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March 12, 2021

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
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Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

**Re: *Reliability and Resource Adequacy Study Review* – Assessment of Labrador-Island Link Reliability**

As part of Newfoundland and Labrador Hydro's ("Hydro") *Reliability and Resource Adequacy Study Review* proceeding, Hydro committed to undertaking an assessment of the as-built structural reliability of the Labrador-Island Link ("LIL") with respect to the CSA 60826 – Design Criteria of Overhead Transmission Lines standard. The assessment, titled "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," was completed by an external consultant, Haldar & Associates Inc. and is included as Attachment 1.

The purpose of the work is to provide a further understanding of the impact of extreme weather scenarios (in particular glaze and rime icing) on the overall as-built structural reliability of the overhead transmission line. The findings of the assessment will inform customers and stakeholders with respect to future provincial reliability decisions.

Also included herein is a summary report which provides an overview of the Haldar & Associates assessment, as well as Hydro's conclusions with respect to the findings.

Should you have any questions, please contact the undersigned.

Yours truly,

**NEWFOUNDLAND AND LABRADOR HYDRO**

SWalsh

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Encl.

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# Labrador-Island Link Reliability Assessment – Summary Report

March 12, 2021

A report to the Board of Commissioners of Public Utilities

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Attachment 1: Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads

# 1.0 Introduction and Summary of Findings

Early in 2020, Newfoundland and Labrador Hydro ("Hydro") commissioned Haldar & Associates Inc. ("Haldar & Associates") to undertake an "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads" ("Haldar & Associates Assessment"). The purpose of the Haldar & Associates Assessment is to identify the overall structural reliability of the Labrador-Island Link ("LIL") with respect to the probability of failure based on the integrity of the system components and considering climatological conditions which could potentially result in an extended bipole outage.[1] The completed Haldar & Associates Assessment is enclosed as Attachment 1. This summary report provides an overview of the Haldar & Associates Assessment, as well as Hydro's conclusions with respect to the findings.

The Haldar & Associates Assessment considered the LIL design with respect to CSA[2] 60826 - Design Criteria of Overhead Transmission Lines[3] and the overall likelihood of failure of the LIL with respect to both glaze and rime icing events. Scenarios not directly following the guidance of the CSA standard were also considered to provide a fully informed assessment. The assessment also included a qualitative review of local conditions based on past operational experience.

Table 1 outlines the findings of the assessment when considered: (i) in accordance with the CSA standard, Damage Limit States ("DLS"), and (ii) in accordance with an Ultimate Limit States ("ULS").[4] Based on the assessment of the <u>as-built</u> design of the LIL, the <u>baseline</u> measure of reliability for the LIL is:

- 1:72 year return period[5] based on CSA 60826; or
- 1:160 year return period based on an ULS analysis.

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[1] "*Reliability and Resource Adequacy Study Review* – Further Information and Filing Schedule," Newfoundland and Labrador Hydro, October 2, 2020. For the purpose of this report, an extended bipole outage is defined as a forced outage that would result in the inability of the utility to supply customers with power via the Labrador-Island Link for multiple days.
[2] Canadian Standards Association.
[3] This national standard specifies the loading and strength requirements of overhead lines derived from reliability based design principles.
[4] Details on the complete list of scenarios considered are detailed in the Haldar & Associates Assessment.
[5] Return period, also known as recurrence interval, is an estimate of the likelihood of a climatological event to occur. It is usually used for risk analysis (e.g., to design structures to withstand an event with a certain return period).

**Table 1: Assessment Findings – CSA Standard and Ultimate Limit States**

| | Scenario Attributes | Annual Failure Rate[6] (%) | Return Period (years) |
|---|---|---|---|
| 1 | Based on **Damage Limit States in accordance with CSA**<br>Glaze and rime ice considered<br>All line components[7] considered<br>Segmented line lengths | 1.10 | 1:72 |
| 2 | Based on **Ultimate Limit States**<br>Glaze and rime ice considered<br>All line components considered<br>Segmented line lengths | 0.48 | 1:160 |

## 1.1 CSA 60826 (Damage Limit States)

The DLS is a requirement of the CSA standard and is based on the system's governing critical component. In the case of the LIL, the governing critical component[8] is the Optical Ground Wire ("OPGW"). A violation of the DLS does not automatically imply that the line has failed structurally (e.g., collapse of a tower, foundation, etc.). In the case of the LIL, it represents the overstressing of the OPGW past its set design limit, which is not expected to have an effect on the structural system of the LIL, nor is it expected to affect any level of power transfer over the LIL.

The Haldar & Associates Assessment findings indicate that based on CSA 60826 (DLS analysis), the as-built design of the LIL reflects a return period of 1:72 years with an associated annual failure rate of 1.10%.

## 1.2 Ultimate Limit States

The ULS is outside the CSA standard. This scenario was considered as the governing component of the LIL is the OPGW, and considering a return period and failure rate on the governing component only does not realistically represent the possibility of a structural failure of the LIL. The ULS reflects an ultimate failure scenario in which the system components are stretched to their ultimate limit, thus resulting in a higher probability of a forced outage of power delivery. To inform the *Reliability and Resource Adequacy* proceeding, Hydro required an assessment of the possibility of interruption of power delivery over the LIL. In the analysis presented, the strength factors for all cable and structural elements were increased

[6] Annual failure rate is the theoretical statistical yearly failure probability. As defined, it is the theoretical statistical probability of occurrence, but is not a true indication that the line will fail annually.
[7] The assessment included structures, conductors, insulators and hardware.
[8] Governing component is that by which the system strength is dictated as it proves to be the weakest link.

to their maximum limits (i.e., 90 % for all cable elements and 100 % for all structural elements). The ULS scenario would represent the possibility of a structural issue occurring on the LIL under this analysis, which could have the potential to result in an extended bipole outage.

Using the same climatological conditions and segmented line lengths, and applying ULS, the return period increases to 1:160 years with an associated annual failure rate of 0.48%.

### 1.3 Segmented Line Lengths versus Full Line Length

In line with CSA standards, the LIL reliability has been assessed based on segmented line lengths (i.e., 11 individual line segments based on geographical region) versus the full line length. Prior studies on the reliability of the LIL, as well as the scenarios outlined in Table 1, considered the line as segments with the reliability assessment based on the weakest component

The Haldar & Associates Assessment identified full line length as an important consideration in assessing the reliability of the LIL. While not required by CSA, applying a probabilistic failure analysis considering the full line length and regional grouping, as identified by Haldar & Associates, the return period under both a DLS and ULS analysis is less than 50 years. Haldar & Associates have identified that, in comparison to failure statistics experienced by other utilities throughout the world for similar infrastructure, the increased probability of failure is a realistic possibility and similar results would be expected as additional operating experience is gained. To Hydro's knowledge, consideration of full line length was not a standard design consideration pre-CSA 60826 and it remains unclear how widely adopted such an approach is at present.

## 2.0 Background

The original design of the LIL was considered to be equal to or greater than Hydro's historical transmission line designs, which are deemed to have a 1:50 year return period based on historical design practise governed by the earlier editions of the CSA 22.3 No.1 standard and historical operating experience. This was supplemented by Lower Churchill Project specific model and test programs targeted towards the site specific location of the LIL. As the CSA 60826 code was in infancy stage at the time of the LIL design, Nalcor Energy referenced CSA 60826 while considering local conditions based on 50 years of operating experience.

In 2014/2015, an analysis of the LIL reliability was completed by SNC Lavalin in coordination with Nalcor Energy.[9] The analysis identified the LIL as having a minimum of a 1:150 year return period overall with specific sections having a 1:500 year return period. This study focused only on the supporting structures and not the entire system components (i.e., the cable system and other components were not included).

As a result of continued queries on the reliability of the LIL, Hydro committed to undertaking a reliability assessment of the infrastructure, considering all system components and reflecting as-built data, to better understand the overall reliability of the line and determine the strengths and weakness associated with the infrastructure. This study was completed in accordance with the principles outlined by CSA 60826 for the Canadian utility industry.

## 2.1 EFLA Assessment of As-Designed Structural Capacity of the Labrador-Island Link

In the first stage of the reliability assessment undertaken by Hydro, EFLA Consulting Engineers ("EFLA") was engaged to complete a comprehensive review of the structures and cable systems benchmarked against CSA.[10] EFLA's findings identified the LIL as having a 1:150 year return period as benchmarked against CSA overall. This study did not take into account the effects of rime icing as CSA does not include specific requirements for such occurrence.

As a result of the variance between the EFLA findings and the SNC Lavalin findings for select areas, it was decided to have SNC Lavalin complete a peer review to qualify the differences. Based on that review, SNC Lavalin has identified that the variance in return periods is due to both different input ice loads used in the studies and different calculation methods based on an engineering interpretation of the CSA standard.

## 2.2 EFLA's Rime Ice Modelling

To further its understanding of rime ice impacts on the LIL, Hydro subsequently contracted EFLA to complete weather forecasting modelling of the LIL's Alpine regions, which would be necessary to determine the predicted return period rime ice accretion levels. EFLA's modelling work included a comprehensive rime ice study using local weather data from the past 50 years and data collected at

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[9] Filed with the Board of Commissioners of Public Utilities ("Board")on January 30, 2015 in response to NP-NLH-004 as part of the *Investigation and Hearing into Supply Issues and Outages on the Island Interconnected System* proceeding.
[10] EFLA findings were filed with the Board on April 30, 2020.

historical and new test sites. This investigation used an industry standard “Weather Research and Forecasting Model” to predict rime icing levels for specific return periods based on the as-built in Alpine regions. The forecasting modelling technique employed by EFLA is commonly used in Scandinavian countries that have numerous years of experience in rime icing on transmission systems; similar modelling was completed on rime icing during the LIL design. The weather modelling forecasting was undertaken due to the length of time between the design studies, the progression of data accuracy due to modelling technology advances, and the additional ten years of data since the LIL design modelling was completed.

At the time of the LIL design, the weather forecasting modelling guided the line routing, avoiding elevated areas of exposure to avoid increased loading scenarios. The results of EFLA’s most recent modelling completed in 2020 confirmed that the routing chosen during the design was successful in avoiding the higher exposed areas of rime. The recent weather research and forecasting modelling resulted in rime ice loading for specific segments of the line being significantly lower, up to a maximum reduction factor of six, than that used in the design. This is a significant finding as Alpine zones for the LIL are the more remote and hard to access areas from an emergency restoration perspective. A higher level of reliability in these zones aids in the overall assessment of the line’s strength. The revised load values based on various return periods for the sections of the line governed by rime icing were utilized in the final reliability assessment undertaken by Haldar & Associates.

# 3.0 Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads - Haldar & Associates Assessment

The Haldar & Associates Assessment considered the impact of two types of icing on the structural reliability of the LIL’s HVdc line: (i) glaze icing due to freezing precipitation and (ii) rime icing due to in-cloud precipitation. The study assessed line reliability by exposing the lines to these two types of icing in various scenarios. The objective of the study was to identify the probability of failure for various scenarios which could lead to an extended bi-pole outage. This work was based on the guiding principles of CSA 60826 where applicable and supplemented by other engineering principles and studies including the rime ice evaluation completed by EFLA.

## 3.1 CSA 60826 Analysis

Based on CSA 60826, the Haldar & Associates Assessment indicates that the as-built LIL has a return period of approximately 1:72 years and an estimated annual failure rate of 1.10% where the CSA standard is based on a DLS analysis and considers the OPGW as the governing critical component. The entire line was reviewed as a segmented system (similar in approach to that taken by SNC Lavalin). The difference between prior studies and the Haldar & Associates Assessment is the latter considered all line components (i.e., structures, conductors, insulators, and hardware) and both types of icing—glaze and rime. Based on requirements from the CSA standard with respect to DLS analysis, the mechanical failure limits of the LIL are not expected to be reached and therefore, theoretically, it should not represent an extended outage scenario for the LIL. The basis for this conclusion is that the OPGW was set to a 60% tension limit for combined wind and ice when compared to a higher value of 75% as specified per CSA, resulting in a higher safety factor and the cable being theoretically under-utilized. Although exceeding DLS limits is not expected to result in an extended outage due to major failure, it could potentially result in operating issues if the environmental conditions (hazards) that led to the exceedance of DLS persist for a long duration or occur frequently.

## 3.2 Ultimate Limit State Analysis

The return period and failure rates under an ULS was also considered to provide a more complete picture of the considerations necessary with respect to the LIL reliability. The ULS analysis was undertaken to truly represent an ultimate failure scenario which has a higher probability of resulting in a forced outage. Under this scenario, the system was stretched to the ultimate limit during the analysis by allowing the strength factors for all cable and structural elements to be increased to maximum limits, 90% for all cable elements and 100% for all structural elements.

The ULS analysis findings are based on the assumption that the LIL infrastructure is exposed to an extreme loading event that would result in the OPGW being stressed to the maximum tension limit in accordance with utility best practise. This would allow the cable to stretch to a maximum of 90% of the Rated Tensile Strength, at which point, it would be assumed that the cable would experience a mechanical failure. From Hydro's perspective, the mechanical failure of a cable(s) in such a scenario would be considered a significant failure capable of causing an extended bipole outage as it could potentially result in failure to multiple structures as built up tension is released. Based on the ULS analysis, the as-built line is identified as having a return period of approximately 1:160 years and an associated annual failure rate of 0.48%.

If this extreme scenario were to occur, and prior to reaching the failure limit of the cable(s), the possibility of short interruptions due to flashovers as a result of excessive sag on the cable may occur.

Interruptions due to flashover are considered a low risk as the tower geometry has been designed to provide electrical clearances based on maximum ice and line galloping conditions that would be more conservative than the combined wind and loading cases that cause the maximum cable loading. Operational protocols put in place to regularly monitor and inspect the line during such extreme loading events would mitigate safety or operational concerns.

Haldar & Associates has identified that the design philosophy of the LIL differed from typical utility practise with respect to sequence of failure where typical utility practise prescribes that the cable system be the strongest component in the system. A mechanical break of the cable system could potentially result in a failure which could range from partial damage of a structure(s) to full scale collapse of a structure(s). As a result of the lower tension limits applied during the design for the cable system under the combined wind and ice scenario, the LIL's cable system has additional reserve capacity which provides an additional buffer between the design limit and the failure limit. The occurrence of a mechanical failure on the cable system would require the line to experience extreme loading in exceedance of original design loads or those specified by CSA 60826. If the load were to continue to increase above the design tension limits, the line could still be operable but would require an engineering assessment to determine if there would be clearance violations which could result in sporadic line trips due to violation of electrical clearances. In this scenario, ice removal techniques could be applied in the field to eliminate this risk. Hydro does not feel this will be a major contributor to an extended bipole outage.

## 3.3 Line Length Consideration

The Haldar & Associates Assessment identified long line length as a consideration of the LIL structural reliability. The CSA standard does not require analysis of the impact of line length on reliability; however, Haldar & Associates stated that ". . . it is well known that as the length of the line increases, reliability decreases."[11] In conducting its analysis, Haldar & Associates considered the independency between glaze and rime icing and the line length. These correlations were considered under both a DLS and a ULS scenario and resulted in both having a return period of less than 50 years. The resulting findings were an annual failure rate of 5.17% under a DLS (not expected to impact power transfer for an extended duration) and an annual failure rate of 2.28 % under a ULS (could impact power transfer for an

[11] "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," Haldar & Associates Inc., March 10, 2021 at p.28/868.

extended duration). General line design practise under CSA does not consider the length of the line as a factor in reliability calculations. Haldar & Associates identified this as a ". . . shortcoming of the current standard."[12]

## 4.0 Additional Considerations

The Haldar & Associates Assessment identified additional considerations related to the as-built design of the LIL which are suggested for further investigation. These recommendations were identified as part of a limited sensitivity analysis and are additional considerations above the baseline as-built reliability calculations provided by Haldar & Associates. These include:

- Effect of Icing on Large Diameter Conductor;
- Unbalanced Icing;
- Wind Speed Up Factors; and
- Combined Wind and Ice.

Hydro believes there is merit in further consideration of these recommendations to determine if adjustments to the as-built design of the LIL are required. Hydro, in consultation with Nalcor Energy, is undertaking a preliminary assessment of the additional considerations and will provide further follow-up to the Board on its preliminary conclusions and any necessary next steps.

Some of these items identified by Haldar & Associates are subjective to the designers' discretion based on experience and historical operation. Before decisions are made with respect to reliability impact, the consideration of criteria outside of the original design should be validated through an engineering assessment to ensure the adjustments are warranted. In addition, as some of these topics are relatively new concepts based on the implementation of CSA 60826, historical design practises would not have accounted for some of these criteria; the application of extensive operating experience within the province as a comparator would be considered an appropriate design approach. Brief commentary on each of the additional considerations identified by Haldar & Associates follows.

[12] "Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads," Haldar & Associates Inc., March 10, 2021 at p.28/868–869.

## 4.1 Effect of Large Diameter Pole Conductor

CSA states that an ice load adjustment can be made if the cable diameter is different than the diameter of modelling rod that was used in the measurements or during simulations. Since the extreme ice thickness values are taken from the CSA map, an adjustment is necessary for the pole conductor where the diameter is significantly higher compared to the standard 25 mm diameter rod that was used in the Environment Canada model simulations in producing the CSA ice accretion map. Haldar & Associates has suggested that if assessed fully, an adjustment for the pole conductor diameter will reduce and improve the baseline probability of failure values presented by Haldar & Associates for the existing LIL design. Haldar & Associates has suggested that an engineering assessment be completed to confirm how the revised loading due to reduced ice accumulation on the pole conductor will impact the overall line reliability.

## 4.2 Unbalanced Loading

CSA 60826 suggests that unequal ice accumulations or shedding in adjacent spans will induce critical out-of-balance longitudinal loads on the supports. This loading can occur either during ice accretion or during ice shedding and can result in non-uniform ice loading conditions that can introduce longitudinal, transverse, or torsional effects on a support structure and is typically presented in the form of a percentage of the total design accumulation on each side of the structure. The design of the LIL included specific load cases for unbalanced loading but the cases differed from both the scenario presented in the CSA standard for certain tower types and specific load cases utilized in the past by Hydro on specific projects. While the CSA identifies such loads as reliability loads,[13] Haldar & Associates suggests such loads should be considered as deterministic loads[14] and have indicated that it would be prudent to review the impact of such load cases on the tangent towers (specifically in areas such as Southern Labrador and the Long Range Mountains on the Northern Peninsula). It is recognized that the Haldar & Associates' opinion of unbalanced loading criteria is an engineering design selection based on past Hydro practise and experience that differs from the engineer of record for the LIL. Haldar & Associates has also indicated that this risk is further amplified by the fact that due to colder temperatures in Labrador, the residence time of the ice will be longer, thereby increasing risk.

[13] Reliability requirements aim to ensure that (i) lines can withstand the every day climatic limit loads (wind, ice, ice and wind, with a return period) and (ii) the loads derived from these events during the projected life cycle of the system can provide service continuity under these conditions.

[14] A deterministic static load is a single valued load which has no coefficient of variation and is used in allowable stress design ("ASD").

The LIL has been designed to incorporate specific unbalanced loading in its design as well as security load containment measures. Specifically, the LIL features anti-cascading towers which are in line with CSA recommendations to limit exposure in areas known for heavy icing. As outlined in the Haldar & Associates Assessment, it appears that not all utilities follow the exact guidelines outlined in CSA with respect to unbalanced loading and, in many cases, other utilities have adopted a customized approach to unbalanced loading and the application to line design.

Haldar & Associates recommends the completion of further unbalanced loading studies to ensure that the impact of unbalanced icing is comprehensive and inclusive of all potential scenarios so that the LIL is not at risk of a potential failure. Following such analysis, modifications could potentially be undertaken which would increase the LIL's performance with respect to specific ice shedding.

### 4.3 Wind Speed-Up Factors

CSA provides limited direction on the use of wind speed-up factors associated with local elevated terrain for line design. According to the Haldar & Associates Assessment, it is expected this will have an impact on governing wind and ice conditions that limit the mechanical integrity of the infrastructure. The Haldar & Associates Assessment addressed this issue as a sensitivity to the base analysis by exploring the impact on the line at Hawke Hill, an area known to harbour conditions suitable to allow such loading. The sensitivity analysis indicated that wind speed-up factors could potentially result in wind loads in the range of 30% higher than the original design loads. The specific LIL structures at Hawke Hill, however, were found to meet these criteria. It should be noted that this design criteria would not have been considered in past historical Hydro line designs as it was not addressed in earlier versions of the CSA standard. However, it is acknowledged that the LIL traverses some areas throughout the province where Hydro has limited operating experience.

The original design of the LIL accounted for increased transverse loading within the Alpine zone by utilizing site specific data obtained from local test spans. In addition, the original design aimed to minimize the use of differing towers to achieve manufacturing efficiencies thus likely resulting in a percentage of the existing towers having increased reserve capacity which would allow these additional loads to be tolerated in other regions.

Haldar & Associates recommends that specific areas throughout the line should be reviewed to ensure an appropriate understanding of unknown areas outside of the Alpine zone that may be subject to such unique loading.

### 4.4 Combined Wind & Ice

CSA provides direction on load case combinations for wind on ice accumulation. Within these scenarios, the standard provides a low and high range of factors associated with occurrence. Typically, the decision to use either the low or high range of factors is subjective and based on the designer's judgement and the utility's past operational experience. With the exception of Labrador and the Long Range Mountains, the majority of the LIL traverses areas which Hydro has considerable knowledge of local environmental conditions and operating experience thus providing background for the utilization of the lower limit as provided by the standard. The Haldar & Associates Assessment considers the lower limit of the reference wind speed and ice load values for glaze icing and upper limit values for rime icing. In the areas where there is limited operational experience (i.e., Labrador), Haldar & Associates identified the pertinence to consider the high range factors identified in the CSA standard. As mentioned previously, this risk is further amplified by the longer residence time of the ice accumulation due to the cold temperatures.

Haldar & Associates suggests that additional investigation should be completed to identify any areas where operational experience is limited (i.e., Labrador) and such increase in load could result in a failure if these extreme loads are experienced. It is suggested this additional analysis should be based on actual wind and ice combinations determined through detailed modelling analysis which would be compared to the ranges identified in CSA 60826 to ensure that the design is not over conservative. As the high range of combined wind and ice loading prescribed by CSA is very onerous and could result in a significant increase in loading, it needs to be validated as realistic for the area to ensure that the decision is fully justified.

## 5.0 Conclusion

The Haldar & Associates Assessment was undertaken to identify the overall structural reliability of the LIL with respect to the probability of failure based on the integrity of the system components and considering climatological conditions which could potentially result in an extended bi-pole outage. The assessment considered the as-built design with respect to CSA 60826 and the overall likelihood of failure of the LIL with respect to both glaze and rime icing events.

Based on CSA 60826 (DLS analysis), the as-built design of the LIL reflects a return period of 1:72 years with an associated annual failure rate of 1.10%. Exceeding DLS limits is not expected to result in an extended outage due to major failure. A high-level assessment was also completed considering an ULS analysis which stretched various system components to their ultimate limit, thus resulting in a higher probability of a forced outage of power delivery. The ULS analysis identified a return period of 1:160 years with an associated annual failure rate of 0.48%. Based on the findings of the Haldar & Associates Assessment, it is Hydro's opinion that the LIL has the greatest risk of experiencing an extended bipole outage under a ULS failure scenario.

Additional scenarios and return periods were identified in the Haldar & Associates Assessment based on line length considerations. While the CSA standard does not require analysis of the impact of line length on reliability, Haldar & Associates considered the independency between glaze and rime icing and the line length to be an important consideration. Correlations under both a DLS and a ULS scenario resulted in both having a return period of less than 50 years.

Haldar & Associates has identified additional considerations related to line reliability which are suggested for further investigation. Some of these items identified are subjective to the designers' discretion based on experience and historical operation and it should be recognized that by inclusion of these criteria in the reliability analysis, the engineering parameters will be changed and will not be considered a true reflection of the as-built design. Hydro believes there is merit in further consideration of these recommendations to determine if adjustments to the as-built design of the LIL are required. Any such adjustments would be considered a change in the design criteria utilized by the original designer and could result in a revised projection of the reliability performance of the line; however, it does not change the baseline reliability measures identified through the Haldar & Associates Assessment for the as-built design. It is Hydro's position that before decisions are made with respect to the reliability impact of these items, the consideration of criteria outside of the original design should be validated through an engineering assessment to ensure the adjustments are warranted.

Hydro, in consultation with Nalcor Energy, is currently undertaking a preliminary assessment of the additional considerations identified by Haldar & Associates and will provide further follow-up to the Board on any necessary next steps by April 30, 2021.

The findings of the baseline reliability review outlined in the Haldar & Associates Assessment are not considered to materially impact the LIL restoration plans previously outlined. From a restoration perspective, the timing to restore the LIL to service is variable depending on the failure events type and locations. Previously supplied durations range from one week to seven weeks to return the LIL to service depending on the severity of the incident. The LIL is within its first few years of operation and has been subjected to multiple seasons of icing and wind throughout its whole line length. Recent ice storm damage to the LIL has been experienced in specific regions. The findings of the damage investigation currently underway, together with continued operational experience, will further inform Hydro's understanding of the LIL's performance under severe climatological conditions.

# Attachment 1

## Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads

# Assessment of Labrador Island Transmission Link (LIL) Reliability in Consideration of Climatological Loads

Prepared By:
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Principal Investigator
Haldar & Associates Inc.
St. John's NL

Report Prepared
for
Newfoundland and Labrador Hydro
March 10, 2021

# REPORT DISCLAIMER

This report contains information about the Labrador Island Link ("**LIL**") reliability study (the "**Report**"). The Report uses data specifically related to the structural analysis of the LIL, which was provided by Newfoundland and Labrador Hydro and Nalcor Energy. While every effort was made to ensure the accuracy and completeness of the information contained in the Report, in no event shall the author be liable for any damages whatsoever resulting from the use of this Report, or any information obtained from this Report. The Report and this exclusion of liability have been drafted in contemplation of the Report being made public once submitted to the Public Utility Board.

# Executive Summary

This report presents the impact of two types of icing on the structural reliability of the Labrador-Island Link (LIL) HVdc transmission line. The two types of icing are (a) glaze icing due to freezing precipitation and (b) rime icing due to in-cloud precipitation. The study assessed the structural reliability of LIL by exposing the line to these two types of icing in various scenarios. This allowed for a better assessment of the likelihood and consequences of an extended outage under extreme weather circumstances and provided insight into the impact of system reliability (structural) on a LIL outage. This reliability assessment was also conducted to validate the LIL design with respect to CSA 60826 -2010 under reliability loads and to determine the overall likelihood of failure of the LIL with respect to glaze and rime icing events (Figure A). The reliability assessment and the expected LIL failure rate ($\lambda$) based on a probabilistic assessment of the LIL was determined by considering the full line length and both types of icing exposures (Figure A). The failure rate ($\lambda$) and repair rate ($\mu$) are the key input parameters required to calculate the system planning reliability study. The report addresses the failure rate both with and without the impact of line length under various scenarios. It also includes a qualitative benchmarking of the LIL with respect to utility-based operational statistics and a discussion on Hydro's operational experience with selected existing transmission lines and a comparison of failure rate normalized in terms of line length with limited published data.

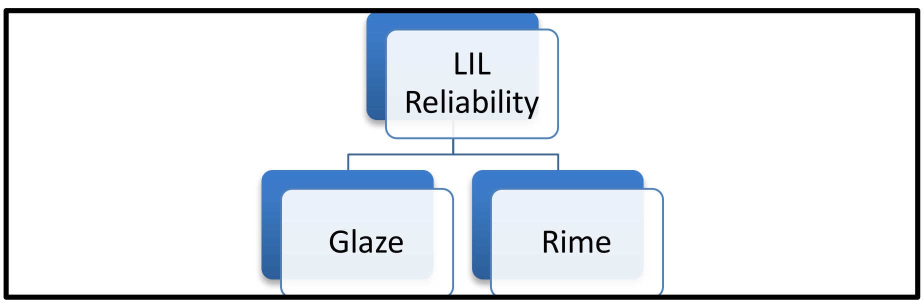


Figure A Two Types of Icing

All the probability of failure (POF) values are reported here as baseline values and they include the baseline extreme ice, extreme wind and combined wind and ice loads following CSA 60826-10. The code only provides the glaze icing map for line design. Unbalanced ice loads are excluded from the reliability analysis and treated as deterministic after a careful review of the CSA standard. Combined wind and ice loads consider the lower limit of the reference wind speed and ice load values for glaze icing and upper limit values for rime icing. Specific topographic exposures and its impact were not included explicitly in the baseline values.

Based on the study, the author finds that the annual POF of LIL can range from little over 1% for Scenario # 1 (a simple series model with full correlation along the entire line length) to 5% for Scenario # 4D (considering two different types of icing exposures, correlation among the elements and regional independence of the various weather zones) under the CSA 60826-10 Damage Limit State (DLS) criterion. All these scenarios are described in Section 5. It must be understood that the violations of DLS do not automatically imply that the complete structural failure of the line (collapse of a tower, foundation, rupture of a conductor etc.); it could instead be a loss of a specific line performance criterion. CSA provides some guidance on what are under DLS violations. These violations under DLS can create safety violations and other serviceability problems but they may also lead to LIL outages. In terms of the return period of a limit load (T) under Scenario # 1, this is estimated in the range of 45 $< T < 91$ following CSA 60826-10. The POF range could be much wider if one considers all possible probability distributions. A factored strength based semi-probabilistic calculation shows this return period under Scenario # 1 is estimated to be 72 years. However, POF level in Scenario # 4D is considerably high (five folds compared to Scenario # 1) under DLS criterion when the impact of line length and the regional climatic independence, the exposure to two icing types, and the correlation among the elements are considered explicitly in the calculations. Cable systems control the LIL system POF; similarly, foundation for tangent tower is likely to fail first compared to tower and these observations are in contradiction to industry's best practices on sequence of failure. Scenario # 1 can be directly compared to CSA 60826-10 methodology. All other Scenarios are not directly covered by CSA 60826-10 but are relevant to provide a realistic reliability (or POF) assessment of LIL in consideration of climatological loads. Figure B presents POF, failure rate ($\lambda$) and the computed theoretical POF in 5 and 50 years of the asset life (exceedance level in %).

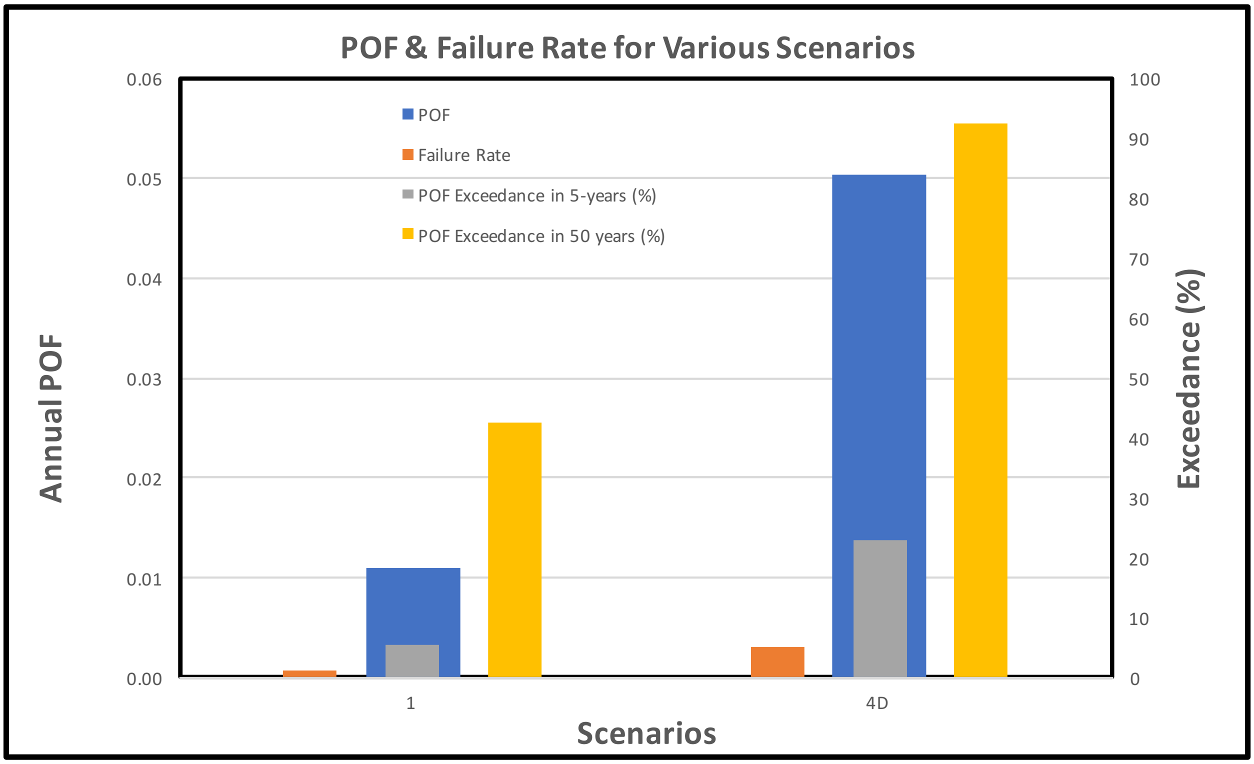


Figure B POF, Failure Rate and Exceedance level in 5 & 50 Years

A high level Ultimate Limit State (ULS) analysis for cable systems based on the baseline Scenario # 1 provides a relative comparison of the POF levels between DLS and ULS and shows that POF under ULS is forty-three (43%) of that presented under DLS. Therefore, following CSA 60826-10, this will translate the baseline POF value to the return period (T) of a limit load in the range of $106 < T < 211$; based on a factored strength based approach, this return period (T) is closer to 160 years under Scenario #1; For Scenario # 4D, direct return period comparison with respect to CSA 60826-10 is not made but the POF is five times of that computed under Scenario # 1.

The baseline POF values reported here will change (most likely increase) when a full assessment has been made based on several recommendations for follow up work that will explicitly consider the full effects of terrain roughness and topography on the LIL structure support system. This analysis should be done with and without the effects of combined loads (ice, wind) with due consideration on both upper and lower limit values specified in CSA 60826-10. Also, many critical structures those located in Labrador should be checked specifically for upper limit of CSA 60826-10 combined loads (ice, wind) because of long residence time of ice in these zones (ice will be expected to stay longer time on the cables and structures) and therefore a higher value of 0.85 or more is appropriate for reference wind speed value than 0.6 which was considered in EFLA report (2020) and in this study under all scenarios. Because of the terrain roughness and topographic effects, the baseline POF values reported will be impacted considerably for towers located on higher elevations (specifically located on escarpment, 2D ridge or 3D hills). A limited sensitivity study carried out here shows that this topographic effect coupled with increased combined wind and ice loads above the baseline values used will have an impact on the overall LIL POF for structure support system and further, increase the baseline POF values reported here.

Initial sensitivity analysis indicates that the POF for structure support system in Zone 3a for 85/40 combined wind and ice load is 0.0539 (a fifteen-fold increase compared to 60/40 case under a baseline value) and this will make the LIL POF significantly higher (1% versus 5%) than stated earlier under Scenario #1. Of course, all other Scenarios for DLS will be also affected and will increase considerably. Only scenario #1 was re-evaluated under 85/40 load combination with Type B (open terrain) roughness and it shows that LIL will have a very high failure rate with respect to DLS violation under combined wind and ice loads. In terms of return period of the limit load, this is estimated in the range of 10 to 20 years. Under these combined wind and ice loads, elastic tower analysis under DLS may not be sufficient because it may not capture the POF of the tower fully unless it shows clearly that main members (leg, heavy bracing members) are overloaded significantly under DLS. A progressive collapse analysis (post elastic behaviour) is needed to estimate the collapse probability of coupled structure support-wire support system. This should be pursued for a few critical segments already identified in this report.

In addition, the study has also identified an inherent weakness in the LIL line design under ice shedding phenomenon. LIL design in some sections met neither CSA requirement (probabilistic) nor did it follow Hydro's design philosophy (deterministic) based on standard design load combinations that were used in 230kV steel transmission line design since 80's. The author disagrees with CSA 60826-10 stipulation that the UBI should be based on return period and be classified under reliability class of loads. A design that accounts for adequate load combinations is crucial for assessing the impact of unbalanced ice loads on the structure support system, particularly the "harsh" environments that the LIL line traverses. The load combination criteria were not considered during LIL design, and it is our assessment that the LIL is vulnerable due to unbalanced ice load exposures particularly in Labrador. This needs to be closely examined for the LIL line and all the critical towers should be checked.

The present study also identified an opportunity to revise the current design loads based on the effect of large diameter of pole conductor on the design ice thickness. This was not considered in the original LIL design and in the earlier climatological loading studies. The revised loads and combinations, once assessed fully, will reduce and improve the baseline POF values for existing LIL design as well as reduce some of the expected increases from combined wind and ice loads considering the effects of topographic and terrain roughness. This improvement will only affect the

POF (or reliability) under glaze ice exposure. It is likely that the increase in the loads due to increased values for reference wind speed and glaze ice load effects may be compensated by the expected decrease in the transverse and vertical load effects on pole conductor due to the impact of large cable size on ice accretion. This will also reduce the impact of UBI load/load combination effects, but the overall impact is unknown and this should be assessed quantitatively.

Based on our analysis, it shows that POF and failure rate under Scenario # 4D is more appropriate and realistic for such a long line considering DLS criterion. In general, the baseline annual POF value and failure rate values are normalized in terms of line length (failure rate\year\100km) and the failure rate is compared with data from several sources. These include limited published data on EHVAC and EHVDC line failures under extreme weather events and three specific EHVDC line failure data that the author has compiled from external sources through his own contacts. It shows the annual POF of 0.05 and the failure rate 0.052 in Figure B under Scenario # 4D (Table 6.2) will translate to a normalized failure rate (0.0047\year\100km) that considered the effect of line length of 1100km and this failure rate is better aligned with the data in Figure C. The annual POF of 0.0110 also translates to a normalized failure rate of (0.0010\year\100km) under Scenario # 1(Table 6.2). This value is approximately one fifth of the failure rate under Scenario # 4D and appears to be a low value and does not align well with the data in Figure C because it does not consider the impact of line length. All these failure rate\year\100km values will likely increase further when the LIL is assessed fully for terrain and topographic effects with and without the increased combined wind and ice loads. However, the POF and failure rate values in Scenario #4D could also decrease if the storm correlation study can show the natural loads are partially correlated along the line length. The failure rate presented in this study under Scenario # 4D is an upper bound estimate while the failure rate under Scenario # 1 is an estimated lower bound value.

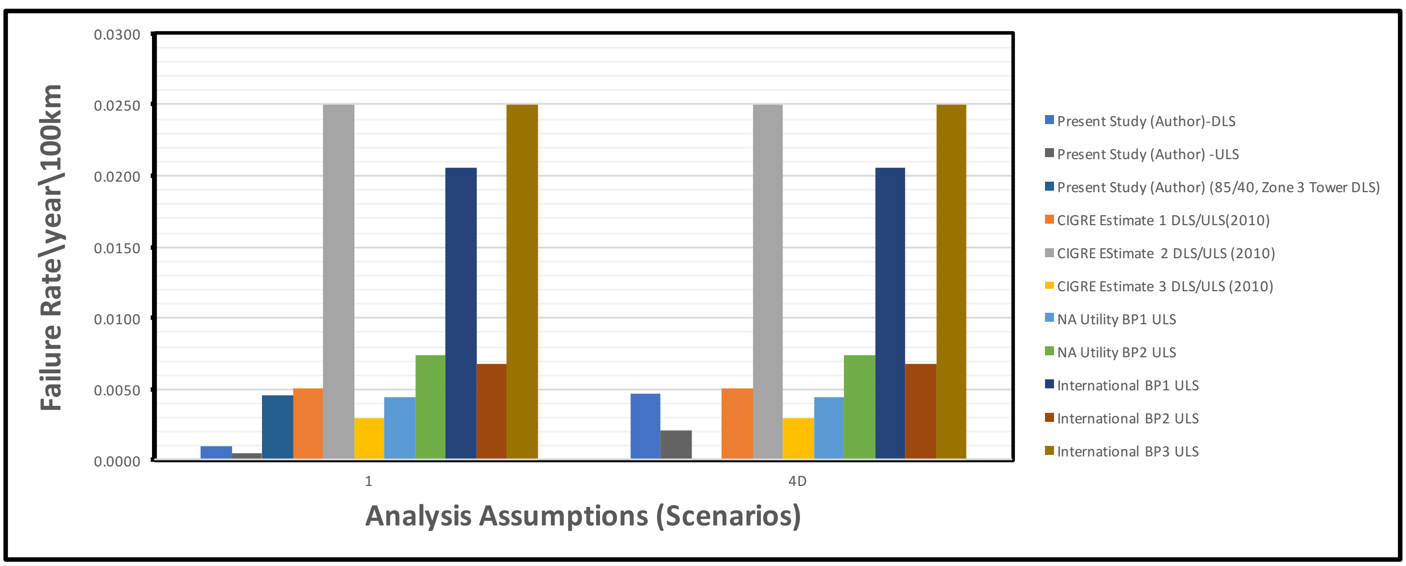


Figure C Comparison of Line Failure Rate Data

The unavailability of LIL is calculated as the product of the failure rate multiplied by the recovery time. If the recovery time is assumed to be one week (168 hours), unavailability could vary from 1.84 to 8.40 hours per year considering the failure rate bounds. Since the failure rate is given and the unavailability is linearly proportional to repair rate, one can reduce this repair rate to minimize the LIL unavailability. This may involve better monitoring programs, frequent inspections, high quality maintenance, and a high caliber emergency restoration program. All this will significantly help to reduce the repair and recovery rate and reduce the unavailability of the LIL and improve the resiliency of the LIL

Once the ULS risk levels are assessed for the LIL line system, all mitigation options should be considered in a cost-effective manner, including any generation expansion plan. This report makes several recommendations that need to be followed systematically to assess the POF of LIL line system beyond the baseline values presented and evaluate the consequences of the mechanical/structural failures and its impact on the NLH's power grid.

