

NSPML Application to Review the Holdback Mechanism
(NSEB M12696)
NSPML Responses to NSEB Information Requests

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Request IR-01:

On page 6 of the application, NSPML requests an end to the holdback mechanism and that holdback amounts retained after May 1, 2024, be distributed with updated WACC to the date of the Board's decision.

- (a) Is NSPML able to provide information on how these balances have been treated for accounting purposes by NS Power? i.e., If the amounts have been expensed in the FAM, and therefore accrued NS Power's WACC payable by customers, is it possible customers will be paying WACC on the balance twice?**
- (b) If NSPML considered that the holdback release conditions were satisfied by the end of April 2024, please explain why it waited 21 months, until February 3, 2026, to file its application requesting release of the holdback funds.**
- (c) Since it was NSPML's choice to delay its request to release holdback funds, please explain why ratepayers should be responsible for paying accrued WACC for that 21-month period.**
- (d) Please explain why NSPML believes it is appropriate to use NS Power's WACC rates for its calculations.**

Response IR-01:

- a) What is being proposed in terms of WACC would not result in customers paying WACC on the balance twice. NSPML has confirmed with NS Power that, although the full amount of NSPML's monthly assessments have been expensed in the FAM account, the corresponding WACC related to holdback funds has been removed from the FAM balance.
- b) As explained during NSPML's 2026 Assessment Hearing, the primary reason for the timing of the filing is that NSPML has a relatively small contingent of employees to balance competing operational and regulatory obligations. Although NSPML believes it is appropriately resourced to deliver on its obligations, staffing levels occasionally present challenges, such as in this case.

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1
2 Additional factors included the desire to have more complete information from the
3 Compliance Period. As 100 percent of the holdback disallowances relate to NLH's
4 performance and energy delivery information primarily sits with NS Power, a significant
5 amount of information for the Application needed to be sourced from third parties.
6 Specifically, NS Power for delivery information and NLH for information relating to all
7 outages and their asset performance.

- 8
9 c) WACC is a standard financing mechanism that compensates for the cost of capital. WACC
10 is paid to customers when money is owed to them and WACC is paid to the utility when
11 customers owe money. Should the Board agree with NSPML's request in this Application,
12 the \$15.3 million should have been paid to NSPML in 2024 and 2025.

13
14 In the Decision in M11009 released on January 31, 2024, in paragraphs 38 and 39, the
15 Board outlined the approach it takes with respect to WACC:

16
17 [38] NSPML's Compliance Filing calculations of the released holdback funds
18 included WACC on balances owing. The Industrial Group opposed this aspect
19 of the calculations because the payment of WACC was not explicit in the
20 Board's prior holdback decisions.

21
22 [39] Where funds are owed but not yet paid, either between utilities, or between
23 a utility and its customers, there are financing costs for the party awaiting the
24 funds. Historically, the Board has allowed for recovery of financing costs in a
25 reciprocal manner. When funds are owed to customers, they are repaid inclusive
26 of WACC. Consistent with the calculations in the Compliance Filing, the Board
27 will allow the released holdback funds to be paid to NSPML with WACC to
28 recognize the reciprocal nature of WACC on funds owing or receivable by NS
29 Power and its customers. The Board notes NSPML's statement that with funds
30 being released prospectively on a monthly basis, the necessity for WACC is
31 removed. The Board agrees with this treatment.

32
33 NSPML agrees with this approach to applying WACC.

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1 In allocating and prioritizing resources, NSPML was attempting to balance obligations in
2 a manner that provided the most benefit to Nova Scotians – with an emphasis on a reliably
3 operating the Maritime Link. NSPML does not believe that the timing of the holdback
4 filing prejudiced the regulatory process and it is reasonable (and consistent with past
5 practice) for the weighted average cost of capital to be returned if the applicable holdback
6 funds are returned.

7
8 The holdback funds (by design) were withheld from NSPML's assessment payments and
9 no WACC was attributed to customers during this period. If the funds are determined to be
10 owed to NSPML, then the impact of WACC on customers is the same as if the funds were
11 provided to NSPML in the first place.

- 12
13 d) The amounts in question are managed through NS Power's FAM account where customers
14 have benefitted (or saved) at NS Power's WACC. By utilizing NS Power's WACC, it
15 provides a balancing of the benefits received if the funds are determined to be refundable.

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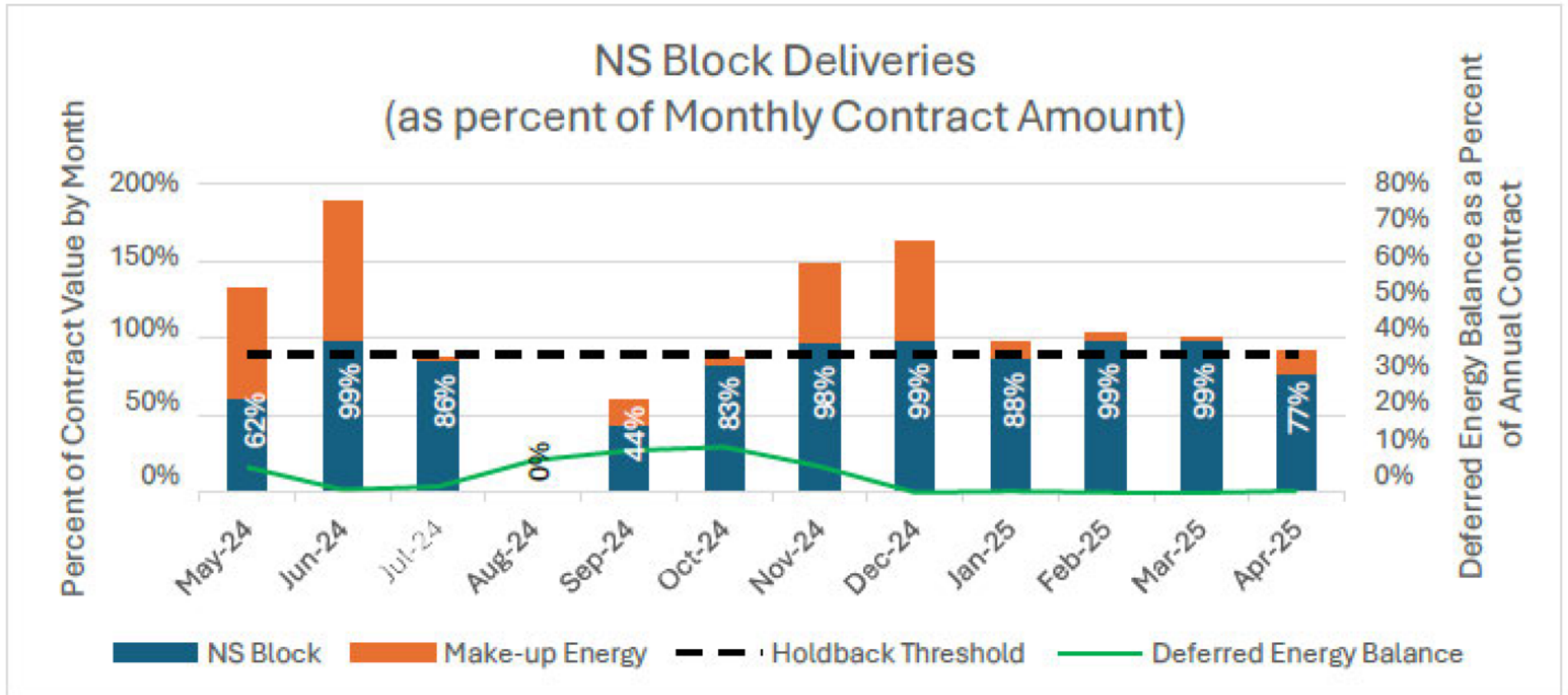
Request IR-02:

Referencing the chart on page 10 of the application - NS Block Deliveries (as percent of Monthly Contract Amount), please reproduce the chart for the following year, i.e., May 2024 – April 2025.

Response IR-02:

Please refer to Attachment 1.

For reference, due to prior period Deferred Energy amounts, total NS Block deliveries in May 2023 through April 2024 were 400,000 MWh greater than NS Block delivery amounts in May 2024 through April 2025, with both periods exceeding 100 percent of NS Block contractual requirements. Please also refer to Appendix C of the Application.



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Request IR-03:

Please confirm, or explain otherwise, that there is no make-up energy outstanding as of February 3, 2026.

Response IR-03:

As of February 3, 2026, there was a 49 MWh credit balance for Base Block energy and a 211 MWh debit balance for Supplemental Energy, resulting in an overall debit balance of 171 MWh or less than one hour of Supplement Energy.

Since commissioning of the LIL was completed in April 2023, energy deliveries have been stable, consistent and reliable. Large volumes of Deferred Energy have not accumulated as happened before the LIL was commissioned. Throughout any year there will be planned and unplanned outages, shaping of deliveries, and electrical losses of energy deliveries that will result in Deferred or Credit Energy. Losses are trued-up monthly per the process defined in the Energy and Capacity Agreement. However, Make-up Energy is delivered on a timely basis. As a result, there will often be a small balance of Deferred Energy – sometime positive and sometimes negative.

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Request IR-04:

On page 14, the application references Deferred Energy was redelivered. Please define deferred energy and explain how it is different from make-up and supplemental energy.

Response IR-04:

Deferred Energy is defined on page 3 of the Application in footnote 2, as follows:

“Undelivered Energy” or “Deferred Energy” means any part of the Base NS Block or Supplemental Energy not delivered when initially required pursuant to the Energy & Capacity Agreement, which amount of energy is added to the balance of Undelivered Energy.

In footnote 2, Make-up Energy is also defined, as follows:

“Make-up Energy” means Undelivered Energy when delivered, which amount of energy is subtracted from the balance of Undelivered Energy.

Deferred Energy is the energy that was not delivered as originally intended whereas Make-up Energy is the energy that was subsequently delivered at a later date to make up for the Deferred Energy. Customers have received all the Deferred Energy they were owed as outlined in the Energy & Capacity Agreement.

Supplemental Energy was also defined in footnote 2, along with NS Block and Base NS Block, as follows (emphasis added):

The NS Block means both the Base NS Block, being 0.986 TWh of Energy delivered annually during peak hours, and Supplemental Energy, presently being 240 GWh of Energy delivered during off-peak hours every winter period (November through March and ending March 2026) for the first five years of the 35-year term of the NS Block.

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Request IR-05:

Does NSPML have a schedule for planned outages?

(a) If not, why not?

(b) If so:

i. How far in advanced are they scheduled?

ii. Are they shared with the NSIESO?

iii. Approximately how long are the planned outages?

Response IR-05:

a) Yes, NSPML has its annual planned maintenance outage for 2026 currently scheduled for mid-September. For NSPML this includes outages taken one pole at a time in order to maintain half the transfer capability of Maritime Link over the outage period. The annual outage is generally scheduled to align with the Labrador Island Link outages at times where there are low-to-no transfers taking place, other critical system assets are available and subject to logistics and coordination. For 2026, Maritime Link Pole 1 is scheduled for maintenance September 14-17, and subsequently Pole 2 is scheduled for maintenance September 17-20.

b)

- i) Annual outages are tentatively planned approximately a year in advance, and the schedule is firmed up roughly 6 months in advance of the annual outage. Other planned outages may be required and can be requested within a few days notice but typically have 30 or more days notice. Parties strive to provide as much notice as possible; however, this is subject to the critically of the outage being requested.
- ii) All outages are submitted and approved by the NSP outage plan coordinator who will in turn share with the appropriate parties, including the NSIESO.

