377	0.084
			1768.5[4]	175	2.00	99.960	3,789	0.038
			1818.5[5]	79	0.90	99.982	1,465	0.014
			1868.5[6]	23	0.26	99.994	461	0.004
			1918.5[7]	4	0.04	99.999	38	0.0004
2037	2006	10228	1861.5[1,3,8]	118	1.34	99.973	2,342	0.022
			1911.5[2]	48	0.54	99.989	875	0.008
			1961.5[4]	10	0.11	99.998	233	0.002
			2011.5[5]	0	0.00	100.00	0	0.000

Notes
1: Hardwoods 50 MW CT retired in 2022
2: 1 x 50 MW CT added
3: Stephenville 50 MW CT retired in 2024
4: 2 x 50 MW CT added
5: 3 x 50 MW CT added
6: 4 x 50 MW CT added
7: 5 x 50 MW CT added
8: Portland Creek at 23 MW and new CCCT at 170 MW Added

To this point the worst case two week outage window has been considered. That is to say, the unsupplied energy has been determined using the peak load period to determine the maximum number of exposed hours during the two week repair window. Historically, outages on the Avalon Peninsula have occurred in the off peak, or shoulder, periods when there is freezing rain resulting in the accumulation of glaze ice at the higher transmission line elevations.

A review of the Avalon Peninsula storms reveals the following information:

- 1970 – February storm resulting in damage to 111 structures on 138 kV and 230 kV transmission lines and 120 miles of conductor
- 1984 – occurred early to mid April lasting several days
- 1988 – April 14th TL217 returned to service in 18 days (parallel line did not fail)
- 1990 – April 25th TL217 one day outage
- 1994 – Dec 8th TL201 returned in 14 days
  Dec 9th TL217 returned in 1.25 days
  Dec 10th TL217 returned in 15 hrs

The data indicates that a 14 day, or two week repair time is a valid assumption for analysis purposes. It also permits one to refine the level of exposure and unsupplied energy calculations. While the peak load analysis provides the "worst" case view, a refined analysis provides a more realistic expectation based upon observed icing events in one of the most heavily loaded sections of the HVdc route. For the refined icing event analysis the following periods are extracted for the annual load shape for evaluation:

- Based upon the load shape presented in Figure 1, a "mild" occurs in mid to late February[10]. To account for the potential of a repeat of the 1970 storm the week of Feb 19th to Feb 27th (a total of 168 hrs) has been selected:
- Given the spread of storms in April (1984, 1988 and 1990) the entire month of April is selected (i.e 30 days or 720 hrs); and
- Based upon the 1994 storm the first two weeks of December (Dec 1st to 15th, 14 days or 336 hrs) have been selected for the evaluation, bringing the total exposure hours to 1224.

Tables 8 and 9 provide the level of exposure and unsupplied energy calculations for known Avalon Peninsula icing events without and with the Maritime Link. The analysis indicates a significant reduction in the number of hours of exposure per year and a corresponding increase in availability when only the icing load conditions, and not the winter peak load conditions, are considered.

[10] Mild period evidenced by a noticeable drop in the hourly peak loads for the week in February.

Table 8
Level of Exposure and Unsupplied Energy
Known Avalon Peninsula Icing Events
No Maritime Link
50 MW Combustion Turbines Added

