Request IR-01:

Reference: N-01 Application, pages 3 and 13 of 37; Appendix D (Concentric Expert Evidence of Danielle S. Powers); 2023 NSUARB 175, para. 95; Decision M11009 (2024 NSUARB 17), para. 19.

Preamble: The Board's October 2023 Decision set out the conditions for termination of the holdback, including that NSPML may apply for relief if "good utility practice or exceptional circumstances" caused it to fail to meet the consecutive 12-month requirement. In its January 31, 2024 Decision, the Board specifically stated that it intentionally did not attempt to provide a definition or describe the scope of "good utility practice or exceptional circumstances" in its decision, as it contemplated this could be the subject of evidence or argument when NSPML eventually files its application to end the holdback.

The Application's Appendix D introduces a capitalised, defined term "Good Utility Practice," sourced from Concentric's interpretation of the Joint Operations Agreement (JOA). In Section 1.0, Introduction, lines 7-12, NSPML states:

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

a. Please confirm:

i. that the proposed definition of "Good Utility Practice" has never been decided on by the Board, and in no way informed the Board's 2023 NSUARB 175 decision or

setting of the flexible relief available to NSPML in relation to the holdback mechanism.

ii. that the Concentric definition of "Good Utility Practice" is not binding on the Board in this proceeding and is simply offered as evidence filed on behalf of NSPML for the Board's consideration.

iii. that in 2023 NSUARB 175, at para. 95, which NSPML appears to quote at page 13, lines 15-17, the Board specifically did not capitalize "good utility practice" or otherwise define it as a term with a specific regulatory meaning.

b. How does NSPML define a planned vs. an unplanned outage? Specifically, what is NSPML's planning horizon for outages?

c. Identify any scenario, in NSPML's view, in which a planned outage or unplanned outage would fall *outside* the scope of the proposed "Good Utility Practice" as defined by Concentric in Attachment 1, explain why, and highlight any planned or unplanned outages from May 2023 to present that would not meet that definition.

d. Does NSPML take any position regarding whether planned or unplanned outages should be considered on a singular basis, or cumulatively through the 12-month period (i.e. does it matter if there are 4-5 events versus 1-2)?

e. Is it NSPML's position that any inclement weather event resulting in an outage would constitute "exceptional circumstances" for the purposes of the relief available for the 12-month Compliance Period? If not, identify the threshold that NSPML proposes the Board apply in distinguishing qualifying exceptional circumstances from normal weather variability.

Response IR-01:

a)

i) Confirmed, to NSPML's knowledge the definition has not been decided by the Board. However, the term Good Utility Practice and the associated definition provided in the Application is that used by NSPML. The term and definition are embedded in and fundamental to the Lower Churchill Project Commercial Agreements (which were reviewed by parties and the Board during that process), as well as Canada's Federal Loan Guarantee with NSPML as agreed at the outset of the Maritime Link Project. Also refer to the response to NSEB IR-07.

ii) Confirmed. As noted in the response to (i) above, NSPML is subject to the definition in the Application in its commercial agreements, including the Joint Operating Agreement with NLH.

iii) Confirmed. Also refer to the response to NSEB IR-07.

b) NSPML uses definitions consistent with CIGRE TB 956 for outage terminology:

i) **Outage** is defined as the state where all or a portion of the HVDC system is unavailable for operation.

ii) **Planned (or scheduled) outage** is defined as an outage which has been planned, and for which actual dates and timing are coordinated through the Utility's Outage Coordination Process. An example would be the annual shutdown(s) for preventative maintenance.

iii) **Unplanned (or forced) outage** is defined as an outage which has not been planned or coordinated through the Utility's Outage Coordination Process. An example would be a trip of a pole.

c) An example would be an outage taken for which there is no technical reason why an outage is required to complete the work identified (changing a lightbulb in a hallway). None of the outages from May 2023 to the present day are unreasonable in their nature, an outage of the HVDC system in part or in whole was technically required to safely execute the work and given the same circumstance other utilities would choose to do the same.

d) NSPML submits that the number of outages is less important than when outages occur. From a simplistic point of view, NLH and NSPML are aligned in terms of the preferred timing of planned outages – that is during the non-winter period. Outages during the non-winter period can generally take longer and can be more common as there is not the system urgency for the underlying resource. For winter period outages, there is greater concern regarding the availability of capacity to serve the increased load and, therefore, winter outages are generally limited to what is required to be done in order to get full functionality and there is greater potential to double shift and/or undertake activities with monopole outages as opposed to complete bipole.

NSPML is much less concerned with non-winter period outages as (i) the capacity is not required for reliable service due to lower load and, traditionally, variances in energy value are lower in the non-winter period. In respect to the latter point, redeliveries during this same period are expected to be relatively close in value and, if the redeliveries are pushed into the winter period, there is a reasonable possibility that the value of the redelivered energy could be higher. In addition, all of the delivered energy is considered renewable.

Generally, in terms of the non-winter outages, NSPML does not believe there is any material (if any) harm to customers. Since the LIL commissioning, NSPML submits that holdback disallowances relating to the non-winter period are not reflective of actual (if any) harm to customers.

Over the winter period, NLH (and NS Power) generally avoid planned outages with the exception being if weather permits a short outage without risk to the system. The outages during the winter period have predominantly been related to extreme weather conditions and, in NSPML's opinion, have been rectified in a timely manner. Also, in terms of winter reliability, the availability of the NS Block since LIL commissioning has been at a level that is consistent with NS Power's other energy resources. Nova Scotia carries reserve generation equivalent to its largest generation source/unit in order to maintain reliability if a unit (including the NS Block) trips.

e) NSPML believes the determination of whether inclement weather constitutes "exceptional circumstances" is to be determined on a case-by-case basis.

Request IR-02:

Reference: N-01 Application, page 6, lines 7–13; Footnote 4 (page 6); Footnote 15 (page 12); and 2023 NSUARB 175, paras. 137–138.

Preamble: The Application states that energy delivered over the Maritime Link in 2023 through 2025 served approximately 19% of NSPI's customer sales, having an estimated value in the 2023/2024 period of approximately $495 million, which exceeds NSPML's assessment costs of approximately $325 million over the same period by over $165 million.

a. Please provide the 2025 benefit figures referenced in Footnote 4 of the Application which were not yet available at the time of filing.

b. Does the approximately $325 million in assessment costs referenced in the Application incorporate costs associated with the Federal Loan Guarantee (FLG2) repayment obligations? If not, explain why those costs are excluded from the comparison cost of the Maritime Link. If so, please provide a detailed breakdown of how FLG2 costs were incorporated.

c. Provide all workpapers, models, and underlying data used to derive:

i. the approximately $495 million estimated value for the 2023/2024 period (and 2025 as available);

ii. the net benefit figures of over $45 million in 2023, and $125 million in 2024 as cited in the Application at page 12 (and the applicable figure for 2025 if available); and

iii. the 19% of NSPI customer sales figure.

d. Explain how NSPML proposes the Board consider and take into account the increased costs of the Maritime Link in relation to the FLG2 repayment period in relation to addressing the overall rationale for the Holdback and reconcile this with the Board's prior findings

regarding the realignment of benefits of the Maritime Link with costs in connection with the FLG2.

e. Footnote 15 refers to "Chart 3" in Appendix A for a comparison of the Maritime Link benefits and the Annual Assessment, but there is only one figure at Appendix A. Confirm what "Chart 3" refers to and/or provide a copy of the Chart 3 referenced.

Response IR-02:

a) The figure for 2025 is approximately $203,000,000, to be confirmed in the Q1 2026 Maritime Link Benefits Report to be filed by NS Power.

b) The figures referenced are intended to reflect the annual benefits as compared to the annual operating costs.

FLGII refinancing costs are a reprofiling of previously incurred costs that primarily relate to the delayed start of the NS Block and the impact of the war in Ukraine. The design of FLGII includes principal and interest costs from August 2021 through the end of 2024, a period where 100 percent of the NS Block energy has been received. Although the FLG II conceptually repays a significant portion of the operating costs in the referenced years (2023 and 2024) and then reprofiles those costs over 28 years starting in 2025, NSPML believed it was appropriate to continue to apportion those amounts to the applicable referenced years in terms of comparing yearly costs with yearly benefits as, in NSPML's opinion, doing so provides a more accurate representation of operating costs applicable to those years to compare to benefits in those same years.

c)

i) The underlying data was sourced from NS Power's Q4 2023 and Q4 2024 Maritime Link Benefits Reports.

ii) The costs are from NSPML's regulated financial statements for 2023 and 2024.

iii) The reference to the "approximately 19 percent" figure is derived from total customer sales by NS Power in 2023, 2024 and 2025 (FAM Annual Report), as compared to the amount of energy purchased by NS Power (ML Benefits Report) in each of those same years.

Year	NSP Sales [GWh]	ML Energy [GWh]	Percentage
2023	10,434.6	1,938.2	18.6
2024	10,580.6	1,926.3	18.2
2025	10,705.1	2,080.3	19.4
Total	31,720.3	5,944.8	18.7

d) NSPML believes the Board adopted the present Holdback mechanism to protect against performance levels that were reflective of the early days after the Acceleration Agreement was entered. Given FLG II does not impact operating performance (either positively or negatively), it is not apparent to NSPML how (or if) FLG II should be considered in regard to the efficacy of continuation of the holdback mechanism. If the Application was considering the impact of the delayed start of the NS Block, the FLG II could be taken into consideration as a mitigating factor but, as mentioned above, this is not the subject of the present Application.

e) Footnote 15 was included in error. The figures and sources of the applicable information were included in the main text of the Application. Please also see response to (c) above.

Request IR-03:

a) Reference: N-01 Application, page 9.

a. The Application states that as a direct result of NLH's delivery performance prior to commissioning of the LIL, NSPML had been assessed over $30 million in holdback-related disallowances. Provide the full calculation underlying the "$30 million in holdback-related disallowances" figure and explain the relevance of this figure with respect to satisfaction of the Board's conditions for termination of the holdback.

b. Please also explain the relevance of the $10 million penalty assessed against NSPI relating to Renewable Energy Standards (noted as under appeal) to the question of whether the holdback termination conditions have been satisfied.

Response IR-03:

a) Items prior to LIL commissioning, including the ~$30 million in disallowances, are not directly relevant to the Board's conditions for termination. The information is provided for context in that there have been a number of IRs in past proceedings (as well as the present one) relating to the early period that NSPML submits has, to a material extent, been mitigated by FLG II and the $30 million in disallowances.

The $30 million of disallowances referenced, is an accumulated holdback total from 2018 through April 2023. Calculations have been previously determined and settled through the FAM audit and M11009. Please see table below for holdback total by year.

	2018	2019	2020	2021	2022	2023	Total
Total	8.4	4.5	5.9	0.0	8.0	4.2	31.0

b) Similar to part (a) above, the disputed RES penalty is not, in NSPML's opinion, relevant to the assessment of whether the two conditions for termination of the holdback have been satisfied.

Request IR-04:

Reference: N-01 Application, page 11.

The net balance of Deferred Energy dropped below 10% in March 2024 and was essentially eliminated in June 2024.

Preamble: The Board decision in 2023 NSUARB 175 at para 4, states that the holdback will continue until at least 90% of the NS Block (excluding Make-up Energy) is received within a consecutive 12-month period, and the net outstanding balance of undelivered energy is less than 10% of the contracted annual amount of the NS Block.

(a) Please confirm "Deferred Energy" means "undelivered energy". If not, please explain the definition for both.

(b) Please explain NSPML's interpretation of how the 10% threshold of undelivered energy condition applies, specifically:

i. Whether the <10% Deferred Energy threshold must be satisfied on a continuous basis, for any minimum period of time, or merely at a single point in time within or around the 12-month Compliance Period.

ii. Whether NSPML's position is that the 12-month Compliance Period can commence before the Deferred Energy balance falls below 10%, and if so, explain how this interpretation gives independent effect to the Board's second condition.

iii. Why NSPML considers it appropriate for the claimed Compliance Period to include approximately 11 months during which the Deferred Energy balance exceeded

10%, and explain how the Board should interpret this data.

(c) **Please confirm the percentage of "Make-up Balance" included at Appendix C is the same as the percentage of Deferred Energy/undelivered energy. If not, please provide the percentage of Deferred Energy/undelivered energy, by month, from May 2023 to the most current month available**.

Response IR-04:

a) Confirmed. Please refer to the response to NSEB IR-04.

b)

i) NSPML understands the second condition, namely "The net outstanding balance of undelivered energy is less than 10 percent of the contracted annual amount of the NS Block", is independent of the first condition. In other words, both conditions need to be satisfied, and one is not dependent on the conditions of the other. There is no express requirement in the second condition for the Deferred Energy balance to be below 10 percent on a continuous or minimum period of time. NSPML believes that the objective of the second condition was for the Board to have comfort that the Deferred Energy balance, that had built up after the start of the Acceleration Agreement, was reduced to a reasonable level as deliveries normalized. The historical Deferred Energy balance was below 10 percent of contracted volumes during the Compliance Period (specifically March 2024) and was essentially eliminated in June 2024.

ii) NSPML understands the 12-month requirement set out in the first condition, namely "at least 90% of the NS Block, measured in MWh (excluding Make-up Energy), is received during each of 12 consecutive months", can start before the second condition is satisfied. If the Board intended for the Deferred Energy to be lower than 10 percent

before the 12 months at 90 percent could start, NSPML believes the Board would have stated that in the conditions. Also, if the Board had intended for the 12 months to start after the 10 percent was achieved, they would have specifically stated so and they would have made the 10 percent requirement the first condition followed by the 12-month requirement as the second condition.

iii) NSPML suggests that what is appropriate for the Board to consider is that the Deferred Energy balance declined steadily to 9 percent in the Compliance Period as a result of strong deliveries of Make-up Energy throughout 2022, 2023 and 2024. NSPML respectfully suggests that the Board interpret this data as fully satisfying condition two of the requirement to abolish the holdback mechanism. In other words, the net outstanding balance of Undelivered Energy was 9 percent of the contracted energy as of March 2024, which was lower than the 10 percent specified in the condition.

c) Confirmed.

Request IR-05:

Reference: **N-01 Application, p. 15, lines 5–12; Appendix A and Appendix C page 36 of 37.**

Preamble: **The Application states that deliveries were over 100% (both NS Block and Make Up Energy) in every month but September 2023, which fell short due to a planned outage in advance of the winter period, and that the deficit in September 2023 was made up in early October 2023. The Application describes this as a "winter readiness outage." The shortfall in September 2023 is described in the Application as both approximately 6,000 MWh (page 15) and elsewhere as approximately 6,500 MWh (page 16).**

In the table providing the full review of the holdback mechanism in Appendix C, dating back to 2021 and up to December 2025, September consistently has lower Base Contract Delivery percentages, but in September 2024, that amount is 44% rather than the 65/66% that appears in 2023 and 2025.

a. **Describe in detail what the "winter readiness outage" in September 2023 entailed, including:**
    i. **all work items performed during the outage;**
    ii. **the planned vs. duration of the outage in days;**
    iii. **the rationale for scheduling the outage in September rather than an alternative period; and**
    iv. **whether the outage was also conducted in September 2024 and/or September 2025, and if so, whether it includes the same scope, and for what duration.**
b. **Please confirm the exact MWh shortfall in September 2023.**
c. **Confirm that the approximately 6,000 MWh (or 6,500 MWh) shortfall in September 2023 was attributable solely to the planned outage, and**

was not caused, in whole or in part, by any unplanned event, extreme weather or any other intervening circumstances.

d. What portion of the shortfall relates to expected Base Block energy?

e. If the winter readiness outage, or annual planned outage, occurs every September, is the shortfall always around 6,000 MWh? Please confirm the shortfalls for 2024 and 2025 specifically related to this annual outage (if applicable).

f. The Application states later that these planned outages are "typically" taken at times when load and associated replacement energy costs are lower (page 24 lines 22-24). Identify any occasion in the last three years in which this annual planned outage (or any other planned outage) was taken at a time when load and associated replacement energy costs were not lower and explain the circumstances.

Response IR-05:

a) The September 2023 planned outage is described in NSPML's application at p.19 lines 17-27.

i) This routine maintenance includes preventative checks and maintenance on disconnect switches, reactors, capacitors, circuit breakers, valve cooling pump skid, valve cooling de-ionization skid, outdoor coolers, indoor valve climate control facilities, valve inspections and component replacements as required, control and protection calibration, cyber security patching, upgrades, cleaning, backups, etc. along with maintenance at electrode stations/lines, transition compounds, subsea cable termination inspections, overhead line climbing inspections and corrective work identified through prior inspections.

ii) The planned outage dates were:
September 17 - September 26: LIL Bipole outage
September 3 - September 26: LIL Pole 1 outage
September 17 - October 8: LIL Pole 2 outage

iii) Outages for the Labrador Island Link and the Maritime Link are scheduled in the Fall for several operational reasons. Firstly, the Lower Churchill Project assets are only a part of the much wider NL and NS systems and, due to other outages/requirements in both NS and NL systems, there is a requirement for coordination. Secondly, based on historic tendencies, the expected hydrology driving plant output at Muskrat Falls is typically lower than other times of the year. Finally, conducting this annual maintenance work outage ahead of the winter period provides the utilities with the opportunity to maximize winter readiness of these activities addressing the many non-critical and occasionally critical redundancy elements that have appeared through the year prior to the start of the systems critical demand period.

iv) Maintenance outages for the Labrador Island Link and Maritime Link were planned for the Fall of 2024 and 2025 with a similar scope and duration anticipated as in previous years. This is not to say all annual outages will be a similar length, as there will be the requirement from time to time for extended and more detailed maintenance outages. These outages will occur annually for the life of the asset but will occasionally shift in timing and in duration based on both the requirements of the interconnected systems, as well as the required maintenance work for the given planning/execution period.

b) 6,333 MWh. This accounts for the delivery of Make-up Energy in September 2023 of 20,904 MWh.

c) Confirmed.

d) 100 percent is related to Base NS Block. Supplemental Energy is only delivered between November 1 and March 31, with the final Supplemental Energy MWh delivered on March 31, 2026.

e) The amount of energy that is delayed during a winter readiness outage will vary year-to-year since the work to be completed can be different each time. One should also take into account that in September of 2023 there was Deferred Energy delivered as Make-up Energy earlier in the month.

All energy that is delayed due to an outage is fully delivered as Make-up Energy shortly after the outage is completed. Customers always receive the energy as originally contemplated, but it may not be delivered in the same month as originally contemplated. Since the LIL was commissioned in April 2023, deliveries have been steady and all Make-up Energy has been delivered on a timely basis. Before commissioning of the LIL, Deferred Energy often took a long time to be delivered, but this has not been the case since LIL commissioning.

In September 2023, the shortfall compared to the NS Block Contract Amount was 6,333 MWh including the delivery of Make-up Energy, and 27,237 MWh not including the delivery of Make-up Energy. The shortfall from this September outage was all delivered in October 2023 when 71,399 MWh of Make-up Energy was delivered.

In September 2024, the shortfall compared to the NS Block Contract Amount was 31,906 MWh including the delivery of Make-up Energy, and 44,897 MWh not including the delivery of Make-up Energy. The shortfall from this September outage was all delivered as Make-up Energy by December 2024 in accordance with the Energy & Capacity Agreement and, although not a contractual requirement (or guarantee), at a higher economic value to customers (see SBA IR-05).

In September 2025, the shortfall compared to the NS Block Contract Amount was 28,280 MWh including the Make-up Energy balance, and 28,290 MWh not including the Make-up Energy balance. The shortfall from this September outage was all delivered by the end of 2025 as Make-up Energy.

It is noteworthy that the total NS Block Contract Amount for all of 2025 was 1,226,000 MWh and the total amount of energy delivered in the year was 1,225,943 MWh. This annual view shows that customers in Nova Scotia are receiving all the energy expected and any delayed energy deliveries throughout the year are delivered as Make-up Energy in a timely manner that does not harm customers and is in line with the delivery provisions in the Energy and Capacity Agreement.

f) NSPML is not aware of a planned outage that was taken at a time when load and associated replacement energy costs were not expected to be substantially the same or lower due to lower load levels. This is not to say that the value of Make-up Energy will necessarily be higher (or lower) but that the overall outage has been taken during a lower load period. NSPML does not have access to such information but believes it will be made available through NS Power's FAM Audit process through a study called the Similar Value Analysis.

Request IR-06:

Reference: N-01 Application, Sections 3.0 and 4.0; and Appendix A.

Preamble: The Application relies on the 12-month period from May 2023 to April 2024 as the "Compliance Period", during which NSPML asserts that the 90% Base Block energy delivery threshold was met on a consecutive basis, subject to relief being sought from the Board for four months. The Application further states that the net balance of Deferred Energy dropped below 10% in March 2024 and was essentially eliminated in June 2024. The Application also notes that the Deferred Energy that accumulated during post-Compliance Period outages was entirely redelivered by December 25, 2024.

The deferred energy balance data in the Application indicates a higher deferred energy balance during the period from July to December 2024, and that five of the twelve preceding months did not meet the 90% Base Block energy threshold.

(a) Does NSPML contend the 12 months immediately following the claimed Compliance Period (i.e., May 2024 – April 2025) also satisfy both of the Board's termination conditions? If so, please provide the relevant data and explanations for relief required for that period. If not, please elaborate why not.

(b) Does NSPML contend the 11-month period from May 2025 to March 2026 (up until the most available data) satisfies both termination conditions? If so, please provide the relevant data and explanations for relief required for that period. If not, please elaborate why not (regardless that it excludes April 2026 due to timing).

(c) Does NSPML take the position that it is only required to establish satisfaction of the Board's conditions for one historical 12-month window of its choosing, and is not required to demonstrate compliance for any more recent periods?

If so, please provide the basis for that position with consideration to the rationale behind the Board's imposition of the holdback mechanism.

(d) How should the Board interpret the more current operational and delivery information that is now available?

(e) Please explain why the deferred energy balance appears to increase, above the 10% threshold (assuming "Make-up balance (%)" fits that definition) between July and December 2024, in the months following the claimed Compliance Period, and confirm whether the Board's second condition (net outstanding balance less than 10% of contracted annual NS Block) was continuously satisfied throughout that period.

Response IR-06:

a) Yes, NSPML is of the position that the Board intended the holdback mechanism to cease once its conditions were met. NSPML believes that the 12 months following the Compliance Period also satisfies both of the Board's termination conditions. The data and explanations relating to the outages are contained in NSPML's Application and various IR responses.

b) Yes, for the same reasons as set out in a) above, also taking into consideration that NS Block (Base and Supplemental) deliveries in January, February and March of 2026 (which were not provided in the Application) were significantly above the 90 percent hourly threshold in each of those months, that the Make-up or Deferred Energy balance in each of those months was at or near zero during this period, and there was significant Purchased Energy provided.

c) Yes, NSPML's belief is that the Energy Board wanted a period of experience with Newfoundland and Labrador Hydro's operation of its assets and the associated delivery levels prior to ending the Holdback Mechanism and, assumedly, reverting to more

traditional oversight of holding NSPML and NS Power responsible for management of its assets and the associated agreements with NLH.

NSPML believes it is important to acknowledge that 100 percent of the holdback disallowances have related to the performance of an arms-length counterparty that NSPML and NS Power manage through contractual relationships, that since LIL commissioning contractual requirements have been met, winter availability has been strong and, although not a contractual term, there has been minimal (if any) financial impact relating to outages once the value of the associated Make-up Energy deliveries are taken into consideration.

Please also refer to NSEB IR-9, BW IR-7, and SBA IR-2.

In the Board's Decision that set the parameters, the Board recognized recent deliveries were significantly improved[1] and, from NSPML's perspective, deliveries have been aligned with the goals of the overall Lower Churchill Project. They were not perfectly level with NS Block hourly averages 24 hours a day, 356 days a year. That was not NSPML's expectation at the time of negotiating the Agreements, as NSPML specifically negotiated flexibility in hourly deliveries and included language that the parties would continue to seek to optimize delivery profiles (please refer to BW IR-07). NSPML does not believe perfectly level deliveries are/were the Board's expectation. NSPML believes that the Board's desire was to see benefits that were substantially aligned with the parameters of the original deal: renewable energy to offset fossil fuel, capacity that enable the closure (or avoidance) of an additional generation plant, and a significant amount of market energy availability during the complete term.[2]

[1] See paragraphs 73, 83 and 84 of the Board's 2023 Decision in M11009.
[2] Please refer to BW IR-07, NSEB IR-9, NSEB IR-10, and NSEB IR-19.

Importantly, the Board's past decisions have been very consistent in terms of disallowances matching harm to customers. At the start of the Holdback process, there was little question that the extent of delays was having a negative impact on customers and that the holdback amounts during that period were providing a partial contribution to reduce the associated impact. However, there has been negligible impact (slightly negative or slightly positive, but all in line with the negotiated terms) to customers as a result of the outages and associated Make-up Energy deliveries since LIL commissioning and zero negative impact when considering the contractual remedies negotiated. Specifically:

- Make-up Energy deliveries have been timely and during periods where the value of such deliveries are expected to be substantially similar or higher in value. NSPML understands that Bates White and NS Power are in the process of completing a Similar Value Analysis that will shed further light on this item, with an expected availability in early July 2026.[3] NSPML understands that this Similar Value Analysis is only up to the month where the historical Deferred Energy had been made up – that being June 2024.

  In addition to the Similar Value Analysis, NSPML (with the assistance of NS Power) has also reviewed the replacement cost relating to outages in July through October 2024 as compared to when that same energy was delivered as Make-up Energy, which shows the value of the Make-up Energy being more than [redacted] million more than if it was received in a flat delivery profile (please see SBA IR-05 Attachment 1). Not only has there been no harm to customers, but there was a corresponding benefit.

[3] NSPML understanding of this study is to compare the estimated value of energy if it was delivered in a perfectly levelized manner since the Acceleration Agreement (August 2021) as compared to the actual delivery profile, which will include the relevant period to this Application – that being May 2023 through April 2024. Additionally, the Energy & Capacity Agreement is not a financial make whole, it requires timely redelivery which invariably will involve variances in value.

- Capacity of the NS Block has been at a level that allows NS Power (and now the IESO-NS) to treat the NS Block in the same manner as its other generation assets for short-, mid- and long-term planning. Yes, there have been longer outages in the non-winter period that NLH has taken in order to further improve reliable performance, but NSPML submits that the impact of such outages has been minimal if not positive to customers.
- As the NS Block capacity has been integrated into the Nova Scotia system in the same manner as other generation resources, there have been no outages in Nova Scotia as a result of NLH's (or NSPML's) planned (or unplanned) outages since LIL commissioning.
- 100 percent of the contracted renewable energy (the NS Block) has been delivered to the benefit of customers.
- Less relevant to how the Board should view the operation of the Agreements, but interesting in the least, is that since LIL commissioning (and actually since the start of 2022) estimated benefits have exceeded estimated costs – even if 100 percent of the FLGII annual financing costs (~$40M per annum) that are primarily related to the combined impact of the NS Block delay / Ukraine are considered 100 percent attributable to the NLH delivery performance.
- Given when the NLH planned outages are occurring (non-winter period) and that the applicable system operators and the Regional Coordinator have to be comfortable with the approach to such planned outages, NSPML has little ability (or incentive, aside from the implications of the holdback) to accelerate / condense the planned outages that have been taken to date by Newfoundland and Labrador Hydro on its assets – especially when such outages are undertaken to augment performance. This would be a different concern if such outages were taken during the peak load, winter period.
- Finally, the holdback is based on the management, maintenance and performance of the complete Lower Churchill Project of which NSPML has control over the

~$1.7 billion Maritime Link and NLH for $13+ billion in remaining assets. Given performance since LIL commissioning, NSPML believes it is appropriate for oversight to return to a more traditional approach in terms of prudent management of its assets and the contractual relationship with NLH.

d) Please see response to c) above.

e) NSPML believes the intent of the Board's 10 percent threshold was a point in time in order to ensure that the past impacts of deficient deliveries (those that accumulated shortly after the Acceleration Agreement) were essentially caught up. Although the Board knows what it intended, NSPML did not interpret this requirement as a continually running obligation – especially now that Make-up Energy deliveries are occurring in a timely basis.

The increase in amount of Deferred Energy was due to non-winter planned outages that, as set out above, provided a financial benefit to customers as the Make-up Energy was more valuable than the cost of Replacement Energy.

Request IR-07:

Reference: N-01 Application, Section 4.2, Relief for Planned and Unplanned Outages, Table at pages 17-18; and pages 23-25.

Preamble: The Application includes in Section 4.2 a summary table of LIL outages relevant to the claimed Compliance Period, in which NSPML seeks relief from the compliance requirements. At pages 23-25, the Application summarizes the outages that followed the noted Compliance Period.

(a) Please update and supplement the outage summary table to include, for each listed outage, and all additional outages from the period of LIL commissioning to present,::

(i) **the planned outage timeline as originally scheduled, compared to the actual outage start and end dates, or identify if unplanned;**

(ii) **the cause of each outage and whether within the control of NSPML, NLH, or external;**

(iii) **the assets affected (ML, LIL, NLH transmission, other);**

(iv) **when the issue, maintenance, or repair required was first identified and when it was determined an outage was required to address the concern/issue;**

(v) **confirmation of whether the outage was coordinated in accordance with the 30-day outage coordination requirements;**

(vi) **the delivery shortfall attributable to the specific outage, expressed both in MWh and as a percentage of the**

contracted NS Block amount for the relevant month(s);

(vii) **Identify if / how those variances influenced monthly delivery reliability.**

(viii) **the holdback funds value attributable to that outage (as applicable);**

(ix) **the contracted NS Block amount (in MWh) impacted by the outage; and**

(x) **confirmation of whether, in scheduling the outage, NSPML considered the potential impact of the outage on the monthly holdback calculation or the 12-consecutive-month termination test.**

(b) Please provide NSPML's and NLH's outage schedule forecasts for 2023, 2024, 2025 and 2026 (as available prior to each calendar year).

Response IR-07:

a) Data is available from April 14, 2023 up to the end of 2025. As unavailability of the LIL only has an effect on deliveries when the LIL bipole is unavailable, the response is limited to those outages. NSPML did not schedule any of these outages, as the outages all relate to NL Hydro (NLH) assets that NLH is responsible for coordinating with their own System Operator who will in turn coordinate with the Nova Scotia Power System Operator to coordinate outages. NSPML is aware of the outage requests through close engagement with both parties. NSPML has never exerted any influence upon outage dates considering the holdback mechanism. In terms of the following tables, the outages all relate to the collective LIL assets and the attributed MWh volumes and holdback amounts by month are included in the original application.

Planned Outages:

Start Date and Time	End Date and Time	Duration [h]	Cause	Identified Date
6-18-23 16:00	6-26-23 23:00	199	Non-critical punch list, SCADA & electrol line fault indicator	01-May-23
7-10-23 7:00	7-15-23 17:00	130	Preparation for final software update, correction of identified deficiencies, testing SCADA points	01-Jun-23
9-17-23 10:00	9-26-23 19:00	225	Planned annual preventative maintenance	31-Aug-22
3-26-24 6:00	3-27-24 20:00	38	Planned repair of transmission line damage from ice accumulation to preserve reliability.	N/A
5-21-24 12:00	5-30-24 23:00	227	Attempted remediation of transition compound GPR (Cable Switching Sequence issue)	01-Apr-24
7-28-24 15:00	9-1-24 6:00	831	DC Current Transformer Replacements, Transition Station GPR Remediation (attempt), final software load (attempt)	6-1-24 0:00
9-21-24 5:00	10-2-24 23:00	282	Planned annual preventative maintenance	31-Aug-23
10-10-24 7:00	10-11-24 19:00	36	New LIL softare loaded and tested	01-Jul-24
10-18-24 12:00	10-18-24 19:00	7	Cable switching sequence testing	01-Jul-24
9-20-25 5:00	9-30-25 19:00	254	Planned annual preventative maintenance	31-Aug-24

* The March 2024 transmission repair work was the only planned outage undertaken with less than 30 days notice.

Forced Outages - DCCT Transformers (See NSEB IR-16 and IG IR-11):

Start Date and Time	End Date and Time	Duration [h]	Cause
6-1-23 17:00	6-2-23 0:00	7	DC Current Transformer Noise
6-27-23 0:00	6-27-23 9:00	9	DC Current Transformer Noise
12-3-23 9:00	12-3-23 14:00	5	DC Current Transformer Noise / Cable Switching Sequence GPR
12-16-23 22:00	12-16-23 23:00	1	DC Current Transformer Noise / Cable Switching Sequence GPR
12-20-23 13:00	12-20-23 18:00	5	DC Current Transformer Noise / Cable Switching Sequence GPR
12-29-23 4:00	12-29-23 8:00	4	DC Current Transformer Noise / Cable Switching Sequence GPR
2-9-24 12:00	2-9-24 21:00	9	DC Current Transformer Noise / Cable Switching Sequence GPR
3-5-24 8:00	3-5-24 21:00	13	DC Current transformer noise
4-10-24 6:00	4-10-24 11:00	5	DC Current Transformer Noise
4-30-24 7:00	5-4-24 0:00	89	Cable and wiring modifications for DCCT noise mitigation.

Forced Outages - Other

Start Date and Time	End Date and Time	Duration [h]	Cause
8-24-23 12:00	8-24-23 13:00	1	Lightning strike on Labrador Electrode Line
9-14-23 16:00	9-14-23 17:00	1	Faulty ground switch at soldiers pond
3-30-24 7:00	4-8-24 20:00	229	LIL Transmission Line Ice Accumulation
4-17-24 6:00	4-19-24 21:00	63	Continuation of outage to facilitate repairs on damaged towers and lines.
7-21-24 14:00	7-21-24 15:00	1	Transition from Pole 1 outage to Pole 2 outage
7-23-24 13:00	7-24-24 17:00	28	Forest fire in QC
9-13-24 10:00	9-13-24 17:00	7	Occurred during lane changeover trip test on LIL
1-13-25 15:00	1-13-25 23:00	8	Electrode line conductor break and trip on electrode line unbalanced.
1-15-25 6:00	1-19-25 19:00	109	A lightning arrestor failed and needed replacement on P2 and the transmission line tripped on P1 with no permanent damage found.
3-3-25 15:00	3-3-25 18:00	3	Damaged electrode line cross arm in Labrador
4-13-25 7:00	4-19-25 16:00	153	Loading of the final LIL control and protection software that needed to be reverted after a version control error was found
7-13-25 21:00	7-14-25 10:00	13	LIL taken offline as a precaution during forest fire event on the island.
10-7-25 20:00	10-8-25 20:00	24	Found a switch burned at Dowdens Point Electrode Station

b) The below chart shows the planned annual maintenance outages for 2023, 2024, 2025 and prospectively for 2026. As in previous years, there will be other, typically shorter duration planned outages that will be aligned with the outage coordination procedures. The corresponding items are likely known prior to the start of a year but are not scheduled as they are either items that can wait for the appropriate opportunity and/or outages that could only be planned once components were available from the supplier (e.g., awaiting DC current transformers from the manufacturer).

	ML P1	ML P2	LIL P1	LIL P2	LIL BP
2023	September 11 to September 14, 2023	September 14 to September 17, 2023	September 3 to September 26, 2023	September 17 to October 8, 2023	September 17 to September 26, 2023
2024	September 23 to September 26, 2024	September 26 to September 29, 2024	September 16 to September 23, 2024	September 28 to October 6, 2024	September 23 to September 28, 2024
2025	August 21 to August 24, 2025	August 24 to August 28, 2025	August 21 to August 29, 2025	September 6 to September 18, 2025	August 30, 2025 to September 8, 2025
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Request IR-08:

Reference: N-01 Application, page 19, lines 10-11.

The Application states that more than 370 software updates have been completed at the Maritime Link since commissioning in 2018. Of those 370 software updates, please confirm how many required multi-day bipole outages, and provide a list of those multi-day outage events.

Response IR-08:

There were no software updates for the Maritime Link that required multi-day bipole outages, or multi-day outages at all.

Request IR-09:

Reference: N-01 Application, pages 21-22; and Footnote 26.
Preamble: The Application states that April 2024 fell short of the 90% threshold due to extreme weather conditions (specifically icing), causing damage to electrode wings on NLH transmission facilities that had otherwise been in service since 2018; that, the nearest location (Blanc Sablon, approximately 21 km from the nearest failed structure) recorded a maximum wind speed on the day of the failures of 73 km/h, with the wind speed at the approximate time of failure being 64 km/h; and the relevant section of line is designed for a maximum of 50 mm of radial glaze ice, a maximum wind of 120 km/h, and a combined wind and ice load of 25 mm of radial glaze ice with 60 km/h wind.

(a) Please explain why the section of line at issue is designed for a maximum of 50 mm of radial glaze ice and a combined wind and ice load of only 25 mm of radial glaze ice with 60 km/h wind, given the climatic conditions prevalent in the geographic region of the affected facilities, and confirm whether those design criteria were consistent with applicable standards at the time of construction.

(b) Please confirm whether this has been an issue on any other lines, either before the Compliance Period, at any other time during the compliance period, or since the Compliance Period. Please provide specific dates and relevant information regarding the other icing incident(s) (if applicable).

(c) The Application refers to the outage commencing March 30, 2024. Please confirm:

(i) **whether the outage notation in the Application of "13 days" for the March/April 2024 period means that the outage ran from March 30 to April 11, 2024, and if not,**

please provide the precise start and end dates of the outage;

(ii) **whether this entire outage period related solely to the icing incident, and if not, what else caused and/or was completed during this period; and**

(iii) **the quantified reduction in Base NS Block deliveries (excluding Make-up Energy) attributable solely to this icing event and repair in each of March 2024 and April 2024, in MWh (if not already addressed in IR 7).**

(d) Please provide all engineering reports, root cause analyses, and/or post-event corrective action plans prepared by NLH or any third party in connection with the March–April 2024 icing event, including any findings comparing actual weather conditions to design criteria and any recommendations for design upgrades.

Response IR-09:

a-d) As NSPML does not have access to information relating to part (b) of the IR request (information relating to "any other lines"), NSPML requested assistance from Newfoundland & Labrador Hydro (NLH) in replying to this IR. Please see Attachment 1 for NLH's responses, which NSPML affirms through prior knowledge to the extent the responses relate to the Labrador Island Link and Labrador Transmission Assets.

For part (b), NSPML's understanding is that the outages on non-LIL lines had no impact on the assets required to deliver energy from Muskrat Falls through to Nova Scotia.

Q. **Reference: N-01 Application, pages 21-22; and Footnote 26.**

Preamble: The Application states that April 2024 fell short of the 90% threshold due to extreme weather conditions (specifically icing), causing damage to electrode wings on NLH transmission facilities that had otherwise been in service since 2018; that, the nearest location (Blanc Sablon, approximately 21 km from the nearest failed structure) recorded a maximum wind speed on the day of the failures of 73 km/h, with the wind speed at the approximate time of failure being 64 km/h; and the relevant section of line is designed for a maximum of 50 mm of radial glaze ice, a maximum wind of 120 km/h, and a combined wind and ice load of 25 mm of radial glaze ice with 60 km/h wind.

a) Please explain why the section of line at issue is designed for a maximum of 50 mm of radial glaze ice and a combined wind and ice load of only 25 mm of radial glaze ice with 60 km/h wind, given the climatic conditions prevalent in the geographic region of the affected facilities, and confirm whether those design criteria were consistent with applicable standards at the time of construction.

b) Please confirm whether this has been an issue on any other lines, either before the Compliance Period, at any other time during the compliance period, or since the Compliance Period. Please provide specific dates and relevant information regarding the other icing incident(s) (if applicable).

c) The Application refers to the outage commencing March 30, 2024. Please confirm:

i. whether the outage notation in the Application of "13 days" for the March/April 2024 period means that the outage ran from March 30 to April 11, 2024, and if not, please provide the precise start and end dates of the outage;

ii. whether this entire outage period related solely to the icing incident, and if not, what else caused and/or was completed during this period; and

iii. the quantified reduction in Base NS Block deliveries (excluding Make-up Energy) attributable solely to this icing event and repair in each of March 2024 and April 2024, in MWh (if not already addressed in IR 7).

d) Please provide all engineering reports, root cause analyses, and/or post-event corrective action plans prepared by NLH or any third party in connection with the March–April 2024 icing event, including any findings comparing actual weather conditions to design criteria and any recommendations for design upgrades.

A. **a)** Line L3501/2 is the 350 kV HVdc overland transmission line portion of LIL traversing a distance of approximately 1,100 km through three major meteorological loading zones: average, alpine and eastern, with 8 further subcategories related to meteoroidal loads, pollution levels (inland and coastal), and geographic location. The resulting combination lead to the HVdc line consisting of 19 separate loading zones. Eleven tower types were designed to meet the loading requirements, which consist of a specified wind load, ice load, and combination of both applied to the line as per CSA Group standards and utility experience. Structure numbers that sustained damage during the April 2024 incident are str. 1218–1228 and 1232, located on the south coast of Labrador in an average loading zone.[1]

The main root cause of the damage to the tower electrode crossarms, the optical ground wire ("OPGW") tower peaks, and the electrode conductor was an overload failure due to ice loads exceeding the design for this section of the line. Ice loads in the area at the time of the failure were estimated to range from 100–125 mm of radial glaze ice with a density of 0.6 g/cm^3. The area of damage ranged from str. 1218–1232, and the design loads for the line change from "alpine" to "average" loading at str. 1209. The ice load design of the alpine zone is 115 mm of radial ice with a density of 0.5 g/cm3. Temperatures at the nearby weather station at Blanc Sablon were near zero during the time when ice was accumulating on the lines, and rose to 3°C the day of the failures, suggesting that ice shedding causing unbalanced ice loads on the structures could have contributed to the damage of the towers. It is also noted that galloping due to wind could have contributed to the failure by causing cyclic loading on the conductor prior to the failure.

Due to the importance of L3501/2 to the inter-provincial energy grid and the need to understand the line's performance, investigations have been completed for each failure event to recommend actions to mitigate further damage to the line. Recommendations from these investigations were analyzed as part of a 2024–2025 capital project, which implemented some of the recommended

[1] While the design loads for this section of line are slightly below the combined load case specified by CSA 22.3 No. 60826, the final as-built line will meet the CSA 50 year combined loads.

scope items[2], while others required additional analysis and design development. These remaining recommendations are proposed to be actioned in a 2026–2028 capital project, which includes reinforcement of the tower peak and electrode crossarms, reinforcement of the OGPW top plate connection, installation of modified electrode insulator assemblies, and removing sections of the electrode conductor from the towers for installation on wood poles. These solutions will be used on different sections of the line as required to increase the reliability of the LIL and decrease the risk of failure due to ice loading.[3] For further detail on the April 2024 Failure Investigation and the LIL Strengthening Project, please refer to Request IG IR-09, part d, Attachment 1[4] and Attachment 2[5], respectively.

b) Refer to Table 1 for a listing of customer outages caused by extreme icing on Hydro's transmission and distribution lines between 2020 and 2026. Details are provided for outages in the area of the Line L3501/2 structures that sustained damage during the April 2024 incident (str. 1218–1228 and 1232).

Table 1: Outages Due to Extreme Icing (2020-2026)

Date	Location	Description
2021-11-25	Labrador East	On November 25, 2021, at approximately 03:10 hours (AST), Hydro experienced an unplanned outage to customers in Labrador East. At the time of the outage, the region was experiencing significant rain and freezing rain. On the afternoon of November 27, 2021, a helicopter patrol identified the issue on L1301 approximately 70 km west of Happy Valley–Goose Bay. Structure 1010 was found to have a broken pole and broken conductor. The repairs to Structure 1010 were not completed as Hydro proceeded with the planned retirement of L1301 after the 2021-2022 winter season.
2021-01-08	Cartwright	On January 8, 2021, Hydro experienced an outage to two customers in the Cartwright area. Weather conditions were poor in the area at the time and ice accumulation was occurring. Crews found multiple broken distribution poles and approximately 15 downed spans of conductor on the feeder servicing the two customers due to excessive ice accumulation.

[2] Some of the recommended scope items implemented by Hydro through its LIL Engineering Studies Capital Project (2024–2025) included the installation of ice monitoring, optimized alternative suspension clamps, OPGW suspension clamp assemblies, and a reinforced top plate design.
[3] For the section of line containing str. 1218–1228 and 1232, sections of the electrode conductor will be removed from the towers for installation on wood poles, and reinforcement will be completed for the OPGW peaks.
[4] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended March 31, 2025," Newfoundland and Labrador Hydro, April 30, 2025, att. 2, app. B.
[5] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended December 31, 2025," Newfoundland and Labrador Hydro, February 5, 2026, att. 1, app. B.

		Due to site conditions, limited access, and the extent of damage, repairs could not be undertaken immediately; the two impacted customers restored their service through their own backup power source. Repairs were completed and power was restored on February 1, 2021 at 1030 hours.
2022-01-15	Hawke's Bay	On January 15, 2022, at approximately 2152 hours, Hydro experienced an unplanned outage to the communities of Port Saunders, Port aux Choix and Eddies Cove East. Recloser HB3-R1 had operated due to galloping conductor causing line slapping. Snow and ice build up on insulators and framing hardware was also prevalent in the area. Crews determined a section of line 3 could be sectionalized to restore a portion of HBY L3; the remaining section of HBY L3 (Port aux Choix) had experienced several locations of damaged, broken, and downed primary conductor. All remaining customers were restored at 1605 hours.
2022-12-09	Red Bay, Line 2 (L'Anse-au-Loup/Red Bay)	On December 9, 2022 at approximately 1130 hours, Hydro experienced an unplanned outage to customers supplied through a section of Line 2 of the L'Anse-au-Loup distribution system. Weather conditions were poor in the area at the time and ice accumulation was occurring. Upon arrival, crews found damage to power lines and 21 distribution poles, which would need to be repaired or replaced due to excessive ice accumulation. Communications lines were also down in the area. All customers were restored using an emergency mobile generator by December 11, 2022 at approximately 1415 hours.
2023-05-09	Black Tickle	On May 9, 2023 at approximately 1930 hours, Hydro experienced an unplanned outage to its 96 customers in the community of Black Tickle. Weather conditions were poor in the area at the time with high winds and ice accumulation. Crews identified the damages as four broken poles and crossarms with downed primary, neutral, and customer wires. Phone lines were also down in the area. Remaining customers were restored on May 13, 2023 at approximately 2000 hours following final line repairs and the installation of a new transformer.
2024-02-09	LIL	On February 9, 2024 at approximately 1145 hours, the LIL experienced an unplanned outage on Pole 2 due to a "DC Line Protection Fault." That same day, at approximately 1153 hours, the LIL experienced a trip on Pole 1 due to a "DC Line Protection Fault"; the trip occurred while ramping down the LIL to acceptable monopole limits. On February 9, 2024, Pole 1 of the LIL was restored at 2147 hours; Pole 2 was restored at 2201 hours. Preliminary investigations indicate the dc lines flashed over due to ice build up; as a result, both poles were operated in Reduced Voltage Mode until February 12, 2024, to prevent further protection activations while ice build up was present.

2024-03-29	Hampden	On March 29, 2024, at approximately 2005 hours, recloser HA1-R1 in Hampden Terminal Station operated multiple times before staying open, resulting in a loss of power to customers on the Hampden distribution system (including Hampden, Bayside, and the Beaches). Weather conditions at the time included heavy freezing rain resulting in significant icing of trees, lines, and equipment, with numerous trees found to be in contact with lines. All remaining customers were restored at approximately 1515 on March 31, 2024.
2024-03-30	Jackson's Arm	On March 30, 2024, at approximately 0520 hours, recloser JA2-R1 in Jackson's Arm Terminal Station operated multiple times before staying open, resulting in a loss of power to customers fed from Jackson's Arm L2 (including Sop's Arm and Pollard's Point). Weather conditions overnight had included heavy freezing rain resulting in significant icing of trees, lines, and equipment. Numerous trees were found to be in contact with lines, and a structure on Line 2 was broken off at the butt and required replacement. Repairs were completed and all customers restored by 1615 hours on March 31, 2024.
2024-03-31	L'Anse-au-Loup Line 2	On March 31, 2024, at approximately 0140 hours, Hydro experienced an unplanned outage to its 323 customers serviced through L'Anse-au-Loup ("LAL") Line 2, which includes the communities of LAL, Capstan Island, West Saint Modeste, Pinware, and Red Bay. Weather conditions at the time included heavy freezing rain resulting in significant icing of trees, lines, and equipment. Significant ice damage was observed throughout the area, with numerous broken crossarms. All customers were restored by 2000 hours on March 31, 2024.

c)

i. The unplanned outage to the LIL began March 30, 2024 and concluded on April 10, 2024. Pole 2 tripped at 0645 hours on March 30, 2024, resulting in the LIL being available at 450 MW due to the forced Monopole derating. Pole 1 subsequently tripped at 0652 hours that same day on electrode line fault protection, resulting in a forced outage to the LIL. The LIL returned to service at 1042 hours on April 10, 2024 at 450 MW due to a forced Monopole derating. At 2046 hours, April 20, 2024, the LIL became available at 450 MW due to forced Bipole derating.

ii. The unplanned outage to the LIL which began March 30, 2024 and concluded on April 10, 2024 was solely related to the icing incident. Crews and equipment mobilized to site on April 3, 2024. Work began on April 4, 2024 with cleanup of the failed electrode conductor

and securing the OPGW to allow for tower repairs. Repair work which allowed the LIL to return to monopole operation began on April 10, 2024. All repair work, which included replacement of tower steel and electrode conductor, was completed by April 19, 2024.

iii. The quantified reduction in Base NS Block deliveries attributed to this event was 26,513 MWh, measured at the generating point. This number excludes Supplemental and make-up energy.

d) Please refer to Request IG IR-09, part d, Attachment 1[6] and Attachment 2[7].

[6] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended March 31, 2025," Newfoundland and Labrador Hydro, April 30, 2025, att. 2, app. B.
[7] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended December 31, 2025," Newfoundland and Labrador Hydro, February 5, 2026, att. 1, app. B.

Attachment 1

LIL Strengthening Overview



LIL Strengthening Overview

January 2026

newfoundland labrador hydro



Contents

1.0 Introduction 1
2.0 Background 2
3.0 Investigation Overview 4
4.0 LIL Engineering Studies Capital Project (2024–2025) 6
5.0 LIL Strengthening Capital Project (2026–2028) 8
5.1 Evaluation of Alternatives 8
5.1.1 Mid-Span Structures 9
5.1.2 Remove Electrode Line Conductor from Towers and Install on Wood Poles 9
5.1.3 Re-design EL Assembly 10
5.1.4 Reinforcement and Re-design of OPGW Peaks and EL Crossarms 10
5.2 Recommended Alternative 10
5.3 Scope of Work 11
5.4 Project Budget 12
5.5 Project Schedule 12
6.0 Conclusion 13

List of Appendices

Appendix A: Summary of all Failure Investigation Recommendations

Appendix B: LIL Engineering Study – Mid-Span Structure Addition Report

Appendix C: LIL Engineering Study – A1 Electrode Suspension Assembly

Appendix D: LIL Engineering Study – Calculations for OPGW Peak Reinforcement

Appendix E: Wood Pole and Mid-Span Cost Estimates Summary

Appendix F: Analysis of Removing the Electrode Conductor from L3501/2

1.0 Introduction

The Labrador-Island Link ("LIL") is an important transmission line for the provincial energy grid due to its power carrying capacity that is used to deliver a large portion of the winter peak energy and demand to the Island Interconnected System. In total, there have been ten failure events on L3501/2[1] over the past five years; each of these failures was a localized issue affecting a small number of specific transmission line components. These issues have not affected Newfoundland and Labrador Hydro's ("Hydro") ability to provide customers on the Island with reliable service, and all critical repairs resulting from the failures have been completed.