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- 1 iii) The annual planned maintenance outage for September 2026 is scheduled from
2 September 14-20 for a total of 7 days.

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Request IR-06:

Please provide the tables in Appendix A, B and C in excel format with cells intact.

Response IR-06:

Please see Attachment 1 for the data in Appendix A and C.

Please see Attachment 2 for the data in Appendix B. While Appendix B of the Application erroneously references a Weighted Average Cost of Capital (WACC) of 6.75% for the period of April 2024 – March 2025, the calculations supporting Appendix B applied the approved WACC for that period of 6.72%.¹ As a result, no numerical adjustments are required.

¹ NSPI WACC and AFUDC Rates Application 2024 (M11563), Decision.

**NSEB IR-06 Attachment 1
has been filed electronically**

**NSEB IR-06 Attachment 2
has been filed electronically**

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Request IR-07:

On page 3 of its application NSPML stated:

In its October 2023 Decision in that matter [M11009], the Board ordered that the Holdback would continue until (i) at least 90% of the NS Block (excluding Make-up Energy) is received during each of twelve consecutive months (with flexibility to account for Good Utility Practice (as defined in Concentric Evidence, Attachment 1, A24) outages and/or exceptional circumstances) and (ii) the net outstanding balance of undelivered energy is less than 10% of the NS Block annual contracted amount. [footnote omitted] [emphasis added]

However, pages 44-45 of the Board’s Decision dated October 4, 2023 stated the following:

5) The monthly holdback mechanism will continue each month until both of the following conditions are satisfied:

- a) at least 90% of the NS Block, measured in MWh (excluding Make-up Energy), is received during each of 12 consecutive months, and**
- b) the net outstanding balance of undelivered energy is less than 10% of the contracted annual amount of the NS Block.**

6) NSPML/NS Power may apply to the Board for relief if it considers that good utility practice or exceptional circumstances caused it to fail to meet the consecutive 12-month requirement. If the Board is satisfied that good utility practice or exceptional circumstances existed, it may provide relief and may attach any terms and conditions it deems appropriate at that time.

Please confirm that the conditions stated in the Board’s Decision do not include “Good Utility Practice (as defined in Concentric Evidence, Attachment 1, A24)”.

Response IR-07:

NSPML believes the definition negotiated between the parties as contained in the *Joint Operating Agreement* that was provided during the original Maritime Link Application, and that is also consistent with FERC’s definition, as well as the definition supporting the Project’s Federal Loan

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- 1 Guarantee, is a reasonable reference for the Board's consideration. However, NSPML confirms
- 2 that the Board's Decision does not reference any particular definition of "good utility practice".

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Request IR-08:

Page 10 of the Board’s Decision 2024 NSUARB 17 (M11009) dated January 31, 2024, stated:

The Board intentionally did not attempt to provide a definition or describe the scope of “good utility practice or exceptional circumstances” in its decision, as it contemplated this could be the subject of evidence or argument when NSPML eventually files its application to end the holdback.

- (a) Does NSPML disagree that determining what constitutes “good utility practice” can be subjective? If so, please explain.**
- (b) Does NSPML disagree that determining what constitutes “exceptional circumstances” can be subjective? If so, please explain.**

Response IR-08:

(a - b)

NSPML believes it would be appropriate for the Board to consider “good utility practice” and “exceptional circumstances” in a similar manner to adjudicative bodies considering the reasonable person standard. This looks at how a reasonable person (or in this case reasonable utility) would act in, or assess, the circumstances. While judgment is involved in the analysis, the test would be objective in nature.

Our understanding of the Board utilizing a subjective test would be having the Board determine whether NLH subjectively believed that they acted in accordance with good utility practice and whether they subjectively believed the extreme weather events qualified as exceptional circumstances. Although that approach would likely work to the favour of NSPML’s position in this filing, NSPML believes the use of an objective standard by the Board is likely more appropriate in determining whether NLH’s actions were in actuality

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1 consistent with good utility practice, or whether it is reasonable to categorize the particular
2 weather events as exceptional circumstances.

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Request IR-09:

In its application, NSPML expressed its view that customers are receiving the full benefits of the Maritime Link investment. It also noted the “disappointing early energy deliveries” and the “corresponding need for Nova Scotians to purchase replacement energy while also paying NSPML’s assessments”.

When NSPML says that customers are receiving the full benefits of the Maritime Link investment, does that imply that customers have recovered the additional multi-million dollar costs for purchasing replacement energy? Please elaborate.

Response IR-09:

Yes, for the relevant period of this Application (post LIL commissioning and primarily, the Compliance Period) NSPML submits that customers have received and are receiving the full benefits of the Maritime Link investment.

Please refer to BW IR-7 for additional detail supporting NSPML’s position that customers are receiving what was contracted, which pursuant to the Energy & Capacity Agreement is delivery of the energy as Make-up Energy. However, in terms of the cost of purchasing replacement energy during this period, NSPML believes that the overall financial imbalance (although not contractually required) should be minimal (possibly positive) given timely Make-up Energy deliveries and, where Make-up Energy deliveries took slightly longer, they occurred in the more valuable winter period.

The reference to “disappointing early energy deliveries” and the “corresponding need for Nova Scotians to purchase replacement energy while also paying NSPML’s assessments” relates to the period prior to the Compliance Period, before LIL commissioning and primarily prior to the

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1 Acceleration Agreement. Although NSPML believes there were negative impacts on customers
2 during the pre-LIL commissioning period, they have also been materially mitigated by FLG II,
3 ~\$30 million in holdback disallowances and delivery of 100 percent of the NS Block and delivery
4 as Make-up Energy of all previously Undelivered Energy since execution of the Acceleration
5 Agreement in August of 2021.

6
7 Support for the position that the relevant period is post LIL commissioning can be found in the
8 Board's 2023 Decision in Matter 11009 at paragraphs 50 and 53 as follows:
9

10 [50] The Board considers that a retrospective accounting of all forecasted benefits of
11 the Maritime Link compared to actual results from 2018 onward is not appropriate. As
12 noted by Mr. Reed in his Rebuttal Testimony, this would effectively amount to a re-
13 litigation of past issues already canvassed by the Board in prior NSPML proceedings
14 and would raise legitimate concerns about retroactive ratemaking.
15

16 ...
17

18 [53] Many of the issues raised by the Intervenor, including the economic value of
19 Make-up Energy and the calculation of replacement energy costs will be subject to
20 detailed reviews in FAM audits. For greater certainty, this includes the administration
21 of the contractual terms between NSPML/NS Power and Nalcor for the provision of
22 the NS Block and Make-up Energy under the Energy and Capacity Agreement (the
23 issue of Market-priced Energy is further canvassed later in this decision). The Board
24 expects NSPML/NS Power to prudently administer the terms of these contracts and
25 others to the full benefit of ratepayers.

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Request IR-10:

Reference: Exhibit N-1, p. 10:

- NSPML states that, “With the LIL’s strong performance since its commissioning in April 2023 and the continuing strong availability of the Maritime Link, customers are receiving the full benefits of the Maritime Link investment.”
- In its initial decision conditionally approving the Maritime Link, the Nova Scotia Utility and Review Board found the project was only the lowest long-term alternative for electricity ratepayers in Nova Scotia with market-priced energy factored in.

Please demonstrate the receipt of “full benefits” by comparing the Maritime Link and market-priced energy assumed in the original Maritime Link application, as set out in Figure 4-4 and Exhibit M-11 (NSUARB IR-37) in that proceeding with actual receipt of Maritime Link and market-priced energy, showing all variances from forecast on an annual basis.

Response IR-10:

NSPML assumes this question relates to performance post LIL commissioning. Please also see response to NSEB IR-9 and BW IR-7.

NS Block Energy

Figure 4-4 references Maritime Link energy, which is NS Block Energy, defined in the Application as “The NS Block means both the Base NS Block, being 0.986 TWh of Energy delivered annually during peak hours, and Supplemental Energy, presently being 240 GWh of Energy delivered during off-peak hours every winter period (November through March and ending March 2026) for the first five years of the 35-year term of the NS Block.”

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Demonstration of the receipt of the full benefits of the NS Block can be found in the data in Appendix C of the Application, which provides details on the volumes of MWh received. The table shows the original contracted amount (defined in the Application as the “Contract Amount” refers to the amount of Base Block and Supplemental Energy required to be delivered in any given period pursuant to the Energy & Capacity Agreement”) for the NS Block compared to the amount delivered. NSPML also submits that Make-up Energy delivered is necessary to consider as this is energy that was originally contracted to be delivered to customers and customers received value from that Make-up Energy in the month it was delivered because other energy purchases were offset. The graph in Appendix C shows, in percentages, that in most months the NS Block Energy delivered and the Make-up Energy delivered exceeded 100% as compared to the Contract Amount. The annual comparison of Contract Amount and NS Block and Make-up Energy, commencing in 2023, being the year that the proposed Compliance Period commenced, is as follows:

	Contract Amount (MWh)	NS Block Energy Delivered (MWh)	Make-Up Energy Delivered (MWh)	Difference (All energy delivered – Contract Amount)
2023	1,226,000	1,055,994	506,240	+336,234
2024	1,226,000	982,911	503,171	+260,082
2025	1,226,000	1,152,521	73,422	-57

The table above shows that in 2023 and 2024 customers received more energy (NS Block Energy plus Make-up Energy) than the Contract amount. This higher energy represents the Deferred Energy that was not redelivered in 2021 and 2022. By March of 2024, the amount of Deferred Energy represented only 9 percent of the annual contracted NS Block (thereby meeting the second condition set by the Board to terminate the holdback mechanism)¹ and by June 2024 all Deferred

¹ In its October 2023 Decision regarding NSPML’s application to end the holdback mechanism (M11009) the Board ordered that the Holdback continue until (1) at least 90% of the NS Block (excluding Make-up Energy) is received during each of twelve consecutive months (with flexibility to account for Good Utility Practice (as defined in Concentric Evidence, Attachment 1, A24), outages or exceptional circumstances) and (ii) the net outstanding balance of undelivered energy is less than 10% of the NS Block annual contracted amount.

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1 Energy (aside from a small amount of Supplemental Energy) since the Acceleration Agreement
2 was initiated in 2021 was redelivered as Make-up Energy. Throughout 2025, energy delivered
3 was virtually the same as the Contract Amount energy. Since LIL commissioning, Make-up
4 Energy has generally been redelivered within days or weeks of the scheduled delivery – as would
5 be expected in normal operation of the Maritime Link. The annual view in the table above is a
6 good illustration that since LIL commissioning customers are receiving the full volume of energy
7 expected over the Maritime Link.

8
9 Figure 4-4 calculated a \$/MWh for the Maritime Link energy which was described in the response
10 to IR-37 – “The Maritime Link prices were determined by taking the Revenue Requirement (as
11 shown in the Application Financial Appendix 4.01) and divided it by the annual MWh energy
12 deliveries from Nalcor.” While this calculation done today would likely generate similar results
13 to the data presented in Figure 4-4, it does not represent the actual value to customers. As the first
14 table above shows, customers are getting the full volume of energy contracted.