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# List of Abbreviations

ASCE – American Society of Civil Engineers
CFD – Computational Fluid Dynamics
COV – Coefficient of Variation
CSA – Canadian Standard Association
CEATI – Center for Energy Advancement and Technology Innovation
DLS – Damage Limit State
ULS – Ultimate Limit State
EC – Environment Canada
ECOST – Energy Cost
EENS – Expected Energy Not Supplied
EHSS – Extra High Strength Steel Supported
EHVAC – Extra High Voltage Alternating Current
EHVDC – Extra High Voltage Direct Current
GNP – Great Northern Peninsula
IEC – International Electrotechnical Commission
LCOST – Line Cost
LRM – Long Range Mountain
LIL – Labrador Island Transmission Link
LOLE – Loss of Load Expectation
MHI – Manitoba Hydro International
PUB – Public Utility Board
NBCC – National Building Code of Canada
NP – Newfoundland Power
NLH – Newfoundland and Labrador Hydro
OPGW – Optical Ground Wire
OHGW – Overhead Ground Wire
OHL – Overhead Line
POF – Probability of Failure
RBD – Reliability Based Design
RFI – Request for information
SI – Severity Index
SS – Structure Support
UBI – Unbalanced Ice
UF – Use Factor
WS – Wire Support
WRF – Weather Research and Forecasting Model

# Definitions of Key Terms

Characteristic Strength – minimum strength given in the standard or determined based on actual tests

Coefficient of Variation – The coefficient of variation represents the ratio of the standard deviation to the mean and is a measure of the degree of variation of a data series

Damage Limit of a Component – strength limit corresponding to a state where permanent deformation occurs (yielding, shortening of a member etc.)

Damage State – the state where some repair/replacement is needed because the component has exceeded the damage limit

Exclusion Limit (%) – a value prescribed to assess the characteristic strength, guaranteed minimum strength from a probability distribution

Failure Limit of a Component – strength limit of a component which leads to the failure of the system if this limit is exceeded.

Failure State of the System – the state at which the system/component has failed (rupture of a cable, buckling of a tower member etc.)

Intact State – This is the state where the system has no damage and can meet the performance criteria

Structural Reliability – a measure of structural safety, the success that a system performs a given task, under a set of operating conditions, during a specified time

Probability of Failure – probability for exceeding a limit state; the complement to reliability is the probability of failure or unreliability

Return Period of a Climatic Event – the recurrence interval is an average time or an estimated average time between climatic events (ice storm, hurricane etc.)

Service Life – expected operating life of an asset

Strength Factor – a factor applied to the characteristic strength or to a nominal capacity as defined in the standard and code

Use Factor – ratio of actual load effect on a structural component to the limit load of the component

# 1.0 Introduction

Newfoundland and Labrador Hydro (NLH) manages approximately 5300 km of transmission line operating at 69 kV, 138 kV, 230 kV, 315 kV, and 735 kV voltage levels. The transmission network system consists of wood pole structures as well as steel and aluminum tower lines. NLH's transmission system covers a vast region (Figure 1.1) and is exposed to a harsh, cold environment. Most low-pressure storm systems moving across North America, particularly on the eastern seaboard, pass over Newfoundland (Figure 1.1) and bring heavy precipitation (freezing rain or snow) and strong wind conditions. These maritime storms can stall for a day or two and often produce heavy snow or freezing rain during the winter months. This creates significant operational challenges for maintaining the overhead line system in Newfoundland and Labrador.

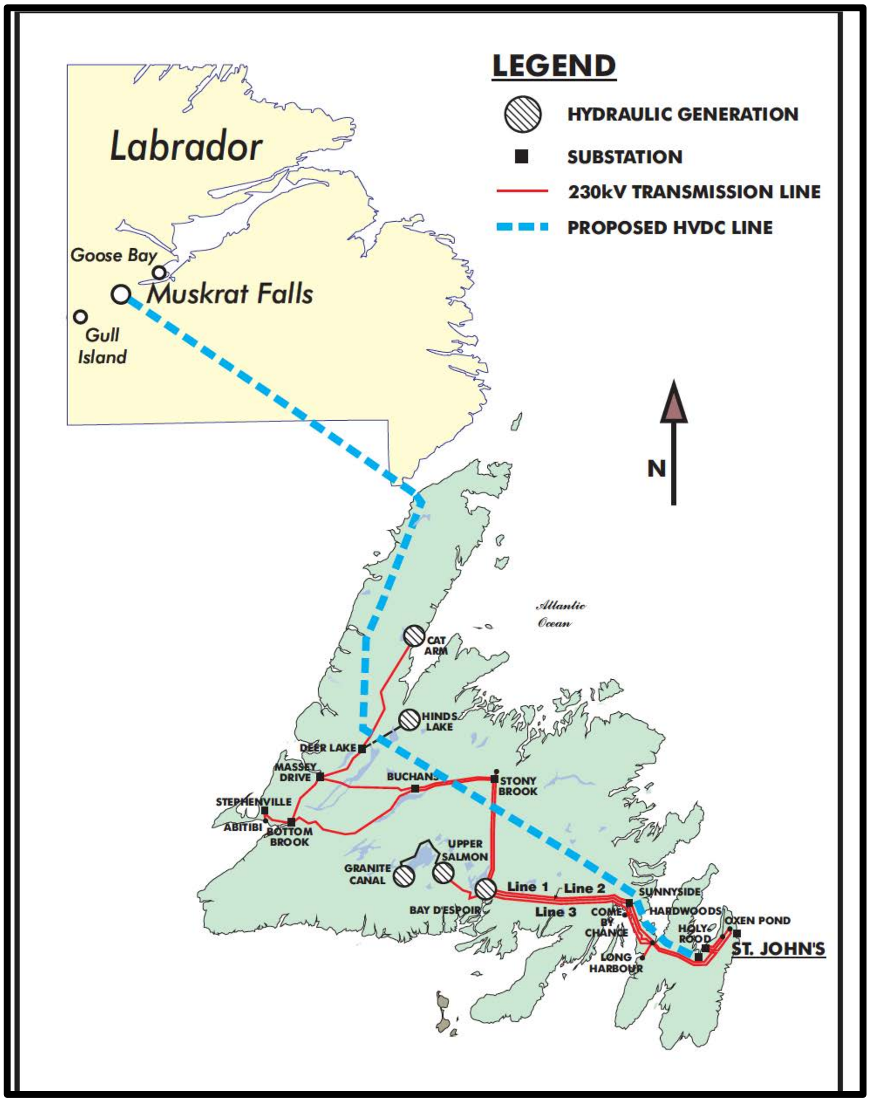



Figure 1.1 Newfoundland and Labrador Hydro's 230 kV Line System

## 1.1 Impact of Weather Events on Power Delivery

Since the commissioning of Hydro's (NLH's) transmission lines in the 60's, much of NLH's system has experienced ice storms and severe ice loadings. The original design wind and ice loads for these lines were based on CSA C 22.3 No.1 heavy load (Canadian Standards Association), which was 12.5 mm glaze ice combined with 117-km/hr wind with appropriate overload factors (Haldar, 1996). Upon review of the pertinent information available at the time, two basic load conditions evolved: Normal Zone with 25.4 mm radial glaze ice and Ice Zone with 38 mm radial glaze ice. The Ice Zone was used for a small section of the transmission line system; the overloads factor for all metal tower design was 1.33 and 2.0 for wood pole structures.

Several large ice accumulations have been observed. Since 1965, there have been at least four (4) major line failures on the Avalon Peninsula (eastern part of Newfoundland, Figure 1.1). Similar line failures have been observed in other parts of Newfoundland, including the Buchan's Plain, located in the western part of Newfoundland (elevation 600 m above MSL, Figure 1.1) (Haldar, 1990). Figure 1.3 presents the percentage of line failures and outages in the US related to weather storm events.

Figure 1.2 Large Angle Tower Failure near Hawke Hill (1988 Storm Avalon Peninsula, Haldar, 1996)

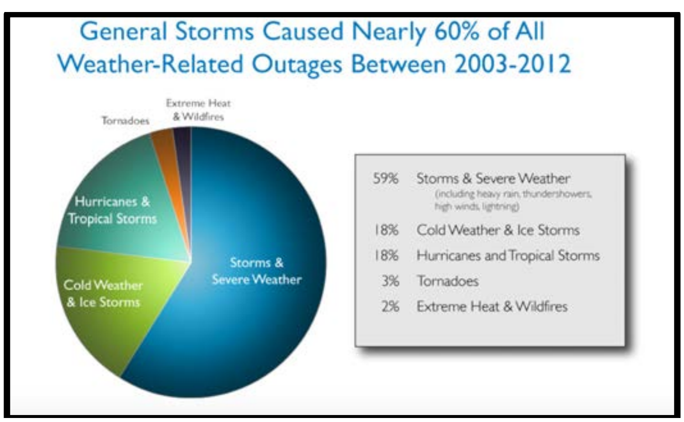



Figure 1.3 Types of Severe Weather Responsible for All Weather-Related Power Outages From 2003-12 (Climate Central, 2014)

## 1.2 Labrador Island Transmission Line (LIL) System Configuration

The ± 350 kV HVdc line route extends from the Muskrat Falls generating station in Labrador to the Strait of Belle Isle, before passing under the Strait of Belle Isle via an underwater submarine cable system to the Island of Newfoundland. From the Strait, the HVdc transmission line follows the western coast of the Great Northern Peninsula (GNP), crosses the Long-Range Mountains (LRM), passes south of Grand Falls, and terminates at the Soldier's Pond Terminal station near St. John's. The HVdc line passes through a region of the LRM known for severe in-cloud glaze and rime icing conditions (Figure 1.4, Zone 7 and Figure 1.5). The line in the Southern Labrador section is also vulnerable to both severe glaze and rime icing conditions. The 1093 km consists of 388km in Labrador and 705km in Newfoundland. The DC line is fully integrated in the island's AC system and transports energy to the Maritimes via a sub-sea cable link. Figure 1.4 presents the layout of the HVdc line configuration.

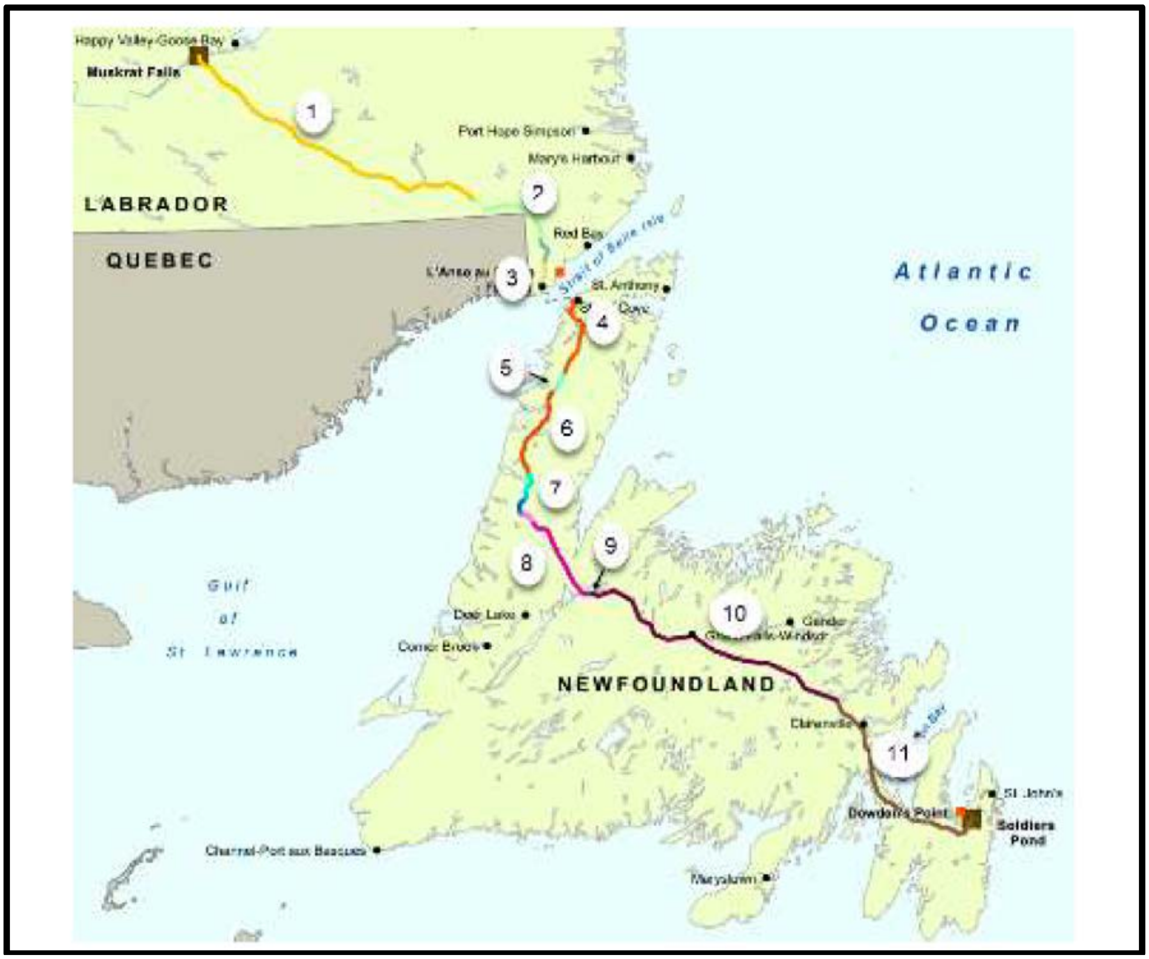



Figure 1.4 LIL Routing with Main Segments Identified (11 Main Loading Zones, EFLA 2020)

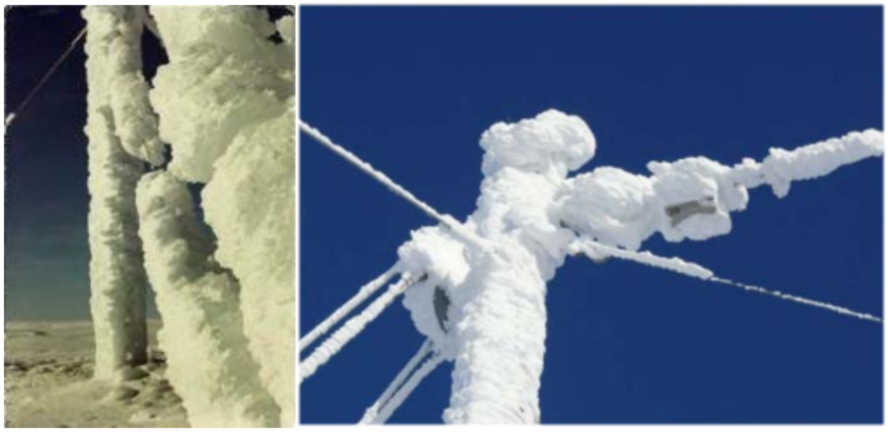


Figure 1.5 (a) Rime Icing in Labrador, 1977 (courtesy NLH) and (b) Rime Icing on a test Span (2010, LRM)

The ± 350 kV HVdc transmission system is designed to deliver up to 900 MW to the island. The transmission system includes the following key components (Figure 1.6):

- Overhead Transmission Line – Muskrat Falls to Strait of Belle Isle
- Strait of Belle Isle Cable Crossing
- Overhead Transmission Line - Strait of Belle Isle to Avalon Peninsula
- Converter Stations at Muskrat Falls and Soldiers Pond
- Electrodes
- Integration of HVdc line to Newfoundland and Labrador Hydro's (NLH's) existing AC network system
- More than 3,000 lattice steel towers with two climatic zones and 11 different loading zones

The Maritime link includes:

- The transport power to the west coast of Newfoundland
- A submarine cable system to the Maritimes

The current study is based on a recent EFLA report entitled "Structural Capacity of as-built Design of the LIL following CSA C22.3 60826-10" and was completed in April 2020. This study also reviewed several Nalcor documents (2012-18) that were made available to the author. The author has also considered other relevant documents available at the PUB website and the recent RFI responses (2020) that were submitted by NLH. All base analysis data for the LIL were provided by NLH engineers, notably the structural analysis of LIL line including PLSCADD and PLS TOWER model runs. Data has been reviewed at a high level and no attempt has been made to validate all design and model assumptions, design approximations, etc., for this LIL reliability analysis. Maritime link is not part of this study.


Figure 1.6 LIL Routing - Maritime Link

## 1.3 Historical Information on LIL Review – Critical Data

Following the 2011 submission of a Public Utility Board (PUB) document entitled "Generation Expansion Alternatives for the Island Interconnected Electrical System" for the Muskrat Falls project, Nalcor reported that this HVdc line was designed for a 1:50 year return period following CSA 60826-06, operational experience of NLH for the past 50 years, and operational risk identified by Hydro. Manitoba Hydro International (MHI) was hired by PUB to review Nalcor's design philosophies of this HVdc line in 20111. MHI (2012) concluded that the LIL design criteria were inadequate with respect to reliability and operational criteria. They also determined that the design philosophies did not meet the industry's standards (CSA 60826-2006/2010) and best practices (MHI, 2012). In May 2018, Nalcor submitted a detailed report in response to RFI (CIMFP Exhibit P-03188 and NP-NLH-004, 2018) and indicated that LIL met the 1:150 and/or 1:500 CSA 60826-10 based on further structural analysis of design data along the line route. However, it did so only for selected zones. The following section provides some background information from the document (CIMFP Exhibit P-03188 and NP-NLH-004, 2018). It specifically reported that LIL met CSA 500-year return period loads on the Avalon Peninsula, which is known to experience severe freezing precipitation.

Three sections of LIL are extremely vulnerable: the region where it crosses Southern Labrador and is exposed to both rime and glaze icing zones; the LRM and Alpine regions where it is exposed to Severe Rime Icing zones, and the Avalon Peninsula region (Segment 11), particularly the Isthmus area, where it is exposed to Severe Glaze Icing. In addition to the above observations made by the author, a NP review report (Ghannoum, 2016) and subsequent report submitted by EFLA (2020) noted that LIL design and subsequent review analysis did not meet the following criteria (paraphrased):

- terrain roughness for LIL was considered as Type C (based on some vegetation coverage) rather than Type B (open country as suggested in CSA 60826); therefore, the review suggested that wind speed was underestimated along the LIL route,

- uncertainty of the topographical effects on the LIL design,
- selection of combined wind and ice load values in LIL design that did not follow CSA; a specific load-case recommended in CSA 60826-06, ice plus wind design load case was not considered. Questions were later raised with respect to an EFLA report (2020) used to develop load combinations for wind and ice values that only included minimum reference values for wind speed and ice load; in addition, the impact of increased reference wind speed due to terrain characteristics (Type B) and the local effects of topography were not explicitly considered in developing these loading envelopes,
- underestimation of Optical Ground Wire (OPGW) icing by failing to derive the design loads from conductor ice loads (breaking from CSA Standard Clause 6.4.3.1),
- hydro not following its own internal design recommendations for selecting ice loads on the Avalon Peninsula (Avalon Study report, 1996),
- determination of rime icing loads that did not account for the full effects of topography and terrain characteristics, and finally
- "the NLH should choose to validate the design for an increased return period based on ice and wind loads; however, the clearances due to increased sag and due to swing angles need to be addressed (serviceability criteria)".

Mr. Alteen's submission from Newfoundland Power to PUB (2018) also raised several issues regarding LIL and Island system reliability, the most important one being the crossing of four parallel lines, three 230kV lines (TL 207/TL237, TL 203 and TL 267), and one EHV lines (± 350 HVdc) through the narrow Isthmus zone, which is known for severe glaze icing. Once the Holyrood is decommissioned, this Isthmus zone (Figure 1.7) becomes the critical corridor for transporting power in both easterly and westerly directions. Item 44 in Mr. Peter Alteen's submission notes that Nalcor did not consider the line length in it's reliability assessment.

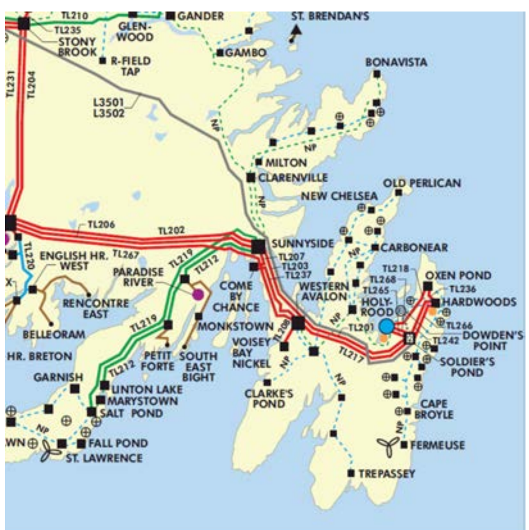



Figure 1.7 Isthmus Zone – Severe Icing Area

## 1.4 Return Period Concept in Selecting Overhead Line Design Loads

One of the major concerns that has been raised during the review and information gathering process is that LIL did not strictly meet the CSA C 22.3 60826-06 standard and that design loads have been underestimated. In P03188 submission (2018), Nalcor responded that the LIL design is based on a 50-year return period following CSA 60826-06, the operational experience of NLH for the past 50 years, and the operational risk identified by Hydro. However, CSA 60826-06 stipulates that lines of such importance should be designed to higher reliability (Level III) and not the minimum level selected (Level I), unless the lower selected level can be justified by a study backed by local weather and operational and line performance data. The optimum return period can be selected by balancing the cost of building, operating and maintaining the line against the future failure costs (including outage costs) to maximize availability. A clear methodology for this cost-risk optimization problem has been presented by the author for two major upgrading projects in the 80's and 90's (Haldar, 1990, 1996, 2006) and was later developed and extended for general line design problems that semi-probabilistically consider both reliability and cost explicitly in determining the optimum return period (Haldar et al, 2009, 2011, 2012, 2016). Later, the concept was extended to include security to determine the placement of the containment structure during the design process to balance the cost and risk (2018, 2020). This methodology is well suited for such an important radial line and is discussed further in Section 2.

## 1.5 Objective of this Study

The primary objective of this report is to assess the structural reliability of the LIL considering two predominant types of icing to which the line is exposed. These are (a) glaze icing due to freezing precipitation (86% of line length) and (b) rime icing due to in-cloud precipitation (14% of line length). The line passes through a region of the LRM known for severe in-cloud glaze and rime icing conditions as well the line is also exposed in the Southern Labrador section to these types of icing (Figure 1.4, and Figure 1.5). This reliability assessment is also conducted to validate the LIL design with respect to CSA 60826 -2010 under reliability loads and to determine the overall likelihood of failure of the LIL with respect to glaze and rime icings. The report addresses the failure rate with and without the impact of line length under various scenarios. It also includes a qualitative benchmarking of the LIL with respect to utility-based operational statistics and a discussion on Hydro's operational experience with selected existing transmission lines.

A targeted sensitivity study was conducted to determine the impact of key parameters on the reliability of the as-built LIL. The line reliability test considered various line exposure scenarios. This allowed for an assessment of the likelihood and the range of consequences of an extended outage under extreme weather circumstances and provided further insight into the associated implications for system planning reliability. Since CSA does not cover rime icing, correlation among key elements and the impact of length on line reliability and POF, a different approach was used in addressing these issues. The goal is to determine the overall expected line failure rate ($\lambda$) based on a probabilistic assessment of the LIL considering both types of icing exposure. This failure rate ($\lambda$) is one of the key input parameters that is needed to complete the system planning reliability study.

## 1.6 Scope of this Study

This study evaluated the overall line reliability of LIL with respect to the likelihood of failure based on a range of climatological loading scenarios. This report includes the inputs and data from the following reports:

- an assessment of structural capacity of as-built design of the LIL following CSA C22.3 60826-10; this report was submitted to PUB in April 2020;
- recalibration and hindcasting of rime icing in the LRM and Southern Labrador sections of the LIL, including an assessment of extreme design rime icing and combined wind and rime ice loads in view of additional data that has been collected;
- an assessment of the as-built structural capacity of the LIL under rime icing conditions;
- a qualitative targeted benchmarking included in the reliability study report with respect to utility-based operational statistics and a discussion on Hydro's operational experience with certain existing lines.

The combined findings of Hydro's "Assessment of the LIL Reliability in Consideration of Climatological Loads," will also provide critical input factors, including the likelihood of failure for climatological loading scenarios and the repair rate, which will help to determine the associated expected outage duration, should a failure occur.

## 1.7 EFLA (2020) Report on Strength Assessment of LIL – Summary

With respect to first item under the "Scope of the Study", EFLA has submitted a report in April 2020 entitled "Structural Capacity of as-built Design of the LIL following CSA C22.3 60826-10". This report analyzed several line components under LIL design loads and CSA 60826-10 loads under three levels of reliability class. Four load cases were considered: extreme ice, extreme wind, combined wind plus ice, and ice plus wind. Unbalanced ice loads were not considered, and the foundation was dealt with at a very high level.

The primary conclusion was that LIL design did not meet the 500-year return period load effect that was initially reported. Instead, the LIL design met the CSA 150-year return period load effect in most cases, except in specific zones where OPGW and hardware failed to meet the 150-year return period load effect criteria. Recommendations were made to follow up with an impact study to assess the loss of OPGW on line reliability and integrity. EFLA report did not consider the impact of rime icing on LIL strength nor did it consider unbalanced ice loads in assessing design strength capacity.

## 1.8 Deliverables

- Baseline LIL reliability (and probability of failure and failure rate) that considers two types of icing exposures and associated climatic hazard exposures
- A targeted sensitivity of the following parameters is included alongside the baseline reliability study
    - Terrain issues - #1
    - Topographic issues (one case study on the Avalon Peninsula) - #2
    - Combined wind and ice (increased reference values of wind speed and ice load parameters as per CSA 60826) - #3

- Justification of Avalon extreme ice loads; #4
- OPGW loading issue #5
- Addressing uncertainty issues in rime ice modelling - # 6
- Variation of selected strength parameters - #7
- Clearance issues due to increased structural loads (the last bullet under Section 1.3) is not addressed in this report

## 1.9 Layout of the Report

Section 1 provides a brief historical background of this project and the objective and the primary focus of this study. This section also presents a high-level chronological overview on the Nalcor's submissions to PUB on the LIL design and summarizes the salient points, particularly with respect to selecting the LIL design return period and non-compliance of CSA 60826-2006/10.

Section 2 presents a brief overview of basic system concepts in line design considering reliability, security, and availability issues and their impact the selection of the optimum return period for the LIL. This section also provides information on "Planning Perspective" for selecting the design return period at a system level with the goal of minimizing line unavailability.

Section 3 presents an overview of reliability-based design approach (RBD) and a review of CSA 60826-2010 at a high level. The section also identifies several shortcomings of the standard.

Section 4 presents the basic loads and strengths of this HVdc line for reliability analysis. This includes loads, load effects, strength assessment, factors used in the original design, and strength factor reference values that have been used in the "baseline" reliability analysis.

Section 5 considers the interaction of various line segments on line reliability. The line interactions include exposures to two types of icing, correlation effects of various critical elements under a specific load case within a segment, under various load cases, and the impact of line length on the LIL's reliability when considering weather events for various zones (Regional Grouping).

Section 6 presents the results of the analyses along the LIL line length for five load cases (reliability class) for glaze icing and rime icing and discusses the "baseline" results for the most vulnerable segments. The author strongly believes that the impact of line length should be considered on LIL reliability. This is extremely important for such a long radial line carrying bulk power to the Island system (almost 50% of the current system load). Furthermore, it is well known that as the length increases, reliability decreases.

Section 7 presents the results of the sensitivity study of several key parameters and their overall impact on the LIL reliability analysis. The sensitivity study is done on selected segments, and its overall impact on the LIL is discussed qualitatively.

Section 8 presents a qualitative benchmarking study considering NLH's more than 50 years of operational experience running HV lines in harsh environments, lessons learned and mitigation approaches that NLH successfully executed for several lines in 80's and in 90's, and a comparison of outage statistics prior and following upgrade work. This section also compares the LIL reliability with another Canadian utility's critical line. This section also presents the comparison of line failure data in terms of normalized line length.

Section 9 presents the summary and conclusions and several recommendations for future work.

Section 10 presents the references.

Section 11 presents the CV of the author in the Appendix.

# 2.0 Basic System Design Concept

In overhead line design, reliability is determined by assigning a fixed return period to extreme climatic events, such as wind, ice, and combined wind and ice loads. This implies some expected failure rate during the service life of a line. On the other hand, the security of a line is affected by (1) designing structures for sufficient longitudinal capacity and (2) inserting containment structures (anti-cascading structures) at fixed intervals (e.g., usually every 10-20 structures). It is to be noted LIL design uses containment structures at a regular interval along the entire line length. The suspension structures are also designed for unbalanced loads due to (1) uneven ice formation or ice shedding considering load combinations and (2) the loss of a phase conductor and/or their combination (without ice).

The most common deterministic security criterion used in bulk electric power system (BEPS) planning is the N-1 criterion, which requires that there be no outage if there is loss of a single BEPS component (such as a generating unit or a transmission line or a critical station component such as a transformer). Some utilities also use N-2 criterion or N-1-1 criterion, which assumes that the system should be able to withstand the simultaneous loss of two components (N-2) or the forced outage of a single component in conjunction with scheduled maintenance of another component (N-1-1).

In the power network, reliability includes system adequacy (sufficient generation to meet the load demand) and system security, which means that the system can respond to transient disturbances (faults or unscheduled removal of components). This contrasts with the structural design of overhead lines where both reliability (semi-probabilistic) and security (deterministic) are treated separately.

## 2.1 Power System Hierarchy

A typical power delivery system consists of three basic components: generating power plants, transmission lines and facilities, and distribution lines and facilities and the distribution of customer types. Figure 2.1 presents the hierarchical representation of the electrical grid system and how they operate together.

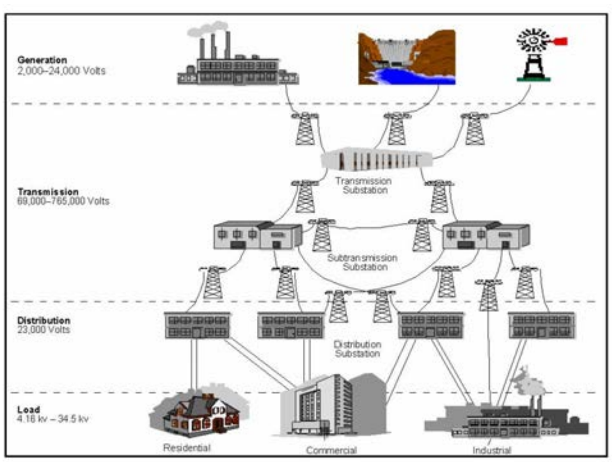



Figure 2.1 Hierarchy of Power System and Customer Types and Distributions (Florida Public Service Commission Report, 2007)

### 2.1.1 Definitions

**Mechanical System**

**Reliability**: Reliability of a line is defined as the probability that the line will perform under specified conditions for a specified period, normally defined as the service life.

**Security**: Security is often referred as the line's ability to withstand a catastrophic loss, particularly a cascade failure. One way to mitigate this failure, at present, is to design suspension structures for adequate longitudinal RSL, as well as to insert anti-cascading towers ("stop towers") at certain intervals (normally every 20 to 25 towers).

**Power System**

The primary function of an electric power system is to economically supply electrical energy to its customer with adequate reliability and service continuity. Billinton and Allan (2007) describe the system reliability in terms of system adequacy and system security. Figure 2-2 presents this in graphical form.

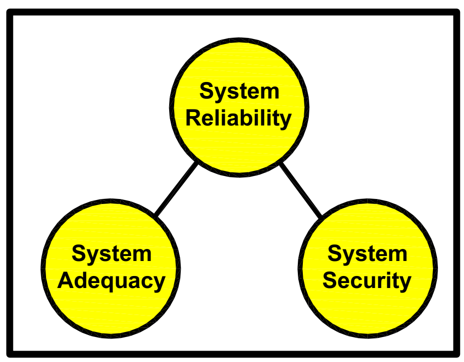



Figure 2.2 System Reliability (Billinton and Allan, 1996)

**System Adequacy** is the system's capacity to respond to its customer requirements (load demand), considering line constraints (voltage and thermal limits) and component outages.

**System Security** is the system's ability to respond to transient disturbances (faults or unscheduled removal of components).

System adequacy is linked to "long term" planning criteria (steady state) while security relates to "short term" disturbances on the system (dynamic situation).

In line design, the security criterion is deterministic and treated separately from the reliability criterion which is often probabilistic. However, it is the author's opinion that the structural design of a continuously operated system should link reliability and security through an **availability** model that can provide the probability of the line component in the operating state at some points in the future.

**Availability** of a repairable system (such as a transmission line) is a function of both failure ($\lambda$) and repair ($\mu$) rates, which are directly related to the design return period of the climatic loads and the duration of the repair respectively (hours, days etc. after a failure) should the line fail. The repair duration is normally linked to repair rate. The system planner is normally in charge of determining the availability and ensuring that N-1 criterion or similar criterion is satisfied for the power system. However, by not linking these two parameters (reliability and security) in line design quantitatively, the current method of determining the design return period (T) may not be optimized (Haldar, 2011). This is especially important for the LIL because it is a long critical transmission line infrastructure (a long radial line) which carries significant amounts of bulk power for Nalcor/NLH's electrical system (almost half of the current electrical peak load). The catastrophic loss of such an important line would result in severe consequences for the island's electric power system.

Some national and international standards prescribe that the design load be selected based on the importance of the line. A 50-year return period is normally selected for line design, but a larger return period value can be selected if the line is extremely important. "*According to the Canadian Standards Association, all transmission lines should be built with a return period of at least 50 years. A 1:150-year return period is suggested for high-voltage lines as well as for lower-voltage lines that "constitute the principal or perhaps the only supply to a particular load." A 1:500-year return period is suggested for high-voltage lines that "constitute the principal or perhaps the only source of supply to a particular electric load (MHI report, 2012)." Recent judicial inquiry (2018) finding stated: "The reliability of the LIL (or, conversely, its vulnerability to adverse weather events) is critical to maintaining power on the Avalon Peninsula once the Project comes on-line, but there are some question about the level of reliability of the line, and about how Nalcor has communicated that reliability".*

The importance of the line is determined based on its electrical capacity (MW transfer), the consequences of the loss of the line, and the impact of the loss of the line on the overall BEPS reliability. Therefore, the line design engineer may choose a higher return period such as 500 years to reduce the probability of exceedance to 10% during a 50-year service life in contrast to a 64% probability of exceedance when selecting a 50-year return period design load value. The capital cost of a line increases significantly as the return period increases (Young and Schell, 1971, Ghannoum, and Keiloch, 2011, Haldar, 2009, 2012), particularly when the design ice load is onerous (Haldar, 1996, 2011). Therefore, the investment cost (line capital cost) needs to be balanced against the future damage cost that includes the cost of replacement of the failed section of the line and the expected outage cost (Figure 2.3). The expected outage cost includes the cost of energy not supplied (EENS) and can be explicitly determined from a system model study; this can be done based on a probabilistic planning model (Haldar, 2010, 2011, 2012, 2016; Billinton and Allan, 1996). Haldar et al (2018, 2020) have expanded the above concept to include the security-related optimum tower placement by balancing the initial containment cost against the line damage cost that includes the expected outage cost. This study was sponsored by a consortium of 30 global utilities under the sponsorship of CEATI International. A probabilistic planning model (Figure 2-4) is more appropriate to determine the EENS, system severity index (SI), LOLE, expected duration of outage, etc. (Billinton and Allan, 1997, Haldar, 2009, 2012). An earlier study (Haldar, 2009) showed that the optimum return period of this line was 150 year, complimented by the installation of additional generation support near the load center (Avalon) to support the future load growth increases.

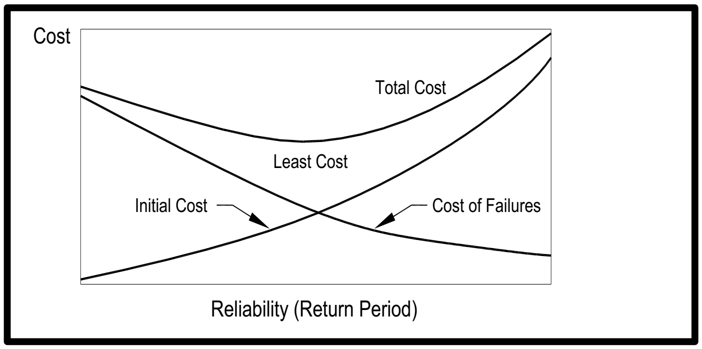



Figure 2.3 Typical Optimization Problem

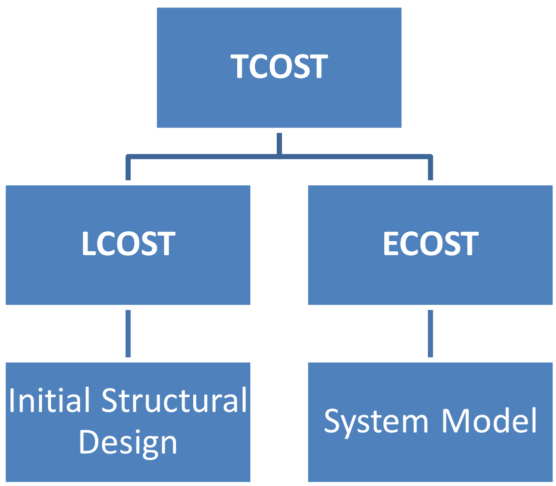



Figure 2.4 Flow Chart for Optimum Return Period Study (Haldar, 2009, 2012)

## 2.2 Selection of Optimum Return Period

The initial line cost (LCOS) will increase as the reliability increases, and the future failure cost (DCOST) will decrease as line reliability increases. An optimum reliability can be found by balancing these two costs. A methodology based on a probabilistic system model for a ± 450 kV HVdc transmission system was developed (Haldar, 2010) and various system state contingencies were evaluated and assessed in terms of a cost-risk model. Figure 2-3 shows the point where the total cost is the least. Figure 2.4 presents the flow chart. The initial study was developed for an isolated system without a Maritime link, and a recommendation was made to expand the study to include the Maritime link in the future. The inclusion of the Maritime link decreases the risk level. This was followed up in (Teshmont Study, 2016).

It is well known that two lines designed with same reliability level can have very different availabilities should the failure modes and the extent of the failure zones be different. Haldar et al (2007, 2009, and 2010) have used finite element models to estimate the extent of the failure zone of overhead lines due to cascade failures. The model included multiple tower failures. The purpose was to estimate the cascade failure zone and to link the expected number of towers lost with the repair time and rate ($\mu$). Although the numerical model for cascading failures requires some improvement, the study concept was further explored to determine the optimum placement of anti-cascade structure using a probabilistic methodology that also explicitly considered cost of containment structures with variable spacing intervals and the extent of the line damage and its effect on the repair rate and line availability (Haldar et al, 2018, 2020).

During the preparation of the Avalon upgrade study report (Haldar, 1995), the author raised the question as to how to determine the value of "reliability worth". To assess the "reliability worth value", one needs to explicitly include the line failure costs. At the time, the total damage cost was assumed to be the fixed replacement cost for a failed section of a line. It was clearly pointed out in the report that the upgrading cost of the transmission line system on the Avalon Peninsula could not be justified based on damage cost unless it could be shown that the benefit derived from such an upgrade was economically viable. However, it was also recognized that a more detailed approach was needed to assess this "reliability worth" issue, including customer interruption costs.

## 2.3 Reliability Worth - Acceptable Value

Determination of line reliability (failure rate, $\lambda$) can be estimated (in ranges) with some degree of confidence, in contrast to line security risk, where the design philosophy is strictly deterministic. The expected line length under a failed state, should the line suffer a catastrophic loss, is often unknown. The length of the cascade will control the recovery rate ($\mu$) and is directly related to line availability (or unavailability), which will determine some of the key system parameters (LOLE, EENS, SI etc.) when the LIL is subjected to under extreme weather events. Severity Index (SI) defines the expected energy not supplied divided by the system peak load expressed in minutes These two parameters ($\lambda$ and $\mu$) can be linked directly to the unavailability of the LIL.