Due to the importance of L3501/2 to the provincial energy grid and the need to understand the line's performance, investigations were completed for each event. The investigations determined that the root cause for many of these events was overloading due to icing and unbalanced icing. The investigation results helped Hydro understand the root cause of each incident so that proactive actions can be taken, where necessary, to mitigate against any impact on the long-term reliability of the LIL. The investigations were led by Hydro's Transmission Engineering team. Third party consultants were brought in as necessary for detailed calculations and modelling, material testing, laboratory simulations, and review of the process, findings, and recommendations. There were numerous recommendations from the investigations that required engineering analysis, design and cost estimation.

Through 2024 and 2025, Hydro undertook a series of studies to address the recommendations within the Investigation Reports in order to mitigate future issues, including:

- Installation of ice and galloping monitoring equipment;
- Further study into damper issues and a new damping system;
- Re-design and cost estimation for replacement of the top plate connections for A2, A4, B1, and B2 towers;
- Installation of alternate suspension clamps;

[1] L3501 refers to Pole 1 and L3502 refers to Pole 2 of the line.

- Design and cost estimation for tower modifications to the peak and electrode crossarms;
- Feasibility analysis and cost estimation for moving the electrode conductor to wood pole structures;
- Feasibility analysis and cost estimation for the installation of mid-span structures; and
- Re-design and cost estimation for an alternate electrode insulator assembly.

The completion of these analyses, designs, and cost estimates determined the scope of the 2026–2028 "LIL Strengthening Capital Project" proposed within this report. The project scope includes reinforcement of the tower peak and electrode crossarms, reinforcement of the Optical Ground Wire ("OPGW") top plate connection, installation of modified electrode insulator assemblies, and removing sections of the electrode conductor from the towers for installation on wood poles. These solutions will be used on different sections of the line as required to increase the reliability of the LIL and decrease the risk of failure due to ice loading.

2.0 Background

Line L3501/2 is the 350 kV High Voltage direct current ("HVdc") overland transmission line portion of the LIL, traversing approximately 1,100 km through three major meteorological loading zones, referred to as average, alpine, and eastern. As shown in Figure 1, the HVdc line has two poles, one OPGW, and two electrode conductors, mounted on steel lattice towers. The electrode conductor is attached to the towers for a part of the line from Muskrat Falls to approximately 384 km southeast of Muskrat Falls, where it diverts to a separate right-of-way ("ROW") on wood pole structures. From there, the electrode line ("EL") travels to an electrode site approximately 16 km away, located in the L'Anse-au-Diable area. sections of L3501/2 without the electrode on the towers do not have electrode crossarms.

The HVdc transmission line corridor has been divided into the three major meteorological loading zones referenced above in combination with eight further subcategories related to loads, pollution levels (inland and coastal), and geographic location. This combination results in 19 separate loading zones. 11 tower types (A1, A2, A3, A4, B1, B2, C1, C2, D1, D2, and E1) were designed to meet the loading requirements, which consist of a specified wind load, ice load, and combination of both applied to the line. The tower types consist of both guyed towers and self-support towers. The tower types are summarized in Table 1 and a depiction of the structure types is shown in Figure 1.

Table 1: Tower Types

Tower Type	Structure Type	Insulator Assembly Type	Deflection Angle Limit (degree)
A1, A2, A3, A4	Guyed	Suspension	0–1
B1	Guyed	Suspension	0–3
B2	Self-Support	Suspension	0–3
C1, C2	Self-Support	Dead-End	0–30
D1, D2	Self-Support	Dead-End	0–45
E1	Self-Support	Dead-End	45–90

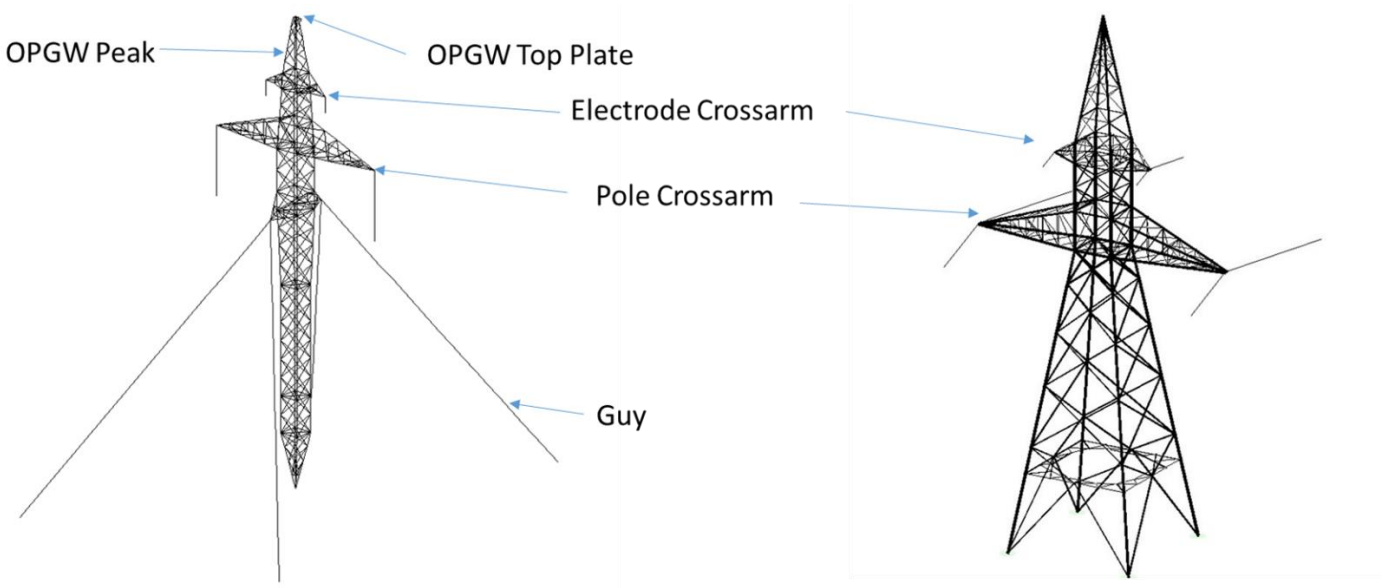


Figure 1: Suspension and Self-Support Tower Diagram

Of the total number of towers on L3501/2, 90% are suspension towers – types A1, A2, A3, A4, B1, and B2. Figure 2 provides a breakdown of the tower distribution on L3501/2, with suspension towers shown in red and self-support towers shown in blue.

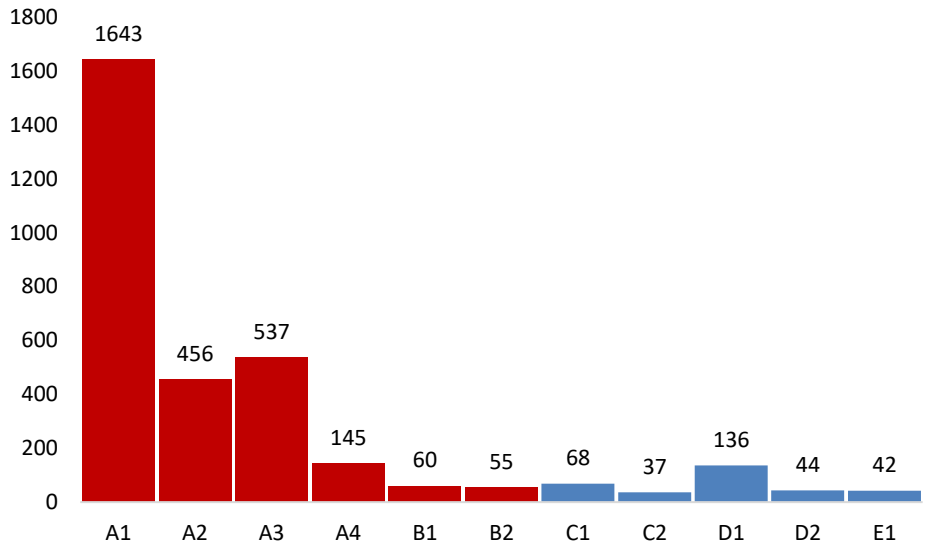


Figure 2: Distribution of Tower Type on L3501/2

3.0 Investigation Overview

Issues with components of the LIL during ice events over the past five years have primarily caused damage to the electrode crossarms, OPGW tower peaks, and the electrode conductor. Investigations determined that the root cause of the damage for seven of the 10 events was overloading due to significant ice accumulation and unbalanced ice loads from ice shedding; the root cause of failure for the remaining three investigations was determined to be galloping.[2] Information regarding six of the seven events due to ice loading is shown in Table 2. All these events occurred on A1 type towers in sections of the line with the electrode conductor attached to the tower. The maximum design ice load case for this section of the line is 50 mm of radial glaze ice with a density of 0.9 g/cm3 (equivalent to 11.9 kg/m on the electrode conductor); all events shown in Table 1 exceeded the design ice load case, except for the event in Southern Labrador in December 2022. The unbalanced ice load cases include 70% of the maximum ice back span[3], with 100% of the maximum ice ahead span on a tower (and vice versa) for one wire at a time, while all other wires have 100% of the maximum ice load on both spans.

[2] Implementation of recommendations for two of these failures is complete; a capital project is proposed for 2026 to address recommendations from the final investigation. For further information, please refer to Failure Investigation Report – L3501/2 Pole Assembly Turnbuckle Failure – Failure Event February 2021 in Labrador; and L3501/2 Failure Investigation – Turnbuckle Failures Structure 1872, 1806 and 1014.

[3] Back span refers to the section of line that runs behind a specific tower, opposite the ahead span.

Table 2: Summary of Events

Date	Location	Number of Damaged EL Crossarms	Number of Locations of Damaged EL Conductor	Number of Damaged OPGW Peaks	Number of Damaged OPGW Top Plates	Approximate Radial Equivalent Ice Thickness (mm)[4]	Approximate Weight of Ice on EL Conductor (kg/m)
Jan–2021	Central Labrador	12	34	0	0	54–65	13.1–17.8
Dec–2022	Central Labrador	0	3	0	0	70–72	20.6–21.6
Dec–2022	Southern Labrador	0	0	2	0	20–30	2.0–3.8
Feb–2024	Central Newfoundland	0	0	8	0	50–75	9.1–19.0[5]
Mar–2024	Southern Labrador	16	17	4	0	79–99	25.2–37.4
Jan–2025	Central Labrador	4[6]	2	0	0	55–60	10.8–12.4

The remaining event due to ice loading occurred during an icing event in Western Newfoundland in December 2022, which caused damage to two OPGW top plates on two A3 towers. During this event, the top plate connections failed and caused deformation and damage to the top plate and the hanger bracket on two A3 towers. While there was approximately 70 mm of icing on the lines with a density of 0.9 g/cm3 (17.9 kg/m) at the time of the event, this is less than the design ice load case for this tower type, which is for 75 mm of radial glaze ice with a density of 0.9 g/cm3 (20.3 kg/m). The root cause of this issue was determined to be a design error – the connection capacity of the top plate and hanger bracket was not sufficient for the vertical design load from ice. A contractor was engaged to reinforce the top plate connection of the 61 critical A3 towers; this work was completed in 2024.

A complete list of the recommendations on ice related issues can be found in the Investigation Reports listed in Table 2, and the status of each recommendation is summarized in Appendix A. Some recommendations have been addressed through capital projects, while other recommendations require more detailed analysis and engineering, and therefore remain ongoing.

[4] Ice loads converted to radial equivalent thickness based on a density of 0.9 g/cm3 to compare to design ice load.
[5] The approximate weight of ice per m (kg/m) was on the OPGW in this event.
[6] The icing event caused damage to three electrode crossarms; the fourth electrode crossarm was damaged during planned ice removal activities.

Table 3: Investigation Reports

Report Title	Document Number
Failure Investigation Report – TL3501/2 Tower and Conductor Damage Icing Event January 2021 in Labrador[7]	ILK-EG-ED-6200-TL-H15-0001-01
L3501/2 Failure Investigation – OPGW Tower Peaks – Structure 1230 and 1231[8]	ILK-EG-ED-6200-TL-H15-0004-01
L3501/2 Failure Investigation – OPGW Top Plates – Structure 2135 and 2136[9]	ILK-EG-ED-6200-TL-H15-0005-01
L3501/2 Failure Investigation – OPGW Tower Peaks - Central Newfoundland[10]	ILK-EG-ED-6200-TL-H15-0006-01
L3501/2 Failure Investigation – Ice Storm Southern Labrador[11]	ILK-EG-ED-6200-TL-H15-0007-01
Failure Investigation Report – Icing Event December 2022 in Labrador[12]	ILK-EG-ED-6200-TL-H15-0008-01
L3501 Failure Investigation – Ice Storm Central Labrador – January 2025[13]	ILK-EG-ED-6200-TL-H15-0010-01

4.0 LIL Engineering Studies Capital Project (2024–2025)

A 2024–2025 capital project was executed based on the recommendations within the Investigation Reports to mitigate future events. A summary of the scope items included within this capital project, and their status, is detailed below.

Ice Monitoring

A total of three sensors were installed on structures 514 (central Labrador), 1224 (southern Labrador) and 2597 (central Newfoundland) in 2025 to monitor ice load and galloping.

Damping system

In 2024, an engineering consultant was engaged to provide an updated damper technical specification based on past issues. A damper supplier was also engaged to determine the quantity and type of dampers to provide adequate damping for the line. Vibration equipment was installed on the line in 2024 to gather information required for the damper study. The equipment experienced issues due to severe weather, and new equipment was installed in 2025 to continue monitoring and gather additional information. A recommendation for a new damping system is expected in 2026.

[7] Filed within "Reliability and Resource Adequacy Study Review – Labrador-Island Link Failure Investigation Reports," Newfoundland and Labrador Hydro, May 31, 2021.
[8] *Supra,* f.n. 6.
[9] *Supra,* f.n. 6.
[10] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended March 31, 2025," Newfoundland and Labrador Hydro, April 30, 2025, att. 1, app. B.
[11] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended March 31, 2025," Newfoundland and Labrador Hydro, April 30, 2025, att. 2, app. B.
[12] *Supra,* f.n. 6.
[13] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended September 30, 2025," Newfoundland and Labrador Hydro, October 31, 2025, att. 1, app. B.

Top Plate Design

Analysis was completed in 2024 to determine the towers that were susceptible to top plate connection issues due to design error. 61 A3 towers and 2 A4 towers were determined to be critical and should be fixed as soon as possible. A contractor was engaged to reinforce the top plate connection of the 61 critical A3 towers. This work was completed in 2024.

An engineering consultant was engaged to complete the reinforcement design of the other tangent tower types (A2, A4, B1, and B2). This design and cost estimate were completed in 2025. There are two A4 towers that require top plate reinforcement; tower reinforcement will be purchased and installed as required. Installation work to replace the two remaining top plates is expected to begin in 2026, with expected completion in 2028.

Engineering analysis determined that the other structures, which includes A2, A3, A4, B1, and B2 towers that did not have top plate reinforcement work completed, may experience bending of the top plate that would not result in failure of the OPGW connection or an outage of the line. To date, there have been minimal issues with other tower types; these structures could be repaired as part of annual maintenance if required. Hydro will keep the alternate design in stock as a precaution and will schedule installation on other tower types as required if deformation of the top plate occurs.

Optimizing Clamp Designs

Three alternative suspension clamps were installed on the electrode conductor at 10 structures in 2024, and will be inspected annually for performance. These alternative clamp designs are intended to reduce static and dynamic stresses at the conductor support point, protecting the conductor against the effects of oscillations.

An alternative OPGW suspension clamp assembly was designed and ordered in 2024 and will be installed as required during maintenance and repairs. These clamps have been installed in some areas in 2025.

Assessment, re-design and cost estimation for the electrode suspension assembly[14] was completed in 2025 based on findings from the investigations. The assembly was re-designed to increase its length to

[14] The assembly consists of the hardware and insulators between the tower and conductor.

allow for a larger swing angle, and decrease the force on the tower and conductor from unbalanced icing.

Tower Analysis and Design Modifications

An ice study was completed in 2024 to determine the ice load levels experienced on the geographic areas of the line where failures occurred, and has produced updated design ice loads. An engineering consultant was engaged to complete tower analysis and design modifications based on the updated design ice loads and provide a cost estimate for the implementation of these design changes.[15]

Tower reinforcement would require the replacement of the tower peak and electrode crossarms with reinforced sections and add additional bracing to the tower cage. Moving the electrode conductor to wood pole lines was technically feasible in some locations and would also reduce the loads on the tower. Installation of mid-span structures to reduce the loads on the towers were also assessed; however, the reduction was not sufficient to address the overloading due to the ice loading, and tower reinforcement was determined to be a better technical solution.

Actions to address these recommendations are planned in the capital project discussed in Section 5.0.

5.0 LIL Strengthening Capital Project (2026–2028)

5.1 Evaluation of Alternatives

For the LIL Strengthening Capital Project proposal, four alternatives were evaluated to address issues with the OPGW peak, the electrode crossarm and the electrode conductor:

- Installation of mid-span structures;
- Removal of electrode conductor from the towers and installation on wood poles;
- Re-design of the electrode assembly; and
- Reinforcement and re-design of the OPGW peak and electrode crossarm.

Note that some of these alternatives can be implemented concurrently; for example, the electrode conductor can be moved to a wood pole line, and the OPGW peaks can be reinforced. The electrode

[15] The consultant reports for the Mid-Span Structure Addition, A1 Electrode Suspension Assembly, and Calculations for OPGW Peak Reinforcement are provided as Appendix B, C and D, respectively.

crossarms can be reinforced, and the electrode assembly can be re-designed and installed. Additionally, as these alternatives are recommended for multiple line sections and hundreds of towers, different alternatives may be recommended for different sections. All estimated costs per structure include allowance for mobilization and demobilization based on 230 structures. The cost estimate for the installation of a wood pole line or mid-span structures is provided as Appendix E. Additional detail related to the analysis to remove the electrode conductor from L3501/2 is provided as Appendix F.

5.1.1 Mid-Span Structures

This alternative would include the installation of mid-span structures to reduce the ice loads on the towers. Analysis determined that the reduction in loading on both the electrode crossarm and OPGW peaks is not sufficient to address the overstress due to increased ice and unbalanced ice loads. As a result, this alternative was determined not to be technically feasible.

5.1.2 Remove Electrode Line Conductor from Towers and Install on Wood Poles

This alternative would remove the EL from towers and install on a wood pole line. In addition to reducing the ice loads on the towers, there are several other advantages specific to this alternative. Due to the smaller size of the wood poles and the separation from the pole conductors, any required repairs to the electrode conductor or associated structures are made easier. The electrode conductors would also be at a lower elevation and likely to accumulate less ice.

Disadvantages for this alternative include the requirement to build a new ROW parallel to the existing L3501/2 ROW. This new ROW would have to be assessed for constructability and conflicts with existing infrastructure or land ownership.[16] Additionally, the removal of the electrode conductor will not address the issues with unbalanced ice loads on the OPGW.

The estimated cost of this alternative per LIL tower (not per wood pole structure) is approximately $101,562. Due to the difference in span length, approximately five wood pole structures are required for each tower span.

[16] The wood pole line will have shorter span lengths and may not be able to transverse obstacles such as waterbodies and large elevation changes.

5.1.3 Re-design EL Assembly

This alternative would include the installation of a newly designed electrode assembly on the electrode crossarm. Two options were designed under the 2024-2025 project: one that can be installed on the existing electrode crossarms, and one that can be installed on the newly designed, reinforced electrode crossarm. Both options increase the length of the electrode assembly and will allow more longitudinal swing under unbalanced ice loads, decreasing the chance of contact with the insulator and deformation of the conductor. This alternative would decrease the longitudinal load on the crossarm and address the forces on the conductor at the suspension clamp; however, loads on the electrode crossarm will not be reduced enough to address the high unbalanced ice loads, and it does not address the loads on the OPGW peak.

The estimated cost of this alternative per structure, including installation, is $10,000 for the assembly that can be installed on the existing electrode crossarms, and $29,000 for the assembly and newly designed, reinforced electrode crossarm.

5.1.4 Reinforcement and Re-design of OPGW Peaks and EL Crossarms

This alternative would include replacing the existing electrode crossarms and OPGW peak with new reinforced sections and adding reinforcing members to the existing cage.[17,18] The reinforcement is specifically designed for the ice and unbalanced ice loads that were encountered during past events, and installation can be completed during a monopole outage. This alternative will mitigate issues with both the electrode crossarm and OPGW with a relatively low cost per structure; however, it will not address the electrode conductor failures.

The estimated cost of this alternative per structure, including installation, is $36,000 for the OPGW peak and the electrode crossarm, and $29,000 for only the electrode crossarm.

5.2 Recommended Alternative

The recommended alternative is the Reinforcement and Re-design of OPGW Peaks and EL Crossarms with Re-design of the EL Assembly for most sections, with two exceptions. The combination of these alternatives will address issues with the OPGW peak, the electrode crossarm and the electrode

[17] The cage is the section of the tower located between the main tower body and the peak.
[18] It was determined that due to the amount of reinforcing steel required on the crossarms and peak, installation of new sections would be more cost effective than adding reinforcement to the existing sections.

conductor, resulting in the best alternative for increased reliability. This alternative is also considerably less costly than the installation of Mid-Span Structures or the option to Remove EL Conductor from Towers and Install on Wood Poles.

The first exception to the recommended alternative is for the section of line from structure 1209 to 1229 in southern Labrador. For this section, the recommended alternative is to Remove EL Conductor from Towers and Install on Wood Poles, and the Reinforcement and Re-design of the OPGW Peaks only. This section of line has experienced higher icing than any other section considered for strengthening, and is located adjacent to a section (structures 1110 to 1209) designed for much higher ice loads.[19] Currently the EL taps off the steel lattice transmission line at structure 1229 and travels to the electrode site on a wood pole line; this alternative would require one tap from the line at structure 1209. This area also has light vegetation and would require minimum clearing.

The second exception to the recommended alternative is for the section of line from structure 1230 to 1245 and structure 2520 to 2629. In these sections, the recommended alternative is the Reinforcement and Re-design of the OPGW Peaks only, as these sections of line do not have electrode conductor or electrode crossarms.

5.3 Scope of Work

The project scope includes procurement and installation work on a total of 309 Type A1 towers, as follows:

- Replacement of OPGW peaks, EL crossarms, and EL assemblies for 186 towers:
    - 18 A1 towers from structure 114 to 131
    - 33 A1 towers from structure 208 to 242
    - 37 A1 towers from structure 329 to 369
    - 57 A1 towers from structure 406 to 466
    - 41 A1 towers from structure 499 to 541

[19] The maximum design ice load case for the section of line from structure 1209 to 1229 is 50 mm of radial glaze, while structures 1110 to 1209 are designed for 115 mm of radial rime ice.

- Replacement of OPGW peaks, and removal of EL conductor and installation on wood poles for 18 towers:
    - 8 A1 towers from structure 1210 to 1228
- Replacement of OPGW peaks only for 105 towers:
    - 16 A1 towers from structure 1230 to 1245
    - 89 A1 towers from structure 2531 to 2628

Structures were selected based on priority, with the highest priority being the sections of line that have experienced multiple events; medium priority are locations that have experienced a single event; and low priority are locations that have not experienced failures but have similar characteristics[20] to locations where issues have been experienced.

The project scope will also include material procurement for reinforcement of the OPGW top plate connection for all affected tower types (A2, A3, A4, B1, and B2), and installation of the solution on two A4 towers. The towers selected to be fixed were determined to be at risk of bolt failure under maximum ice loads. The extra material will be procured for towers that are at risk of top plate bending. Although these plates will have to be replaced if bending occurs, there is no risk of outage from this issue, and the repairs are not urgent.

5.4 Project Budget

The estimated cost for this project is $21,800,000, with $8,700,000 in 2026, $6,700,000 in 2027 and $6,300,000 in 2028.

5.5 Project Schedule

The construction schedule for the 2026-2028 project is shown in Table 4. Procurement of all material will occur in year 1, and installation work will take place over a three-year period based on priority.

[20] Similar characteristics include loading zones, tower types, icing, elevation, or elevation changes.

Table 4: Project Schedule

Activity	Date
Procurement:	
Materials ordered.	Year 1
Top Plate Reinforcement:	
2 A4 towers, structure 1831 and 1821	Year 1
Replacement of OPGW Peaks, and Removal of EL Conductor and Installation on Wood Poles:	
18 A1 towers, structure 1210 to 1228	Year 1
Replacement of OPGW Peaks only:	
16 A1 towers, structure 1230 to 1245	Year 1
89 A1 towers, structure 2531 to 2628	Year 2
Replacement of OPGW peaks, EL crossarms, and EL assemblies:	
41 A1 towers, structure 499 to 541	Year 1
37 A1 towers, structure 329 to 369	Year 2
18 A1 towers, structure 114 to 131	Year 2
33 A1 towers, structure 208 to 242	Year 3
57 A1 towers, structure 406 to 466	Year 3

6.0 Conclusion

There have been 10 failure events on L3501/2 over the past five years. These failures were localized issues, affecting a small number of transmission line components. Due to the importance of L3501/2 to the provincial energy grid and the need to understand the line's performance, investigations have been completed for each event to recommend actions to mitigate further damage to the line. Investigations determined that the root cause of the damage for seven of the 10 events was overloading due to significant ice accumulation and unbalanced ice loads from ice shedding. Recommendations from these investigations were analyzed as part of a 2024–2025 capital project, which implemented some of the recommended scope items, while others required additional analysis and design development. These remaining recommendations are proposed to be actioned in a 2026–2028 capital project. The project scope includes reinforcement of the tower peak and electrode crossarms, reinforcement of the OGPW top plate connection, installation of modified electrode insulator assemblies, and removing sections of the electrode conductor from the towers for installation on wood poles. These solutions will be used on different sections of the line as required. The work proposed in the project will increase the reliability of the LIL and will decrease the risk of failure due to ice loading.

Appendix A

Summary of all Failure Investigation Recommendations



Summary of all Failure Investigation Recommendations

Document Number	Report Title	Recommendation	Status	Comments
ILK-EG-ED-6200-TL-H15-0001-01	Failure Investigation Report - TL3501/2 Tower and Conductor Damage - Icing Event January 2021 in Labrador	Monitor ice by line patrol	Addressed	• Lines are monitored regularly during the winter by helicopter line patrol. Additional helicopter patrols are scheduled as needed after an icing event.
		Install real time ice monitoring on lines	Ongoing	• One test span and weather monitoring station installed, another to be installed in 2026. • Three sensors were installed on structures 514 (central Labrador), 1224 (southern Labrador) and 2597 (central Newfoundland) in Q3 of 2025 to monitor ice load and galloping.
		Develop procedure of mechanical ice removal	Addressed	• Procedure has been implemented for Engineering, Operations, and Helicopter pilots.
		Tower modifications to peak and electrode crossarms to increase tower capacity	Ongoing	• Ongoing through LIL Strengthening Capital Project.
		Determine an alternate damping design	Ongoing	• In 2024, an engineering consultant was engaged to provide an updated damper technical specification based on past failures. A damper supplier was also engaged to determine the quantity and type of dampers to provide adequate damping for the line. • Vibration equipment was installed on the line in Q4 of 2024 to gather information required for the damper study. The equipment experienced issues due to severe weather, and new equipment was installed in Q3 of 2025 to continue monitoring and gather additional information. • A recommendation for a new damping system is expected in 2026.
		Install air spoilers to reduce galloping	Addressed	• Air flow spoilers have been installed in areas with identified galloping issues. Spare air flow spoilers are on hand for any further installations as required.
		Modify electrode insulator assembly to reduce load on tower and conductor	Ongoing	• Ongoing through LIL Strengthening Capital Project. • Three alternative suspension clamps were installed on the electrode conductor at ten structures in Q3 of 2024, and will be inspected yearly for performance. • Assessment, re-design and a cost estimate for the electrode suspension assembly was completed in Q3 of 2025.
ILK-EG-ED-6200-TL-H15-0004-01	L3501/2 Failure Investigation - OPGW Tower Peaks - Structure 1230 and 1231	All recommendations covered in other reports		
ILK-EG-ED-6200-TL-H15-0005-01	L3501/2 Failure Investigation - OPGW Top Plates - Structure 2135 and 2136	Redesign top plate connection on A3 towers	Addressed	• Redesign completed by consultant in 2023.
		Fix all critical A3 tower top plates	Addressed	• A contractor was engaged to reinforce the top plate connection of the 61 critical A3 towers. This work was completed in 2024.
		Check and redesign all other tower type top plate connections	Addressed	• An engineering consultant was engaged to complete the reinforcement design of the other tangent tower types (A2, A4, B1, and B2). This design and cost estimate were completed in Q3 of 2025.
		Fix all other critical tower type top plates	Ongoing	• Ongoing through LIL Strengthening Capital Project. • Two A4 towers require top plate reinforcement; tower reinforcement will be purchased and installed as required. Installation work is expected to be completed in 2026. • To date, there have been minimal issues with other tower types. Hydro will keep the alternate design in stock as a precaution and will schedule installation on other tower types as required if deformation of the top plate occurs.
ILK-EG-ED-6200-TL-H15-0006-01	L3501/2 Failure Investigation - OPGW Tower Peaks - Central Newfoundland	All recommendations covered in other reports		
ILK-EG-ED-6200-TL-H15-0007-01	L3501/2 Failure Investigation - Ice Storm Southern Labrador	Investigate radiography to evaluate conductor issues.	Ongoing	• Investigation ongoing. Pilot project in 2025, but looking for a solution that will detect damage at the clamp.
ILK-EG-ED-6200-TL-H15-0008-01	Failure Investigation Report - Icing Event December 2022 in Labrador	Determine protocols for evidence collection	Addressed	• Protocols are in place including check lists for damage and icing observations.
		Inspect conductor at suspension clamps to determine if different clamp types cause wear	Ongoing	• An alternative OPGW suspension clamp assembly was designed and ordered in 2024 and will be installed as required during maintenance and repairs. These clamps have been installed in some areas in 2025.
		Move electrode to conductor to wood pole structures	Ongoing	• Ongoing through LIL Strengthening Capital Project.
		Install mid-span structures to reduce loads	Ongoing	• Ongoing through LIL Strengthening Capital Project.
ILK-EG-ED-6200-TL-H15-0010-01	L3501/2 Failure Investigation - Ice Storm Central Labrador - January 2025	Investigate thermal and mechanical methods to reduce ice accumulation	Ongoing	• Mechanical method known, and procedure in place. Thermal options being explored internally but may not be feasible.

Appendix B

LIL Engineering Study – Mid-Span Structure Addition Report



TETRA TECH

LIL Engineering Study – Mid-Span Structure Addition Report

Newfoundland and Labrador Hydro Report No. ILK-TT-CD-6200-TL-H15-0003-01
TT Document Number 705-2579500100-REP-G0002-00
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NSPML 2026 Holdback Mechanism IG IR-09 Attachment 1 Page 27 of 195

TABLE OF CONTENTS

1.0 INTRODUCTION **1**

2.0 STUDIED TOWER LOCATIONS **1**

3.0 METHODOLOGY **2**

3.1 S4-502 (2469) 2

3.1.1 Wind and Weight Span 3

3.1.2 Maximum Structure Usage 4

3.1.3 Discussion 5

3.2 S4-576 (2543) 5

3.2.1 Wind and Weight Span 5

3.2.2 Maximum Structure Usage 6

3.2.3 Discussion 7

3.3 S4-598 (2565) 7

3.3.1 Wind and Weight Span 7

3.3.2 Maximum Structure Usage 8

3.3.3 Discussion 9

3.4 S1-318 (319) 9

3.4.1 Wind and Weight Span 9

3.4.2 Maximum Structure Usage 10

3.4.3 Discussion 13

3.5 S1-370 (371) 13

3.5.1 Wind and Weight Span 13

3.5.2 Maximum Structure Usage 14

3.5.3 Discussion 15

3.6 S1-307 (308) 15

3.6.1 Wind and Weight Span 15

3.6.2 Maximum Structure Usage 16

3.6.3 Discussion 17

3.7 Reinforced Model Overstresses 17

3.7.1 Tower S4-576 (2543) Reinforced Model Overstresses 17

3.7.2 Tower S1-307 (308) Reinforced Model Overstresses 18

4.0 CONCLUSIONS **19**

LIST OF TABLES

Table 1: Studied Tower Locations 1
Table 2: Wind & Weight Span Comparison for S4-502 (2469) 3
Table 3: Maximum Structure Usage Comparison for S4-502 (2469) 4
Table 4: Wind & Weight Span Comparison for S4-576 (2543) 5
Table 5: Maximum Structure Usage Comparison for S4-576 (2543) 6
Table 6: Wind & Weight Span Comparison for S4-598 (2565) 7
Table 7: Maximum Structure Usage Comparison for S4-598 (2565) 8
Table 8: OPGW Wind & Weight Span Comparison for S1-318 (319) 9
Table 9: Maximum Structure Usage Comparison for S1-318 (319) 10
Table 10: OPGW Wind & Weight Span Comparison for S1-370 (371) 13
Table 11: Maximum Structure Usage Comparison for S1-370 (371) 14
Table 12: OPGW Wind & Weight Span Comparison for S1-307 (308) 15
Table 13: Maximum Structure Usage Comparison for S1-307 (308) 16
Table 14: Load Cases Comparison for S4-576 (2543) (As built VS Envelope Loads) 17
Table 15: Load Cases Comparison for S1-307 (308) (As built VS Envelope Loads) 18

LIST OF FIGURES

Figure 1: Profile for S4-502 (2469) 3
Figure 2: Overstressed Members Element Labels (No Electrode) 4
Figure 3: Profile for S4-576 (2543) 6
Figure 4: Profile for S4-598 (2565) 8
Figure 5: Profile for S1-318 (319) 10
Figure 6: Overstressed Members Element Labels (Electrode Strung) 12
Figure 7: Profile for S1-370 (371) 14
Figure 8: Profile for S1-307 (308) 16
Figure 9: Reinforced Overstressed Member Element for S4-576 (2543) 17
Figure 10: Reinforced Overstressed Member Element for S1-307 (308) 18

1.0 INTRODUCTION

NL Hydro has experienced several performance issues for the Labrador-Island Transmission Link, +/- 350 kV HVDC. Performance issues include the following:

- Electrode conductor failure
- Electrode cross-arm structural failure
- Suspension clamp slippage on electrodes and OPGW
- OPGW cantilever failing and disconnecting from peak
- Tower peaks buckling

This technical memo discusses potential improvements that may be made by addition of mid-span structures. The introduction of mid-span structures on an existing line will reduce tower loading by changing the wind and weight span. Mid-span structures may also improve a back/ahead weight span imbalance (largely applicable to applied longitudinal loads).

2.0 STUDIED TOWER LOCATIONS

Six tower locations were inspected for potential candidates for mid-span structure additions. Locations were chosen to have unique characteristics that may represent a good sample space for potential highly loaded tower positions. The tower names are as per the PLS-CADD models provided by NL Hydro on January 15, 2025.

Table 1: Studied Tower Locations

Tower Location	Structure Number	Reason for Selection
S4-502	2469	Large span imbalance, back span coincident with a wet, low-lying area. No electrode strung.
S4-576	2543	Long weight spans both sides of the tower. Creates high vertical ice load. No electrode strung.
S4-598	2565	Large span imbalance, both spans running downhill relative to increasing stationing. No electrode strung.
S1-318	319	Long spans both sides of tower, long weight spans on both sides of the tower. Creates high transverse wind loads and high vertical ice loads.
S1-370	371	Ahead span crosses an area where the terrain is lower than both adjacent towers making it difficult to spot a new mid-span tower without experiencing uplift.
S1-307	308	Large span imbalance, both spans running uphill relative to increasing stationing. Similar to S4-598 (2565) but with strung electrodes.

3.0 METHODOLOGY

The following PLS-CADD modelling was completed for each tower location and is discussed in the following sections.

- The additional load cases from the tower A1 tower reinforcement scope were added to the Criteria Structure Loads table as follows:
    - UBI EL1 63 mm 70/100%
    - Ice Load 63 mm
    - UBI G 50 mm 100/50%
    - UBI G 55 mm 100/70%
    - UBI G 70 mm (50 mm on Pole) 100/80%
    - Ice Load 70 mm (50 mm on Pole)
- Existing load cases from the original design as per design loading drawings ILK-SN-CD-6200-TL-DD-0065-01-C1 & ILK-SN-CD-6200-TL-DD-0065-02-C1 were maintained.
- The subject existing tower model was replaced with a tower model that was created under the A1 tower reinforcement scope. The new model has all information verified against fabrication & insulator hardware drawings, connection capacities are added, and redundant members added.
- The load combination file for the existing tower configuration was output from the PLS-CADD model using level 2 analysis. Subject tower usage was calculated.
- One mid-span structure was added on the span that had the higher one-sided weight span for the MAX ICE weather condition to assist in balancing the weight spans on the subject structure. Mid-span structure heights were selected generally to provide the same suspension elevations as the subject tower to effectively reduce weight span and avoid uplift. The load combination file for the subject tower was output. Subject tower usage was calculated.
- If relevant for the subject tower position, a second mid-span structure was added on the other side of the subject tower to further reduce the wind and weight span. Subject tower usage was calculated.
- Finally, for comparison, the existing configuration load combination was run for a reinforced A1 tower.

3.1 S4-502 (2469)

Tower position S4-502 (2469) was chosen due to the presence of a significant ahead/back weight span imbalance with a ratio of approximately 1.63 for the ‘Max ice’ weather case. Weight span imbalances amplify unbalanced icing cases longitudinal loads relative to towers in a balanced ahead/back weight span condition.

This structure position does not have the electrode strung however it appears that when the A1 tower is used in this configuration, the span lengths are increased which causes higher loading locally in the peak. Tower type A1 peak failures have occurred in this configuration, see L3501/2 Failure Investigation (Doc No. ILK-EG-ED-6200-TL-H15-0006-01).

3.1.1 Wind and Weight Span

Table 2: Wind & Weight Span Comparison for S4-502 (2469)

Condition	Total Wind Span	Back Weight Span*	Ahead Weight Span*	Total Weight Span*
Existing	380 m	265 m	163 m	428 m
One mid-span structure	256 m	140 m	158 m	298 m
Change	-124 m (33%)	-125 m	-5 m	-130 m (30%)

* Because maximum overstresses are in the peak, the OPGW weight spans are reported.

In the figure below, the blue catenaries represent the existing condition with no mid-span structures at 'Max ice' MAX SAG FE. The yellow catenaries represent the catenaries when one mid-span structure is added "S4-501A", also at 'Max ice' MAX SAG FE. The tick marks represent the low point on the conductor delineating the weight spans. A second mid-span structure was not considered because the ahead span is already short.

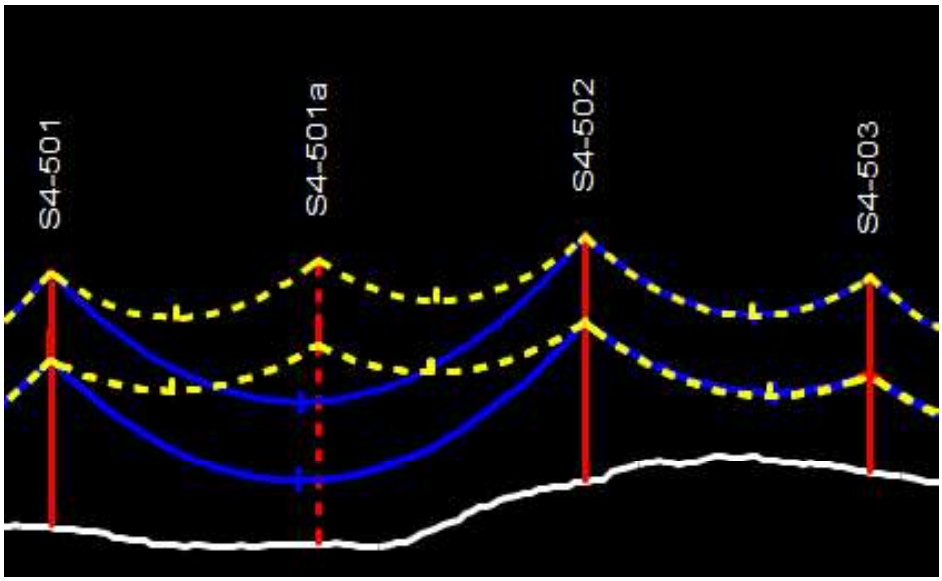


Figure 1: Profile for S4-502 (2469)

3.1.2 Maximum Structure Usage

Table 3: Maximum Structure Usage Comparison for S4-502 (2469)

Load Case	Existing		One Mid-Span Structure		Reinforcing Existing Tower
	Maximum Usage %	Element Label	Maximum Usage %	Maximum Usage Difference	Maximum Usage %
F1 LC70 AS UBI G 50mm 50/100%,C NA+	**149.6**	GW216YR	**122.4**	-27.2	94.3
F1 LC71 BS UBI G 50mm 50/100%,C NA+	**145.9**	GW214YR	**119.7**	-26.2	86.3
F1 LC75 BS UBI G 70mm (50 mm on Pole) 100/80%,C NA+	**107.3**	GW210-212-5Y	83.1	-24.2	74.2
F1 LC72 AS UBI G 55mm 70/100%,C NA+	**105.6**	GW216YR	85.2	-20.4	69.6
F1 LC73 BS UBI G 55mm 70/100%,C NA+	**103.0**	GW214YR	83.5	-19.5	74.6

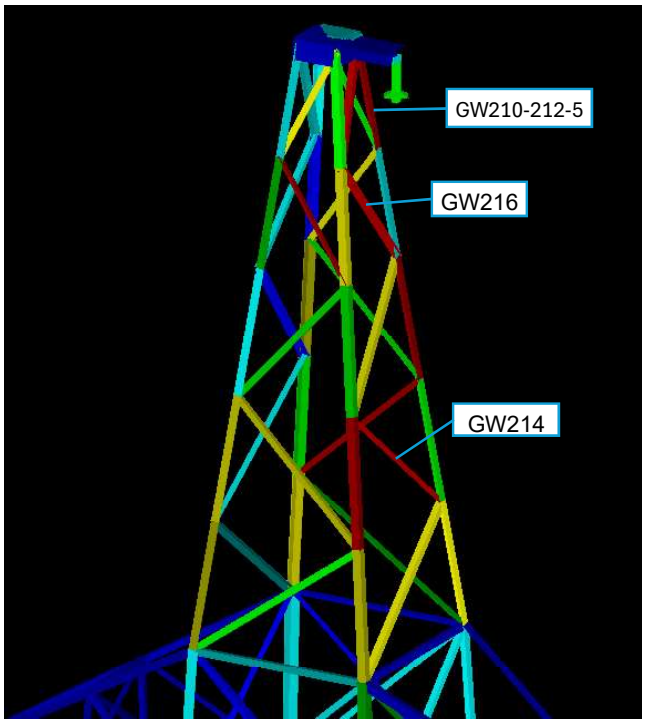


Figure 2: Overstressed Members Element Labels (No Electrode)

The existing configuration applied loads shows overstressed members in the peak, both braces and legs, as shown in Figure 2. All overstressed load cases are for unbalanced ice loading on the OPGW. All overstressed load cases are the additional load cases presented in the RFP. The mid-span structure addition provides significant reduction of the governing maximum overstress, remediating some cases but not all of them. The reinforced A1 tower does not experience any overstresses.

3.1.3 Discussion

The introduction of a mid-span tower between S4-501 (2468) and S4-502 (2469) provides significant reduction to the wind and weight spans for icing cases however does not address all structural overstresses in the peak members for the loading conditions considered. Some reinforcing of S4-502 (2469) would still be required to address all overstresses. Also, the mid-span position of tower S4-501A coincides with a wet low-lying area which would require significant construction costs to install.

The reinforced A1 tower in the position of S4-502 (2469) does not incur any structural overstresses for the load cases considered. Reinforcing S4-502 (2469) only would be more economical than the installation of mid-span structure S4-501A with reduced reinforcing of S4-502 (2469).

3.2 S4-576 (2543)

Tower position S4-576 (2543) was chosen due to long weight spans on both sides of the tower, as shown in Table 4. To avoid weight spans imbalance, it was decided to add two mid-span structures; one in the back span (BS) and one in the ahead span (AS). The presence of long weight ahead and back spans creates a high vertical load during ice weather cases. Although this tower does not have electrodes strung, local peak failures were observed during ice events.

3.2.1 Wind and Weight Span

Table 4: Wind & Weight Span Comparison for S4-576 (2543)

Condition	Total Wind Span	Back Weight Span*	Ahead Weight Span*	Total Weight Span*
Existing	478 m	274 m	234 m	508 m
One mid-span structure	365 m	156 m	235 m	391 m
Two mid-span structures (AS & BS)	239 m	155 m	126 m	281 m
Change (1 Structure)	-113 m (24%)	-118 m	-1 m	-117 m (23%)
Change (2 Structures)	-239 m (50%)	-119 m	-108 m	-227 m (45%)

* Because maximum overstresses are in the peak, the OPGW weight spans are reported.

In Figure 3, the blue catenaries represent the existing condition with no mid-span structures. The yellow dotted catenaries represent the catenaries when one structure is added at the back span, while the red catenaries are for 2 mid-span structures added (one AS and one BS). All catenaries are shown at 'Max ice' MAX SAG FE.

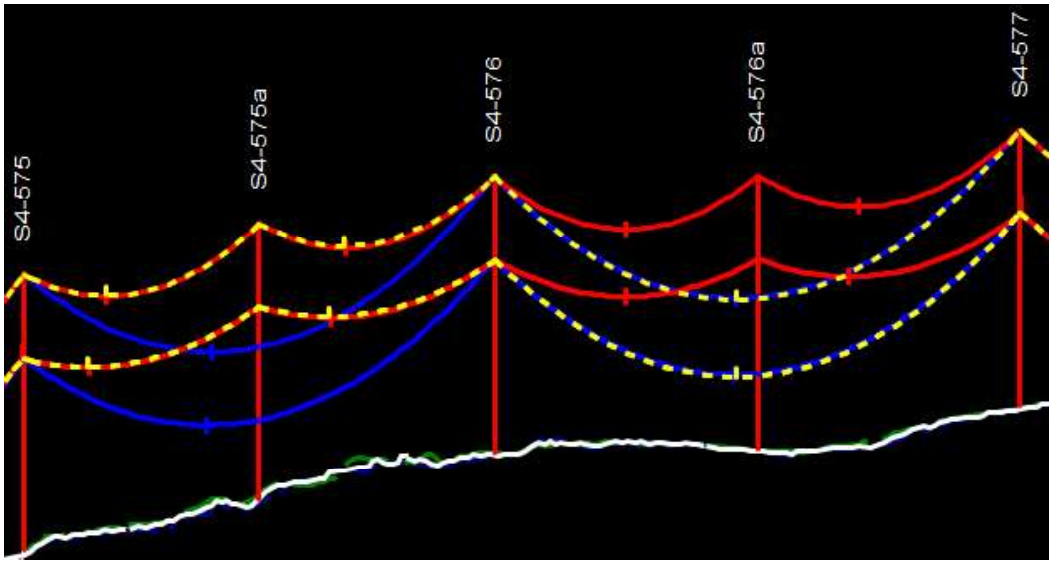


Figure 3: Profile for S4-576 (2543)

3.2.2 Maximum Structure Usage

Table 5: Maximum Structure Usage Comparison for S4-576 (2543)

Load Case	Existing		One Mid-Span Structure		Two Mid-Span Structures		Reinforcing Existing Tower
	Maximum Usage %	Element Label	Maximum Usage %	Maximum Usage Difference	Maximum Usage %	Maximum Usage Difference	Maximum Usage %
F1 LC70 AS UBI G 50mm 50/100%,C NA+	**158.9**	GW216YR	**154.6**	-4.3	**149.3**	-9.6	**100.2***
F1 LC71 BS UBI G 50mm 50/100%,C NA+	**155.2**	GW214YR	**151.6**	-3.6	**146.1**	-9.1	92.8
F1 LC75 BS UBI G 70mm (50 mm on Pole) 100/80%,C NA+	**124.1**	GW210-212-5Y	**110.4**	-13.7	97.0	-27.1	83.4
F1 LC72 AS UBI G 55mm 70/100%,C NA+	**112.8**	GW216YR	**109.5**	-3.3	**105.4**	-7.4	79.8
F1 LC73 BS UBI G 55mm 70/100%,C NA+	**110.1**	GW214YR	**107.3**	-2.8	**103.1**	-7.0	78.7
F1 LC74 AS UBI G 70mm (50 mm on Pole) 100/80%,C NA+	**106.6**	GW216YR	**103.2**	-3.4	99.0	-7.6	87.6

* Reinforced model overstresses are discussed in section 3.7.

Similar to tower S4-502 (2469), the existing configuration shows overstressed members in the peak, both braces and legs. The overstressed members are labelled in Table 5 and shown in Figure 2.

The overstressed members in the S4-502 (2469) tower configuration are the same as those in the S4-576 (2543) configuration, and they are all for unbalanced ice loading on the OPGW (i.e., additional load cases in the RFP).

3.2.3 Discussion

As shown in Table 5, adding one mid-span structure only does not address the peak members overstresses. This is due to the unbalanced weight spans that were introduced when only one mid- span structure was added (i.e., imbalance over-usages). Also, adding two mid-span structures (AS and BS) addressed the overstresses in only 2 unbalanced ice loading cases but not for all of cases. Tower A1 in the configuration of S4-576 (2543) would still need reinforcement after adding the 2 mid-span structures. This scenario will be encountered in any 2 long spans at both sides of any tower with a relatively close wind/weight ratio. This would make the solution of adding two towers, one from each side, not practical because it will lead to the addition of multiple new towers along the line. The reinforced tower shows very minor overstresses which are discussed in section 3.7.

3.3 S4-598 (2565)

Tower S4-598 (2565) has no electrodes strung, and it was chosen due to its location on a downhill with increasing stationing, which causes high longitudinal loads due to the weight span imbalance with a ratio of approximately 2.4 for the ‘Max ice’ weather case. Similar to towers S4-502 (2469) and S4-576 (2543), local peak failures were observed during unbalanced ice weather cases.

3.3.1 Wind and Weight Span

Table 6: Wind & Weight Span Comparison for S4-598 (2565)

Condition	Total Wind Span	Back Weight Span*	Ahead Weight Span*	Total Weight Span*
Existing	392 m	153 m	368 m	521 m
One mid-span structure	316 m	154 m	238 m	392 m
Change	-76 m (19%)	1 m	-130 m	-129 m (25%)

* Because maximum overstresses are in the peak, the OPGW weight spans are reported.

In Figure 4, the blue catenaries represent the existing condition with no mid-span structures. The yellow dotted catenaries represent the catenaries when one structure is added at the ahead span. All catenaries are shown at 'Max ice' MAX SAG FE.