15
16 **Purchased Energy**

17 In the NSEB Decision on the Disposition of the holdback for 2022 and 2023 (M11009), issued on
18 October 4, 2023, the Board outlined the relationship of market-priced energy (defined as
19 “Purchased Energy” in the Application in this matter, more specifically it “means any energy
20 purchased by NS Power from NLH in addition to the NS Block, including pursuant to the Energy
21 Access Agreement”) in the context of the “original bargain” of the Maritime Link project. The
22 Board explained, starting at paragraph 87, as follows:

23
24 [87] The Board notes that the prospect of Market-priced Energy delivered by
25 Nalcor was never intended to be a guarantee that 1.2 TWh of Market-priced Energy
26 would actually be delivered annually. The provision of Market-priced Energy was
27 covered in the Energy Access Agreement, which was secured by Emera (NSPML)
28 and NS Power with Nalcor after the Board ruled in the original Maritime Link

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1 Decision,² that, without such an agreement or provision, the Maritime Link Project
2 could not be approved. Applying the test under s. 5(1)(a) of the ML Regulations,
3 the Board concluded that the Maritime Link Project (with Market-priced Energy
4 factored in) represented the lowest long-term cost alternative for electricity for
5 ratepayers in Nova Scotia once the Market-priced Energy was included.
6 Accordingly, the Board directed:

7
8 [228] ...as a condition to its approval of the ML Project that NSPML
9 obtain from Nalcor the right to access Nalcor Market-priced Energy
10 (consistent with the assumptions in the Application as noted in
11 NSUARB IR-37 and Figure 4-4) when needed to economically
12 serve NSPI and its ratepayers; or provide some other arrangement
13 to ensure access to Market-priced Energy.

14 [2013 Maritime Link Decision]
15

16 [88] The Energy Access Agreement was filed as a compliance filing in that original
17 matter to satisfy the Board's above-noted condition. Moreover, it was never
18 intended that the Market-priced Energy was "guaranteed delivery of energy" from
19 Nalcor to NS Power. It was always contemplated to operate as, in effect, a right of
20 first refusal in favour of NS Power to access Nalcor energy on an economic basis.
21 In its 2013 Supplemental ML Project decision, the Board held that the Energy
22 Access Agreement satisfied the principal condition for NS Power's access to Nalcor
23 Market-priced Energy. The Board's decisions resulted in an agreement requiring
24 Nalcor to make available to NS Power at least 1.2 TWh of non-firm energy per
25 year, **on average** (emphasis added), over the course of the agreement until 2041.

² M05419, 2013 Maritime Link Application

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1 In terms of Purchased Energy volume, the average offered by NLH in the first three years was
2 approximately [REDACTED] per year; however, the qualifying EAA quantities have been impacted by
3 various items including low hydrology and the amount of Deferred Energy balance at the start of
4 the Compliance Period. Please see BW IR-7(a) for further detail.

5
6 In terms of price, the data in Figure 4-4, referenced in the question, assumed that Purchased Energy
7 from NLH would be based on MassHub pricing. Figure 4-4 was based on price forecasts from
8 2013 – 2040. These price forecasts were used to complete a point in time analysis. The material
9 comparison to the data in Figure 4-4 is that Purchased Energy today is based on MassHub pricing,
10 as was contemplated in 2013. NS Power buys Purchased Energy from NLH primarily³ based on
11 economics, meaning the energy from NLH is the lowest priced source of energy compared to other
12 options available at the time, ensuring the best value for customers.

13
14 **Capacity**

15 Additionally, the Maritime Link provides capacity benefits and is being included in the NS System
16 Operators short-, medium- and long-term planning as a unit that provides capacity.

³ Exceptions could include purchase of emergency energy or not purchasing due to unrelated system conditions.

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Request IR-11:

Regarding the performance of the Labrador Island Link:

- a) Has testing to establish that the LIL can operate at full capacity of 900MW been completed? If so, when?
- b) Why was the testing to demonstrate that the LIL can operate at full capacity delayed?
- c) Please explain the impact of a failure to successfully achieve operation at full capacity on the ongoing delivery of Maritime Link and market-priced energy, including any update to the forecast provided in M05419, Exhibit M-11, NSUARB IR-37, as necessary.

Response IR-11:

- a) The final 900 MW test for the LIL was completed on March 26, 2026. Please also see response to (b) below.
- b) NLH files quarterly reports with the Board of Commissioners of Public Utilities on the LIL. In the latest report, “Reliability and Resource Adequacy Study Review – Labrador-Island Link Update for the Quarter Ended December 31, 2025”, NLH reported the following:

1.1 900 MW Test and Software

All software functionality required for operation up to 900 MW was proven and accepted as satisfactory during pole overload tests in winter 2023 prior to the April 2023 commissioning; however, as committed, controlled testing at the highest power levels will be performed prior to operation in this range when system conditions permit.

As previously reported, the following are prerequisite conditions for the test to occur:

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- Satisfactory system conditions are present, including both those in Newfoundland and Labrador, where a high system load can be reasonably expected to occur, and in neighbouring jurisdictions;
- Successful coordination with all relevant neighbouring system operators is attained; and
- Identification of risks and implementation of all necessary risk mitigation actions are in place.

As previously reported in Hydro's final 2025–2026 Winter Readiness Report, the high-power test of the LIL has been postponed because of Hydro's prioritization of reliable service to customers during the winter period, including supporting reservoir levels to meet peak load requirements. If system conditions permit, the high-power test will be conducted in the first quarter of 2026.¹

Up to March 2026, when the 900 MW was completed, NLH determined the three conditions for conducting the test were not met, which are largely related to system conditions and coordination. Based on the update, all components of the LIL were ready for 900 MW since pre-commissioning.

- c) Since the 900 MW test is complete, the LIL is proven to operate at full capacity having no impact on operations.

¹ [Board of Commissioners of Public Utilities](#)

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Request IR-12:

Reference: Exhibit N-1, Testimony of Danielle S. Powers, Attachment 1, p. 17 of 36:

- **Ms. Power states, “Planned outages to address necessary repairs, upgrades, and maintenance that require the asset to be taken out of service are scheduled in advance through the system operator to ensure optimal coordination and notice to the power grid.”**

- a) Please confirm, or explain in detail otherwise, that the fact that an outage is planned does not necessarily mean it was occasioned as a result of good utility practice.**
- b) Please confirm, or explain in detail otherwise, that planned outages to address repairs, upgrades, and maintenance may be required because a failure to follow good utility practice resulted in the need to undertake the repairs, upgrades or maintenance.**

Response IR-12:

- a) Confirmed.

- b) The fact that an outage is planned does not, in and of itself, establish whether the outage is consistent with, or contrary to, good utility practice. The designation of an outage as “planned” reflects the manner in which it is scheduled and coordinated through the system operator to ensure safe de-energization of equipment and orderly execution of work. It is not a determination of the underlying cause of the outage or an assessment of prior utility practices.

Planned outages are a standard and necessary aspect of operating and maintaining electric transmission systems. They are routinely used to facilitate a wide range of activities, including inspections, preventative and corrective maintenance, repairs, and system

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1 upgrades, all of which require equipment to be taken out of service to ensure worker safety
2 and system reliability. The act of scheduling and executing such outages in a controlled
3 and coordinated manner is, in itself, consistent with good utility practice.
4

5 While it is possible that some work performed during a planned outage may address
6 conditions that developed over time, including those associated with equipment
7 performance or degradation, the need for such work does not inherently indicate a failure
8 to adhere to good utility practice. Equipment aging, external factors, and evolving system
9 requirements are all common drivers of maintenance and repair activities within well-
10 managed utility systems.

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Request IR-13:

Software problems have plagued the commissioning and testing of the Labrador Island Link. Please demonstrate that the software and deficiency work associated with the July 2023 outage was not needed to address a problem or problems associated with any previous failure to adhere to good utility practice.

Response IR-13:

Please also refer to IG IR-10, BW IR-05 and BW IR-06.

In terms of responding to the specific question, NSPML believes the relevant input relates to the LIL's commissioning, actions post LIL commissioning and reliability post commissioning.

The LIL (including its software) was tested and commissioned in April 2023; and handed over to the Newfoundland System Operator for its operations and control. The NS System Operator and the Regional Coordinator were privy to the testing and the associated results and were comfortable with this asset being part of the regional system.

Separately, the Government of Canada's Independent Engineer reviewed the testing and commissioning results. Canada has provided guarantees of over \$9 billion in support of the Lower Churchill Project and the engagement of the Independent Engineer is a critical piece of the Federal Government's monitoring of this material obligation. The Independent Engineer confirmed that the assets were commissioned to the extent that they will operate at a level of reliability such that it can be handed over to the System Operator. The Independent Engineer did have a list of non-critical punch list items for NLH to close out after commissioning (a similar list was provided for the Maritime Link), which NLH has since worked to eliminate. Although not determinative of the question, the fact that none of the holdback triggering winter period outages since LIL

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1 commissioning relate to the performance of the LIL should provide comfort that the Newfoundland
2 & Labrador System Operator, Canada's Independent Engineer and many others involved in the
3 commissioning of the LIL were correct in their findings that the LIL was fit for use.

4
5 Throughout the commissioning process of any asset, deficiencies are noted and classified by their
6 criticality and in large projects, because of the magnitude and complexity compiled into lists
7 known as 'Punch Lists'. These deficiencies are classified into buckets of criticality, with some
8 requiring remediation immediately before proceeding, and others requiring remediation at some
9 point into the future but are not considered critical enough to keep the project commissioning
10 efforts from advancing further. Completion of a project typically entails completing the
11 commissioning required for the asset to be turned over for commercial operation, along with a
12 complete listing of remaining punch list items. After the LIL was commissioned on April 14, 2023,
13 there was an outstanding list of non-critical punch list items. This outage was related to installing
14 the 'final version'¹ of HVDC Control and Protection Software that dealt with all of the software
15 related non-critical punch list items (HMI deficiencies, SCADA point deficiencies, Lane
16 Switching deficiencies, etc). Given the nature of software, a change in one component can
17 influence the functionality somewhere else, therefore, testing is prudent. General Electric (GE)
18 requested an outage of the LIL to facilitate loading of the new software and appropriate testing
19 (offline and online). Unfortunately, while the new version of software was tested in the factory
20 and witnessed by NL Hydro, it introduced functionality problems. After 5-7 days of trying to make
21 the update work, the software was eventually rolled back to the previous working version.

22
23 In this context, the July 2023 outage was necessary to address the items that were known at the
24 time of the April 2023 testing and LIL commissioning, and it was also known at that time that
25 additional work would be required to incorporate those items into the software. NSPML does not
26 believe that work, that was part of completing what Canada's Independent Engineer describes as

¹ Reference to "final" version is specific to completion of the non-critical punch list items. Similar to Maritime Link operating software, there will continue to be software updates, upgrades and modifications.

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- 1 non-critical punch list items on a \$15+ billion mega project, is indicative of failure to follow good
- 2 utility practice.

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Request IR-14:

Please demonstrate that the corrective actions and problems with the LIL's overload capability that caused the need for the outage in March 2024 were not associated with any previous failure to adhere to good utility practice.

Response IR-14:

The Labrador Island Link (LIL) was designed to the applicable design standards (IEEE, CSA, IEC, ANSI, ASTM, CIGRE, etc.) with full anticipation of ideal, reliable operation as any utility globally would perform and expect. Real world conditions differ from the studies performed to design systems like this and unintended events occur, such as the Ground Potential Rise (GPR) at the transition station when the cable switching sequence operated. This GPR caused interface boards that were part of the HVDC Control and Protection system to fail, causing the cable switching sequence to fail and the pole to trip.