Billinton and Wangdee (2006) have provided guidelines for degrees of severity for BEPS (system minutes) and local disturbances (MW minutes). Some of these concepts are discussed and presented in (Haldar, 2009, 2011) and should be pursued further to address PUB's specific concern: "*Hydro should promptly examine the likelihood and the range of consequences of an extended bi-pole outage under extreme weather circumstances, and should undertake a robust examination of generation options (including continuous use of the steam units) to mitigate that risk*" (Liberty Recommendation # 1, dated October 31, 2019). Once the LIL failure rate ($\lambda$) and recovery rate ($\mu$) under extreme weather conditions are known, system planning can use this information in their model to answer the PUB question. This study only deals with the structural reliability assessment of the LIL line to climatological loads that include two different types of icing along a 1100km line route.

The BEPS disturbance is classified as follows:

- Loss of system stability
- Cascading outages of transmission lines
- Abnormal range of frequency and/or voltage

The local disturbance is an event that causes a local interruption resulting in major customer interruptions due to the duration or the amount of load affected. The measurement unit is MW-minutes. MW-minutes is defined by the lost MW multiplied by the severity index in minutes (SI). SI is a measure of electrical system vulnerability. This is an equivalent parameter to the structural reliability index ($\beta$) used in a mechanical system and will be discussed in the next section. Both indices measure the system/component's reliability level.

**Table 2.1 Degree of Severity for BES Disturbances and Local Disturbances (Billinton and Wangdoe, 2006)**

| Degree of security | Description | BES Disturbance (System Minutes) | Local Disturbance (MW-minutes) |
|---|---|---|---|
| Degree 0 | -an unreliability condition normally considered acceptable | < 1 | <1000 |
| Degree 1 | -an unreliability condition which may have a significant impact to one or more customers but is not considered serious<br>-typically, the customer impact is less than 10 times above that which is considered acceptable | 1-9 | 1000-9999 |
| Degree 2 | -an unreliability condition which may have a significant impact to one or more customers but is not considered serious<br>-typically, the customer impact is 10 to 100 times above that which is considered acceptable | 10-99 | 10,000-99,999 |
| Degree 3 | - an unreliability condition which may have a very serious impact to customers<br>-typically, customer impact is 100 times above that which is normally acceptable | ≥100 | >100,000 |

## 2.4 Reliability Model – Component Level

When assessed at a high level, Overhead lines (OHL) can be divided into two main systems. These are (1) the Wire Support System (WS) and (2) the Structure Support System (SS). The SS can be further broken down to include (1) the tangent support subsystem and (2) the dead-end support subsystem. The loads are transferred to the foundation and to soil and rock media through the WS and the SS. The WS primarily consists of conductors and overhead ground wires including optical ground wires, insulators, and other hardware components that are used to attach the wires to the support structures (ASCE 74, 2010). Figure 2-5(a) shows a typical line system (between two dead ends and a segment), and Figure 2-5(b) presents components in a fault tree diagram format.

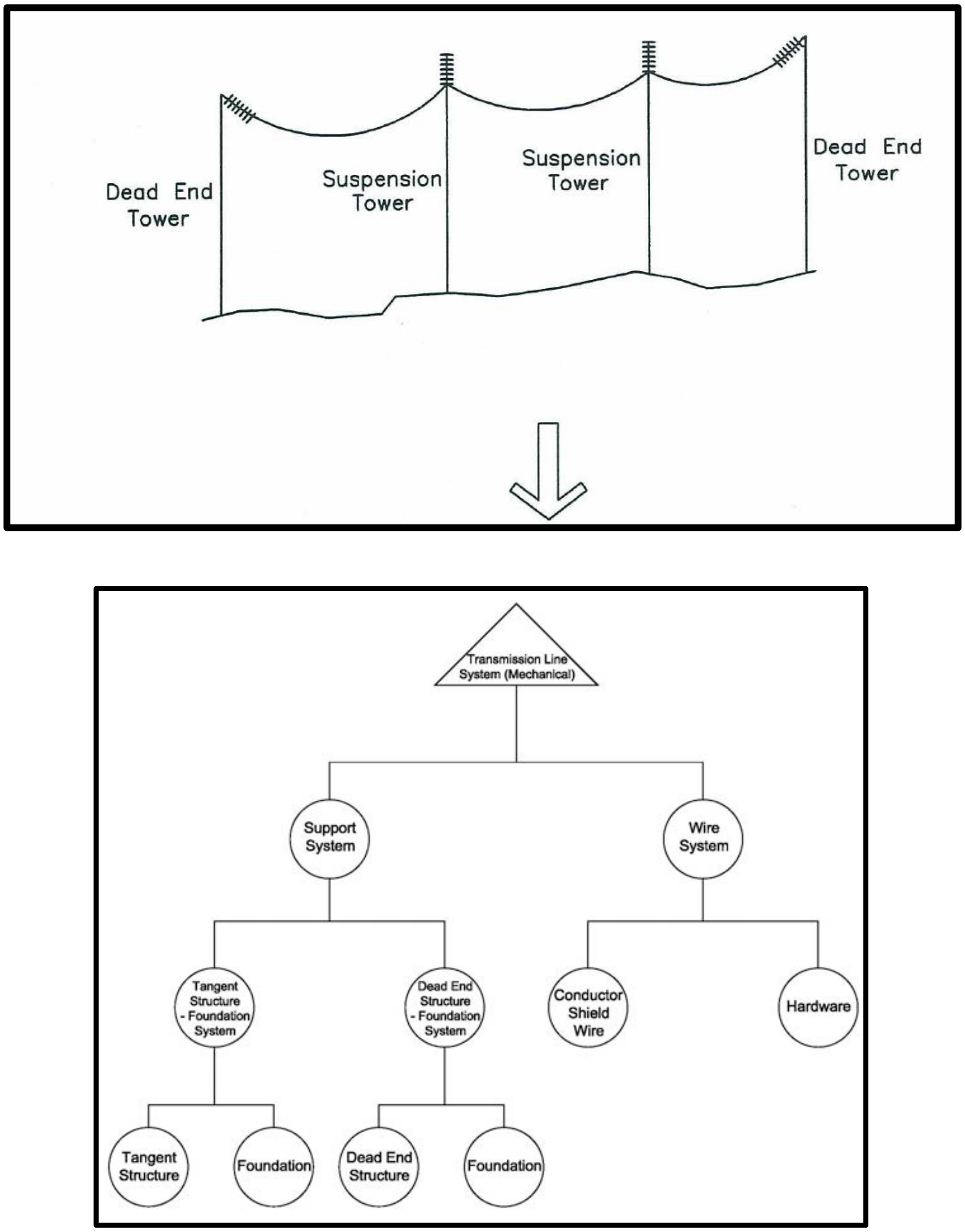



Figure 2.5 (a) Line Segment and (b) System Model

## 2.5 Reliability Model – System Level

In system design, there are two fundamental systems: series and parallel. A series system fails when any member has failed. This is also a characteristic of the "weakest-link" system.

### 2.5.1 Reliability Model – System vs. Component

It is known that for a series system, the system reliability is always less than the individual component reliability and the system fails when any one of its components fails. On the other extreme, a parallel system (redundant system) may survive even the failures of one or two elements.

In this case, system reliability is greater than the reliability of any individual component. An example of a series system is a typical cable system (series system), while a transmission tower is an example of a parallel system.


Figure 2.6 A Typical Wood Pole H-Frame Line System

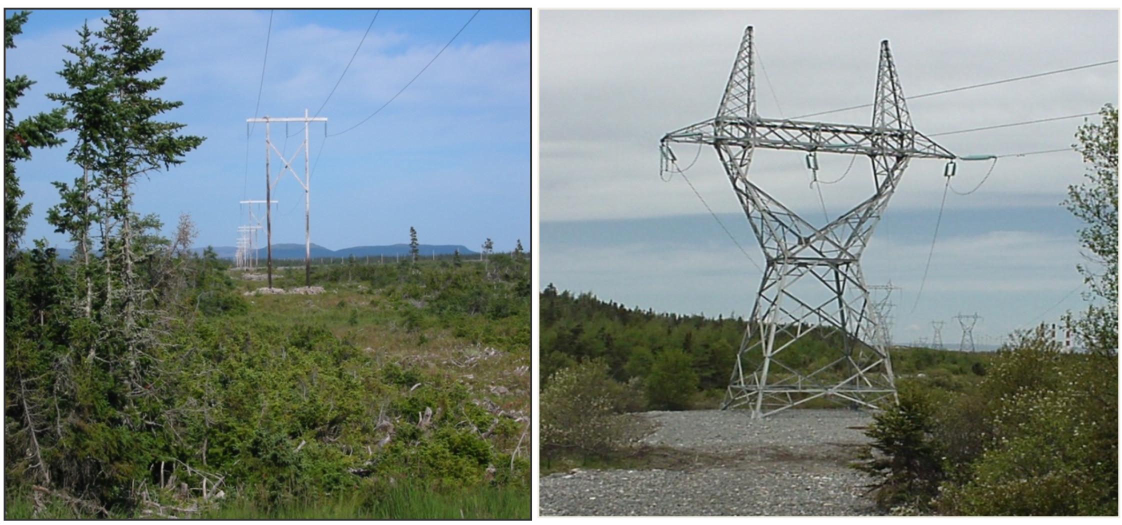
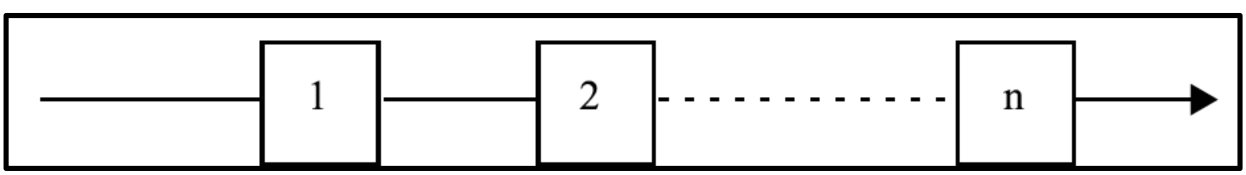


Figure 2.7 (a) Series Systems and (b) Parallel System



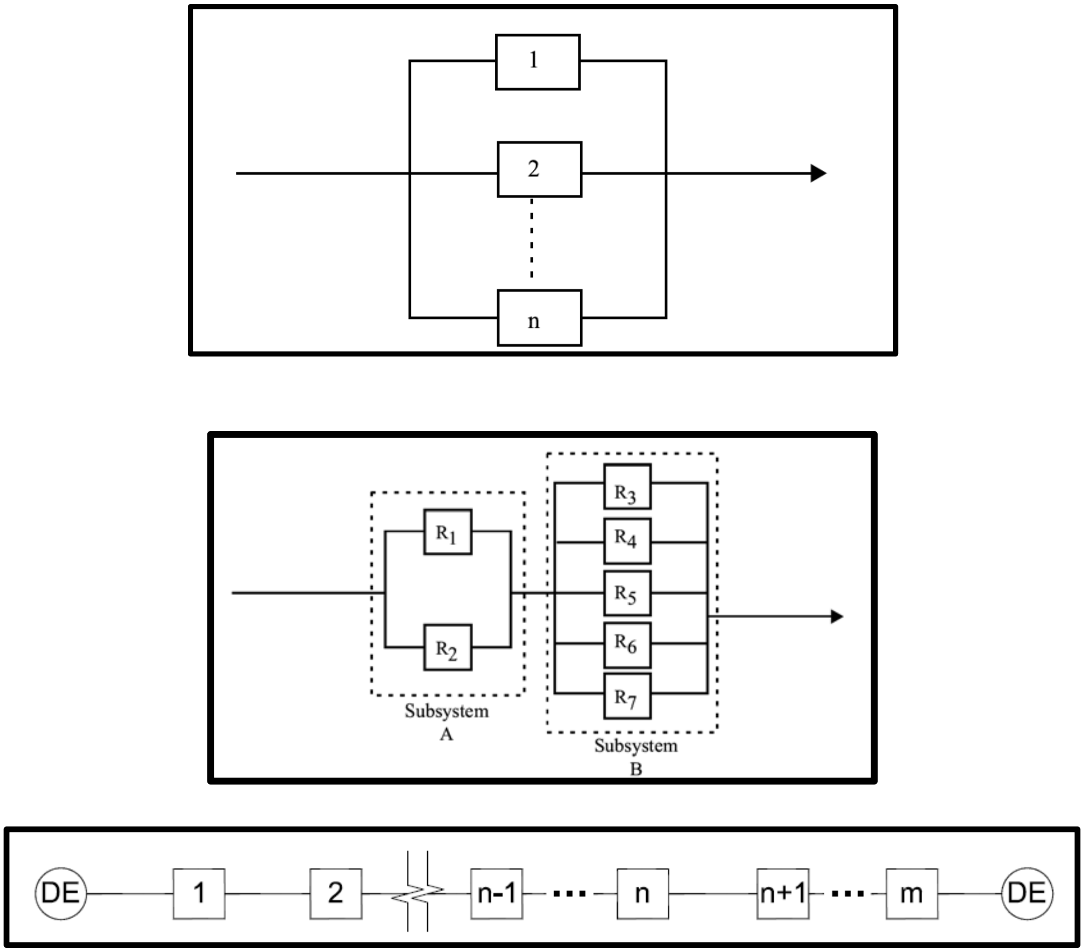



Figure 2.8 (a) Series System (b) Parallel System (c) Compound System and (d) a Typical Line Segment modelled as series system

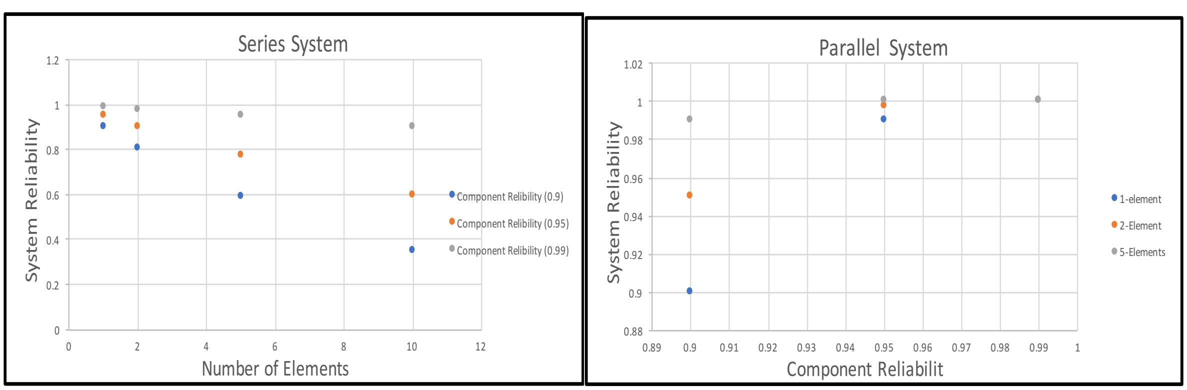



Figure 2.9 Reliability of n-components (a) Series and (b) Parallel

Figure 2.9 presents the impact of number of elements on series and parallel system reliabilities. It is shown that in a series system, the reliability decreases as the elements are added while in a parallel system, this increases the system reliability due to redundancy effect.

# 3.0 Reliability-Based Design (RBD) Methodology

A basic concept in RBD is that the design procedure should consider that the line components (structure, conductor, etc.) may fail within their expected service life. Thus, the development of a RBD procedure begins with the mathematical theory of probability that considers the interference of stress (effects of all the possible combination of loads) and the strength (resistance). Failure probability is often computed in terms of a reliability index beta (β). Figure 3-1 depicts the load-resistance interference diagram, where the overlap region presents a measure of the failure probability. The objective is to ensure that the two diagrams are separated further apart to minimize the failure probability (higher beta value). Higher the (β) value, lower is the probability of failure.

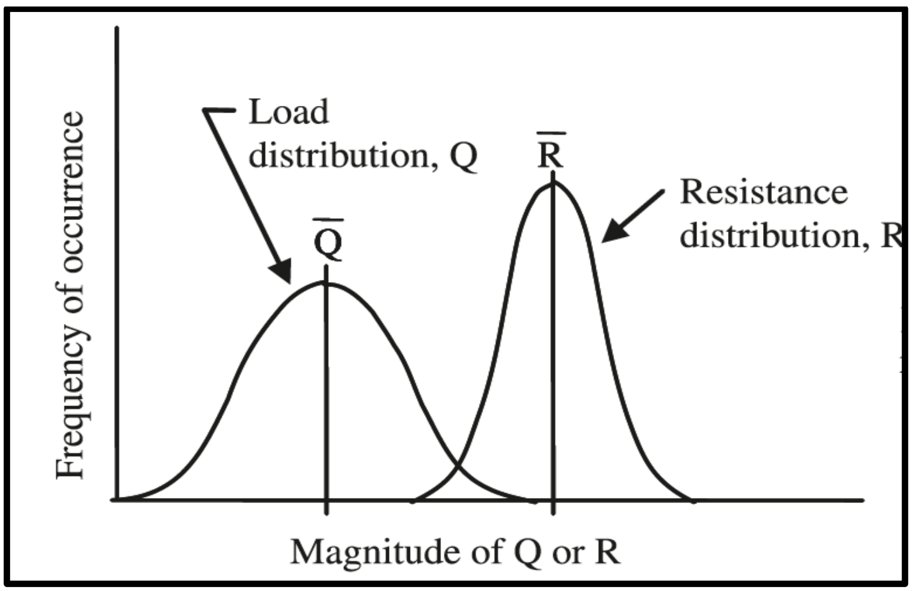



Figure 3.1 Load-Resistance Interference Diagram (Bathurst et al, 2008)

Although the ASD approach has served the utility industry reasonably well, utilities' design practices are increasingly moving towards a RBD methodology to quantify the line reliability in a predictable manner. RBD assumes that the strength and the load effects on the line and its components (such as structure, conductor, insulator etc.) are random variables that can be defined by their respective probability distributions.

In structural reliability analysis, this overlap can be measured in terms of a "beta value" ($\beta$), which is directly related to the failure probability (Nowak and Collins, 2012). For example, a $\beta$ value of 1.282 represents a 10% failure probability, while a $\beta$ value of 1.645 represents a 5% failure probability. The higher $\beta$ value indicates a lower failure probability. Figure 3-2 presents the $\beta$ versus $P_f$ scale. Once the failure probability, $P_f$ is assessed under a specific loading scenario, the risk can be calculated by simply multiplying the failure probability by the consequences of the failure expressed in monetary values.

$$P_f = P\,(R-Q \leq 0) = \int_0^\infty f_Q\,(x)\, F_R\,(x)\, dx \qquad [3.1]$$

where R is the resistance, Q is the load effect in the same unit of resistance, $F_R$ (x) is the cumulative distribution of resistance, and $f_Q$ (x) is the density function of the load. A closed form solution can be used for normal and log-normal distributions of load and strength, while an iterative method is required for non-normal distributions of load and strength. R-Q defines the limit state.

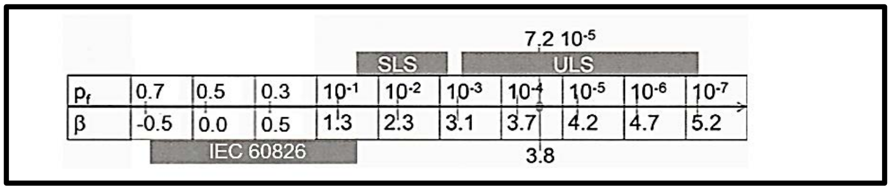



Figure 3.2 Target Reliability Indices and Corresponding Failure Probabilities for Design of Civil Engineering Infrastructures and Overhead Lines (modified after Gulvanessian, 1990).

## 3.1 Service Life versus Reliability

Table 3.1 presents the relationship between lifetime reliability index to the annual reliability index.

**Table 3.1 Relationship between Lifetime Reliability and Return Period (T)**

| Return Period, T | 50 | 150 | 500 |
|---|---|---|---|
| Reliability During 50-year Asset Life | 0.36 (0. 50)* | 0.71 | 0.90 (1.3) |
| POF during Asset's Life (50 years) | 0.64 | 0.29 | 0.10 |

*Bracketed value is reliability index

The lifetime reliability index can be calculated from the annual probability of failure and the service life of the asset. The lifetime reliability index provides a probability of survival during the service life of the asset where the asset life is assumed to be 50 years. Typical lifetime reliability index values for civil engineering infrastructures lie between 1 and 5, with values for overhead lines in the order of 0.5 to 1.3. A 50-year return period-based load will produce a service life β value of 0.5 ($P_f$ = 0.64), while a 500-year return period load exposure will produce a β value of 1.3 ($P_f$ = 0.10).

Figure 3.2 also presents a comparison of the lifetime probability of failure for buildings and bridges (β as 3.8) and the probability of failure for overhead lines (lying between β as 0.5 and 1.3), following CSA 60826-10 load values based on a 50-year RP, 150-year RP, and 500-year RP respectively. According to CSA 60826-10, the three levels of failure probability range that one will expect for these three classes of loading are 0.01-0.02, 0.0033-0.0066, and 0.001-0.002 respectively. Compared to general civil infrastructure (building, bridges etc.), these low values are acceptable because of N-1 and N-2 contingency criteria. It is also author's understanding that this is valid for a typical transmission line of low-to-moderate line length because the power system is designed to withstand the loss of one or two components without any service interruption and is always supported by intermediary AC substations for BEPS. <u>However, the loss of the LIL may not fall automatically under this category, and therefore, a different approach is needed to quantify reliability or POF that considers the long line length and the exposures to severe weather conditions, particularly severe icing hazards on the Avalon and Northern Peninsulas and in the Labrador zones, Alpines and LRM.</u>

## 3.2 Introduction – CSA 60826-06/10

Under reliability class of loads, CSA 60826-10 stipulates that extreme ice, extreme wind, two types of combined wind and ice loads, and unbalanced ice load cases be considered in line design. CSA also recognizes three levels of reliability class and, accordingly, three specific return period values. CSA 60826-10 recommends that the design return period value be selected based on the importance of the line. A return period value is warranted for a HV-level line. As noted above, a typical minimum value return period for HV line design is 50 years.

CSA also provides national weather maps for selecting the basic climatological loading parameters, such as wind speed (km/h) and ice thickness due to freezing precipitation (glaze icing in mm). These maps are presented for a 50-year return period value and appropriate conversion factors are provided to transform this 50-year value to 150-year or 500-year return period values. CSA does not provide any national map for rime icing (in-cloud icing), which is a major environmental hazard as the LIL line is exposed to this type of icing in southern Labrador, Alpine zones and on the top of the LRM (14% of the line length).

CSA suggests that reliability analysis should be based on the damage limit state (DLS), while the failure is considered under security load analysis. CSA 60826-06/10 recommends a 10% exclusion limit for characteristic strength assessment and provides the appropriate strength factors and coefficients of variation (COV) for key components in line design. The COV is a measure of the data dispersion that's equal to the ratio between the standard deviation and the mean. Only one limit state is normally considered in CSA 60826 for RBD based overhead line design and this is damage limit state (DLS). DLS refers to initial damage from an intact system under a reliability class of load condition (loads associated with extreme events). Failure refers only to security loads (broken conductor, tower failure etc.), and the design is deterministic. Security loads are not considered in this study.

It must be understood that the violations of DLS do not automatically imply that the line has failed structurally (collapse of a tower, foundation etc.); it could instead be a loss of a specific line performance criterion. For example, a tower member may have undergone excessive yielding, non-elastic deformation from l/500 to l/100 under compression, tension adjustment requirement for guys, or a foundation may have undergone a large displacement or differential movement, but all these violations under DLS may or may not always lead to an outage. Some of these violations and related damages could be detected during routine line inspection (particularly any structural damages) and can be mitigated. POF calculations based on DLS and the relatively higher values must be understood in this context. CSA 60826-10 requires that reliability assessment considers DLS unlike other civil engineering infrastructures, where POF (failure probability) of a structure and reliability index are determined for both serviceability limit state criteria (SLS) and ultimate limit state criteria (ULS). DLS can be considered as equivalent to serviceability limit state in civil infrastructure design. CSA 60826-10 requires that the failure limit be referred to security loads and strength factor in this case is used as 1.0.

## 3.3 Understanding Failure Modes and Determining Reliability of a Transmission Tower

The failure of a single member in a tower system does not necessarily result in the failure of the complete system (i.e., the collapse of the tower) because the remaining elements are able to carry the remaining loads and distribute the load via an alternate load path. This will happen for a highly static indeterminate structure, like a transmission tower. Transmission towers have a high degree of redundancy, so when one or two lightly loaded members are overloaded and exceed the DLS criteria, the tower may still survive by redistributing the loads to the other members. Failure of a transmission tower with a high degree of redundancy will require that more than one element fails in such a way that as to form a mechanism for the tower's collapse. The ideal way to assess the

**Table 3.2 Design Requirement for the System (CSA 60826, 2010)**

| Condition | Type of Load | Required Performance | Corresponding Limit State |
|---|---|---|---|
| Reliability | Climatic Loads with a Return Period, T years | To ensure reliable and safe power transmission | Damage Limit |
| Security | Torsional, Vertical. and Longitudinal Loads | To reduce the probability of uncontrollable propagation of an event (failure containment) | Failure Limit |
| Safety | Construction and Maintenance Loads | To ensure safe construction and maintenance conditions | Damage Limit |

reliability of a transmission tower is to model this as a "parallel system," although in practice it is treated as a "series system" that assumes that when one member fails in yielding or in compression, the tower fails—this could even be a lightly loaded bracing member. This is a very conservative assumption in DLS. In a statically indeterminate system like a lattice tower, there are many failure modes and actual reliability can only be determined by modelling the tower system as a series parallel system under a progressive collapse analysis mode. Alternatively, it could be evaluated using simulation technique by modeling the entire system as a nonlinear inelastic dynamic system subjected to dynamic loading (Hong, 2021).

Correlation must also be considered among the failure modes (Haldar, 1985, 1988). This is rarely done in traditional design practice; DLS criteria needs to be understood in this context. DLS analysis may be sufficient if it can be shown that a main leg member or a major bracing member is highly overloaded (large UF) and has failed. Without carrying out a strength analysis fully for all the critical structure support system towers in LIL, the POF determined under DLS should be considered as the initiation of the damage and not the complete failure. However, the next section provides some events on DLS and ULS and it shows clearly that an event may be caused with a DLS violation but whether this will further progress to a ULS or not will depend on the individual case/scenario and the environmental hazards that the line is experiencing at the time. Therefore, it is important to ensure that POF under DLS be considered seriously and an event tree analysis should be done to isolate those events under DLS may lead to full ULS condition and the consequences. The actual

POF with respect to strength failure will remain unknown unless additional work on ULS determination for the LIL system is done. This study provides several recommendations to close this gap.

## 3.4 Limit States of Transmission Lines –Examples

### 3.4.1 Damage Limit State (DLS)

Three 735kv lines run parallel from the Churchill Falls generating station to the Hydro Quebec Montagnasis substation and serve to transport power to the Hydro Quebec system. These lines have experienced severe icing in 1995 and 1997 since their commissioning in 1971. Icing between December 3 and 22 in 1997 caused the OHGW to pull through the clamp causing excessive sag in the adjacent span. The sequence of events indicated that the OHGW was near the phase conductors, resulting in phase-ground short circuits on these lines.

In both cases (1995 and 1997), line outages were caused by flashovers between a phase conductor and the ground wire. Typically, heavily loaded OHGW should not have sufficient sag near the phase conductors to create a flashover. However, a flashover can occur without any contact whenever the distance between the phase conductor and ground wire approaches the clearance limit which was one meter. A failure investigation study indicated that unbalanced longitudinal ice loads due to uneven spans on either side of a tower were responsible for ground wire slippage through the suspension clamps in 1997 which allowed sufficient sag to reach the phase conductor level. Wind condition led to the OHGW being pushed transversely towards the phase conductor, thus creating a temporary flashover. Although the event in 1997 started with the violation of DLS, OHGW had to be cut at various places to resume the power delivery. Approximately 20km was affected by the ground wire removal.

A similar event occurred in December 1995 that led to an initial DLS violation. This event caused outages because a U-bolt got damaged initially and eventually failed as the icing event continued. In both cases, it appears that the event started with the violation of DLS criterion and led to inoperable line due to the severe icing conditions that continued. No structural damage was experienced in 1995 and in 1997. The event in 1995 led to ULS because of the failed U-bolt.

Figure 3.3 735 KV AC Line Failure at Churchill Falls (Heavy Icing on Conductors)

### 3.4.2 Ultimate Limit State (ULS)

<u>Manitoba Hydro $+ 500kV$ HVdc Lines</u>

Manitoba Hydro HVDC transmission system consists of three Bipole lines called Bipole I(BP1), Bipole II (BP2), and Bipole III (BP3) respectively. Bipoles I and II were built in the 70's and 80's (?) while Bipole III was commissioned in 2018. The two transmission lines BP1 and BP2 start at the northern Radisson and Henday converter stations near Gillam, run alongside each other for much of their 895-km route, and end in the south at the Dorsey converter station just northwest of Winnipeg. Due to their proximity to each other, a severe weather event could damage Bipole I and Bipole II simultaneously. This would have left Manitoba Hydro unable to transmit enough electricity to meet demand, and would result in extended outages and potential blackouts. Prior to the commissioning of Bipole III, 70% of Manitoba's electricity was transported via Bipoles I and II.

In the early hours of September 5, 1996, a severe thunderstorm moved through the rural area immediately northwest of Winnipeg. Seventeen guyed steel towers of the two parallel HVDC transmission lines collapsed (Figure xx), causing the complete failure of the Radisson-Dorsey Transmission System carrying 2020 MW. In addition, 3 steel towers and 18 wood pole structures were damaged. The storm was a microburst wind (non-synoptic wind) that produced extremely high intensity wind (HIW) that caused downward pressure and lateral winds that moved through a narrow strip approximately 2 km wide. Based on the damage evidence, it was estimated that low end wind speed that occurred in the area was equivalent to an Enhanced Fujita scale F1 wind speed of 180 km/h. It took almost four days to restore power. Since this line failure, Manitoba Hydro has invested significant R & D funds to understand better the effects of HIW on transmission lines.

Figure 3.4 DC Tower Failure under Microburst (High Intensity Wind, MH Bipole Lines)

<u>Churchill Falls 735kV Lines</u>

In the December 27, 1995 storm, several line trips and subsequent clearing were first experienced on line 7051 and, on the following day, lines 7052 and 7053 experienced outages. The heavy icing caused a ground wire to detach from a tower due to broken U-bolts at the tower connection. This failure is classified under ULS. The failure of 1997 is classified as DLS initially but eventually the lines were taken out of service because of the removal of the OHGW.

## 3.5 Typical Asset Component State Classification – Reliability Index and POF

Reliability indices are a relative measure of component's POF and provide a qualitative measure of the expected performance. A structure support system (SS) or a wire support system (WS) with a high reliability index value is expected to perform well while the same system with a low reliability index is expected to perform poorly and may cause more failures. Line design with a very low reliability index can be hazardous. The figure below provides the asset/component classification status based on reliability indices. Figure 3.5 presents system/component's state classifications that are based on typical civil engineering structures' state conditions. These may not be directly applicable to OHL but are presented here as a guide. The figure below presents the classification of a component state based on reliability index and POF values.

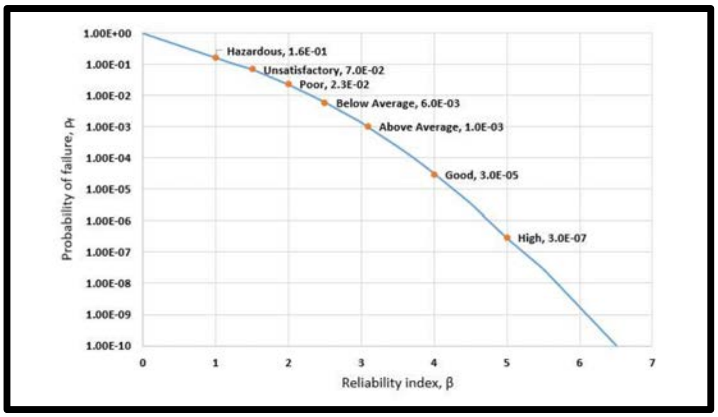



Figure 3.5 Asset Classification Based on Structural Reliability Index and POF (UACE, 1997)

The unsatisfactory classification with a POF of 0.07 indicates that there is a 7% probability that the performance function value will approach the limit state (DLS, ULS etc.). Assuming the DLS criterion defined in terms of a dead-end hardware under tension is 0.023 (poor), this implies 23 out of 1000 events will cause a hardware damage that could be a safety hazard and can eventually lead to a failure if the hazard condition persists.

For example, the beta value for building and bridges could be between 3 and 4 while a beta of 5 or above can be used for an offshore structure. Typical POF (annual) for the design of transmission line lie between 0.02 and 0.001. Anything below 0.02 will be considered "poor" according this chart but in OHL design, this is compensated for by N-1, N-2 criteria. Anything above 0.001 can be considered "above average"; this will be most likely for very important line as recommended in CSA 60826 for a line designed for 500-year return period climatic load. This is acceptable for a short-to-medium length line and depends on the type of exposures. *However, for a long radial line of significant importance, the author recommends that the key component should be designed for one order of higher magnitude of "above average" value 0.001. In this case, the target should be 0.0001 to maintain an acceptable overall line reliability*.

## 3.6 Review of CSA 60826 (2010)

In the CSA standard, the line is considered a system that consists of many major components (sub-systems), such as supports, foundations, conductors, insulators, and hardware. Each component can be further broken down into many elements and the following figure presents the hierarchy of the system, sub-system (elements), and various components. The primary objective of the CSA standard is to provide safe and reliable lines. Line reliability is achieved by ensuring that the design strength of a line component is greater than the quantifiable effects of specified weather-related loads. Figure 3.6 presents a system diagram showing the connectivity of components and elements to the line system.

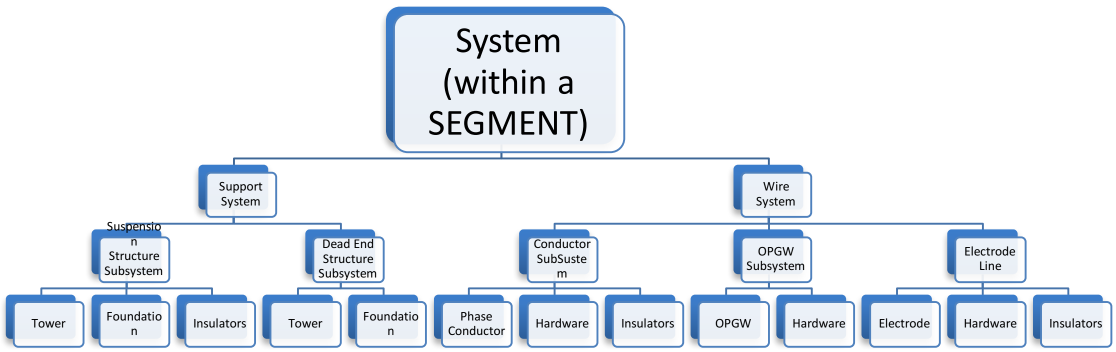



Figure 3.6 Transmission Line Design - System, Components and Elements

### 3.6.1 Design Equation

CSA 60826 (2010) provides a framework where the semi-probabilistic design equation is given in terms of the load effect on a component and the strength of the component. The basic equation relates the characteristic strength (capacity) value to the appropriate load effects over a specified return period of T years. In simple form, this can be expressed as:

$$R_C \geq Q_T \qquad [3.3]$$

where $R_C$ is the characteristic strength (capacity) of the component with e% exclusion limit and $Q_T$ is the load effect with a T-year return period.

The design equation assumes that the load distribution is Gumbel type 1 and the strength follows a normal distribution. The design equation provides a constant annual failure probability between (1/T to 1/2T), provided the coefficient of variation (COV) of strength ($V_R$) is $0.05 \leq v_R \leq 0.20$ and the load effect COV ($V_Q$) is $0.20 \leq v_Q \leq 0.50$. For a COV of 0.1 (structural member), the POF is closer to 1/2T. However, CSA 60826 does not provide guidance on how to deal with design that may require POF computation when $V_Q$ is significantly larger than 0.5. For example, it is well known that COV of wind speed can be bracketed narrowly but it could be quite wide for ice thickness. A COV of ice thickness greater than 0.6 (0.6-0.9) is quite possible and the nonlinear transfer function will make the COV of the ice load $V_Q$ considerably larger than 0.5 as presented in CSA 60826-10. A 1/T - 1/2T approach could lead to the overestimation or the underestimation of the POF value. In addition, the choice of the distribution function can also make this POF estimation quite variable.

Gumbel Type 1 distribution of wind speed does not automatically produce a wind load of Gumbel Type 1 when the speed is converted to load. This is because the conversion is non-linear and the EX I distribution type is not automatic. This is also true for conversion from ice thickness to ice load. Furthermore, any distribution fit should be validated based on a statistical test, otherwise the error introduced in the probability calculation will remain unknown. In recent years, Rosowski et al (1999) has shown that the wind load effect can be modelled approximately by a log normal distribution than an Extreme Type 1 distribution.

Also, the standard determines the characteristic design capacity by dividing the load effects with several strength factors. However, it does not distinguish between the use of a determinate versus indeterminate structure in selecting the final structural configuration. A tower is a complex structure with many redundancies and therefore, a single characteristic capacity value may be in adequate to define reliability. Correlation is not considered, and this may overestimate the probability of failure of a tower.

However, the author points out that the “true” failure probability of a transmission tower should be determined through a progressive collapse analysis under extreme load events and load combinations. The effect of the member load after the initial yielding or post buckling should be included in the computation of collapse probability of the tower. It is expected this collapse probability will be lower than what is recommended under DLS and will provide a more realistic assessment of the coupled structure support and wire support system (ULS). This analysis will be appropriate when a secondary or a lower level member fails first and will allow to determine the alternate load path. However, if the main member (say a leg member fails with a large UF), then the system is likely in the ULS state.

Extreme events are normally defined by low probability of occurrence and are determined based on return period values following codes and standards. Therefore, extreme wind, extreme ice, and combination of wind and ice loads are well suited for the reliability analysis of overhead lines. However, the same cannot be stated for unbalanced ice loads due to ice formation and/or shedding. These loads may not be suitable for probabilistic analysis as prescribed in CSA 60826-10 because the effects of these loads lack statistical data. They should be considered as deterministic loads, as is done for other classes of loads such as security, construction, and maintenance loads. Refer to Section 4 and Section 6 on this item.

In CSA C22.3 60826-10, the strength factor ($\phi$) is further expanded to include the effects of various other elements, including strength coordination and quality control of construction. No discussions are presented on the impact of line length on line reliability in CSA C22.3 60826-2010. However, it is well known that as the length of the line increases, reliability decreases. This is a shortcoming of the current standard. It is author’s assessment that the standard is more applicable to short to medium length lines.

# 4.0 Loading and Strength of LIL Line

Overhead lines are normally designed for two types of loads, (1) reliability (normal) loads and (2) security loads. During the operation of the asset, normal loads—sometimes called probabilistic climatological loads such as ice, wind, and combined wind and ice loads—are expected to occur within the service life ($t_L$). These loads are often quantified in terms of a single return period value (T-year). The line and its components are expected to survive the effects of these normal loads without any failure within the expected service life of the asset. Should the line system fail, the line is also designed to limit (contain) the extent of the failure zone. Security-based design loads (containment loads) are also considered in the design process, and the objective is to minimize the loss of the components' effects to avoid a major cascade failure. Overhead lines are also designed for regular maintenance and construction loads and safety loads.

In designing transmission lines, climatological loads like extreme wind, extreme ice, and combined wind and ice are a primary interest for the line designer. These loads are often classified under reliability loads. The ability to account for realistic extreme wind, extreme ice, and combined wind and ice loads on overhead lines can be hampered by the lack of site-specific data and associated meteorological parameters. One alternative approach is to review the meteorological data from nearby weather stations and use a specific ice accretion model to predict the wind and ice loads on the lines.

At the design level, extreme values of design wind speed and ice thicknesses are provided in the form of weather maps published by Environment Canada, which are often derived from the climatological data obtained from the nearby weather stations. However, as the lines are often built at remote locations, information on these basic design parameters are often extrapolated which result in greater uncertainty in the design process. An alternative approach is to directly measure the climatological load data along a proposed line route and correlate this information with that obtained from the model runs (ice accretion model) based on meteorological data. The underestimation of the wind and ice load will significantly reduce the line reliability while the overestimation of the load will significantly increase the initial capital cost of the line.