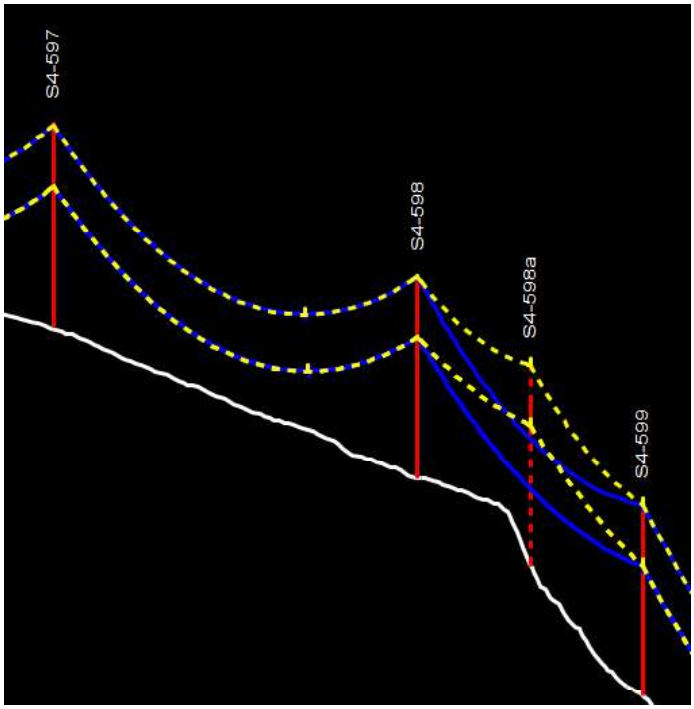


Figure 4: Profile for S4-598 (2565)

3.3.2 Maximum Structure Usage

Table 7: Maximum Structure Usage Comparison for S4-598 (2565)

Load Case	Existing		One Mid-Span Structure		Reinforcing Existing Tower
	Maximum Usage %	Element Label	Maximum Usage %	Maximum Usage Difference	Maximum Usage %
F1 LC70 AS UBI G 50mm 50/100%,C NA+	151.6	GW216YR	148.1	-3.5	95.0
F1 LC71 BS UBI G 50mm 50/100%,C NA+	148.6	GW214YR	144.9	-3.7	90.6
F1 LC75 BS UBI G 70mm (50 mm on Pole) 100/80%,C NA+	123.5	GW210-212-5Y	103.8	-19.7	83.8
F1 LC72 AS UBI G 55mm 70/100%,C NA+	107.4	GW216YR	104.6	-2.8	80.8
F1 LC73 BS UBI G 55mm 70/100%,C NA+	105.1	GW214YR	102.3	-2.8	80.9
F1 LC74 AS UBI G 70mm (50 mm on Pole) 100/80%,C NA+	101.5	GW216YR	98.6	-2.9	84.0

Similar to towers S4-502 (2469) and S4-576 (2543), local overstresses in the peak braces and legs were observed during the new unbalanced ice loading conditions, as shown in Figure 2.

3.3.3 Discussion

As shown in Table 7, adding one mid-span structure decreases the peak braces and legs overstresses, however, members reinforcement would still be required. The addition of the mid-span structure in this scenario of the line running downhill is not very effective based on the weight span reduction and member overstress reduction presented. Spotting this mid-span structure reduces the weight span imbalance of the subject structure but creates an imbalance on the mid-span structure itself and the following downhill structure S4-599. For these reasons, a mid-span structure in this scenario is not practical. Reinforcing the existing tower does not show any overstresses as shown in Table 7.

3.4 S1-318 (319)

Tower position S1-318 (319) was chosen due to the long wind spans as well as weight spans on both sides of the tower with electrode wires strung. This tower configuration induces high transverse loads during wind events and vertical loads during ice events. Due to the long spans, adding one mid-span structure on one side of the tower will cause weight spans imbalance and increase longitudinal loads. For this reason, it was decided to add 2 mid-span structures (AS and BS). In the current tower A1 configuration, local peak diagonals and legs, electrode cross arms, cage bracing overstresses have been observed.

3.4.1 Wind and Weight Span

Overstresses are observed in the peak, electrode cross-arms, and the cage above the pole compression chord connection, therefore the OPGW and electrode loads are most relevant. The OPGW and electrode wind & weight spans were found to be similar so only the OPGW is presented.

Table 8: OPGW Wind & Weight Span Comparison for S1-318 (319)

Condition	Total Wind Span	Back Weight Span*	Ahead Weight Span*	Total Weight Span*
Existing	419 m	252 m	232 m	484 m
One mid-span structure	305 m	250 m	108 m	358 m
Two mid-span structures (AS & BS)	209 m	129 m	109 m	238 m
Change (1 Structure)	-114 m (27%)	-2 m	-124 m	-126 m (26%)
Change (2 Structures)	-210 m (50%)	-123 m	-123 m	-246 m (51%)

In Figure 5, the blue catenaries represent the existing condition with no mid-span structures. The yellow dotted catenaries represent the catenaries when one structure is added at the ahead span, while the red catenaries represent the catenaries when two mid- span structures are added (AS and BS). All catenaries are shown at 'Max ice' MAX SAG FE.

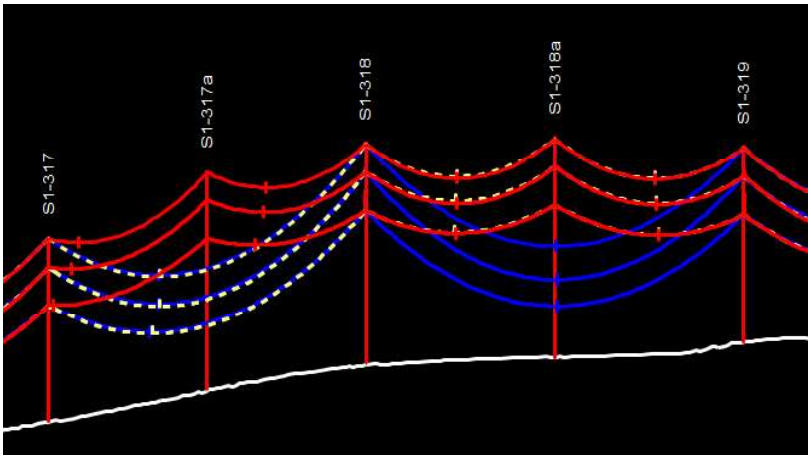


Figure 5: Profile for S1-318 (319)

3.4.2 Maximum Structure Usage

Table 9: Maximum Structure Usage Comparison for S1-318 (319)

Load Case	Existing		One Mid-Span Structure		Two Mid-Span Structures		Reinforcing Existing Tower
	Maximum Usage %	Element Label	Maximum Usage %	Maximum Usage Difference	Maximum Usage %	Maximum Usage Difference	Maximum Usage %
F1 LC70 AS UBI G 50mm 50/100%,C NA+	142.1	GW216YR	136.9	-5.2	133.1	-9.0	89.7
F1 LC71 BS UBI G 50mm 50/100%,C NA+	137.8	GW214YR	132.7	-5.1	129.8	-8.0	87.4
F1 LC75 BS UBI G 70mm (50 mm on Pole) 100/80%,C NA+	131.8	EA188-189-2X	98.5	-33.3	85.3	-46.5	98.6
F1 LC74 AS UBI G 70mm (50 mm on Pole) 100/80%,C NA+	131.6	EA188-189-2XY	98.3	-33.3	87.6	-44.0	98.6
F1 LC76 Ice Load 70mm (50 mm on Pole),C NA+	128.9	EA188-189-2Y	95.8	-33.1	73.1	-55.8	93.0
F1 LC66 AS UBI EL2 63mm 70/100%,C NA+	120.0	EA188-189-2Y	104.2	-15.8	82.1	-37.9	95.4
F1 LC67 BS UBI EL1 63mm 70/100%,C NA+	119.9	EA188-189-2X	95.8	-24.1	81.3	-38.6	93.9
F1 LC65 AS UBI EL1 63mm 70/100%,C NA+	119.8	EA188-189-2XY	104.0	-15.8	82.1	-37.7	93.9
F1 LC68 BS UBI EL2 63mm 70/100%,C NA+	119.6	EA188-189-2P	95.7	-23.9	81.2	-38.4	95.4

Load Case	Existing		One Mid-Span Structure		Two Mid-Span Structures		Reinforcing Existing Tower
	Maximum Usage %	Element Label	Maximum Usage %	Maximum Usage Difference	Maximum Usage %	Maximum Usage Difference	Maximum Usage %
F1 LC69 Ice Load 63mm,C NA+	**111.0**	EA188-189-2Y	82.6	-28.4	68.1	-42.9	88.3
F1 LC24 BR E1 + P1 D,C NA+	**109.2**	CG92-93P	**109.9**	0.7	**107.5**	-1.7	99.0
F1 LC25 BR E2 + P2 D,C NA+	**108.9**	CG92-93X	**109.7**	0.8	**107.4**	-1.5	99.0
F1 back LC24 BR E1 + P1 D,C NA+	**107.4**	CG92-93Y	**104.9**	-2.5	**106.1**	-1.3	99.0
F1 back LC25 BR E2 + P2 D,C NA+	**107.1**	CG92-93XY	**104.7**	-2.4	**105.9**	-1.2	99.0
F1 LC72 AS UBI G 55mm 70/100%,C NA+	**100.4**	GW216YR	96.3	-4.1	93.3	-7.1	81.9

The existing configuration shows overstressed members in the peak, electrode cross arms, and cage diagonals, as shown in Figure 6. Overstressed load cases are for unbalanced ice loading on the OPGW and electrodes, heavy ice event, or electrodes broken wire scenario. Although adding mid-span structures will reduce overstresses, reinforcement will still be required. No overstresses were observed with the reinforced A1 tower.

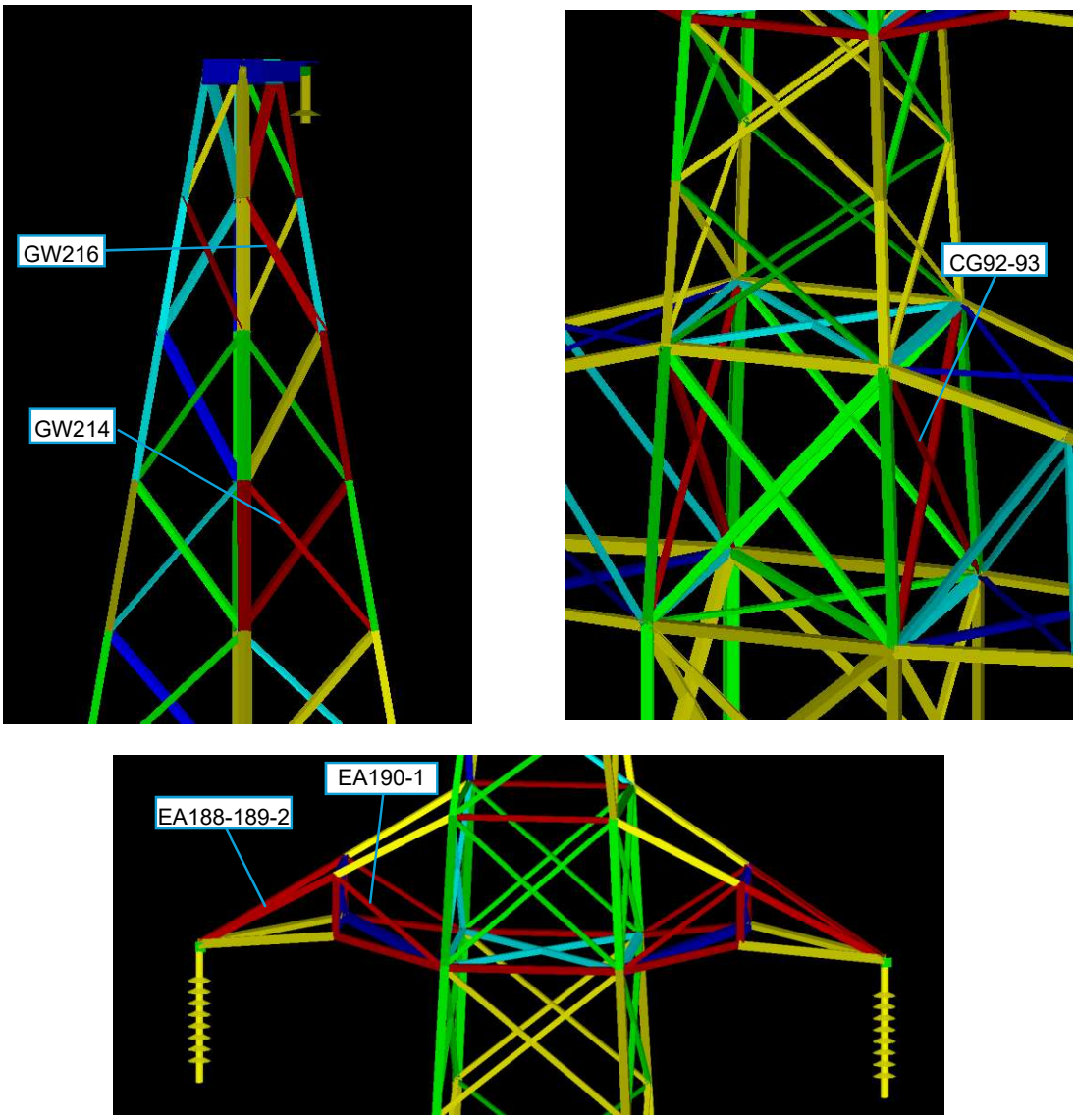


Figure 6: Overstressed Members Element Labels (Electrode Strung)

3.4.3 Discussion

Adding one or two mid-span structures will reduce tower S1-318 (319) overstresses. Reinforcing of overstressed members will still be required. This makes the mid-span structure addition not an economical solution in this scenario. Hence, existing tower reinforcement is a better approach.

3.5 S1-370 (371)

Tower S1-370 (371) has electrode wires strung, with a weight span imbalance ratio of approximately 2.4 for the 'Max ice' weather case. These conditions increase longitudinal loads during an ice event. A possible solution to fix imbalance is the addition of a new mid-span structure at the ahead span. However, the suggested new tower will be in a location where the terrain is lower than the adjacent towers, making it challenging to spot the new tower without experiencing significant uplift conditions.

3.5.1 Wind and Weight Span

Similar to tower S1-318 (319), the OPGW and electrode wind & weight spans were found to be similar so only the OPGW is presented.

Table 10: OPGW Wind & Weight Span Comparison for S1-370 (371)

Condition	Total Wind Span	Back Weight Span*	Ahead Weight Span*	Total Weight Span*
Existing	392 m	112 m	298 m	410 m
One mid-span structure	273 m	114 m	204 m	318 m
Change (1 Structure)	-119 m (30%)	2 m	-94 m	-92 m (22%)

Note that the added mid-span structure S1-370a is the tallest A1 extension (+18 m) available and only achieves a weight span reduction of 92 m. The weight span ratio is only reduced from 2.4 to a minimum of 1.8 because of the topography of the span.

In Figure 7, the blue catenaries represent the existing condition with no mid-span structures, while the yellow dotted catenaries represent the catenaries when one structure is added at the ahead span. catenaries are shown at 'Max ice' MAX SAG FE.

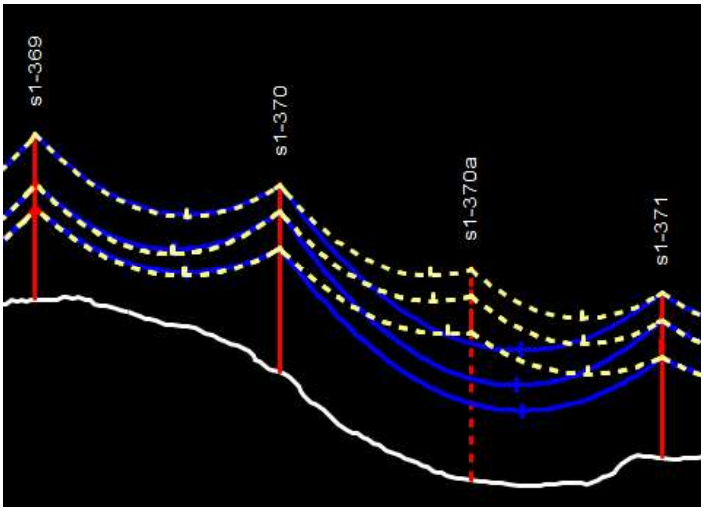


Figure 7: Profile for S1-370 (371)

3.5.2 Maximum Structure Usage

Table 11: Maximum Structure Usage Comparison for S1-370 (371)

Load Case	Existing		One Mid-Span Structure		Reinforcing Existing Tower
	Maximum Usage %	Element Label	Maximum Usage %	Maximum Usage Difference	Maximum Usage %
F1 LC70 AS UBI G 50mm 50/100%,C NA+	140.1	GW216YR	133.0	-7.1	84.7
F1 LC71 BS UBI G 50mm 50/100%,C NA+	136.5	GW214YR	129.5	-7.0	84.4
F1 LC75 BS UBI G 70mm (50 mm on Pole) 100/80%, C NA+	118.2	EA188-189-2X	91.5	-26.7	90.0
F1 LC74 AS UBI G 70mm (50 mm on Pole) 100/80%, C NA+	118.0	EA188-189-2XY	91.3	-26.7	89.3
F1 LC67 BS UBI EL1 63mm 70/100%,C NA+	116.0	EA190-1Y	97.4	-18.6	86.1
F1 LC68 BS UBI EL2 63mm 70/100%,C NA+	115.9	EA190-1XY	97.3	-18.6	87.1
F1 LC76 Ice Load 70mm (50 mm on Pole),C NA+	115.4	EA188-189-2Y	89.0	-26.4	83.9
F1 back LC24 BR E1 + P1 D,C NA+	110.3	CG92-93Y	109.1	-1.2	99.1
F1 back LC25 BR E2 + P2 D,C NA+	110.0	CG92-93XY	108.9	-1.1	99.1
F1 LC66 AS UBI EL2 63mm 70/100%,C NA+	108.1	EA190-1X	96.0	-12.1	86.9

Load Case	Existing		One Mid-Span Structure		Reinforcing Existing Tower
	Maximum Usage %	Element Label	Maximum Usage %	Maximum Usage Difference	Maximum Usage %
F1 LC65 AS UBI EL1 63mm 70/100%,C NA+	**107.8**	EA190-1P	95.8	-12.0	85.6
F1 LC24 BR E1 + P1 D,C NA+	**103.9**	CG92-93P	**104.2**	0.3	99.1
F1 LC25 BR E2 + P2 D,C NA+	**103.6**	CG92-93X	**104.0**	0.4	99.1

The existing configuration shows overstressed members in the peak, electrode cross arms, and cage diagonals as shown in Figure 6. All failures occurred during unbalanced conditions, either unbalanced iced or broken electrodes wire scenario. This is due to the weight span imbalance ratio. Adding a mid-span structure will address some overstresses but not all of them as shown in Table 11.

3.5.3 Discussion

Adding one mid-span structure will reduce tower S1-370 (371) overstresses, but does not eliminate all of them. Reinforcing of overstressed members will still be required. Due to the topography at the new mid-span structure location, even the tallest extension does not balance the ahead and back weight spans. Reinforcing the existing S1-370 (371) tower is a more feasible and reliable solution in this scenario.

3.6 S1-307 (308)

Tower S1-307 (308) has a large span imbalance due to both AS and BS running uphill relative to increasing stationing. This tower configuration shows local peak overstresses, in addition to overstresses in the electrode cross arms (due to the electrode wires tension) as well as cage diagonal overstresses.

3.6.1 Wind and Weight Span

Similar to tower S1-318 (319), the OPGW and electrode wind & weight spans were found to be similar so only the OPGW is presented.

Table 12: OPGW Wind & Weight Span Comparison for S1-307 (308)

Condition	Total Wind Span	Back Weight Span*	Ahead Weight Span*	Total Weight Span*
Existing	337 m	265 m	56 m	321 m
One mid-span structure	225 m	151 m	57 m	208 m
Change (1 Structure)	-112 m (33%)	-114 m	1 m	-113 m (35%)

In Figure 8, the blue catenaries represent the existing condition with no mid-span structures. The yellow dotted catenaries represent the catenaries when one structure is added at the ahead span. All catenaries are shown at 'Max ice' MAX SAG FE.

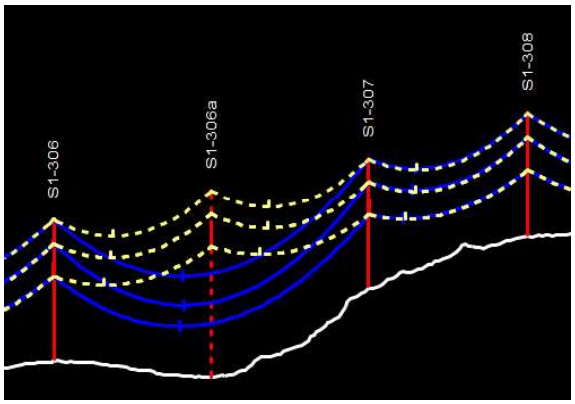


Figure 8: Profile for S1-307 (308)

3.6.2 Maximum Structure Usage

Table 13: Maximum Structure Usage Comparison for S1-307 (308)

Load Case	Existing		One Mid-Span Structure		Reinforcing Existing Tower
	Maximum Usage %	Element Label	Maximum Usage %	Maximum Usage Difference	Maximum Usage %
F1 LC70 AS UBI G 50mm 50/100%,C NA+	**142.3**	GW216YR	**136.3**	-6	87.9
F1 LC71 BS UBI G 50mm 50/100%,C NA+	**138.0**	GW214YR	**132.8**	-5.2	81.4
F1 LC24 BR E1 + P1 D,C NA+	**111.8**	CG92-93P	**109.5**	-2.3	**101.9***
F1 LC25 BR E2 + P2 D,C NA+	**111.6**	CG92-93X	**109.4**	-2.2	**101.9***
F1 back LC24 BR E1 + P1 D,C NA+	**104.5**	CG92-93Y	**105.0**	0.5	**102.3***
F1 back LC25 BR E2 + P2 D,C NA+	**104.4**	CG92-93XY	**104.9**	0.5	**102.3***
F1 LC66 AS UBI EL2 63mm 70/100%,C NA+	**104.3**	EA190-1X	82.2	-22.1	75.0
F1 LC65 AS UBI EL1 63mm 70/100%,C NA+	**104.1**	EA190-1P	82.1	-22	74.1
F1 LC72 AS UBI G 55mm 70/100%,C NA+	**100.1**	GW216YR	95.6	-4.5	74.6

* Reinforced model overstresses will be discussed in section 3.7.

The existing configuration shows local peak overstresses in braces and legs, in addition to electrode cross arms and cage overstresses. The longitudinal loads caused by the large weight span imbalance has led to overstresses in unbalanced ice load cases as well as electrodes and OPGW broken wire cases.

3.6.3 Discussion

As shown in Table 13, adding a mid-span structure will slightly improve weight imbalance, but it won't be enough to avoid overstresses. This is due to the land topography at this section (towers running uphill), which introduced the weight imbalance. For this reason, reinforcing the existing tower is considered a more practical solution.

3.7 REINFORCED MODEL OVERSTRESSES

3.7.1 Tower S4-576 (2543) Reinforced Model Overstresses

As shown in Table 5, the reinforced model shows overstresses with a ratio of 100.2%. This scenario is encountered if no mid-span structures are added and only reinforcing of the existing tower A1 is implemented. The overstresses are seen due to the discrepancy between the envelope load cases provided for tower A1 reinforcement scope and the as built load cases obtained from PLS CADD. As shown in Figure 9, overstresses are seen in one of the peak diagonals (GW217).

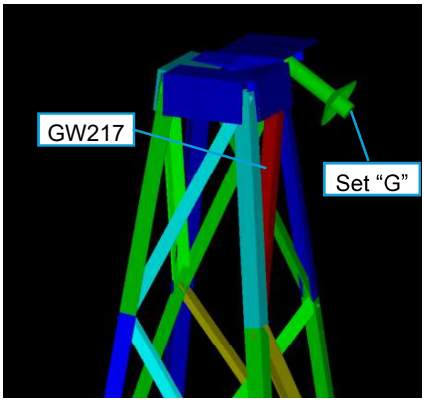


Figure 9: Reinforced Overstressed Member Element for S4-576 (2543)

Table 14 below shows a comparison between as built forces obtained from PLS CADD during this mid-span tower addition scope and envelope forces obtained from NL hydro for tower A1 reinforcement scope. The comparison is made for the governing load case (F1 LC70 AS UBI G 50mm 50/100%,C NA+). This load case is one of the new additional load cases provided by NL Hydro. The difference between the as-built forces and the envelope forces is shown below (negative indicates as-built loads exceeding the envelope loads). The increase in vertical load for the as-built condition is causing a higher axial force in member GW217 resulting in the minor overstress of 100.2%.

Table 14: Load Cases Comparison for S4-576 (2543) (As built VS Envelope Loads)

LCA/Set name	Load direction	Envelope forces (kN)	As built forces (kN)	Difference (kN)
G	V (Vertical)	31.2	34.7	-3.5
	T (Transverse)	-0.2	0	-0.2
	L (Longitudinal)	52.9	52.1	0.8

3.7.2 Tower S1-307 (308) Reinforced Model Overstresses

As shown in Table 13, the reinforced model shows overstress with a ratio of 102.3%. Similar to tower S4-576 (2543), the overstresses are seen due to the discrepancy between the envelope load cases and the as built load cases. Figure 11 shows the overstress occurs in the upper chord of the guy cross arm (GA136-137-2).

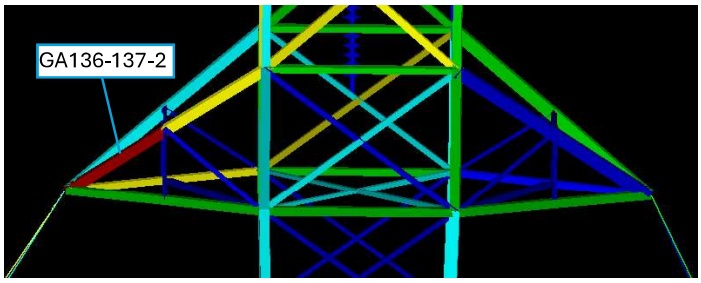


Figure 10: Reinforced Overstressed Member Element for S1-307 (308)

Similar to S4-576 (2543), the comparison between envelope and as built forces for all sets are shown in Table 15 below. The governing load case (F1 back LC25 BR E2 + P2 D,C NA+) causing overstresses is a broken wire scenario for sets E2 and P2 (electrode and pole wires respectively). As seen in the table, envelope forces are generally higher than as built forces (positive values), except for longitudinal loads of sets E2 and P2 (highlighted in grey). These increased loads are translated to overturning moments and torque on the cage, which is resisted by the guy cross arms, causing the overstress.

Table 15: Load Cases Comparison for S1-307 (308) (As built VS Envelope Loads)

LCA/Set name	Load direction	Envelope forces (N)	As built forces (N)	Difference (kN)
P1	V (Vertical)	29.2	21.6	7.6
	T (Transverse)	1.3	0.0	1.3
	L (Longitudinal)	0.0	0.0	0.0
P2	V (Vertical)	16.2	3.9	12.3
	T (Transverse)	1.0	0.0	1.0
	L (Longitudinal)	**-111.5**	**-112.9**	**-1.4**
E1	V (Vertical)	10.9	7.6	3.3
	T (Transverse)	0.6	0.0	0.6
	L (Longitudinal)	0.0	0.0	0.0
E2	V (Vertical)	10.9	1.3	9.6
	T (Transverse)	0.4	0	0.4
	L (Longitudinal)	**-24.0**	**-32.1**	**-8.1**
GP	V (Vertical)	3.8	2.4	1.4
	T (Transverse)	0.3	0.0	0.3
	L (Longitudinal)	0.0	0.0	0.0

4.0 CONCLUSIONS

The introduction of mid-span structures can effectively reduce the wind and weight spans and therefore the applied loads. The weight span imbalance may be improved to reduce longitudinal loads. For the structures studied, this reduction was not sufficient to address structural overstresses caused by the additional load cases in the RFP. The mid-span structure addition may allow for study structures to have reduced reinforcing effort, but some reinforcing is still required to address all structural overstresses. The position of mid-span structures may incur high construction costs due to wet low-lying areas or require tall extensions.

Reinforcing the A1 structures addressed structural overstresses in most studied structures, except for some cases where there were discrepancies between as built PLS CADD loads and envelope loads. Some reinforcing scope may not be required for a given structure location but would have to be inspected on a case-by-case basis.

In brief, it is more economical to reinforce the A1 structures than to add mid-span structures.

Appendix C

LIL Engineering Study – A1 Electrode Suspension Assembly

newfoundland labrador hydro

TETRA TECH

LIL Engineering Study – A1 Electrode Suspension Assembly

Newfoundland and Labrador Hydro Report No. ILK-TT-CD-6200-TL-H15-0001-01
TT Document Number 705-2579500100-REP-G0001-00
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NSPML 2026 Holdback Mechanism IG IR-09 Attachment 1 Page 51 of 195

TABLE OF CONTENTS

1.0 INTRODUCTION **1**

2.0 WORK COMPLETED TO DATE **1**

3.0 PERMISSIBLE LENGTH INCREASE **1**

3.1 Existing Insulation Length (Electrode and Pole) 2
3.2 Electrode Conductor Drop 2
3.3 Transverse Swing Under Maximum Wind Swing 3
3.4 Vertical and Horizontal Separations to Pole Conductors 4
3.5 Galloping Ellipse Clearances 4
3.6 Option 1 Permissible Increase 5
3.7 Option 2 Permissible Increase 6

4.0 LONGITUDINAL ARTICULATION ANGLE **7**

5.0 OPTION 1 DESIGN **7**

6.0 OPTION 2 DESIGN **8**

7.0 LONGITUDINAL LOAD REDUCTION **10**

8.0 CONCLUSIONS **12**

LIST OF TABLES

Table 1: Relative Change for Insulator Lengthening Option 2 11

LIST OF FIGURES

Figure 1: Vertical Departure Angles 2
Figure 2: Conductor Drop 3
Figure 3: Transverse Swing Angles 3
Figure 4: MPS HDW-100-SS 4
Figure 5: Option 1 Permissible Length Increase 5
Figure 6: Option 2 Permissible Length Increase 6
Figure 7: Longitudinal Articulation Angle 7
Figure 8: Option 1 Design 8
Figure 9: Option 2 Design 8
Figure 10: Option 2 Structural Improvements 9
Figure 11: Option 2 Minimum Electrical Clearance 10

APPENDICES

APPENDIX A: GALLOPING ELLIPSE RESULTS

APPENDIX B: NEW HARDWARE CUTSHEETS

APPENDIX C: NEW HARDWARE DRAWINGS

1.0 INTRODUCTION

NL Hydro has experienced several performance issues with the electrodes that are mounted on the same towers as the pole conductors (tower type A1) for the Labrador-Island Transmission Link, +/- 350 kV HVDC. Electrode performance issues include the following:

- Conductor failure
- Insulator units contacting conductor under longitudinal loading
- Cross-arm structural failure
- Suspension clamp slippage

This technical memo discusses potential improvements to address the performance issues identified. The challenges for available approaches are discussed and two recommendations are presented, one with minimal cost and effort to address the top priority improvements, and a second that requires more field work but will improve additional performance issues.

2.0 WORK COMPLETED TO DATE

Extensive study of the performance issues has previously been completed by NL Hydro and the root cause of most of the issues is that the line has experienced weather loading events that exceeded the initial design assumptions. The performance issues are caused by electrode suspension longitudinal loading during icing events whether through weight span imbalance, unbalanced ice accumulation, or unbalanced shedding. The following reports describe the performance issues.

- Failure Investigation Report – L3501/2 Tower and Conductor Damage (2021)
- L3501/2 Failure Investigation – Ice Storm Southern Labrador (2024)

3.0 PERMISSIBLE LENGTH INCREASE

The length that the electrode suspension insulator string can be increased is dependent on the required electrical clearances, minimum separations to pole conductors, and existing tower geometry. The main inputs are the electrical clearance drawing ILK-JY-SD-6200-TL-D99-0012-01-A3 and the design requirements drawing ILK-SN-CD-6200-TL-DD-0112-01-C4. The values in the drawing are inspected for accuracy and as-built conditions to maximize improvement in the following sections.

The tower ranges (final tower numbers) inspected for as-built conditions are from the PLS-CADD models provided by NL Hydro on January 15, 2025. Only tower types A1 where electrode is present were considered. The following ranges do not represent all of the A1 towers, they cover areas where damage has occurred, but the total number of tower type A1 positions of 239 is assumed to be a representative sample.

- 244-340
- 342-388
- 499-596
- 1210-1228

3.1 EXISTING INSULATION LENGTH (ELECTRODE AND POLE)

The electrode insulator length on the tower type A1 electrical clearance drawing ILK-JY-SD-6200-TL-D99-0012-01-A3 is listed as 1245 mm from string attachment point on tower to center of conductor. This matches what is in the existing PLS-TOWER models in the PLS-CADD line models. The same value from the suspension insulator assembly drawing ILK-SI-SD-6200-TL-D04-0016-01-C3 however is 1133 mm. The electrode insulator length of 1133 mm has more dimensional certainty and is used in this report.

The pole insulator length on the tower type A1 electrical clearance drawing ILK-JY-SD-6200-TL-D99-0012-01-A3 is listed as 6065 mm from string attachment point on tower to center of conductor. The existing PLS-TOWER models in the PLS-CADD line models however have a pole insulator length of 5757 mm. Furthermore, the insulator assembly drawing ILK-SI-SD-6200-TL-D04-0007-01-C4 has a value of 5562 for the same value (from table, tower family zones F1, F3, F4, F5). The pole insulator length of 5562 mm has more dimensional certainty and is used in this report.

3.2 ELECTRODE CONDUCTOR DROP

The electrode conductor drop on the tower type A1 electrical clearance drawing ILK-JY-SD-6200-TL-D99-0012-01-A3 is listed as 270 mm. This value is dependent on the vertical departure angle and describes decreased electrical clearance due to the conductor descending from the suspension clamp elevation before surpassing the tower width. The distribution of as-built occurrences of vertical departure angle for a condition of 0°C, no ice, no wind, max sag FE is shown in Figure 1 below.

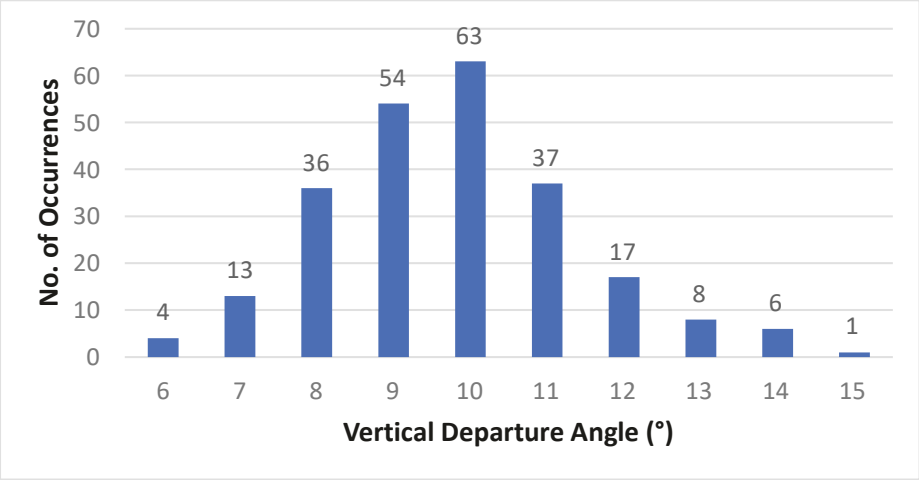


Figure 1: Vertical Departure Angles

The maximum vertical departure angle considered in this report is 14°. Note that the single occurrence of 15° may be neglected because a high vertical departure angle is not coincident with a high transverse swing angle. This is because a high vertical departure angle is correlated to a large weight span which will limit the transverse swing angle. As per Figure 2 below, the as-built conductor drop will be considered as 200 mm.

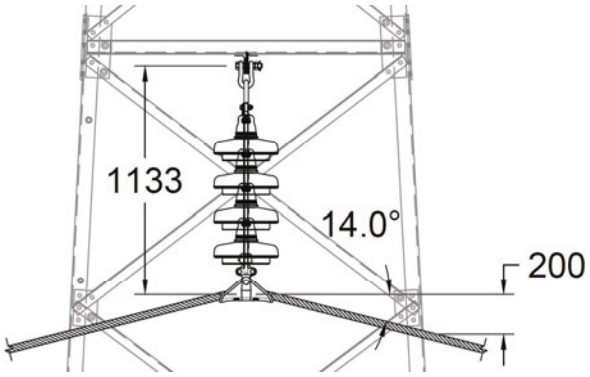


Figure 2: Conductor Drop

3.3 TRANSVERSE SWING UNDER MAXIMUM WIND SWING

The transverse swing angle on the tower type A1 electrical clearance drawing ILK-JY-SD-6200-TL-D99-0012-01-A3 is listed as 70°. The distribution of as-built transverse swing angles under maximum wind swing condition is presented in below in Figure 3.



Figure 3: Transverse Swing Angles

Both improvement options rely on a reduced maximum transverse swing angle. Improvement option 1 can accommodate a transverse swing angle of 67° before violating electrical clearance to the cage. Improvement option 2 can withstand a transverse swingle of 66° before violating electrical clearance to the bottom of a new straight bottom cross-arm chord.

Towers positions that exceed this maximum 66° transverse swing angle could be brought below the maximum with the addition of conductor weights. The preferred style of conductor weight to avoid interfacing with existing hardware and limit impacts on electrical clearance is Maclean Power Systems (MPS) HDW-100-SS, see Figure 4. Weight should be placed close to the suspension clamp to avoid adding energized diameter to the conductor at the conductor drop position. Due to the limited cases where the swing limit is exceeded, this hardware detail is not considered in scope for the drawing deliverable.



Figure 4: MPS HDW-100-SS

3.4 VERTICAL AND HORIZONTAL SEPARATIONS TO POLE CONDUCTORS

Tower type A1 design requirements drawing ILK-SN-CD-6200-TL-DD-0112-01-C4 outlines the required separation between the electrode and the poles. The limitations are as follows:

- Horizontal separation of ≥ 4.9 m in static position
- Vertical separation of tower attachment points of ≥ 4.8 m

The limitations are assumed to be related to galloping ellipse clearance. The true requirement for the separations in this case is from the conductor attachment points rather than the tower attachment points. Given the geometry in the drawing, the equivalent required vertical separation to between the conductor attachment points is as follows:

$$D = 4800 - electrode\ vang - electrode\ insulator\ length + pole\ vang + pole\ insulator\ length$$

$$D = 4800 - 285 - 1245 + 120 + 6065 = 9455\ mm$$

Because the insulator attachment points are set at the limits of the design criteria drawing on the layout and the pole insulator strings are shorter than anticipated (see Section 3.1), the minimum vertical separation is already exceeded in the existing design. Lengthening of the electrode insulator will cause further violation of minimum vertical separation and any horizontal attachment point offset increase will cause violation. Due to these reasons the galloping ellipse clearance must be studied to ensure encroaching on these minimums is acceptable.

3.5 GALLOPING ELLIPSE CLEARANCES

The galloping ellipse method used for the transmission line design is described in the 350 kV HVdc LINE DESIGN CRITERIA, document number ILK-SN-CD-6200-TL-DC-0001-01, Appendix A. No results or reporting was available for the evaluation of that method, so the impact of the proposed attachment geometry and insulator length had to be studied because the electrode insulator string lengthening brings the electrode and pole ellipses closer together.

Because galloping ellipse amplitude is related to sag, the longest span length was studied, assumed to be conservatively representative of any span on the line. The maximum span length for tower type A1 with electrode strung was between towers 258 and 259 at 496 m. The pole insulator length identified in section 3.1 was used , the new electrode cross-arm shown in Figure 6 was used, and the insulator geometry shown in Figure 9 was used.

Refer to Appendix A for the results of the study. There is adequate separation from the electrode galloping ellipse to the pole galloping ellipse with the new cross-arm and electrode insulator string.

3.6 OPTION 1 PERMISSIBLE INCREASE

The permissible increase for option 1 was determined to be 295 mm governed by the maximum wind swing case with electrical clearance to the cage, see Figure 5. Note that the EDT (0°C, 0 Pa) limit at 11° transverse swing and the REDUCED WIND SWING (-20°C, 296 Pa) limit at 47° swing are not shown because the required electrical clearances are the same and are covered by the MAXIMUM WIND SWING (-20°C, 788 Pa) limit at 67°. See previous section for justification of reduction of transverse swing angle from 70°. Note that electrode shielding angle improves with additional insulator length.

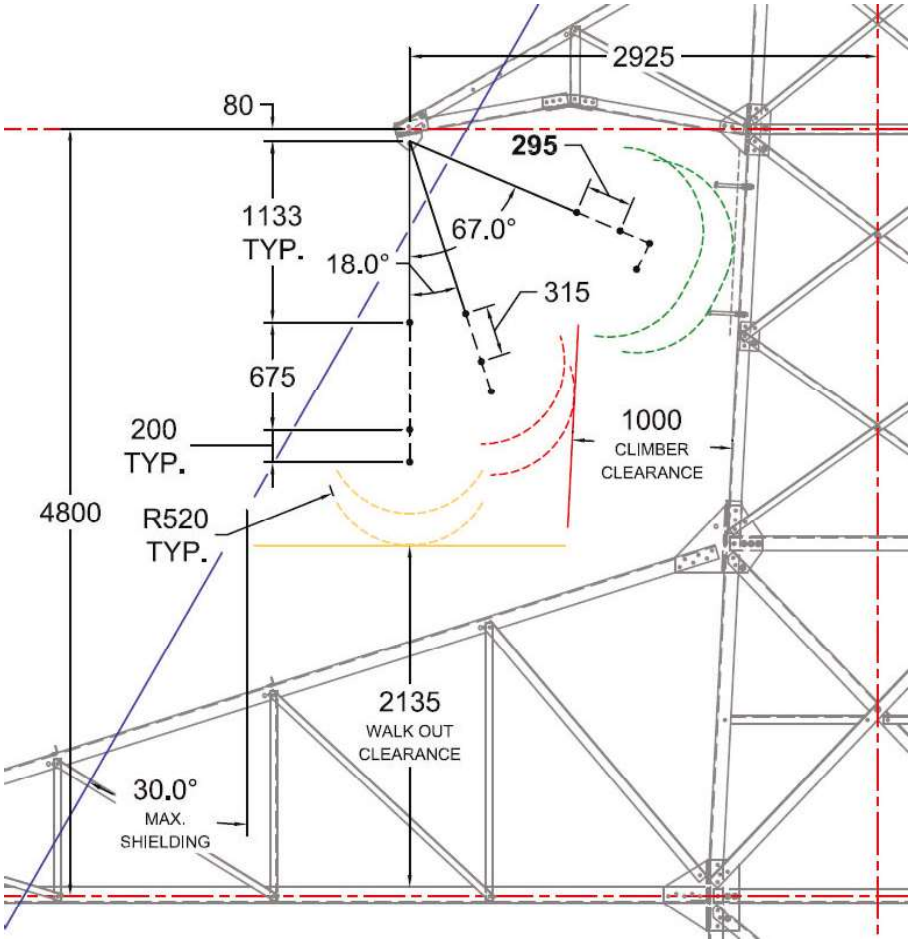


Figure 5: Option 1 Permissible Length Increase

3.7 OPTION 2 PERMISSIBLE INCREASE

The tower type A1 reinforcement scope showed significant overusages in most of the electrode cross-arm members that are not easily addressed with reinforcement. For this reason, it is more economical to design and construct a cross-arm replacement rather than implement reinforcements. An arm replacement offers the opportunity to improve several structural items identified in the *Failure Investigation Report – L3501/2 Tower and Conductor Damage* report, in addition to offering more insulator lengthening to balance longitudinal load. The insulator attachment offset from centerline increases from 2925 mm to 2985 mm, see the Option 2 design section for more details.

The permissible increase for option 2 after considering the new proposed arm geometry was determined to be 325 mm governed by the maximum wind swing case with electrical clearance to a climbing bolt. As with option 1, the EDT (0°C, 0 Pa) limit at 11° transverse swing and the REDUCED WIND SWING (-20°C, 296 Pa) limit at 47° swing are not shown because the required electrical clearances are the same and are covered by the MAXIMUM WIND SWING (-20°C, 788 Pa) limit at 66°. See previous section for justification of reduction of transverse swing angle from 70°. As with option 1, the electrode shielding angle improves with additional insulator length.

Note that an additional 50 mm of insulator length for a total of 375 mm increase may be included if the step bolt is removed. NL Hydro confirmed March 11, 2025 that the removal of the climbing bolt is acceptable.

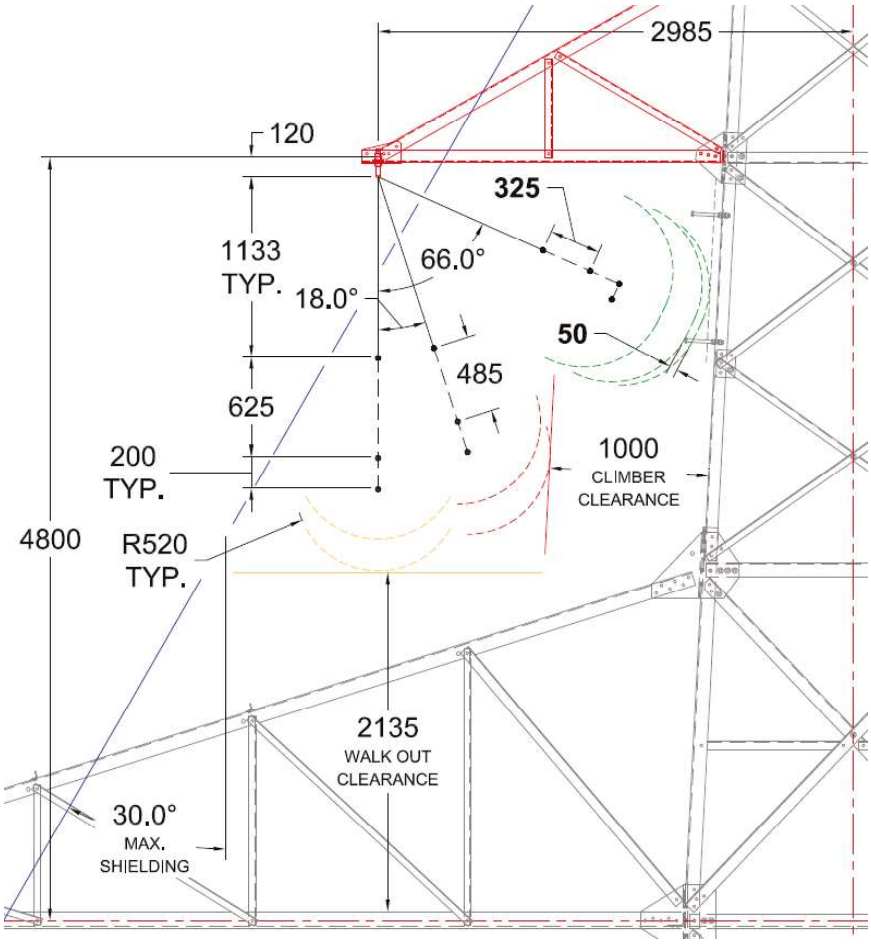


Figure 6: Option 2 Permissible Length Increase

4.0 LONGITUDINAL ARTICULATION ANGLE

One of the field observations from existing conditions is contact of the bottom insulator unit and the electrode conductor under longitudinal loading cases. Based on the geometry from the electrode insulator hardware drawing ILK-SI-SD-6200-TL-D04-0016-01-C3, the maximum permissible longitudinal articulation angle prior to contact is approximately 50° assuming a vertical take-off angle of 0°, see Figure 7 (left).

Ignoring broken wire cases, the maximum required longitudinal angle from the design loading drawings ILK-SN-CD-6200-TL-DD-0065-01-C1 & ILK-SN-CD-6200-TL-DD-0065-02-C2 and the additional loading table included in the RFP is 33° for load case “UBI EL1 64 mm 70/100%.” Because this is within the permissible range for the existing assembly, the target articulation angle is not defined. Photo 22 from the *Failure Investigation Report – L3501/2 Tower and Conductor Damage (2021)* shows a longitudinal swing angle of approximately 60°, see Figure 7 (middle).

Both options presented feature hardware length increase on the energized end to increase the longitudinal articulation angle. The permissible articulation is now expected to exceed 70°, see Figure 7 (right). The longitudinal articulation of the socket tongue fitting to suspension clamp was confirmed by SLACAN to also exceed 70° (approximately 80°).

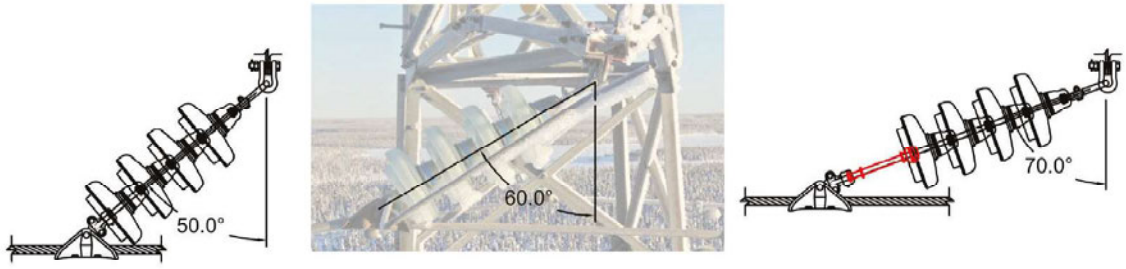


Figure 7: Longitudinal Articulation Angle

5.0 OPTION 1 DESIGN

The design solution for option 1 to meet the permissible insulator length increase of 295 mm is to add a socket ball extension SLACAN catalogue no. 63149 between the bottom insulator and the socket tongue, see Figure 8. See appendix B for cutsheet. With a spacing of 292 mm, this fits within the permissible length increase. This item meets the requirements of *350 kV HVdc LINE DESIGN, TESTING AND SUPPLY OF HARDWARE ASSEMBLIES TECHNICAL SPECIFICATION, DOC. NO. ILK-SN-CD-6200-TL-TS-0013-01*.

Adding this hardware item also requires the replacement of the arcing horn to maintain the spark gap geometry. It is expected that only lengthening the vertical leg of the lower arcing horn assembly will meet this requirement. See Appendix C for design drawing (ILK-TT-CD-6200-TL-D04-0004-01).

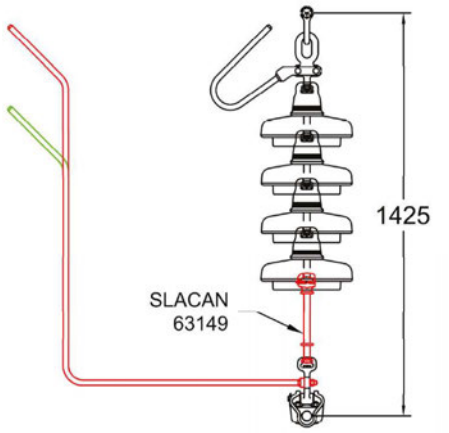


Figure 8: Option 1 Design

6.0 OPTION 2 DESIGN

The second design option is to further increase the insulator length and address structural shortcomings in the insulator attachment to the cross-arm as described in the Failure Investigation Report. The hardware changes include replacing the shackle with a U-bolt (SLACAN catalogue no. 83573), adding the same socket ball extension as option 1 (SLACAN catalogue no. 63149), and adding one insulator unit (SEDIVER N220P/C170DR), see Figure 9. The net increase in insulator length is 363 mm which requires the removal of the climbing bolt to meet the permissible length increase requirements, see Figure 6. These hardware items meet the requirements of *350 kV HVdc LINE DESIGN, TESTING AND SUPPLY OF HARDWARE ASSEMBLIES TECHNICAL SPECIFICATION, DOC. NO. ILK-SN-CD-6200-TL-TS-0013-01*.

The lower arcing horn will also have to be replaced in this option.