When these real-world conditions are experienced, their cause must be identified and mitigations engineered to mitigate. In many instances the first set of mitigations are successful; however sometimes they are not and more engineering is required as was the case with the Cable Switching Sequence; first the ground grid at the transition compounds was modified in an attempt to reduce the GPR, this proved unsuccessful so the design choice was then made to add interposing relays with a voltage rating adequate to survive the GPR conditions present.

This iterative approach does consume time; however, it is essential to the understanding of problems experienced when real world conditions do not match the design intention of a complicated system like the LIL.

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Request IR-15:

Reference: Exhibit N-1, Testimony of Danielle S. Powers, Attachment 1, p. 25 of 36:

Regarding the April 2024 ice and wind event:

- a) Please explain how it is consistent with good utility practice for the 50-year design-life for the Labrador Island Link to have based on an ability to withstand a 1 in 50 year climatic event rather than including a margin for safety with a longer cycle climatic event return assumption.
- b) Please confirm, or explain in detail otherwise, that 15 years ago when the Labrador Island Link was being designed, climate change had been recognized and significant weather events were being observed at that time, such as Hurricane Igor, which in 2010 was one of the most powerful storms to hit Newfoundland and Labrador at that time.
- c) Please provide more detail about the solutions that will be required to address the climate severity design limitation assumption “in order to ensure the reliability of the transmission assets.”

Response IR-15:

- a) Ms. Powers is not a design engineer and does not possess independent expertise regarding the specific engineering assumptions underlying the Labrador Island Link's structural or climatic design parameters. Ms. Powers therefore is not in a position to provide a technical defense of those parameters as a matter of engineering judgment.

Ms. Powers can confirm, however, that the Labrador Island Link was designed, reviewed, and approved in accordance with the design criteria applicable at the time of project sanction. The selection of a 1-in-50-year climatic return period as the design basis was

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1 made by qualified engineers as part of that approved design, and Ms. Powers is not aware
2 of any finding by a regulatory body, independent engineer, or other authority that the
3 approved design criteria were inconsistent with good utility practice at the time of project
4 approval.

- 5
- 6 b) Ms. Powers confirms that climate change had been broadly recognized as a scientific and
7 policy matter at the time the Labrador Island Link was being designed, and that significant
8 weather events, including Hurricane Igor, which made landfall in Newfoundland and
9 Labrador in September 2010, had occurred during the relevant design period. Respondent
10 does not dispute these general propositions.

11

12 Ms. Powers disagrees, however, with the implication that awareness of these conditions
13 rendered the approved design criteria for the Labrador Island Link inconsistent with good
14 utility practice. The existence of singular notable weather events does not establish that the
15 design criteria adopted for the facility were deficient or that a more conservative climatic
16 return period was required as a matter of prudent engineering practice. Design criteria for
17 major transmission infrastructure are established through rigorous engineering analysis,
18 review of applicable standards, and regulatory oversight, not by reference to individual
19 weather events, however significant.

- 20
- 21 c) Ms. Powers disagrees that the Labrador Island Link was designed with what could be
22 termed a "climate severity limitation". The facility was designed, reviewed, and approved
23 in accordance with the design criteria applicable at the time of project approval, and Ms.
24 Powers does not accept the premise that those criteria constitute a "limitation" requiring
25 remediation.

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Request IR-16:

Please demonstrate that the software and work associated with the April 30, 2024, outage was not needed to address a problem or problems associated with any previous failure to adhere to good utility practice.

Response IR-16:

The above referenced outage was undertaken to remediate an issue with DC Current measurement at all Labrador Island Link (LIL) sites. These Optical Current Transformers (OCTs) had caused monopole pole and bipole trips from 2021 forward and were physically installed prior to 2018. It was observed that the DC Current measurements were being affected by electromagnetic interference which got worse when the ambient temperature dropped below minus 10°C. This was not consistent with the standards that the OCTs were designed to or the expectation when they were placed into service on the LIL which experiences significant cold weather at each of their stations.

Newfoundland and Labrador Hydro and GE had to first understand what caused the issues, design mitigations, then implement and test. As re-creating specific electromagnetic interference in a lab environment is very challenging, this took time and re-creating the electromagnetic interference at low ambient temperatures took even more time. Eventually a design change was proposed, implemented and tested on the OCTs themselves requiring deployment for each of the several units at each of LIL's sites. These OCTs then needed to be tested, and the original problem confirmed to have been mitigated which required operational experience at low ambient temperatures.

The outage referenced was to facilitate the replacement of some of these units as they were made available from GE's manufacturing facility.

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Request IR-17:

Please provide detailed reasons for the causes of the failure to achieve 90% base contract delivery in five out of the six months following the “Compliance Period”, including how the underlying causes of the outages (regardless of whether they were planned or unplanned) were not associated with any failure to adhere to good utility practice.

Response IR-17:

During the 6 months following the compliance period (May, June, July, August, September and October 2024) the 90% threshold for delivery of the NS Block was not met in May, July, August, September and October. These outages were required to replace a number of faulty DC Current transformers, make repairs and improvement to the DC transmission line to prepare for the upcoming winter season (removal of turnbuckles on dead-end structures and installation of air flow spoilers on critical spans among other things), and install a version of the HVDC Control and Protection Software that solved most of the non-critical punch list items identified through the Labrador Island Link’s (LIL) commissioning period. In September 2024 running into October 2024 the LIL was offline (monopole and bipole) for scheduled preventative maintenance ahead of the 2024/2025 Winter season. All these outages were planned in accordance with both NS Power and NL Hydro transmission outage planning processes with work executed as expected.

Please refer to BW IR-6 b) and CA IR-03 Attachment 1.

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Request IR-18:

On pages 11 and 12, NSPML stated “...the LIL had (and continues to have) a high reliability level when available for service (i.e. outside planned outage periods). Specifically, the LIL’s equivalent Forced Outage Rate (eqFOR) has been below 3% since its commissioning in April 2023.”

- a) What was the equivalent Forced Outage Rate that was originally forecast for the LIL?**
- b) Please explain the reasons for any change from the original forecast.**

Response IR-18:

- a) NSPML’s expectation for LIL availability would have been in line with their publications referenced in PUB-NLH-212, which NSPML understands forecast a Bipole Forced Outage Rate for the LIL of 0.0114 percent. Please see Attachment 1 for further detail. Please also refer to BW IR-7, Attachments 1 and 2, and BW IR-21.
- b) Following the commissioning of the Labrador Island Link, NLH determined that absent any long-term experience with the LIL post-commissioning, the previously anticipated bipole forced outage rate of 0.0114 percent (equivalent to 1 hour of forced outage time per year) was impractical and focused only on the LIL converter technology and not the wider LIL transmission system. The LIL is a complex system resulting in the need to calculate its performance as an end-to-end system for reliability planning (EqFOR). In 2022, NLH engaged Daymark Energy Advisors (“Daymark”) to assess considerations for HVdc¹ outage and unavailability rates. Daymark gathered information pertaining to metrics, methodologies, experience, and issues relevant to outages of HVdc paths that utilities or other energy industry participants utilize or have witnessed. The assessment focused on

¹ High-Voltage Direct Current (“HVdc”).

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1 Nordic areas of Europe, with coastal conditions of a similar latitudinal place as the LIL and
2 use of land and undersea cables.

3 NLH has indicated that absent any long-term operational experience with the LIL post-
4 commissioning, NLH does not have a basis to assume a LIL EqFOR of less than 1
5 percent; and until the LIL has multiple years of operational experience to better inform
6 the selection of a bipole forced outage rate, they have determined that the LIL bipole
7 forced outage rate will be addressed with a range of upper and lower limits (i.e., 1–10
8 percent). NLH’s current reference planning assumption for LIL bipole eqFOR is 5
9 percent, and NLH considers sensitivities at 3 percent and 1 percent. NLH’s eqFOR
10 planning assumptions are subject to change as more experience is gained with LIL
11 operation.

12 The EqFOR in this instance measures the performance of the LIL end-to-end system,
13 including converter stations at Muskrat Falls and Soldiers Pond, overhead lines between
14 Muskrat Falls and Soldiers Pond, transition compounds in Shoal Cove and Forteau Point,
15 and subsea cables in the Strait of Belle Isle.

16 For reference, as expected over the early performance period after a material asset is
17 commissioned, the EqFOR for the LIL and DAFOR for Muskrat Falls Generation have
18 shown gradual availability improvements, with the LIL’s EqFOR in 2025 being less than
19 1 percent and Muskrat Falls Generation’s DAFOR being 1.35 percent – significantly
20 better than Electricity Canada Average of 5.27 percent.²

² “Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended December 31, 2025”, February 5, 2026, Filed with the Newfoundland & Labrador Board of Commissioners of Public Utilities.

1 Q. Please provide any studies of reliability for the post Muskrat Falls project and
2 Labrador Island Link project.

3

4

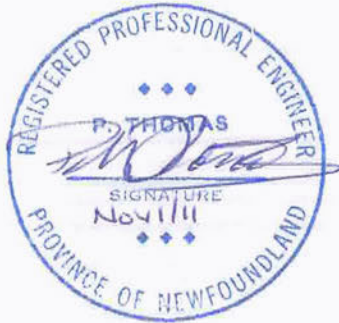
5 A. Please refer to the following attached reports:

6

7 PUB-NLH-212 Attachment 1: “Technical Note Labrador – Island HVdc Link and
8 Island Interconnected System Reliability” dated October 30, 2011 which provides an
9 overview of the impacts of the HVdc link on the Island Interconnected System.

10

11 PUB-NLH-212 Attachment 2: “Reliability & Availability Assessment of the HVdc
12 Island Link” dated April 10, 2012 which provides a detailed assessment of the
13 impacts of the HVdc link on the Island Interconnected System.



 Approved for Release	<u>Nov 9 / 2011</u> Date
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TECHNICAL NOTE

Labrador – Island HVdc Link and Island Interconnected System Reliability

Date: October 30, 2011

System Planning Department

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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~~ 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 year¹.

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability².

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 line³ 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 generator⁴. The rationale for this deviation is the fact 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, 1998, 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
 - o 2 x 450 MW, 1406 A per pole;
 - o 900 MW at Muskrat Falls;
 - o 92.1 MW peak losses;
 - o 807.9 MW at Soldiers Pond
- Monopolar operation – ten minutes
 - o 1 x 900 MW, 2812 A;
 - o 900 MW at Muskrat Falls
 - o 272.8 MW peak losses;
 - o 627.2 MW at Soldiers Pond
- Monopolar operation – continuous
 - o 1 x 675 MW, 2109 A;
 - o 675 MW at Muskrat Falls;
 - o 144.4 MW peak losses;
 - o 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 demand⁷.

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 MW plus 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 System⁸. 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.