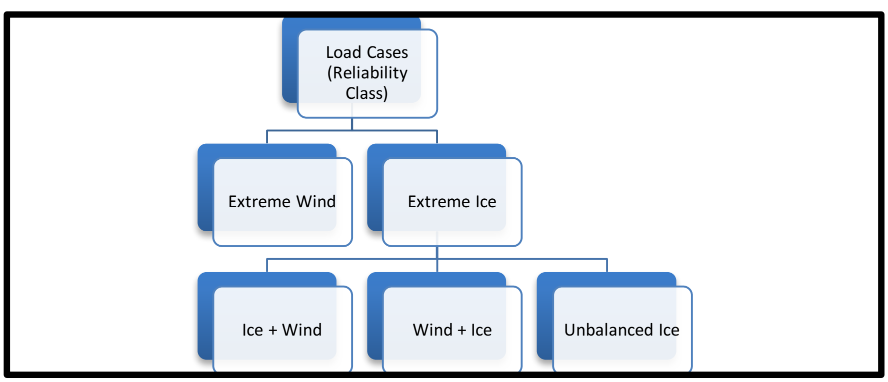



Figure 4.1 Reliability Load Class as per CSA 60826

## 4.1 Glaze Ice Loads

Freezing precipitation usually occurs when a cold air mass with temperature less than or equal to $0^0$ C is positioned below a layer of warm air through which rain or drizzle is falling. When the liquid droplets pass from the warm layer into the cold air mass, droplets become supercooled and tend to freeze on impact with a cold surface, such as on a conductor or OPGW. Depending on the surface temperature and wind conditions, the droplets could freeze completely or partially. Glaze forms in wet growth conditions when the surface temperature of the cable is $0^0$ C. Normally freezing fraction under this condition is less than 1 and density is 900gm/cm$^3$. Figure 4.2 presents the glaze ice thickness following CSA 60826-10. LIL design values are also shown in this plot.

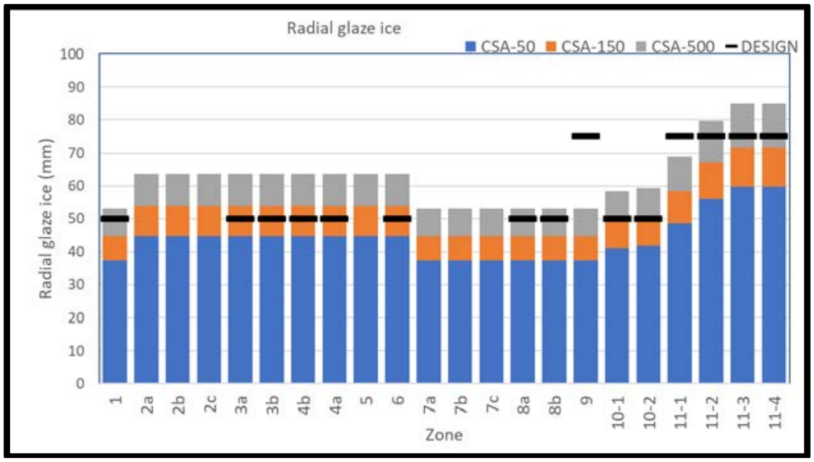



Figure 4.2 Ice Thickness According to CSA (50, 150 or 500) and DESIGN Ice Thickness (EFLA, 2020)

## 4.2 Rime Ice Loads

Rime icing results from accretion of super cooled water droplets which freeze immediately upon contact with a surface. The density of rime ice varies depending on the size and speed with which the supercooled water droplets freeze. Hard rime ranges in density from 100 to 600 kg/m$^3$ while soft rime has density of 100-300 kg/m$^3$. Rime icing is primarily driven by four key parameters: (1) wind velocity; (2) temperature; (3) droplet size distribution, often defined by median volume diameter (MVD); and (4) liquid water content per unit volume of water (LWC). Glaze ice is formed when the air temperature and the wind speed are high and the droplet size is large, while rime ice occurs when the temperature and the wind speed are low and the droplet size is small. The ice that forms on the object is primarily due to particles in the air colliding with the object (Figure 4.3). The ice formation is not completed immediately. Depending on the surface temperature of the object and the supercooled particles and the heat balance that follows, the rate of ice accretion is given as:

$$\frac{dM}{dt} = \alpha_1 \alpha_2 \alpha_3 U w D \qquad [4.1]$$

where M is the accreted ice mass, U is the wind speed normal to the cylinder, w is the cloud liquid water content (LWC), and D is the diameter of the cylinder (cross sectional area considering unit length). $\alpha_1$, $\alpha_2$, and $\alpha_3$ are correction factors that represent the collision, sticking, and accretion efficiencies, respectively. These correction factors vary between 0 and 1 and are explained in detail in the report (CEATI TODEM 3384 Report, Haldar et al 2016).

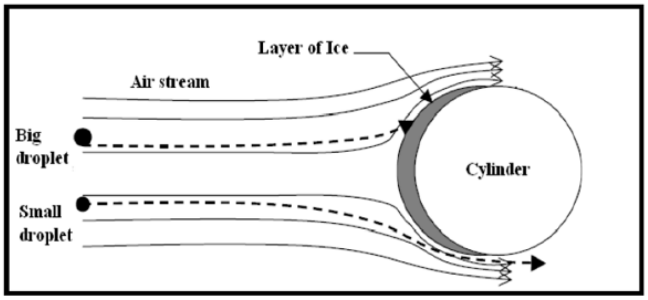



Figure 4.3 Trajectories of Cloud Droplets in the Flow Around a Non-rotating Cylinder (Nygaard 2011).

### 4.2.1 Rime Icing Forecast along LIL Route in Zones 2, 5, and 7 (EFLA, 2021)

CSA 60826-10 does not provide any rime ice map as it does for glaze icing. EFLA-KVT was retained by NLH to develop the rime icing loads (in-cloud icing loads) on the cables at high altitudes where the cloud base is below the conductor level and temperature is below zero. The study focused on Zones 2 in Labrador, Zone 5 in Alpine, and Zone 7 on the top of LRM. Extreme rime ice load occurrences can happen successively without any shedding in between. Rime ice can often be very localized and can be impacted by the topography and the terrain roughness.

To study the icing phenomenon along the proposed HVdc transmission line route, NLH installed several ice monitoring test stations (test spans and guyed towers at specific locations along the route) and operated these stations from 1979-87. Figure 4.4 depicts a typical icing event that was observed on a test tower located in a southern part of Labrador.

Figure 4.4 Observed Rime Icing in Labrador

The modeling techniques used to simulate the ice loads in the study were based on 40 years of hindcast weather data, which was used along with the Makkonen icing model to predict the new rime ice loads for each affected zone and for each of the conductor types at a defined height above ground. The study also determined the factors to be applied to the design wind and ice loads when calculating the combined wind and ice loading. The simulations found that glaze ice and wet snow contributed to the critical loading for each section. Data from the test spans located in the LRM, operated by Nalcor for 7 years since 2009, was used to verify the simulations. The model was found to overpredict icing compared to the test span data in the studied zones.

Figure 4.5 compares the 50 largest observed and modeled icing events for the two test spans 2009-01 and 2009-2 during the entire measurement period (November 2009 - October 2016).

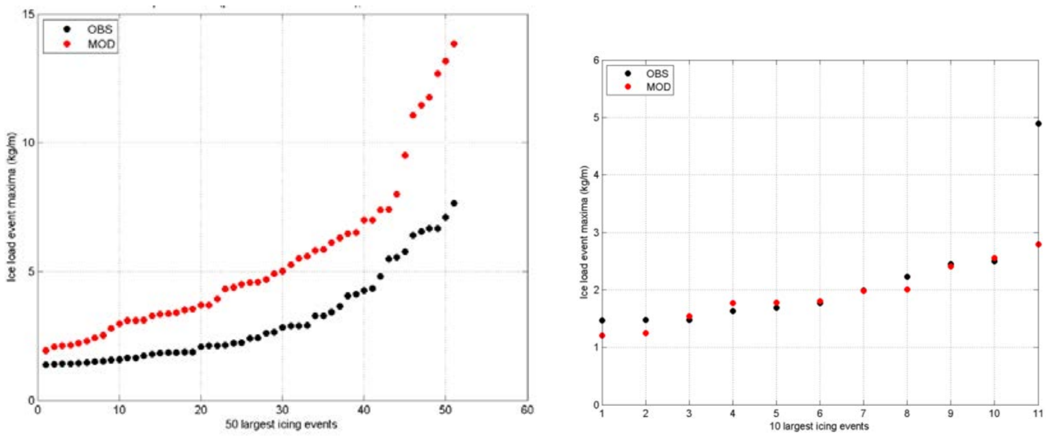



Figure 4.5 Comparison of largest icing events from test span 2009-01 (black dots) and the horizontal span icing model (red dots) between November 2009 and October 2016. Left: the 50 largest event for test span 2009-1. Right: 10 largest events in test span 2009-2 (KVT, 2021).

The model used has been shown to predict higher loads than those measured in test span 2009-1. Less difference is observed in test span 2009-2, as shown in Figure 4.5. The modelling of Site 2009-1 is challenging due to local topographical influence. The site is open to the sea towards the west and is unsheltered. A nearby valley can channel moist air from the Gulf of St. Lawrence and this wind speed moves perpendicular to the span; the air mass is cooled and condensed into droplets which can enhance rime icing. Wind observation shows very high wind in a westerly direction. The difference in the predicted and measured values is partly related to the ice shedding influence in the test span. In comparison, test span 2009-02 shows values that are quite close with the icing model and generally predicts slightly higher icing. The exception is the largest value in test span 2009-2 (4.9 kg/m), which is considerably higher in the test span.

The final simulated loads are in general lower than those used for the design of the LIL. KvT performed simulations of the loading while EFLA reviewed the results and compared them to previous studies. The simulated data enabled the establishment of combined wind and ice loads, which largely match those used in the design. The icing values results in this study are in general lower than those used in the design of the LIL. This is the first study available on the rime icing in the LIL that can quantify local icing condition using a reasonably reliable model. The model shows that rime ice loading varies significantly depending on local topographical conditions. The study replicates the variation in historical icing observation in the area. The low icing values predicted in the line route of the LIL are partly explained by the line-route selection that avoids critical rime icing areas.

The rime icing was evaluated using an icing model whose inputs are weather parameters such as wind speed, wind direction, temperature, and water particles (cloud water, snow, rain, graupel) obtained using a WRF (Weather Research Forecast) hindcast simulation covering the period from 1979-2019. The WRF model hindcast was split into two simulations. One coarse resolution simulation (4 km x 4 km grid resolution) for 1979 – 2020 and one high-resolution simulation (0,5 km x 0,5 km grid resolution) for two full winter seasons. The two datasets were combined using sector-wise statistical regression models and correction factors for main input parameters (wind, cloud LWC, and temperature). The icing model input and output data are calculated for a 500m x 500m grid over the rime ice areas (Figure 4.6). An explanation of the WRF analysis, method and assumptions used in the study can be found in the supplemental report (KVT, 2021) and in the CEATI report (Haldar et al, 2016). Once the meteoroidal parameters are extracted, the Makkonen model is run to predict the icing event on a continuous basis and to determine the time histories of the events. Ice shedding is also a challenge, but the model used here is an improved version of the one used by Haldar et al (2016). Details of the rime icing study will be submitted as a separate report. Here, we only present the summary loads in Figure 4.7 that outlines the extreme rime ice and ice thickness for combined wind and ice loads (EFLA-KVT, 2021)

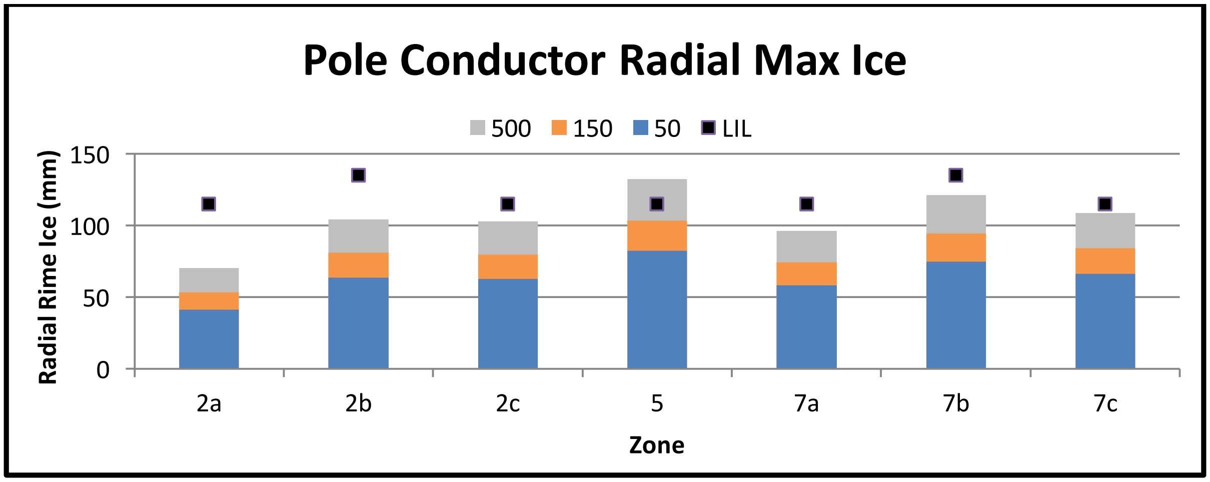

Figure 4.6 Setup of the WRF model simulations (The WRF4km domain is shown as the white rectangle and the two green rectangles show the two WRF500m domains) –EFLA (2021)

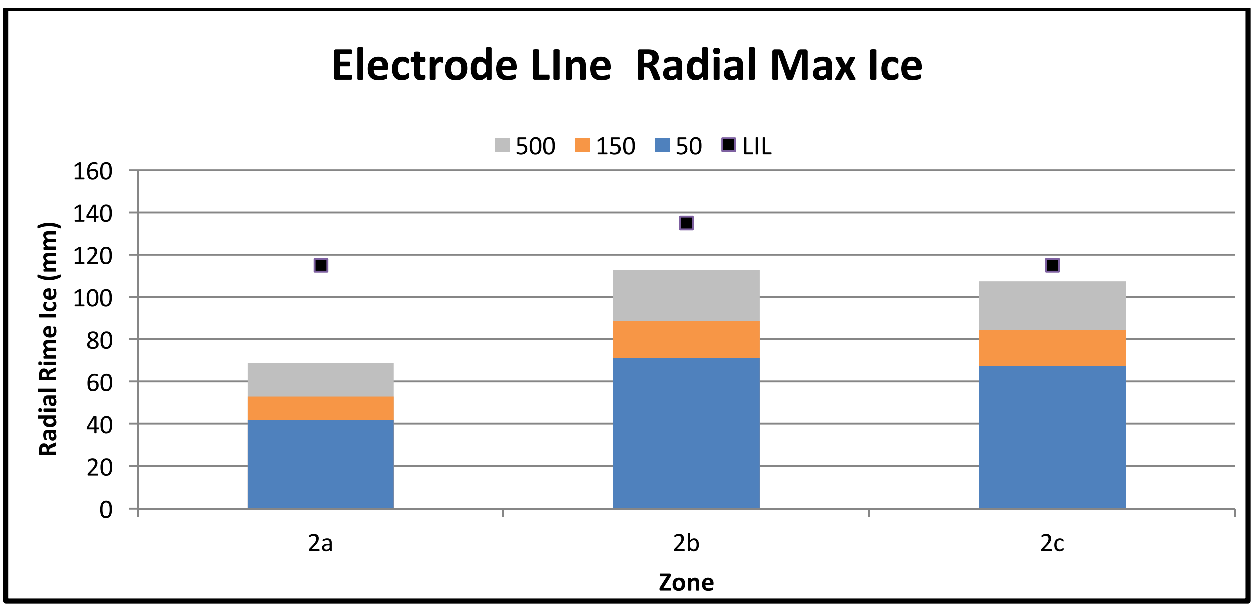
The proposed load combinations of "Wind and Ice" and "Ice and Wind" as described in Table 4.1. are used and the factors for reference wind speed and ice load values are within the typical range mentioned in the CSA 60826-10. $g_R$ is the reference rime ice load with a T –year return period.

**Table 4.1 Proposed values of wind speed and ice load in a combination of wind and rime ice (EFLA, 2021).**

| Load case | Ice load | Wind speed |
|---|---|---|
| Wind and Ice | $0.40*g_R$ | $0.80*V_R$ |
| Ice and wind | $g_R$ | $0.5*V_R$ |

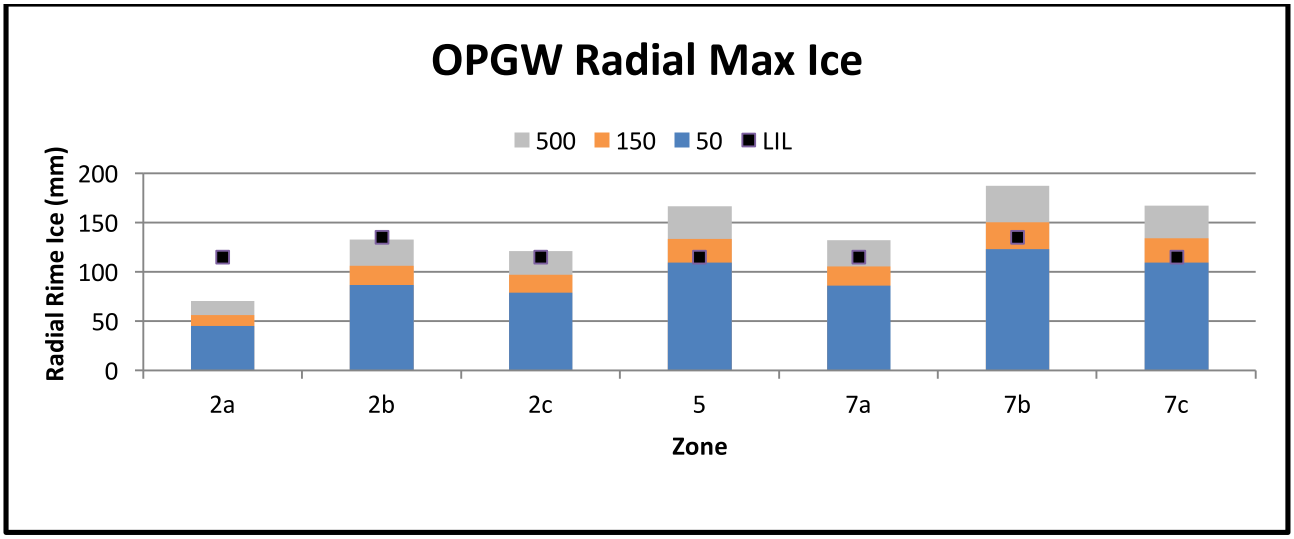
Both load combinations have a relatively high wind in combination with ice. The can be explained by the long period that rime ice can remain on the conductor before shedding occurs and the probability of experiencing high wind during that period. The KvT report (2020) lists the length of icing duration of the largest event, many of the severe events last more than 30 days and some more than 100 days

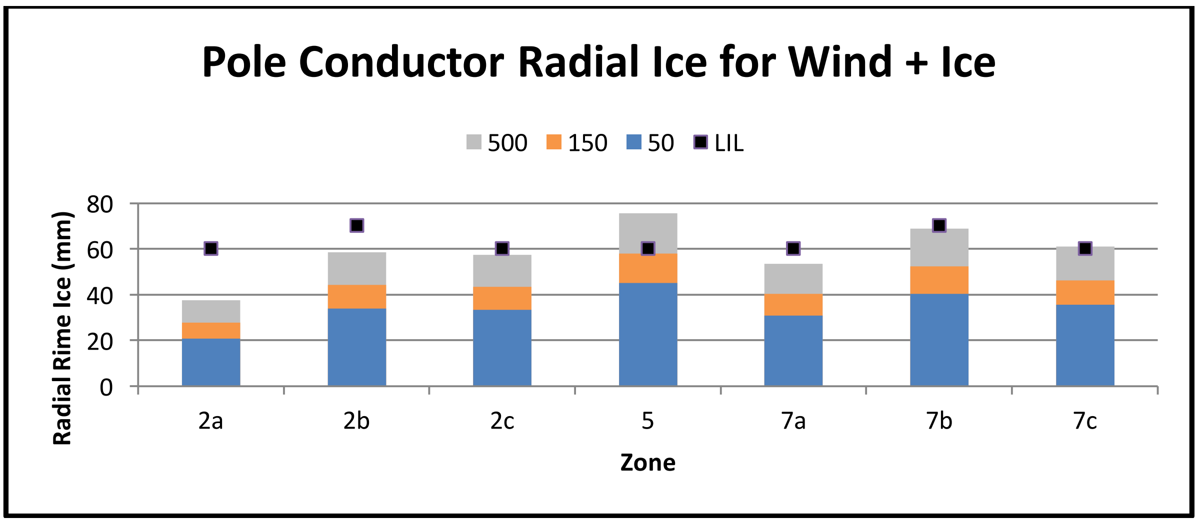


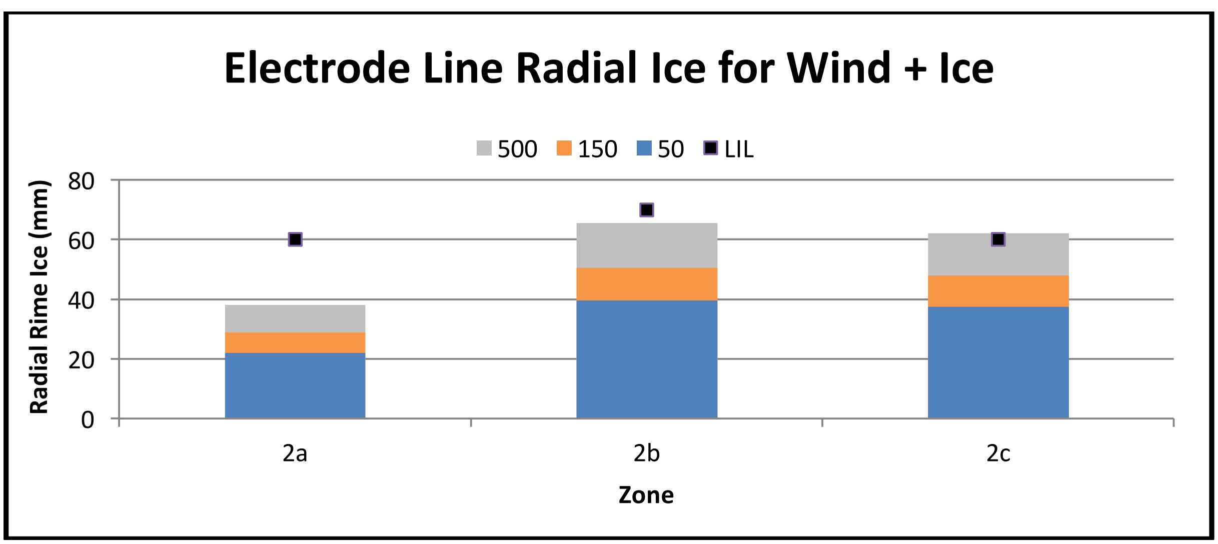




## 4.3 Wind Loads

The design wind speed and pressure used in the reliability analysis are based on CSA 60826-10 for 50, 150, and 500-year return period values and is presented in Figure 4.8.


OPGW Radial Max Ice
500
150
50
LIL
Radial Rime Ice (mm)
200
150
100
50
0
2a
2b
2c
5
7a
7b
7c
Zone


Pole Conductor Radial Ice for Wind + Ice
500
150
50
LIL
Radial Rime Ice (mm)
80
60
40
20
0
2a
2b
2c
5
7a
7b
7c
Zone


Electrode Line Radial Ice for Wind + Ice
500
150
50
LIL
Radial Rime Ice (mm)
80
60
40
20
0
2a
2b
2c
Zone

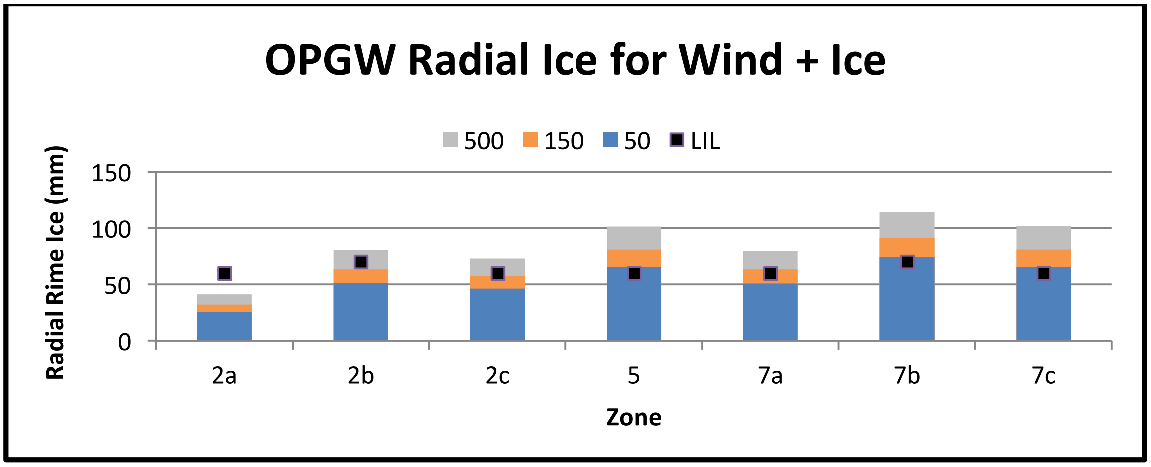



Figure 4.7 Rime Ice Determined from Numerical Weather Prediction Model – Zones 2, 5, and 7 (EFLA, 2021)

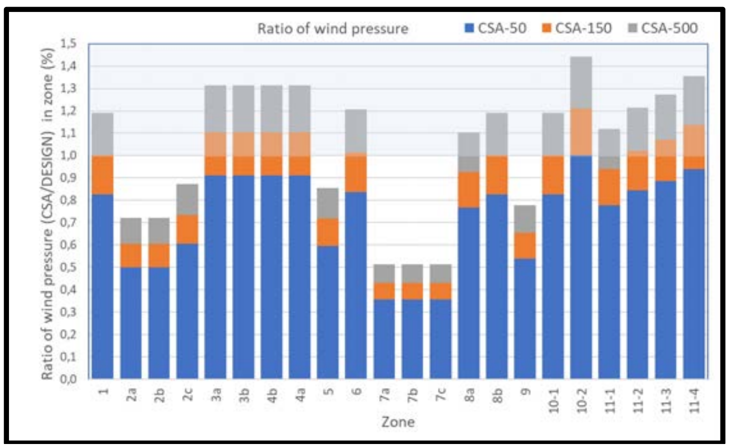



Figure 4.8 Ratio of Wind Pressure According to CSA (50, 150 or 500) against DESIGN Wind Pressure (EFLA report, 2020)

## 4.4 Combined Wind and Ice Loads

Traditional design for combined ice and wind load requires that the wind speed be applied to ice covered conductor that includes the diameter of the conductor plus the twice of the equivalent ice thickness. Two methods are available to determine this transverse load on the ice-covered conductor. The first is the historical storms method, where the extreme value load is determined based on the ice accretion model run and annual maximum selecting extreme value. The second method, known as the combined load probabilities method, combines the separate probabilities of occurrences of wind and radial ice under the assumption of statistical independence.

### 4.4.1 Historical Storm Method

This method requires the computation of transverse and vertical loads at each hour of the model simulated runs as the load diameter builds up, using the wind speed during the hour. The transverse load is recorded for the hour and the marching scheme continues until the build-up stops when the temperature indicates that the load would have melted off the conductors. The maximum load during the event is noted. This is carried out for many events each year. Annual maxima are selected for each year and this produces a time series of all annual maxima for a n-years historical record. Next, an extreme value analysis is carried out to predict the load for 50-years, 150-years, and 500-years. CSA 60826-10 presents these wind and ice maps for 50-year return period, and conversion factors are provided to determine the extreme wind speed and ice thickness for other return period values.

### 4.4.2 Combined Probability Method

Combined wind and ice loads can also be predicted statistically by combining the probability of the occurrences of wind and ice to meet a desired return period. The underlying assumption is that the two events are independent and that there is no correlation between ice accretion and wind speed frequencies of occurrences. This is not true and therefore estimates from combined probability method has produced loads which are significantly higher than the historical storm method (Goodwin et al, 1982). Correction factors are often required to reduce this overestimation by validating against the historical storm method. It is to be noted that the historical storm method is known to be more accurate. It is not clear to the author why CSA/Environment Canada does not produce this combined wind and ice load map directly from the model runs by stipulating maximum ice with concurrent wind and maximum days that the ice stayed on the cable (residence time)

**Table 4.2 Definition of combined loading with wind and ice in the CSA60826 Standard (reproduced from EFLA, 2020)**

| | Wind and Ice | Ice and wind |
|---|---|---|
| Ice load | 0.40 $g_l$ | $g_l$ |
| Wind speed | (0.60 to 0.85) $V_R$ | (0.4 to 0.5) $V_R$ |
| Description | Low probability wind during icing (return period T) associated with the average of the maximum yearly icing | Low ice probability (return period T) associated with the average of yearly maximum winds during icing presence |

$g_l$ is reference design glaze ice load (N/m) for the specified return period ($T$= 50, 150 or 500 years)

$V_R$ is reference wind speed for the specified return period ($T$= 50, 150 or 500 years

## 4.5 Unbalanced Ice Loads

Apart from direct climatological loads (transverse and vertical), the line is also exposed to loads arising from differential ice loads. These loads arise from non-uniform ice formation or ice shedding, when ice drops from one span or multiple spans in a random fashion, and the phenomenon creates unbalanced loads on the adjacent structure(s). A typical line design considers the effects of these unbalanced loads from ice shedding as static unbalanced load for individual phase load or load combinations, where loads from more than one phases are combined. However, the shedding mechanism is also dynamic and happens when ice falls from the span due to changes in temperature or in line orientation. Sometimes, the change in line direction from a non-sheltered region to a sheltered region can also cause ice shedding.

An estimation of longitudinal load on a transmission tower due to ice shedding is normally determined based on the deterministic approach where factor(s) are applied either on the ice thickness or the ice weight to quantify the shedding amount. However, the shedding process itself is random (Haldar and Prasad, 2000), and the net load effect of the shedding on a support structure (i.e. longitudinal unbalance or vertical unbalance load, or torsional) should be estimated to reflect the randomness of this phenomenon. Haldar and Prasad (2000) used a simulation method to compute the probabilistic unbalanced force on a transmission tower to represent ice shedding and the uncertainties associated with the unbalanced force. The simulated model was for a two span system.

Shedding phenomenon can also cause cable jump, an additional dynamic stress in the cable, which can cause problem to the safe operation of transmission lines, such as severe line clashing, if not properly controlled. The conductor can experience peak tension and the structures can experience large, unbalanced loads. The random behavior of the phenomenon requires simulations to envelope all the possible load cases, with shedding occurring in different spans. Thus, a full stochastic analysis is required to understand the phenomenon and its impact on line integrity rather the use of two factors that have been proposed in CSA 60826-10 to capture the randomness of the phenomenon. This oversimplifies a complex phenomenon and gives an "impression" that loads are probabilistic and therefore, can be included as part of the reliability class load. CSA also stipulates *"Where the exposure of the line to its surroundings changes from one span to another, unbalanced loads larger than those described above should be considered. Note: Unbalanced ice loads due to unequal accretion or ice shedding will invariably occur during icing events. Statistics of unbalanced ice loads are not usually available; however, the recommendations given in this standard should be sufficient to simulate typical unbalanced ice loads that occur such conditions."*

A recent study by CEATI's TODEM group has shown that the dynamic amplification factor could be significant depending on the structure type and configuration (CEATI 33109, 2020). NLH has considered this load a deterministic load and used in designing HV lines for the past 50 years and operated 1300km of steel transmission lines in harsh environments. This is further discussed in the next section and later in Section 6.3.3.

### 4.5.1 Brief Review of Design Philosophy for Unbalanced Ice Loads including NLH's Design Brief

In Newfoundland and Labrador Hydro (NLH), unbalanced ice loads have always played a significant role because of the harsh environment and towers designed in 60's known as SAE towers included load on any or all of three conductors support phases as combination of longitudinal loads. Unbalanced Ice loads in the 60's (SAE tower) did not consider the vertical unbalance load or their combinations and this was included during the CAT Arm steel line design in the 80's (TL 247/248). Later, the same design philosophy was adopted for two major upgrading projects in which the author was closely involved and all phase combinations were considered both in flexural and transverse bending cases (TL 228 Upgrading,1988 and Avalon Upgrade,1996). After the Avalon upgrading project, all these load cases were documented in a standard NLH drawing ((NLH A1-2200-T-546, May 2002) that summarized all the 11 load cases diagrams for 230kV Guyed V tangent tower with specific values that were used for Avalon Upgrades. NLH design loads are based on full ice thickness (100%), partial ice thickness of (70%) for flexural and torsional loads, and 100%/50% ice thickness combination for transverse bending. The NLH design standard considers loads at any one phase or any combination of conductor phases and is quite conservative. Members load effects derived from load combinations are checked against the capacity to ensure that the load effect is less than the factored capacity.

The author concludes that an unbalanced load due to ice shedding should be determined based on random simulation and exceedance of a specific load magnitude should be determined from random simulation. This is not normally done in the overhead line design because there are many span combinations and structure configurations one may encounter in the design. Therefore, this unbalanced load case is treated in a deterministic manner. A typical assumption is that the span in one side is assumed to have full ice thickness (notice load) and the span on the other side will have a factored ice thickness to simulate the phenomenon of unbalanced load due to shedding. To evaluate the uncertainty in the prediction, a sensitivity study that includes the effects of various important parameters—such as unequal spans, effects of elevation difference that is central support being in a different elevation compared to other supports, variable ice thickness, etc.—needs to be conducted.

The unbalanced ice loads for the LIL design assume that the load acts on one phase at a time. *Transverse bending is excluded*. It also assumes full ice thickness (100%) on one side and 70% of design ice thickness on the other side. In LCP design specification, it states "***For suspension towers, unbalanced ice loads shall be checked by 100% of ice at one side and 70% of ice on the other side, one conductor at a time".*** The residual static load should not be considered Design ice thicknesses are presented in Table 18 of the EFLA report and in Figure 4.2. By applying these loads one at a time, the LIL design produces maximum values of member forces under the individual phase loads and checked for factored capacities to ensure that the load effects are less than the factored capacities. No load combination is considered.

Both design philosophies (CSA 60826-10 and NLH) are similar, except one uses ice load as reference while NLH considers loads in terms of ice thickness. Both considers flexural, transverse, and torsional loads and load combinations, but the thickness and load factors are different.

Since the ice shedding phenomenon is random, it is difficult to capture a specific design load in terms of a single load event. Although IEC/CSA 60826 stipulates a single combination factor in the design process and classifies the unbalanced ice load under a reliability class of load, the author disagrees with this approach because it is not demonstrated how these factors were determined, nor does it show how these factors relate to the specific return period of ice load. These factors remain constant even when the return period of the load increases.

The best practice in the industry is to treat unbalanced ice loads as deterministic. The load is determined based on full ice in one side and the partial or zero ice on the other side. Unbalanced loads are determined in terms of flexural bending, transverse bending, and torsional. At least, one overhead ground wire (OPGW) and one phase conductor are used to determine the unbalanced ice load combination. This is the "best practices" that is followed by many North American utilities.

## 4.6 Strength of Component

The assessment of the characteristic strength of each component and the load effects on this component, following equation (3.3) in Section 3, is necessary to develop the reliability calculation model. Figure 4.9 presents the key elements that have been considered within the support and wire subsystems.

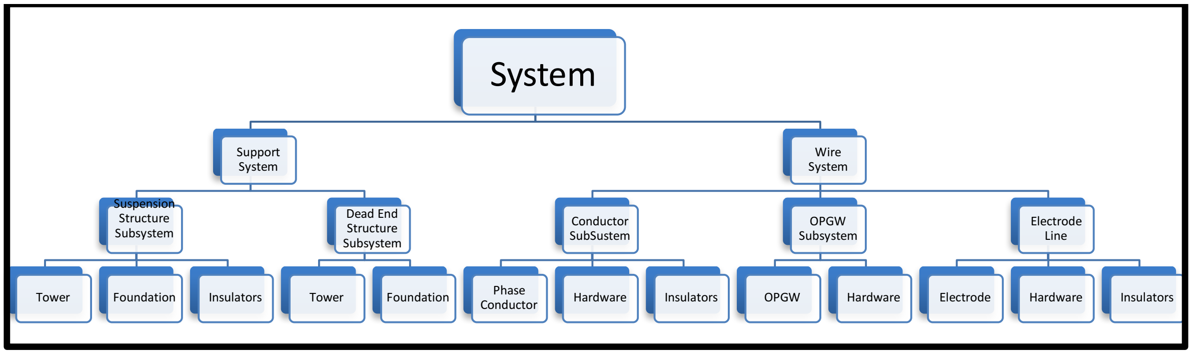



Figure 4.9 Key Components Considered in the Analysis in Each Segment

### 4.6.1 Characteristic Capacity

The characteristic capacity ($R_c$) of a component is determined based on an exclusion limit of e%, and for a normal distribution

$$R_c = \bar{R}\,(1\text{-}k_\alpha V_R) \qquad [4.2]$$

where $\bar{R}$ defines the mean strength value, $k_\alpha$ is the factor that determines the shaded area for e% exclusion limit, and $V_R$ is the coefficient of variation. This is presented in Figure 4.10 and implies that the strength would be above $R_c$ with 90% confidence.

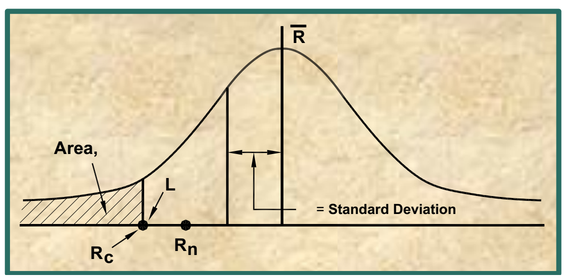



Figure 4.10 Characteristic Capacity

### 4.6.2 Characteristic Capacity – No Test Done

CSA 60826 determines characteristic strength based on test data of the line components. However, the characteristic strength, $R_c$, can also be found in the governing standard and can be interpreted as a 10% exclusion limit value. The CSA 60826 table provides the typical coefficient of variation of key line components as default values in the absence of relevant data. CSA 60826 also allows the use of both normal and lognormal distributions to determine $R_c$ based on e = 10% exclusion limit value.

# 5.0 LIL Reliability Assessment

The POF and the reliability of LIL under two different types of icing scenarios is determined in this section based on the reliability of individual line segment's exposure to these icing phenomena. A line segment is defined as a section between two dead-end towers in which design loading remains nearly constant or unchanged. The LIL consists of 11 major line segments (Figure 1.4). These line segments are broken down into glaze and rime icing zones. A single-line system consists of two primary sub-systems, the support (structural) sub-system, and the wire sub-system (reproduced Figure 4.7).

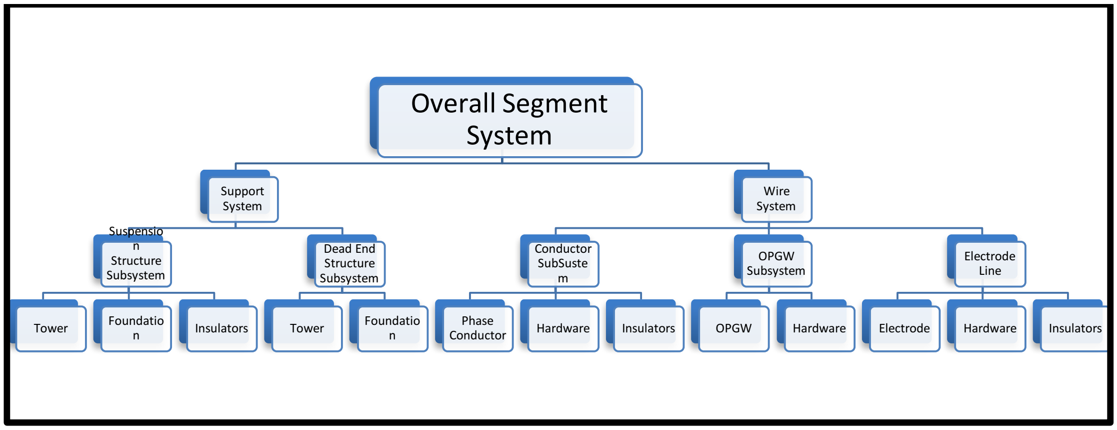



Figure 5.1 Reproduced from Section 4

Each subsystem has many components. A typical suspension tower subsystem consists of a tower, foundation and insulators. The wire support sub-system consists of conductors, OHGW, electrode line and strain hardware, and insulators within the segment. Figure 5.1 presents a typical segment of a LIL line with m-structural systems.