Year	Load Forecast		Island Standby Generation	Level of Exposure Load Exceeds Generation		Availability %	Unsupplied Energy Worst 2 wk Window	
	MW	GWh	MW	Annual Hours	Annual %		MWh	% of Annual
2017	1704	8666	1468.5	84	0.96	99.980	2,136	0.024
			1518.5[1]	34	0.38	99.992	624	0.007
			1568.5[2]	9	0.10	99.998	130	0.002
			1618.5[3]	1	0.01	99.9998	11	0.0001
2022	1776	9065	1418.5[4]	269	3.07	99.938	9,449	0.104
			1468.5[1]	173	1.97	99.960	5,424	0.060
			1518.5[2]	97	1.10	99.978	2,702	0.030
			1568.5[3]	54	0.62	99.988	943	0.010
			1618.5[5]	17	0.19	99.996	232	0.002
			1668.5[6]	2	0.02	99.9995	40	0.0004
2027	1856	9464	1368.5[4,7]	503	5.74	99.885	25,620	0.270
			1418.5[1]	390	4.45	99.910	17,275	0.182
			1468.5[2]	229	2.61	99.948	11,224	0.118
			1518.5[3]	191	2.18	99.956	6,813	0.072
			1568.5[5]	113	1.28	99.974	3,655	0.038
			1618.5[6]	66	0.75	99.984	1,590	0.016
			1668.5[7]	30	0.34	99.993	423	0.004
			1718.5[8]	7	0.08	99.998	100	0.001
			1768.5[9]	1	0.01	99.9998	6	0.0006
2032	1934	9860	1368.5[4,7]	649	7.40	99.852	37,674	0.382
			1418.5[1]	519	5.92	99.881	27,880	0.282
			1468.5[2]	401	4.58	99.908	19,291	0.196
			1518.5[3]	318	3.63	99.927	12,830	0.130
			1568.5[5]	210	2.40	99.952	8,112	0.082
			1618.5[6]	140	1.60	99.968	4,615	0.046
			1668.5[7]	84	0.96	99.980	2,286	0.023
			1718.5[8]	35	0.40	99.992	771	0.008
			1768.5[9]	14	0.16	99.996	206	0.002
			1818.5[10]	2	0.02	99.9995	40	0.0004
2037	2006	10228	1561.5[4,7,11]	337	3.84	99.923	14,710	0.144
			1611.5[1]	242	2.76	99.944	9,650	0.094
			1661.5[2]	167	1.90	99.962	5,844	0.057
			1711.5[3]	98	1.12	99.978	3,155	0.030
			1761.5[5]	57	0.65	99.986	1,306	0.012
			1811.5[6]	20	0.22	99.995	374	0.004
			1861.5[7]	4	0.04	99.999	90	0.0008

Notes
1: 1 x 50 MW CT added
2: 2 x 50 MW CT added
3: 3 x 50 MW CT added
4: Hardwoods 50 MW CT retired in 2022
5: 4 x 50 MW CT added
6: 5 x 50 MW CT added
7: Stephenville 50 MW Ct retired in 2024
7: 6 x 50 MW CT added
8: 7 x 50 MW CT added
9: 8 x 50 MW CT added
10: 9 x 50 MW CT added
11: Portland Creek at 23 MW and new CCCT at 170 MW Added

Table 9 Level of Exposure and Unsupplied Energy Known Avalon Peninsula Icing Events With Maritime Link 50 MW Combustion Turbines Added								
Year	Load Forecast		Island Standby Generation MW	Level of Exposure Load Exceeds Generation		Availability %	Unsupplied Energy Worst 2 wk Window	
	MW	GWh		Annual Hours	Annual %		MWh	% of Annual
2017	1704	8666	1768.5	0	0.00	100.00	0	0.000
2022	1776	9065	1718.5[1]	0	0.00	100.00	0	0.000
2027	1856	9464	1668.5[1,2]	30	0.34	99.993	422	0.004
			1718.5[3]	7	0.08	99.998	100	0.001
			1768.5[4]	1	0.01	99.999	6	0.0001
2032	1934	9860	1668.5[1,2]	84	0.96	99.980	2,286	0.023
			1718.5[3]	35	0.40	99.992	770	0.008
			1768.5[4]	14	0.16	99.996	206	0.002
			1818.5[5]	2	0.02	99.9995	40	0.0004
2037	2006	10228	1861.5[1,2,6]	4	0.04	99.999	90	0.0008
			1961.5[3]	1	0.01	99.9998	5	0.00004

Notes
1: Hardwoods 50 MW CT retired in 2022
2: Stephenville 50 MW CT retired in 2024
3: 1 x 50 MW CT added
4: 2 x 50 MW CT added
5: 3 x 50 MW CT added
2: Portland Creek at 23 MW and new CCCT at 170 MW Added

Beyond the evaluation of the level of exposure and valuation of unsupplied energy, NLH transmission planning also considers the temporary, or intermittent, loss of the bipole due to commutation failures associated with 230 kV ac system faults and pole to pole dc line faults. System integration analysis to date has indicated that in order to maintain power system stability for temporary loss of the bipole a 230 kV transmission line is required between Bay d'Espoir and Western Avalon and three high inertia synchronous condensers are required at Soldiers Pond Converter Station. These additions are included in the overall system reinforcement program associated with the integration of the Labrador – Island Link into the Island Interconnected System.

Clearly, the transmission planning for reliable integration of the Labrador – Island Link into the Island Interconnected System is within the bounds of good utility practice and falls within the requirements of the NERC reliability standards for transmission planning.