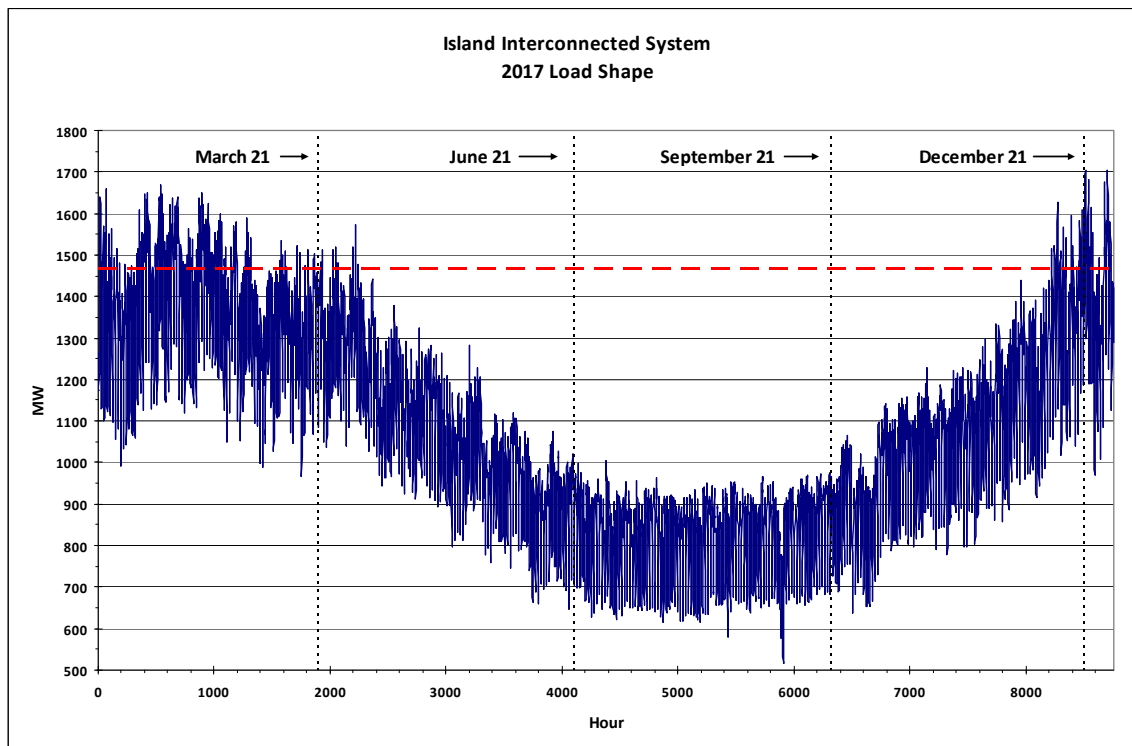


Figure 1 – 2017 Load Shape

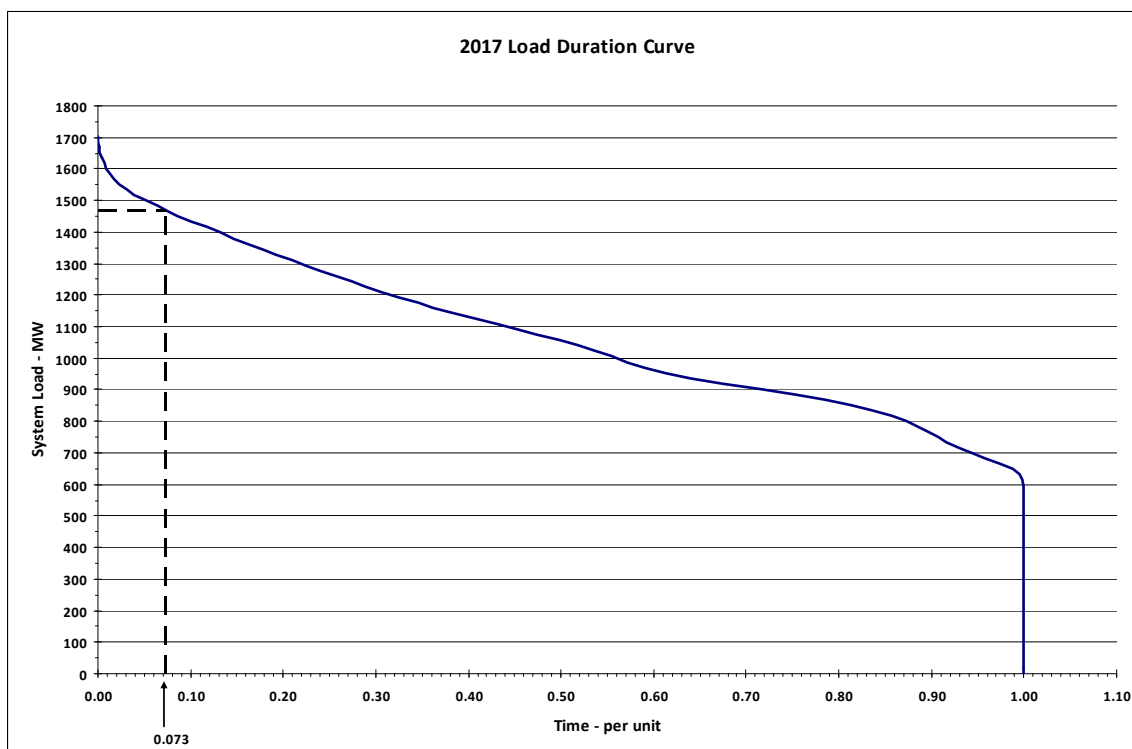


Figure 2 – 2017 Load Duration Curve

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 MW	Level of Exposure Load Exceeds Generation		Availability %	Unsupplied Energy Worst 2 wk Window	
	MW	GWh		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 is 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 February¹⁰. 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 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	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 6: 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, 300 MVAR 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 intact¹¹ 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 unserved 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

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2. National Standard of Canada CAN/CSA-C22.3 No. 60826:06 Design criteria of overhead transmission lines published October 2006 by Canadian Standards Association
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
6. “Transmission Planning Manual”, System Planning Department, Newfoundland and Labrador Hydro, September 2009, Revision 2 – Filed as Exhibit 105

Document Front Sheet



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Lower Churchill Project

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1 INTRODUCTION

1.1 Overview of the System

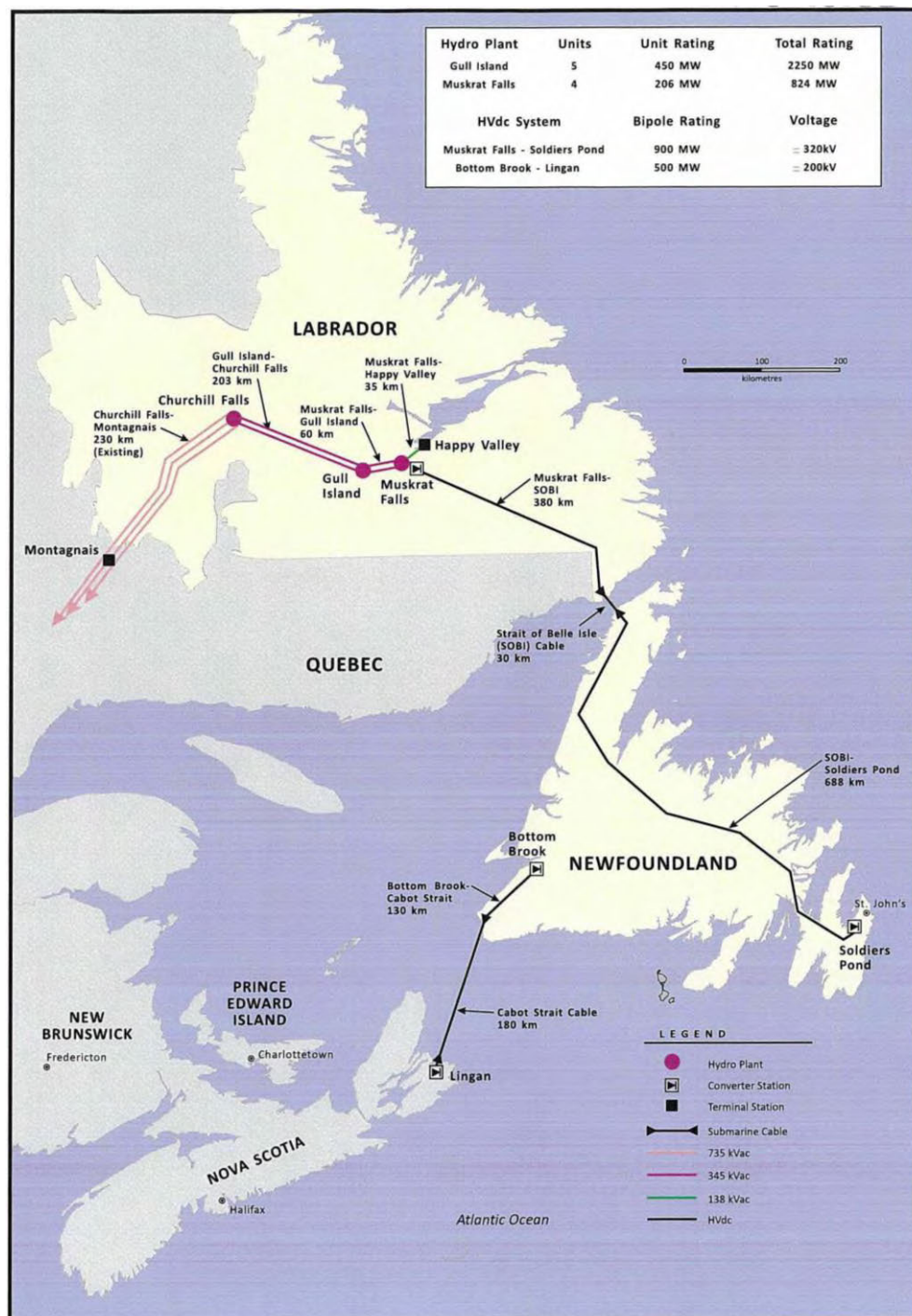
This Report presents the results of the reliability and availability analysis carried out to determine the expected performance of the ± 350 kV, 900 MW HVdc interconnection between Muskrat Falls and Soldiers Pond (Island Link) [1]. The Maritime Link between Bottom Brook and the Nova Scotia power system was not considered in this study. The results consider the performance of each element of the Island Link as well as the composite reliability of the complete link from Muskrat Falls to Soldiers Pond.

Figure 1-1 provides an overview of the project area.

The assessment considered only the Island Link from the ac bus at the converter station in Muskrat Falls to the ac bus at the Soldiers Pond converter station. The generation at Muskrat Falls, the 315 kV interconnection to Churchill Falls and the synchronous condensers at Soldiers Pond were not included in this assessment since their influence on the reliability of the link itself is considered to be negligible. The number and rating of the synchronous condensers at Soldiers Pond was determined from the steady-state and transient stability analyses and an economic assessment considering single contingency outages of equipment.

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Figure 1-1: Project Area Map



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1.2 Objectives of the Studies

The objectives of this Reliability and Availability (R&A) Assessment are:

- To develop R&A performance indices for the converter stations
- To develop R&A performance indices for the HVdc transmission line from Muskrat Falls to Soldiers Pond
- To assess the R&A performance indices of the submarine cables from Forteau Point to Shoal Cove,
- To develop R&A performance indices for the electrode lines from Muskrat Falls to L'Anse au Diable and from Soldiers Pond to Dowden's Point
- To assess the improvements that could be made in the above indices considering design aspects such as the provision of spare equipment, over-rated equipment, etc.
- To assess the composite R&A performance indices of the complete HVdc Island Link from Muskrat Falls to Soldiers Pond

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2 COMPONENT RELIABILITY

This section examines the reliability indicators available for the individual elements within the Island Link: HVdc converter stations, HVdc overhead line, HVdc transition compounds, HVdc submarine cables and electrode lines. An explanation of the reliability calculations used in this assessment is provided in Appendix A.