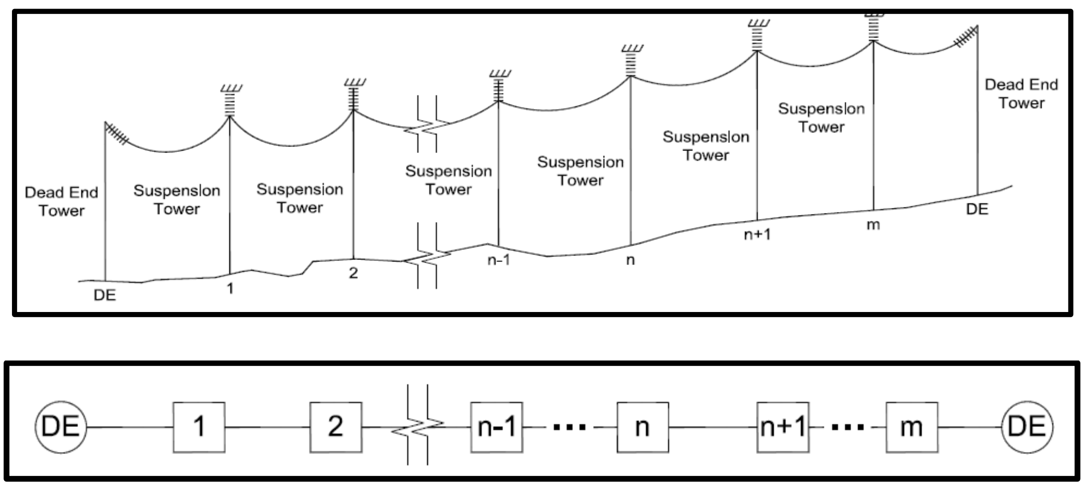



Figure 5.2 (a) A Typical Line Segment and (b) Series System Model with n-structural Subsystems

The reliability of a typical subsystem (i) within a *segment* (j) is determined based on the "weakest link" concept. Components within a typical subsystem (Figure 5.2) in a *segment* are modelled as part of a "series" system, and the entire LIL line is modelled as a chain of m-segments having n-number of "structural support subsystems" and k-number of "wire support sub-systems" (Figure 5.2 and Figure 1.4).

It is well known that for a series system, the system reliability is always less than the individual component reliability and the system fails when any one of its components fails. On the other extreme, a parallel system (redundant system) may survive even the failures of one or two elements. In this case, system reliability is greater than any of its component's individual reliability. An example of a series system is a typical insulator string, a guy wire system (series system), while an example of a parallel system is a transmission tower, pole conductors in a HVdc line.

## 5.1 LIL Modelled as a Series System

The LIL is modelled as a series system and the system acts as a "weak link" because the system fails and may lose its functionality if one of the line element fails. The series system model is described in Section 2.5. In Section 2, we have defined the mechanical and electrical system failures and their impact on line system reliability. Power systems are designed based on N-1, N-2 criteria and failure of one (N-1) or two (N-2) key components/lines may not cause a customer outage provided the system can still function and meet the demand at the time of the failure (system adequacy met during the recovery period), and assuming power can be redirected through another part of the network without significant short-term overloading. However, the failure of one critical mechanical component (structure, foundation, insulators, wires etc.) may cause the line to be out of service for a significant amount of time. Figure 5-2a presents a typical segment modelled as a series system, and Figure 5-2b presents the system model with n–number of structural elements. Assuming the probability of failure of a single $i^{th}$ element is $P_{fi}$, then system failure probability can be determined in terms of upper and lower bound values following Cornell (1967).

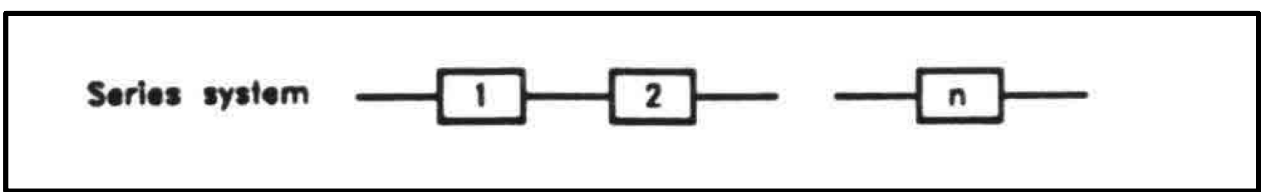



Figure 5.3 Typical Series Elements (Thoft-Christinsen and Sorensen, 1982)

**Upper Bound** = ${P_{fs}}^{U}$ = 1 - (1-$P_{f1}$) (1-$P_{f2}$) (1-$P_{f3}$) ……… (1-$P_{fn}$) [5.1a]

**Lower Bound =** ${P_{fs}}^{L}$ = max $P_{fi}$ [5.1b]

where max $P_{fi}$ is the maximum probability of failure among all elements ($i$ = 1, 2, …. n). The upper bound corresponds to no correlation (independence) among elements' failure modes ($\rho = 0$). while the lower bound refers to full correlation ($\rho = 1$) among the failure modes (dependency). The correlation property $\rho$ defines the strength of the relationship between the elements' failure modes and how one failure mode affects the other failure mode for the purposes of determining the system reliability index (or probability of failure). The higher the correlation value, the stronger the dependency.

Equation (8.1a) can be approximated as

$$P_{fs}{}^{U} \cong \sum_{1}^{n} P_{fi} \qquad [5.2]$$

if $P_{fi}$ values are small. Otherwise, one needs to consider the full expression in equation (8.1a).

Within the structure support sub-system, several elements for a single tower sub-system will be subjected to a typical load event; there will be a strong dependency among the failure modes of these elements. Several support sub-systems within a segment may also be subjected to a common storm front. In this case, the failure mode of one element in one support sub-system may have some degree of correlation to other elements of the support sub-system that are exposed to the common storm front. One would expect that the correlation would be high in this event. Therefore, the system failure probability would be closer to the lower bound value when several elements of a sub-system are considered. If the reliability index (or failure probability) for all elements is equal and there is no correlation, the system failure probability is the number of elements multiplied by the individual element failure probability (Cornell, 1967), provided the failure probability is small ($P_{fi} \ll 1$). Figure 5.4 presents the probability of failure with correlation variation of correlation coefficient for 1, 2, 5, and 10 elements in a series system.

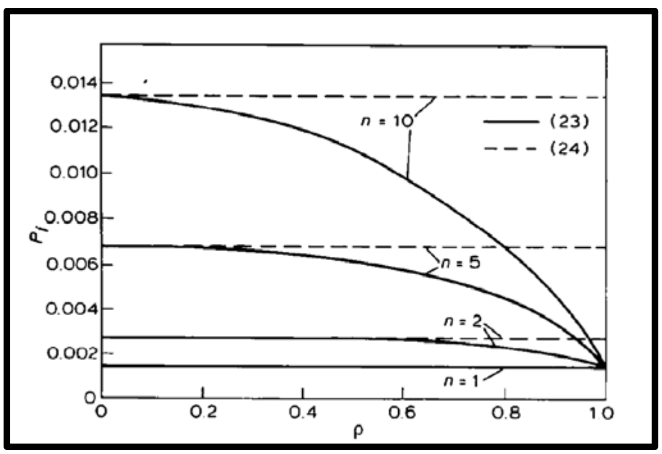



Figure 5.4 System Failure Probability for Equally Correlated Elements ($\boldsymbol{\beta_e}$ = 3.0) – Series System (Thoft-Christinsen and Sorensen, 1982)

It is noted that as $\rho$ increases, failure probability ($P_f$) decreases and tends toward a lower bound value in equation (5.1b). It should be noted that as the number of elements increase, the probability of failure also increases. For a typical sub-system, we consider n-elements and the load effect on these elements will have a common mode effect when subjected to a specific load case (j =1). There would therefore be some degree of correlation (among the force distribution), and failure modes for these elements under a load case (j), such as extreme ice load, would be highly correlated and can be assumed as full correlation for simplicity's sake. The system probability of failure would be a lower bound, as presented in (equation 5.2).

The system probability of failure may be underestimated if one does not consider the effect of correlation within a sub-system when the elements are exposed to a load effect or a group of loads. Figure 8.4 presents a flow chart in determining the system reliability of LIL. Three levels of correlation effects are considered. These are: (a) correlation among various elements within a typical sub-system under a critical load case, (b) selective correlation among critical load cases acting on a structural component in different segments within a zone, and (c) spatial correlation (zero and/or full) of weather events on various segments based on geography, terrain categories (inland versus coastal, consideration of regional grouping, independence and effects).

### 5.1.1 Correlation Issue – Among Key Elements

Figure 4.7 presents the element layout diagram used to determine the correlation value of a typical segment. Ten key elements are considered for two sub-systems. The selection of ten elements is valid for all segments except Segments 1, 2, and 3a. In these three segments, there are electrode lines and associated hardware: this adds three more elements under strain arrangement—an electrode line, associated insulators, and hardware (a total of 13 elements). The correlation study under extreme ice load case (for one typical load case) reveals that this is generally greater than 0.90.

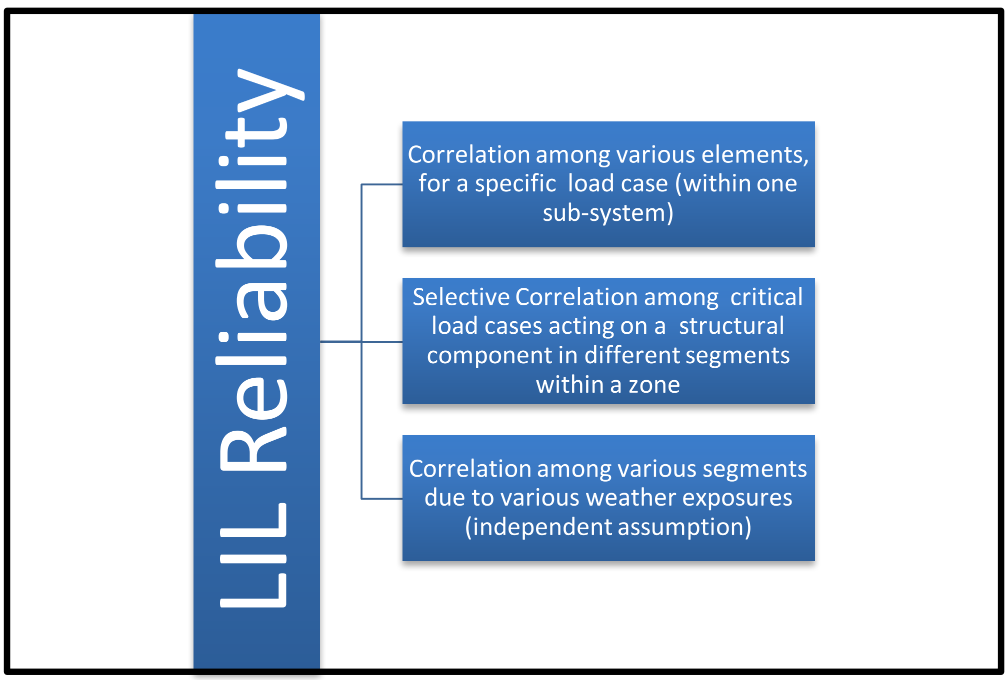



Figure 5.5 Flow Diagram for Determining LIL Reliability

### 5.1.2 Reliability Considering Correlation among Multiple Load Cases

Considering n-elements in a system subjected to m-load cases the bounds can be extended

$$\text{Max } p_{fij} < P_s < \sum_1^m \sum_1^n p_{fij} \qquad [5.3]$$

where $p_{fij}$ is the probability of failure of the $i^{th}$ element under $j^{th}$ load case. $P_{fs}$ is the failure probability of the subsystem

$$P_{fs,j}{}^{U} \cong \sum_{1}^{n} P_{fi} \cong \text{n}^{*}P_{fi} \qquad [5.4]$$

if $P_{fi} \ll 1$

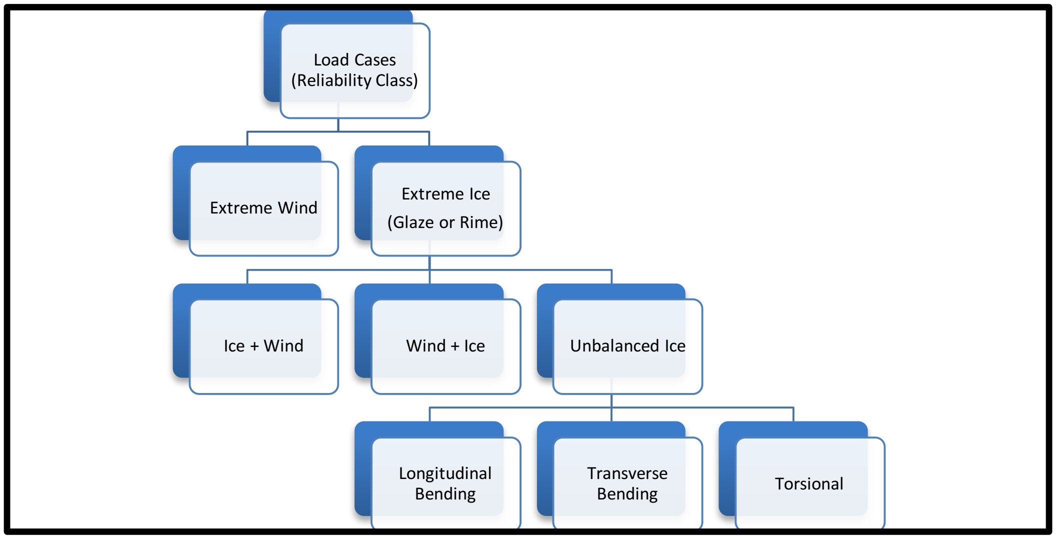



Figure 5.6 Loading Diagram

## 5.2 LIL Reliability – System Approach

Very long lines are often divided into several segments (several weather zones) because of different loading criteria for various weather zones. Lines below 200km in a severe climatic zone may be designed for one uniform loading zone. However, as the line length increases, one may need to consider breaking down the line length into sub-climatic zones to realize realistic loading conditions for various zones. In this situation, the probability of failure of each individual line zone is determined first. The reliability is determined based on the assumption that the line is modelled as a series system in which each zone represents one component. If the assumption of independence is valid between each-weather zones, the probability of failure of the entire line to a specific type of loading exposure (wind, ice etc.) is

$$\text{P[FL]}_{j} \approx 1\text{-} \prod_{1}^{N}(1 - P[SEG]_{k}) \qquad [5.5]$$

in which N is the number of segments exposed to a specific type of loading.

$P[SEG]_k$ is the probability of failure of a typical segment, k, under a typical load case, j.

For all load cases, one can use the adjusted upper bound values, if one assumes some independence among ice load case and wind load case. The adjusted lower bound value considering correlation among key elements under a load case is used under all ice load cases.

$$P[FL] = [1-(1-P[FL]_1)*((1-P[FL]_2)* \ldots\ldots ((1-P[FL]_k)] \quad [5.6]$$

where
P [FL] = LIL reliability under one type of icing considering all relevant segments (super zones-zones grouping)

$P[FL]_j$ = failure probability of a segment or several segments under a specific type of icing (glaze or rime)

## 5.3 Regional Grouping Considering Multiple Segments Under Various Weather Zones

In a technical note, Thomas (2011) outlined the justification for selecting the 50-year return period for LIL and showed that the higher return period could not be justified because the 230kV line feeding the Soldier's Pond converter station will still be operating under a 50-year return period based design. Under an extreme event which has a return period higher than 50-year, the LIL line could not survive because the converter station may not have the power due to the loss of the 230kV line. Although the author disagrees with the main premise of Thomas's argument, the author would like to highlight that Thomas (2011) recognized the importance of the length of the LIL line, the environmental exposures to which the line is subjected and the long repair time necessary should the line fail due to extreme weather loads.

"*Forced outages to the HVDC overhead transmission line is of more concern in the context Labrador-Island Link given the length, environmental conditions, and mean time to repair. The CIGRE report does not provide long term average forced outage rates for overhead lines or cable systems*". Long term forced outage rate data implies that line failure rate and recovery rate and is particularly significant for extreme weather-related damages and/or failures.

The author is not aware of how this line length issue was dealt in the original LIL design to assess its impact on mechanical/structural reliability of LIL. It is easily understood that a 10km line and a 1000km line designed with the same return period of climatic event (design load) will have a very different failure frequency/year/100km. It is also well recognized that reliability decreases as the line length increases, unless the design loads are adjusted in terms of return period in the beginning. This will be benchmarked in Section 8.6 with some published data and actual DC line performances.

### 5.3.1 Determination of Reliability for LIL (Assumptions for Various Levels)

- Level 1 (No regional grouping, full correlation along the entire line length and among elements, no distinction made between different exposure levels, e.g., icing types, extreme wind) – Base Cases # 1 and #1A

- Level 2 (No regional grouping, full correlation along line length and among elements, distinction made between different exposure levels, e.g., glaze icing, rime icing, and extreme wind) – Base Cases #2 & #2A

- Level 3 (No regional grouping, full correlation along line length and the elements within subsystems, independency between support and wire subsystems, distinction made between different exposure levels, e.g., glaze icing, rime icing, and extreme wind) – Base Cases #3 and #3A

- Level 4 (Regional grouping, full and /or no correlation along line length, partial correlation in all elements within the subsystems, distinction made between different exposure levels, e.g., glaze icing, rime icing, and extreme wind) – Base Cases #4A, #4B, #4C and #4D

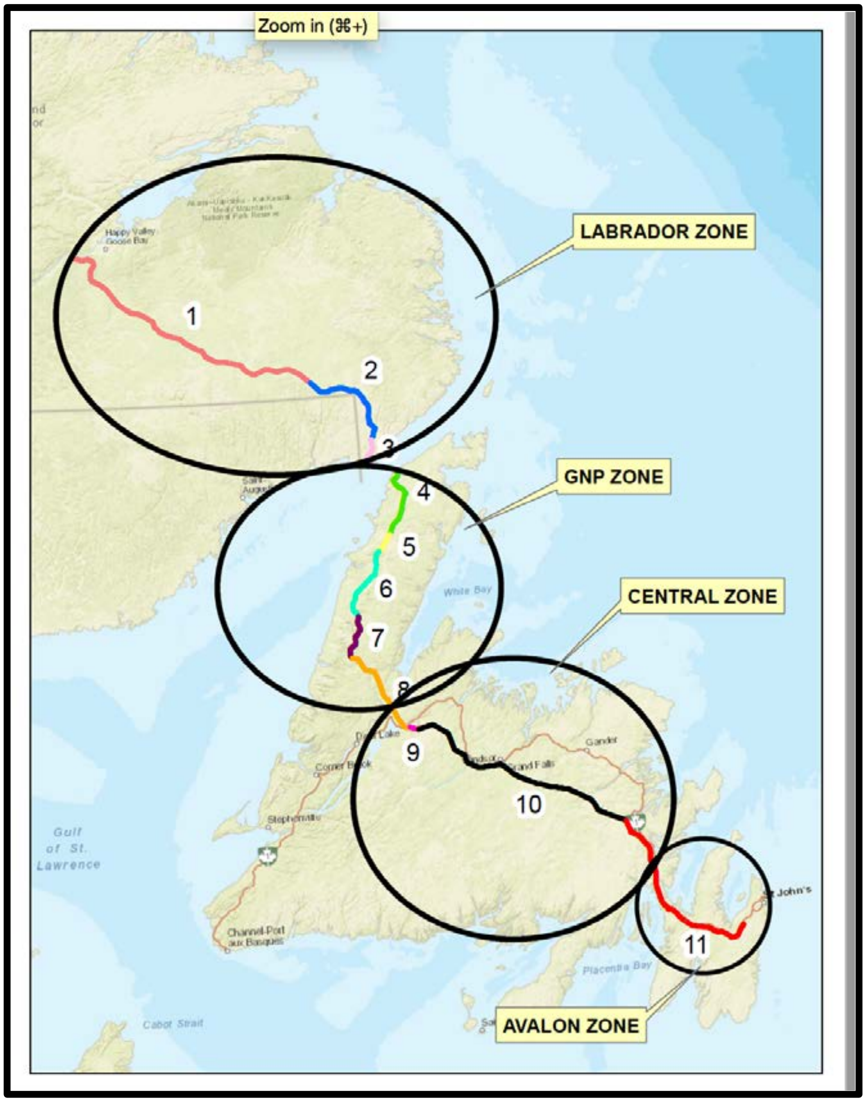



Figure 5.7 Approximate Regional Grouping of Various Zones

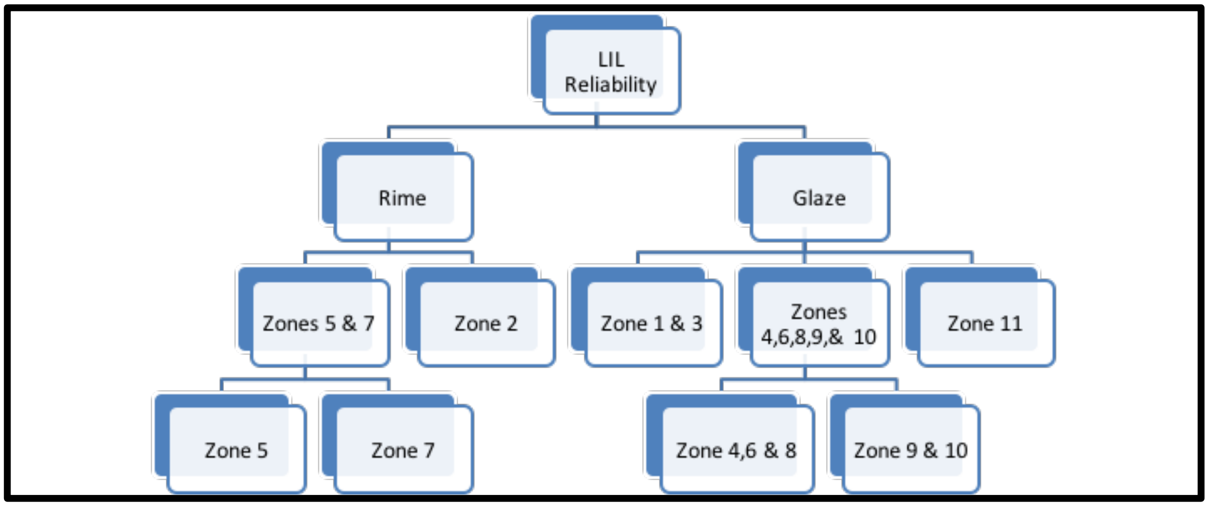



Figure 5.8 Segments Identification Under Various Regions Reflecting Primary Icing Exposures

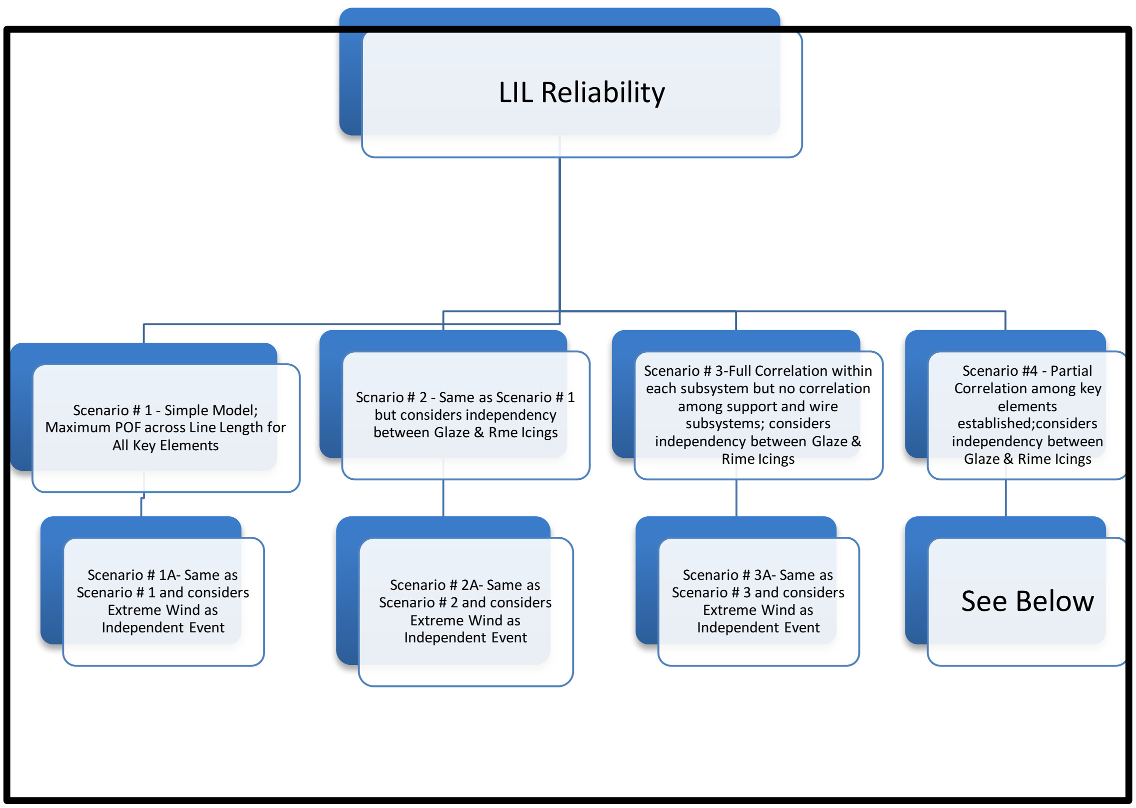



Figure 5.9 Reliability of LIL Considering Various Scenarios

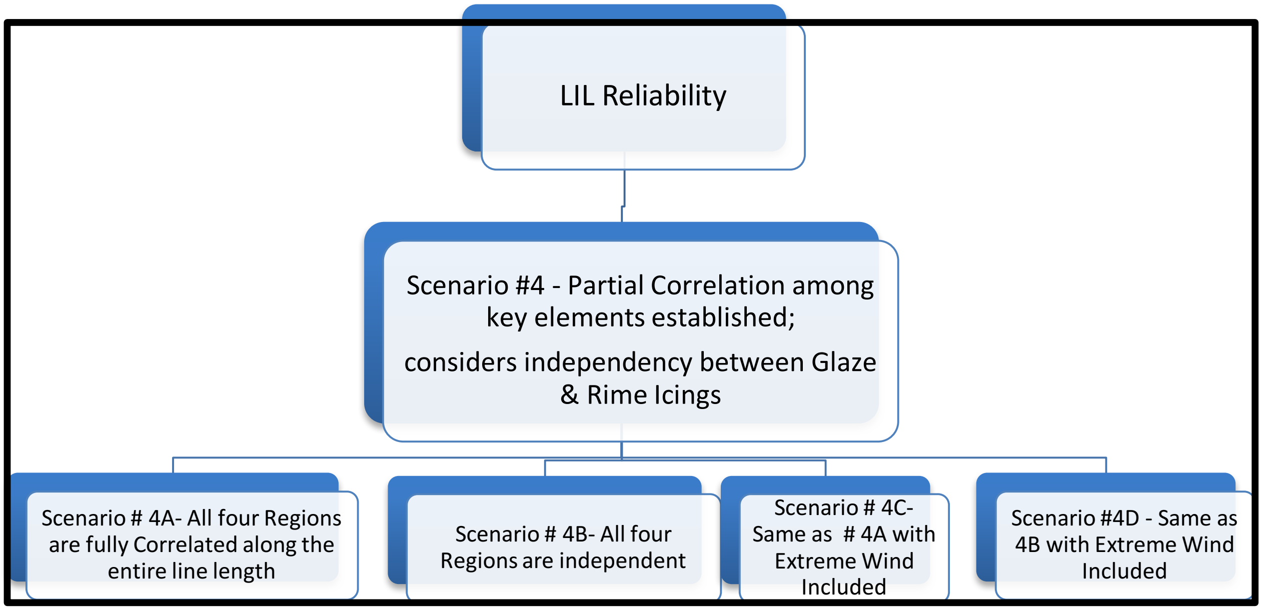



Figure 5.10 Reliability of LIL Considering Scenario #4

# 6.0 Summary Results for Various Zones

In this section, summary results are presented for the following load cases and are presented following the Figure 3.1 and the methodology outlined in Sections 4 and 5. This analysis uses the following load cases impacting the line reliability for both glaze and rime icing (Figure 6.1):

- Extreme wind
- Extreme ice
- Combined wind with ice
- Combined ice with wind
- Unbalanced ice loads

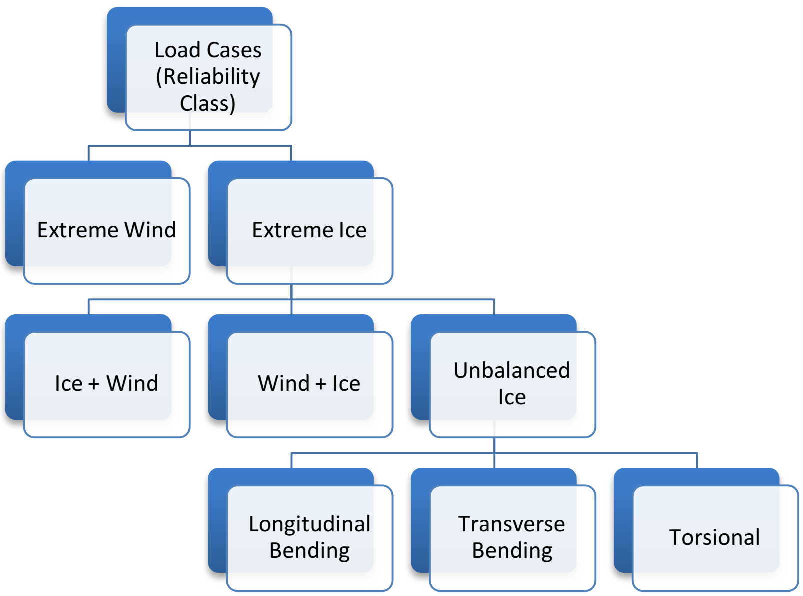



Figure 6.1 Loading Diagram

The author identified some issues with unbalanced ice load being considered as part of the reliability class of loads in Section 4. Section 6.1.3 discusses this and explains why this load should be excluded from the line reliability calculation. The reliability analysis results include the analysis of data for 29 segments, 22 of these segments for glaze icing zones and 7 of these segments are for rime icing zones.

## 6.1 CSA RBD Analysis – Reliability Classes of Loads

Based on the structural reliability analysis conducted by the author, all components meet CSA 150-year return period except OPGW and electrode lines in few segments. These analyses are applicable to the previously cited normal climatological loads under reliability class of loads.

### 6.1.1 CSA RBD Analysis – Reliability Classes of Loads (Glaze Icing)

Figure 6.2 summarizes the results for the glaze icing zones.

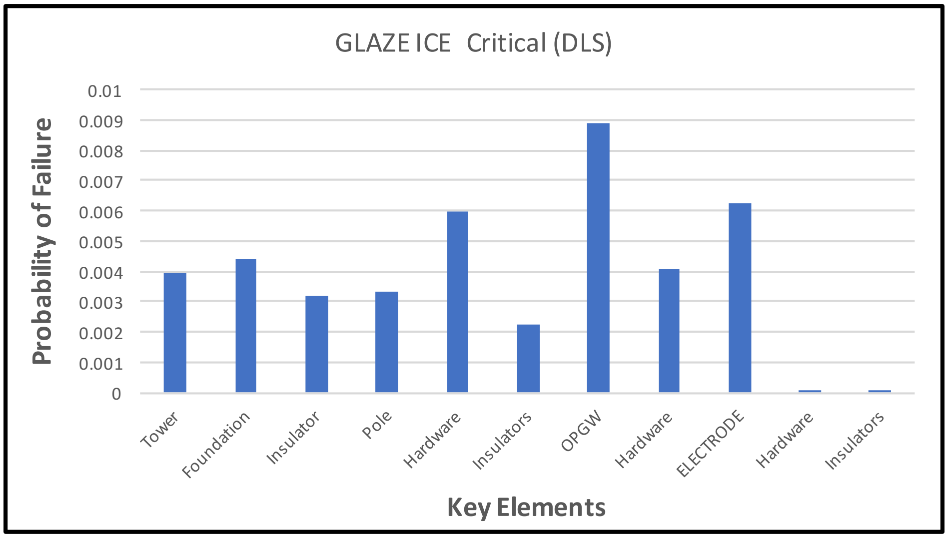



Figure 6.2 Annual POF Under Glaze Icing

Figure 6.3 shows that in all segments, foundation POF's are higher than the POF's of the tower except in Zones 4a and 10-1. This is in contrast with industry's best practices where tower is supposed to fail before the foundation (Figure 6.3). Similar observation is also made where cable system is likely to fail first compared to structure support system.

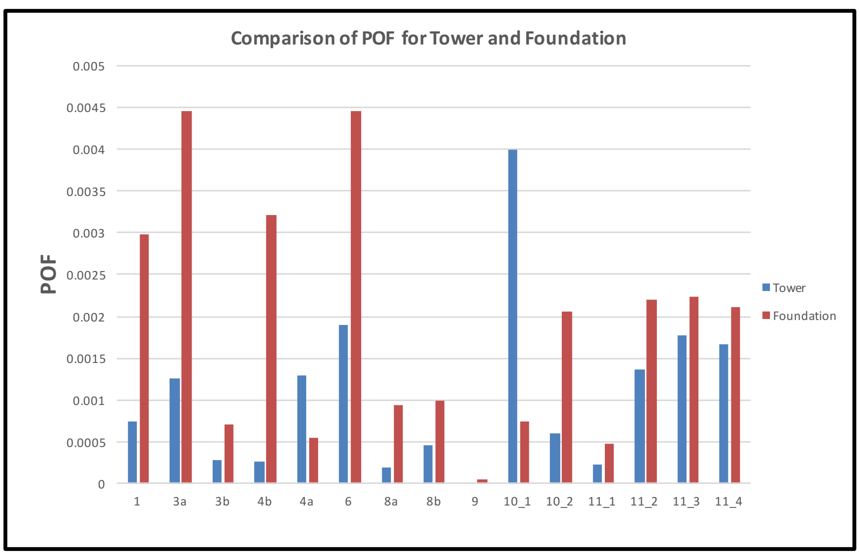



Figure 6.3 POF Comparison for Tower and Foundation

### 6.1.2 CSA RBD Analysis – Reliability Classes of Loads (Rime Icing)

Figure 6.4 summarizes the results for rime icing zones. Here, sequence of failure between tower and foundation is acceptable, POF of tower is significantly higher compared to foundation.

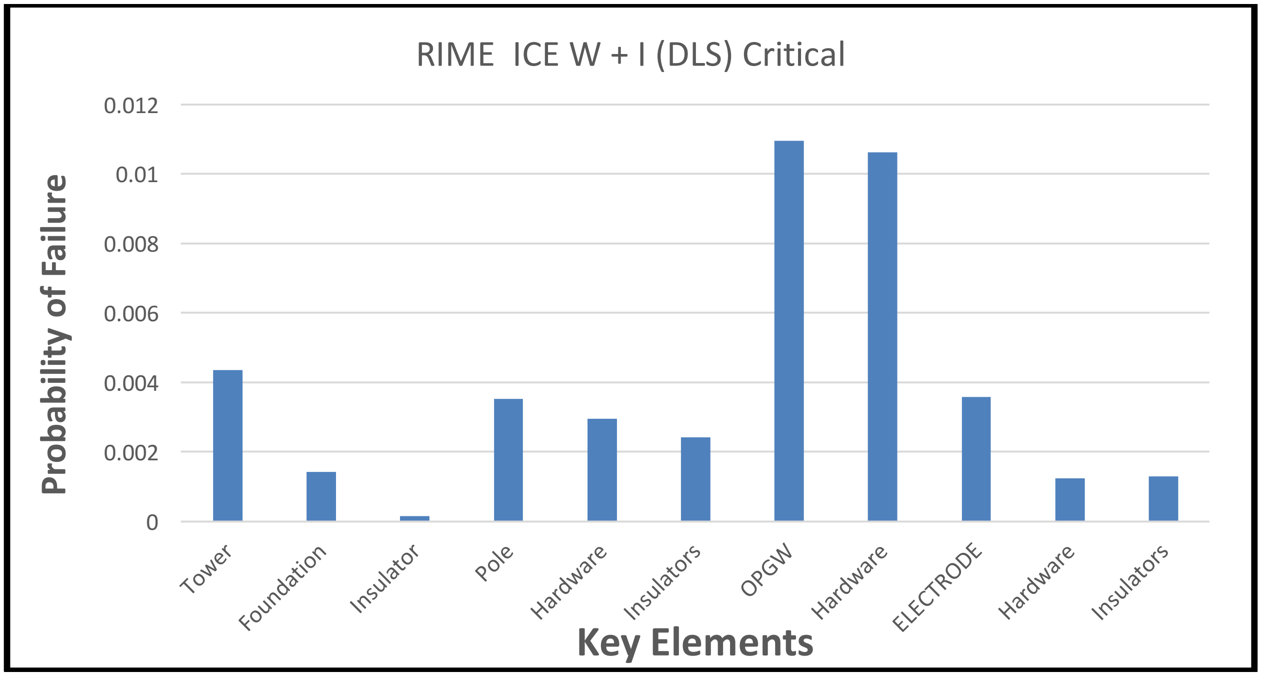



Figure 6.4 Annual POF Under Rime Icing

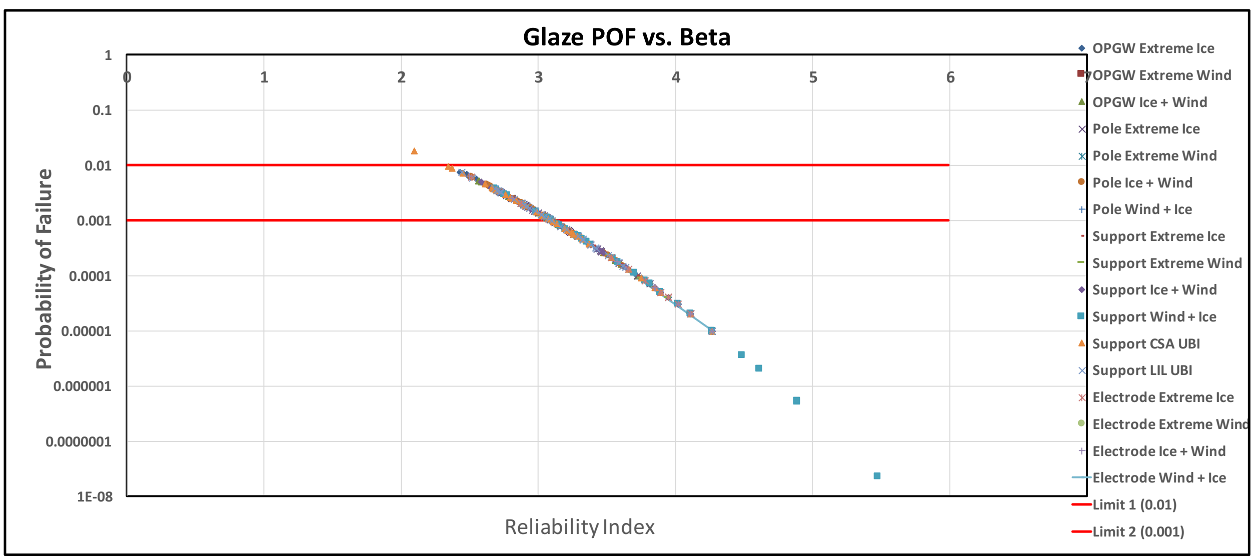



Figure 6.5a Overall Plot of All Data Points for Glaze Icing & 5 Load Cases

Figures 6.5a and 6.5b summarize the results of the entire analysis in terms of glaze and rime icings and 5 load cases; The points that are above 0.01 line (upper red line) indicates that POF is greater than 0.01. The one point showing in Figure 6.5a refers to S2-541 for UBI following CSA 60826-10 analysis. The actual POF value is 0.01928. Similarly, points that are above 0.01 in Figure 6.5b refers to OPGW and strain hardware under rime icing.