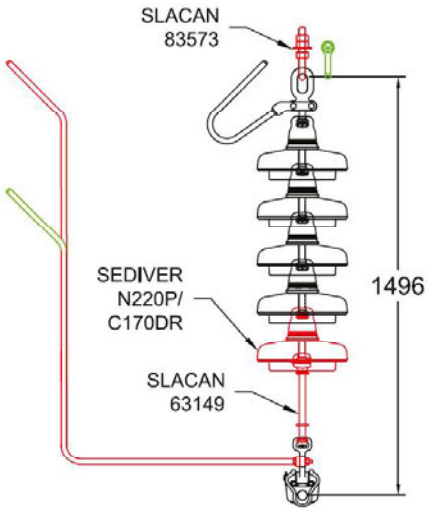


Figure 9: Option 2 Design

The following dimensions for the new electrode cross-arm are preliminary and subject to change pending final tower detailing. The attachment style will change from back to back angles and a shackle that does articulate in the longitudinal direction to a U-bolt. As a result, the longitudinal load moment arm will reduce from 162 mm to 111 mm. The plan eccentricity will reduce from 270 mm to 210 mm by extending the bottom chords and moving the attachment point out 60 mm, see Figure 10. By using a welded plate assembly, the torsional load will be distributed to bolts on the bottom face of the arm in tension as well as the front and back face in shear, mitigating the block shear failure seen in the Failure Investigation Report.

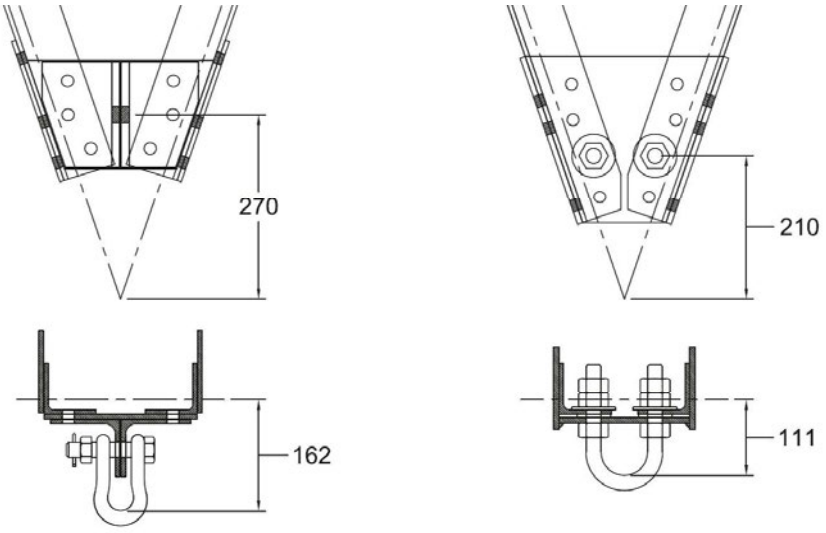


Figure 10: Option 2 Structural Improvements

The bottom chord of the cross-arm will be set level to simplify detailing, fabrication, and erection as well as avoid high axial forces in the bracing. This requires a maximum transverse swing angle of 66° to maintain electrical clearance to the bottom of the cross-arm, see Figure 11, and transverse swing angle section for justification. Bottom chord plan bracing will be framed on the top of the bottom face to avoid reductions in electrical clearance.

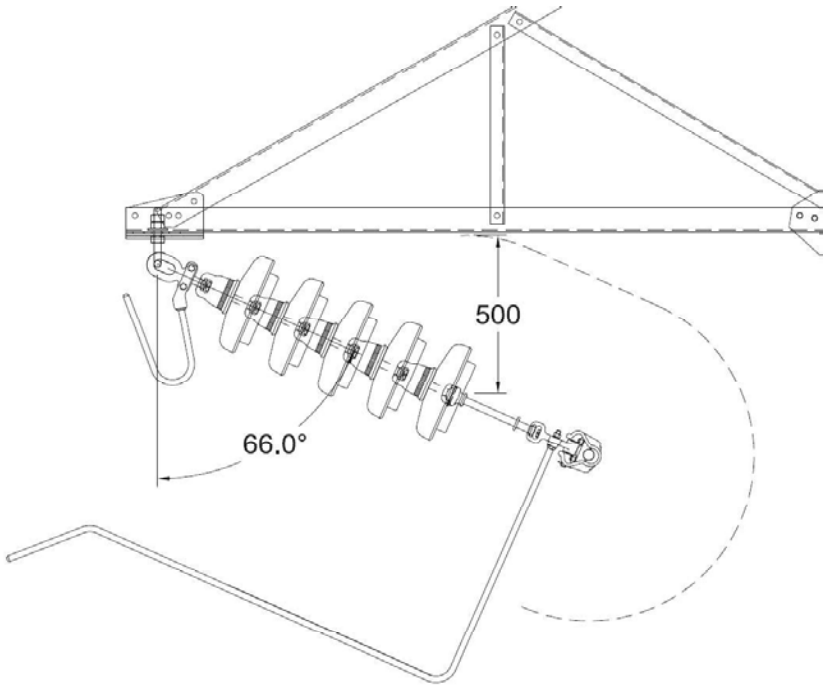


Figure 11: Option 2 Minimum Electrical Clearance

7.0 LONGITUDINAL LOAD REDUCTION

An assessment of longitudinal load reduction was completed to determine the benefit of the insulator lengthening of option 2. The following procedure was completed to compare the existing condition to the improved condition.

1. For towers in existing PLS-CADD models, change electrode insulator length from 1245 mm to 1133 mm and write structure loads in L4 for the unbalanced icing load cases. The difference between E1 and E2 cases is generally negligible and either the ahead or back case will experience more applied longitudinal applied load depending on the magnitude of the one-sided weight span. Only the maximum of the four load cases is reported for each structure.
    a. F1 back LC29 UBL E1,T NA+
    b. F1 back LC30 UBL E2,T NA+
    c. F1 LC29 UBL E1,T NA+
    d. F1 LC30 UBL E2,T NA+
2. Change the insulator string length from 1133 mm to 1496 mm. Write the same structure loads as described in step 1.
3. Compare the relative change (longitudinal load reduction) between the two conditions.

This procedure was completed for tower locations that were known to have electrode cross-arm damage during ice events. The average relative change in the locations inspected was found to be 10%.

Table 1: Relative Change for Insulator Lengthening Option 2

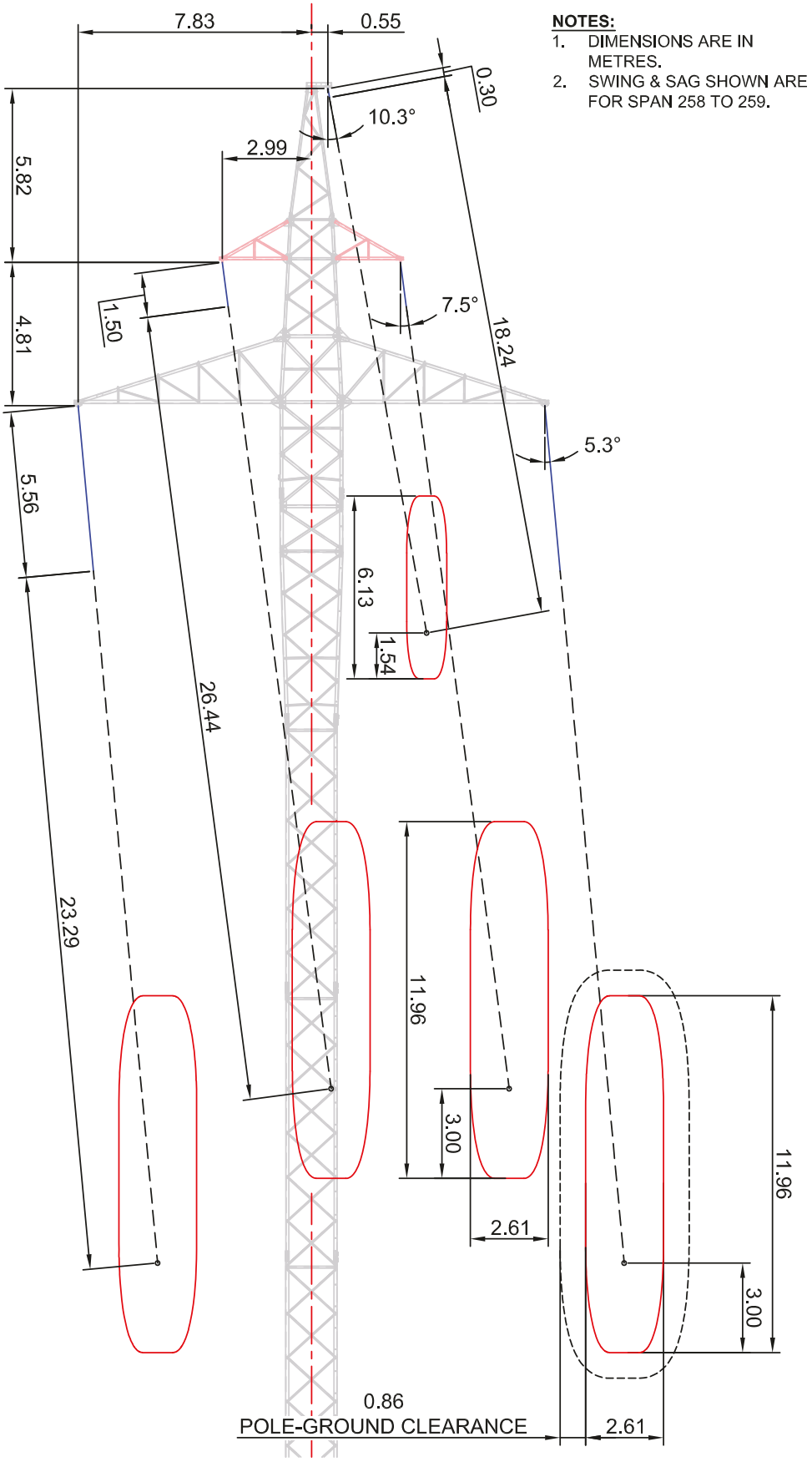
Tower No.	Long. Load Before (N)	Long. Load After (N)	Relative Change
335	16020	14226	11.2%
340	19779	17429	11.9%
343	20320	18408	9.4%
362	16209	14497	10.6%
363	21330	19415	9.0%
364	21083	19114	9.3%
366	20547	18649	9.2%
368	18061	16213	10.2%
526	19477	17663	9.3%
527	19099	17299	9.4%
1218	17715	15946	10.0%
1219	17752	16274	8.3%
1221	19321	17387	10.0%
1222	19343	17261	10.8%
1223	15881	14616	8.0%
1224	17855	16085	9.9%
1225	18736	16893	9.8%
1226	16712	15098	9.7%
1227	14530	13091	9.9%
1228	16565	14363	13.3%
		Average	10.0%

8.0 CONCLUSIONS

The two proposed options meet the required minimum electrical clearances and improve the performance issues seen on the electrode. The primary means of improvement is to increase the insulator length available to balance longitudinal loading under unbalanced ice conditions. Both options provide a significant improvement in permissible longitudinal articulation range to avoid insulators contacting the conductor.

Option 1 can be implemented with relatively minimal construction effort and no costs related to tower modifications. Option 2 provides additional insulator length for longitudinal load imbalance in addition to increasing the capacity of the insulator attachment to the cross-arm tip.

APPENDIX A: GALLOPING ELLIPSE RESULTS

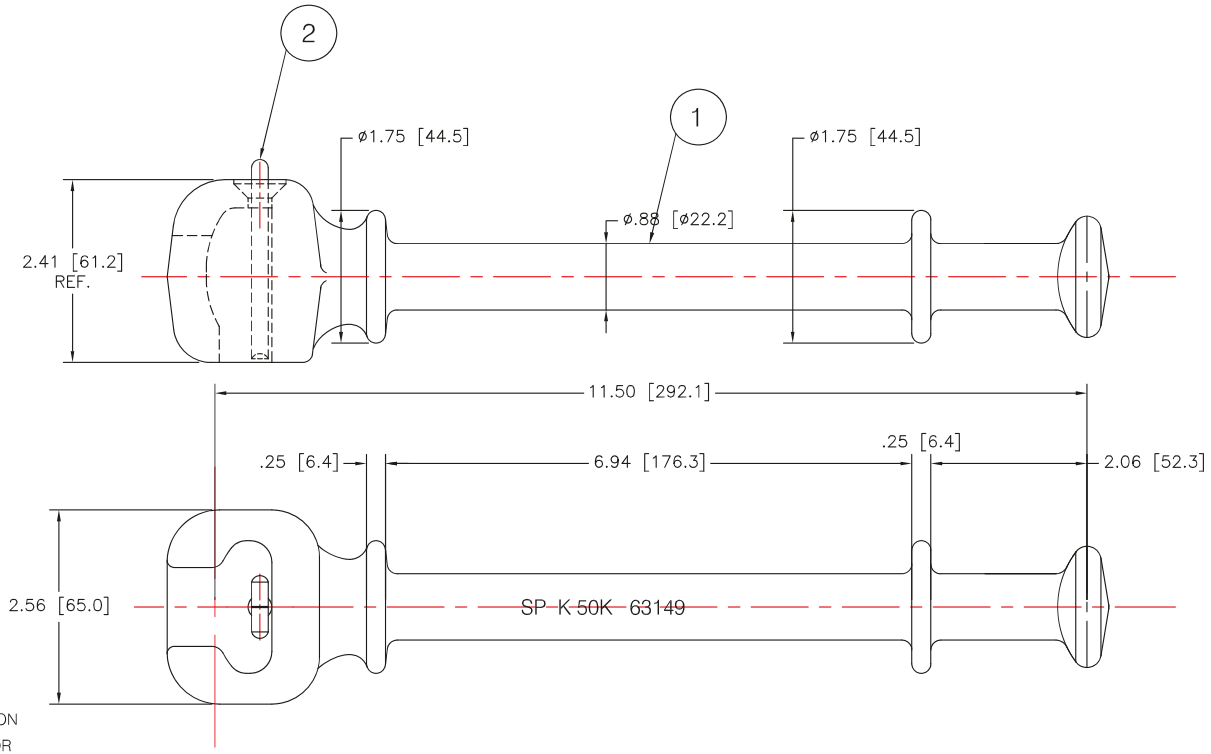


NOTES:

1. DIMENSIONS ARE IN METRES.
2. SWING & SAG SHOWN ARE FOR SPAN 258 TO 259.

APPENDIX B: NEW HARDWARE CUTSHEETS

DWG. No. 18887 B



YIELD: LOAD 50,000 LBS. [222 KN]
WITHOUT ANY PERMANENT DEFORMATION
WHICH WOULD IMPAIR THE FUNCTION OR
REUSABILITY OF THIS PART

ULTIMATE: LOAD 60,000 LBS. [267 KN]
WITHOUT FAILURE

IMPACT: IN ACCORDANCE WITH ASTM A370 AND E23
20 FT. LBS. @ -22 °F
27 J. @ -30 °C

M.P.I. : BEFORE GALVANIZING IN ACCORDANCE WITH ASTM A275.

FINISHED PRODUCT TO MEET SPEC ANSI C29.2 CLASS 52.8 & 52.11 FOR SOCKET & BALL END

DIMENSIONS: UNLESS OTHERWISE SPECIFIED
ALL DIMENSIONS ARE IN INCHES.

TOLERANCES:- UNLESS OTHERWISE SPECIFIED
TO SLACAN SPEC. NO. 12508

ITEM	QTY.	DESCRIPTION		DWG. NO.
2	1	SOCKET COTTER KEY STAINLESS	STEEL	16494 B
1	1	SOCKET - BALL EXTENDED DETAIL	STEEL	25535 B

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R	DESCRIPTION	DATE	REV.	APP.
5	REDRAWN AUTOCAD	04/02/15	JS	SD

REVISION

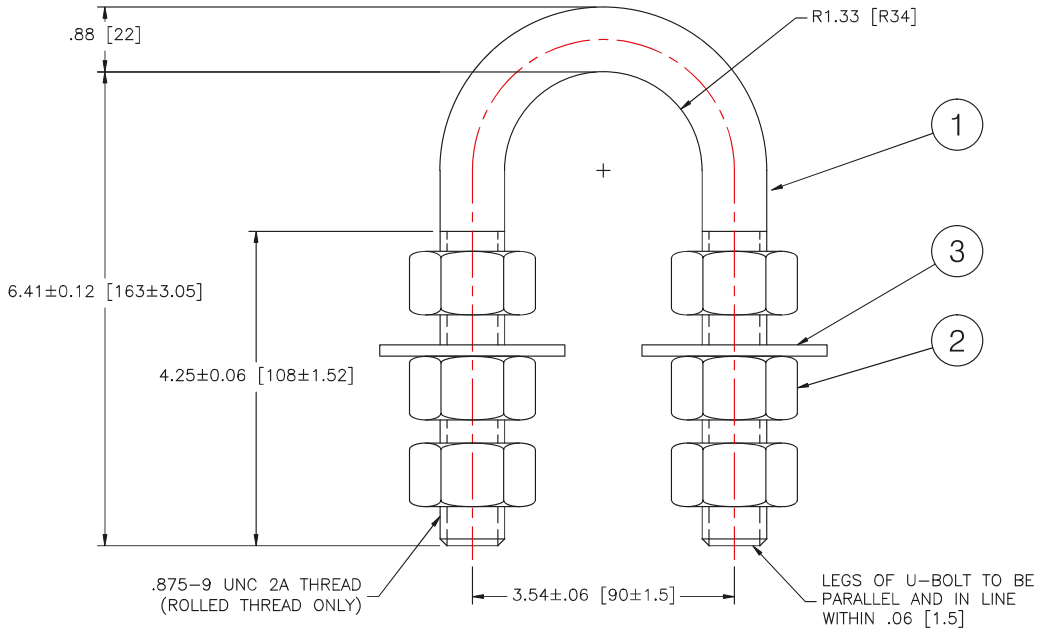
M. JOVANOVIC — DRAWN BY
P. LYNCH — APPROVED BY
01/14/80 — DATE
81105 — MC No.

SLACAN Industries Inc.

SOCKET - BALL EXTENDED HOT LINE ASS'Y 50K CLASS 52.8 & 52.11 TYPE K

PROJ. No. | CAT. No. 63149
SCALE | DWG. No. 18887 B | 5

DWG. NO.	22597 B



MATERIAL: STEEL

HEAT TREATMENT: ITEM 1 - NORM., QUENCH & TEMPER
TO SLACAN SPEC. NO. 12620

GALVANIZING: *HOT DIP GALVANIZED TO SLACAN
SPEC. NO. 12505 CSA G164.
*ITEM 1 ~DRY - DO NOT PICKLE~

IMPACT: IN ACCORDANCE WITH ASTM A370, E23
AND CSA G40.20
ITEM 1 ONLY 20 FT.-LBS. @ -22°F
27 J @ -30°C

M.P.I. : ITEM 1 - BEFORE GALVANIZING IN
ACCORDANCE WITH ASTM A275 AND E709

ULTIMATE STRENGTH: 70,000 LBS. [311kN] WITHOUT FAILURE

DIMENSIONS: UNLESS OTHERWISE SPECIFIED
ALL DIMENSIONS ARE IN INCHES.
BRACKETED VALUES ARE METRIC (mm)
EQUIVALENTS.

TOLERANCES: UNLESS OTHERWISE SPECIFIED
1 DECIMAL PLACE 0.0 = ± .06 (1.5)
2 DECIMAL PLACES 0.00 = ± .03 (.8)
3 DECIMAL PLACES 0.000= ± .015 (.4)

ITEM	QTY	DESCRIPTION	DWG. NO.
3	2	Ø.875 [Ø22.2] PLAIN ROUND WASHER, CAT. 63807 ITEM 9	11950 B
2	6	.875-9 UNC - 2B REG. FIN. HEX. NUT, SPEC. 12538, SAE J995 GR 5 +.020 OVS.	
1	1	Ø.875 [Ø22.2] U-BOLT DETAIL	SEE ABOVE

BILL OF MATERIAL

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R	DESCRIPTION	DATE	REV.	APP.
2	REDRAWN AUTOCAD & CHANGED ULTIMATE LOAD 311 KN	05/03/17	IA	SD
1	IMPACT TEMP NOW -30°C (-22°F)	08/09/10	JB	SD

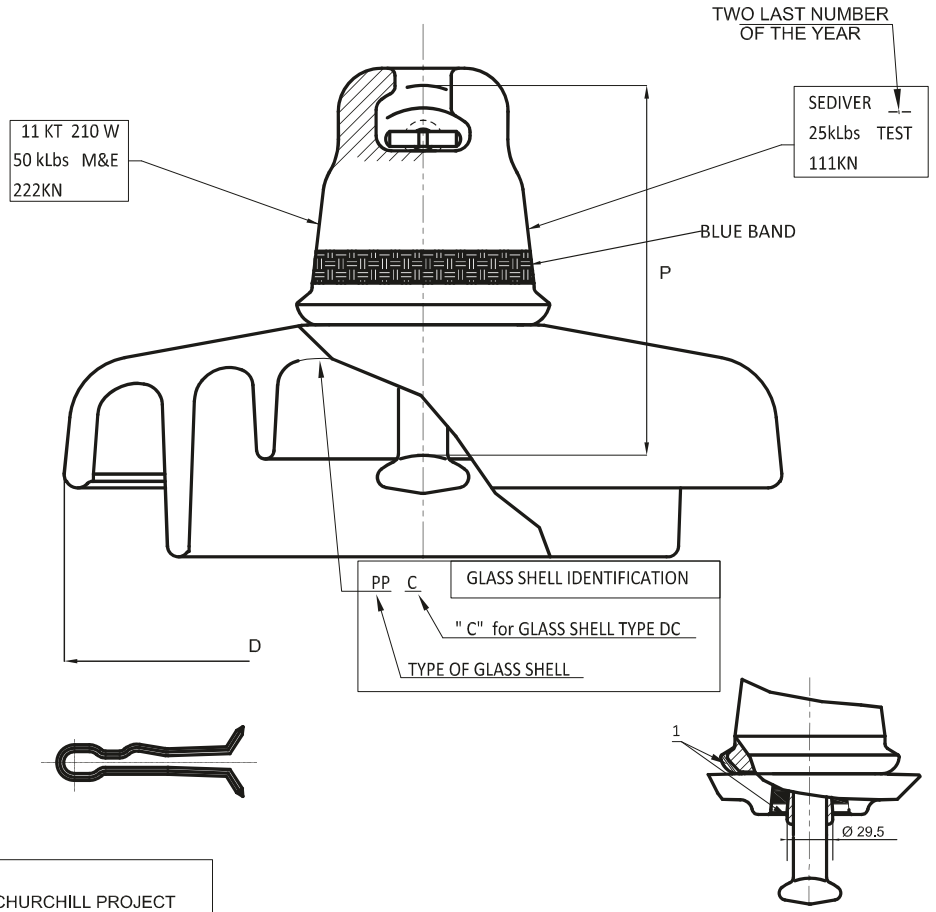
REVISION

Woodward
DRAWN BY
S. Dinsmore
APPROVED BY
04/24/97
DATE
83573
MC No.

SLACAN Industries Inc.

Ø.875 [Ø22.2] U-BOLT ASS'Y

PROJ. No.	CAT. No. 83573	
SCALE	DWG. No. 22597 B	2



DIMENSIONS

According to CAN/CSA C1325-99 and CAN/CSA C411.1-10

CSA Designation		Type CSDC-3
DIAMETER OF SHELL (D)	mm	320
SPACING (P)	mm	170
MINIMAL NOMINAL CREEPAGE DISTANCE	mm	550
COUPLING ACCORDING TO CSA-C411.1-10		Type:CS-11
APPROXIMATE NET WEIGHT	kg	10.5

ELECTRICAL PERFORMANCES

According to CAN/CSA C1325-99

d.c. withstand voltage		
dry one minute ±	kV	170
wet one minute ±	kV	65
50% dry d.c. flashover voltage ±	kV	175
50% dry lightning impulse flashover voltage ±	kV	150
d.c. puncture withstand voltage (SF6)	kV	300
Max Radio Interference voltage at 1MHz		50µV ±30 kVdc

MECHANICAL PERFORMANCES

According to CAN/CSA C1325-99 and CAN/CSA C411.1-10

COMBINED MECHANICAL AND ELECTRICAL STRENGTH	kN	222
TENSION PROOF	kN	111
MECHANICAL IMPACT STRENGTH	Nm	45

COMPONENTS PARTS

DIELECTRIC SHELL	:	HIGH RESISTIVITY HVDC TOUGHENED GLASS
CAP	:	HOT DIP GALVANIZED CAST IRON
PIN	:	HOT DIP GALVANIZED FORGED STEEL
COTTER KEY	:	STAINLESS STEEL
CEMENT	:	ALUMINOUS, hot cured
Sacrificial sleeve (1) :		>99.8% ZINC (adherent sleeve)

VERIFIED CORRECT
FOR USE IN LOWER CHURCHILL PROJECT
PT0329-350kV HVdc
SIGNED : J.M. GEORGE

***** DATUM REFERENCE: ALL ELEVATIONS ARE IN METRES REFERENCED TO GEODETIC. COORDINATE REFERENCE: UTM 6° (UNIVERSAL TRANSVERSE MERCATOR) PROJECTION, NAD83, ZONE CENTRAL MERIDIAN 63° 00' W LONGITUDE. *****

ISSUE	REV.	DATE	DISTRIBUTION & STATUS
	3	20-May-2014	Lower Churchill project was Low Churchill project.
	2	31 Jan 2014	ADDED CAP IDENTIFICATION
	1	03-Dec-2013	ADDED GLASS IDENTIFICATION
	0	08-Nov-2013	ISSUED FOR REVIEW

ISSUE REGISTER | No. | REFERENCE DRAWING

No.	DATE	REVISION	MOD	VER.	APP.

REVISION REGISTER

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2. REVIEWED - INCORPORATE COMMENTS, RESUBMIT & RESUBMIT
3. REVIEWED - NOT ACCEPTED
4. INFORMATION ONLY
5. NOT REVIEWED
LEAD REVIEWER: M. Raissi 18-Dec-2014
NE-LCP MANAGEMENT:
PROJECT MANAGER:

sediver

DESIGNED MC | DRAWN MC | VERIFIED ST | DATE 27-Nov-2014 | APPROVED (Discipline Lead Engineer) | APPROVED (Engineering Manager) | SCALE 1/1

CLIENT: nalcor energy
PROJECT: 315kVac Transmission LinePurchase Order #PT0301-001
TITLE: Sediver model N220P/C 170 DR
Code : NC220PP170Z(X/Y)11KNI (GI020090NON)
SUPPLIER DOC No. ENG 68934 | NE DOC No. ILK-SV-SD-6200-TL-D04-0002-01 | Rev. C1

FORMAT ANSI D (22x34)

This document has been reviewed & coded electronically via Aconex.

APPENDIX C: NEW HARDWARE DRAWINGS

Appendix D

LIL Engineering Study – Calculations for OPGW Peak Reinforcement





TETRA TECH

LIL Engineering Study – Calculations for OPGW Peak Reinforcement

Newfoundland and Labrador Hydro Report No. ILK-TT-CD-6200-TL-H15-0002-01
TT Document Number: 705-2579500100-REP-G0003-00
July 21, 2025

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Project Manager



REVISION HISTORY

Tetra Tech REV. NO	ISSUE DATE	PREPARED BY	REVIEWED BY	APPROVED BY	DESCRIPTION OF REVISION
00	July 21, 2025	Tarek Ghazal	Julien Dupas	Greg Sheppard	Issued for Use

NSPML 2026 Holdback Mechanism IG IR-09 Attachment 1 Page 75 of 195

TABLE OF CONTENTS

1.0 INTRODUCTION **1**

2.0 METHODOLOGY **1**

2.1 Geometery 1

2.2 Constraints 2

2.3 Material Properties 2

2.4 Loading 3

2.5 Meshing 4

2.6 Connectors 5

2.7 Contact Surfaces 6

3.0 RESULTS **7**

LIST OF TABLES

Table 1: Material Properties 3

Table 2: Loading Cases for Each Tower Family Group 4

LIST OF FIGURES

Figure 1: OPGW Peak Model for Towers A2 and B2 1

Figure 2: OPGW Peak Model for Towers A4 and B1 2

Figure 3: Finite Element Model Constraints 2

Figure 4: Loading Direction 4

Figure 5: Mesh and Mesh Controls Used for Tower Family B1 5

Figure 6: Connectors Used for Bolts Modeling. 6

Figure 7: Assigned Separation Contact Surfaces 6

Figure 8: Von Mises Stress Distribution for Tower Group A2 7

Figure 9: Von Mises Stress Distribution for Tower Group A4 8

Figure 10: Von Mises Stress Distribution for Tower Group B1 9

Figure 11: Von Mises Stress Distribution for Tower Group B2 10

1.0 INTRODUCTION

Newfoundland and Labrador Hydro have experienced structural failures on the suspension towers for the Labrador-Island Transmission Line, +/- 350 kV HVDC. One of these failures occurred on suspension tower type A3 where the OPGW support attaches to the peak of the tower. Report number ILK-EG-ED-6200-TL-H15-0005-01 outlines these observed failures.

Report ILK-AJ-6200-TL-H15-0001-01 investigates the capacity of the A3 tower as well as the other suspension and running angle towers A1, A2, A4, B1, and B2. Tower types A2, A3, A4, B1, and B2 were found to have an inadequate design to support the original design loads. The report discusses the design for peak reinforcements for A3.

This technical memo discusses the reinforcement methodology of the OPGW peak for tower groups A2, A4, B1 and B2, which was used to generate drawings 705-2579500100-DWG-H0008-00 to 705-2579500100-DWG-H0015-00. The design approach is similar to the approach completed for the A3 reinforcements.

2.0 METHODOLOGY

Finite element models using Autodesk Inventor's Nastran was performed for the studied tower groups (i.e., A2, A4, B1 and B2). Since all towers were modelled using the same methodology, only sample figures are presented in the following subsections. However, the analysis results for each tower family are presented separately in Section 3.

2.1 GEOMETERY

As seen in Figure 1 below, the grey members are the existing members, while the green members represent additional steel sections to be added for reinforcement. As shown in the figure, the suggested reinforcement includes adding one bent plate bolted to the existing connector plate and the bottom of the double angles. Also, 2 back-to-back angles will be bolted to the existing double angles from one side and bolted to a new bent plate from the other side. For towers A4 and B1, the addition of a stiffener was needed at the lower bent plate as shown in Figure 2.

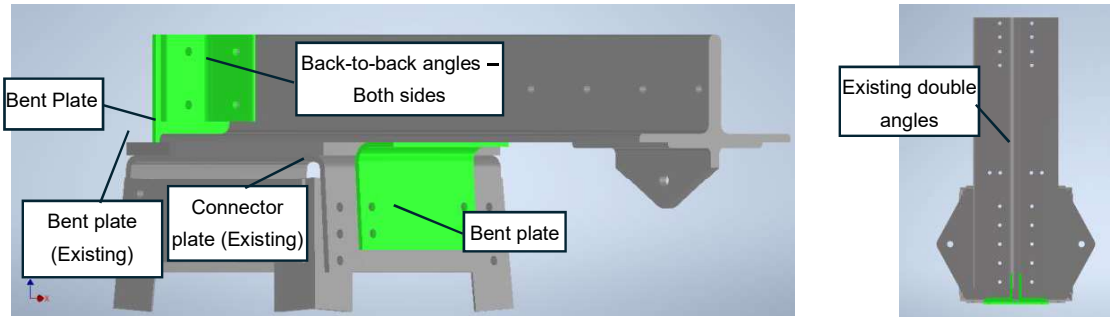


Figure 1: OPGW Peak Model for Towers A2 and B2

a) Isometric View

b) Plan View

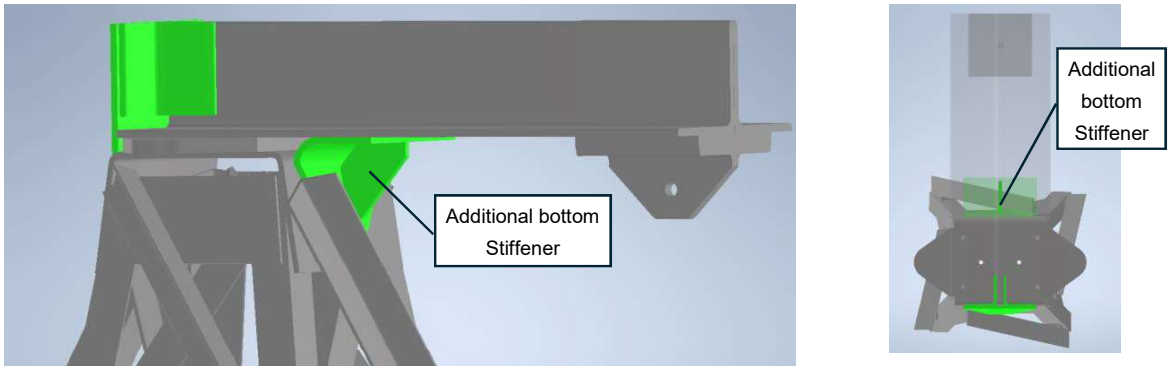


Figure 2: OPGW Peak Model for Towers A4 and B1

a) Isometric View

b) Plan View

2.2 CONSTRAINTS

As shown in Figure 3 below, only the tower peak was modelled since this is the scope of this study. Fixed constraints were assigned to the bottom of the legs (seen in blue color at the bottom of the legs). This prevents any rotation or translation at these nodes.

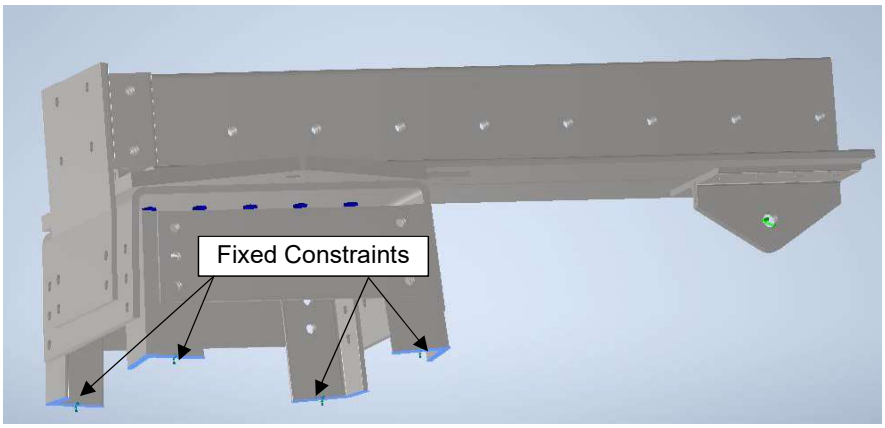


Figure 3: Finite Element Model Constraints

2.3 MATERIAL PROPERTIES

350 WT steel was used in the analysis, as per CSA G40.21 standard. The material properties are outlined in the table below. Since large deformations were not expected to occur, linear static analysis was performed. In other words, stresses will remain in the linear elastic range of the material.

Table 1: Material Properties

E (Modulus of Elasticity)	200 GPa
α (Coeff. of Thermal Exp.)	1.2e-5 (/k)
v (Poisson Ratio)	0.29
F_y (Yield Stress)	350 MPa
F_u (Ultimate Stress)	480 MPa

2.4 LOADING

NL Hydro provided design loading drawings for each tower family listed below:

- Tower A2
  - ILK-SN-CD-6200-TL-DD-0070-01
  - ILK-SN-CD-6200-TL-DD-0070-02
- Tower A4
  - ILK-SN-CD-6200-TL-DD-0199-01
- Tower B1
  - ILK-SN-CD-6200-TL-DD-0066-01
  - ILK-SN-CD-6200-TL-DD-0066-02
  - ILK-SN-CD-6200-TL-DD-0066-03
  - ILK-SN-CD-6200-TL-DD-0066-04
- Tower B2
  - ILK-SN-CD-6200-TL-DD-0201-01
  - ILK-SN-CD-6200-TL-DD-0201-02
  - ILK-SN-CD-6200-TL-DD-0201-03
  - ILK-SN-CD-6200-TL-DD-0201-04
  - ILK-SN-CD-6200-TL-DD-0201-05
  - ILK-SN-CD-6200-TL-DD-0201-06

As shown in Table 2 below, four maximum loading cases were identified and chosen to be studied as follows:

1. Maximum vertical load case
2. Maximum positive transverse load case
3. Maximum negative transverse load case, and
4. Maximum longitudinal load case.

All four loading cases were applied at the insulator suspension insulator vang in vertical, transverse and longitudinal directions, as shown in the figure below.

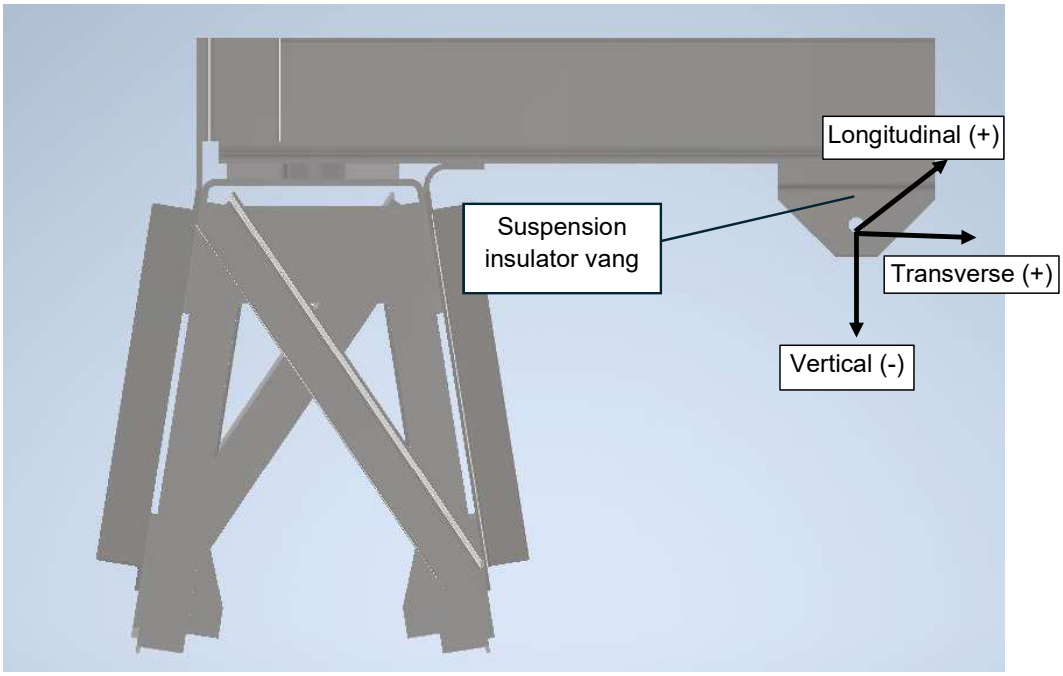


Figure 4: Loading Direction

Table 2: Loading Cases for Each Tower Family Group

Tower Family /LC	Max. Vertical Load (kN)			Max. Positive Transverse Load (kN)			Max. Negative Transverse Load (kN)			Max. Longitudinal Load (kN)		
	V	T	L	V	T	L	V	T	L	V	T	L
A2	-89.9	3.5	0.0	-31.9	60.9	0.0	-31.9	-54.8	0.0	-69.8	2.9	-60.0
A4	-119.0	3.7	0.0	-40.0	86.7	0.0	-40.0	-79.6	0.0	-91.7	3.1	-65.0
B1	-103.3	0.0	0.0	-28.6	47.9	0.0	-30.9	-45.6	0.0	-81.1	0.0	-59.3
B2	-119.0	0.0	0.0	-34.3	90.7	0.0	-40.0	-88.1	0.0	-2.7	2.2	-83.1

2.5 MESHING

Parabolic tetrahedron elements were used for meshing. Bolt holes were not modelled for some towers for simplicity, except for the bolts connecting the top double angles with the dead end and bent plates. These specific bolts were modeled to increase the model accuracy and capture the actual behavior of the connection at this location under the applied loads. These were at the location where on-site actual overstresses occurred for tower family group A3. It was expected that the rest of the towers will behave similarly. For sharp edges/curved, mesh control parameters were identified to decrease the mesh size at these locations to avoid stress concentration. Figure 5 below shows a sample snapshot of the mesh used for tower family B1.

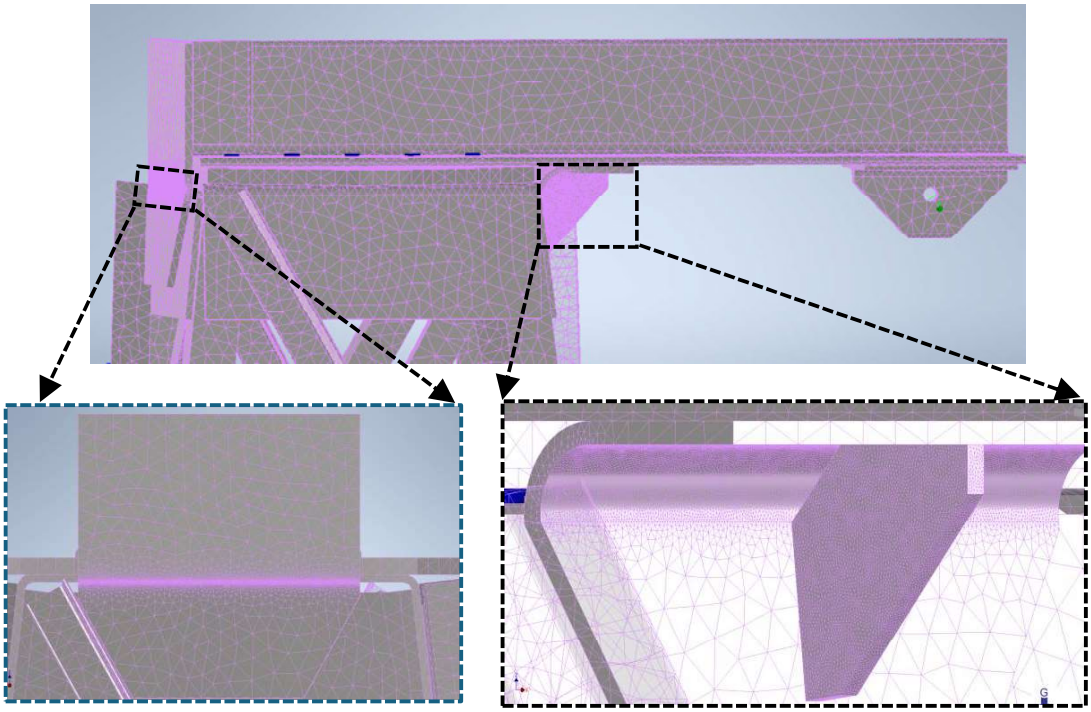


Figure 5: Mesh and Mesh Controls Used for Tower Family B1

2.6 CONNECTORS

As mentioned in Section 2.5, only the connection between the double back-to-back angles and the dead end, and bent plates were modeled. Connectors in Autodesk Inventor Nastran were used to represent the bolt assemblies. These connectors represent beam elements having the same material properties of ASTM A394 5/8” diameter bolts, as shown in Figure 6 below.

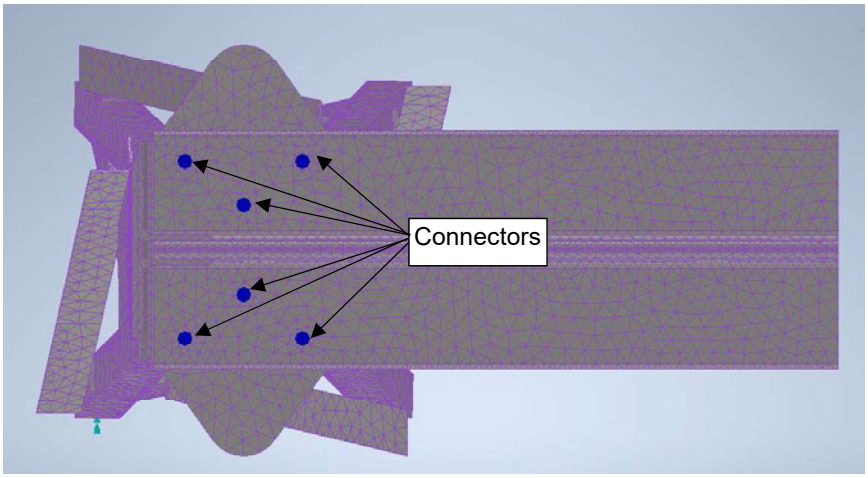


Figure 6: Connectors Used for Bolts Modeling.

2.7 CONTACT SURFACES

Separation contacts were used at 2 locations, between the bent plate and the dead-end bottom plate, as well as between the bottom of the back-to-back angles and the top of the dead-end plate, as shown in Figure 7 in blue. Assigning separation contacts were needed to simulate the movement of the assembly relative to each other. On the other hand, for all other surfaces that are bolted together with no relative movement to each other allowed, bonded surfaces were assigned.

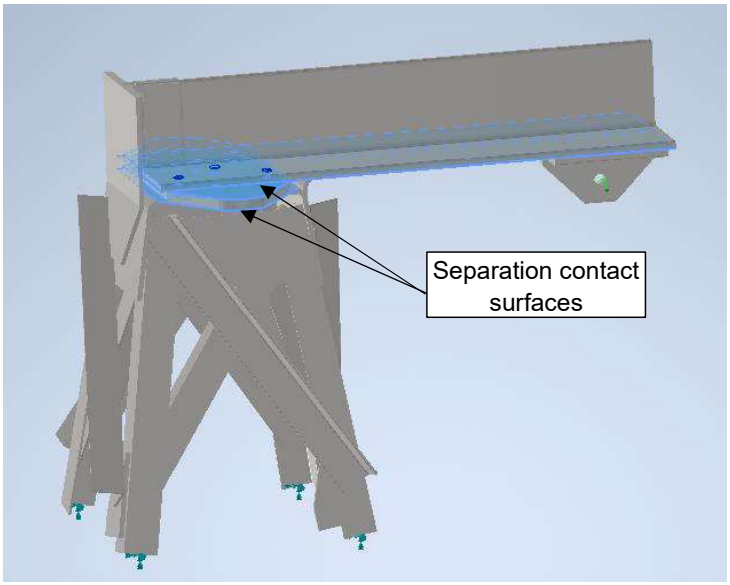


Figure 7: Assigned Separation Contact Surfaces

3.0 RESULTS

Finite element analysis was conducted for OPGW peak of each tower family (i.e., A2, A4, B1, and B2). Von mises stress distribution was checked for each of the 4 loading cases shown in Table 2. Stress values were compared to the yield stress of 350 WT steel (Fy=350 MPa). Figures 8 to 11, show the Von Mises stresses distribution for towers A2, A4, B1, and B2 respectively, for the loading cases shown in Table 2. The deformed shape in the figures is magnified with a displacement factor of 10% for presentation purposes. As seen in the figures, the maximum stress for all load cases of the 4 tower groups was kept below 350 MPa, except for some areas, where sharp edges/change in geometry existed. These overstresses are only due to stress concentration and can be ignored.

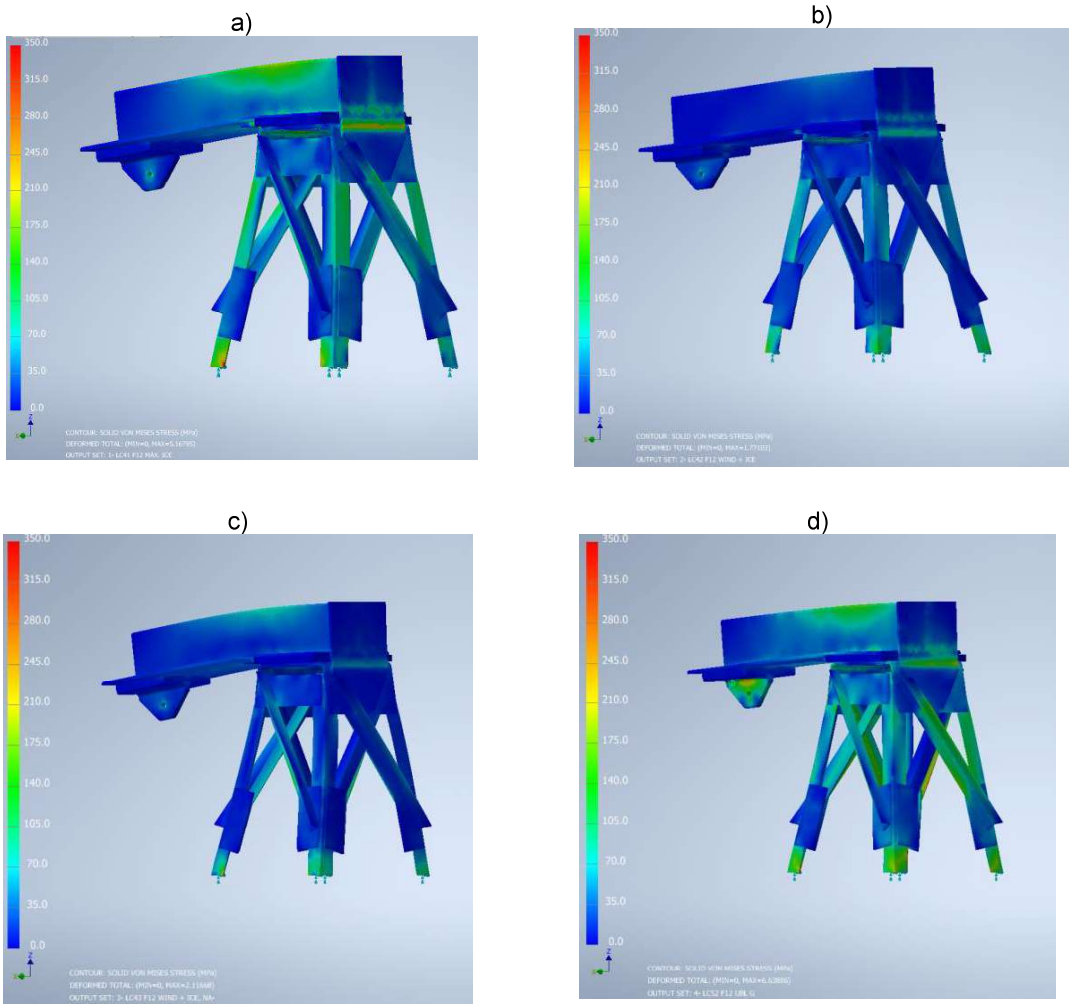


Figure 8: Von Mises Stress Distribution for Tower Group A2
a) Max. Vertical Load
b) Max. Positive Transverse Load
c) Max. Negative Transverse Load
d) Max. Longitudinal Load

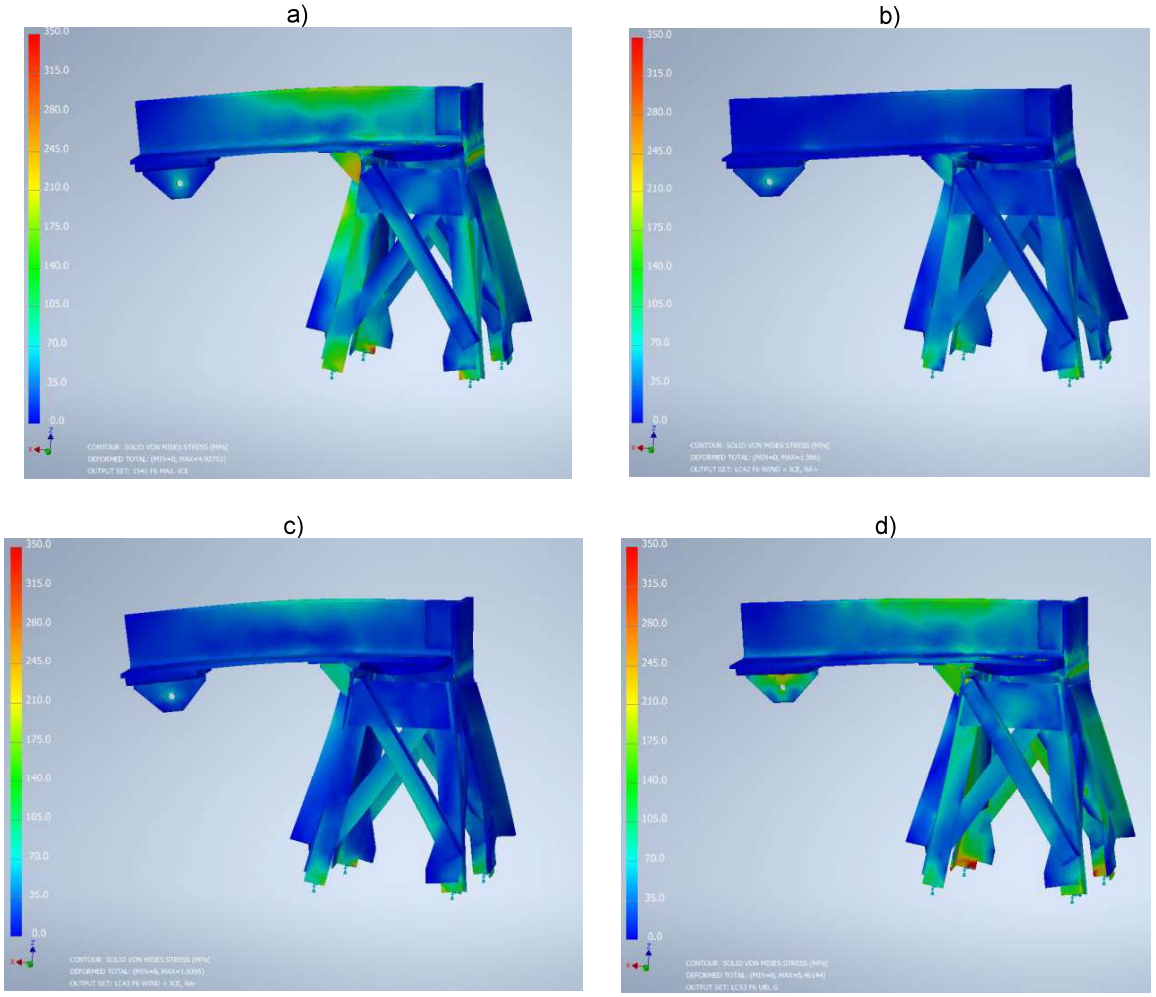


Figure 9: Von Mises Stress Distribution for Tower Group A4
a) Max. Vertical Load
b) Max. Positive Transverse Loa
d) Max. Negative Transverse Load
d) Max. Longitudinal Load.