2.1 HVdc Converter Stations

A major input to this assessment was the information compiled by CIGRE on the performance of HVdc converter stations covering 158 terminal-years over the period 1988-2008[2] and the information contained in the PTI report R-64-81 [3]. For the 2-terminal, single-converter-per-pole stations, the following key performance indicators were determined:

- Forced Outage Rate (FOR) in %
- Forced Unavailability or downtime (FU) in hours/year

These indices are for the complete converter including valves, converter transformers, smoothing reactors, filters, etc. The following table summarizes the results, which are shown in detail in Appendix B:

Table 2-1: Summary of FOR and FU (per terminal)

Period	Outage	FOR (%)	FU(hrs/yr)
2007	Pole	0.15	13
	Bipole	0.0003	0.02
2008	Pole	0.38	34
	Bipole	0.0002	0.02
1988-2008	Pole	0.49	43.4
	Bipole	0.003	0.27

The average failure rate per terminal over the period 1988-2008 for pole outages was 2 failures/terminal/year; with an average repair time of 21 hours. The corresponding values for bipole outages were 0.2 failures/terminal/year and 1.3 hours.

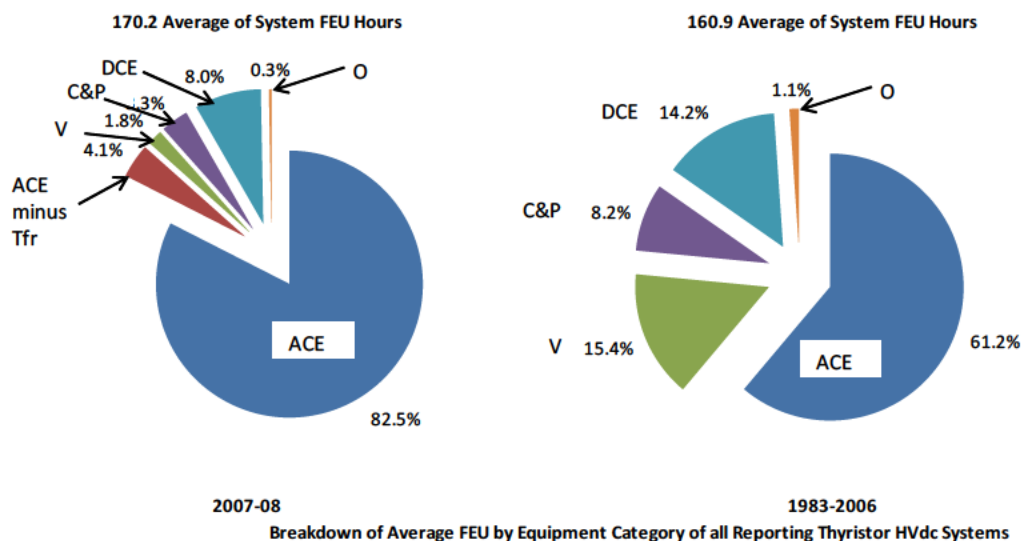
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Thus, for a 2-terminal bipole, the estimated average reliability indicators would be:

- 4 pole outages per year with a repair time of 21 hours per outage (FOR=0.98%)
- 0.4 bipole outages per year with a repair time of 1.3 hours per outage (FOR=0.006%)

The same source also provides information on the breakdown of forced energy unavailability (FEU) into the major components of a converter station: ac equipment and auxiliaries (ACE), thyristor valves (V), dc equipment (DCE), control & protection (C&P) and others (O) as shown in Figure 2-1.

Figure 2-1: Forced Energy Unavailability (FEU) as reported by CIGRE



The data for 2007-2008 indicate that the major contributors to the energy unavailability of the converter stations are the converter transformers, followed by the dc smoothing reactors. The provision of a spare unit for these major equipment items greatly improves the availability of the complete converter station, as shown in the following illustrative example.

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Spare Converter Transformer

λ = Failure rate (1-phase) = 0.01 f/yr

N = No. of Components = 6

R_1 = Repair Time (replacement with spare) = 168 hrs

R_2 = Repair Time at Factory = 4380 hrs

With no spare,

Average outage time per pole

= $0.01 \times 3 \times 4380 = 131$ hrs/yr

With one spare (for 6 single phase units),

Effective outage time per outage

= $R_1 + R_2/2 \times [N \lambda R_2 / (8760 + N \lambda R_2)] = 168 + 64 = 232$ hrs

Average outage time per pole

= $0.01 \times 3 \times 232 = 7$ hrs/yr

Almost all recent HVdc converter stations have been built with a spare transformer unit of each type and a spare smoothing reactor per terminal. The impact of this design measure is shown by the following CIGRE statistics:

Table 2-2: Converter Unavailability

Item		Performance Indicator		
Spare Transformer		No	Yes	Yes
Spare Smoothing Reactor		No	No	Yes
Terminal	Unavailability	3.04%	0.94%	0.21%
	Hours/ Year	266	82.5	18.6

Based on the above information, it is recommended that a spare transformer unit of each type and a spare smoothing reactor be provided at each terminal of the Island Link. With spare units at each terminal, the reliability performance indicators of the converter stations can be taken as the average of the 2007 and 2008 statistics from Table 2-1 above since the most recent converter stations were designed with spare units.

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Table 2-3: Converter Reliability (Average 2007-2008)

Outage	FOR (%)	FU(hrs/yr)	F/yr	Repair Time (hrs)
Pole	0.265	24	1.64	13.8
Bipole	0.00025	0.02	0.24	0.13

With the continuing improvements in the technology and design of converter stations, it would not be unreasonable to expect lower failure rates and repair times for the Muskrat Falls and Soldiers Pond converters. However, for the purpose of this analysis it was considered prudent to use the historical information from the recent past as this would give more conservative results. Insufficient information is available in the historical records to allow for a distinction to be made between each converter at either end of a dc link, one of which may be in a remote area. In the case of the Island Link, the Soldiers Pond converter will be located within a short distance of St. John's, close to the Nalcor headquarters with easy access by road. The Muskrat Falls converter station is within easy access of Happy Valley but if repairs to any converter fault have to be made by staff mobilized from St. John's, then significantly longer repair times would apply to the Muskrat Falls converter. For this assessment, the two converter stations are assumed to be identical.

2.2 HVdc Line

Transmission line outage statistics for HVdc lines are not as readily available as those for ac lines. However, the available outage data of selected projects are presented in Table 2-4 from a compilation of CIGRE statistics produced during the 1990's to provide an indication of the performance of HVdc lines to date. The reporting periods indicated below are the numbers of years for which data was available and do not necessarily represent the total numbers of years in service for each line.

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Table 2-4: HVdc Transmission Line Outage Statistics

System	Length km	Reporting Period(yrs)	km-yrs	No. of Outages	f/100km /yr/pole	Avge Duration hrs
Pacific Intertie	847	8	6,776	51	0.376	1.48
Nelson River-1	960	11	10,560	45	0.213	0.53
Nelson River-2	960	11	10,560	41	0.194	0.52
Square Butte	749	9	6,741	5	0.037	1.69
CU	710	11	7,810	6	0.038	4.72
Itaipu-1	1200	6	7,200	21	0.146	2.06
Itaipu-2	1200	3	3,600	10	0.139	0.24
IPP	784	3	2,352	18	0.383	2.96
Average					0.191	1.78

Using the averages from Table 2-4, for a route length of 1,100 km, the expected reliability performance would be:

- 2.101 outages per pole per year,
- With an average repair time of 1.78 hours per outage

This translates into an unavailability and FOR of 0.0425% per pole.

The common-mode failure of both overhead poles must also be taken into account. It is assumed that this type of failure mode is at least one order of magnitude less likely than a single pole failure but with a longer average repair time and is therefore assumed to have a failure rate of 0.02 f/100km/yr with an average repair time of 24 hrs.

2.3 HVdc Submarine Cable

There is even less information related to the reliability of submarine cables than for overhead dc lines. Cable installations of all types are generally considered to be very reliable since they are installed in a protected environment. However, in the case of submarine cables, the repair time for a cable fault can be extremely long since it involves the mobilization of a repair ship and recovery of the cable, which may not be feasible during certain seasons of the year. The submarine cable crossing of the Straits of Belle Isle is being designed with a spare cable to cover the loss of one cable. Each cable will be rated to carry the rated power of one pole continuously with a 5-minute overload capability of 2x rated power.

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A report by C-Core [4] examined the incidence of iceberg strikes on the submarine cables and concluded that the expected failure rates for such events would be:

- 0.004 failures/year for a single cable
- 0.002 failures/year for 2 cables
- 0.001 failures/year for 3 cables

Repair times for cables in the Strait of Belle Isle could be very long and a repair time of 6 months (4,380 hours) has been assumed. Other cable failures, due to internal failures and other external causes, such as fishing and shipping activities, are assumed to be no worse than 1 in 50 years or 0.02 failures/year. Since there is a spare cable that can be quickly switched to replace a failed cable, the probability of losing a single pole due to a cable fault is the sum of the independent failure of 2 cables plus the probability of an iceberg strike affecting 2 cables. The independent failure of 2 cables can therefore be calculated by:

$$F_C = \lambda_{C1} \cdot U_{C2} + \lambda_{C2} \cdot U_{C1} + \lambda_{C1-2}$$

$$U_C = U_{C1} \cdot U_{C2} + U_{C1-2}$$

Where λ_{C1-2} , U_{C1-2} represents the failure rate and downtime of 2 cables due to an iceberg strike.

This evaluates to a failure rate of 0.00022 f/yr for the independent failure of 2 cables and 0.002 f/yr due to iceberg strikes, for a total failure rate of 0.0022 f/yr with an average repair time of 4,163 hrs/outage and an average downtime of 9.24 hours/year. This corresponds to an FOR of 0.105%.

For the complete loss of the link, either all 3 cables would need to fail due to independent failure events or an iceberg strike would need to affect all 3 cables. The independent failure mode evaluates to a very small value (9.9E-6 f/yr) and is considered insignificant, leaving a failure of 3 cables due to an iceberg strike as the remaining cause with a failure rate of 0.001 f/yr with an average repair time of 4,380 hours/outage and an average downtime of 4.38 hours/year (An FOR of 0.05%).

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2.4 Electrode Line

An electrode line will be provided at each converter station to connect to a remote ground electrode. These lines, under bi-pole mode, will carry only the unbalance current between the two poles of the dc line but will also be used at 150% rated pole current during mono-polar operations involving ground return. These lines are essentially medium voltage lines with 2 conductors for redundancy in case of conductor failure and will be continuously monitored for integrity. At the Muskrat Falls end, the electrode line is 400 km in length and at the Soldiers Pond end; it is only 10 km in length.

CEA statistics on transmission equipment performance for ac lines up to 110 kV indicate the average failure rate for such lines to be 5 outages/100km/year with an average repair time of 8.2 hours (downtime = 41 hours/100km/year, 0.47%). Using these values for the Muskrat Falls electrode line would result in 20 outages/year. This appears to be a high value for a line that is continuously monitored and that spends most of its time operating at a voltage well below its rated value. Accordingly, a failure rate equal to one-tenth of this value (i.e. 0.5 failures/100km/year) was assumed and the repair time was kept at 8.2 hours per outage.

For the common-mode failure of both circuits of the electrode line, a failure rate one order of magnitude lower was assumed (i.e. 0.05 failures/100km/year) and the repair time was taken to be the same as for the common-mode failure of both poles of the bipole (i.e. 24 hours). Even with both circuits of the electrode line out of service, it will still be possible to operate the link at rated power with the unbalance current being handled by the station ground or, at worst, running at reduced power in mono-polar mode using metallic return.