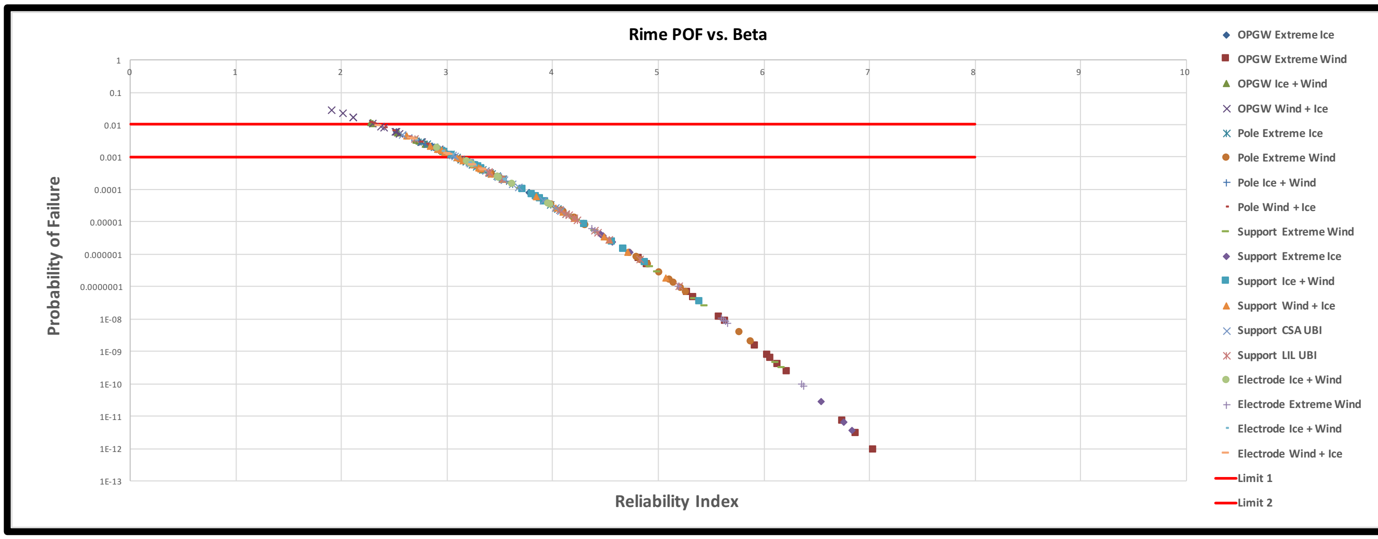



Figure 6.5b Overall Plot of All Data Points for Rime Icing & 5 Load Cases

### 6.1.3 CSA RBD Analysis – Unbalanced Loads due to Ice Shedding

Unbalanced ice load analyses consist of two parts. In the first part, we compare the effects of UBI on two towers selected in the Labrador region deterministically. In this case, the comparison is based on use factors of several critical members of these two towers. In the second part, we analyze these two tower with UBI loads probabilistically. The results of these analyses are presented here.

#### 6.1.3.1 Deterministic Analysis – LIL DESIGN Using NLH Criteria

In this section, we compare the analysis results of the two critical towers located in Zones 1 and 3a respectively. These towers are in Labrador and each tower carry five cables (1 OPGW, 2 Pole Conductors and 2 Electrode lines). Design ice thickness is 50mm radial. Comparison is done based on the use member's factor (UF): (1) LIL design based on UBI on each phase at a time (deterministic) and (2) NLH design criteria with load combinations (deterministic).

Figure 6.6a presents the comparison and it is seen that under NLH criteria, towers have many critical members exceed the UF significantly (greater than 100%). For tower located in Zone 1, there are 8 members whose UFs' are above 100% while for the tower located in Zone 3a (figure 6.6b), 4 members' UF are greater than 100%. Figure 6.5b presents the locations of these critical members. In general, the maximum values of UF are 138% and 127% compared to 97% and 83% for LIL design. POF for these two critical towers are: 0.009 (≈1%) for the tower in Zone 1 and 0.0189 (≈2%) for the tower in Zone 3a respectively. For Zone 1 tower, there are 6 members are more than 100% and for Zone 3a, there are 4 members whose UF is significantly higher than 100%. Considering just combination of ground wire and one pole conductor, under NLH design criteria, UF for mast member (Figure 6.6c) will be 120% for both towers. It is most likely these two towers may not survive should they encounter the specific load combination of OPGW and Pole conductor shedding simultaneously. It is to be noted that industry's current best practices are to take at least one OPGW and one phase conductor in load combination. The author suggests that NLH's design practice for UBI is quite robust and reliable and therefore, all these critical towers and the similar ones should be checked for NLH's load combinations. A recommendation has been made to follow this up for the next phase of the LIL reliability study.

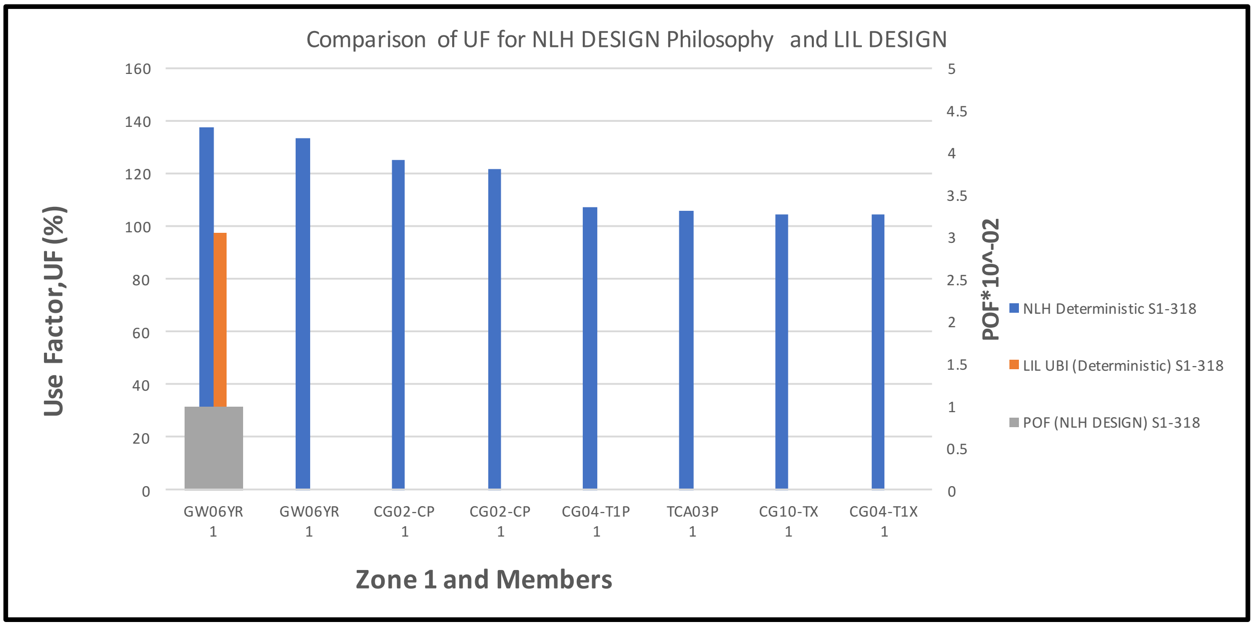



Figure 6.6a Comparison of Critical Members UF and POF (only the Damaged/failed members shown)

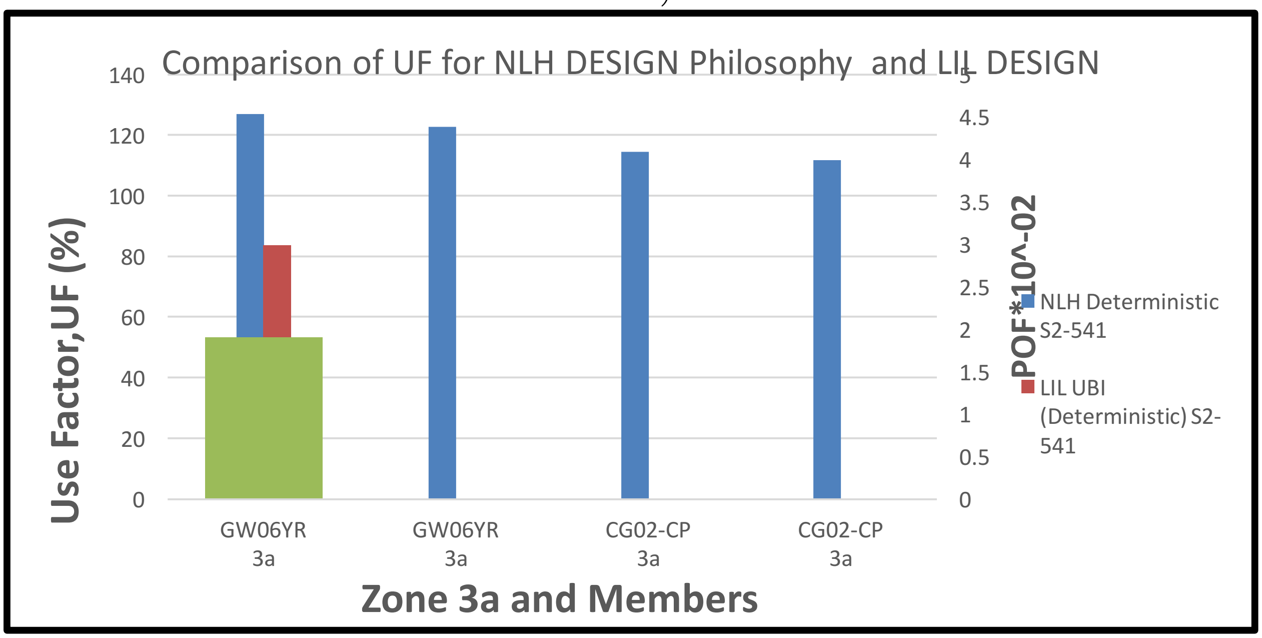



Figure 6.6b Comparison of Critical Members UF and POF (only the Damaged/failed members shown)

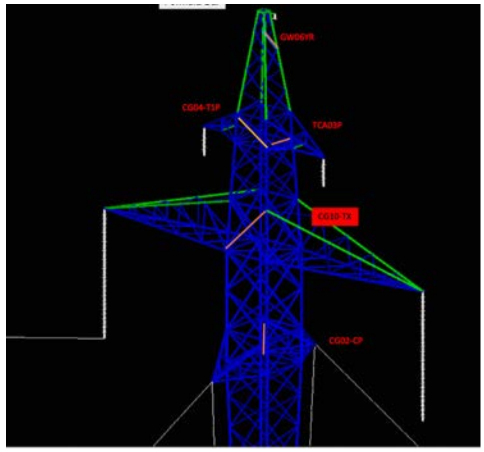


Figure 6.6c Tower Members that have exceeded Strength Capacity Significantly (Vulnerability Under NLH Design Criteria)

6.1.3.2 Probabilistic Analysis – LIL DESIGN and CSA 60826 and selected towers Using NLH Criteria

Figures 6.7 present the comparison under unbalanced ice loads based on CSA 60826-10 and LIL design. We also compare here NLH unbalance ice load results for Zones 1 and 3 for two critical towers which also considered load combinations (Figure 6.5). Figure 6.7 presents the comparison under unbalanced ice loads based on CSA 60826-10, LIL design, and S1-318 (Zone 1) and S2-541(Zone 3a) towers using NLH criteria. The author noted that NLH design criteria produces POF which is 18% greater compared to CSA 60826-10 for this specific structure S1-318, implying NLH design is more conservative than CSA 60826-10. For Zone 3a, NLH and CSA POF are close. *However, LIL design is significantly underestimating the POF and it is obvious that this is due to not considering the load combinations*. NLH design considers 100%/70% design ice thickness in flexure (longitudinal bending) and 100%/50% of design ice thickness in transverse bending. Figure 6.7 also presents some sensitivity of CSA 60826-10 load combination as 70/28, 70/56 and 70/42 for Structure S1-318.

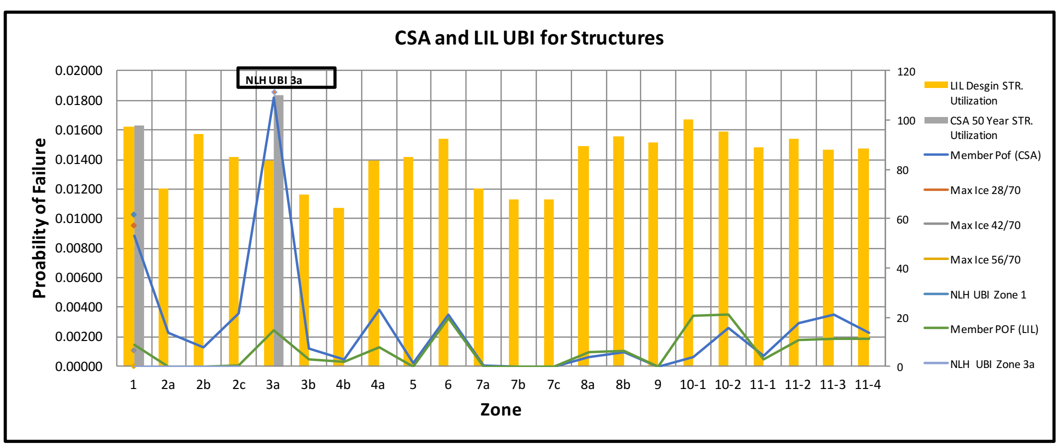



Figure 6.7 Annual POF Under Unbalance Ice Loads (CSA 60826, NLH and LIL design)

It is likely that when ice shedding occurs, it may shed from both phase conductors and OPGW and/or the electrode line simultaneously. It is unclear to the author why the load combinations were not considered to produce a more conservative and robust design, since the LIL line traverses through severe harsh meteorological conditions with respect to severe glaze and rime icings.

The author also questions the validity of CSA's stipulation of 0.7 and (0.7 x 0.4) factors in determining the return period based unbalanced ice loads. The author also does not support the LIL design's failure to consider the load combinations, and it appears the design under unbalanced ice load case did not even meet NLH's own internal design practices used for many past line design projects. NLH unbalanced ice load criteria are based on combinations of phase loads and shield wires and is therefore more conservative compared to LIL approach. This has served NLH's 1300km steel transmission line assets well for the past 50 years and the author does not see the need for including unbalanced ice loads as return period based loads as suggested in CSA 60826-10 until an additional study can support the basis for these two deterministic numbers/factors cited in CSA 60826-10. Current standard CSA does not provide the basis for these two deterministic factors, which are invariant to return period based load values.

In view of the above, the author recommends that unbalanced ice loads should not be considered as probabilistic loading (return period) based on the discussion in Sections 4, 5 and the results presented here rather they be treated deterministically, and therefore, be excluded from the reliability analysis presented in Section 6.2. However, the author makes recommendations to check all towers for unbalanced ice load combinations and assess the vulnerabilities of these towers under a separate follow up study using full NLH deterministic loading criteria. (see recommendation in Section 9.3)

## 6.2 Various Levels of Analyses and Assumptions - (DLS Criterion)

This section shows the various levels considered, scenarios under each level, and a clear description of what is included in each scenario and the underlying assumptions.

**Table 6.1 Various Assumptions Made in Determining the LIL POF/Reliability (Component to System)**

| Level | Scenario | Description | Remarks |
|---|---|---|---|
| 1 | 1 | (No regional grouping, full correlation along the entire line length and among elements, no distinction made between different exposure levels e.g. icing types) | Can be compared directly to CSA 60826-10, Tables A1 and A2 |
| | 1A | Same as above except extreme wind load considered | Since two extreme loads are independent, POF cannot be compared directly with CSA 60826 Table A2, but in an equivalent sense |
| 2 | 2 | (No regional grouping, full correlation along line length and among elements, distinction made between different exposure levels e.g. glaze icing, rime icing etc.) | Since two extreme icing loads are independent, POF cannot be compared directly with CSA 60826 Table A2, but in an equivalent sense |
| | 2A | Same as above except extreme wind considered | Since two extreme icing loads are independent, POF cannot |

| | | | |
|---|---|---|---|
| | | | be compared directly with CSA 60826 Table A2, but in an equivalent sense |
| 3 | 3 | (No regional grouping, full correlation along line length and the elements within the two subsystems, independency between support and wire subsystems, distinction made between different exposure levels, e.g., glaze icing, rime icing) | Since items considered are outside of CSA 60826-10, POF cannot be compared directly with CSA 60826 Table A2, but compared in an equivalent sense |
| | 3A | Same as above except rime icing added | Since items considered are outside of CSA 60826-10, POF cannot be compared directly with CSA 60826 Table A2, but compared in an equivalent sense |
| 4 | 4A | (Regional grouping, full correlation along line length, partial correlation in all elements within the subsystems, distinction made between different exposure levels, e.g., glaze icing, rime icing) – #4A | Since items considered are outside of CSA 60826-10, POF cannot be compared directly with CSA 60826 Table A2, but compared in an equivalent sense |
| | 4B | (Regional grouping, no correlation along line length, partial correlation in all elements within the subsystems, distinction made between different exposure levels, e.g., glaze icing, rime icing) – #4B | Same as above |
| | 4C | Same as 4A except extreme wind added | Same as above |
| | 4D | Same as 4B except extreme wind added | Same as above |

## 6.3 POF Results Based on CSA 60826-10

The following table is calculated based on Figures 5.8, 5.9, and 5.10.

### 6.3.1 DLS Criterion

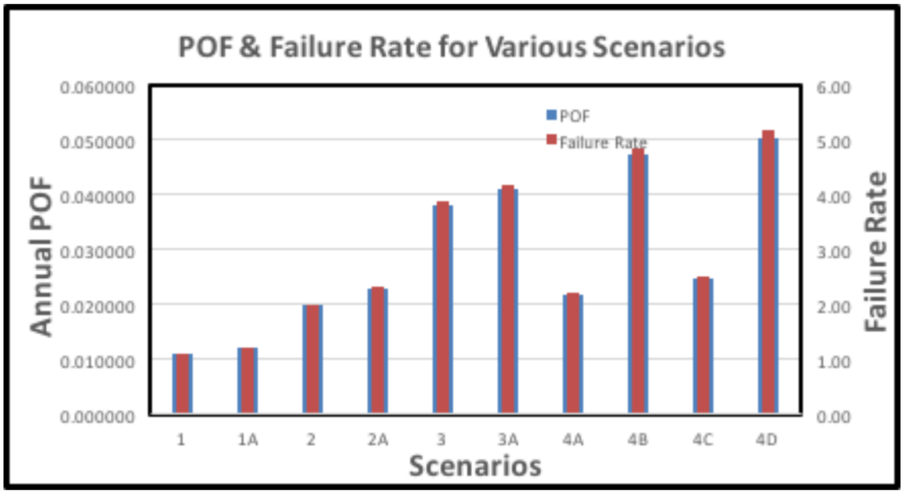
Table 6.2 presents the summary results that provide POF for LIL under various scenarios outlined in Table 6.1. The POF presented considers the load effect and strength interference following Figure 3.1 and it indicates the measure of this interference (shaded are in Figure 3.1). In the reliability (or POF) evaluation of LIL which is the objective of this study, direct computation of POF and failure frequency are the parameters required for system planning reliability study. There is no need to consider return period once the direct POF is calculated. However, question is often asked on what return period of the limit load (T), the line is good for? It's a valid question and this can be done (relating the POF to T) provided the underlying assumption is not violated in doing this return period estimation. CSA 60826-10 provides some guidance on how to estimate this return period (T) in terms of an equivalent climatic limit load by linking POF with T. This estimation also relates to some limiting values of COV of R and Q; Outside these values as presented in CSA 60826-10, the author is not sure whether this relationship is valid. If the both load effect and the strength have uncertainties, CSA 60826-10 suggests the POF should be linked to 1/2T; however, it also states if the strength remains constant (deterministic) and only the load effect has the uncertainty, in this case POF can be linked to 1/T; In our case, both R and Q vary following Figure 3.1 and all computations consider COV's of R and Q; therefore, the return period of the limit load (T) is estimated based on POF in Table 6.2 for Scenario # 1 and is presented in Table 6.2 (a) separately in bracketed form following CSA 60826-10 (1/2T to 1/T). However, the author also did a semi-probabilistic calculation like what EFLA (2020) has presented earlier for glaze icing. Based on this factored strength based analysis, this limit load is 72 years return period. Only Scenario # 1 is considered here because all other scenarios that the author considered are not covered under CSA 60826-10. It is to be noted that CSA 60826-10 based POF calculation can be quite sensitive to the assumption of underlying distribution functions (Hong, 2021). Figures 6.8(a) and (b) presents the POF, Failure rate and exceedance levels for 5-and 50 years for all scenarios considered. The failure rate is calculated based on exponential distribution assumption.

**Table 6.2 POF, Failure Rate Determined for Various Scenarios (DLS)**

| RISK of EXCEEDING DLS - CSA 60826 (In 5 and 50 Years) | | | | |
|---|---|---|---|---|
| Scenario # | POF-Annual | 5 Years (%) | 50 Years (%) | Failure Rate(%) |
| 1 | 0.0110 | 5.36 | 42.36 | 1.10 |
| 1A | 0.0120 | 5.84 | 45.21 | 1.20 |
| 2 | 0.0199 | 9.54 | 63.30 | 2.00 |
| 2A | 0.0229 | 10.95 | 68.63 | 2.32 |
| 3 | 0.0379 | 17.58 | 85.54 | 3.87 |
| 3A | 0.0410 | 18.89 | 87.68 | 4.19 |
| 4A | 0.0218 | 10.44 | 66.81 | 2.21 |
| 4B | 0.0473 | 21.53 | 91.15 | 4.85 |
| 4C | 0.0249 | 11.84 | 71.63 | 2.52 |
| 4D | 0.0504 | 22.79 | 92.47 | 5.17 |

**Table 6.2a Return Period Range for scenario # 1**

| Scenario # | Return Period Estimate Based on CSA Table A2-year | Semi-probabilistic (Return Period Estimate) -year |
|---|---|---|
| 1 | $45 < T < 91$ | 72 |



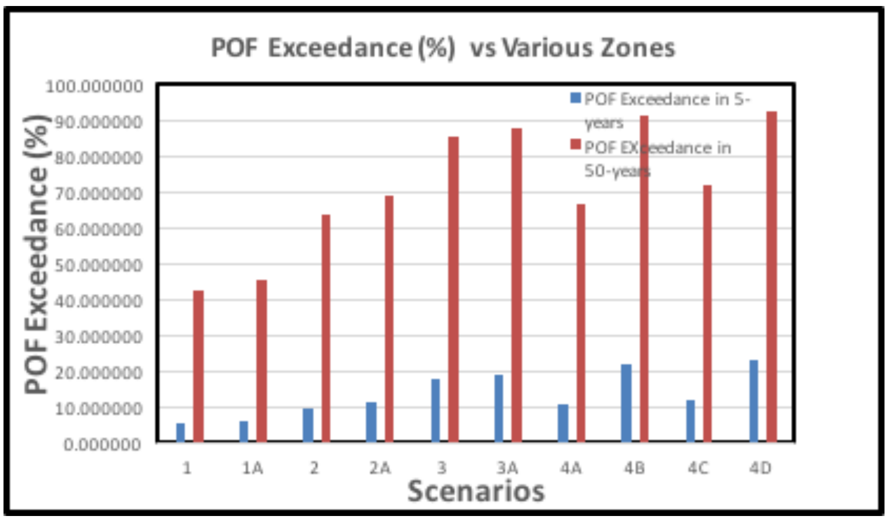




Figure 6.8 (a) POF and Failure rate for All Scenarios Considered and (b) POF Exceedance (%) in 5- and 50 –years of Asset's Life

### 6.3.2 ULS Criterion

The elements within the OPGW and the electrode line systems were identified under DLS, as the most critical elements; POF for this OPGW element was relatively high. In general, the study has also identified that the cable system is likely to fail first compared to the structural support system, which is contrary to the industry's best practices.

A high level Ultimate Limit State (ULS) analysis for cable systems provides a relative comparison of the risk levels between DLS and ULS and shows that POF under ULS is forty-three (43%) of that presented under DLS. Therefore, following CSA 60826-10, this will translate to an equivalent limit load return period (T) between 106 and 211 years under Scenario # 1. Based on strength factor approach, this is estimated as 160 years. The strength factors for all cable elements were used as 0.9 and 1.0 for all structural elements. Based on this analysis, Table 6.4 provides the POF exceedance in 5 and 50 years for ULS criteria

**Table 6.3 POF, Failure Rate Determined for Various Scenarios (ULS)**

| RISK of EXCEEDING ULS - CSA 60826 (5 and 50 Years) | | | | |
|---|---|---|---|---|
| Scenario # | POF-Annual | 5 Years (%) | 50 Years (%) | Failure Rate (%) |
| 1 | 0.00474 | 2 | 21 | 0.48 |
| 1A | 0.00543 | 3 | 24 | 0.54 |
| 2 | 0.00905 | 4 | 37 | 0.91 |
| 2A | 0.01017 | 5 | 40 | 1.02 |
| 3 | 0.01559 | 8 | 54 | 1.57 |
| 3A | 0.01671 | 8 | 57 | 1.68 |
| 4A | 0.00996 | 5 | 39 | 1.00 |
| 4B | 0.02144 | 10 | 66 | 2.17 |
| 4C | 0.01107 | 5 | 43 | 1.11 |
| 4D | 0.02256 | 11 | 68 | 2.28 |

**Table 6.3a Return Period Range for scenario # 1 (ULS)**

| Scenario # | Return Period Estimate Based on CSA Table A2-Year | Semi-probabilistic (Return Period Estimate) Year |
|---|---|---|
| 1 | $106 < T < 211$ | 160 |

As noted earlier, the risk of exceeding DLS criterion can be severe and may lead to an extended LIL outage if the environmental conditions (hazards) that led to the exceedance of DLS persist for a long duration or occur frequently. CSA 60826 does not require the reliability assessment under ULS however, it should be clearly understood that a full ULS system reliability analysis (structural reliability) that considers LIL as a structure-cable-insulators system and goes beyond traditional elastic analysis has not been done and should be done before the generation expansion planning is considered. The table only provides a relative comparison of the risk levels between DLS and ULS at a very high level. It is noted that POF under ULS is forty-three percent of that presented under DLS under Scenario # 1.

# 7.0 Sensitivity Study

This section presents the sensitivity of some key parameters regarding the load effects and strength on LIL POF and reliability. In section 1, the author listed several issues that were raised through RFI process. Upon consultation with NLH, the author agreed to do few case studies where the impact of the various key parameters on POF can be assessed and presented. These are: (1) terrain roughness (2) topography and wind speed up effect (3) combined wind and ice loads with higher coefficient values (upper limits) for reference wind speed and glaze ice load (4) justification for Avalon ice load, (5) justification for OPGW ice loads (not specifically following CSA clause 6.4.3.1) (6) uncertainties in rime ice load prediction due to terrain category, topography etc. and (7) sensitivity of COV for selected component's strength values. Item 3 for rime ice is not considered because it includes the upper limit value closer to CSA 60826-10 based on WRF models and statistics for site specific rime ice loads.

## 7.1 Terrain Roughness

To address the effects of terrain roughness (Type B vs. Type C) and topographical issue with respect to "wind speed up effect", the profile of the line on the top of the Hawke Hill is selected. This site is 25km of west of St. John's Airport. The example case study assesses the impact of terrain roughness category C versus B on a specific tower due to extreme wind load. This specific tower S5-494 (#3160) is located on the top of Hawke Hill. This location is known for severe icing and NLH has experienced several line failures at this location in the 80's and 90's (Haldar, 1996, 2006). Figure 7.1 presents the topo map and identifies structures 3160 and 3170 for the case study.

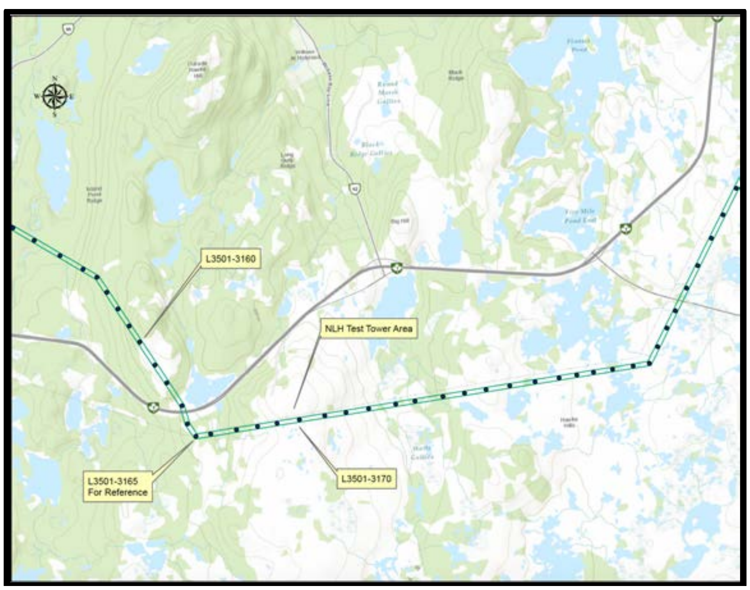



Figure 7.1 Topo Map for the Location Considered

CSA 60826-10 defines four terrain types and how to compute the reference wind speed, except for wind speed for terrain type B (open terrain). The calculation is

$$V_{R,x} = K_R\ V_{RB} \qquad [7.1]$$

where

$V_{R,x}$ = reference wind speed other than terrain type B
$K_R$ = terrain roughness adjustment factor (=1.0 for terrain type B)
$V_{RB}$ = reference wind speed for terrain type B

Nalcor used terrain type C for LIL line design to determine the effect of extreme wind load on structure support system and wire support system. A factor of 0.85 was used for $K_R$ to adjust the reference wind speed. Nalcor has earlier provided a RFI response on this issue and justified why the terrain type C was used for LIL design. This implies a 15% reduction in the reference wind speed along the entire line length for glaze ice load. For rime ice loads, terrain type is described in Section 7.6.

Since this tower #3160 (S5-498) is located on the top of a hill, wind speed up effect is considered in assessing the wind load effect on the tower and the POF (See also Section 7.2). Figure 7.1 presents the POF for this tower comparing the two terrain types and topographic effect. The figure shows that the probability of failure is significantly increased considering the terrain roughness as type B under extreme wind load. The initial LIL design use factor (UF) for this tower is low (a value of 0.66) and, under a 50-year return period, this value is 0.69. The specific impact on POF is significant but the overall POF for this tower is still acceptable considering the terrain roughness (type B) and the effect of topography. However, this may not be the case in other locations unless a study is done to isolate the towers at these special topographic locations where both terrain roughness and topography could be quite different than what was considered in the original design. The author understands that LIL design did not consider the topographic effect explicitly (wind speed up effect) but rather used judgement to adjust the span during spotting to address the issue. For the Hawke Hill site, the author agrees that terrain type B is fully justified (not type C) because of its open exposure and very little vegetation cover. The methodology to determine the wind speed up effect and the impact on combined wind and ice loads is discussed in the next section.

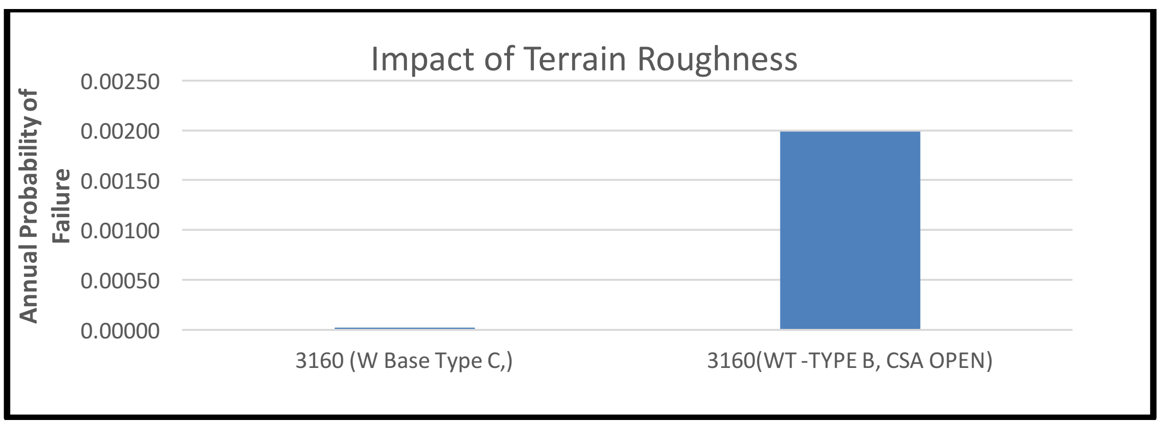



Figure 7.2 Impact of Terrain Roughness on Component Reliability

## 7.2 Uncertainty on the topographical effect on LIL design

Lines are normally designed for two primary classes of loads (1) reliability class and (2) security class. Under reliability class of loads, structures and major line components are designed for climatological loads, including wind, ice, and combined wind and ice loads. Synoptic winds, where design values are selected from the national weather map with a specific return period value, are normally considered for wind loads. Strong winds may cause unexpected damage to the power transmission systems. Two parameters that affect the determination of wind speed and turbulence intensity are: terrain categories and climate. In hills, valleys, and mountains, local wind speed-up effect is often encountered on the line because of the abrupt change of flow pattern due to the blockage by the hill or higher elevation of the mountain ridge. Wind speed can be twice as high at the top of the hill that of the speed at the bottom of the hill. This sudden change in the local topography affects the local wind speed which, in turn, influences wind loading on support structures. More importantly, the transmission line design standards, such as CSA 60826-10, do not provide guidance on topographic effects that consider wind speed-up effects, including turbulence intensity. Turbulence intensity can be significant in line design especially in flow separation areas, such as on the downward hill side and in wake regions. This topographic effect can introduce significant wind speed up effect, increase wind loads on support structures and cable systems, and increase the combined wind and ice loads significantly. It needs to be considered in the assessment of LIL line reliability. It is the author's understanding that this effect was not considered in the LIL design explicitly.

Bitsuamlak et al, (2015) provides guidelines on how to include topographic effect when determining wind load on towers. Three different configurations are considered in this report. These are (1) escarpment, (2) 2D ridge, and (3) 3D Axisymmetric hill. For each of these configurations, the study used four different methods of computations to address the topography effect on wind loads ("wind speed effect") and the associated amplification factors to show that the wind speed and pressure could be significantly higher on the top of the ridge or hill along the tower height compared to the reference wind speed that is prescribed at the bottom of the hill. These methods are (1) NBCC, (2) ASCE 7, (3) EUROCODE, and (4) CFD approach.

Figure 7.3 presents a typical 2D ridge model based on NBCC. Figure 7.4 presents the comparison of base case POF and the effect of increased wind speed due to topography and terrain roughness. It appears that the POF is increased significantly (many folds) under combined ice plus wind when one considers the above two effects. Since the tower has a low UF value in the original design, it has adequate reliability under DLS considering the impact of these two parameters (terrain type B and topography) and combined loads. However, this may not be the case in other locations, where the tower is located on the top of a hill and the UF is high in the original LIL design. In this case, reserve capacity may not be adequate to accommodate the increased wind load effect due to type B roughness and "wind speed up" effects. This should be checked at each tower location which satisfies either of the three configurations (escarpment, 2D ridge or 3D hill). A specific recommendation is made to assess the impact of these two-combined wind and ice load parameters on LIL reliability for these specific locations along the full line length. Terrain type should be classified based on vegetation cover during summer as well in cover in the winter months.

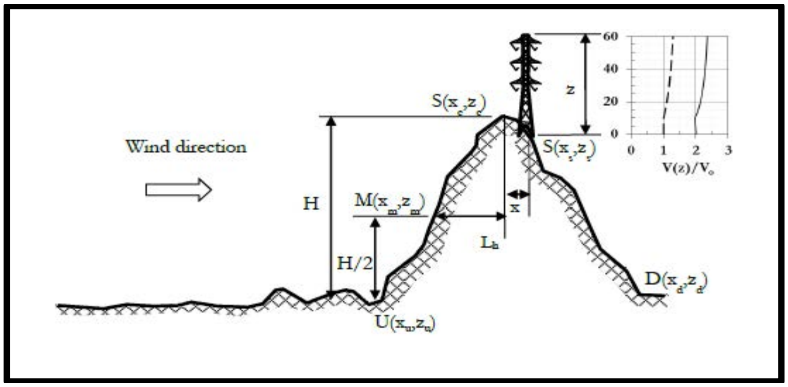



Figure 7.3 Typical 2D Ridge Profile (Bitsuamlak, Girma et al, 2015)

**Table 7.1 Combined Wind and Ice and Ice and Wind Loads**

| Cases | Ice + Wind | Wind + Ice | Reference Wind Type |
|---|---|---|---|
| Standard (Type C Wind)-Base Case EFLA Report (2020) | $g_{lf} + 0.4V_R$ | $0.6{*}V_R + 0.4g_{lf}$ | Type C (Zones 11&3a) |
| Variation 1 - (Type B Wind) | $g_{lf} + 0.5V_R$ | $0.85{*}V_R + 0.4g_{lf}$ | Type B (Zones 11&3a) |

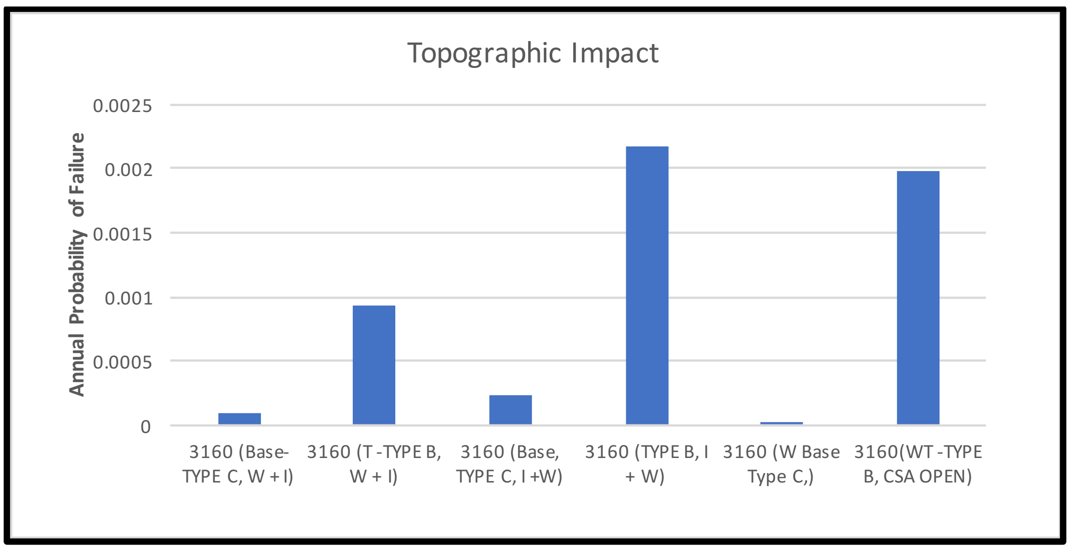



Figure 7.4 Impact of Topography (Speed-up Effect) on Component Reliability (Tower #3160, Hawke Hill)

## 7.3 Combined Wind and Ice loads (Revised – Terrain Type B, Towers in Zones 3a and 11-4)

EFLA report (2020) identified that LIL design did not consider an ice plus wind load (I +W) and that ice plus wind was a new load case following CSA 60826-10 and reported the use factors (UF) for critical towers. Table 7.1 presents the two load cases as standard loads using the terrain roughness type C and the low coefficient values for reference wind speed and ice load. During the review of EFLA report (2020) and the original LIL design review by Newfoundland Power (Ghannoum, 2013), it was identified that these reference values are low and represent the lower limit values in CSA 60826-10. These values should be adjusted to reflect higher reference values for reference wind speed of 0.5 for ice and wind loads; and 0.85 for reference wind speed and for combined wind plus ice load. It is to be noted that these loads are very different load cases than what were considered during LIL design. The original combined wind and ice load for St. John's Avalon was 45mmice and 60km/hour wind which is lower than the Avalon combined wind and ice load as well loads recommended in CSA 60826-10. Figure 7.5 presents the POF results for these two towers under these two specific combined load cases.

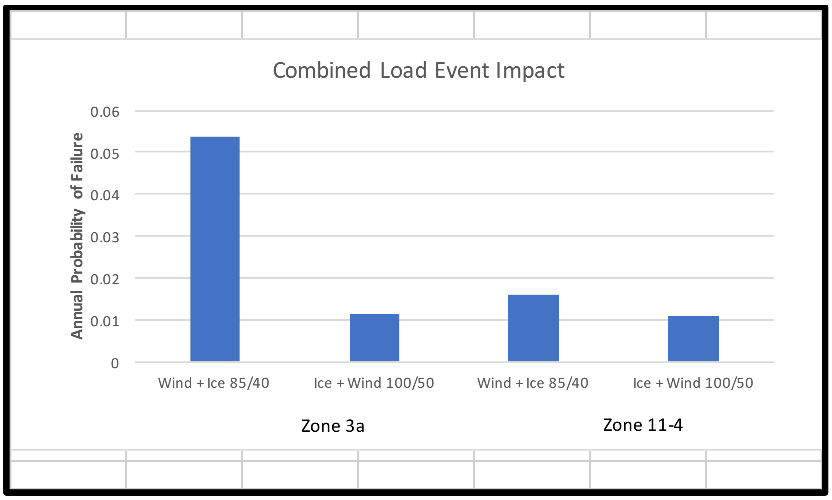



Figure 7.5 Impact of Increased Combined Wind and Ice Load Factors on Support Structures Following CSA 60826-10 (Zone 3a and Zone 11-4)

### 7.3.1 S2-541 Tower (Zone 3a)

Results of the analyses show that the POF is impacted significantly for both towers particularly for S2-541 in Zone 3a when the coefficients are increased for reference wind speed values. The tower in Zone 3a will have annual POF of 5% and 1% under combined wind plus ice and ice plus wind loads respectively. This POF is almost fifteen folds higher compared to the baseline load ($0.6*V_R + 0.4g_{lf}$) that was used in determining the POF for this tower (Figure 7.6a). A support structure will have higher POF compared to OPGW in this combined wind and ice load case and this will increase the annual POF in Table 6.2 almost fivefold under Scenario #1. Of course, this will have also impact on all other scenarios in Table 6.2 and increase the overall POF for the LIL significantly. Only Scenario # 1 is compared here. This also shows that sequence of failure will now be different than what has been reported under the baseline case in Table 6.2. POF of LIL in this case will be 5% under DLS considering Scenario #1, not little over 1% reported in Table 6.2. The significant increase in POF is related to the fact that under combined wind plus ice in standard LIL design, the UF is 0.53 for S2-541 tower in Zone 3a. The UF for combined wind and ice loads ($0.6*V_R + 0.4g_{lf}$) following CSA lower limit value is 0.75 for S2-541 reported in EFLA (2020). The combined wind and ice load case under LIL design (Figure 7.6a) is significantly lower than the UF under CSA 60826 load case ($0.6*V_R + 0.4g_{lf}$) that was used in EFLA report. This is amplified further due to the impact of terrain roughness type B and the increased value of the reference wind speed (from 0.6 to

0.85). The UF under combined load is 1.55 and this is the mast member (CMA01-5R), location shown in Figure 7.6b. Figure 7.7 presents the comparison of wire support system POF and it appears these are acceptable and relative increase in POF is less compared to the one observed for the tower.