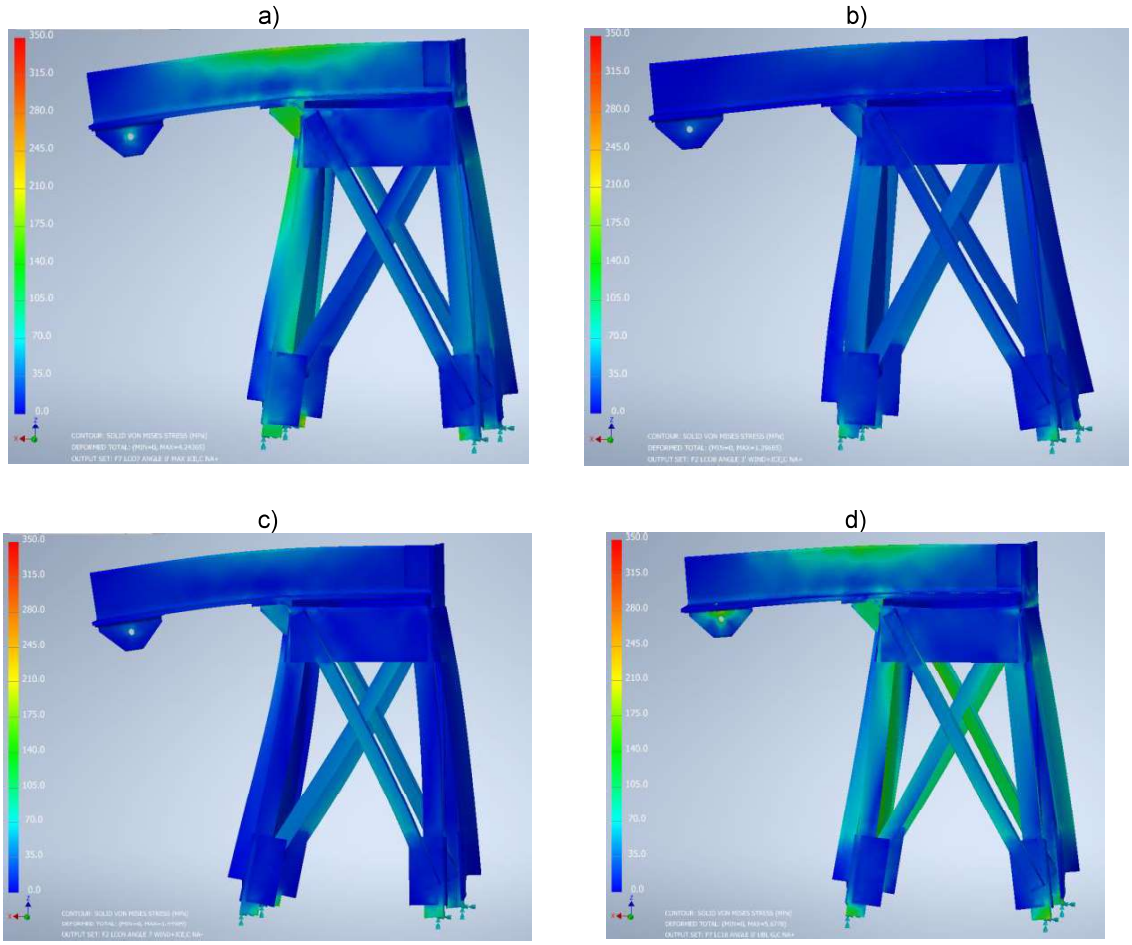


Figure 10: Von Mises Stress Distribution for Tower Group B1
a) Max. Vertical Load
b) Max. Positive Transverse Load
c) Max. Negative Transverse Load
d) Max. Longitudinal Load

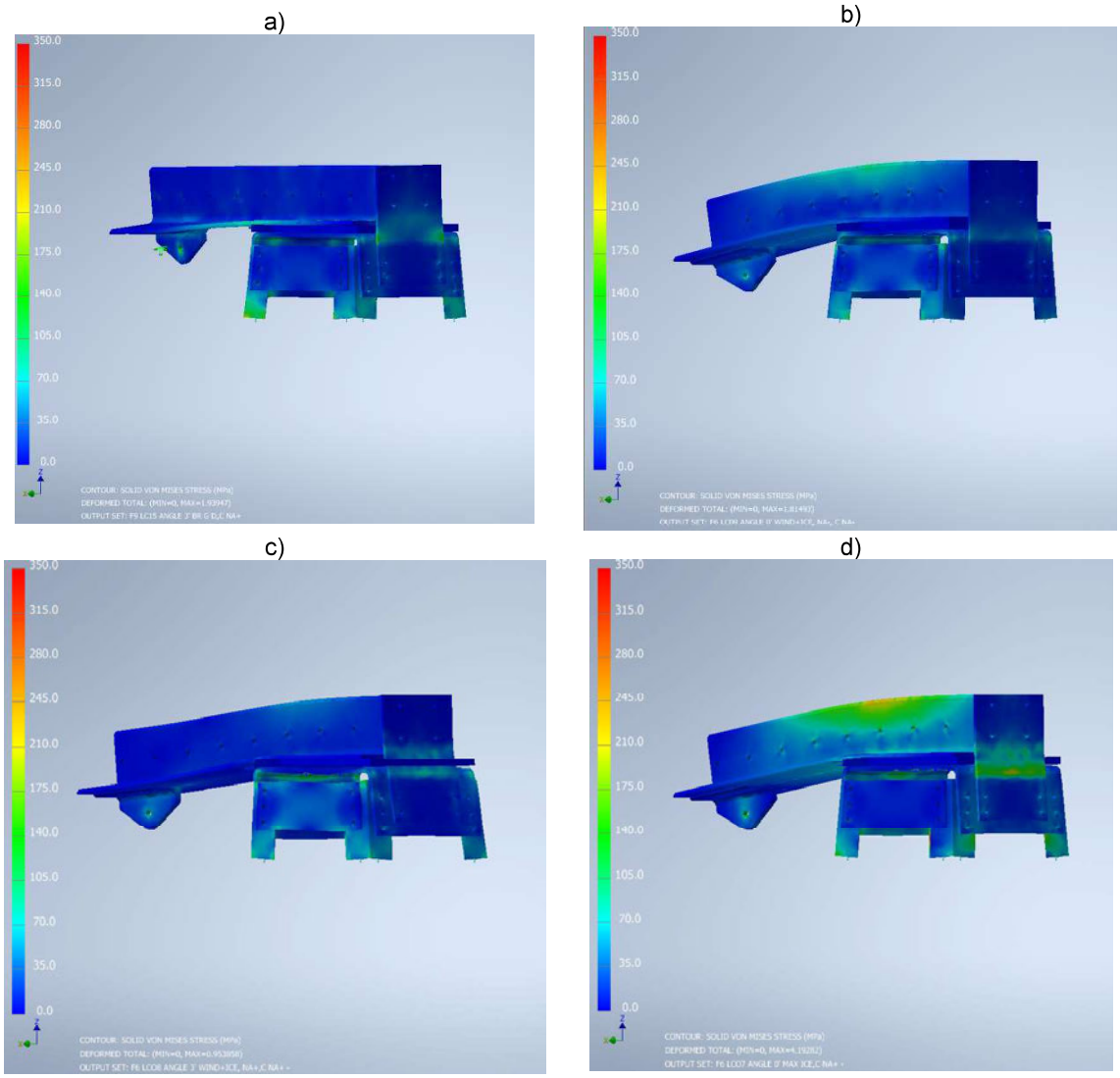


Figure 11: Von Mises Stress Distribution for Tower Group B2
a) Max. Vertical Load
b) Max. Positive Transverse Load
c) Max. Negative Transverse Load
d) Max. Longitudinal Load.

Appendix E

Wood Pole and Mid-Span Cost Estimates Summary



Wood Pole and Mid-Span Cost Estimates Summary

Wood Pole and Mid-Span
Cost Estimates Summary

Contents

1.0 Executive Summary 1
2.0 Purpose 1
3.0 Cost Estimates 2
3.1 Option 1: Wood Pole Line Installation 2
3.1.1 Method 1: Emergency Work Data 2
3.1.2 Method 2: Previous Construction Data 3
3.2 Option 2: Midspan Structures Installation 4
4.0 Discussion 6
4.1 Option 1: Wood Pole Line Installation 6
4.2 Option 2: Midspan Structures Installation 6
5.0 Conclusion 7

1.0 Executive Summary

This report summarizes options to address electrode line failures along the Labrador Island Link (LIL). Various failures have occurred on the 350 kV HVdc line in Southern Labrador. Multiple factors, including large ice accumulations, have resulted in failures at various points throughout the line. High level cost estimates have been developed for two options to reduce loads on the existing infrastructure. Those options include installation of midspan structures in certain high risk areas and removal of the electrode lines from the transmission towers in favour of installation of adjacent wood pole structures. Refer to Section 3 for further information on these options and their associated costs.

2.0 Purpose

The purpose of this report is to summarize costs for two options to reduce electrode conductor failures. Option 1 is to remove the existing electrode lines from the transmission towers and place them on nearby wood pole lines. Option 2 is to install midspan structures along the transmission corridor to reduce spans and thereby reduce loads on the existing infrastructure. Refer to Sections 3.1 and 3.2 for more information on these options respectively.

3.0 Cost Estimates

3.1 Option 1: Wood Pole Line Installation

Two methods were utilized to develop a per km cost estimate for reinstatement of the electrode lines onto new wood pole line. The first method was to review a previous estimate for emergency work supplied by Locke's Electrical in April 2024. Section 3.1.1 summarizes the findings of this method of cost estimate development.

3.1.1 Method 1: Emergency Work Data

Locke's Electrical Original Estimate =	$1,286,374.75
Length of Line Considered in Original Estimate =	5.93 km
Estimated Emergency Factor =	1.5
Labor Cost/km =	**$144,691.99**

The emergency work excluded material costs. An estimate of the material costs is provided below:

12 Wood poles/km=	$35,504.82
Conductor=	$17,434.00
160 KN Insulator CSDC-2 Type=	$2,134.74
Tangent Cross Arm and V-Brace Assembly=	$11,068.61
Dead-end (30-90°) Cross Arm Assembly=	$2,573.46
Extension Bracket=	$7,471.58
Estimated Inflation Factor Steel & Labor=	2
Estimated Inflation Factor Wood=	1.3
Material Cost/km=	**$117,971.60**

The per km costs above are scaled from a previously supplied estimate of emergency work. Costs such as mobilization and demobilization cannot be scaled in this way. These costs are accounted for as a lump sum:

Mobilization =	$140,000.00
Demobilization =	$140,000.00
Estimated Inflation Factor=	2
Total Mob/Demob Cost =	**$560,000.00**

Based on method 1, emergency work data, the total current cost to construct a line from structures would be approximately:

Current Total Cost/km = Labor cost/km + Mat cost/km + Mod&Demob	**$262,663.58/km + $560,000.00**

3.1.2 Method 2: Previous Construction Data

The second method used to develop a per km cost estimate for reinstatement of the electrode lines onto new wood pole line was to review construction costs from when Locke's electrical completed installation of a wood pole electrode line in Southern Labrador as part of the overall construction of the LIL. The following summarizes the findings of this method of cost estimate development:

Table 1: Previous Construction Data Cost Estimate

Item	Unit Price	#Units	Cost
Mobilization	LS		Refer to Section 3.1.1
Demobilization	LS		Refer to Section 3.1.1
Tree Clearing			$0.00
Snow Clearing			$0.00
Excavation Class A (Rock)	$980.00	180	$23,244.91
Rock Anchor Install	$1,530.00	90	$18,145.26
Pole Install – dist and erec 65 ft pole	$4,900.00	90	$58,112.28
Framing – str single pole light-angle (1-10 deg)	$3,920.00	45	$23,244.91
Framing - Structure Single Pole Tangent Guyed	$3,430.00	22.5	$10,169.65
Framing - Structure Single Pole Tangent	$2,744.00	22.5	$8,135.72
Framing - Two Pole Dead-End (30-90 degrees)	$9,800.00	2	$19,600.00
Slack span install	$980.00	7.5	$980.00
Stringing conductor and damper	$35,280.00	7.5	$35,280.00
Counterweights	$1,519.00	5	$1,519.00
Estimated Inflation Factor Steel & Labor=			2
Estimated Inflation Factor Wood=			1.3
Total Cost=			**$313,379.68/km + $560,000.00**

3.2 Option 2: Midspan Structures Installation

Original construction costs were utilized to evaluate the cost of installing midspan structures along the existing 350 kV HVdc line in Southern Labrador. The material costs of installing type A1 towers in Southern Labrador is summarized in the tables below:

Table 2: Midspan Structure Material Costs

Material Cost				
Description	**Unit**	**Unit Price**	**Units Per Tower**	**Price per Tower**
A1+6 Tower	EA	$ 8,776	1	$ 8,776
A1 Foundation	EA	$ 4,000	1	$ 4,000
A1 Guy Anchors	EA	$ 1,760	4	$ 7,040
A1 Guy Assembly	EA	$ 168	8	$ 1,344
A1 Guy Wire	M	$ 12	108	$ 1,296
Tangent Pole Assembly	EA	$ 536	3	$ 1,608
Tangent Pole Insulators	EA	$ 66	52	$ 3,432
Tangent Electrode Assembly	EA	$ 128	2	$ 256
Tangent Electrode Insulators	EA	$ 48	8	$ 384
OPGW Tangent Assembly	EA	$ 162	1	$ 162
Sub-Total				**$ 28,298**
Total with Inflation Factor				**$ 56,596**

Table 3: Midspan Structure Installation Costs

Install Cost				
Description	**Unit**	**Unit Price**	**Units Per Tower**	**Price per Tower**
A1+6 Tower	EA	$ 65,300	1	$ 65,300
A1 Foundation	EA	$ 17,733	1	$ 17,733
A1 Guy Anhors	EA	$ 1,100	4	$ 4,400
Pole Conductor	KM	$ 94,000	0.3	$ 28,200
Electrode Conductor	KM	$ 43,000	0.3	$ 12,900
OPGW	KM	$ 25,000	0.3	$ 7,500
Sub-Total				**$ 136,033**
Total with Inflation Factor				**$ 272,066**

Assuming an Estimated inflation factor of 2, the cost to install a single A1 tower in Southern Labrador is $56,596.00 + $272,066.00 = $328,662.00 per tower.

Additionally, lump sum costs such as restringing and mobilization/demobilization must be accounted for. Restringing costs include removal and restringing of the existing conductors for a 21 structure Dead-end to Dead-end portion of the line. It has been estimated that removal would cost approximately $5,000 per span and restringing would cost about $10,000 per span. Resulting in a total cost of approximately $315,000.

Due to construction complexity it is anticipated that mobilization and demobilization costs would be higher than the costs utilized in Section 3.1. Based on approximate estimation this cost would be $700,000.00.

Total Cost = $328,662.00 per tower + $315,000.00 + $700,000.00

4.0 Discussion

4.1 Option 1: Wood Pole Line Installation

The two methods utilized to develop cost estimates for Option 1: Wood Pole Line Installation result in total costs of **$262,663.58/km** and **$313,379.68/km** (+ mob and demob) respectively. These two values exhibit a variation in their values which could be accounted for by a number of factors including the assumptions made during their development. Assumptions have been listed below for consideration:

1. An general inflation factor of 2 was used to account for inflation of costs since the LIL was first installed.
2. A wood inflation factor of 1.3 was used to account for inflation of costs since the LIL was first installed.
3. An emergency factor of 1.5 was used to account for the probable mark up on costs when Locke's Electrical provided an estimate for emergency work in April 2024.
4. The number of poles per km was estimated based on the existing electrode line from the MF-Forteau junction to L'Anse Aux Diable.

Quotes for emergency work will inherently include a level of uncertainty due to the nature of the work. This uncertainty could result in a less accurate estimate than one developed under normal circumstances.

An additional consideration that will impact the feasibility of each option is the consideration of impacts from lost time. Presumably the wood pole line would be constructed alongside the existing transmission line. The electrode lines could be moved one conductor at a time with minimal outage requirements. These impacts require further investigation to quantify.

4.2 Option 2: Midspan Structures Installation

The cost of installing new midspan structures is approximately **$328,662.00 per tower + $315,000.00 + $700,000.00**. Assumptions were made in the development of this estimate which can be reviewed to ensure accuracy. They are as follows:

1. An general inflation factor of 2 was used to account for inflation of costs since the LIL was first installed.
2. The midspan structure would be an A1 type structure.

An additional consideration that will impact the feasibility of each option is the consideration of impacts from lost time.. The new midspan structures would be constructed inside the path of the existing transmission lines. Completing the construction, and connecting the conductors to the new structures, would likely require outages on the LIL. Further investigation is required to determine if this is even a possibility and to quantify potential financial impacts. If an outage on the LIL is required costs in the ballpark of $500,000/day have been mentioned.

5.0 Conclusion

In conclusion the preliminary data suggests that out of these two options the most cost effective approach would be to install a dedicated wood pole electrode line near the existing transmission line in identified high risk zones. The cost of which would be approximately **$313,379.68/km + $560,000.00.** Further consideration should be given to the assumptions listed in this report, analysis of the options in PLS-CADD, the constructability and loss time implications of each option.

Appendix F

Analysis Removing the Electrode Conductor from L3501/2

newfoundland labrador hydro

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Analysis of Removing the Electrode Conductor from L3501/2

May-2025



Table of Contents

1. Background 2
2. Sections for Consideration 4
3. Analysis 5
4. Summary, Conclusions, and Recommendations 15

1. Background

Line L3501/2 is the 350 kV HVdc overland transmission line portion of LIL traversing a distance of approximately 1,100 km through three major meteorological loading zones: average, alpine and eastern. The HVdc line has two poles, one OPGW, and two electrode conductors for a portion of line. See Figure 1. The electrode conductor is attached to the lattice towers for a part of the line from Muskrat Falls to about 384 km southeast of Muskrat Falls where it diverts to a separate right of way (ROW) on wood poles to an electrode site approximately 16 km away, located in the L'Anse-au-Diable area. Note that sections of L3501/2 without the electrode on the towers do not have electrode cross arms.

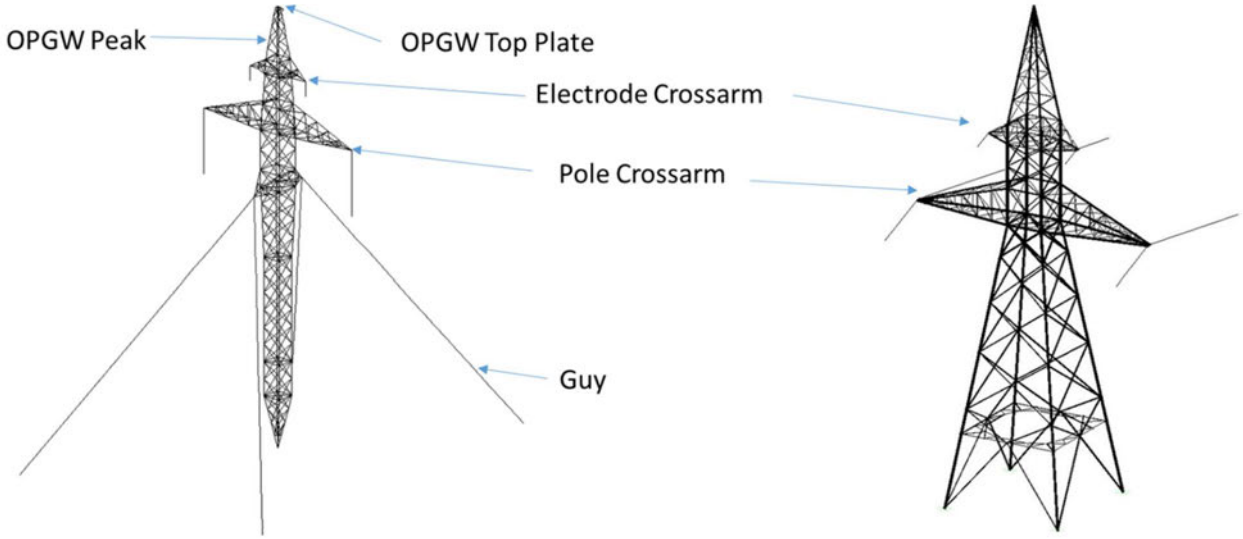


Figure 1 - Suspension and Deadend Tower Diagram

The HVdc transmission line corridor has been divided into three major meteorological loading zones referenced above in combination with 8 further subcategories related to meteoroidal loads, pollution levels (inland and costal), and geographic location. The resulting combination led to the HVdc line consisting of 19 separate loading zones. Eleven tower types (A1, A2, A3, A4, B1, B2, C1, C2, D1, D2, and E1) were designed to meet the loading requirements, which consist of a specified wind load, ice load, and combination of both applied to the line.

There have been a number of failures to components of the transmission line during ice event over the past 4 years. The electrode crossarms and the electrode conductor are two components that are often damaged in these events. All the failures detailed below occurred on A1 type towers, in sections of the line with the electrode conductor attached to the tower. The maximum design ice loads case for this section of the line is 50 mm of radial glaze ice with a density of 0.9 g/cm^3 (equivalent to 11.9 kg/m on the electrode conductor). The unbalanced ice load cases include 70% of the maximum ice back span, with 100% of the maximum ice ahead span on a tower (and vice versa) for one wire at a time, while all other wires have 100% of the maximum ice load on both spans.

In January of 2021 there was an icing event in central Labrador that caused damage to 12 electrode crossarms and damage to the electrode conductor in 34 locations. The ice was estimated to be from 54 to 65 mm of radial glaze ice with a density of 0.88 g/cm^3 (13.1 to 17.8 kg/m), and the damage likely occurred due to unbalanced ice loads from ice shedding. There were no other components damaged in this icing event.

In December of 2022 there was an icing event in central Labrador that caused damage to the electrode conductor at 3 locations. The ice was estimated to be from 70 to 72 mm of equivalent radial glaze ice at a density of 0.9 g/cm^3 (20.6 to

21.6 kg/m), and the damage likely occurred due to unbalanced ice loads from ice shedding. There were no other components damaged in this icing event.

In March 2024 there was an icing event in southern Labrador that caused damage to 16 electrode crossarms and damage to the electrode conductor at 17 locations. The ice was estimated to be from 100 to 125 mm of radial glaze ice with a density of 0.6 g/cm^3 (25.2 to 37.4 kg/m), and the damage likely occurred due to unbalanced ice from ice shedding. During this icing event, there was also damage to the OPGW tower peaks.

In January of 2025 there was an icing event in central Labrador that caused damage to 3 electrode crossarms and damage to the electrode conductor at 2 locations. The ice was estimated to be from 55 to 60 mm of radial glazed ice with a density of 0.7 g/cm^3 (10.8 to 12.4 kg/m), and the damage likely occurred due to unbalanced ice from ice shedding. The only other components damaged during this event occurred during planned ice removal.

All failures are shown in Table 1. The total number of failures to electrode components is 30 electrode crossarms and damage to the electrode conductor at 56 locations.

Table 1- Summary of Electrode Damage All Events

Structure Number	Damaged Components				Structure Number	Damaged Components			
	Crossarm EL1	Crossarm EL1	Conductor EL1	Conductor EL2		Crossarm EL1	Crossarm EL1	Conductor EL1	Conductor EL2
127	*		*		507			X	
128	*				513			X	X
129					514				0
130	*		*		515				X0
335	X		X		516			X	
336			X		517				X0
338			X		518				X
339			X		519				X
340	X		X		520				X
342				X	521				X
343		X	X	X	522				X
344			X		523				X
351			X		525				X
352			X		526	X	X	X	X
361			X		527	X		X	
362	X		X		1218		#		#
363	X		X		1219		#		#
364	X				1220				#
365			X		1221		#		#
366	X				1222	#	#	#	#
367			X		1223	#	#	#	#
368	X		X		1224	#	#	#	#
369			X		1225	#	#	#	#
					1226	#	#	#	#
					1227	#	#	#	#
					1228	#		#	

X - Jan 2021 Failure
0 - Dec 2022 Failures
- Mach 2024 Failures
* - Jan 2025 Failures

One of the ways to reduce damage to the lines due to icing would be to remove the electrode conductor from the towers and run it parallel to L3501/2 on a wood pole line. During 3 of the 4 icing events detailed in this report, only the

electrode components were damaged. This suggests that if the electrode conductors were on wood poles, there would be no damage to the towers during the 3 icing events. While damage could still occur to the electrode conductors and the wood pole structures during icing events, this damage would be easier and less time consuming to repair. Repairs could be complete without the need of a bi-pole outage and repairs to wood pole structures would require less time and equipment. In addition, the height of the electrode conductor likely contributes to the amount of ice that accretes on the line during an icing event, with less ice likely to accrete at the lower height of a wood pole line.

2. Sections for Consideration

Due to the cost of building a wood pole line from Muskrat Falls to the start of the existing wood pole electrode line at structure 1229 (approximately 376 km), the removal of the electrode line from L3501/2 will be consider for various sections of the line. The factors that will be considered in determining the sections of electrode removal will include areas with past failures, areas known for high icing, areas of high elevation (relative to surrounding area, areas of high elevation change), and area at risk for galloping. These factors are summarized in Figure 2. Figure 2 also shows the sections of line that will be considered for removal based on these factors.

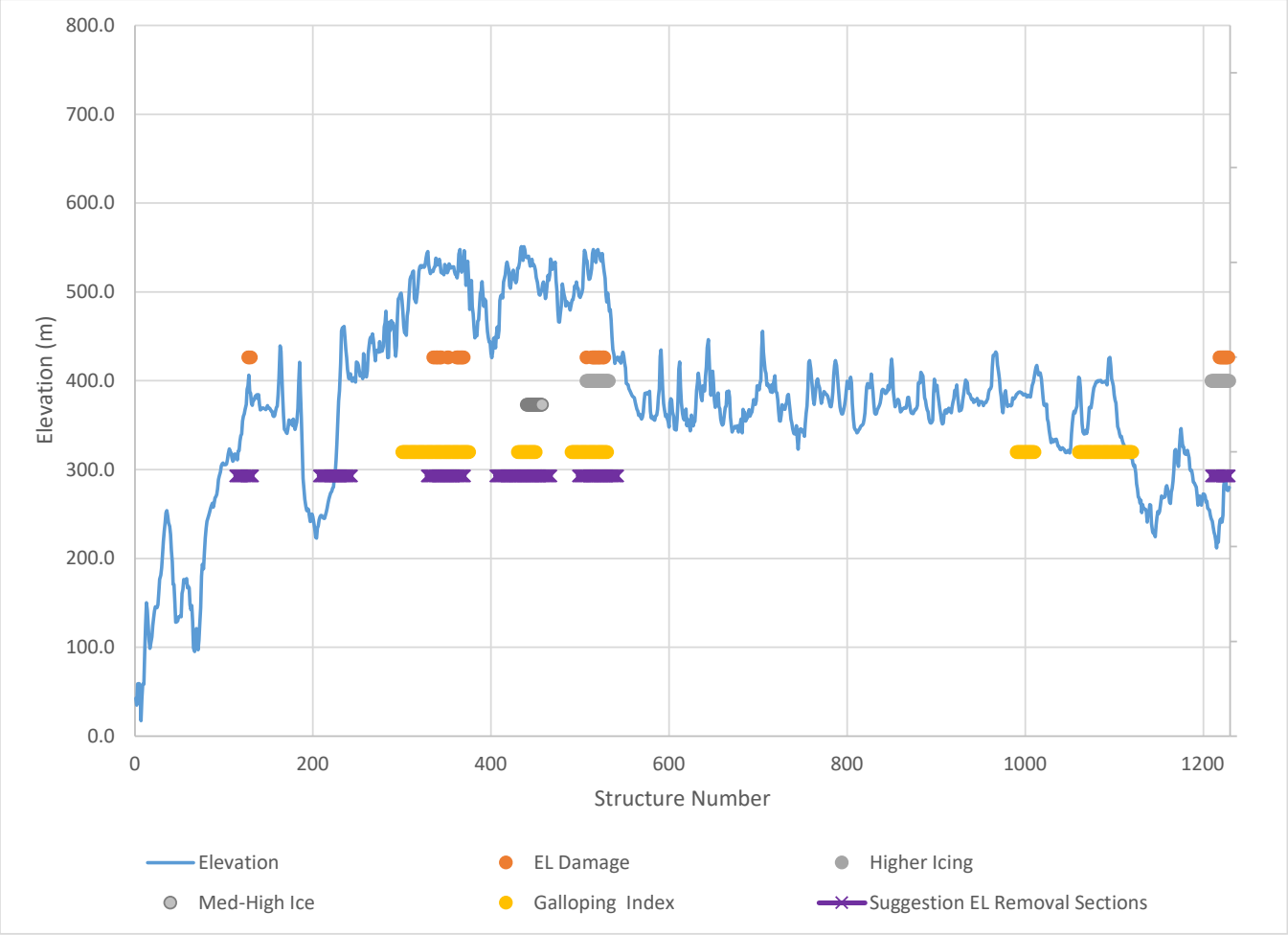


Figure 2 - Summary of Factors in Electrode Failures

There are 6 sections recommended for electrode removal from the towers or L3501/2. These 6 sections total approximately 85 km.

3. Analysis

The failure investigations of damage to the towers and conductors in past events determined the root cause was overloading due to unbalanced ice loads. To determine the benefits of removing the electrode conductor from the towers, the sections of the line to be considered were run for a series of balanced ice loads, and unbalanced ice loads both with and without the electrode conductor on the towers. The balanced ice loads cases include: 60, 70, 80, 90, 100 mm of radial glaze ice with a density of 0.9 g/cm^3. Note that all these ice load cases are greater than the design maximum ice load. The unbalanced ice load cases include the unbalanced combinations of 50/100, 60/100, and 70/100% for 60, 70, 80 mm of radial ice on one wire at a time on the wires: OPGW (G), electrode 1 (EL1), electrode 2 (EL2), pole 1 (P1), and pole 2 (P2).

The results for each section of the line are shown in Figure 3 to Figure 8, with a summary of all the results shown in Figure 9. The charts show the percentage of failed structures for a particular section of the line for each load case for the line with the electrode conductor, and without the electrode conductor. A failure is defined as any member of the tower exceeding 100% of its capacity.

In the section from structure 113 to 132 (Figure 3) under balanced ice loading with the electrode attached to the structure, between 5% and 80% of the structures in the section will fail with 60 mm and 70 mm of radial ice respectively. Without the electrode attached to the structures, there are zero structure failures in this section for 60 mm and 70 mm of radial ice. This shows a clear benefit to removing the electrode in this section. Over 70 mm of balanced ice load, all structure will fail with the electrode attached to the structures and between 90% to 95% will fail without the electrode attached to the structures.

Under unbalanced ice load (UBL), with 60 mm of ice:

- structures with the electrode:
    - on the OPGW (G) the percentage of structure failures range between 60% to 85% as the unbalance increases,
    - on EL1, EL2, P1, and P2 the percentage of structure failures is much less, ranging from 5% to 60%,
- structures without the electrode:
    - on the OPGW (G) the percentage of structure failures range between 40% to 85% as the unbalanced increases,
    - on EL1, EL2, P1, and P2 there are no structure failures. (Note that load case with UBL on EL without EL conductor is equivalent to balanced ice on all other wires).

Under unbalanced ice load (UBL) with 70 mm of ice:

- structures with the electrode:
    - the percentage of structures failures range between 80% to 90% for all load cases,
- structure without the electrode:
    - on the OPGW (G) the percentage of structure failures range between 60% to 85%
    - on EL1, EL2, P1, and P2 there are no structure failures.

Under unbalanced ice load (UBL) with 80 m of ice:

- structures with the electrode:
    - all structures failed for all load cases,
- structures without the electrode:

- on the OPGW (G) the percentage of structure failure for 70/100% unbalanced is 85% (note that for load cases 60/100% and 50/100%, the loads are so high that the structure analysis failed to converge and all structures are assumed to have failed),
- on EL1, EL2, P1, and P2 the percentage of structure failures range from 30% to 45%.

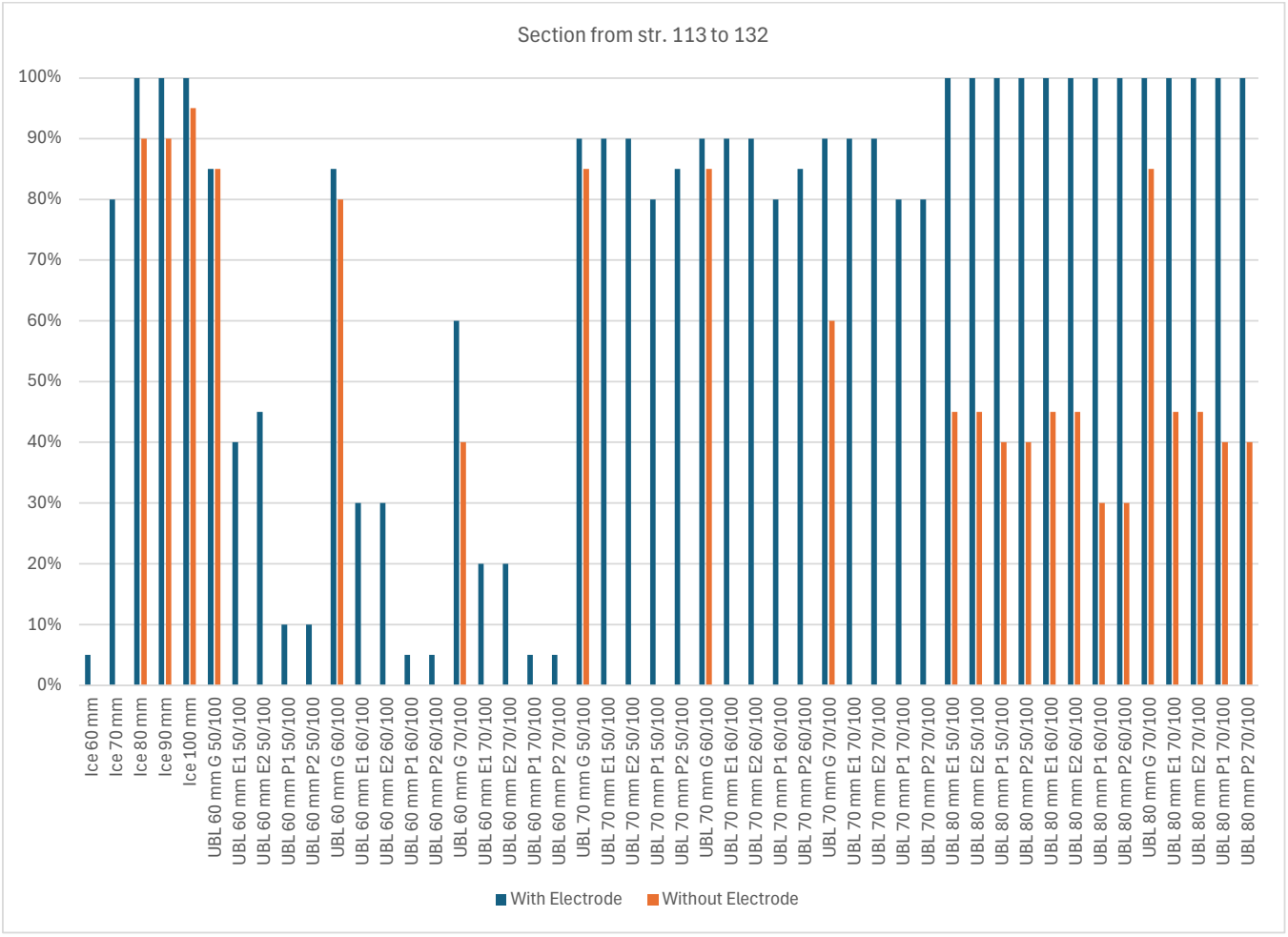


Figure 3 - Percentage of Structure Failures - Section 113 to 132

The results for the section from structure 222 to 243 (Figure 4) are similar to the section from 113 to 132, with slightly lower percentages of failures overall. Under balanced ice loading, between 0% and 77% of the structures with electrode in the section will fail with 60 mm and 70 mm of ice load, respectively. Without the electrode on the structure, there are zero structure failures in this section for 60 mm and 70 mm of ice load. This shows a clear benefit to removing the electrode in this section. Over 70 mm of balanced ice load, between 95% to 100% of structures will fail with the electrode and 82% to 95% will fail without the electrode.

Under unbalanced ice load (UBL), with 60 mm of ice:

- structures with the electrode:
    - on the OPGW (G) the percentage of structure failures range between 55% to 86% as the unbalance increases,
    - on EL1, EL2, P1, and P2 the percentage of structure failures is much less, ranging from 14% to 32%.
- structures without the electrode:
    - on the OPGW (G) the percentage of structure failures range between 41% to 86% as the unbalanced increases.
    - on EL1, EL2, P1, and P2 there are no structure failures.

Under unbalanced ice load (UBL) with 70 mm of ice:

- structures with the electrode:
    - the percentage of structure failure range between 77% to 91% for all load cases,
- structures without the electrode
    - on the OPGW (G) the percentage of structure failures range between 68% to 86%,
    - on EL1, EL2, P1, and P2 there are no structure failures.

Under unbalanced ice load (UBL) with 80 m of ice:

- structures with the electrode:
    - 95% of structures failed for all load cases,
- structures without the electrode:
    - on the OPGW (g) the percentage of structure failure for 70/100% unbalanced is 82%,
    - on EL1, EL2, P1, and P2 the percentage of structure failures range from 32% to 36%.

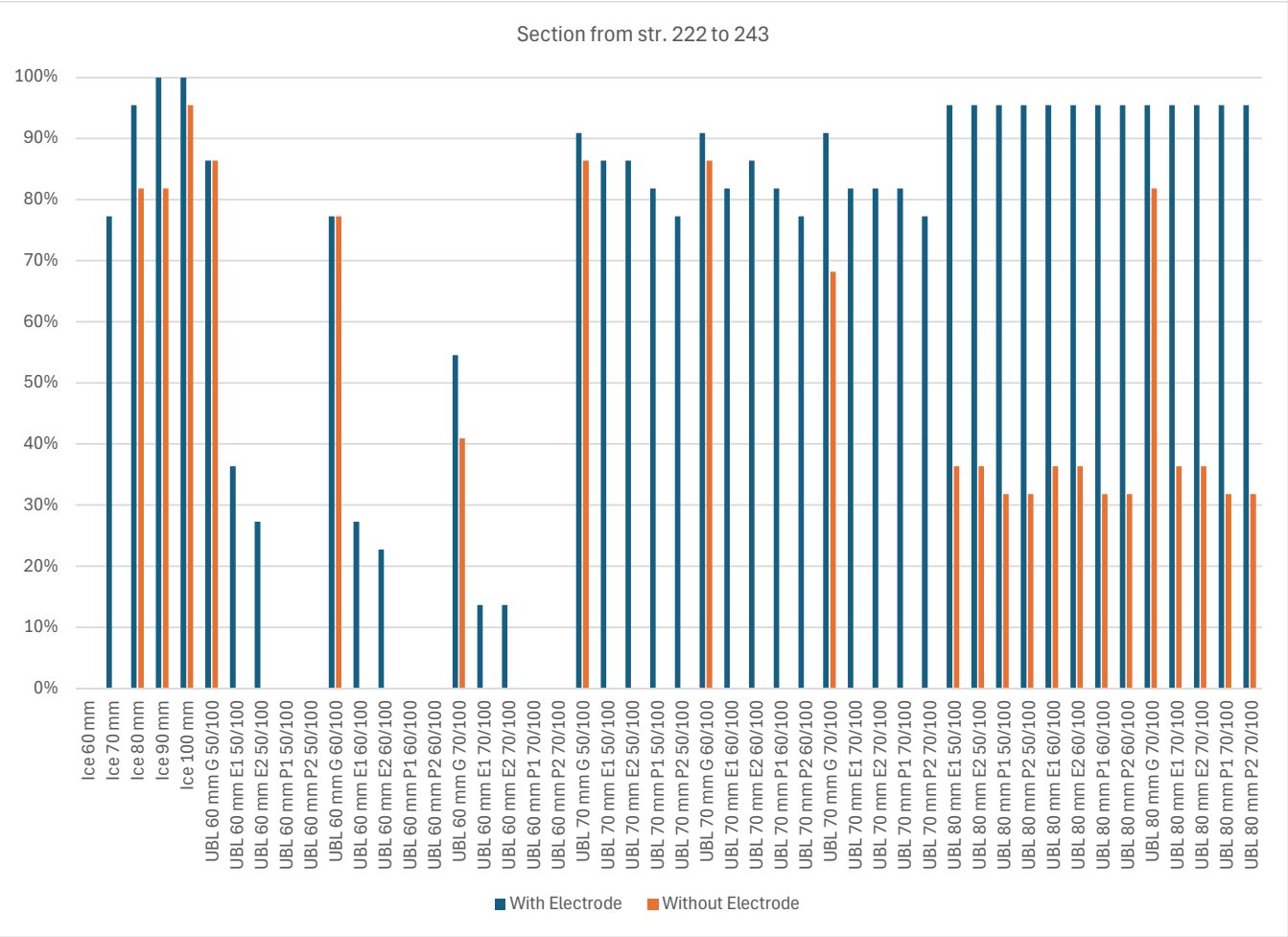


Figure 4- Percentage of Structure Failures - Structure 222 to 243

The results for the section from structure 328 to 370 (Figure 5) are very similar to the section from 222 to 243. Under balanced ice loading for structures with the electrode, between 7% and 81% of the structures in the section will fail with 60 mm and 70 mm of ice load, respectively. Without the electrode attached to the structure, there are zero structure failures in this section for 60 mm and 70 mm of ice load. This shows a clear benefit to removing the electrode from the structures in this section. Over 70 mm of balanced ice load, 100% of structures will fail with the electrode and 79% to 95% will fail without the electrode.

Under unbalanced ice load (UBL), with 60 mm of ice:

- structures with the electrode:
    - on the OPGW (G) the percentage of structure failures range between 51% to 81% as the unbalance increases,
    - on EL1, EL2, P1, and P2 the percentage of structure failures is much less, ranging from 7% to 35%,
- structures without the electrode:
    - on the OPGW (G) the percentage of failures range between 40% to 84% as the unbalanced increases.,
    - on EL1, EL2, P1, and P2 there are no failures.

Under unbalanced ice load (UBL) with 70 mm of ice:

- structures with the electrode:
  - the percentage of structure failures range between 81% to 95% for all load cases,
- structures without the electrode
  - on the OPGW (G) the percentage of structure failures range between 67% to 81%,
  - on EL1, EL2, P1, and P2 there are no structure failures.

Under unbalanced ice load (UBL) with 80 m of ice:

- structures with the electrode:
  - 95% of structures failed for all load cases,
- structures without the electrode:
  - on the OPGW (g) the percentage of structure failure for 70/100% unbalanced is 79%,
  - on EL1, EL2, P1, and P2 the percentage of structure failures range from 21% to 33%.

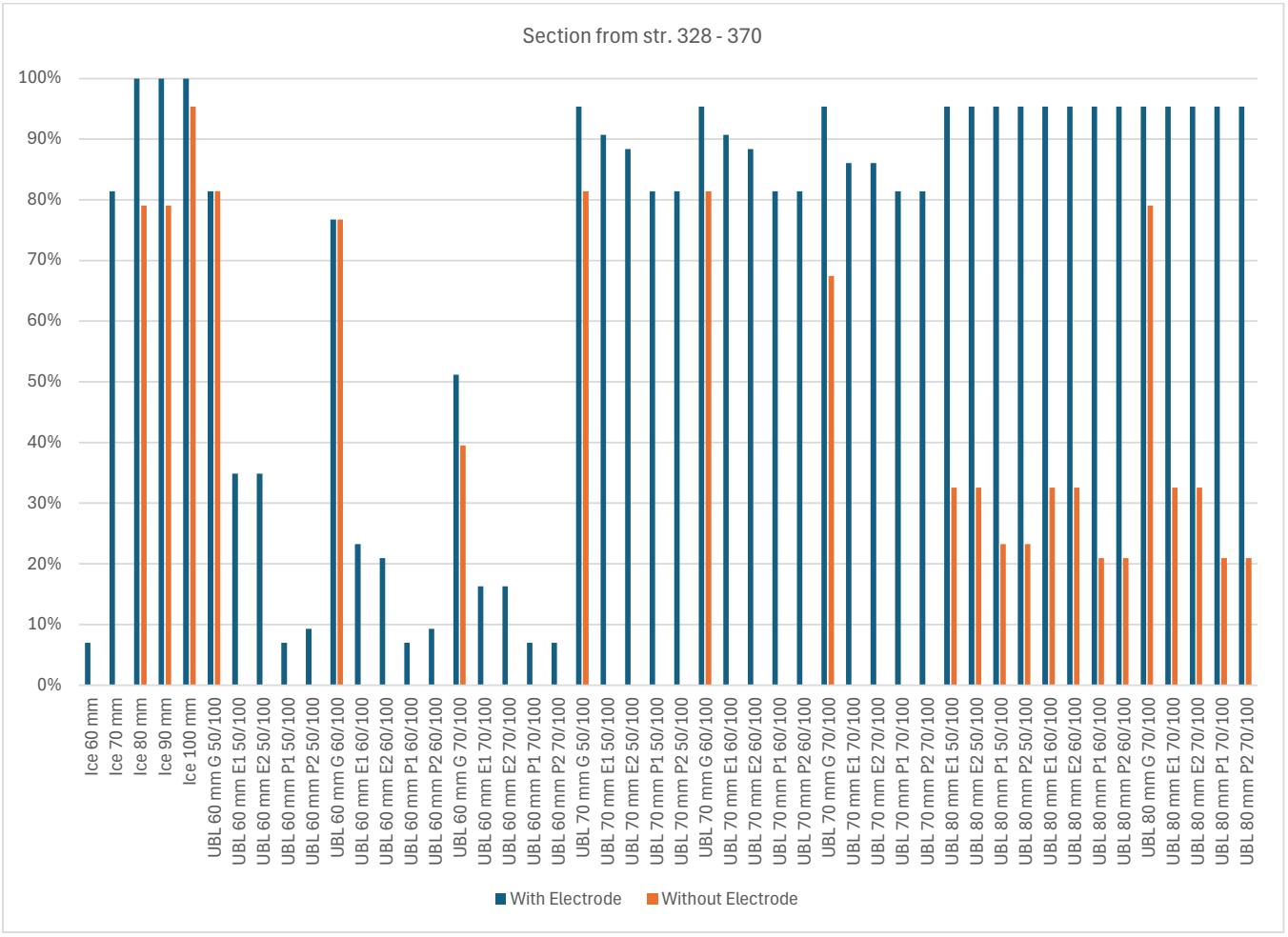


Figure 5 - Percentage of Structure Failures - Structures 328 to 370

The results for the section from structure 424 to 467 (Figure 6) are similar to the section from 113 to 132. Under balanced ice loading, between 9% and 77% of the structures with the electrode in the section will fail with 60 mm and

70 mm of ice load, respectively. Without the electrode attached to the structure, there are 2% failures in this section for 60 mm and 70 mm of ice load. With over 70 mm of balanced ice load, 98% of structures will fail with the electrode and 89% to 93% will fail without the electrode. This shows a clear benefit to removing the electrode in this section.

Under unbalanced ice load (UBL), with 60 mm of ice:

- structures with the electrode:
    - on the OPGW (G) the percentage of structure failures range between 57% to 84% as the unbalance increases,
    - on EL1, EL2, P1, and P2 the percentage of structure failures is much less, ranging from 9% to 41%.
- structures without the electrode:
    - on the OPGW (G) the percentage of structure failures range between 41% to 84% as the unbalanced increases,
    - on EL1, EL2, P1, and P2 there are no failures.

Under unbalanced ice load (UBL) with 70 mm of ice:

- structures with the electrode:
    - the percentage of structure failures range between 77% to 91% for all load cases,
- structures without the electrode:
    - on the OPGW (G) the percentage of structure failures range between 68% to 84%,
    - on EL1, EL2, P1, and P2 there are 2% structure failures for all load cases.

Under unbalanced ice load (UBL) with 80 m of ice:

- structures with the electrode:
    - 98% of structures failed for all load cases,
- structures without the electrode:
    - on the OPGW (g) the percentage of structure failures for 70/100% unbalanced is 84%,
    - on EL1, EL2, P1, and P2 the percentage of structure failures range from 34% to 43%.