With the generation and transmission planning aspects ensuring a reliable integration of the Labrador – Island Link, one can easily highlight the improvements in operation flexibility on the system afforded by the HVdc transmission line from water management of the reservoirs on the Island and in Labrador, allocation of spinning reserve among units, better frequency regulation with access to the reserves in Labrador and maintenance scheduling for generating units on the Island.

HVdc Line Design Load

The final question with respect to the reliability of the Labrador – Island Link relates to the exposure of the approximately 1100 km of overhead transmission line and how to prevent failure. In the context of the loss, the generation and transmission planning processes provide for capacity and energy from alternate sources while the overhead HVdc line is being repaired. The question ultimately becomes “to what standard does one build the overhead HVdc line so that it doesn’t fail”?

There are two broad categories of failure – electrical and mechanical. For this discussion the electrical failure of the overhead transmission line is limited to the impact of lightning. To provide the overhead line with protection from lightning events the line will be designed with a continuous overhead ground wire along its entire length. NLH has limited experience with lightning performance of 230 kV transmission lines with continuous overhead ground wire. Historically NLH transmission lines have been designed with an overhead ground wire on the first 1.6 km from each station to provide lightning protection for the station. NLH transmission line TL233 is an H-frame wood pole transmission line between Buchans and Bottom Brook on the western portion of the Island Interconnected System and is the only 230 kV transmission line with overhead ground wire along its entire length. Lightning performance for this transmission line for the period 2006 to 2010 indicates a total of 11 recorded lightning strikes with 7 successful recloses and 4 unsuccessful recloses (sustained outages). The only other NLH 230 kV transmission line on the Island Interconnected System with lightning protection along its entire length is located in the eastern portion of the system. TL206 between Bay d’Espoir and Sunnyside was fitted with lightning arresters on each phase at each structure after very poor lightning performance lead to simultaneous outages to a parallel circuit (TL202) and subsequent outage to the Avalon and Burin Peninsulas. For the period 2006 – 2010 there have been no sustained outages to TL206. By comparison, over the same period TL202 has had a forced outage frequency of 0.4 per terminal per year or 4 forced outages. Based upon the available data it is expected that overhead ground wire on the entire length of the HVdc transmission line will provide acceptable protection to the line from direct lightning strikes, thereby limiting the number of transient pole outages to those listed in the CIGRE statistics.

The second broad category of failures of the overhead transmission line, mechanical failure, is founded in the meteorological loadings used in original transmission line design. The utility industry has migrated from a deterministic-based transmission line design to the reliability-based design methodology/criteria. That being said CAN/CSA C22.3 No.60826.06 requires a minimum weather load based on a 1:50 year return period. It is suggested that for voltages above 230 kV, or where the line constitutes the

principal or only source of supply the reliability level should be set based on a 1:150 year return period for weather loads. The standard goes on to suggest that if loss of the line in question has serious consequences to the supply then the reliability level should be set based upon a 1:500 year return period of weather loads.
Clearly, using a reliability–based design approach for the Labrador – Island Link, a 1:50 year return period for weather load is the starting point. In the context of the NLH experience on the Avalon Peninsula, the HVdc line crossing the Avalon Peninsula would be designed for a radial ice thickness of 75 mm (3 inches) in this region and not the 60 mm (2.4 inches) determined from Figure CA.2.

The question becomes "is a 1:50 year return period sufficient"?

Given that Phase I of the Lower Churchill Project includes a second HVdc transmission line, the Maritime Link, which is geographically diverse from the Labrador – Island Link and provides a connection to an alternate supply of power in the event of failure of the Labrador – Island Link, loss of the Labrador – Island Link does not imply the serious consequences as suggested in the design standard for use of the 1:500 year return period. Further, given that the project includes the availability of generating capacity from alternate, geographically diverse sites implies that the suggested 1:150 year return period is questionable.

One must keep in mind that the existing 230 kV transmission lines on the eastern portion of the Island Interconnected System have equivalent reliability-based designs ranging from the 1:10 year return period for the wood pole lines, to the 1:25 year return period for rebuilt steel lines and a 1:50 year return period for the proposed Bay d'Espoir to Western Avalon steel transmission line. For the HVdc converter at Soldiers Pond to function properly, the 230 kV transmission system must be reasonably intact[11] to provide the necessary equivalent short circuit ratio (ESCR – a measure of ac system strength). Building the HVdc line to a very high reliability level (i.e. 1:500 year return period) while the connected ac transmission system has a lower reliability level (i.e. 1:25 year return period) is problematic as a 1:50 year weather loading will result in failures to the ac transmission system while the HVdc line is unaffected. The end result is that the HVdc line is intact but the converter station cannot function as there is insufficient ac system transmission strength and capacity to operate the station or transmit power to load centers.