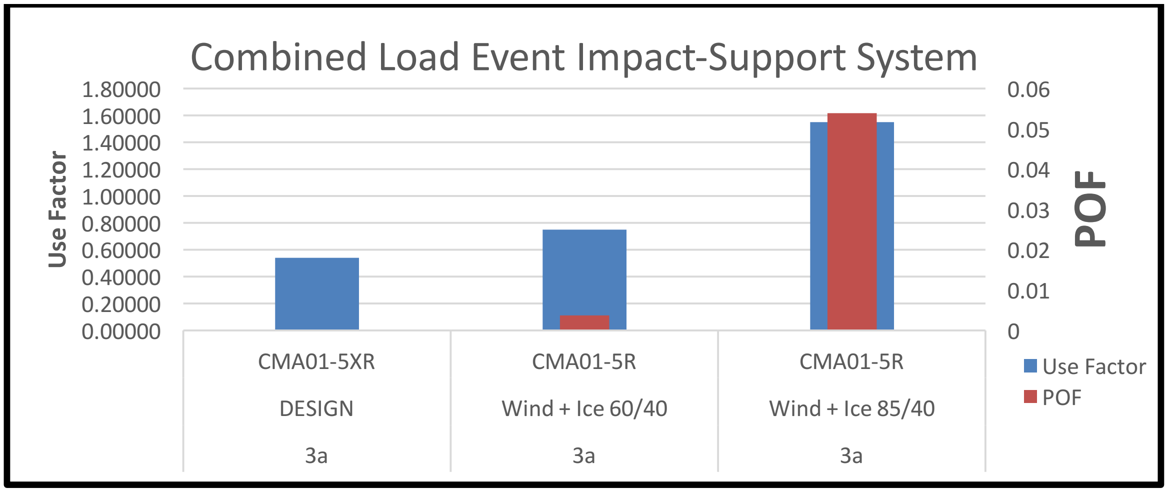



Figure 7.6a Comparison of UF and POF for Selected Members on Support Structure

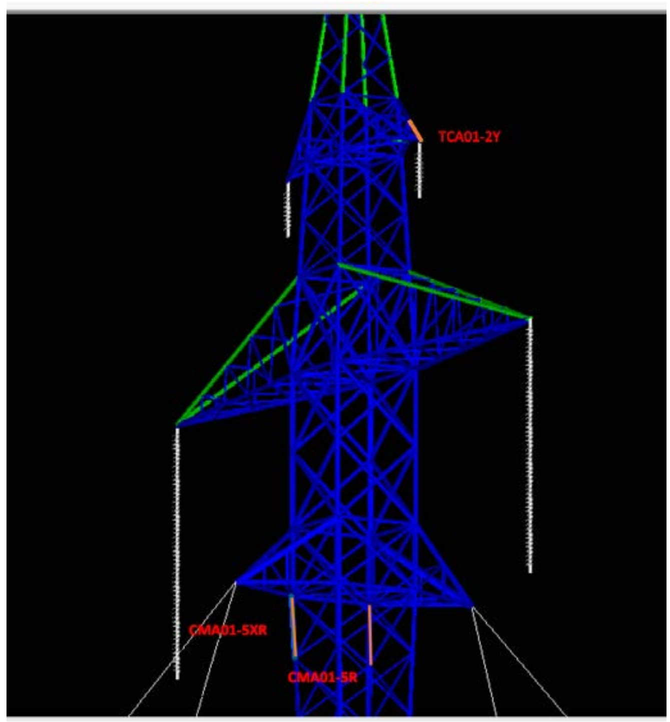



Figure 7.6b Selected Members – Tower S2-541 that have exceeded 100% limit

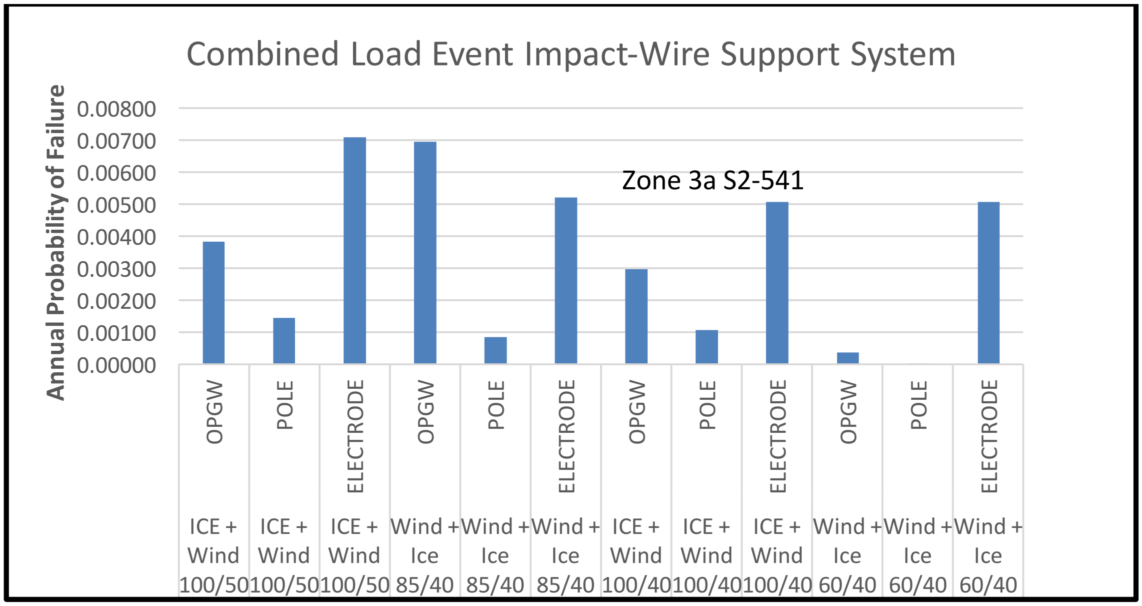



Figure 7.7 Comparison of UF and POF for Selected Cable Members on Wire Support System

### 7.3.2 S5-468 Tower (Zone 11-4)

A similar observation is also made on POF for one critical tower in Segment 11-4, S5-468. The POF has also increased significantly from 0.2% to 1.1% (5 times, for load cases 100/40 and 100/50) under combined Ice +Wind, and the critical overloaded member in the tower is "tower mast member". For combined Wind + Ice, the increase was from 0.39% to 1.6% (4 times, for load cases 60/40 and 85/40) and the critical overloaded member in the tower is also "tower mast member". It shows clearly that this increased CSA 60826-10 load combination (85/40) will also have an impact on the tower reliability under DLS criterion and requires a much closer look and a more in-depth study for all these critical towers. The UFs' for combined wind plus ice load case for Design, 60/40 and 85/40 are 0.58, 0.74 and 1.07 respectively. A specific recommendation made in Section 9.3 to check these critical towers with increased reference values of combined wind and ice loads.

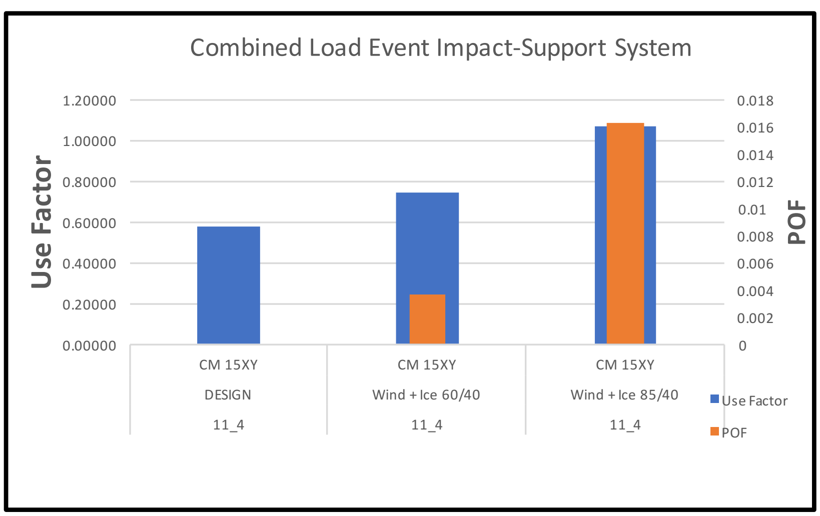



Figure 7.8a Comparison of UF and POF for Selected Members on one Support Structure (Zone 11)

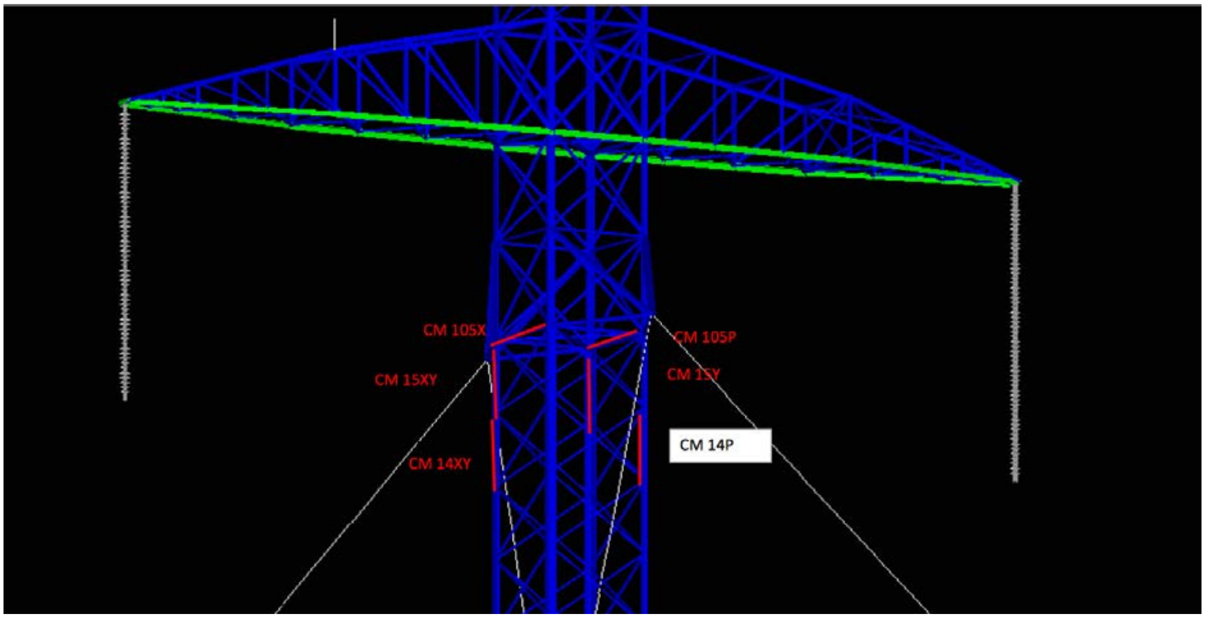



Figure 7.8b Selected Members – Tower S5-468 that have high UF (one exceeded 100% limit)

As explained before, the load exceedance of a lighter member does not imply that tower is going to collapse, rather it is an indication that DLS criterion has been violated. Follow-up work is needed to assess the collapse probability of the tower under combined wind and ice load coupled with or without topographic effect and terrain roughness when secondary members (or lighter member) are overloaded; this requires a progressive collapse analysis to determine the correct load path that will allow to form a mechanism. In this case, the mast member is clearly overloaded even under a 50-year return period load. So, if the UF is very high then ULS may not be required. However, this demonstrates that more work is needed to address this issue (POF under ULS) for critical support structures, specifically those located on the top of an escarpment or a hill to assess the vulnerabilities of these towers. This impact may not be considerable when the LIL tower design UF is low under extreme combined loads and the tower has the capacity to resist full or part of these increased combined load effects. This needs to be verified and a specific recommendation is made to assess the impact of these two revised combined load cases on LIL reliability identifying all locations including those towers located on top of an escarpment or a ridge or a hill.

The author also recommends that the higher wind speed factor (reference value) should be used in Labrador and all exposed ice regions where ice residence time is significantly high. Similar adjustment can be made in other segments of the line to reflect that the ice residence time will be quite different in Labrador compared to what has been experienced on the Avalon Peninsula. The wind speed reference factor is a function of wind speed COV and the ice residence time.

## 7.4 Glaze Icing on Avalon Peninsula – (Avalon Study)

This section reviews the Avalon glaze ice load that was used during LIL design. Question has been raised in several RFI's why Nalcor did not follow the internal NLH study recommendation (Haldar, 1996); accordingly, this load should have been 75mm for a 50-year return period. Therefore, a 500-year return period load would be over 100mm based on this single study. It is to be noted that the Avalon study was done based on a conductor diameter of 28mm, which is a typical conductor diameter for many 230kV line and was done based on the failure information and data available at the time. The author also recommended to update this data periodically based on the new meteorological data and new failure and operating information.

### 7.4.1 Review Literature and show the effects on Thickness (Reduction in Transverse Load)

Clause 6.3.4.1 of CSA states that an ice load adjustment can be made if the cable diameter is different than the diameter of rod that was used in the measurements or during simulations. Since the extreme ice thickness values are taken from CSA map, an adjustment is necessary for the pole conductor where the diameter is significantly higher compared to the standard 25mm diameter rod that was used in the Environment Canada model simulations in producing the CSA ice accretion map. Accordingly, a $K_d$ factor of 1.33 is needed to compute the ice load. It also stipulates that if $K_d$ x $\bar{g}$ exceeds 100N/m, no further adjustment is required. $\bar{g}$ is the average maximum ice load and is estimated as $0.45g_{max}$. A height factor should also be applied in adjusting this ice load.

The author has conducted a literature review on the impact of diameter on ice accretion. Figure 7.9 presents the accretion on a 34mm and 19mm cable for the same experimental parameters as droplet size, wind speed etc. It clearly shows that the larger cable will have less ice accretion thickness compared to the smaller cable.

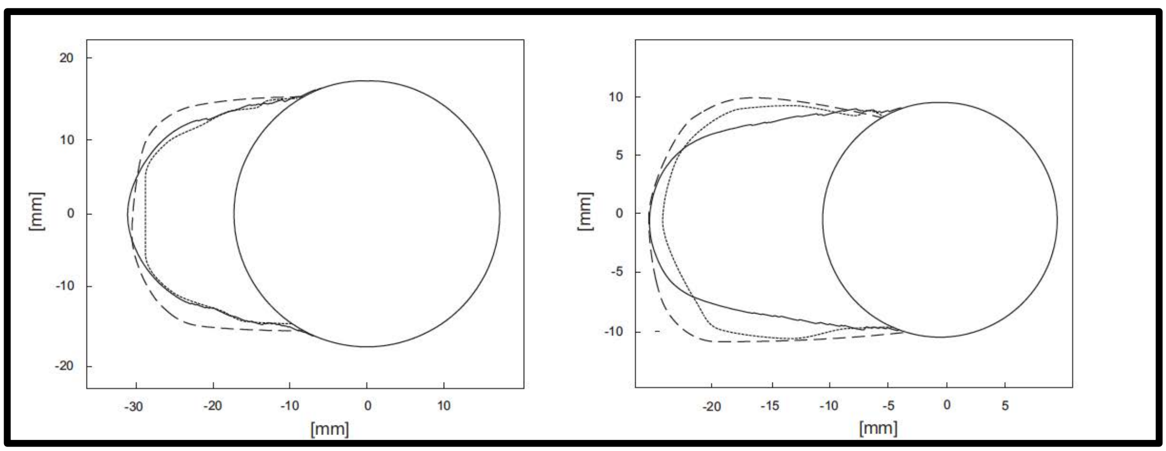



Figure 7.9 Simulation of Ice Accretion on Two Different Cables Sizes (Wagner et al,1995)

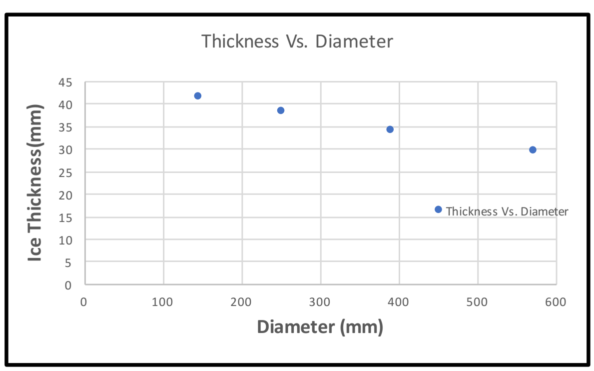



Figure 7.10a Impact of Cable diameter on Glaze Ice Thickness (Reference Yip, 1995)

Yip (1995) has also studied this as part of model simulation using Chaine and Skeates' model and showed that there could be significant drop in ice accumulation on large conductor compared to a small diameter conductor. Figure 7.10a presents the impact of various LIL cable sizes on ice accretion thickness based on St. John's Airport data.

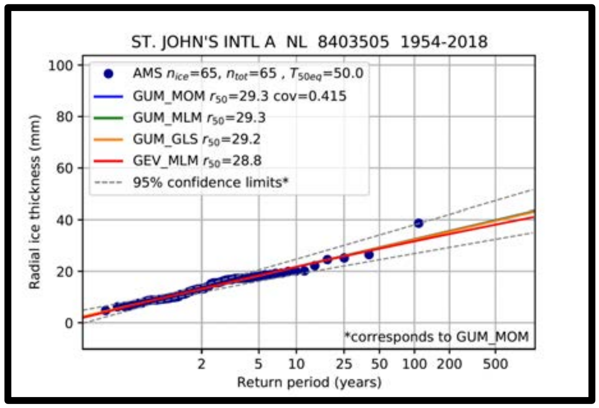



Figure 7.10b Extreme ValueAnalysis of data for a 57mm diameter conductor –St. John's(Morris, 2021)

Icing map that is published by Environment Canada is based on a single size diameter rod (25mm) and normally, the extreme ice thickness from the map requires some adjustment if the cable size is significantly different than that was used to produce the map. The author contacted the Environment Canada (Jarrett, 2020) to run the Chaine model for four different diameter cables for St. John's Airport. These cable sizes reflect the OPGW, electrode line, and the pole conductor for LIL line. Based on these runs, an extreme value analysis was performed and it shows that the pole conductor with 56.9 mm diameter will have 30% less icing compared to the value prescribed in the CSA 60826-10 map for a 50-year return period (Figure 7.10b). Therefore, the study ice thickness following CSA should be 30mm for 50 year and 45mm, 54mm and 67mm for 50-year, 150-year and 500-year return periods that includes the spatial and height factors (1.5 factor that includes height and spatial effects). Design ice thickness for LIL in Zone 11-4 is 75mm which is higher than the ice thickness predicted by the Environment Canada model for a 500-year return period. This will also have an impact on all other load cases and should be examined further when pursuing the increased combined wind and ice load impact considering terrain roughness and topographic effects.

### 7.4.2 Revision of Avalon Load Based on Lower Failure Rate Value

The above load on the Avalon can also be justified based on 1996 Avalon study. During this study, design loads for upgrading and for a short section of a new line on the Avalon Peninsula was assessed as 63mm (25-year return period for upgrading load) and 50 mm for a 50-year return period for the new line respectively. The author also cautioned at the time that these loads are estimated based on the frequencies of failure on the Avalon over a 30-year operational life that was observed at the time. Since the Avalon upgrading in 2004, NLH has experienced one major icing failure in the Long Harbor area (TL208), and this provides a slightly different failure rate over a 54-year operational life than what was used during the Avalon project. Adjusting this revised failure rate of 11-year interval, the estimated 50-year load will be closer to 2.7 inches (68mm) which is for a conductor size of 28mm (Avalon Study, 1996). Based on the review in Section 7.4.1, this will be comparable to 45mm which considers the effect of diameter on ice load. Because of a 30%

reduction, the above computed ice thickness (68mm) should be reduced to provide a 48mm ice thickness for a 50-year return period value, which is closer to the value presented in the previous section. The Avalon load includes the spatial factor because this load was determined based on actual line failures observed over a 30-year period. Therefore, there is no need to include a 1.5 factor.

## 7.5 Underestimation of OPGW Icing

Clause 6.3.4.1 suggests considering equivalent conductor load in the design of OPGW in the same span. Research by McComber et al and others (2001) have shown that the OPGW cable has lower torsional rigidity compared to the pole conductor, and OPGW may accrete larger ice compared to the conductor. The work clearly shows that at the early stage of ice accretion process the cable with lower rigidity (OPGW) will accrete ice more and, as the ice accretes, its rigidity will change with the accreted ice suspended. As time progresses, the cable with larger rigidity will have a lower initial icing rate but will eventually catch up. According to McComber et al (2001), based on the limited work, “the rate of ice accretion was not found to vary at a given time when the rigidity of the cable was modified”. Figure 7.11 presents the ice simulations for different cable torsional rigidities

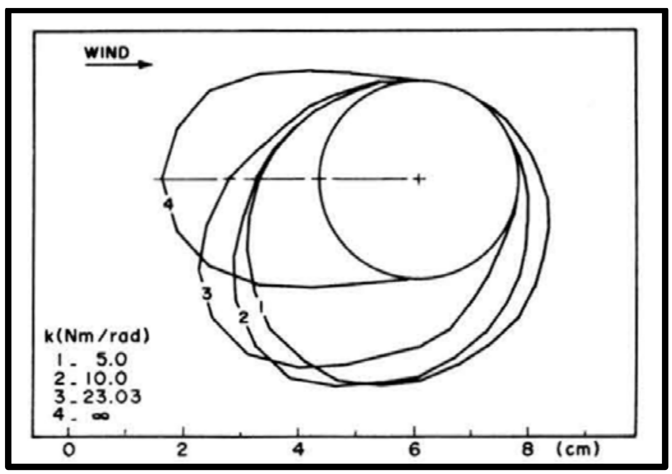



Figure 7.11 Ice Accretion After 20 Minutes for Different Cable Torsional Rigidities (McComber et al, 2001)

The conclusion drawn from this study shows that a cable of larger rigidity (pole conductor) makes the accretion shape more elliptical, whereas a smaller rigidity cable (OPGW) makes the accretion shape circular. Results also indicate that accretion rate is independent of the twisting of the cable, but twisting has a significant effect on the accretion shape obtained and therefore, the ice loads. The author is not sure whether this will be true on a continuous basis as ice started building for several hours because the change in rigidity due to different shapes as the accretion progresses is unknown. Therefore, it is not possible to conclude based on such a short simulation that one should design the entire OPGW of 1100 km to the full conductor load. It is a subject of further research interest and NLH should conduct further work to validate this from field measurements and observations. The author also has discussed this with his colleagues across North America and at present, the author’s understanding is that utility “best practices” is to design OPGW and conductors for the same design ice thickness. Some other mitigation actions can be used selectively and strategically at certain critical locations to increase the torsional rigidity by mechanical means which will be considerably cheaper compared to designing OPGW for full conductor ice loads.

## 7.6 Rime Icing on LRM – (EFLA & KVT Study, Full Effects of Topography and Terrain Characteristics)

Several studies have been presented as part of this LIL project to assess rime ice loads on the LIL. As reported in Section 4, the recent study by EFLA is a state-of-the-art and uses a numerical weather prediction forecasting model (WRF) in assessing the revised rime ice loads for Zones 2 in (Labrador) and 5 (Alpine), and 7 (LRM) on the Island. It is author's understanding that in assessing wind loads along the route, the land surface characteristics, including surface roughness, are considered in the WRF simulations. EFLA-KVT has used landuse data obtained from USGS (https://www.usgs.gov/core-science-systems/eros/lulc/data-tools) in these simulations. These data have ~1km resolution and apply 27 different categories for classification of the land surface properties. It is author's understanding that this roughness category label is mixed with most represented as "Mixed Forest" while some of the rout covers are identified as "Wooded Tundra". The WRF simulations does not consider topographic effects such as escarpments, 2D ridges, and 3D hills. The author recommends that this be reviewed under a separate study as is to be done for glaze icing.

## 7.7 Variation of COV of Strength on Reliability

All the COV's that were used in the reliability assessment were taken from CSA 60826-10 following Table 19 in the standard. However, the author has done some literature search and noted that COV's can vary and some sensitivity analyses are needed to assess the impact on LIL support system POF and the reliability. The following variations are considered: (1) Member strength, mean to nominal and COV's in compression, and (2) foundation COV's,. It shows that for compression member, POF will be reduced by 10% using an increased mean to nominal strength following Mozer (1982). Similarly, foundation POF will increase significantly when the COV is increased from 0.2 to 0.3 (Figure 7.13).

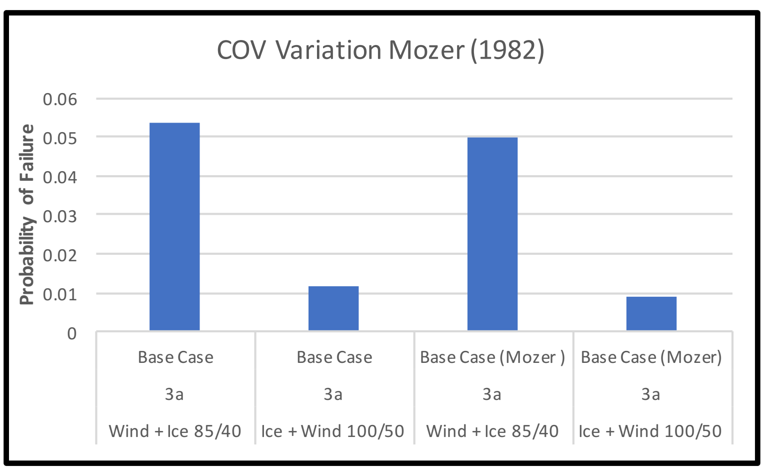



Figure 7.12 Strength Variation of Compression member

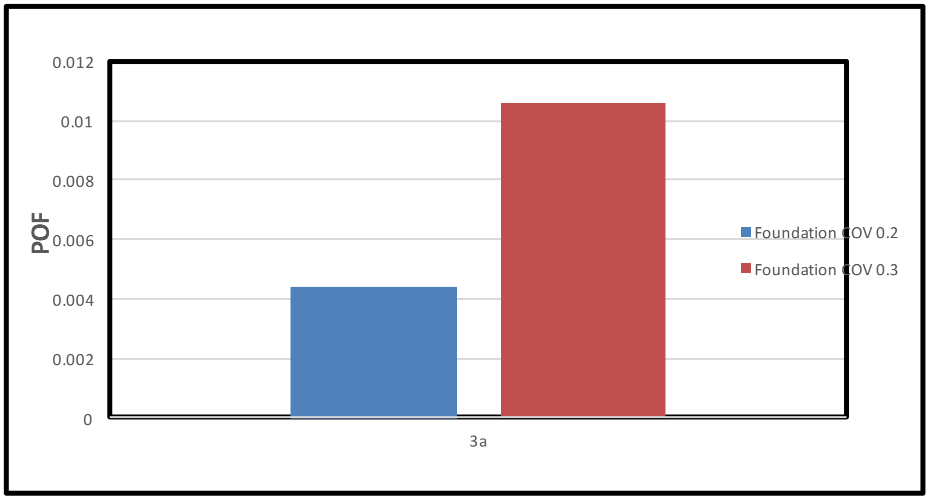



Figure 7.13 Strength Variation of Foundation

# 8.0 Review of Hydro's Operational Experiences and Benchmarking

This section presents a review of past line failures that NLH experienced during the operation of transmission line assets during the past 50 years. The objective here is to understand some of the causes of line failures, lessons learned and presents this in terms of outage hours per 100km. This data is also compared with National average (CEA database) and a review is conducted. The author compared the LIL probability of failure on the Avalon Peninsula (Tower and Conductors) with the Avalon Upgrade reliability under extreme ice loads and with the reliability of one of the Canadian utilities line that followed CSA 60826-10.

## 8.1 NLH System at a High Level

Figure 8.1 presents the Newfoundland and Labrador Hydro bulk power system at the 230-kV level. The transmission line system connects the major hydraulic generating stations. The basic 230 kV transmission line system primarily originates from Bay D'Espoir (BDE) generating station and runs east and west. The first combines the loads west of BDE and the second combining the loads east of BDE. In the west, the schematic shows there are two parallel 230kV lines (L3 and L4) between BDE and the west coast load center.

This 230kV parallel line configuration is several transmission lines running between Bay D'Espoir terminal station (BDE) and the west coast load center. For example, TL 204 and TL 231 run between BDE and STB (Stony Brook station), TL 205 and TL 232 run between STB and BUC (Buchans station), and TL 211 ties MDR (Massey Drive) and BBK (Bottom Brook). However, TL 228 (BUC to MDR) and TL 233 (BUC to BBK) do not run exactly parallel but both feed the west coast load center. A full parallel line is defined if both lines start from the same terminal station and end also in a common terminal station. L5 represents the radial interconnection of TL 247 & TL 248 (CAT ARM Transmission System) and, to a lesser extent, the radial interconnection of Hinds lake on the underlying 138kV transmission system. On the western part of the island there are two hydroelectric generating plants (Cat Arm and Hinds Lake) which also provide power to the network through high voltage lines. Figure 8.2 presents the single line diagram for 230 kV system which also includes the LIL but not the Maritime link. This line diagram is drawn at a high level.

In the east, L1 and L2 run parallel as 230kV parallel steel lines (between BDE and Sunnyside stations) and then as almost-parallel lines to St. John's Oxen Pond station as one wood pole line system (TL 201, TL 203, and TL 218) while TL208/TL 237, TL 217, and TL 242 as steel line systems. We consider L1 on the Avalon as a steel line (upgraded as part of Avalon Project) and L2 as a wood pole line (well maintained under WPLM program but with original design loads and lower reliability).

## 8.2 Design Loads during Bay D'Espoir Power Development in mid 60's

Upon review of the pertinent information available during the rural electrification in 60's, two basic load conditions evolved: normal zone, with 25.4 mm radial glaze ice, and ice zone, with 38 mm radial glaze ice. The ice zone was used for a small section of the transmission line system. The overload factor for all metal tower design was 1.33, while this factor was 2.0 for wood pole structures. Table 8.1 presents the original design loads for bulk electric power system in Newfoundland and Labrador.

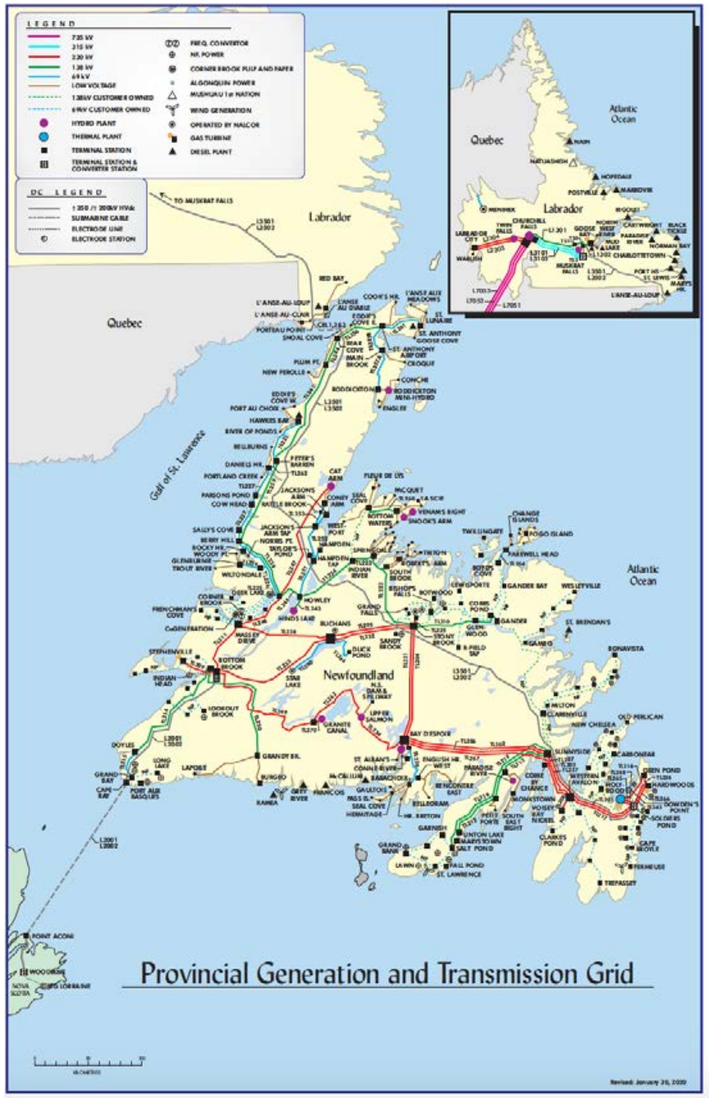



Figure 8.1 Newfoundland and Labrador Hydro's 230 kV Line System

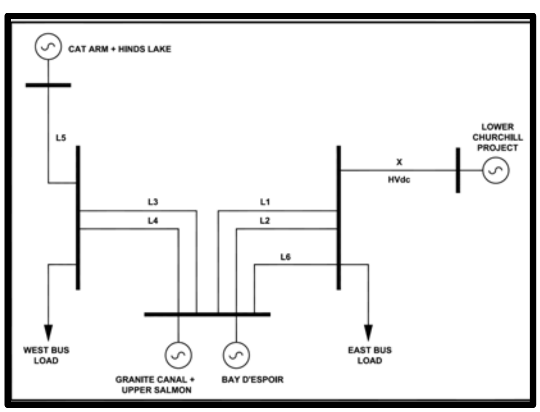



Figure 8.2 Single Line Diagram of the Island's Bulk BEPS at 230 kV Level

**Table 8.1 Design Ice and Wind Loads Developed During Bay D'Espoir Power Development (mid 60's)**

**Design Wind and Ice Loads for Bay D'Espoir Power Development**

| Load Zone | Radial Ice inch (mm) | | Gust Wind Speed mph (km/hr) | | Temp 0° F (-° C) | | Max. Cond. Tension % RTS* |
|---|---|---|---|---|---|---|---|
| Normal Zone | 1.0 | (25) | 0 | (0) | 0.0 | (-18) | 70 |
| | 0.5 | (13) | 73 | (117) | 0.0 | (-18) | 50 |
| | 0 | (0) | 110 | (176) | 0.0 | (-18) | 50 |
| Ice Zone | 1.5 | (38) | 0 | (0) | 0.0 | (-18) | 70 |
| | 1.0 | (25) | 73 | (117) | 0.0 | (-18) | 50 |
| | 0 | (0) | 110 | (176) | 0.0 | (-18) | 50 |

## 8.3 Review of Selected Line Failures (230kV level)

### 8.3.1 East Coast Failures (Avalon Peninsula, Haldar 1988, 1996, 2006)

The line failures on the Avalon Peninsula occurred in 1970, 1984, 1988, and 1994 (Haldar, 1995). Figure 8.3 depicts the observed glaze ice sample on conductor during the 1984 failure. The ice sample weighed approximately 7.8 kg/meter. Figure 8.3 also depicts the bridge failure of a 230-kV suspension tower (guyed-V) under vertical ice load in 1988. In 1994, one 230 kV wood pole line on the Avalon Peninsula failed, causing a forced outage in the system. In all cases, the lines experienced conductor/hardware failures due to ice overload. In many cases, this led to moderate to severe cascades, indicating an inherent weakness in the design about coordination of strength (Haldar, 2006). The ice load was also significantly underestimated in certain sections of these lines on the Avalon Peninsula and on the Buchans Plain. Figure 8.3 depicts the failure of a 230-kV heavy angle tower (self-supported) in the 1988 ice storm. In most cases, the lines experienced conductor/hardware failures due to ice overload. In this case, the line experienced a cascade where a few suspension guyed-v towers and the heavy angle strain tower were lost.

The 1994-line failure caused a cascading event in which seven (7) H-frame wood pole structures (230 kV) were lost due to the failure of a forged eye bolt on a dead-end structure (Figure 8.3). The replacement cost of the failed section of this line alone was approximately $500,000 dollars. In 1970 and in 1984, NLH incurred several million dollars in repair costs and a long-forced outage time before the system was brought back into operation.

In 1995, a detailed failure investigation study (Haldar, 1995) concluded that the observed failure rate of the system based on the many events over a 30-year operational life could be modeled with an annual rate of 0.1 (10-year return period) for the entire Avalon region. In reviewing the observed ice load on conductors, 38 mm to 50 mm of equivalent radial glaze ice was found on the conductors and/or on guy wires in many instances. This information was used to revise the original design ice load (Normal Zone) to 63 mm radial glaze ice thickness for the upgrading of the existing transmission line system (Haldar, 1995, 2006). Figure 8.4 presents some of these failure zones on the Avalon Peninsula. In this figure, the HVDC line is also shown and runs almost parallel to three other 230kV lines running east of Sunnyside terminal station. The recently-built TL 267, line # 3 (230kV) is also shown running parallel to TL 202 (Line #1) and TL 206 (Line #2).