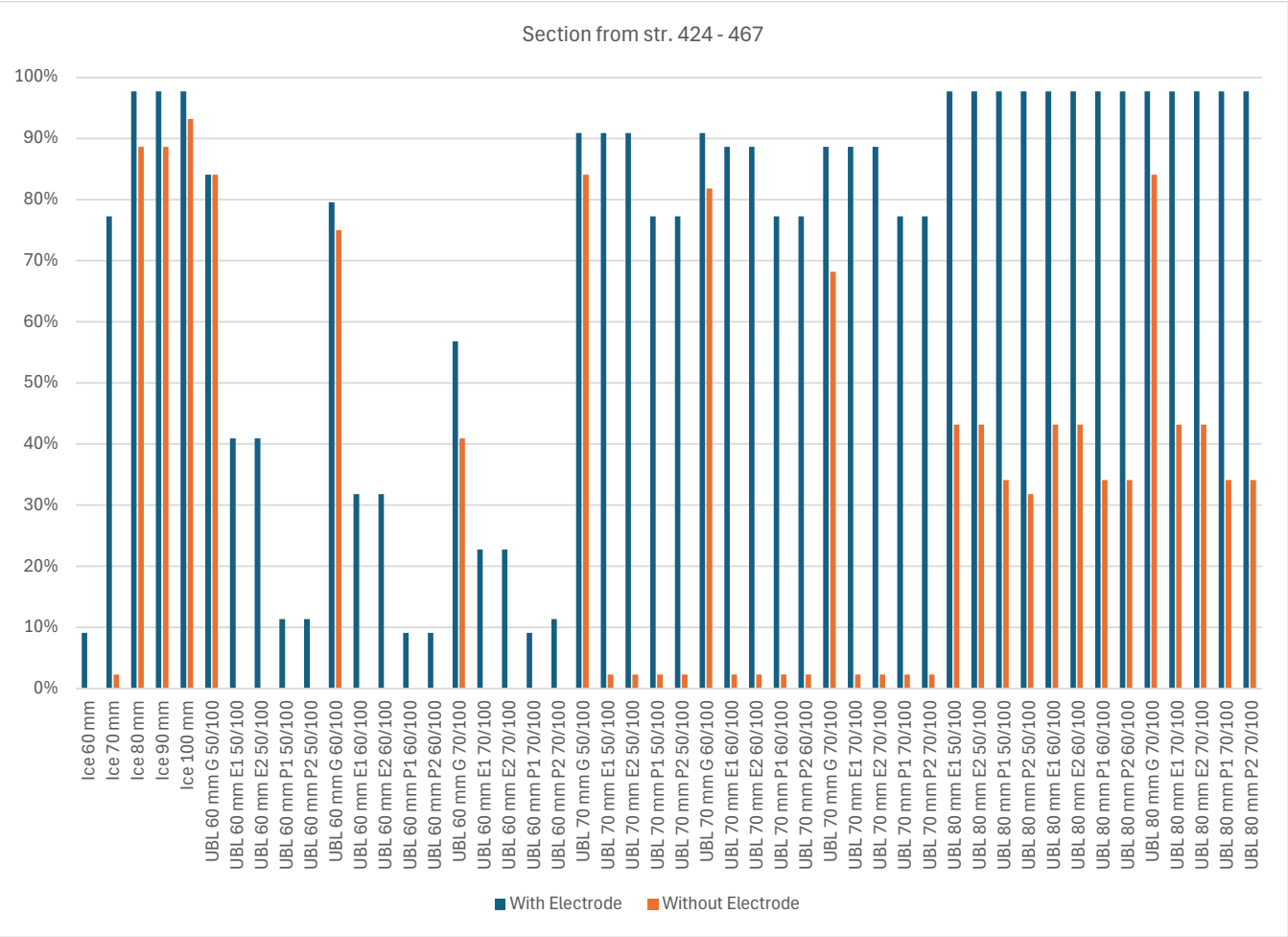


Figure 6 - Percentage of Structure Failures - Structures 424 to 467

The results for the section from structure 498 to 542 (Figure 7) are similar to the section from 113 to 132. Under balanced ice loading, between 9% and 82% of the structures with the electrode in the section will fail with 60 mm and 70 mm of ice load, respectively. Without the electrode attached to the structures, there are no failures in this section for 60 mm and 70 mm of ice load. With over 70 mm of balanced ice load, 100% of structures will fail with the electrode and between 80% to 91% will fail without the electrode. This shows a clear benefit to removing the electrode from the structures in this section.

Under unbalanced ice load (UBL), with 60 mm of ice:

- structures with the electrode:
  - on the OPGW (G) the percentage of structure failures range between 64% to 84% as the unbalance increases,
  - on EL1, EL2, P1, and P2 the percentage of structure failures is much less, ranging from 9% to 49%,
- structures without the electrode:
  - on the OPGW (G) the percentage of structure failures range between 40% to 82% as the unbalanced increases,
  - on EL1, EL2, P1, and P2 there are no structure failures.

Under unbalanced ice load (UBL) with 70 mm of ice:

- structures with the electrode:
  - the percentage of structure failures ranged between 82% to 100% for all load cases,
- structures without the electrode:
  - on the OPGW (G) the percentage of structure failures ranges between 64% to 82%,
  - on EL1, EL2, P1, and P2 there are no structure failures.

Under unbalanced ice load (UBL) with 80 m of ice:

- structures with the electrode:
  - 98% to 100% of structures failed for all load cases,
- structures without the electrode:
  - on the OPGW (g) the percentage of structure failures for 70/100% unbalanced is 87%,
  - on EL1, EL2, P1, and P2 the percentage of structure failures range from 42% to 44%.

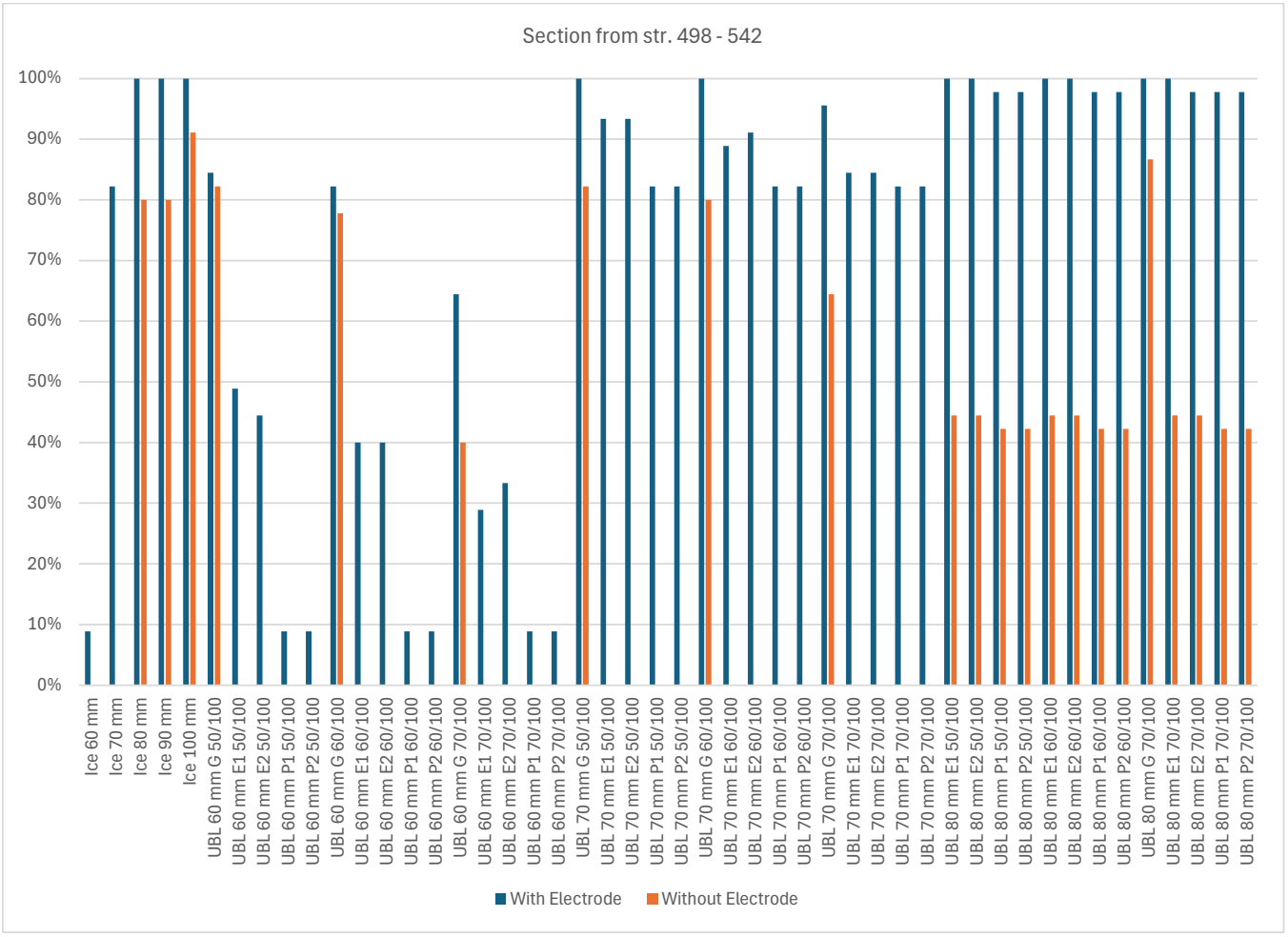


Figure 7- Percentage of Structure Failures - Structure 498 to 542

The results for the section from structure 1209 to 1229 (Figure 8) have less failures than all other section. Under balanced ice loading, between 0% and 43% of the structures with the electrode in the section will fail with 60 mm and

70 mm of ice load, respectively. Without the electrode, there are no suructure failures in this section for 60 mm and 70 mm of ice load. With over 70 mm of balanced ice load, 90% of structures will fail with the electrode and between 62% to 86% of structures will fail without the electrode. This shows a clear benefit to removing the electrode in this section.

Under unbalanced ice load (UBL), with 60 mm of ice:

- structures with the electrode:
    - on the OPGW (G) the percentage of structure failures range between 33% to 81% as the unbalance increases,
    - on EL1, EL2, P1, and P2 the percentage of structure failures is much less, ranging from 0% to 10%,
- structures without the electrode:
    - on the OPGW (G) the percentage of structure failures range between 29% to 81% as the unbalanced increases,
    - on EL1, EL2, P1, and P2 there are no failures.

Under unbalanced ice load (UBL) with 70 mm of ice:

- structures with the electrode:
    - the percentage of structure failures range between 43% to 86% for all load cases,
- structures without the electrode:
    - on the OPGW (G) the percentage of structure failures range between 62% to 81%,
    - on EL1, EL2, P1, and P2 there are no structure failures.

Under unbalanced ice load (UBL) with 80 m of ice:

- structures with the electrode:
    - 81% to 86% of structures failed for all load cases,
- structures without the electrode:
    - on the OPGW (G) the percentage of structure failure for 70/100% unbalanced is 71%,
    - on EL1, EL2, P1, and P2 the percentage of structure failures range from 5% to 10%.

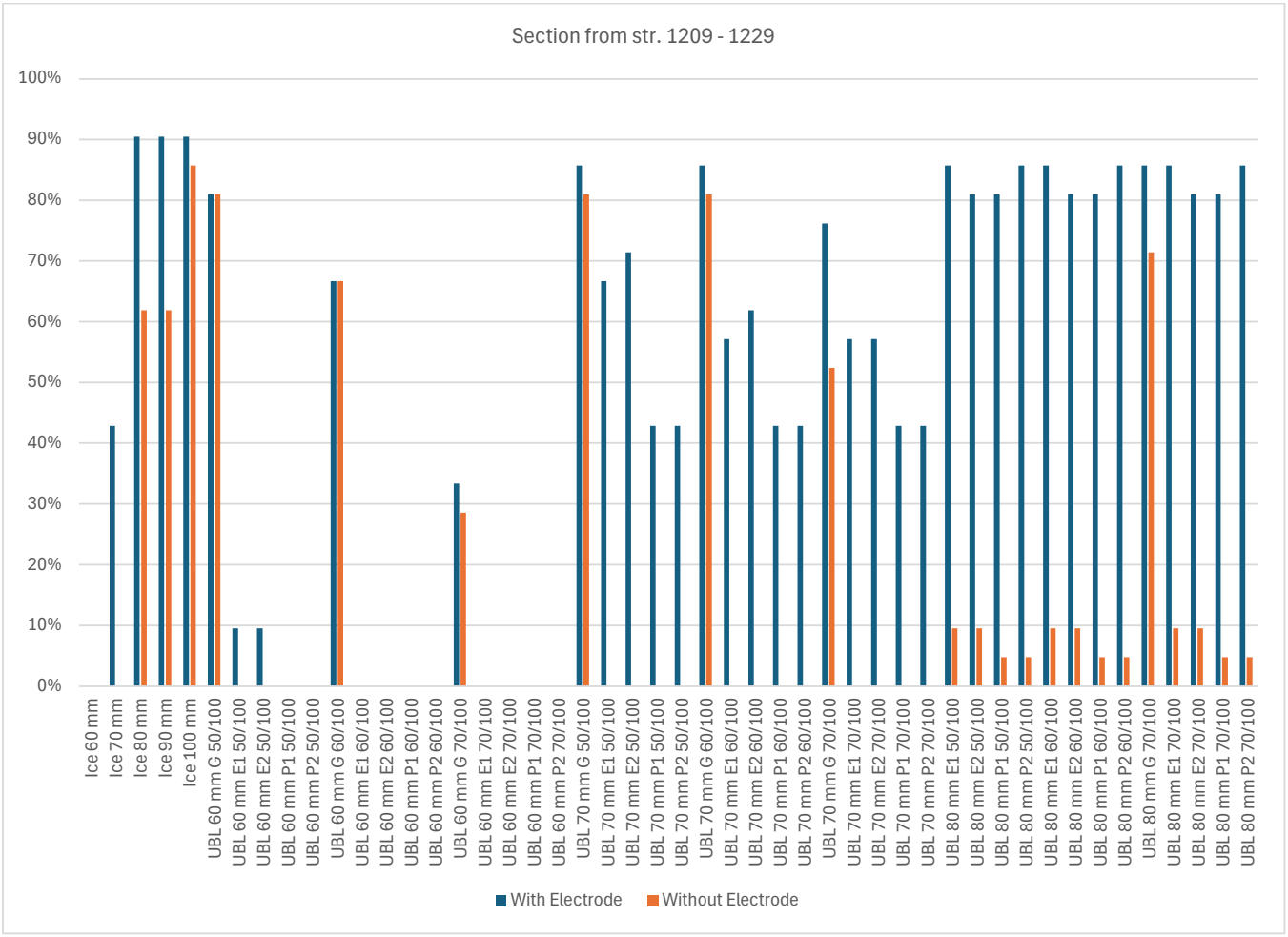


Figure 8 - Percentage of Structure Failures - Structures 1209 to 1229

Figure 9 shows the summary of all sections combined.

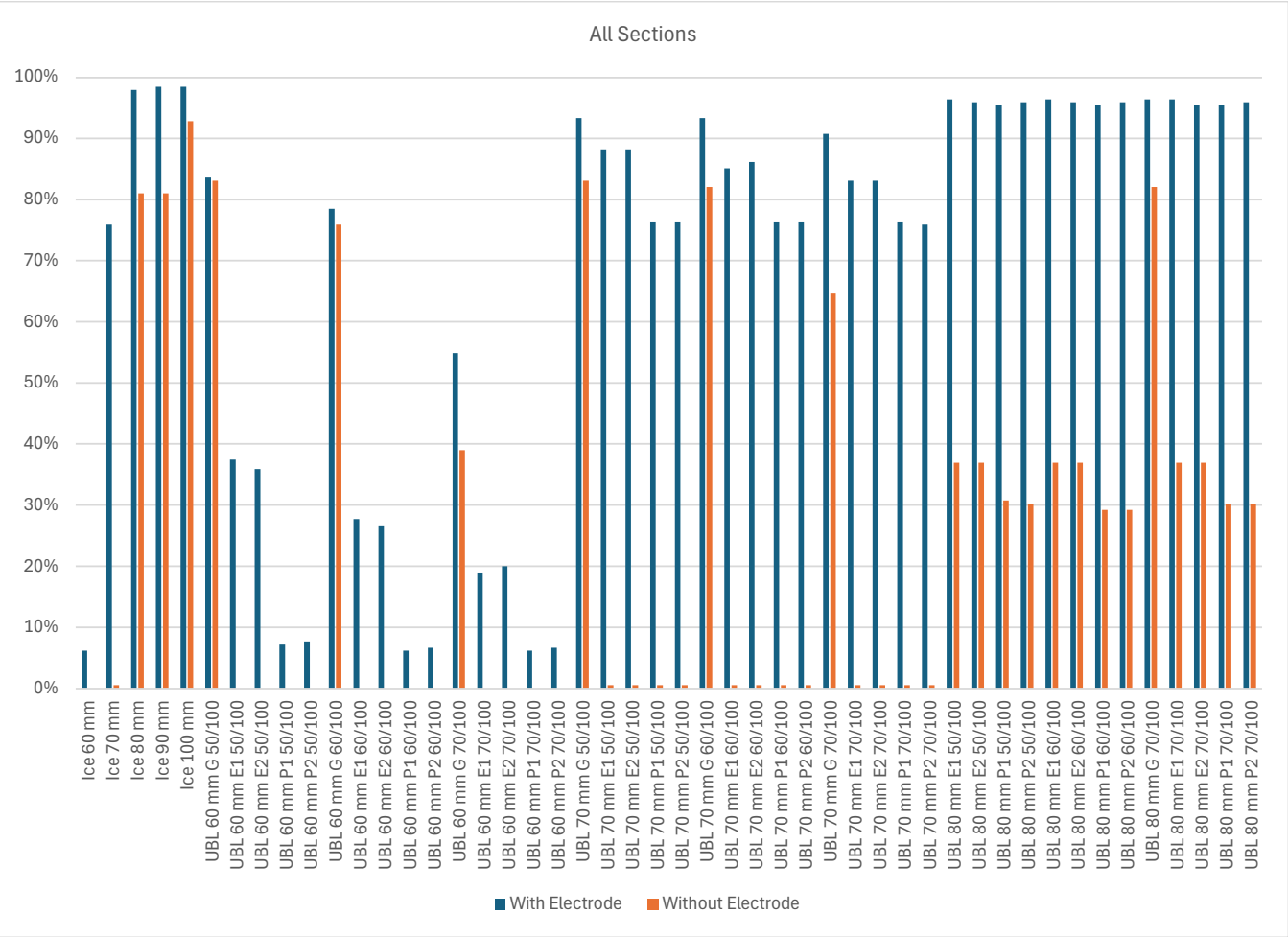


Figure 9 - Percentage of Structure Failures Summary of All Sections

4. Summary, Conclusions, and Recommendations

There have been a number of failures on the L3501/2 transmission line due to ice events over the past 4 years. The electrode crossarms and the electrode conductor are two components that are often damaged in these events, and for all these failures the most probable root cause was determined to be overloading due to unbalanced ice loads.

A possible approach to reduced damage to towers due to icing would be to remove the electrode conductor from the towers and run it parallel to L3501/2 on a wood pole line. Sections where removing the electrode conductor would be beneficial were selected based on a number of factors including: areas with past failures, areas known for high icing, areas of high elevation change, and areas at risk for galloping. Six sections were selected and analyzed.

The analysis shows there is a benefit to removing the electrode conductor from the towers for all sections. Under high icing (greater than the design ice loads) there would be fewer failures of the tower with the electrode removed for both balanced and unbalanced ice. Table 2 shows the comparison of the difference in the percentage of failures in each section without and with the electrode attached to the towers for all load cases. A colour scale is used to show the most beneficial with the highest difference (80 – 90%, dark green) to least beneficial with the least difference (0 – 10%, dark red). The greatest benefits are identified for ice loads of 70 mm. This is to be expected and aligns with the amount of ice that is more likely to occur on the lines. Removal of the electrode conductor does not greatly improve failures due to

unbalanced ice on the OPGW. The section from structure 498 to 542 shows the most benefit from removal of the electrode, followed by the section from structure 113 to 132. The section from structure 1209 to 1229 differs from the other sections in that the benefits are greater for the higher ice loads than lower ice loads.

Table 2 - Difference in Percentage Without and With the Electrode Conductor

Load Case	Difference between Without Electrode and With Electrode						
	All Sections	Str. 113 - 132	Str. 222 - 243	Str. 328 - 370	Str. 424 - 467	Str. 498 - 542	Str. 1209 - 1229
Ice 60 mm	6%	5%	0%	7%	9%	9%	0%
Ice 70 mm	75%	80%	77%	81%	75%	82%	43%
Ice 80 mm	17%	10%	14%	21%	9%	20%	29%
Ice 90 mm	17%	10%	18%	21%	9%	20%	29%
Ice 100 mm	6%	5%	5%	5%	5%	9%	5%
UBL 60 mm G 50/100	1%	0%	0%	0%	0%	2%	0%
UBL 60 mm E1 50/100	37%	40%	36%	35%	41%	49%	10%
UBL 60 mm E2 50/100	36%	45%	27%	35%	41%	44%	10%
UBL 60 mm P1 50/100	7%	10%	0%	7%	11%	9%	0%
UBL 60 mm P2 50/100	8%	10%	0%	9%	11%	9%	0%
UBL 60 mm G 60/100	3%	5%	0%	0%	5%	4%	0%
UBL 60 mm E1 60/100	28%	30%	27%	23%	32%	40%	0%
UBL 60 mm E2 60/100	27%	30%	23%	21%	32%	40%	0%
UBL 60 mm P1 60/100	6%	5%	0%	7%	9%	9%	0%
UBL 60 mm P2 60/100	7%	5%	0%	9%	9%	9%	0%
UBL 60 mm G 70/100	16%	20%	14%	12%	16%	24%	5%
UBL 60 mm E1 70/100	19%	20%	14%	16%	23%	29%	0%
UBL 60 mm E2 70/100	20%	20%	14%	16%	23%	33%	0%
UBL 60 mm P1 70/100	6%	5%	0%	7%	9%	9%	0%
UBL 60 mm P2 70/100	7%	5%	0%	7%	11%	9%	0%
UBL 70 mm G 50/100	10%	5%	5%	14%	7%	18%	5%
UBL 70 mm E1 50/100	88%	90%	86%	91%	89%	93%	67%
UBL 70 mm E2 50/100	88%	90%	86%	88%	89%	93%	71%
UBL 70 mm P1 50/100	76%	80%	82%	81%	75%	82%	43%
UBL 70 mm P2 50/100	76%	85%	77%	81%	75%	82%	43%
UBL 70 mm G 60/100	11%	5%	5%	14%	9%	20%	5%
UBL 70 mm E1 60/100	85%	90%	82%	91%	86%	89%	57%
UBL 70 mm E2 60/100	86%	90%	86%	88%	86%	91%	62%
UBL 70 mm P1 60/100	76%	80%	82%	81%	75%	82%	43%
UBL 70 mm P2 60/100	76%	85%	77%	81%	75%	82%	43%
UBL 70 mm G 70/100	26%	30%	23%	28%	20%	31%	24%
UBL 70 mm E1 70/100	83%	90%	82%	86%	86%	84%	57%
UBL 70 mm E2 70/100	83%	90%	82%	86%	86%	84%	57%
UBL 70 mm P1 70/100	76%	80%	82%	81%	75%	82%	43%
UBL 70 mm P2 70/100	75%	80%	77%	81%	75%	82%	43%
UBL 80 mm E1 50/100	59%	55%	59%	63%	55%	56%	76%
UBL 80 mm E2 50/100	59%	55%	59%	63%	55%	56%	71%
UBL 80 mm P1 50/100	65%	60%	64%	72%	64%	56%	76%
UBL 80 mm P2 50/100	66%	60%	64%	72%	66%	56%	81%
UBL 80 mm E1 60/100	59%	55%	59%	63%	55%	56%	76%
UBL 80 mm E2 60/100	59%	55%	59%	63%	55%	56%	71%

UBL 80 mm P1 60/100	66%	70%	64%	74%	64%	56%	76%
UBL 80 mm P2 60/100	67%	70%	64%	74%	64%	56%	81%
UBL 80 mm G 70/100	14%	15%	14%	16%	14%	13%	14%
UBL 80 mm E1 70/100	59%	55%	59%	63%	55%	56%	76%
UBL 80 mm E2 70/100	58%	55%	59%	63%	55%	53%	71%
UBL 80 mm P1 70/100	65%	60%	64%	74%	64%	56%	76%
UBL 80 mm P2 70/100	66%	60%	64%	74%	64%	56%	81%

Based on the analysis, removal of sections of the electrode conductor from the towers is a viable technical option for reducing the load on the tower from ice accumulation and therefore reducing the likelihood of failures. This option will be compared to other options such as tower modification to strengthen the electrode crossarms and OPGW peaks, and the installation of midspan structures. The comparison will include the technical benefits of each option as well as the cost.

In addition to reducing the ice loads on the towers, there are several other advantages specific to this option. Any required repairs to the electrode conductor or structures are made easier due to the smaller structure size of the wood poles and the separation from the pole conductors. The electrode conductors would be at a lower elevation and therefore are likely to accumulate less ice.

There are also disadvantages specific to this option. A new right of way (ROW) would be required parallel to the existing L3501/2 ROW. This new ROW will have to be assessed for any conflicts with existing infrastructure or land ownership. The constructability along the new ROW will also have to be assessed. The wood pole line will have shorter span lengths and may not be able to transverse obstacles such as waterbodies and large elevation changes. The removal of the electrode conductor will not address the issues with unbalanced ice loads on the OPGW, which has also led to tower failures.

Attachment 2

L3501/2 Failure Investigation

Ice Storm Southern Labrador

ILK-EG-ED-6200-TL-H15-0007-01



L3501/2 Failure Investigiation – Ice Storm Southern Labrador

Revision						Remarks
No	**By**	**Rev.**	**Chk.**	**Appr.**	**Date**	
1	MV	00	RM	KR	3-Feb-2025	
2						
3						

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Kris Rogers

Contents

1.0 Abbreviations and Acronyms 1
2.0 Introduction 1
3.0 Background 2
4.0 Purpose 4
5.0 Failure Description 4
5.1 Failure Location 8
5.2 Engineering Recommendations for Repairs 9
5.3 Restoration Summary 10
6.0 Weather Information 10
7.0 Construction Quality, and Maintenance Review 13
8.0 Material Testing 14
9.0 Analysis of Loads Causing Failures 14
9.1 Ice Loading 15
9.2 Ice Shedding 18
10.0 Summary and Conclusions 19
11.0 Recommendations 20

List of Appendices

Appendix A: NL Hydro Transmission Line Failure (Conductor EL-1 and EL-2 at Suspension Tower 1225) report by Wayland Engineering Ltd.

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1.0 Abbreviations and Acronyms

- DE – Deadend
- HVdc – High Voltage direct current
- L3501/2 – Line number of the 350 kV HVdc transmission line
- L3501 – Pole 1 of the line
- L3502 – Pole 2 of the line
- LIL – Labrador-Island Link
- OPGW – Optical Ground Wire
- P1 – Pole 1
- P2 – Pole 2
- ROW – Right of Way
- Str. – Structure

2.0 Introduction

On Saturday March 30, 2024, Pole 2 tripped at 06:45. Pole 1 tripped at 06:52 on electrode line fault protection. From a patrol of the line it was discovered that the electrode conductor was broken and damaged at several locations between str. 1218–1228. In some locations, the electrode conductor was touching or close to the pole conductor which would explain the line trip. There was also damage to the steel lattice towers at the electrode crossarm and OPGW tower peaks as shown in Figure 1. There were a few strands of pole conductor damaged in one location. The line patrol noted there was significant ice on the lines before failures (and remaining in some locations).

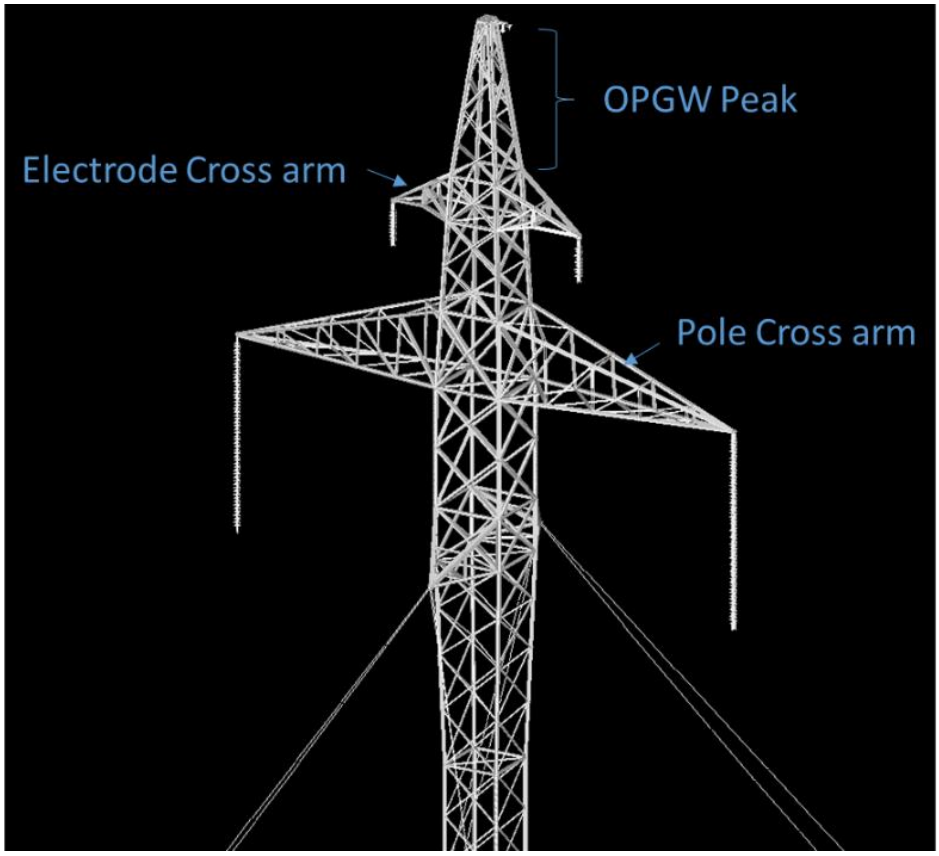


Figure 1: Tower Drawing Showing Sections

3.0 Background

The Labrador-Island Link ("LIL") is an important transmission line for the provincial energy grid due to its power carrying capacity that is used to deliver a large portion of the winter peak energy and demand to the Island Interconnected System. Line L3501/2 is the 350 kV HVdc overland transmission line portion of LIL traversing a distance of approximately 1,100 km through three major meteorological loading zones: average, alpine and eastern. The HVdc line has two poles, one OPGW, and two electrode conductors for a portion of line, as shown in Figure 2. The electrode conductor is attached to the lattice towers for a part of the line from Muskrat Falls to about 384 km southeast of Muskrat Falls where it diverts to a separate right of way ("ROW") on wood poles to an electrode site approximately 16 km away, located in the L'Anse-au-Diable area. Note that sections of L3501/2 without the electrode on the towers do not have electrode cross arms.

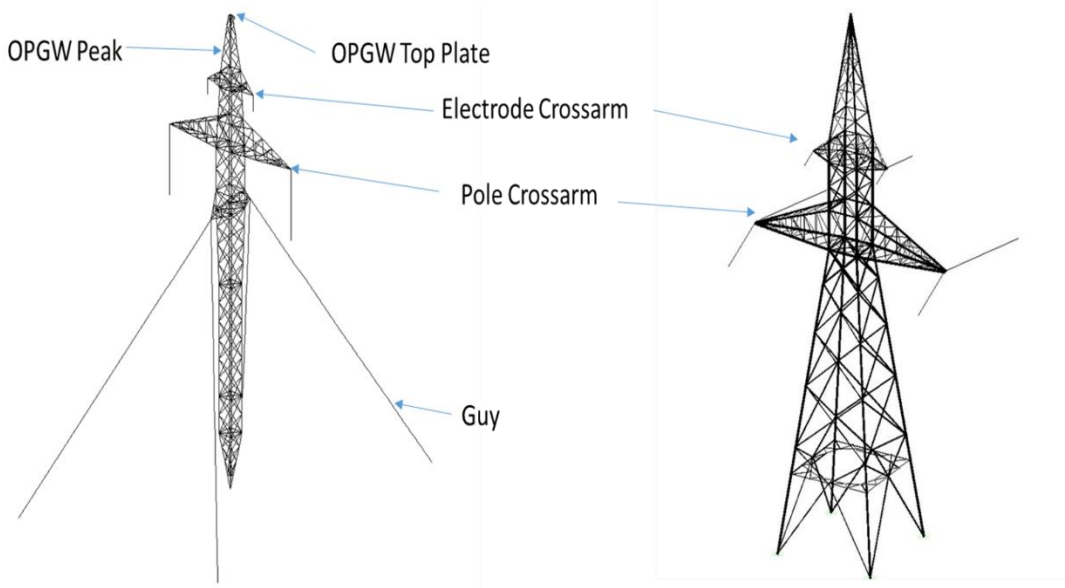


Figure 2: Suspension and Deadend Tower Diagram

The HVdc transmission line corridor has been divided into three major meteorological loading zones referenced above in combination with 8 further subcategories related to meteoroidal loads, pollution levels (inland and costal), and geographic location. The resulting combination lead to the HVdc line consisting of 19 separate loading zones. Eleven tower types (A1, A2, A3, A4, B1, B2, C1, C2, D1, D2, and E1) were designed to meet the loading requirements, which consist of a specified wind load, ice load, and combination of both applied to the line. The tower type consists of both guyed towers and self-support towers. The tower types are summarized in Table 1.

Table 1: Tower Types

Tower Type	Structure Type	Insulator Assembly Type	Deflection Angle Limit (degree)
A1, A2, A3, A4	Guyed	Suspension	0–1
B1	Guyed	Suspension	0–3
B2	Self-Support	Suspension	0–3
C1, C2	Self-Support	Dead End	0–30
D1, D2	Self-Support	Dead End	0–45
E1	Self-Support	Dead End	45–90

Ninety percent of all towers on the L3501/2 are suspension towers, types A1, A2, A3, A4, B1, and B2. Figure 3 breaks down the tower distribution on the L3501/2.

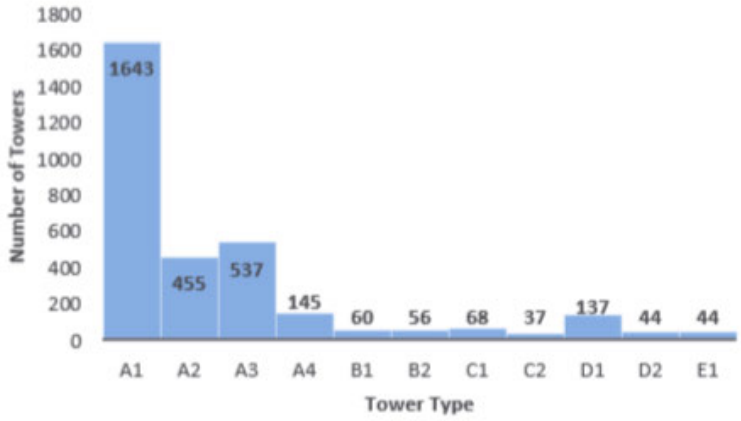


Figure 3: Distribution of Tower Type on L3501/2

4.0 Purpose

Considering the importance of L3501/2 to the provincial energy grid and the need to understand the line's performance, a detailed failure investigation was completed to determine the root cause of the failures and to conclude what action can be taken in order to prevent further damage to the line.

The investigation will be described in detail within this report and includes the following components:

- Failure Description;
- Weather;
- Construction Quality and Maintenance Review;
- Material Testing;
- Analysis of Loads Causing Failures.

5.0 Failure Description

During a line patrol on March 30, 2024, damage was discovered between structure 1218 and 1228. A helicopter patrol the next day identified additional damage at structure 1232, and was able to detail the damage on all structures. The damage included bent and failed steel members in the electrode cross arms and in the OPGW peak, conductor damage included bird caging, broken strands and fully broken conductor, and minor damage to the pole conductor of just a few strands. A summary of the damage is shown in Table 2.

Table 2: Summary of Structure and Conductor Damage

Tower	Crossarm Damage		Conductor Damage		Pole Conductor	OPGW Tower Peak
	EL1	EL2	EL1	El2		
1216	no	no	no	no	no	no
1217	no	no	no	no	no	no
1218	no	yes	no	yes	no	no
1219	no	yes	no	yes	no	no
1220	no	no	no	yes	no	no
1221	no	yes	no	yes	no	yes
1222	yes	yes	yes	yes	no	no
1223	yes	yes	yes	yes	no	no
1224	yes	yes	yes	yes	no	no
1225	yes	yes	yes	yes	no	yes
1226	yes	yes	yes	yes	no	no
1227	yes	yes	yes	yes	yes	no
1228	yes	no	yes	no	no	yes
1229	no	no	no	no	no	no
1232	no	no	no	no	no	yes

Figure 4 to Figure 7 show pictures of the various failures.



Figure 4: Str. 1228 Electrode Cross Arm Failure



Figure 5: Str. 1224 Electrode Cross Arm Failures



Figure 6: OPGW Peak Failure



Figure 7: Str. 1221 Minor OPGW Peak Damage, Bird Caging of Electrode Conductor, Electrode Conductor on Ground

5.1 Failure Location

Structures are numbered sequentially along the line starting at Muskrat Falls. Structure numbers that sustained damage are str. 1218–1228 and 1232. These structures are located on the south coast of Labrador as shown in Figure 8. The structures are located 11–16 km from the closest highway.



Figure 8: Map of Newfoundland and Labrador showing Location of Failures

The structures are located in loading zone 3a. Zone 3a is an Average loading zone. The wind and ice conditions this zone is designed for are summarized in Figure 9.

Zone 3, 4, 6 and 8a

Maximum Ice	**50 mm radial glaze, 0.9 g/cm^3 density**
Maximum Wind	**120 km/h (10 minute average wind speed at 10 m height about ground)**
Combined Ice and Wind	**25 mm radial glaze, 0.9 g/cm^3 density**
	60 km/h ((10 minute average wind speed at 10 m height about ground)

Maximum wind and combined wind values assume Terrain Type C as per CSA C22.3 NO 60826-10.

Figure 9: Zone 3a Wind and Ice Design Loading

The twelve structures with steel or conductor damage are all Type A1 tangent towers. The tower body extension, and electrode and OPGW attachment heights are summarized in Table 3. All towers had a suspension attachment. Structures 1218–1228 are within the same deadend to deadend section, with structure 1232 in a separate section.

Table 3: Damaged Structure Information Summary

Structure Number	Structure Type	Structure Height	Height to Electrode Attachment (m)	Height to OPGW Attachment (m)
1218	A1	A1+6.0	33.968	41.05
1219	A1	A1+12.0	39.966	47.05
1220	A1	A1+6.0	33.969	41.05
1221	A1	A1+7.5	35.469	42.55
1222	A1	A1+12.0	39.966	47.05
1223	A1	A1+9.0	36.962	44.05
1224	A1	A1+6.0	33.965	41.05
1225	A1	A1+4.5	32.462	39.55
1226	A1	A1+12.0	39.969	47.05
1228	A1	A1+9.0	36.964	44.05
1232	A1	A1+10.5	NA	45.55

5.2 Engineering Recommendations for Repairs

There were two options considered for repair of the failed section of line. The first option was to install the failed electrode conductor on wood poles in parallel with the existing steel line. The second option was to replace the failed conductor and structural steel as-built with identical spares.

Installation of electrode conductor on wood poles would include moving the OPGW to the intact electrode crossarms. With this option, less than half of the electrode crossarms would need to be repaired immediately, and none of the tower peaks. The tower peaks could be fixed later during a scheduled outage, and the electrode conductor could remain on the wood poles. This would have the added advantage of reducing the risk of failure to the electrode crossarms and conductor in future icing events. A disadvantage of this option would be the OPGW would not provide optimal lightening protection when on the electrode crossarm.

The second option would restore everything to the as-built state, requiring no additional work at a later date, and providing appropriate lightening protection.

Both options were evaluated for cost and schedule, and it was determined that the second option of restoring to the as-built condition would present less risk of cost and schedule delays.

5.3 Restoration Summary

Crews and equipment mobilized to site on April 3rd with work beginning on April 4th. The work began with cleanup of the failed electrode conductor and securing the OPGW to allow for tower repairs. The contractor started repair work on April 10th. Tower steel was replaced and electrode conductor was replaced, with all work being completed by April 19th.

6.0 Weather Information

There were observations of significant icing on the lines on March 30th, as shown in Figure 10. Observations at site estimated the ice thickness on the conductor to be approximately 120–140 mm of radial ice. An ice sample that fell from the OPGW (see Figure 11) was collected, measured, and weighed. From this sample, the equivalent radial thickness was estimated to be 100–125 mm at a density of 0.6 g/cm^3.



Figure 10: Ice on OGPW at Time of Failure



Figure 11: Ice Sample from OPGW

Weather from the nearest weather station at Blanc Sablon is shown in Figure 12 and Figure 13. The Blanc Sablon weather station is located approximately 25 km southwest of the damage location. The elevation of the weather station is 37.2 m, and the elevation of the damaged structures ranges from 235.6 to 299.7 m. The higher elevation would likely mean higher winds and colder temperature at the structures than reported at the weather station.

Before the failures occurred the weather conditions consisted of a mix of rain and fog and the temperature at Blanc Sablon was recorded near zero. Data from the weather station indicated the temperature started to rise right before the pole tripped. It is assumed that at the locations of the tower and conductor damage, the temperatures were slightly colder and the precipitation types therefore were freezing rain and freezing fog. Figure 14 shows the total precipitation in the 36 h period around the time of the failure from 12:00 h on March 29th to 0:00 h on March 31st. A yellow star on Figure 14 displays the approximate location of the failures. The figure shows that the area received 55 – 60 mm of precipitation during this time. It also indicates that the area of the failures received significantly more precipitation than Blanc Sablon, which recorded 16 mm of rain on March 29th and 14 mm of rain on March 30th.

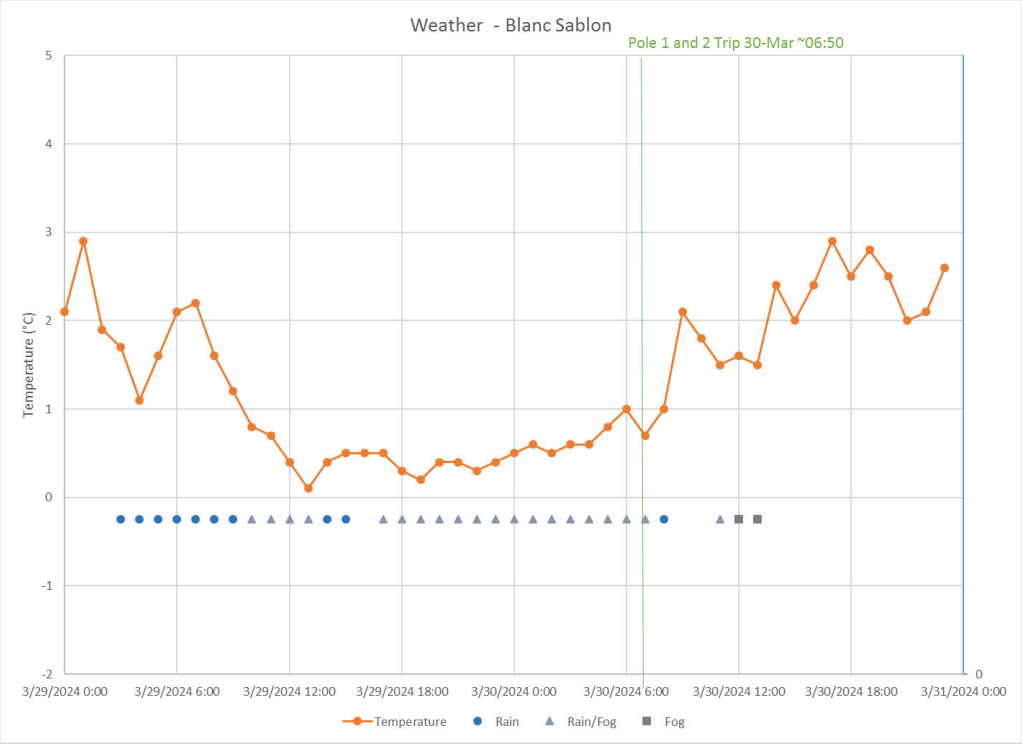


Figure 12: Temperatures and Precipitation Type at Blanc Sablon Weather Station

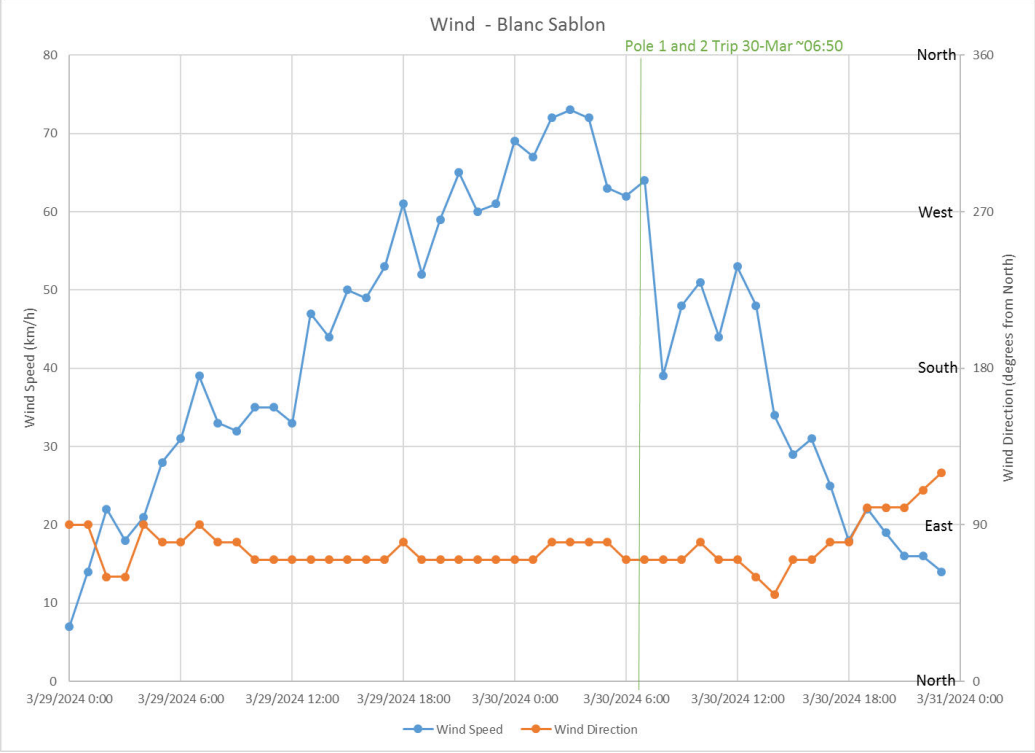


Figure 13: Wind Speed and Direction at Blanc Sablon Weather Station

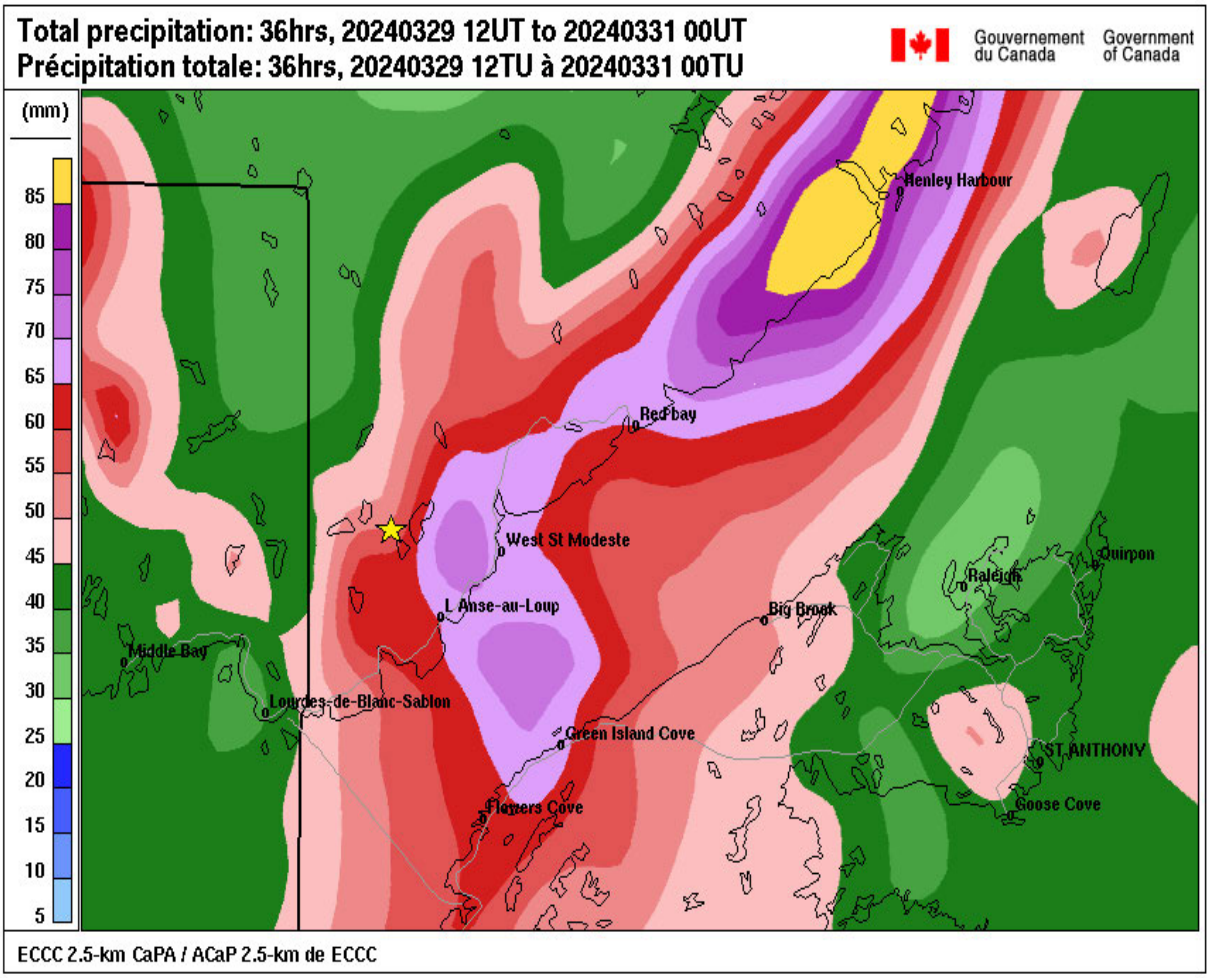


Figure 14: Total Precipitation on Labrador South Coast from 12:00 h 29-Mar-2024 to 0:00 31-Mar-2024

7.0 Construction Quality, and Maintenance Review

The final construction quality control inspection of the structures from 1218–1228, and 1232 was completed in May of 2016, and showed no issue with the tower steel. There were no non-conformance reports on the tower steel for these towers. The electrode conductor of this section of line was strung on March 29, 2016. There were no quantity control issues noted at that time.

On the 12 structures that had conductor or tower damage there were 99 previous corrective work orders. The types of work orders include broken dampers (OPGW, pole, and electrode), broken corona rings, and the OPGW pulled through the suspension assembly. The damper damage could be caused by Aeolian vibration or galloping of the lines. The corona ring damage could be caused by galloping or ice accumulation. The OPGW pull through is likely caused by unbalanced ice load from ice shedding.

8.0 Material Testing

Material testing of the electrode conductor was completed by Wayland Engineering Ltd. ("Wayland") to determine the cause of failure and if there were any issues with the conductor. The summary of conclusions and recommendations is included in this section and the complete report can be found in Appendix A.