With the typical service or economic life of a transmission line consisting of steel structures being 50 years, application of a 1:50 year return period load in design means, at a high level, that on average one can expect the design load to occur once during the 50 year service.

[11] Transmission planning for stable operation of the HVdc converter station at Soldiers Pond is possible with at least one 230 kV transmission line out.

The analysis of level of exposure and unsupplied energy indicates that an HVdc transmission line with a 1:50 year return period design has availability levels in excess of the existing Isolated Island System when simultaneous loss of TL202 and TL206 are considered. As well, the Hvdc transmission line scenario provides for lower levels of unsupplied energy given a two week repair window during peak load conditions. Analysis has indicated that moderate combustion turbine additions over time with load growth can be effective in maintaining a set level of availability while minimizing unsupplied energy during a two week repair window. The application of the import capability provided by the Maritime Link has been demonstrated to significantly reduce the need for stand by combustion turbine additions in the near term, and reduce the total number of combustion turbines required in the longer term when compared to the addition of the Labrador – Island HVdc Link alone. Considering the history of 230 kV transmission line failures on the Avalon Peninsula, reducing the risk of HVdc line failure to the shoulder periods demonstrates further improvements in system availability with corresponding reductions in hours of exposure, levels of unsupplied energy during a two week repair period and reduced requirements for additional stand by combustion turbine. For the known icing periods, a two week repair window and assuming that the Maritime Link is in service, analysis indicates the need for a new 50 MW combustion turbine in the 2032 time frame in order to maintain a very high level of system availability based upon a 1:50 year return period design for the Labrador – Island HVdc Link.

Given the nature of the project in the overall context of system reliability it becomes difficult to justify an increase in the return period of the weather load beyond 1:50 years for design of the Labrador – Island Link.

Should the Maritime Link not materialize then the significance of the sudden loss of the Labrador - Island Link becomes more severe. At this point one must weigh the cost of increasing the quantity of installed standby combustion turbine generation on the Island Interconnected System against increasing the return period of the weather loads to 1:150 or 1:500 years and the probability of failure at these higher reliability levels. The exercise is quite complex and requires the utility to have a sound understanding of the value of an outage to each of its customer classes.

While it may appear desirable to increase the return period for the Labrador-Island Link, the entire 230 kV grid east of Bay d'Espoir would need to be upgraded to a similar return period in order to achieve the desired reliability improvement.

SUMMARY

To date the generation planning process incorporates the forced outage rate and associated impacts of the HVdc transmission line between Labrador and the Island portion of the Province along with appropriate capacity and energy source additions to meet the generation planning criteria – both LOLH and energy balance.

Transmission planning for reliable integration of the Labrador – Island Link into the Island Interconnected System is within the bounds of good utility practice and falls within the requirements of the NERC reliability standards for transmission planning.

In both the Isolated Island and Interconnected scenarios there are low probability events that could, if they occur, result in small amounts of unserviced load. In the event of an outage, an HVdc transmission system designed using a 1:50 year return period meteorological loading and a reasonable mean restoration time of 14 days on average results in a maximum unserved energy which is less than 1% of the total annual load. Based upon historical failures during icing events on the Avalon Peninsula, it is more probable that the maximum unserved energy will be less than 0.4% of the total annual load with a mean restoration time of 14 days.

While the impact of these outage events could be further mitigated with the application of additional combustion turbines on the Island Interconnected System, given the low probability of the event and minimal impact on unsupplied energy, Nalcor, in the interest of minimizing overall cost to the customer, has opted to apply load rotation and other means to minimize the impact to customers should an event occur.

REFERENCES

1. CSA Standard C22.3 No. 1-06 Overhead systems – published October 2006 by Canadian Standards Association
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3. CIGRE B4_2009_2010 "A Survey of the Reliability of HVdc Systems Throughout the World During 2007 – 2008", by M.G. Bennett, N.S. Dhaliwal, A. Leirbukt, CIGRE 2010
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5. "Generation Planning Issues 2010 July Update", System Planning Department, Newfoundland and Labrador Hydro, July 2010 – Filed as Exhibit 16
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