The electrode line at the Muskrat Falls end (400 km) will either be constructed on a separate wood-pole line or will be installed on the towers of the main dc line itself. It would be reasonable to expect the reliability of the electrode line to be improved if it is mounted on the main line since the majority of common-mode failure events associated with the main line would be the same common-mode failure events

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associated with the electrode line. Thus the common-mode failure of the two electrode line circuits is already included in the common-mode failure of the bipole. The impact of this is, however, relatively small.

Given the above considerations, it is considered that the reliability related to the complete loss of the Island Link will not be significantly influenced by the reliability of the electrode lines at either terminal.

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3 COMPOSITE SYSTEM

The composite system reliability of the Island Link can be determined from a consideration of the reliability of the components of the system. The actual connection diagram of the Island Link together with the corresponding connection diagram for the individual components of the reliability is shown in Figure 3-1. The individual poles of the bipole (L1+C+L2) and the converters (CP) are shown as parallel elements since both must fail for the link to fail, while the common-mode failure of the bipole due to a converter fault (BPC or cable/line fault (BPL1, C3 and BPL2) are shown as series elements since any of these failures will result in failure of the link. In all the results tables that are presented in the following sections, the results have been rounded to the appropriate number of significant digits. However, in the actual calculations, the full number of decimal places was retained to ensure the overall arithmetic accuracy of the results.

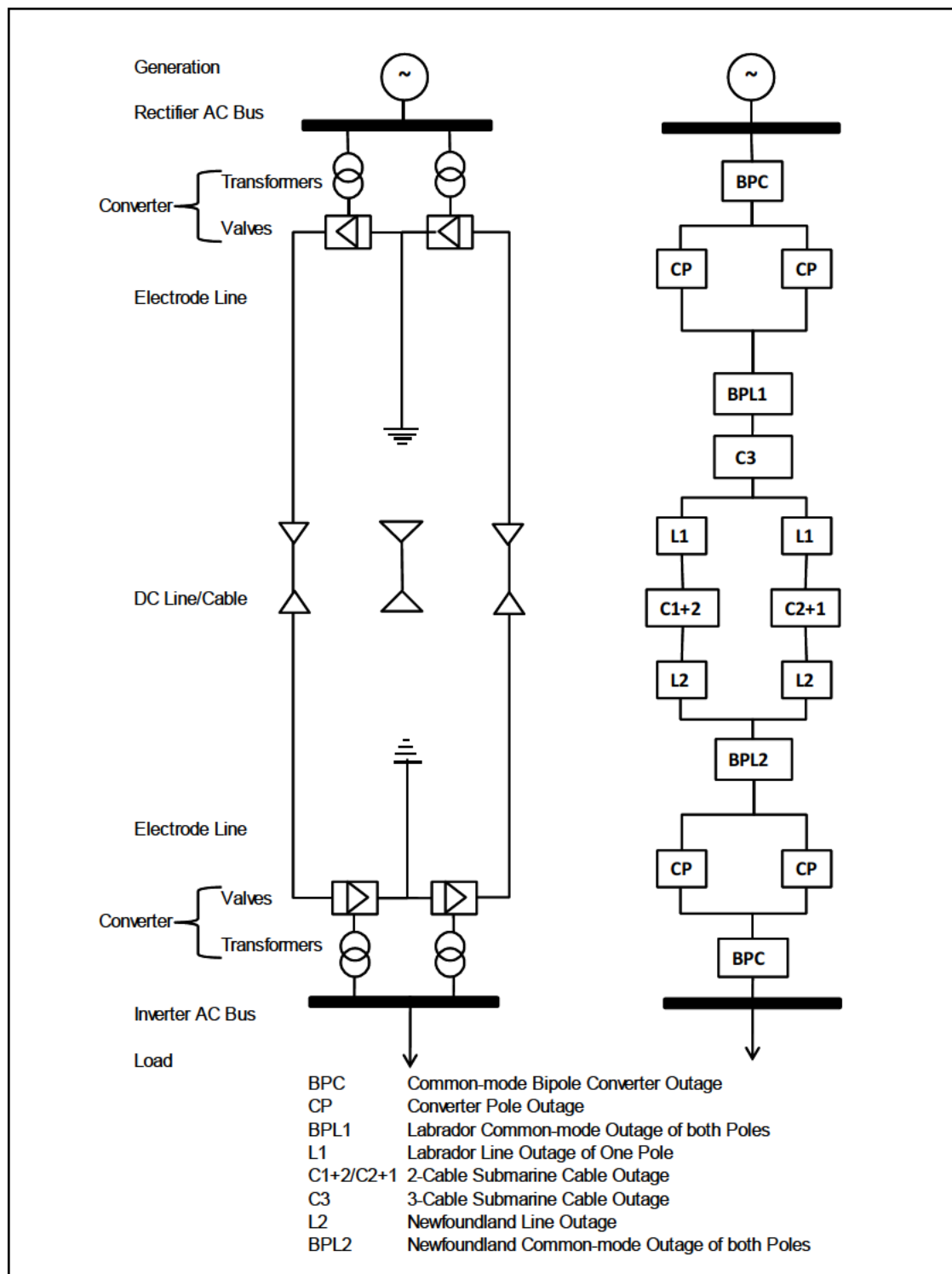
3.1 HVdc Overhead Line and Submarine Cable

First, it is necessary to determine the composite reliability indices associated with each parallel pole element (L1, C1+2, and L2 in series). Since the failure of any one of these elements will result in the failure of one pole, the failure rate and unavailability of each element can simply be added together as shown in Table 3-1. For each element, the downtime (or unavailability) is the product of the failure rate and the repair time ($U=\lambda.r$). Once the total failure rate and downtime have been determined, the repair time can be calculated as $r=U/\lambda$. For the submarine cable, the failure rate, repair time and downtime are those associated with the independent failure of 2 cables and an iceberg strike that impacts 2 cables.

Table 3-1: Reliability Performance of One Pole of the HVdc Line

Element	Failure Rate (f/yr)	Repair Time (hrs)	Downtime (hrs/yr)
L1-388 km	0.741	1.78	1.32
C-Submarine cable	0.0022	4,163	9.24
L2-680 km	1.3	1.78	2.31
Total	2.042	6.3	12.87

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Figure 3-1: Island Link Reliability Connection Diagram

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The reliability indices for the coincident, independent failure of two poles in parallel are given by:

$$\lambda_T = \frac{\lambda_1 \lambda_2 (r_1 + r_2)}{8760} \text{ f / yr}$$

$$r_T = \frac{r_1 r_2}{r_1 + r_2} \text{ hrs}$$

$$U_T = \lambda_T r_T \text{ hrs / yr}$$

From the above composite reliability of each pole, the composite reliability of both poles in independent failure mode is:

$$\lambda_T = (2.042)^2 \cdot (2 \times 6.3) / 8760 = 0.006 \text{ f/yr}$$

$$r_T = (6.3)^2 / (2 \times 6.3) = 3.15 \text{ hrs}$$

$$U_T = 0.006 \times 3.15 = 0.019 \text{ hrs/yr}$$

In addition, for the complete failure of the link, the probability of an iceberg strike impacting all three submarine cables and the probability of a common mode outage of both overhead line sections must be added to the above independent, coincident failure of both poles.

3.2 Converters

Similarly, the coincident failure of both converters in independent mode can be calculated as:

$$\lambda_T = (1.64)^2 \cdot (2 \times 13.8) / 8760 = 0.0084 \text{ f/yr}$$

$$r_T = (13.8)^2 / (2 \times 13.8) = 6.9 \text{ hrs}$$

$$U_T = 0.0086 \times 7 = 0.06 \text{ hrs/yr}$$

3.3 Electrode Lines

As mentioned above, the link can still be operated at full power or reduced power even for the complete loss of the electrode line at either end of the link. As such, the reliability of the electrode line is considered to have no significant impact on the composite reliability of the link.

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3.4 Complete System

For the failure of both lines/cables (P1+P2) or both converters (CP+CP), in series with the common-mode failure of both poles due to converter faults (BP) and main line faults (BPL1 and BPL2), the composite reliability of the Island Link is as shown below.

Table 3-2: Composite Island Link Bi-pole Reliability

Element	Failure Rate	Repair Time	Downtime	
	(f/yr)	(hrs)	(hrs/yr)	% of Total
BP-Muskrat Falls	0.24	0.13	0.031	0.3
CP+CP-Muskrat Falls	0.0084	6.86	0.057	0.6
BPL1-388 km	0.074	24	1.776	18.6
P1 + P2	0.007	621.7	4.479	46.9
BPL2-680 km	0.13	24	3.12	32.7
CP+CP-Soldiers Pond	0.0084	6.86	0.057	0.6
BP-Soldiers Pond	0.24	0.13	0.031	0.3
Total	0.7078	13.49	9.551	100

The composite, forced unavailability and FOR is therefore $9.551 / 8760 \times 100 = 0.109\%$.

It is clear from the above results that the major contributors to the unavailability of the Island Link are the common-mode failure of both poles of the overhead line (representing nearly 52% of the total unavailability) and the independent, coincident failure of both poles for the overhead and submarine cable sections (representing 47% of the total unavailability). Of all the values used for the component reliability, the reliability indices associated with common-mode bipole and submarine cable failures are probably the least certain given the relatively small database of operating experience. The parameter that has the most influence on the overall unavailability due to these failures is the repair time required to return a bipole or submarine cable to service after a common-mode failure. The value used in the above analysis was based on the limited operating experience available worldwide which includes bipolar lines of similar length to the Island Link in remote areas with difficult access.

The implied availability from this result is 99.89%. However, it should be borne in mind that this availability value includes periods of time when the full capacity of the link is unavailable. For a pole outage or converter outage or during scheduled

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maintenance, the link will be operated in mono-polar mode at a power level up to 150% of rated power per pole on a continuous basis.

3.5 Reduced Power Operation

The scheduled maintenance would typically be of the order of 3 days per pole per year, assuming that maintenance work would be carried out at both terminal stations and on each line (pole) at the same time. With respect to forced periods when the Island Link will not be available for full power transmission, it is necessary to consider only those single contingency events that will result in the loss of one pole of the Island Link. These comprise the loss of a converter at either end or the permanent outage of either pole of the main dc line. Using the values from Table 2-3 for the converters and Table 3-1 for the overhead line and submarine cable components, Table 3-3 shows the reliability indices associated with reduced power modes.

Table 3-3: Reduced Power Capability Modes (Mono-polar)

Element	Failure Rate(f/yr)	Repair Time(hrs)	Downtime(hrs/yr)
Scheduled Maintenance	2.0	72	144
Converter-Muskrat Falls	1.64	13.8	22.42
Pole 1	2.04	6.3	12.87
Pole 2	2.04	6.3	12.87
Converter-Soldiers Pond	1.64	13.8	22.42
Total	9.36		214.6

The composite unavailability and FOR is therefore $214.6 / 8760 \times 100 = 2.45\%$.

Thus, the actual availability of the Island Link at full power capacity is $100 - 0.109 - 2.45 = 97.44\%$.

If the use of the station ground for mono-polar operation is not allowed in the event of the loss of the electrode line, the above values will be increased slightly due to the failure of both conductors of the electrode line. Only the loss of the Muskrat Falls electrode line will be significant since the length of the Soldiers Pond electrode line is relatively short. The coincident failure of both conductors of the Muskrat Falls electrode line was estimated at 0.2 failures/year with an average repair time of

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24 hours and a downtime of 4.8 hours/year. If these values are added to those shown in Table 3-3 above, the resulting overall FOR increases from 2.45% to 2,51%.