Wayland concluded that the physical, chemical and metallurgical evidence indicates that the failure of conductors is consistent with ductile limit load fracture of the aluminum conductor strands. The force required to cause the failure was attributed to the combination of ice accumulation and sustained wind velocities. Wayland also suggests it was probable that wind induced galloping was present in the lines prior to the failures, which generated an additional cyclic force. Cyclic force could cause fatigue on the conductor reducing the strength, making it more susceptible to ductile failure.

Wayland notes that the evidence suggests that the steel reinforcing core migrated towards, and was in contact with, the lower surface of the insulator wire clamp. The downward bearing force responsible for the migration was sufficient to distort and cold pressure weld (fuse) adjacent aluminum wires together in the lower circumferential half of the conductor. It is reasonable to assume that the distortion and fusing of the aluminum strands would result in a decrease in the overall breaking strength of the conductor where it enters the wire clamp.

Wayland recommended that radiographing imaging could be used as a non-destructive method to detect if the steel core migration is happening in other sections of the line. They recommended consulting with experts in the field of radiography to investigate the feasibility of this testing.

9.0 Analysis of Loads Causing Failures

A complete as-built model of L3501/2 includes the existing terrain, as-built tower locations and heights, with complete finite element tower models. PLS-CADD is a transmission line design program that allows the user to enter different loading conditions to analyze how they will affect the line and structures under the as-built conditions. The program allows the user to complete detailed analysis of how increasing loads will affect the towers performance and ultimately how the towers will fail under extreme loading conditions.

Tower failure is defined in the analysis as any component of the tower exceeding its maximum damage limit. The reaction of the tower to the load cases can be quantified by the maximum utilization, which is the ratio of the force applied to any member from the specified loads divided by the damage limit capacity, expressed as a percentage. Any value greater that 100% is considered a tower failure.

$$Maximum\ Utilization = \frac{Force}{Damage\ Limit\ Capacity} \times 100\%$$

9.1 Ice Loading

As discussed in Section 6.0, reports from site estimate the ice thickness at the location of the failures at approximately 120–140 mm of radial thickness. The sample of ice that fell from the OPGW was measured and was estimated to range from 100–125 mm of radial glaze ice with a density of 0.6 g/cm^3. Both estimates exceeding the design ice load of 50 mm of radial glaze ice with a density of 0.9 g/cm^3.

Modeling of the section of line was completed with 70, 80, 90, 100, 125, and 140 mm of radial ice with a density 0.6 g/cm^3. The modeling of the ice was also done with the thickness of the pole conductor ice reduced by 70%. This was because ice accretion modeling, and in-field experience have proven there is less ice accretion on the larger diameter conductor.

The modeling showed failures in the tower at the electrode cross arm only at 90, 100, and 125 mm of radial ice. Under 140 mm of radial ice some towers show failure lower in the tower, at the pole crossarm level. Table 4 shows the comparison of the structure damaged in the field to the structures above 100% utilization in the model. The results suggest that the electrode crossarm failure could be caused by radial ice ranging from 90–100 mm.

Figure 15 and Figure 16 show the in-field damage to structure 1224, and the model of str. 1224 under 100 mm of radial ice. The model shows that only the members in the electrode crossarm would exceed the capacity and failure under these conditions, similar to what was observed in the field at this structure.

Table 4: Comparison of Field Damage and Modeling Results for Ice Loading

	Field Damage			Modeling 90 mm		Modeling 100 mm	
	Crossarm Damage			EL Crossarm Damage		EL Crossarm Damage	
Tower	EL1	EL2	OPGW Tower Peak	(% Utilization)	OPGW Tower Peak	(% Utilization)	OPGW Tower Peak
1210	no	no	no	79	no	92	no
1211	no	no	no	44	no	50	no
1212	no	no	no	97	no	114	no
1213	no	no	no	97	no	114	no
1214	no	no	no	86	no	102	no
1215	no	no	no	87	no	103	no
1216	no	no	no	109	no	128	no
1217	no	no	no	92	no	109	no
1218	no	yes	no	105	no	124	no
1219	no	yes	no	114	no	133	no
1220	no	no	no	102	no	119	no
1221	no	yes	yes	101	no	119	no
1222	yes	yes	no	95	no	113	no
1223	yes	yes	no	116	no	135	no
1224	yes	yes	no	107	no	125	no
1225	yes	yes	yes	108	no	126	no
1226	yes	yes	no	98	no	115	no
1227	yes	yes	no	106	no	125	no
1228	yes	no	yes	111	no	130	no
1229	no	no	no	62	no	68	no



Figure 15: Str. 1224 with Damaged Electrode Crossarm

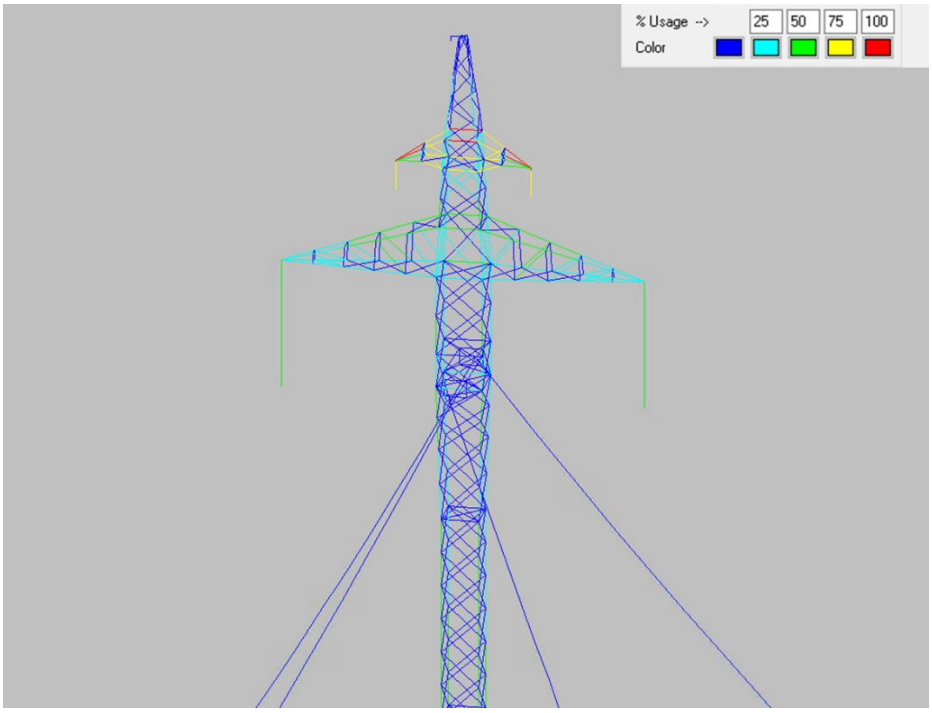


Figure 16: Model of Str. 1224 showing Members in the Electrode Crossarm Exceeding Capacity

The modeling of the electrode conductor shows that the utilization at 90 mm of radial ice is 98% of the ultimate tension and when increased to 100 mm of ice is 109% of the ultimate tension. Therefore, ice accumulation between 90–100 mm of radial ice could cause the conductor to fail. The line was also modeled for a combination of wind and ice. The modeling suggested 60 mm of radial ice with a 60 km/h 10 minute average wind could also cause the conductor to fail.

9.2 Ice Shedding

Modeling of the line was completed with 70, 80, 90, 100, 125, and 140 mm of radial ice with a density of 0.6 g/cm^3, and an unbalanced combination of 100% ice on the back span, and 70%, 80% on the ahead span (or vice-versa). From these modeling runs, it was determined that ice of 95 mm radial thickness with an unbalanced of 70/100% and 80/100% on the OPGW can produce similar failures to those seen on str. 1221 and 1228 respectively with damage to both the electrode crossarms and OPGW peak. See Figure 17 and Figure 18 for comparison of structure 1221 damage and model.



Figure 17: Str. 1221 with OPGW Peak and Electrode Crossarm Damage

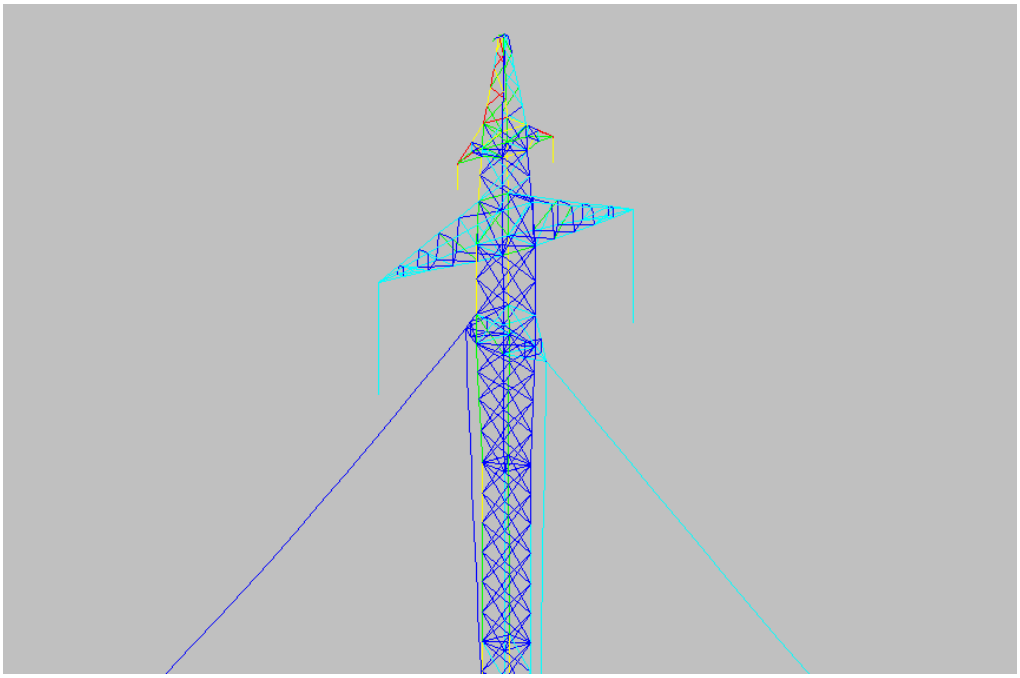


Figure 18: Model of Str. 1221 on Unbalanced Ice Load Case showing Members in the OPGW Peak and Electrode Crossarm Exceeding Capacity

10.0 Summary and Conclusions

The main root cause of the damage to the tower electrode crossarms, the OPGW tower peaks, and the electrode conductor was an overload failure due to ice loads exceeding the design for this section of the line.

Ice loads in the area at the time of the failure were estimated to range from 100–125 mm of radial glaze ice with a density of 0.6 g/cm^3. This far exceeds to the design loads of this section of the line which is 50 mm of radial glaze ice with a density of 0.9 g/cm^3. It is worth noting that the area of damage ranges from str. 1218–1232, and the design loads for the line change from “alpine” to “average” loading at str. 1209. The ice load design of the alpine zone is 115 mm of radial ice with a density of 0.5 g/cm^3.

Temperatures at the nearby weather station at Blanc Sablon were near zero during the time when ice was accumulating on the lines, and rose to 3°C the day of the failures, suggesting that ice shedding causing unbalanced ice loads on the structures could have contributed to the damage of the towers.

The modeling shows the damage to the electrode crossarms could be caused by ice loading range from 90–100 mm of radial ice with a density of 0.6 g/cm^3, and the damage to the OPGW peak could be cause by an 70/100% or 80/100% unbalanced ice load of 95 mm of radial ice with a density of 0.6 g/cm^3. The

modeling also shows the electrode conductor damage could be caused by 100 mm of radial ice with a density of 0.6 g/cm^3.

The material testing found that the physical, chemical and metallurgical evidence indicates the conductor failures were consistent with ductile limit load fracture. The ductile failure was likely caused by overloading due to ice accumulation and wind loads at the time of the failure. It is also noted that galloping due to wind could have contributed to the failure by causing cyclic loading on the conductor prior to the failure.

11.0 Recommendations

Recommendations for consideration to prevent future failures and better understand the issue with the line include the following:

- Monitoring of ice conditions along the line;
- Strengthening of the tower to withstand higher unbalanced ice loads;
- Modifying the line to reduce the loads on towers;
- Look at alternative suspension assemblies and clamp designs; and
- Investigate using radiography to evaluate conductor issues.

Monitoring can be done in a number of ways including line patrol, test spans with ice load and weather monitoring equipment near the line route, and in line ice load monitoring equipment. While monitoring itself will not prevent failures it is sometimes possible to remove ice from the lines if accumulation occurs slowly. Monitoring can also help find, and prepare for failures, and it can be used to better understand the amount of ice on the lines for future upgrades.

Monitoring of ice can be accomplished by line patrol. From a past recommendation, the line crews have increased the helicopter patrols to four times a winter, with additional patrols as needed. The amount of ice on the lines can be estimated from pictures. Ice that has fallen from the lines can be weighed and measured. Check sheets and forms have been created and shared with Engineering and Operations to ensure all the necessary information is being collected when possible. There is an email address to send this information to a centralized location that is monitored by Engineering.

To gain a better understanding of the ice loads experienced by the line, monitoring of the line is required. We currently have a test span installed near str. 1225 with plans to install another test span in 2025. The test span consists of one span of conductor between two wood poles, with a load cell to monitor ice load, and equipment to monitor wind, and temperature. Unfortunately, the icing in the area of str. 1225 at the time of the failures also caused damage to the solar panel power at the test span, so at this time we have no data from that site. Replacement parts have been ordered, delivered and installed, and the repairs are scheduled be completed in 2025.

In addition, monitors will be installed on the line in 2025 to monitor ice loading in three locations along the line.

The tangent towers on the line are designed for unbalanced ice loads of 70% maximum design ice thickness on one wire, on one side of the tower and 100% on one wire the other side of the tower. If the differential in ice thickness is higher, there is a chance the tower will fail. It is recommended that the towers be analyzed for more conservative unbalanced ice loads. Any recommended changes to the towers would have to consider the slip strength of the clamps, the redistribution of loads within the towers, and the constructability of the reinforcements considering the line is built and in service. This recommendation is being actioned as part of a 2024–2025 project that will evaluate and update the unbalanced ice loading design used for L3501/2. This will consist of evaluating all available data (Haldar reports, failures investigation, operational experience to date, CSA 22.3 60826 standard, industry best practices) to determine an updated unbalanced ice load design for L3501/2. This assessment was completed in 2024. A consultant will be contracted to provide a design and cost estimate for tower modification that will be required to meet this new unbalanced ice load design, to be completed in 2025. The feasibility and cost of other options will also be evaluated which will need to meet the new design loads by reducing the loads on the towers. This will include installing mid span structures between existing tangent structures, and removing the electrode conductor from the towers and installing it on wood pole structures for sections of the line, as required.

The failures of the conductor occurred at the suspension clamp. As part of the tower analysis project (initiated in 2024), the electrode suspension assembly will be analyzed to determine if modification can be made to transfer less load to the conductor during unbalanced icing. There is also an ongoing analysis where three different electrode suspension clamps have been installed at 10 structures (20 clamps in total) to determine if they perform better than the existing clamp under unbalanced ice loading

conditions. The conductor at these clamp location will be examined on an annual basis to look for signs of wear or damage.

The material testing found that the steel core of the conductor had migrated down through the aluminum layers, and caused deformation and cold fusing of the aluminum strands. This may have occurred during the high ice accumulation on the lines or during galloping of the lines. To determine if this process of steel core migration has started in other locations of the line, it is recommended that the possibility of using radiography to assess the conductor condition be investigated.

Appendix A

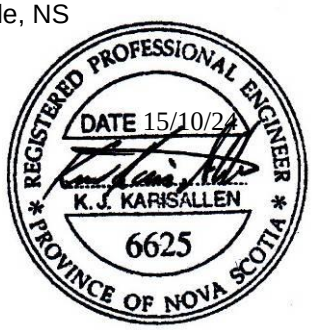
NL Hydro Transmission Line Failure (Conductor EL-1 and EL-2 at Suspension Tower 1225) report by Wayland Engineering Ltd.



NL HYDRO TRANSMISSION LINE FAILURE

(Conductor EL-1 and EL-2 at Suspension Tower 1225)

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Wayland Engineering Ltd – Report No. J2413A
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Executive summary

Wayland Engineering Ltd. was asked by Newfoundland and Labrador Hydro (NL Hydro) to conduct an investigation for two electrical conductors (EL-1 and EL-2) removed from suspension Tower #1225. The conductors routed electrical power along the approximately 1090 km long transmission corridor between Muskrat Falls and Soldiers Pond. On March 30, 2024, Pole #2 tripped at approximately 6:45 am. It was also reported that Pole #1 tripped at approximately 6:52 am owing to an electrode line fault protection event. A subsequent field inspection conducted on the lines detected various forms of damage between Tower #1218 and Tower #1228. NL Hydro requested that Wayland Engineering provide an opinion on the mechanism(s) responsible for the failures sustained by conductor EL-1 and EL-2 from Tower #1225.

A summary of the conclusions and recommendations generated by the investigation conducted includes:

- The physical, chemical and metallurgical evidence indicates that the mechanism responsible for the failure of conductors EL-1 and EL-2 at Tower #1225 is consistent with ductile limit load fracture of the aluminum conductor strands.

- The force required to precipitate a ductile limit load fracture mechanism of the aluminum conductor strands was attributed to the combination of ice accumulation and sustained wind velocities on the day prior to and during the day of the failures. It is also probable that wind induced galloping was present in the lines prior to the failures, which generated an additional cyclic force.

- The evidence suggests that the steel reinforcing core migrated towards, and was in contact with, the lower surface of the insulator wire clamp. The downward bearing force responsible for the migration was sufficient to distort and cold pressure weld (fuse) adjacent aluminum wires together in the lower circumferential half of the conductor. It is reasonable to assume that the distortion and fusing of the aluminum strands would result in a decrease in the overall breaking strength of the conductor where it enters the wire clamp.

- It has been postulated that one in situ, non-destructive method of detecting steel core migration is radiographic imaging. It should be noted that if radiographic imaging is utilized, it should include a reference marker on the bottom surface of the wire clamp. It is recommended that in consultation with experts in the field of radiography, that NL Hydro consider investigating the feasibility of radiographic imaging to detect the presence of incipient damage in the conductors.

Table of contents

Executive summary ii
Table of contents iii
List of figures iv
List of tables viii
1 BACKGROUND 1
2 PRELIMINARY EXAMINATION 4
2.1 Preliminary Examination of Failed Conductor EL-1 4
2.2 Preliminary Examination of Failed Conductor EL-2 10
3 EVALUATION OF THE CONDUCTOR DIMENSIONAL AND MECHANICAL PROPERTIES 17
3.1 Dimensional Characterization of Failed Conductor EL-1 Wire Strands 18
3.2 Dimensional Characterization of Failed Conductor EL-2 Wire Strands 19
3.3 Dimensional Characterization of an Intact Service Exposed (Used) Conductor Wire Strands 20
3.4 Uniaxial Tension Testing of an Intact Service Exposed (Used) Conductor 21
4 METALLURGICAL CHARACTERIZATION OF THE FAILED CONDUCTOR DAMAGE (EL-1 AND EL-2) 25
4.1 Metallurgical Characterization of Failed Conductor EL-1 25
4.2 Metallurgical Characterization of Failed Conductor EL-2 30
5 SUMMARY AND DISCUSSION OF THE PHYSICAL EVIDENCE 35
5.1 Summary of the Physical Evidence 35
5.2 General Discussion 36
6 CONCLUSIONS AND RECOMMENDATIONS 37
References 38
Annex A .. Data Sheet for the ACSR Grackle (Zinc Coated) Conductor 39
Annex B... Dimensional Characterization of the Failed Section of ACSR Grackle (Zinc Coated) Conductor EL-1 41
Annex C... Dimensional Characterization of the Failed Section of ACSR Grackle (Zinc Coated) Conductor EL-2 43
Annex D .. Dimensional Characterization of the Intact Service Exposed Section of ACSR Grackle (Zinc Coated) Conductor 45

List of figures

Figure 1-1: Google map provided by NL Hydro [1] showing the general compass directions of the segments of the transmission lines between Tower #1200 and Tower #1229. The map also shows the reported direction of the reported wind (easterly) on the day prior to and during the day of the failures [1]..... 2

Figure 1-2: General view of suspension Tower #1225 subsequent to the line failures on March 30, 2024 [1]. The image shows the locations of conductor EL-1 and EL-2 (ellipse), which were attached to the crossarms of the tower via suspension insulators. 3

Figure 1-3: Schematic showing the general configuration of an ACSR Grackle 54/19 conductor specification. 3

Figure 2-1: Top-down view of the wire clamp and failed section of the EL-1 conductor as received for analysis. 5

Figure 2-2: Side view of the wire clamp and failed section of the EL-1 conductor as received for analysis. 5

Figure 2-3: Photograph of the upper vertical external circumferential surface of conductor EL-1 as installed in the field. The image shows the fracture ends of the wire strands observed on the upper circumferential surface of the conductor (ellipse). 6

Figure 2-4: Photograph of the lower vertical external circumferential surface of conductor EL-1 as installed in the field. The image shows the significant aluminum strand to strand fusing observed on the lower circumferential surface. 6

Figure 2-5: Close-up view of a representative example of the fracture failure morphologies observed for conductor EL-1 (subsequent to conductor disassembly). The first morphology was characterized by a tapered (necked) interval immediately adjacent to the strand fracture surface. 7

Figure 2-6: Close-up view of a representative example of the fracture failure morphologies observed for conductor EL-1 (subsequent to conductor disassembly). The second morphology was characterized by an oblique fracture plane extending across the diameter of the strand. 7

Figure 2-7: Close-up view of a representative example of the aluminum strand fusing observed (subsequent to conductor disassembly). 8

Figure 2-8: Close-up view of a second representative example of the aluminum strand fusing observed (subsequent to conductor disassembly). 8

Figure 2-9: Top-down view of the lower circumferential surface of the wire clamp associated with conductor EL-1. The image shows the localized brinelling (ellipse) observed adjacent to the outboard axial end (on the conductor failure side) of the clamp. The image also shows the approximate cutline associated with the cross-sectional view of the brinelling in Figure 2-10. 9

Figure 2-10: Close-up sectional view through the localized brinelling (arrow) shown in Figure 2-9. The image shows the approximate semi-circular morphology of the damage observed at the site (ellipse). 9

Figure 2-11: Top-down view of the wire clamp and failed section of the EL-2 conductor as received for analysis. 11

Figure 2-12: Side view of the wire clamp and failed section of the EL-2 conductor as received for analysis. 11

Figure 2-13: Photograph showing a view of the failed section of the EL-2 conductor with an attached Stockbridge damper as received for analysis. 11

Figure 2-14: Photograph showing a second view of the failed section of the EL-2 conductor with an attached Stockbridge damper as received for analysis. 12

Figure 2-15: Photograph of the upper vertical external circumferential surface of conductor EL-2 as installed in the field. The image shows the fracture ends of the wire strands observed on the upper circumferential surface of the conductor. 12

Figure 2-16: Photograph of the lower vertical external circumferential surface of conductor EL-2 as installed in the field. The image shows the significant aluminum strand to strand fusing observed on the lower circumferential surface. 13

Figure 2-17: Close-up view of a representative example of the fracture failure morphologies observed for conductor EL-2 (subsequent to conductor disassembly). The first morphology was characterized by a tapered (necked) interval immediately adjacent to the strand fracture surface. 13

Figure 2-18: Close-up view of a representative example of the fracture failure morphologies observed for conductor EL-2 (subsequent to conductor disassembly). The second morphology was characterized by an oblique fracture plane extending across the diameter of the strand. 14

Figure 2-19: Close-up view of a representative example of the aluminum strand fusing observed (subsequent to conductor disassembly). 14

Figure 2-20: Close-up view of a second representative example of the aluminum strand fusing observed (subsequent to conductor disassembly). 15

Figure 2-21: Top-down view of the lower circumferential surface of the wire clamp associated with conductor EL-2. The image shows the localized brinelling (ellipse) observed adjacent to the outboard axial end (on the conductor failure side) of the clamp. The image also shows the approximate cutline associated with the cross-sectional view of the brinelling in Figure 2-22. 15

Figure 2-22: Close-up sectional view through the localized brinelling (arrow) shown in Figure 2-21. The image shows the approximately semi-circular morphology of the damage observed at the site. 16

Figure 3-1: Image showing the coiled length of the service exposed (used) conductor provided by NL Hydro as received for analysis. 17

Figure 3-2: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the failed conductor EL-1. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 18

Figure 3-3: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the failed conductor EL-2. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 19

Figure 3-4: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the intact service exposed conductor. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 20

Figure 3-5: Photograph showing the epoxy filled socket fixture (ellipse) utilized to terminate the conductor at both ends. 22

Figure 3-6: Photograph showing the load train utilized to test the intact service exposed conductor in uniaxial tension (the arrow indicates the conductor). 22

Figure 3-7: Photograph showing the service exposed conductor subsequent to failure. The axial position of the conductor failure was approximately 21 cm from the beginning of one of the epoxy filled terminations. 23

Figure 3-8: Close-up view of the conductor showing the relative positions of the outer aluminum and the inner steel reinforcing wire strand failures. 23

Figure 3-9: Close-up view of a representative example of the fracture failure morphology observed for the aluminum conductors associated with the uniaxial tension test. The morphology was characterized by a tapered (necked) interval immediately adjacent to the strand fracture surface. 24

Figure 3-10: SEM fractographic images of a representative example of the fracture surface associated with the failure of the outer aluminum wire strands. The image shows the cup and cone failure (A) and the void coalescence (B) typically associated with a ductile, limit load fracture mechanism. 24

Figure 4-1: Low magnification SEM secondary image of a representative example of the fracture surface (ellipse) associated with the tapered-end (necked) geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-1 (Figure 2-5). The image shows the general cup and cone morphology of the failed end of the wire strand. 27

Figure 4-2: High magnification fractographic image within the proximity of the strand centroid shown in Figure 4-1. The image indicates that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site. 27

Figure 4-3: Low magnification SEM secondary image of a representative example of the fracture surface associated with the oblique geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-1 (Figure 2-6). 28

Figure 4-4: High magnification fractographic image within the proximity of the strand centroid showing the topological features associated with the strand fracture mechanism. Similar to Figure 4-2, the image suggests that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site. 28

Figure 4-5: Sectional view SEM backscatter image of a representative example of the strand to strand fusing observed in conductor EL-1. The image also shows the location of the SEM EDS analyses conducted to determine the composition of the high density (light) phase observed (results are summarized in Table 4-1). 29

Figure 4-6: Sectional view SEM backscatter image of a representative example of the clamp material immediately adjacent to the site of localized brinelling observed. The image also shows the location of the SEM EDS analyses conducted to determine the composition of the high density (light) phase observed (results are summarized in Table 4-2). 29

Figure 4-7: Low magnification SEM secondary image of a representative example of the fracture surface (ellipse) associated with the tapered-end (necked) geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-2 (Figure 2-17). The image shows the general cup and cone morphology of the failed end of the wire strand. 32

Figure 4-8: High magnification fractographic image within the proximity of the strand centroid shown in Figure 4-1. The image indicates that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site. 32

Figure 4-9: Low magnification SEM secondary image of a representative example of the fracture surface associated with the oblique geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-2 (Figure 2-18). 33

Figure 4-10: High magnification fractographic image within the proximity of the strand centroid showing the topological features associated with the strand fracture mechanism. Similar to Figure 4-8, the image suggests that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site. 33

Figure 4-11: Sectional view SEM backscatter image of a representative example of the strand to strand fusing observed in conductor EL-2. The image also shows the location of the SEM EDS analyses conducted to determine the composition of the high density (light) phase observed (results are summarized in Table 4-3). 34

Figure 4-12: Sectional view SEM backscatter images of a representative example of the clamp material immediately adjacent to the site of localized brinelling observed. The image also shows the location of the SEM EDS analyses conducted to determine the composition of the high density (light) phase observed (results are summarized in Table 4-4). 34

Figure B-1: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-1. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 42

Figure B-2: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-1. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 42

Figure B-3: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-1. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 42

Figure C-1: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-2. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 44

Figure C-2: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-2. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 44

Figure C-3: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-2. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 44

Figure D-1: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the intact conductor. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 46

Figure D-2: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the intact conductor. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 46

Figure D-3: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the intact conductor. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. 46

List of tables

Table 1-1: Summary of the damage detected by the field inspection between Tower #1222 and Tower #1228 subsequent to the failure events on March 30, 2024 [1]. 2

Table 3-1: Summary of wire strand diameter ranges for the 6 layers associated with the failed conductor EL-1. The detailed measurement results have been provided in Annex B. 18

Table 3-2: Summary of wire strand diameter ranges for the 6 layers associated with the failed conductor EL-2. The detailed measurement results have been provided in Annex C. 19

Table 3-3: Summary of wire strand diameter ranges for the 6 layers associated with the intact service exposed conductor. The detailed measurement results have been provided in Annex D. 20

Table 4-1: Semi-quantitative SEM EDS analysis results for the strand to strand fusing observed in conductor EL-1. Figure 4-5 shows the locations of the EDS analyses. ... 26

Table 4-2: Semi-quantitative SEM EDS analysis results for the clamp material immediately adjacent to the site of localized brinelling in conductor EL-1. Figure 4-6 shows the locations of the EDS analyses. 26

Table 4-3: Semi-quantitative SEM EDS analysis results for the strand to strand fusing observed in conductor EL-2. Figure 4-11 shows the locations of the EDS analyses. . 31

Table 4-4: Semi-quantitative SEM EDS analysis results for the clamp material immediately adjacent to the site of localized brinelling in conductor EL-2. Figure 4-12 shows the locations of the EDS analyses. 31

Table A-1: Manufactures' data sheet for the ACSR Grackle conductor (zinc coated steel reinforcing core). 39

Table B-1: Summary of the outer aluminum conductor and inner steel reinforcing wire strand diameter measurements for the failed section of conductor EL-1. 41

Table C-1: Summary of the outer aluminum conductor and inner steel reinforcing wire strand diameter measurements for the failed section of conductor EL-2. 43

Table D-1: Summary of the outer aluminum conductor and inner steel reinforcing wire strand diameter measurements for the used intact service exposed conductor provided for uniaxial tension testing. 45

1 BACKGROUND

Wayland Engineering Ltd. was asked by Newfoundland and Labrador Hydro (NL Hydro) to conduct an investigation for two electrical conductors (EL-1 and EL-2) removed from suspension Tower #1225. The conductors routed electrical power along the approximately 1090 km long transmission corridor between Muskrat Falls and Soldiers Pond [1]. On March 30, 2024, Pole #2 tripped at approximately 6:45 am [1]. It was also reported that Pole #1 tripped at approximately 6:52 am owing to an electrode line fault protection event [1]. A subsequent field inspection conducted on the lines detected various forms of damage between Tower #1218 and Tower #1228 (Table 1-1 [1]). It has been indicated that there was significant ice accumulation on the line prior to failure (estimated radial thickness of the ice was in the range between 100 – 125 mm) [1]. It was also assumed that based on the failures and observation of icing conditions after the failures, there were unbalanced ice loads on the line due to ice shedding prior to the failures on March 30 [1]. It was reported that on the day prior to the failures, the wind velocity was approximately 70 km/h from an easterly direction [1]. During the day of the conductor failures, an easterly wind velocity of approximately 60 km/h was reported [1]. It has been indicated that the line was designed for a maximum wind velocity of 120 km/h in the absence of accumulated ice [1]. For a radial ice accumulation of approximately 25 mm, the design criterion for the maximum wind velocity reduces to 60 km/h [1]. The combination of the ice accumulation and wind velocities reported suggests that the line was operating in excess of the design criteria both on the day prior to and during the day of the failures sustained by conductors EL-1 and EL-2.

Figure 1-1 is a map showing the general compass directions of the line segments between suspension Tower #1200 and Tower #1229. It was also reported that the distances from Tower #1224 to Tower #1225 and Tower #1225 to Tower #1226 were approximately 378 m and 303 m, respectively [1]. It has been indicated that conductors EL-1 and EL-2 between Tower 1209 and Tower #1228 were installed in 2017 and had been subjected to approximately 7 years of service prior to the failures in 2024 [1]. Figure 1-1 also shows the direction of the easterly wind velocities reported on the day prior to and during the day of the conductor failure events. Of relevance to the current investigation was the approximate orthogonal angle of the wind direction with respect to the axis of the conductors, which may induce large amplitude vibrations (i.e. galloping) in the lines (particularly for conditions of asymmetric ice accumulation on the conductors). It has been noted that galloping of the conductors has been observed by NL Hydro on multiple occasions in the vicinity of Tower #1225 since the installation of the lines in 2017 [1].

Figure 1-2 is a field photograph of Tower #1225 subsequent to the failure of the conductors. The image shows the locations of conductor EL-1 and EL-2, which were attached to the crossarms of the tower via suspension insulators. It was reported that both conductor EL-1 and EL-2 conformed to an ACSR Grackle conductor specification. The Grackle 54/19 conductor specification with a 1192.5 kcmil size is a concentric-lay-stranded configuration with 54 outer aluminum conductors and 19 inner zinc coated steel reinforcing wires (Figure 1-3). The nominal diameters of the outer aluminum and inner steel wire strands were reported as 3.77 mm and 2.26 mm, respectively [1]. The outer aluminum wire strands for an ACSR Grackle conductor specification are manufactured from a material with a minimum aluminum content of 99.50 wt% [2,3,4]. Annex A contains the detailed data sheet for the ACSR Grackle conductor utilized by NL Hydro at Tower #1225 [1]. NL Hydro requested that Wayland Engineering provide an opinion on the mechanism(s) responsible for the failures sustained by conductor EL-1 and EL-2 from Tower #1225, which were provided for analysis.

Table 1-1: Summary of the damage detected by the field inspection between Tower #1222 and Tower #1228 subsequent to the failure events on March 30, 2024 [1].

Tower No.	Description of Damage Sustained by Conductor EL-1 and EL-2
1222	EL1 conductor stripped on 1221 side and birdcaged on 1223 side, EL2 Conductor complete broken on 1223 side.
1223	EL1 conductor stripped on 1222 side and birdcaged on 1224 side, EL2 Conductor complete broken on 1224 side.
1224	Both conductors stripped and birdcaged.
1225	Both conductors stripped and birdcaged.
1226	Both conductors damaged, video is not clear.
1227	Conductor severed and resting on pole conductor.
1228	EL1 conductor appears stripped and birdcaged - video not completely clear. Conductor is touching the ground.

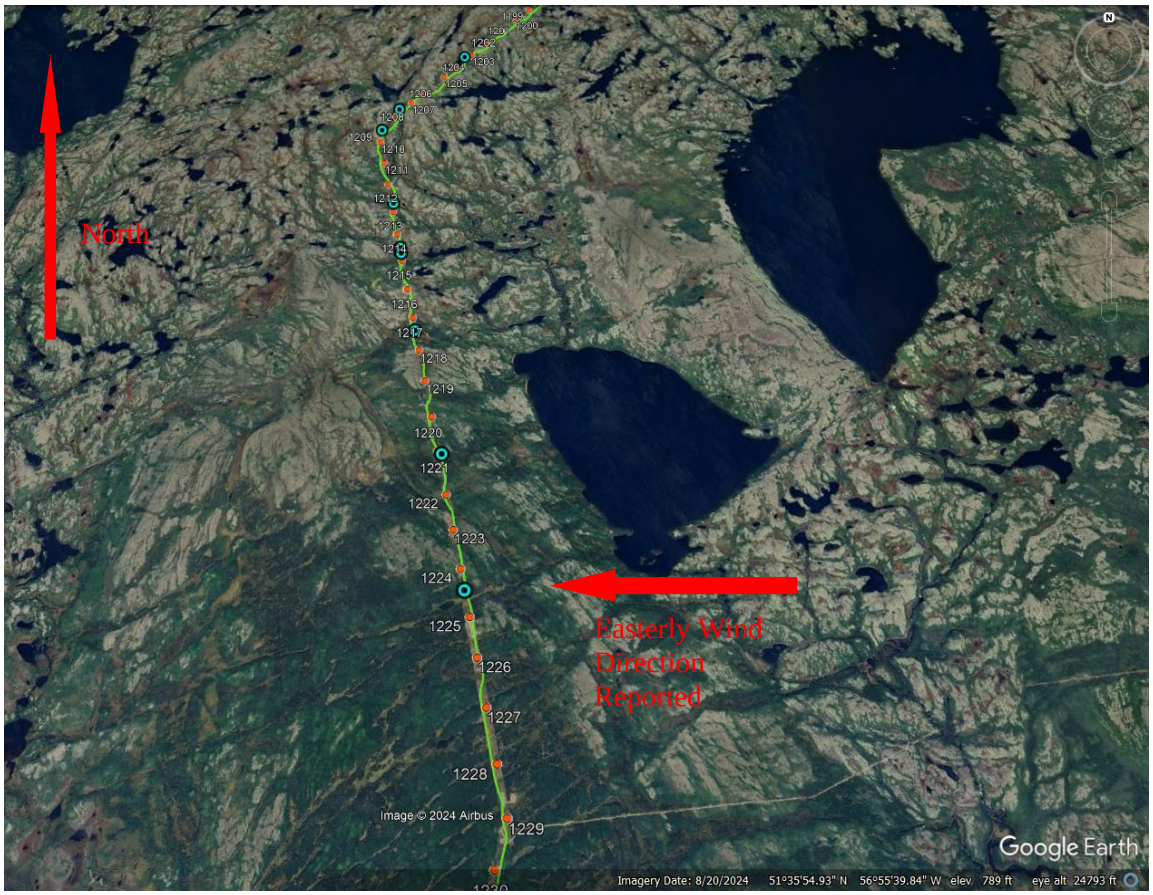


Figure 1-1: Google map provided by NL Hydro [1] showing the general compass directions of the segments of the transmission lines between Tower #1200 and Tower #1229. The map also shows the reported direction of the reported wind (easterly) on the day prior to and during the day of the failures [1].



Figure 1-2: General view of suspension Tower #1225 subsequent to the line failures on March 30, 2024 [1]. The image shows the locations of conductor EL-1 and EL-2 (ellipse), which were attached to the crossarms of the tower via suspension insulators.

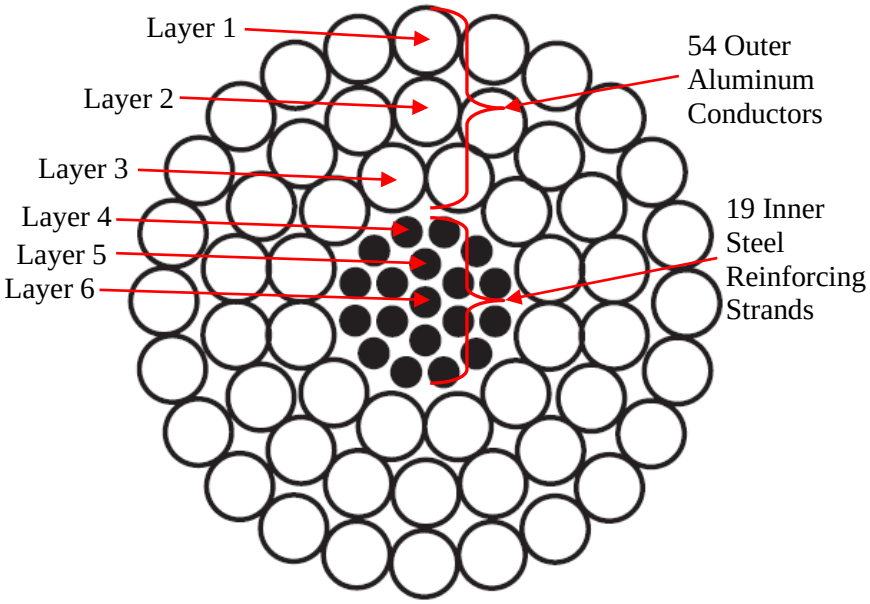


Figure 1-3: Schematic showing the general configuration of an ACSR Grackle 54/19 conductor specification.

2 PRELIMINARY EXAMINATION

Section 2.1 and Section 2.2 detail the preliminary examination conducted for the sections of failed conductor received for analysis from line EL-1and EL-2, respectively.

2.1 Preliminary Examination of Failed Conductor EL-1

Figure 2-1 and Figure 2-2 show two views of the single section of failed conductor EL-1 provided by NL Hydro as received for analysis. The section consisted of an approximately 60 cm long length of conductor and the lower bolted wire clamp associated with the suspension insulator from Tower #1225. At one axial end of the wire clamp, evidence of severe bird-caging of the aluminum conductor strands was observed (cut end of the conductor). At the opposing axial end of the wire clamp, evidence of fractured aluminum conductor strands was observed with an approximately 15 cm long length of the steel reinforcing core extending from the failed aluminum strands. It was reported that at Tower #1225 (Table 1-1 and Figure 1-2), the EL-1 line damage consisted of stripped and birdcaged outer conductors, which suggests that the inner steel reinforcing core remained intact at the site. Figure 2-2 also shows the relative vertical position of the steel reinforcing core, which showed evidence of migration towards the lower circumferential surface of the EL-1 wire clamp.

The wire clamp was subsequently removed from the EL-1 conductor for further characterization of the damage sustained by the aluminum wire strands during the failure event. Figure 2-3 and Figure 2-4 show the upper vertical and lower vertical external circumferential surfaces of the conductor as installed in the field. On the upper circumferential surface, the ends of the aluminum wire strands were terminated by fracture failures (Figure 2-3). Figure 2-5 and Figure 2-6 show close-up views of representative examples of the fracture failure morphologies observed (subsequent to conductor disassembly). The first morphology was characterized by a tapered (necked) interval immediately adjacent to the strand fracture surface (Figure 2-5). The second morphology was characterized by an oblique fracture plane extending across the diameter of the strand (Figure 2-6).

On the lower circumferential surface, evidence of significant aluminum strand to strand fusing was observed (Figure 2-4). The extent of the fusing was observed to increase towards the outboard axial end of the wire clamp. Figure 2-7 and Figure 2-8 show close-up views of representative examples of the strand to strand fusing subsequent to conductor disassembly. Evidence of complete and/or partial fusing together of all three aluminum strand layers was observed in conductor EL-1. Section 4.1 includes the metallurgical characterization of strand fracture failures, as well as the strand to strand fusing observed in conductor EL-1.

Figure 2-9 shows a top-down view of the lower circumferential surface of the wire clamp associated with conductor EL-1. Evidence of localized brinelling (plastic deformation) was observed adjacent to the outboard axial end (on the conductor failure side) of the clamp. The brinelling was located at the approximate bottom dead center circumferential position of the clamp as installed in the field. Figure 2-10 is a close-up sectional view of the localized brinelling observed. The image shows the approximately semi-circular morphology of the damage observed at the site. Section 4.1 includes the metallurgical characterization of the localized brinelling damage observed in the conductor EL-1 wire clamp.

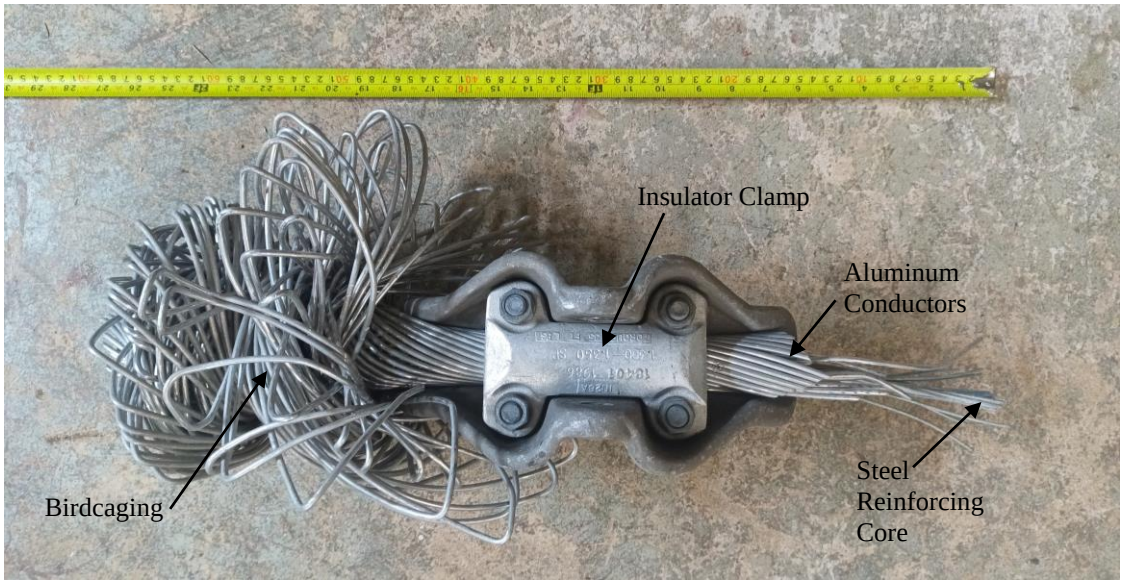


Figure 2-1: Top-down view of the wire clamp and failed section of the EL-1 conductor as received for analysis.

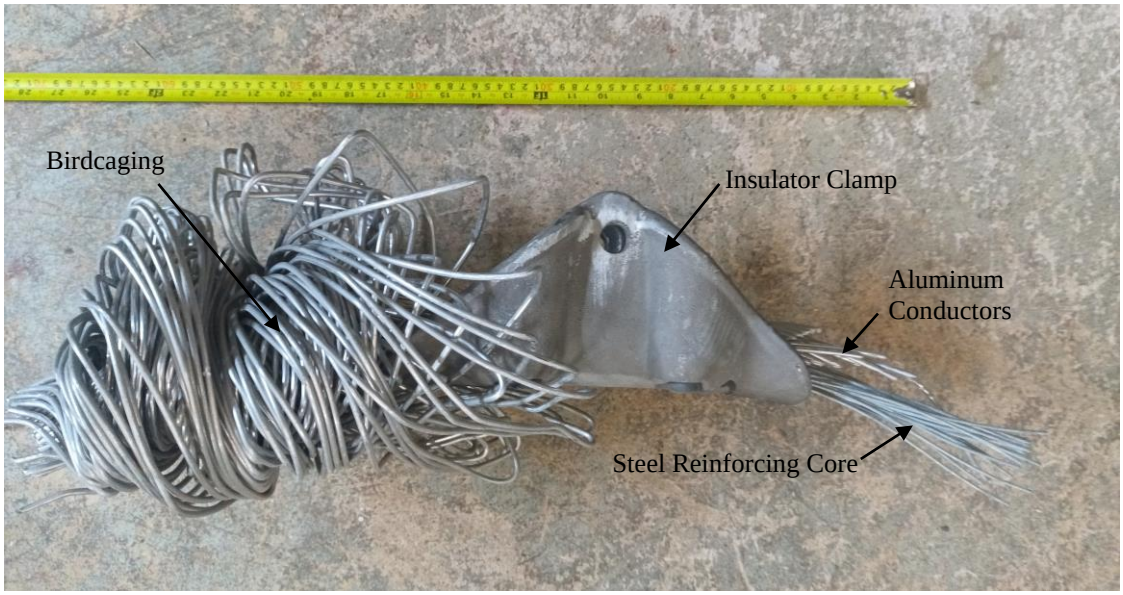


Figure 2-2: Side view of the wire clamp and failed section of the EL-1 conductor as received for analysis.

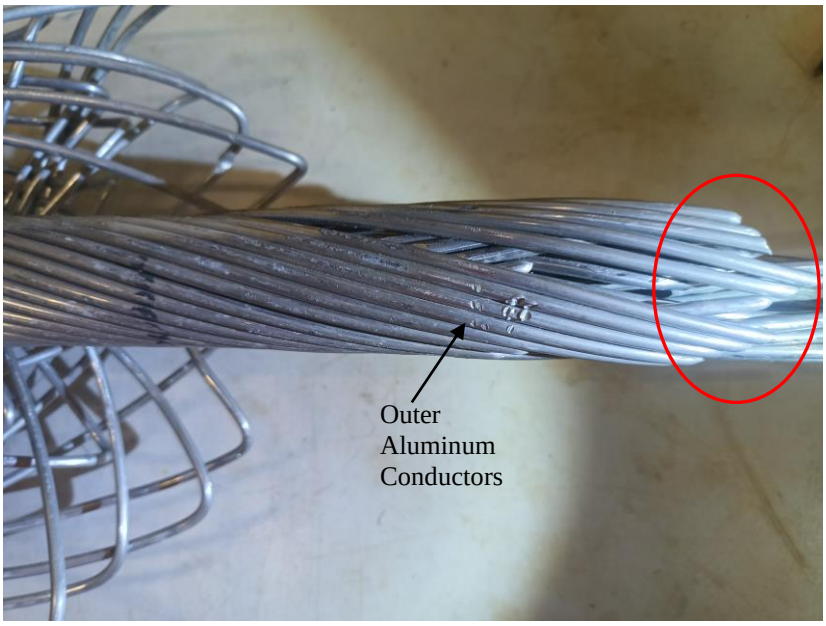


Figure 2-3: Photograph of the upper vertical external circumferential surface of conductor EL-1 as installed in the field. The image shows the fracture ends of the wire strands observed on the upper circumferential surface of the conductor (ellipse).

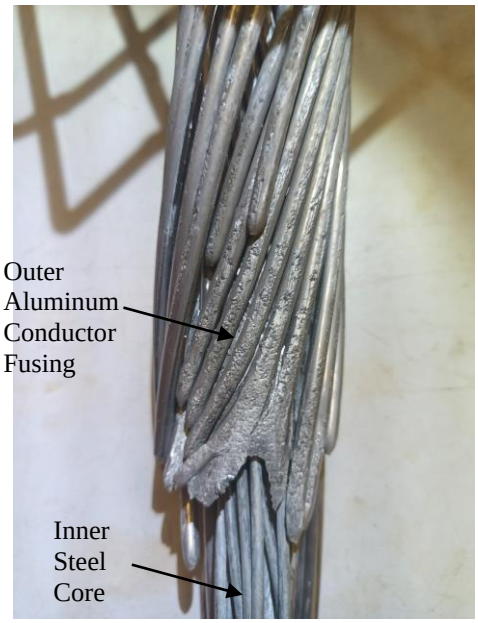


Figure 2-4: Photograph of the lower vertical external circumferential surface of conductor EL-1 as installed in the field. The image shows the significant aluminum strand to strand fusing observed on the lower circumferential surface.



Figure 2-5: Close-up view of a representative example of the fracture failure morphologies observed for conductor EL-1 (subsequent to conductor disassembly). The first morphology was characterized by a tapered (necked) interval immediately adjacent to the strand fracture surface.

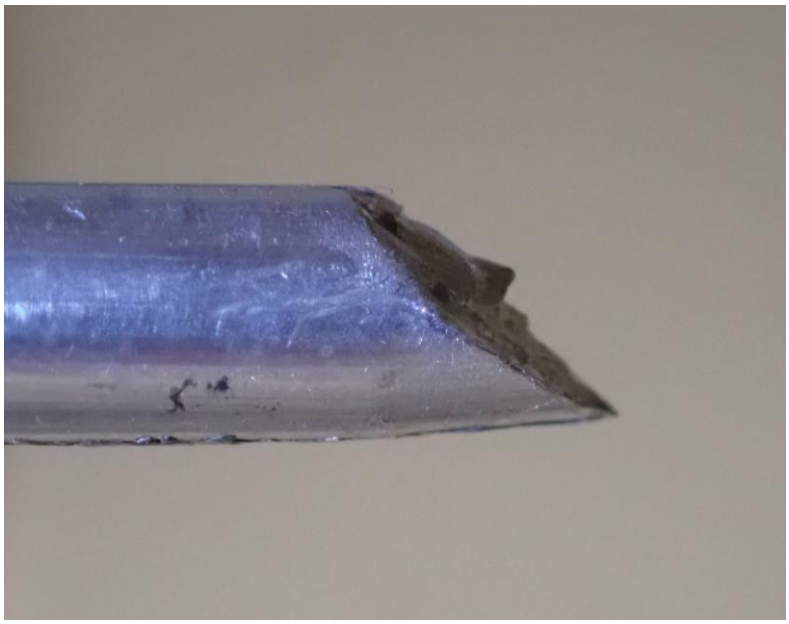


Figure 2-6: Close-up view of a representative example of the fracture failure morphologies observed for conductor EL-1 (subsequent to conductor disassembly). The second morphology was characterized by an oblique fracture plane extending across the diameter of the strand.