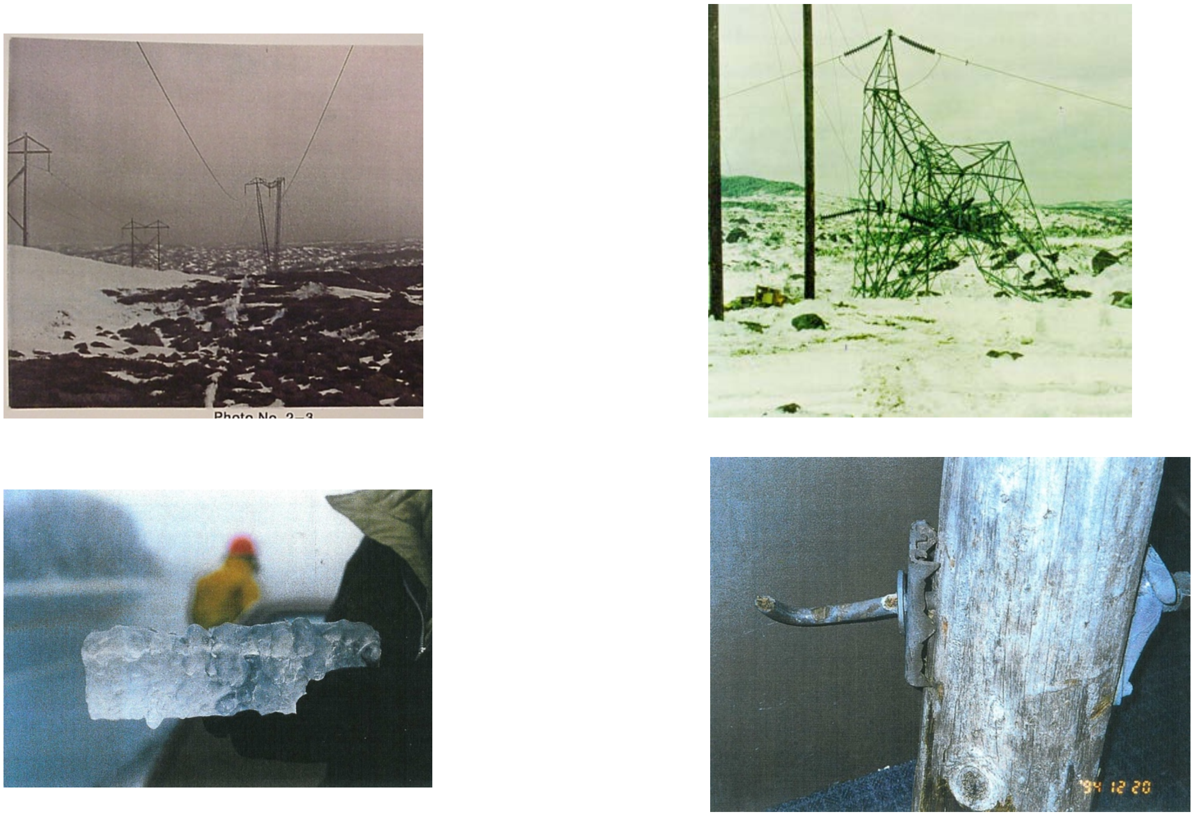


Figure 8.3 (a) Figure 8.3 Bridge Failure of a Guyed-V Suspension Tower in 1988 (b) Large Angle Tower Failure near Hawke Hill (1988 Storm) (c) aa glaze ice sample during 1984 storm on the Avalon Peninsula and (d) Failure of a Forged Eye Bolt in 1994

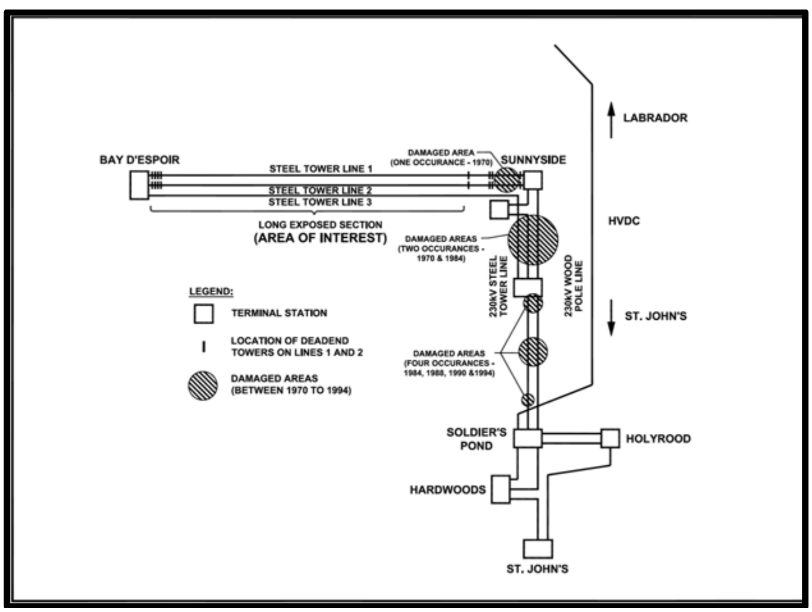



Figure 8.4 Location of the Dead-End Towers on the Existing Two Lines

### 8.3.2 West Coast Failure (TL 228, Haldar 1990)

The 230kV line (TL 228) which runs from Buchans to Massey Drive on the west coast of Newfoundland, was commissioned in 1967. Since its commissioning, the line has experienced several major failures until the line was upgraded in 1990 and 1991 in two stages. All these failures were caused by significant ice accumulation with high wind on the Buchan's plain, and it was estimated that a 5-10-year return period ice load will exceed the line design capacity. Based on the ice accretion model runs validated by observed icing, a revised ice load of 75mm radial ice was estimated for the upgrading work. A cost-risk optimization study was carried out that recommended shortening the existing span as opposed to rerouting the line at a lower elevation. This upgrading work was completed in 1991 that involved two sections of the line, one on the top of the Buchan's plain and the other on the west of Grand Lake crossing. The upgrading work involved adding mid-span towers to shorten the span. Since the upgrade work was completed in 1991, no known damage has occurred on this line.

### 8.3.3 Northern Peninsula (TL 247 & 248, Hannah et al.)

Lines designed and operating at present on the Northern Peninsula have a large dispersion in ice loadings, varying from 0.3 to 4 inches of radial ice. This corresponds to 13.0 to 102mm of glaze ice radial thickness. This corresponds to 1.5 -30kg/m of glaze ice load. Table presents a summary of these lines and the voltage levels vary from 69kV to 230kV. These lines are shown on the Figure xx. Most of the lines on the Northern Peninsula are designed for smaller ice loads except the line from Deer Lake to Cat Arm power house. This line was commissioned in the mid 80's and designed for varying ice loads to a maximum design load of radial ice thickness of 4 inches (30kg/m). This line runs SW to NE up to White Bay. The lower ice loads of 1.75 inches radial (38mm) is for the main line direction. However, a part of this line runs in a NW-SE direction (see Figure), which is almost perpendicular to winds from NE. This wind direction is critical for the freezing precipitation and therefore, a maximum load of 4.0 inches' radial glaze ice load is justified.

## 8.4 Benchmarking Outage Data (Before and after Upgrade, Edwards, 2021)

The cumulative weather related line outage hours between 1980-1999 were approximately 6700 hours and between 2000-2020, approximately 2765 hours. The high value in the 1980-1999 column represents structure failures that occurred on the Buchan's plain during 80's and on the Avalon and Connaigre Peninsulas during the 80's and 90's. These events are outlined in detail in the report, "Reliability Study of Transmission Lines on the Avalon and Connaigre Peninsulas" (Haldar, 1995). There was one major failure in the 70's on the Avalon Peninsula (near Sunnyside Terminal station) that included several key lines on the Avalon and Burin Peninsulas; outage data for this event is not included here. The spike in 2010 represents a structure failure that occurred on TL208. There were no customers attached to TL208 at the time, and there was no urgency to get the line operational. After this failure occurred, an assessment was made to determine which other sections of TL208 required upgrades before the line was put back into service. This specific outage to TL208 accounts for approximately 1500 hours of the total outage hours displayed for 2010. There was no industrial customer at the end of TL 208 and therefore, 1500 hours reflect this recovery time.

To benchmark against the CEA data, each year's data was normalized using the CEA value for that year. The ordinates values in Figures 8.5a and 8.5b present these normalized cumulative values.

Figure 8.5c presents the values for individual year that considers the line length for each year in Hydro's system. It is clear from Figure 8.5a that system performance improved significantly in 2000-2020 compared to 1980-1999 because of NLH's proactive mitigation actions regarding refurbishment and upgrades that led to the significant reduction of the line outages.

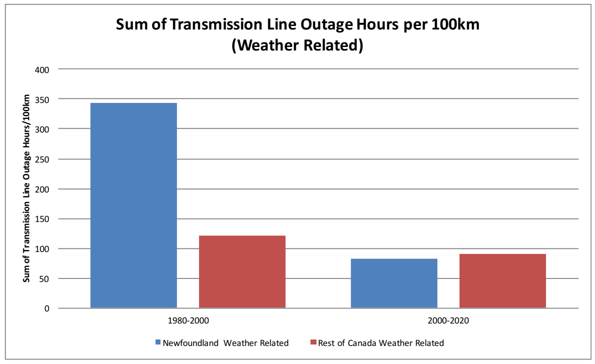



Figure 8.5a Comparison of Weather Related Outage (NL and Rest of Canada, CEA, Edwards, 2021)

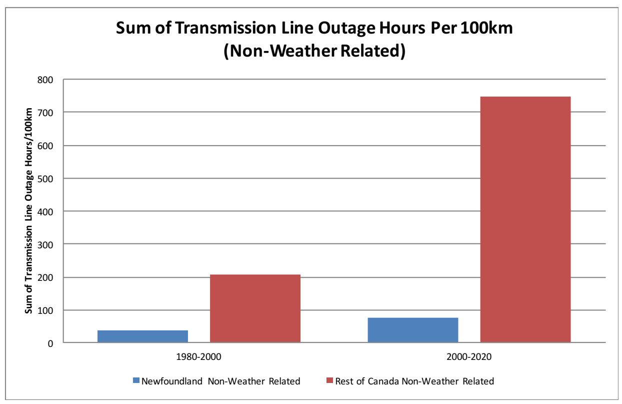



Figure 8.5b Comparison of Non-Weather Related Outage (NL and Rest of Canada, CEA, Edwards, 2021)

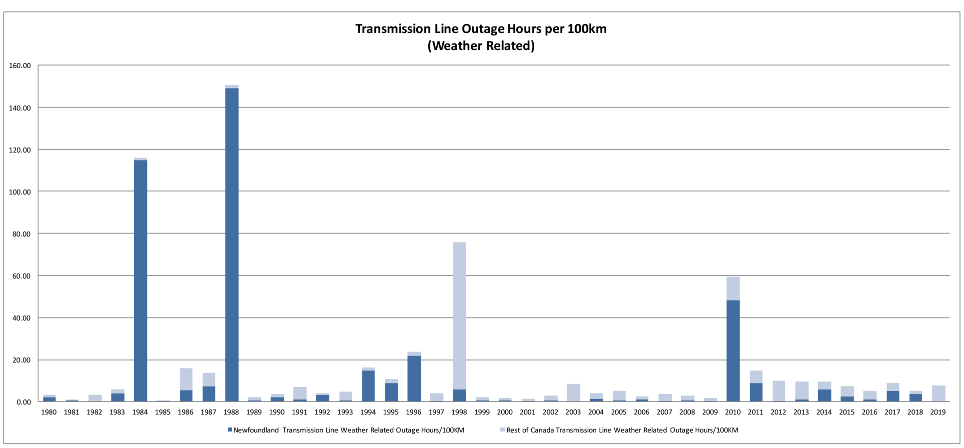



Figure 8.5c Comparison of Weather Related Outage (NL and Rest of Canada, CEA, 1980-2019, Edwards, 2021)

**Data displayed only includes outages to Avalon and Connaigre Peninsulas identified in Asim Haldar 1996 Report entitled, "Reliability Study of Transmission Lines on the Avalon and Connaigre Peninsulas"*

## 8.5 Benchmarking of Transmission Lines

### 8.5.1 Line from a Canadian Utility

To compare the reliability of LIL with other utility lines, the author decided to benchmark the structural reliability of an important line in Canada. This is a line from a 700 MW generating station in Northern Canada and connected to a switchyard through which it is connected to the main power grid. This line is designed for voltages up to 230KV level supporting bundled conductor sizes up to 954MCM. The loss of this line would have significant consequences on the utility's electrical system. The basic analysis data for the line was provided by the utility. The author in consultation with the utility personnel analyzed the data and ran the reliability model following CSA 60826-10. Figure 8.6 presents the comparison of annual failure probability of this line. It shows the failure probability is very low with a large central factor of safety. The author has been told that the line design is controlled by security loads, independent of reliability level, and therefore, a large factor of safety is observed under the reliability class of loads. The reliability class of loads considered are: (1) extreme ice, (2) extreme wind, (3) two combined wind and ice loads and (4) unbalanced ice loads

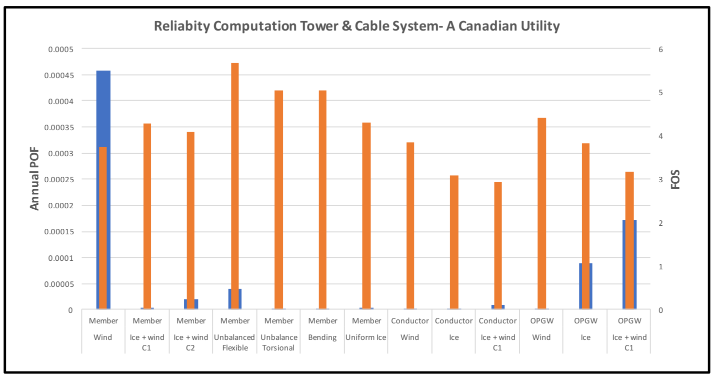



Figure 8.6 POF of a HV Transmission Line in Canada using CSA 60826-10 Analysis

### 8.5.2 Comparison of Avalon Upgrade Steel Transmission Line and LIL

This section compares the structure support system and cable system reliability comparison for the Avalon upgrades and the LIL on the Avalon Peninsula for extreme ice load. Based on the data, it appears that LIL reliability is significantly higher compared to Avalon upgrade lines when the structure support system is considered. However, for cable systems, LIL design is realistic but is significantly lower compared to the Avalon system. This is because the tension limit for extreme ice loading in Avalon Upgrade design was kept well below the nominal 75% criteria to allow for some slack and additional sag so the many in-situ towers can remain in place during the upgrade and only a few mid span structures needed during the upgrading. If the allowable conductor tension was increased, many structures may have undergone uplift situations; this could have major consequences in the upgrading project costs. It was recognized during the upgrading project that the EHSS conductor on the Avalon was underused and thus, increasing the reliability significantly compared to LIL cable system. LIL design is more balanced and maintains a proper sequence of failure between the tower and conductor under extreme ice load.

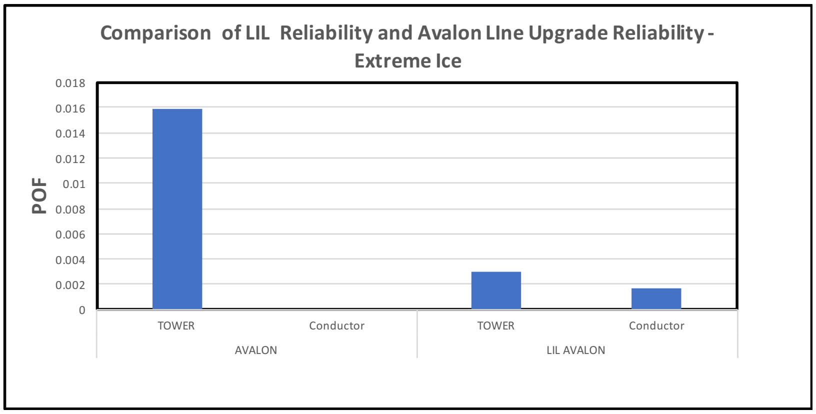



Figure 8.7 Benchmarking POF for 230kV line and LIL on the Avalon Peninsula

The benchmarking study shows that NLH experienced many HV line failures during the 70's, 80's, and early 90's. The author was involved in these failure investigations and the lessons learned were that the major line designs that led to the rural electrification during 60's and 70's (BDE power development) significantly underestimated the conductor strength regarding the icing exposures on the Avalon Peninsula and on the Buchan's plain (West Coast). Reassessment of the revised ice loads prompted two major upgrading works, one on the eastern side of Newfoundland (Avalon upgrading) and the other on the west coast, known as TL 228 system upgrading. Since these upgrade works were completed in the early part of 2001, NLH has significantly improved its system performance with respect to weather related load events. This is clearly reflected in Figures 8.5a, b and c. A selective reliability comparison with one important line of a major Canadian utility and one with Avalon upgrading shows that LIL structural reliability for extreme icing is significantly higher than the Avalon upgrade but well below the one presented based on the data from the Canadian utility. The author will not take the reliability data in Figure 8.6 in direct comparison because design ice load is significantly lower than what is considered here as 50-year load, and the utility confirmed that the very large FOS is due to the tower design is fully controlled by the security loads.

## 8.6 LIL Outage/Failure Rate – Comparison of Results with Published Data

A transmission line outage can be caused by (1) electrical fault and (2) permanent faults caused by mechanical damage/failure of line components. Electrical faults are normally caused by lightning strikes. They are temporary and have a negligible influence on the EHVAC and DC power transfer capability because of the short duration. There is published statistical information available on line outages considering sustained and momentary outages (Vancers et al., 2002). This is normally expressed in terms of fault\year\100km to normalize the line length. So, a 100km line with 0.5 fault per year can be used to design a line with a length of 500km that would be expected to have 2.5 faults per year, assuming very similar isokeraunik level. No such guidance is available for mechanical\structural failure\year\100km rate in design of HV and EHV lines (AC and DC).

In this section, we discuss the permanent faults caused by mechanical damages due to extreme weather loads: insulator strings, unbalanced ice loads, broken conductors due to extreme loads, and towers damaged by wind and ice storms, non-synoptic wind loads etc. EHVAC line faults may also be divided into single-phase or multi-phase faults, as well as single-circuit or double-circuit faults. Linden et al (2010) suggested that more than 95% of EHVAC line faults are typically single-phase faults; multi-phase faults represent less than 5% due to the high overvoltage withstand of the line.

The permanent failure rate has been suggested to be about 0.03/year/100km based on the assumption that 10% of these EHVAC faults are permanent. Although the repair time could vary between couple hours to week, an average time of 24h is suggested in this paper.

A further review of the Linden et al paper (2010) indicates that, in lieu of direct data on DC line failure rate, failure rates could be estimated in the range 0.005 \year\100km to 0.025\year\100km based on reported tower damages on 700-800 kV EHVAC lines in North and South America due to ice storms or tornados. The paper also points out that a value of 0.003/100 km/year with an estimated repair time of about one week (168 h) can be used as an average estimate for permanent double-circuit faults, including lines in other regions not exposed to such harsh weather conditions. Of course, this is based on the limited data in this CIGRE paper. However, the author could not find similar information on mechanical damages/failures normalized in terms of line length in open literature for EHVDC lines. Therefore, it is challenging to compare the results of Tables 6.1 and 6.2 directly with some published data for DC lines.

The author has used one known failure of the Manitoba Hydro's Bipole 1 and Bipole 2 lines during a microburst windstorm in 1996. In this case, Manitoba Hydro lost 17 towers between two Bipole lines. These lines were in a common corridor. Failure rate based on this one event has been compared in Figure 8.9 along with data presented in the Linden et al (2010) paper. The author is aware of failure data for DC lines in South Africa and in US, but they are related to sabotage, floods etc. and are excluded. One incident was reported for a Manitoba Hydro Bipole line in Northern Region where a guy wire was damaged but did not cause any outage. This has been excluded from the data presented in Figure 8.9. Manitoba Hydro's line failures in 1995 caused an outage that led to rotating load curtailment; the recovery time was 96 hours for the BP I and couple of weeks for BP II. It is to be noted that Newfoundland may not experience significant thunderstorm activities but may experience extratropical cyclones, the spatial size of the latter may be much larger compared to microburst front size.

The author received failure data on two ±500kV EHVDC bi-pole lines due to galloping (ice and wind related) and these data have been analyzed and included in Figure 8.9. Although these failures are not under direct reliability class of loads, the actual failure data is relevant here because of the long line length, voltage level and years of operation. These lines have average length of 1000km and operated between 8 and 12 years. In the first case, a tower collapsed due to two tower's components failure, a tower's insulator string dropping (Figure 8.8a) and in the second case, a tower's jumper wire dropping due to two tower's components failure (Figure 8.6b),

Figure 8.8a Photo of the collapsed tower and (b) Tower's cross arm failure (Liu, 2021)

The author also received failure data on one ±600kV EHVDC bi-pole line due to extreme wind and this data have been analyzed and included in Figure 8.9. This data falls directly under reliability class of loads and is also considered because of the long line length, voltage level and years of operation. This ±600kV EHVDC line is 800km long and operated for 20 years before it was upgraded.

In general, the baseline failure rate values normalized in terms of line length (failure rate\year\100km) are compared with data from several sources. These include limited published data on EHVAC and EHVDC line failures under extreme weather events and three specific EHVDC line failures that the author has compiled from external sources through his own contacts. It shows the annual POF of 0.05 and the failure rate 0.052 in Figure 8.9 (Table 6.2) under Scenario # 4D will translate to a normalized failure rate (0.0047\year\100km) that considered the effect of line length of 1100km and is better aligned with the published data in Figure 8.9. The annual POF of 0.0110 (Table 6.2) also translates to a normalized failure rate of (0.0010\year\100km) under Scenario # 1. This value is approximately one fifth of the failure rate under Scenario # 4D and appears to be a low value and does not align well with the published data in Figure 8.9 because it does not consider the impact of line length, correlation and the effects of two different types of icing. The failure rate presented under Scenario # 4D is an upper bound estimate. The comparison in Figure 8.9 shows that by selecting Scenario #1, the failure rate/year/100km is significantly underestimated compared to the available normalized damaged/failure data published in the literature and the data for the three specific EHVDC lines that the author has compiled. The Scenario # 4D presents a more realistic picture given the many uncertainties and the inadequacies that do exist in the LIL design.

All these failure rates\year\100km values will likely increase further when the LIL is assessed fully for terrain and topographic effects with and without the increased combined wind and ice loads. However, the values in Scenario #4D could also decrease if the storm correlation study can show the natural loads are partially correlated along the line length.

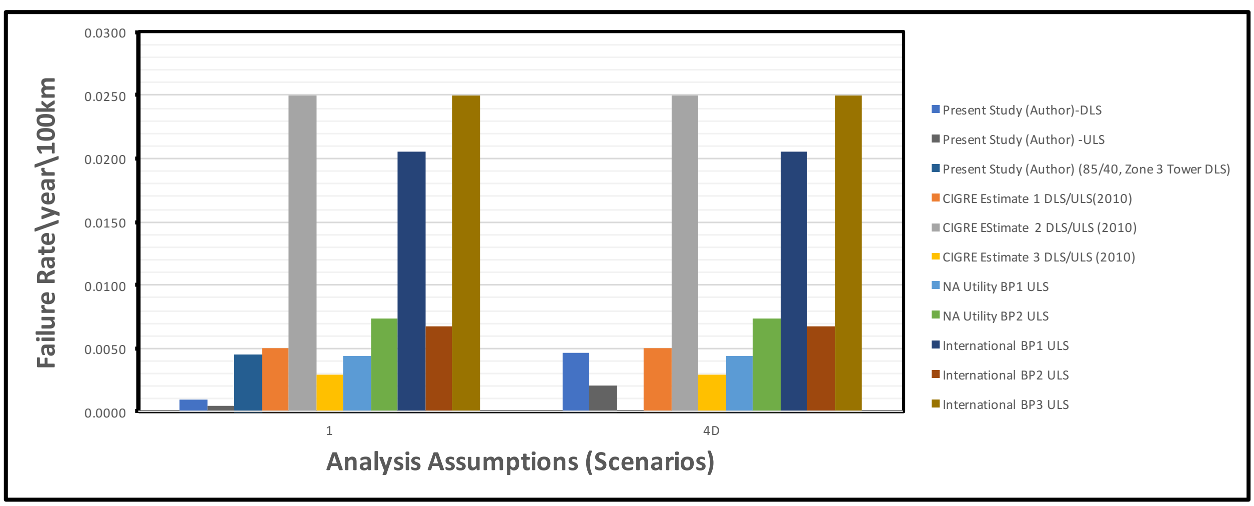



Figure 8.9 Comparison Failure Rate of LIL with Limited Published Information

The unavailability of LIL is calculated as the product of the failure rate multiplied by the recovery time. If the recovery time is assumed to be one week (168 hours), unavailability could vary from 1.84 to 8.40 hours per year. Since the failure rate is given and the unavailability is linearly proportional to repair rate, one can reduce this rate to minimize the LIL unavailability. This may involve better monitoring programs, frequent inspections, high quality maintenance, and a high caliber emergency restoration program. All this will significantly help to reduce the repair and recovery rate and significantly reduce the unavailability of the LIL and improve the resiliency of the LIL.

# 9.0 Summary, Conclusions and Recommendations

## 9.1 Summary

This report assesses the impact of two types of icing on the structural reliability (and probability of failure) of the LIL HVdc line. The two types of icing are (a) glaze icing due to freezing precipitation and (b) rime icing due to in-cloud precipitation (Figure 9.1). The study assessed the LIL line reliability by exposing the line to these two types of icing in various scenarios. This reliability assessment was also conducted to validate the LIL design with respect to CSA 60826-2010 and to determine the overall likelihood of failure of the LIL with respect to both glaze and rime icing (Figure 9.1). The goal was to determine the expected LIL failure rate ($\lambda$) based on a probabilistic assessment of the LIL for both types of icing exposures. The failure rate ($\lambda$) and repair rate ($\mu$) are the key input parameters required to do the system planning reliability study. The report also addresses the failure rate considering the impact of line length under various scenarios. It also includes a limited sensitivity study of some design parameters, qualitative benchmarking of the LIL with respect to utility-based operational statistics on outages and a discussion on Hydro's operational experience with selected existing transmission lines. Finally, a benchmarking on LIL failure rate normalized per 100km is done with respect to limited published data and with some propitiatory data.

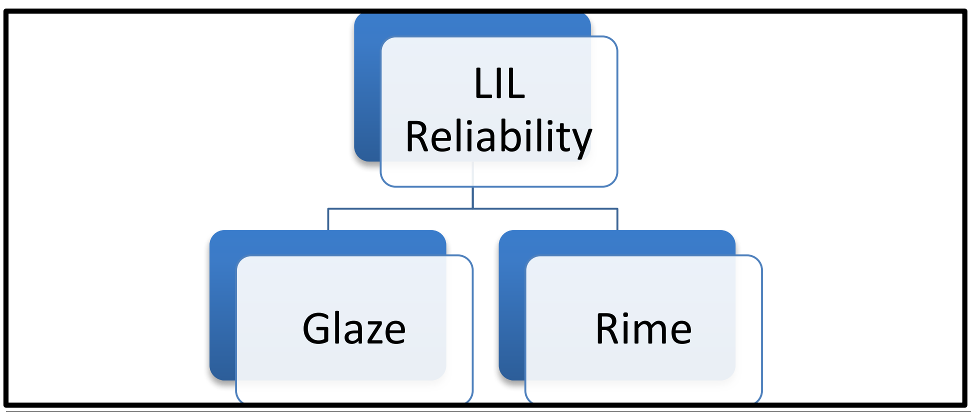



Figure 9.1 Two Types of Icing

The reliability assessment study presented here is detailed and, to the best of author's knowledge, is the first time that Nalcor/NLH has officially undertaken a study on the structural reliability and its impact on overall LIL reliability since the first submission for the project was made to PUB in 2011. The selection of an optimum return period (T) for an important line like LIL, which will likely carry at least the half the province's electrical load in the near term, should have been made based on balancing the installation/investment cost against the future damage cost that account for the outage cost and the replacement cost of a failure (Haldar, 2009, 2011, 2012). CSA stipulates that, in lieu of such an optimization study, reliability analysis should be based on the damage limit state (DLS) and a minimum return period (T) based on the climatic load level class, the importance of the line, and the voltage level.

It must be understood that the violations of DLS do not automatically imply that the complete structural failure of the line (collapse of a tower, foundation, rupture of a conductor etc.); it could instead be a loss of a specific line performance criterion. CSA provides some guidance on what violations fall under DLS criterion. These violations under DLS can create safety hazard and other serviceability problems, and if not controlled or mitigated may lead to LIL outages because of the failure of the support and wire systems.

Results presented in Table 6.2 only reflect that these POFs' are based on DLS criteria following CSA 60826-10 with strength factors specified by Nalcor/NLH. These factors are in line with CSA 60826-10. Before a full system planning reliability study is done based on the LIL failure rate ($\lambda$) as presented here, the author recommends that NLH/Nalcor presents the report to PUB with the recommendations on several follow up work including the determination of POF under ULS criterion to ensure that the input failure rate ($\lambda$) for system planning reliability study also considers the strength failure (ULS), not just the failure rate due to damage limit state alone.

This study also shows that LIL did not meet the requirement of critical load combinations and the design is not adequate with respect to UBI (unbalanced ice) loads. By omitting the load combinations completely, it is shown that the towers in Labrador do not have the sufficient structural integrity and the LIL line is vulnerable to several unbalanced load combinations. Should these loads occur in combination during the shedding process, LIL line could experience structural failure. This is the first major EHV line in the Island that did not meet NLH's own design criteria under UBI loads.

## 9.2 Conclusions

Results of the LIL system reliability study clearly show that the "wire support system" contributes significantly in the reliability analysis. Under combined load cases for glaze icing and for rime icing, elements in OPGW and electrode line systems are critical and significantly impact the overall LIL reliability with respect to damage limit state (DLS) following CSA 60826-10.

### 9.2.1 Probability of Failure (POF) -DLS

Based on our study we find the POF of LIL can range from little over 1% for Scenario # 1 to 5% for Scenario # 4D (Table 6.2). Each scenario considers a set of assumptions and these are presented in Table 6.1. These assumptions consider correlation among various key elements under a specific load type in each segment, the regional independence of LIL passing through several weather zones, and the exposures to two distinct and mutually exclusive types of icing and are used explicitly in assessing the POF of LIL line and the reliability. These issues have not been considered before, and the study results highlight the importance of all these factors in determining a realistic structural reliability and probability of failure of LIL. This contrasts to the "more optimistic" scenario #1 based on a simple assumption that the entire LIL line is exposed to only one type of icing and the storm events are fully correlated across the entire line length and no correlation among the various key elements. The author cautions that the LIL should not be treated like other lines on the Island because of its importance, length and different extreme weather zones that it traverses, large power transfer capability and its exposure to two different types of icing that are mutually exclusive.

Based on the study, the author finds that the annual POF of LIL can range from little over 1% for Scenario # 1 (a simple series model with full correlation along the entire line length) to 5% for Scenario # 4D (considering two different types of icing exposures, correlation among the elements in the two subsystems in a segment and regional independence of the various loading zones) under a Damage Limit State (DLS) criterion. Therefore, LIL reliability and POF of 1% under Scenario # 1 is within the range of 45 to 91 years return period of limit load (climatic event) following CSA 60826-10. Following a direct factored strength based approach, this return period is approximately 73 years. However, POF level in Scenario # 4D is not compared directly with CSA 60826-10 because CSA does not deal with correlation issue, impact of line length and the impact of multiple hazard events that are independent. In general, the study has also identified that the cable system is weaker than the structural support system as well foundation of tangent tower is likely to fail first before the tower fails. These findings are contrary to the industry's best practices.

The unavailability of LIL is calculated as the product of the failure rate multiplied by the recovery time. If the recovery time is assumed to be one week, unavailability could vary from 1.84 to 8.40 hours per year. Since the failure rate is given and the unavailability is linearly proportional to repair rate, one can reduce this repair rate to minimize the LIL unavailability. This may involve better monitoring programs, frequent inspections, high quality maintenance, and a high caliber emergency restoration program. All this will significantly help to reduce the repair and recovery rate and significantly reduce the unavailability of the LIL and improve the resiliency of the LIL.

#### 9.2.2 Probability of Failure (POF) -ULS at a High Level

A high level Ultimate Limit State (ULS) analysis for cable systems provides a relative comparison of the risk levels between DLS and ULS and shows that POF under ULS is almost forty-three percent (43%) of that presented under DLS. Therefore, following CSA 60826-10, this will translate to an equivalent limit load return period that can be bracketed between 106 and 211 years; for a strength based calculation this is 160 year under Scenario # 1.

In addition, the study has also identified the vulnerability of LIL under ice shedding phenomenon (UBI). LIL design neither met CSA requirement nor did it follow Hydro's design standard with respect to load combinations issue. A design that accounts for adequate load combinations is crucial for design for unbalanced loading due to ice shedding, particularly the "harsh" environments that the line traverses for a length of 1100km and its exposure to eleven severe different climatic loading zones. Since the several important load combination criteria for unbalanced ice loads were not considered during LIL design, it is our assessment that the LIL has some inherent design weakness and less robust in certain sections, particularly in Labrador where the suspension tower carries five cables. This vulnerability needs to be examined further in depth and a plan for mitigation should be developed.

The sensitivity study showed clearly that terrain roughness (type B) and topographic effect (wind speed-up effect) can have significant impact on the POF results that have been reported here as baseline values. The author has studied only one critical location for topographic effect, but this needs to be assessed for all other locations along the line route. The sensitivity study also showed that combining terrain type B and topographic effects with the increased reference values of wind speed and ice loads in determining the LIL POF for combined wind and ice loads can have significant impact on the DLS probability of failure and this needs to be assessed fully. This is a significant piece of work that needs to be completed for the entire line length and is outside the scope of this present study.

As explained earlier, the risk of exceeding DLS criterion could be severe and may lead to an LIL outage, if the environmental conditions (hazards) that led to the exceedance of DLS persist for a long duration or occur frequently (refer to the real example of Churchill Falls line in Section 3.3.1). However, it should be clearly understood that a full ULS system reliability analysis (structural reliability) that considers LIL as a structure support-cable system should be done at least for few critical segments/zones before a serious generation expansion planning is considered. Tables 6.2 and 6.3 only provide a relative comparison of the risk levels between DLS and ULS at a very high level..

Our analysis has also revealed that there are many other issues that need to be assessed fully in the reliability assessment of LIL apart from the return period of load issue. These include: (1) the impact of local topographic exposures (wind speed-up effect), (2) underestimation of combined wind and ice loads and the impact of topography on these combined loads, (3) complete omission of unbalanced ice load combinations. In addition, regional correlation or partially correlated natural loads of past storm exposures (extreme events) of such a long line route and its impact on LIL reliability and POF need to be understood and analyzed fully (Hong, 2021). The impact of these parameters needs to be studied carefully and comprehensively to understand the appropriate probability of failure (reliability, risk level) of such an important line and how the POF will impact the overall failure rate ($\lambda$), which is a key parameter for the line availability calculation. The failure rate is directly related to the annual probability of failure presented in tables (6.2 & 6.3). An overestimation or underestimation of this parameter may provide incorrect unavailability at the system level. Once the full ULS risk level including the above issues is addressed, all mitigation options should be considered, including generation expansion, in a cost-effective manner.

The comparison in Figure 8.9 shows that by selecting Scenario #1, the failure rate/year/100km is significantly underestimated compared to the available normalized damaged/failure data published in the literature and the data for the three specific EHVDC lines that the author has compiled. The Scenario # 4D presents a more realistic picture given the many uncertainties and the inadequacies that do exist in the LIL design. The failure rate presented under Scenario # 4D is an upper bound estimate. All these failure rates\year\100km values will likely increase further when the LIL is assessed fully for terrain and topographic effects with and without the increased combined wind and ice loads. However, the values in Scenario #4D could also decrease if the storm correlation study can show the natural loads are partially correlated along the line length.

## 9.3 Recommendations

Based on this study, the decision to make appropriate generation expansion study should not be done strictly based on DLS criteria satisfying CSA 60826-10 rather by doing a full ULS analysis of the structure-cable system and its impact on the LIL failure rate, ($\lambda$). ULS for cable system considered in this study was at a very high level and did not consider the coupling effect of tower-conductor/OPGW/electrode-hardware-insulator system as one full system. A system planning reliability study should consider the failure rate ($\lambda$) not only based on DLS but also with due consideration for ULS. However, this present reliability study has now provided a baseline failure rate ($\lambda$) considering various scenarios for determining the LIL POF, following, in principle, CSA

60826-10 DLS criteria. A future follow-up study should consider the following items in revising the LIL POF and these are prioritized here:

- LIL line should be checked for UBI with load combinations to assess the tower vulnerability and assess the gaps due to complete omission of load combinations in the design and exposures that exist in the current LIL design and a plan should be developed on what measures can be put in place to mitigate this specific issue, particularly for the line section in Labrador. At present, the single-phase load without load combination makes the suspension tower vulnerable to unbalanced ice loads, particularly in Labrador where the tower carries five cables and the tower weight is also lighter compared to that on the Avalon Peninsula. - (Priority # 1)
- Based on the results of one topographic analysis for a tower located on the top of Hawke Hill, the author recommends a full topographic analysis of the LIL line be considered to identify all remaining "hot spots" and to assess the site-specific wind loading considering local terrain characteristics, topography, and the environmental exposures/hazards. The terrain characteristics and topographic information can be gathered using modern (digital) mapping technology regarding the profile of a specific site. The site-specific wind loads should include the uncertainties in terrain data along the line routing and address local terrain roughness issues. This analysis should also assess the impact of the "wind speed-up effect" on combined wind and ice loads and the effects on these towers that are located either on the top of an 3D axisymmetric hill, a 2D ridge, or an escarpment. This was not considered in the LIL design and it is recommended that a plan be developed to identify these towers, assess the POF considering "wind speed-up effect", and assess its impact on overall line POF (reliability, failure rate) to determine what POF (reliability, failure rate) level is acceptable based on a cost-risk scenario. A mitigation action plan should be developed if the reliability level does not meet the industry's best practices. (Priority #1).
- A full correlation study of the line route to past extreme storm events in establishing the correlation between various regions; if a strong correlation among various regions can be established, it may be possible to further improve the POF under Scenarios # 4B and # 4D and reduce the LIL POF (hence, increasing the reliability), and ultimately reduce the failure rate ($\lambda$). (Priority #1)
- An Event tree analysis for all possible violations of DLS including the clearance violations due to load increase and the ones that may lead to ULS should be assessed. In this analysis POF and consequences should be studied carefully to quantify the risk of such DLS violations and LIL outage exposures. The present study did not consider the "clearance violations" issue. (Priority #1)
- The present study has also identified an opportunity in revising the current design loads considering the effect of large diameter of pole conductor on the design ice thickness. This was not considered in the original LIL design and in the earlier studies. The revised loads and combinations, once assessed fully, will reduce and improve the baseline POF values for existing LIL design and reduce some of the expected increases from combined wind and ice loads considering topographic effects. This improvement will only affect the POF (or reliability) under glaze ice exposure. It is likely that the increase in the loads due to increased values for reference wind speed and glaze ice load effects may be compensated to an extent due to the decrease in the transverse and vertical load effects on pole conductor considering the impact of cable size on ice accretion. This will also reduce the UBI load effect, but this should be assessed quantitatively. (Priority #1)

- A comparative evaluation of Combined loads using Environment Canada model data and EFLA data versus combined wind and ice load data based on CSA 60826-10 should be done and if it is shown there is a significant gap, this needs to be closed particularly considering past failure experiences and lessons learned. The author suggests in using combined wind and ice loads directly from Environment Canada model runs and EFLA study rather the use of combined probability based loads from CSA 60826-10; however, reference values for wind speed and ice loads should be derived from COV of data and ice residence time as the model runs suggest for a typical LIL weather zone. It is known that the combined probability based method for wind and ice loads often overestimates the loads compared to historical storm method and this may contribute to the increased baseline POF values (Priority #1)
- Progressive collapse analyses of four suspension towers under reliability class of loads (extreme events) should be carried out at critical segments These analyses cannot be done in PLS TOWER and would require different type of FEM program but should be pursued at least for the above sections. The analysis should also consider the test data to validate the results. By analyzing these towers for progressive collapse, NLH will be able to determine the reliability index $\beta$ under a collapse load and therefore, will be able to assess the POF and the failure rate ($\lambda$) for the structure support system under ULS in a realistic manner. Any adjustment of the POF can be done that has been assessed in this report and this POF and failure rate will be more realistic than what has been reported here under DLS. Although failure under DLS can also cause extended outages as explained before and should not be underestimated and ignored. The analysis should also consider the impact of terrain roughness and topographic effects in considering the revised combined wind and ice loads in the structural collapse analysis. (Priority #2).
- Foundations should be also modelled under the same progressive collapse model and in determining the limit load and the reliability index and the failure rate ($\lambda$). (Priority #2).

All *this could be considered in the next phase to see what would be the POF for the LIL line system when one relaxes the limit state to full ULS condition, outside of CSA 60826-10. Of course, it must be done for all critical components considering a coupled system. This requires a separate study but can be built on based on the work presented in this report and the methodology outlined here.*

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# 11.0 Appendix

Short Biography of Dr. Asim Haldar, P.Eng.

Asim Haldar received his Master's in Structural Engineering and Ph. D in Ocean Engineering from Memorial University of Newfoundland in 1977 and 1985 respectively, with a specialization in behavior of offshore structures. He has worked in the utility industry for 41 years and retired from Nalcor Energy in 2014. Prior to his retirement, he was the Manager of Research and Development in the Engineering services Division of Nalcor Energy, a crown corporation in Newfoundland and Labrador and was responsible for all engineering research activities pertinent to Nalcor's lines of business.

During his earlier career, he has been a lead engineer in the design and upgrading of more than 1500km of existing and new HV lines in Newfoundland and Labrador. Asim has also been involved actively in developing new technologies to better understand and mitigate various line design issues regarding effective ice load monitoring on overhead lines. This has led to the development of RIGD ice sensor (Remote Ice Growth Detector). In 1998, he was the project manager for the Gull Island Transmission Project which included a feasibility study of 735kV AC line between Labrador and Quebec and a DC line $\pm 450KV$ between Labrador and the Island of Newfoundland.

He is at present the Technical Advisor of the Transmission Overhead Line Design and Extreme Event Mitigation (TODEM) Interest Group. He is an active member of the CIGRE Study Committee SCB2 (former TF Leader for B2 23 on Foundations and Secretary for B2.24 on Structures) and a former Canadian delegate to IEC TC-11. He is the former Vice Chairman of Transmission System R & D Committee, Canadian Electricity Association (CEA), and the Chairman of CEATI WISMIG group (later named as TODEM, 2006-08)

Since 1990, Asim also serves as a regular member of the International Technical Advisory Committees namely PMAPS (Probabilistic Methods Applied to electric Power systems). He was an adjunct Professor in the Faculty of Engineering, Memorial University between 2000-2003 when he supervised one graduate student. Asim has published more than 100 technical papers and reports in his field of expertise (overhead line design and asset management issues and behavior of offshore structures); many of them have a worldwide circulation.

On behalf of CEATI International, he organized two very successful international conferences; one in October 2014 on Line design and Asset Management issues in Niagara Falls, Ontario and the other in November 2016 on Best Practices in EHV Line Design in San Diego, California. Both conferences were well attended with more than 150 participants. Later, he coauthored a chapter of the book entitled "Best Practices in EHV (230kv above-765kv) Line Design" published by CEATI International, Montreal, Canada. Since 1990, he has done several R & D projects for CEA and CEATI International which are all published and well circulated nationally and internationally. He is also the founder of Haldar & Associates, Inc., a St. John's, Newfoundland based consulting company primarily focused in providing R & D services to the utility industry.