The impact of the repair time for the common-mode failure of both circuits of either the Muskrat Falls electrode line or the main dc line is dominant to the point where the total forced unavailability can be approximated as being proportional to the repair time for such an event. Varying the fault repair time over the range of 3 hours to 10 days, with all other component reliability indices being held constant, the total forced unavailability in % is approximately $2.5/1000 \times \text{bi-pole repair time in hours}$. If a specific reliability performance is required (e.g. total forced unavailability $\leq 0.5\%$), then the repair time for a bi-pole line fault must be kept within 192 hours (8 days). This strong correlation between the unavailability of the link and the repair time associated with common-mode failures of both poles of the main dc line allows the desired reliability to be associated with target repair times. The unavailability of the link at full power, due to single pole forced outages or maintenance, is shared equally by the repair time for one pole and the time required for pole maintenance.

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4

CONCLUSIONS & RECOMMENDATIONS

Objective 1: To develop R&A performance indices for converter stations

Using historical information compiled by CIGRE from HVdc installations throughout the world over the period 1988-2008, failure rates and repair times were estimated for the converter stations at each end of the Island Link.

Table 4-1: Converter Reliability (Average 2007-2008)

Outage	FOR (%)	FU(hrs/yr)	F/yr	Repair Time (hrs)
Pole	0.265	24	1.64	13.8
Bipole	0.00025	0.02	0.24	0.13

Objective 2: To develop R&A performance indices for the HVdc transmission line from Muskrat Falls to Soldiers Pond

- To assess the improvements that could be made in the above indices considering design aspects such as the provision of spare equipment, over-rated equipment, etc.,
- To assess the composite R&A performance indices of the complete HVdc Island Link from Muskrat Falls to Soldiers Pond.

Table 4-2: Reliability Performance of the HVdc Line

Element	Failure Rate (f/yr)	Repair Time (hrs)	Downtime (hrs/yr)
L1-388 km	0.741	1.78	1.32
C-Submarine cable	0.0022	4,163	9.24
L2-680 km	1.3	1.78	2.31
Total	2.042	6.3	12.87

The associated FOR is 0.147%.

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Table 4-3: Composite Island Link Reliability

Element	Failure Rate	Repair Time	Downtime	
	(f/yr)	(hrs)	(hrs/yr)	% of Total
BP-Muskrat Falls	0.24	0.13	0.031	0.3
CP+CP-Muskrat Falls	0.0084	6.86	0.057	0.6
BPL1-388 km	0.074	24	1.776	18.6
P1 + P2	0.007	621.7	4.479	46.9
BPL2-680 km	0.13	24	3.12	32.7
CP+CP-Soldiers Pond	0.0084	6.86	0.057	0.6
BP-Soldiers Pond	0.24	0.13	0.031	0.3
Total	0.7078	13.49	9.551	100

The associated FOR is 0.109%. The availability is therefore 99.89%.

Table 4-4: Reduced Power Capability Modes

Element	Failure Rate(f/yr)	Repair Time(hrs)	Downtime(hrs/yr)
Scheduled Maintenance	2.0	72	144
Converter-Muskrat Falls	1.64	13.8	22.42
Pole 1	2.04	6.3	12.87
Pole 2	2.04	6.3	12.87
Converter-Soldiers Pond	1.64	13.8	22.42
Total	9.36		214.6

The associated unavailability is 0.81% due to the forced outage of one pole and 1.64% due to the scheduled maintenance outage of a pole. If the station ground cannot be used for mono-polar operation when the Muskrat Falls electrode line is also unavailable, the total FOR will increase from 2.46% to 2.51%.

4.1 Conclusions

The provision of a spare transformer of each type and a spare smoothing reactor at each converter station will significantly improve the availability of the converters. This has become common practice in recent HVdc schemes.

Using representative reliability data from existing HVdc installations throughout the world, the overall forced unavailability of the complete Island Link is predicted to be approximately 0.1%. The forced unavailability of the full power capability of the Island Link is predicted to be less than 2.5%, with the scheduled unavailability for

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maintenance being 1.64%. However, both of the values for forced unavailability are very dependent on the average repair time that can be achieved for pole outages and common-mode failures of both poles of the dc line.

It has been shown that a linear relationship exists between these repair times and the unavailability of the Island Link. Once a target reliability has been decided on, the maximum repair time can be determined. The overall unavailability of the complete link is not sensitive to the repair time for the submarine cables. This is due to the provision of a spare submarine cable across the Strait of Belle Isle and the subsequent very low failure rates for 2 or 3 cables. An increase in the repair time for a common-mode failure of both overhead line sections of the dc line (due to a tower failure, for example) from 24 hours to 2 weeks (336 hours) resulted in an increase in the total unavailability from 0.108% to 0.835%.

Based on the historical data available, the repair time for single pole outages on the overhead line sections was estimated at 1.78 hours/outage, while the repair time for common-mode failure of both poles was assumed as 24 hours. If both these repair times are varied then the overall unavailability will change. The following values of overall FOR were calculated for a range of overhead dc line section repair times (these repair times were used for both independent, coincident failures of both poles and for the common-mode failure of both poles).

Table 4-5: Variation in Overall FOR with DC Overhead Line Repair Time

Repair Time(hrs)	FOR(%)
24 (1 day)	0.112
48 (2 days)	0.179
72 (3 days)	0.251
96 (4 days)	0.33
120 (5 days)	0.416
144 (6 days)	0.507
168 (1 week)	0.605
336 (2 weeks)	1.463

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The relationship is not linear, as may be expected, but does show the dependence of the unavailability on the repair time associated with overhead dc line section faults.

The total unavailability of full power due to a pole outage is determined to a large extent by the scheduled maintenance outage of each pole.

4.2 Recommendations

At each converter station, a spare converter transformer of each type (single phase) and a spare smoothing reactor should be provided. This will significantly improve the availability of the converters.

Other critical components and those items with long lead times should also be considered as items that should be provided with on-site spares. These items are normally determined by the converter supplier in order to meet the specified target reliability and availability values in the converter specification.

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APPENDIX A

RELIABILITY FORMULAE

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Individual Components

The reliability of any individual component of a system can be expressed in terms of its failure rate (λ), repair time (r), availability (A) and unavailability or downtime (U). These indices are linked in the following relationships:

$$U = \lambda \cdot r$$

$$A = (1-U)$$

The failure rate is normally expressed in the number of failures/year, the repair time is normally expressed in hours/repair, availability and downtime are normally expressed in hours/year or in per unit/year where the repair time is divided by 8760 hours/year.

Thus a component with a failure rate of 2 failures/year and a repair time of 24 hours/repair will have a downtime of $2 \times 24 = 48$ hours/year or $48/8760 = 0.0055$ p.u./year (sometimes expressed as 0.55%).

Furthermore, the forced outage rate (FOR) can be calculated as:

FOR = $\frac{U}{1+U}$, which can be approximated as **FOR** = U where U is small in relation to unity.

Components in Series

In a system where the failure of any single component will result in failure of the system, the components are said to be connected in series, using the analogy of an electrical circuit. In such a system, the total system failure rate is simply the sum of the failure rates of the individual components. Similarly, the downtime of the system is the sum of the downtimes of the components.

For example if a system comprises two components, one with a failure rate of 2 failures/year and a downtime of 24 hours/year (repair time = $24/2 = 12$ hours/failure); the other with a failure rate of 3 failures/year and a downtime of 12 hours (repair time = $12/3 = 4$ hours/failure), the system failure rate will be 5 failures/year with a total downtime of 36 hours/year (repair time = $36/5 = 7.2$ hours/failure).

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Components in Parallel

In a system where multiple components must fail to result in failure of the system, the components are said to be connected in parallel, again using the analogy of an electrical circuit. For a two component system, two possible failure modes can be envisaged: the failure of component 2 while component 1 is in a failed state and the failure of component 1 while component 2 is in a failed state. This is expressed mathematically as follows:

$$\lambda_T = \lambda_2 \cdot U_1 + \lambda_1 \cdot U_2 = \lambda_2 \cdot \left(\lambda_1 \cdot \frac{r_1}{8760} \right) + \lambda_1 \cdot \left(\lambda_2 \cdot \frac{r_2}{8760} \right) = \frac{\lambda_1 \cdot \lambda_2 \cdot (r_1 + r_2)}{8760} \text{ failures / year}$$

The total downtime is simply the product of the individual downtimes.

$$U_T = U_1 \cdot U_2$$

From which the average repair time can be calculated as:

$$U_T = \lambda_1 \cdot r_1 \cdot \lambda_2 \cdot r_2$$

$$r_T = \frac{U_T}{\lambda_T} = \frac{\lambda_1 \cdot r_1 \cdot \lambda_2 \cdot r_2}{\lambda_1 \cdot \lambda_2 \cdot (r_1 + r_2)} = \frac{r_1 \cdot r_2}{r_1 + r_2} \text{ hours / failure}$$

Using the same example used for components in series:

$$\lambda_T = \lambda_2 \cdot U_1 + \lambda_1 \cdot U_2 = 3 \times 24 / 8760 + 2 \times 12 / 8760 = 0.011 \text{ failures / year}$$

$$U_T = U_1 \cdot U_2 = 24 \times 12 / 8760 = 0.033 \text{ hours / year}$$

$$r_T = \frac{4 \times 12}{4 + 12} = 3 \text{ hours / failure or } r_T = \frac{U_T}{\lambda_T} = \frac{0.033}{0.011} = 3 \text{ hours / failure}$$

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APPENDIX B

CIGRE HISTORICAL DATA 1988-2008

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CIGRE Historical Data 1988-2008 per Terminal

2 Terminal Systems - 1 Converter per Pole

Name	2007				2008				Average 1988-2008				
	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	0	2	3.8	0.5	1	20	1.54	17.1	0.13	1.03
Square Butte	1	4.1	1.5	0.3	5.25	0.8	0	0	18	2.85	6.2	0.42	2.27
CU	0.5	23.8	0	0	1.25	58.5	0	0	20	1.71	4.6	0.28	1.66
Gotland 2&3	0.25	0.8	0	0	0.5	46.6	0	0	20	0.38	35.8	0.2	1.49
Fennoskan	2	14.2			1.5	46.4			19	2.26	10.1		
SACOI	3.33	1.7			1.67	2.5			16	4.9	2.6		
New Zealand 2	2.5	4.3			0.5	0.7			17	1.65	2.7		
Kontek	0.5	2.7			1	32			7	0.86	15.7		
SwePol	0.5	2.4			2	1.7			8	3.56	21		
Kii Channel	0	0		0	0	0	0	0	8	0.16	99.6	0	0
Grita	4	42.2			4.5	9.3			5	2.7	17.1		
Average	1.44	9.03	0.38	0.06	1.83	18.39	0.10	0.20	158	2.05	21.14	0.21	1.29

Downtime (hrs/yr)	13.0		0.02		34		0.02			43.4		0.27	
FOR/U(hrs/yr)	0.15%		0.0003%		0.38%		0.0002%			0.49%		0.003%	

NSPML Application to Review the Holdback Mechanism
(NSEB M12696)
NSPML Responses to NSEB Information Requests

NON CONFIDENTIAL

Request IR-19:

Considering recent generation issues identified in Newfoundland, and the anticipated growth in demand and energy requirements, what is NSPML's understanding of the continued availability of significant levels of market-priced energy going forward for Nova Scotia customers?

Response IR-19:

NSPML believes that significant levels of market priced energy will be available on a go forward basis and, as contingency, is also comfortable with the contractual protections provided under the Energy Access Agreement (EAA) if availability does not meet contractual requirements.

Please refer to BW IR-07.