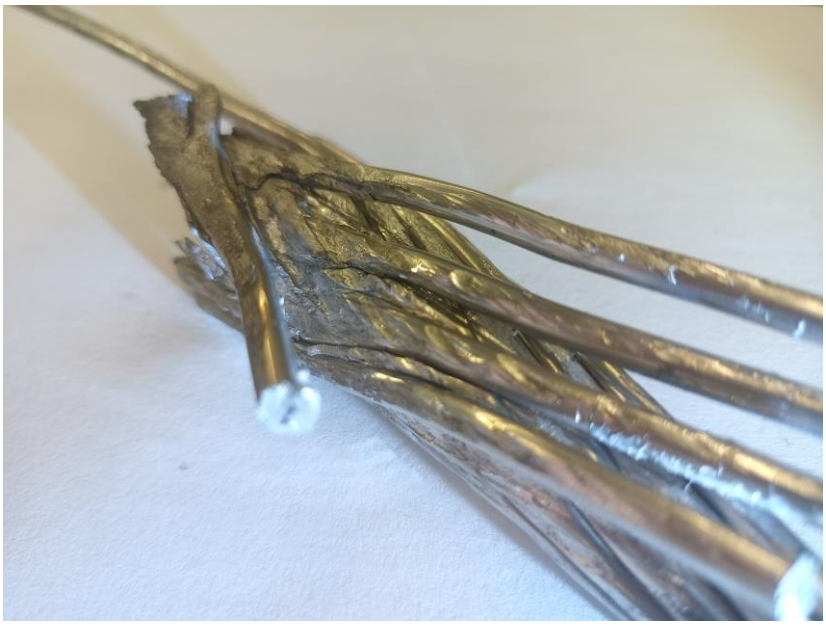


Figure 2-7: Close-up view of a representative example of the aluminum strand fusing observed (subsequent to conductor disassembly).

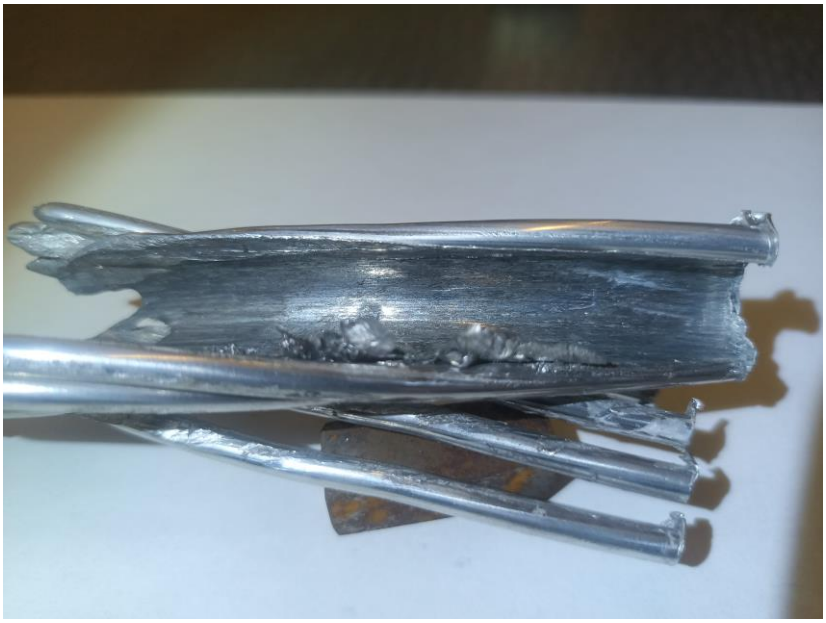


Figure 2-8: Close-up view of a second representative example of the aluminum strand fusing observed (subsequent to conductor disassembly).

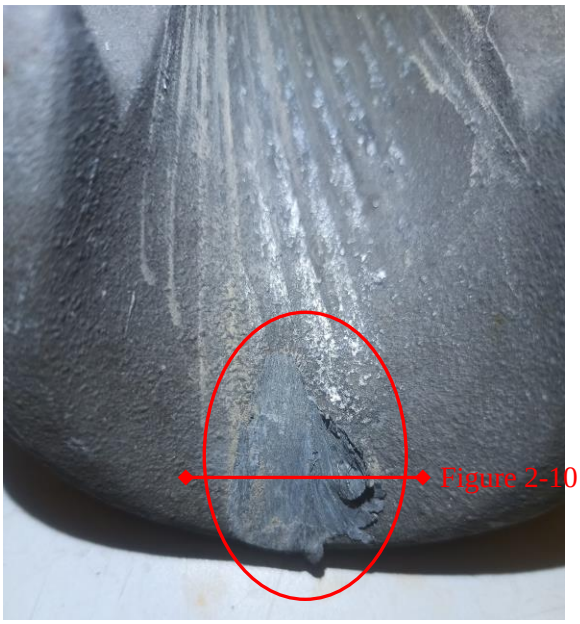


Figure 2-9: Top-down view of the lower circumferential surface of the wire clamp associated with conductor EL-1. The image shows the localized brinelling (ellipse) observed adjacent to the outboard axial end (on the conductor failure side) of the clamp. The image also shows the approximate cutline associated with the cross-sectional view of the brinelling in Figure 2-10.

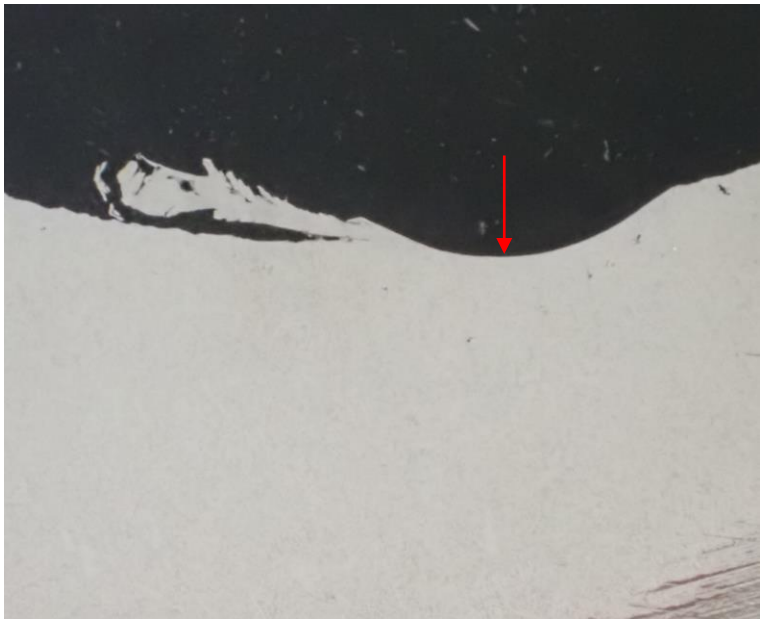


Figure 2-10: Close-up sectional view through the localized brinelling (arrow) shown in Figure 2-9. The image shows the approximate semi-circular morphology of the damage observed at the site (ellipse).

2.2 Preliminary Examination of Failed Conductor EL-2

Figure 2-11 through Figure 2-14 show views of the two sections of the failed conductor EL-2 provided by NL Hydro as received for analysis. The first section (Figure 2-11 and Figure 2-12) consisted of an approximately 45 cm long length of the outer aluminum conductor strands (i.e. the inner zinc coated steel reinforcing core was absent) and the lower bolted wire clamp associated with the suspension insulator from Tower #1225. At one axial end of the wire clamp, evidence of fractured aluminum conductor strands was observed. The second section of the failed conductor EL-2 (Figure 2-13 and Figure 2-14) consisted of an approximately 150 cm long length of conductor with a Stockbridge damper attached to the conductor wire. Evidence of severe bird-caging of the aluminum conductor strands was observed over the entire length of the second section of conductor EL-2 provided for analysis. At one axial end of the section with the attached Stockbridge damper, evidence of fractured aluminum conductor strands was observed. Similar to conductor EL-1, it was reported that at Tower #1225 (Table 1-1 and Figure 1-2), the EL-2 line damage consisted of stripped and birdcaged outer conductors, which suggests that the steel reinforcing core remained intact at the site.

The wire clamp and Stockbridge damper were subsequently removed from the two sections of the EL-2 conductor provided for further characterization of the damage sustained by the aluminum wire strands during the failure event. Figure 2-15 and Figure 2-16 show the upper vertical and lower vertical external circumferential surfaces of the conductor within the wire clamp section as installed in the field. On the upper circumferential surface, the ends of the aluminum wire strands were terminated by fracture failures (Figure 2-15). Figure 2-17 and Figure 2-18 show close-up views of representative examples of the fracture failure morphologies observed (subsequent to conductor disassembly). The first morphology was characterized by a tapered (necked) interval immediately adjacent to the strand fracture surface (Figure 2-17). The second morphology was characterized by an oblique fracture plane extending across the diameter of the strand (Figure 2-18).

On the lower circumferential surface, evidence of aluminum strand to strand fusing was observed (Figure 2-16). While the extent of the fusing was not as prevalent as that observed in conductor EL-1, the extent of the fusing was observed to increase towards the outboard axial end of the wire clamp. Figure 2-19 and Figure 2-20 show close-up views of representative examples of the strand to strand fusing subsequent to conductor disassembly. Similar to conductor EL-1, evidence of complete and/or partial fusing together of multiple aluminum strand layers was observed in conductor EL-2. Section 4.2 includes the metallurgical characterization of strand fracture failures, as well as the strand to strand fusing observed in conductor EL-2.

Figure 2-21 shows a top-down view of the lower circumferential surface of the wire clamp associated with conductor EL-2. Evidence of localized brinelling (plastic deformation) was observed adjacent to the outboard axial end (on the conductor failure side) of the clamp. The brinelling was located at the approximate bottom dead center circumferential position of the clamp as installed in the field. Figure 2-22 is a close-up sectional view of the localized brinelling observed. The image shows the approximately semi-circular morphology of the damage observed at the site. Section 4.2 includes the metallurgical characterization of the localized brinelling damage observed in conductor EL-2 wire clamp.



Figure 2-11: Top-down view of the wire clamp and failed section of the EL-2 conductor as received for analysis.



Figure 2-12: Side view of the wire clamp and failed section of the EL-2 conductor as received for analysis.

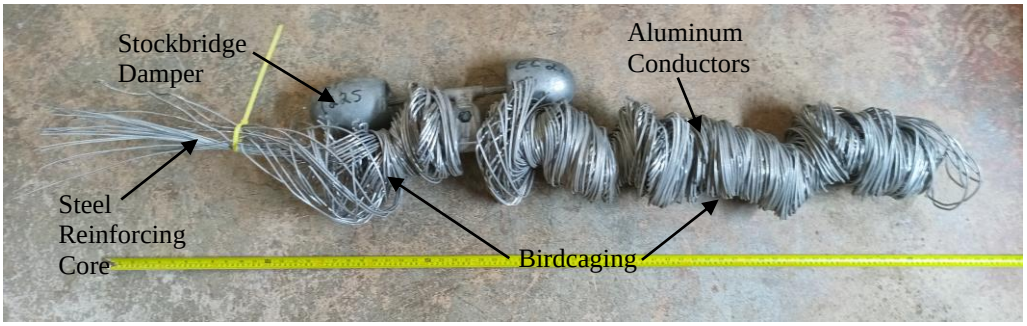


Figure 2-13: Photograph showing a view of the failed section of the EL-2 conductor with an attached Stockbridge damper as received for analysis.

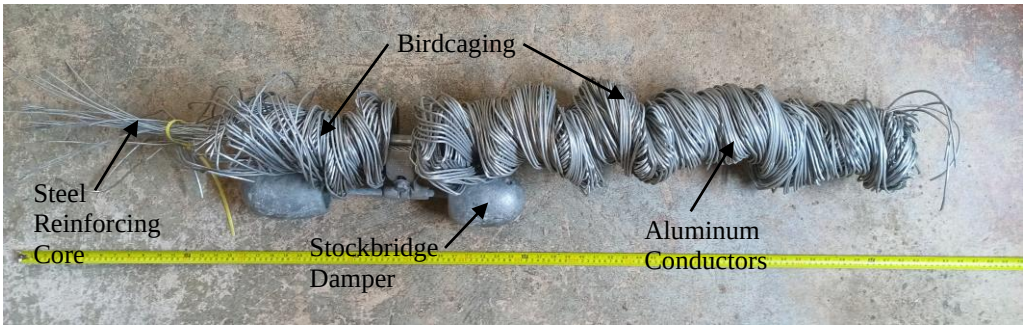


Figure 2-14: Photograph showing a second view of the failed section of the EL-2 conductor with an attached Stockbridge damper as received for analysis.



Figure 2-15: Photograph of the upper vertical external circumferential surface of conductor EL-2 as installed in the field. The image shows the fracture ends of the wire strands observed on the upper circumferential surface of the conductor.

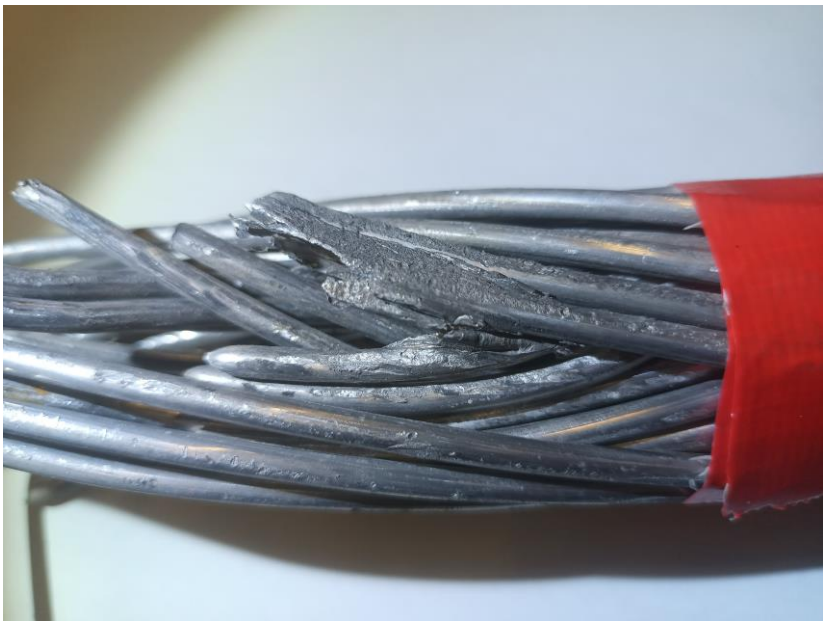


Figure 2-16: Photograph of the lower vertical external circumferential surface of conductor EL-2 as installed in the field. The image shows the significant aluminum strand to strand fusing observed on the lower circumferential surface.

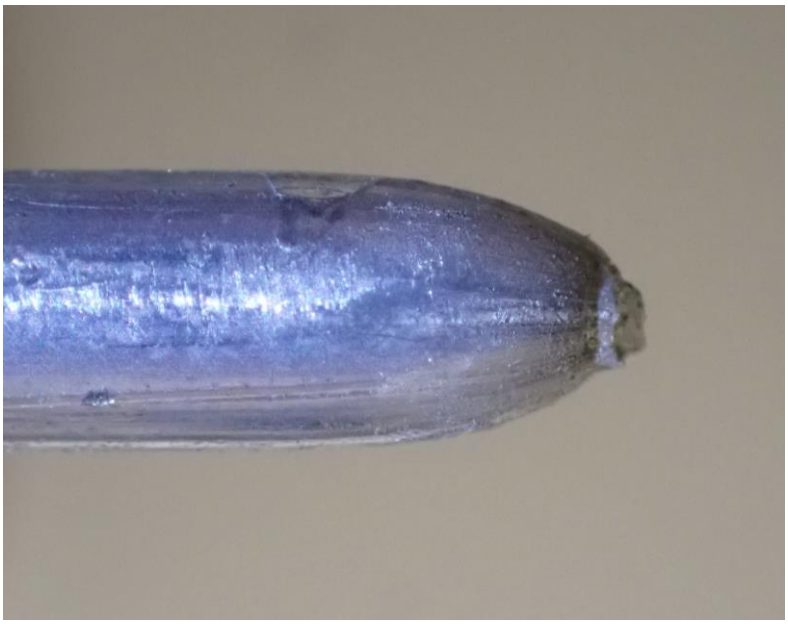


Figure 2-17: Close-up view of a representative example of the fracture failure morphologies observed for conductor EL-2 (subsequent to conductor disassembly). The first morphology was characterized by a tapered (necked) interval immediately adjacent to the strand fracture surface.

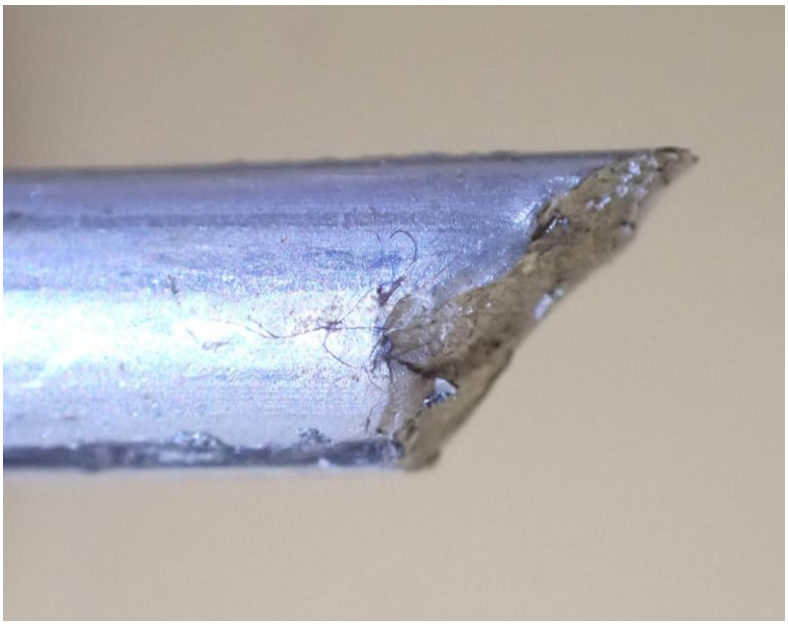


Figure 2-18: Close-up view of a representative example of the fracture failure morphologies observed for conductor EL-2 (subsequent to conductor disassembly). The second morphology was characterized by an oblique fracture plane extending across the diameter of the strand.

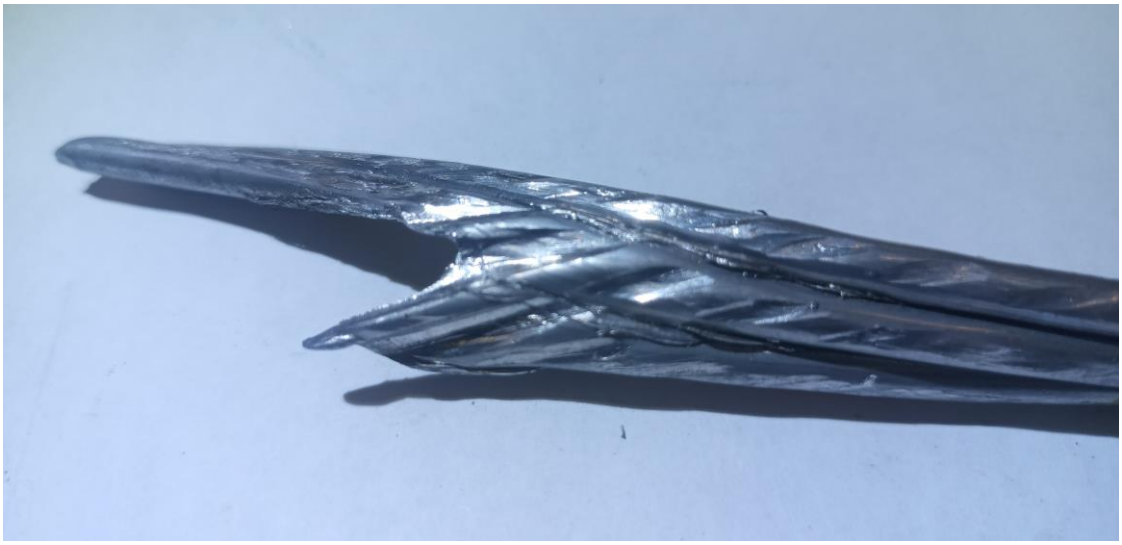


Figure 2-19: Close-up view of a representative example of the aluminum strand fusing observed (subsequent to conductor disassembly).

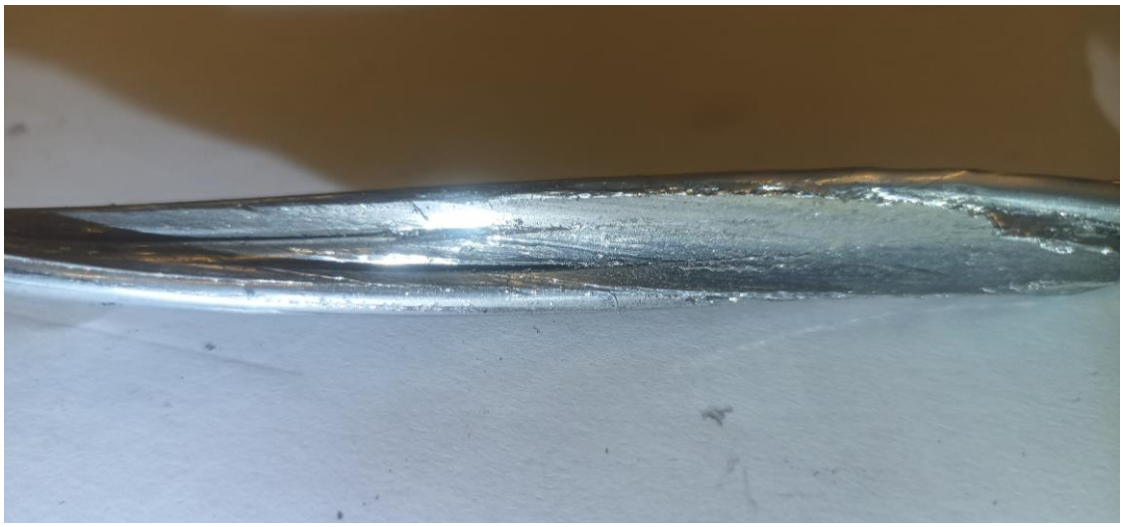


Figure 2-20: Close-up view of a second representative example of the aluminum strand fusing observed (subsequent to conductor disassembly).



Figure 2-21: Top-down view of the lower circumferential surface of the wire clamp associated with conductor EL-2. The image shows the localized brinelling (ellipse) observed adjacent to the outboard axial end (on the conductor failure side) of the clamp. The image also shows the approximate cutline associated with the cross-sectional view of the brinelling in Figure 2-22.



Figure 2-22: Close-up sectional view through the localized brinelling (arrow) shown in Figure 2-21. The image shows the approximately semi-circular morphology of the damage observed at the site.

3 EVALUATION OF THE CONDUCTOR DIMENSIONAL AND MECHANICAL PROPERTIES

The intervals of conductor fixed within the insulator clamps of the failed EL-1 and EL-2 sections were dissembled in order to conduct a dimensional characterization of the wire strand diameters. For the EL-1 and EL-2 strands which did not exhibit either strand to strand fusing and/or severe strand cross-sectional distortions, the diameter of the wire strand was measured at an axial distance of approximately 2 cm to 3 cm away from the terminating fracture surface associated with individual strands. An axial interval was also removed and dissembled from an intact length of service exposed (used) conductor provided by NL Hydro (Figure 3-1). The diameters of the wire strands associated with the intact service exposed conductor were also measured for comparison purposes. For the internal steel reinforcing core strands, the thickness of the protective zinc coating layer was measured on representative wire strands from the three dissembled intervals of conductor using scanning electron microscope (SEM) imaging. Section 3.1, Section 3.2 and Section 3.3 detail the results generated for the failed EL-1, failed EL-2 and intact (service exposed) conductors, respectively.

A uniaxial tension test was also conducted on a length of the intact conductor provided by NL Hydro to determine if the service exposed conductor still met the rated tensile strength requirements for a Grackle ACSR 54/19 conductor. Section 3.4 details the results of the uniaxial tension test conducted.



Figure 3-1: Image showing the coiled length of the service exposed (used) conductor provided by NL Hydro as received for analysis.

3.1 Dimensional Characterization of Failed Conductor EL-1 Wire Strands

Table 3-1 contains a summary of wire strand diameter ranges for the 6 layers associated with the failed conductor EL-1 (the detailed measurement results have been provided in Annex B). For Layer 1, Layer 2 and Layer 3 (aluminum conductor strands) the diameters ranged between 3.40 mm to 3.73 mm, 3.56 mm to 3.73 mm and 3.63 mm to 3.68 mm, respectively. For Layer 4, Layer 5 and Layer 6 (zinc coated steel reinforcing strands) the diameters ranged between 2.06 mm to 2.24 mm, 2.03 mm to 2.11 mm and 2.11 mm, respectively. The diameter ranges measured for both the aluminum conductor strands and the zinc coated steel reinforcing strands for conductor EL-1 were generally within reasonable agreement with the specified wire diameter requirements as per ASTM B-232 [2] for a Grackle ACSR 54/19 (size 1192.5 kcmil) conductor.

Figure 3-2 is a sectional SEM backscatter image of a representative example of a zinc coated steel reinforcing strand (additional representative examples are provided in Annex B). The image shows the variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. The minimum thickness ranged between approximately 31.86 µm and 43.31 µm for the strands evaluated. A range of 31.86 µm to 43.31 µm in zinc coating thickness equates to a layer surface density of approximately 271.9 g/m^2 to 404.9 g/m^2, respectively. While a significant variation in the thickness of the zinc coating was observed around the circumference of individual strands, it should be noted that a breech through the coating to the steel core was not observed at the sites (i.e. the cathodic protection provided by the zinc coating remained intact).

Table 3-1: Summary of wire strand diameter ranges for the 6 layers associated with the failed conductor EL-1. The detailed measurement results have been provided in Annex B.

	Wire Strand Diameter Ranges (mm)					
	Outer Aluminum Strands			**Inner Steel Strands**		
	Layer 1	**Layer 2**	**Layer 3**	**Layer 4**	**Layer 5**	**Layer 6**
Conductor EL-1	3.40-3.73	3.56-3.73	3.63-3.68	2.06-2.24	2.03-2.11	2.11

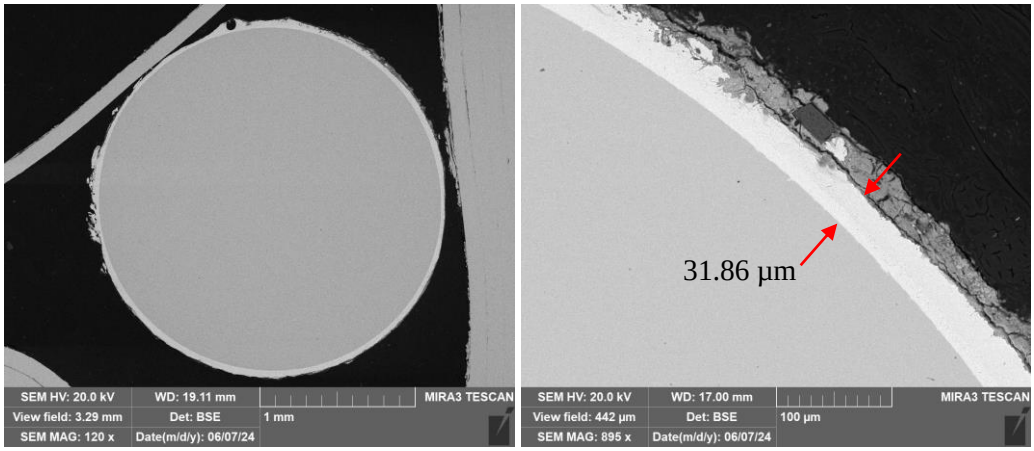


Figure 3-2: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the failed conductor EL-1. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

3.2 Dimensional Characterization of Failed Conductor EL-2 Wire Strands

Table 3-2 contains a summary of wire strand diameter ranges for the 6 layers associated with the failed conductor EL-2 (the detailed measurement results have been provided in Annex C). For Layer 1, Layer 2 and Layer 3 (aluminum conductor strands) the diameters ranged between 3.43 mm to 3.68 mm, 3.56 mm to 3.71 mm and 3.66 mm to 3.71 mm, respectively. For Layer 4, Layer 5 and Layer 6 (zinc coated steel reinforcing strands) the diameters ranged between 2.18 mm to 2.26 mm, 2.16 mm to 2.24 mm and 2.24 mm, respectively. The diameter ranges measured for both the aluminum conductor strands and the zinc coated steel reinforcing strands for conductor EL-2 were generally within reasonable agreement with the specified wire diameter requirements as per ASTM B-232 [2] for a Grackle ACSR 54/19 (size 1192.5 kcmil) conductor.

Figure 3-3 is a sectional SEM backscatter image of a representative example of a zinc coated steel reinforcing strand (additional representative examples are provided in Annex C). Similar to the failed conductor EL-1, the image shows the variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. The minimum thickness ranged between approximately 30.83 µm and 31.57 µm for the strands evaluated. A range of 30.83 µm to 31.57 µm in zinc coating thickness equates to a layer surface density of approximately 261.2 g/m^2 to 268.8 g/m^2, respectively. While a significant variation in the thickness of the zinc coating was observed around the circumference of individual strands, it should be noted that a breech through the coating to the steel core was not observed at the sites (i.e. the cathodic protection provided by the zinc coating remained intact).

Table 3-2: Summary of wire strand diameter ranges for the 6 layers associated with the failed conductor EL-2. The detailed measurement results have been provided in Annex C.

	Wire Strand Diameter Ranges (mm)					
	Outer Aluminum Strands			**Outer Aluminum Strands**		
	Layer 1	**Layer 2**	**Layer 3**	**Layer 4**	**Layer 5**	**Layer 6**
Conductor EL-2	3.43-3.68	3.56-3.71	3.66-3.71	2.18-2.26	2.16-2.24	2.24

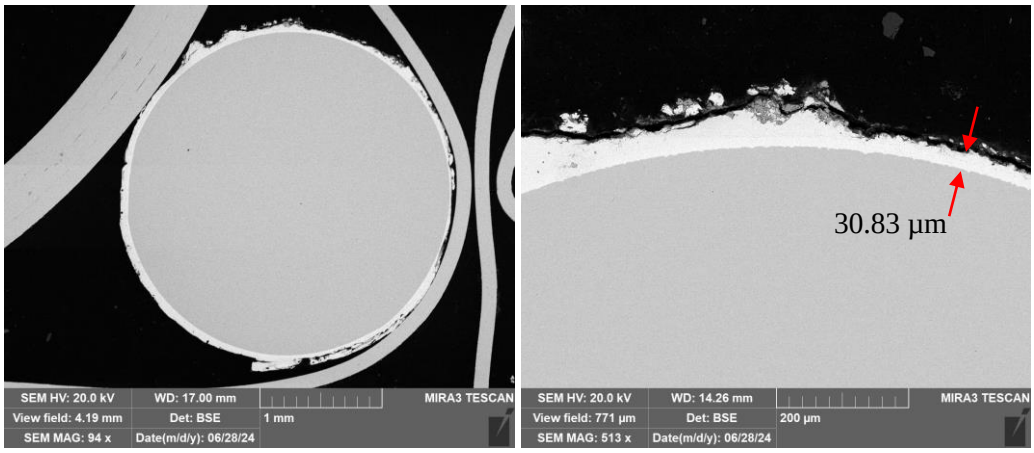


Figure 3-3: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the failed conductor EL-2. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

3.3 Dimensional Characterization of an Intact Service Exposed (Used) Conductor Wire Strands

Table 3-3 contains a summary of wire strand diameter ranges for the 6 layers associated with the intact service exposed conductor (the detailed measurement results have been provided in Annex D). For Layer 1, Layer 2 and Layer 3 (aluminum conductor strands) the diameters ranged between 3.71 mm to 3.76 mm, 3.71 mm to 3.76 mm and 3.71 mm to 3.73 mm, respectively. For Layer 4, Layer 5 and Layer 6 (zinc coated steel reinforcing strands) the diameters ranged between 2.21 mm to 2.24 mm, 2.21 mm to 2.24 mm and 2.21 mm, respectively. The diameter ranges measured for both the aluminum conductor strands and the zinc coated steel reinforcing strands for the service exposed conductor were generally within reasonable agreement with the specified wire diameter requirements as per ASTM B-232 [2] for a Grackle ACSR 54/19 (size 1192.5 kcmil) conductor.

Figure 3-4 is a sectional SEM backscatter image of a representative example of a zinc coated steel reinforcing strand (additional representative examples are provided in Annex D). Similar to the failed conductors EL-1 and EL-2, the image shows the variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand. The minimum thickness ranged between approximately 21.56 µm and 37.36 µm for the strands evaluated. A range of 21.56 µm to 37.36 µm in zinc coating thickness equates to a layer surface density of approximately 171.9 g/m^2 to 332.3 g/m^2, respectively. While a variation in the thickness of the zinc coating was observed around the circumference of individual strands, it should be noted that a breech through the coating to the steel core was not observed at the sites (i.e. the cathodic protection provided by the zinc coating remained intact).

Table 3-3: Summary of wire strand diameter ranges for the 6 layers associated with the intact service exposed conductor. The detailed measurement results have been provided in Annex D.

	Wire Strand Diameter Ranges (mm)					
	Outer Aluminum Strands			**Outer Aluminum Strands**		
	Layer 1	**Layer 2**	**Layer 3**	**Layer 4**	**Layer 5**	**Layer 6**
Intact Conductor	3.71-3.76	3.71-3.76	3.71-3.73	2.21-2.24	2.21-2.24	2.21

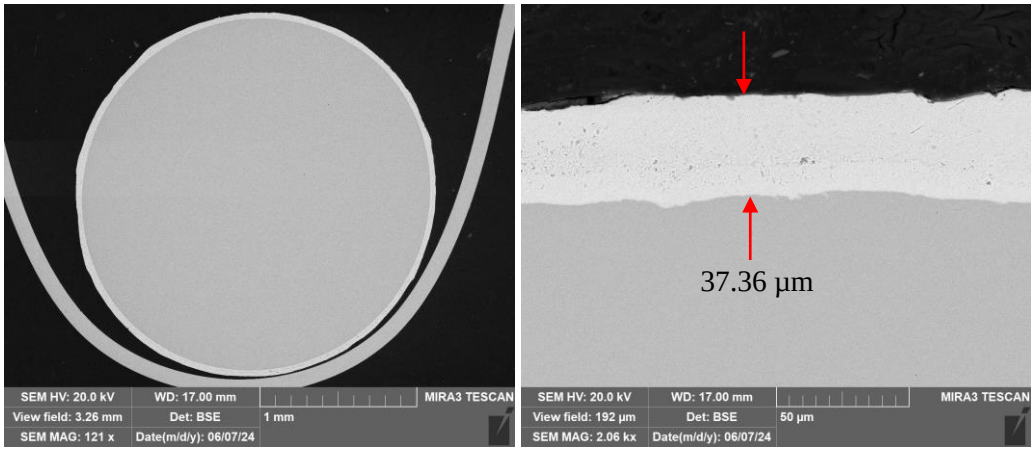


Figure 3-4: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the intact service exposed conductor. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

3.4 Uniaxial Tension Testing of an Intact Service Exposed (Used) Conductor

A length of the intact service exposed (used) conductor provided by NL Hydro (Figure 3-1) was tested in uniaxial tension in accordance with the procedure specified in ASTM A931 [5]. A test sample with a gauge length of approximately 1.55 m was terminated at both ends with an epoxy filled socket fixture (Figure 3-5). Figure 3-6 shows the load train utilized to test the terminated sample. The load train was used to apply a monotonic, stroke controlled, quasi-static deflection rate to the sample until the ultimate rupture of both the outer aluminum and inner steel reinforcing wire strands occurred.

The results of the testing indicated that the applied force when the outer aluminum wire strands selectively fractured was approximately 196.6 kN. The selective fracture of the outer aluminum wire strands resulted in a reduction of the applied force to approximately 94.7 kN. With continued applied deflection to the sample, the applied force increased to approximately 114.3 kN, which resulted in the fracture failure of the inner steel reinforcing wire strands. Measurements indicated that the overall fracture failure of the conductor occurred approximately 21 cm from the beginning of one of the epoxy filled terminations (Figure 3-7).

Figure 3-8 is a close-up view of the conductor showing the relative positions of the outer aluminum and the inner steel reinforcing wire strand failures, which is consistent with that expected for the failure of a Grackle ACSR conductor. Samples of the fractured ends of the outer aluminum wire strands were removed from the failed conductor for additional analyses using SEM fractographic imaging techniques. Figure 3-9 and Figure 3-10 contain a side view and end view fractographic images of a representative example of a fractured aluminum wire strand, respectively. For Figure 3-10, image (A) shows the cup and cone failure morphology and image (B) shows the void coalescence typically associated with a ductile, limit load fracture mechanism. The cup and cone failure morphology observed was consistent with that expected for the applied uniaxial tension force generated by the test procedure. Section 4.1 and Section 4.2 include the fractographic images for the fractured aluminum wire strands from conductor EL-1 and conductor EL-2 for comparison, respectively.

It should be noted that the coil diameter of the length of service exposed conductor provided by NL Hydro was approximately 48 inches, which was below the recommended minimum diameter of 50 times the diameter of the conductor diameter (approximately 68 inches). Coiling the conductor below its recommended bend radius may result in the introduction of permanent plastic strain in the outer aluminum wire strands. In addition, the ends of the service exposed conductor were fixed with electrical tape as opposed to mechanical clamps generally recommended. Insufficient clamping pressure at the ends of the conductor may result in an axial shifting of conductor layers with respect to each other (particularly for the case where the conductor is coiled below the minimum recommended bend radius). Both induced plastic strain in the outer aluminum wire strands and a relative shift between conductor layers may result in a reduction in the ultimate breaking strength of the conductor. Thus, it is possible that the actual breaking strength of the service exposed conductor was higher than that recorded during the uniaxial tension test conducted.



Figure 3-5: Photograph showing the epoxy filled socket fixture (ellipse) utilized to terminate the conductor at both ends.



Figure 3-6: Photograph showing the load train utilized to test the intact service exposed conductor in uniaxial tension (the arrow indicates the conductor).

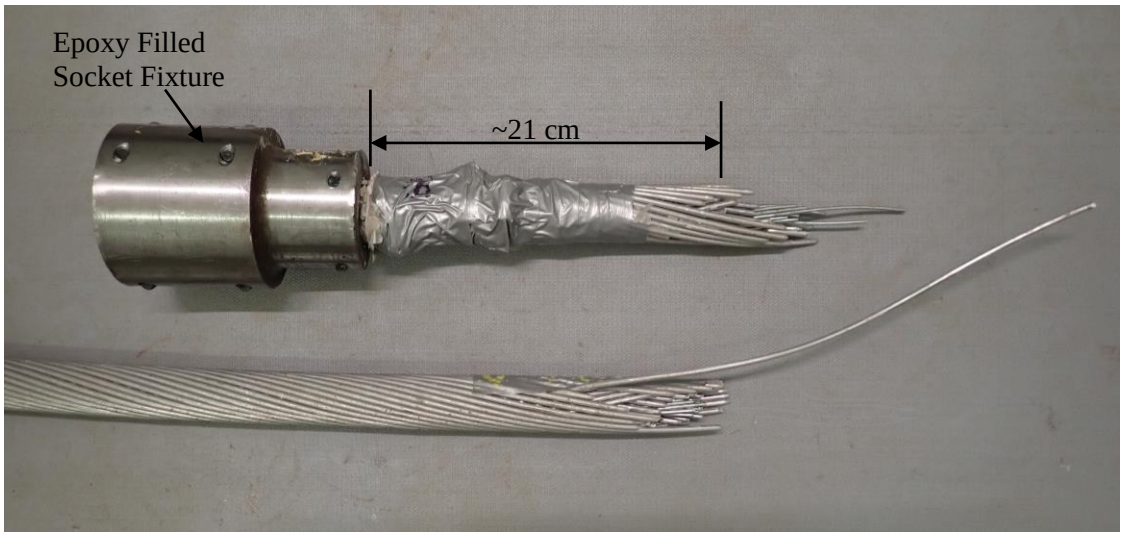


Figure 3-7: Photograph showing the service exposed conductor subsequent to failure. The axial position of the conductor failure was approximately 21 cm from the beginning of one of the epoxy filled terminations.

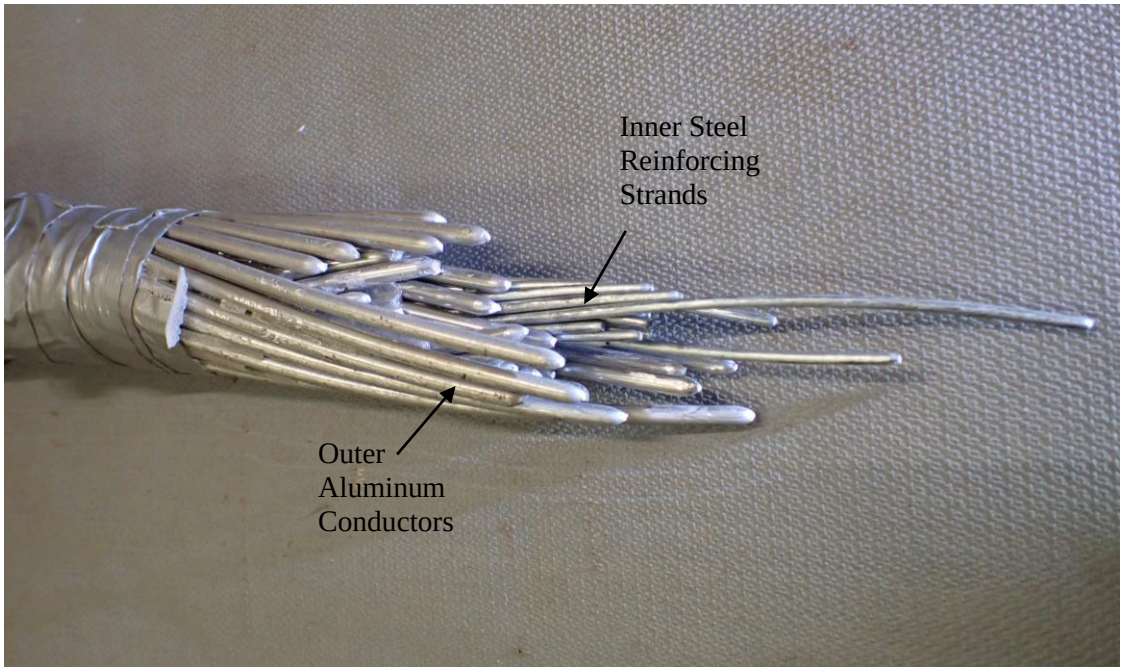


Figure 3-8: Close-up view of the conductor showing the relative positions of the outer aluminum and the inner steel reinforcing wire strand failures.



Figure 3-9: Close-up view of a representative example of the fracture failure morphology observed for the aluminum conductors associated with the uniaxial tension test. The morphology was characterized by a tapered (necked) interval immediately adjacent to the strand fracture surface.

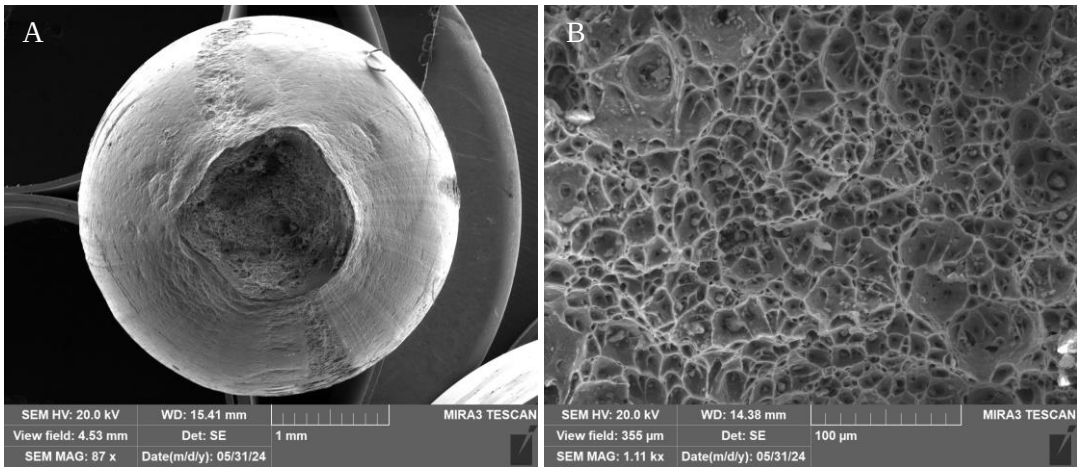


Figure 3-10: SEM fractographic images of a representative example of the fracture surface associated with the failure of the outer aluminum wire strands. The image shows the cup and cone failure (A) and the void coalescence (B) typically associated with a ductile, limit load fracture mechanism.

4 METALLURGICAL CHARACTERIZATION OF THE FAILED CONDUCTOR DAMAGE (EL-1 AND EL-2)

Section 4.1 and Section 4.2 contain the metallurgical results characterizing the conductor and insulator wire clamp damage detected for failed conductors EL-1 and EL-2 provided for analysis respectively.

4.1 Metallurgical Characterization of Failed Conductor EL-1

Samples from several of the outer aluminum wire strands, which included the fracture surface associated with the strand failure were removed from conductor EL-1. The samples were prepared for the characterization of the topological features associated with the fracture mechanism using SEM fractographic imaging techniques. Figure 4-1 is a low magnification SEM secondary image of a representative example of the fracture surface associated with the tapered-end geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-1 (Figure 2-5). The image shows the general cup and cone morphology of the failed end of the wire strand. Figure 4-2 is a high magnification fractographic image within the proximity of the strand centroid showing the topological features associated with the strand fracture mechanism. The image indicates that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site. Figure 4-3 is a low magnification SEM secondary image of a representative example of the fracture surface associated with the oblique geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-1 (Figure 2-6). Figure 4-4 is a high magnification fractographic image within the proximity of the strand centroid showing the topological features associated with the strand fracture mechanism. Similar to Figure 4-2, the image suggests that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site.

Several samples were also sectioned from the outer aluminum wire strands at locations where evidence of strand to strand fusing was observed during the preliminary examination of conductor EL-1 (Figure 2-7 and Figure 2-8). The samples were prepared for metallurgical characterization of the damage using a combination of SEM imaging and energy dispersive X-ray spectroscopy (EDS) analyses. Figure 4-5 is a sectional view SEM backscatter image of a representative example of the strand to strand fusing observed in conductor EL-1. The image shows the severe distortion of the wire strands observed, as well as the presence of a higher density phase embedded within the distorted aluminum strands. To determine the composition of the higher density phase, the material was subjected to EDS analyses. The results of the analyses (Table 4-1) indicated that the higher density phase was comprised primarily of zinc (Zn). The analyses suggest that the Zn from the outer coating associated with the steel reinforcing strands was also fusing with the outer aluminum wire strands.

Several samples were also sectioned from the insulator conductor clamp where evidence of localized brinelling was observed during the preliminary examination of conductor EL-1 (Figure 2-10). Figure 4-6 is a sectional view SEM backscatter image of a representative example of the clamp material immediately adjacent to the site of localized brinelling. Similar to Figure 4-5, the image shows the presence of a higher density phase embedded within the aluminum clamp

material. The results of the analyses (Table 4-2) indicated that the higher density phase was comprised primarily of zinc (Zn). The presence of Zn embedded within the Al clamp material suggests that the Zn coated steel reinforcing strands (from the inner conductor core) were in contact with the intrados associated with the clamp housing at the site.

Table 4-1: Semi-quantitative SEM EDS analysis results for the strand to strand fusing observed in conductor EL-1. Figure 4-5 shows the locations of the EDS analyses.

	Chemical Composition (wt%)						
Position	**Fe**	**Si**	**Zn**	**Al**	**O**	**P**	**S**
A1	ND	ND	93.40	3.40	3.19	ND	ND
A2	ND	ND	90.69	7.10	2.21	ND	ND
A3	ND	ND	94.26	2.82	2.92	ND	ND
A4	ND	ND	ND	97.65	2.35	ND	ND

Note: ND indicates that the element was not detected.

Table 4-2: Semi-quantitative SEM EDS analysis results for the clamp material immediately adjacent to the site of localized brinelling in conductor EL-1. Figure 4-6 shows the locations of the EDS analyses.

	Chemical Composition (wt%)						
Position	**Fe**	**Si**	**Zn**	**Al**	**O**	**P**	**S**
B1	ND	1.09	90.78	6.19	1.94	ND	ND
B2	ND	ND	94.81	3.36	1.83	ND	ND
B3	ND	ND	78.00	18.59	3.41	ND	ND
B4	ND	ND	92.07	3.72	4.21	ND	ND
B5	ND	ND	95.72	2.29	1.99	ND	ND
B6	ND	ND	96.53	2.00	1.47	ND	ND
B7	ND	11.79	ND	86.47	1.74	ND	ND

Note: ND indicates that the element was not detected.

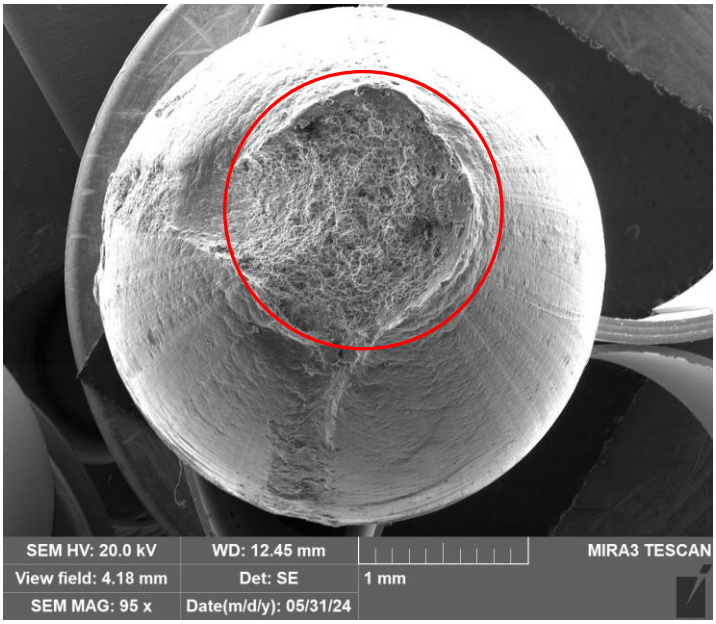


Figure 4-1: Low magnification SEM secondary image of a representative example of the fracture surface (ellipse) associated with the tapered-end (necked) geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-1 (Figure 2-5). The image shows the general cup and cone morphology of the failed end of the wire strand.

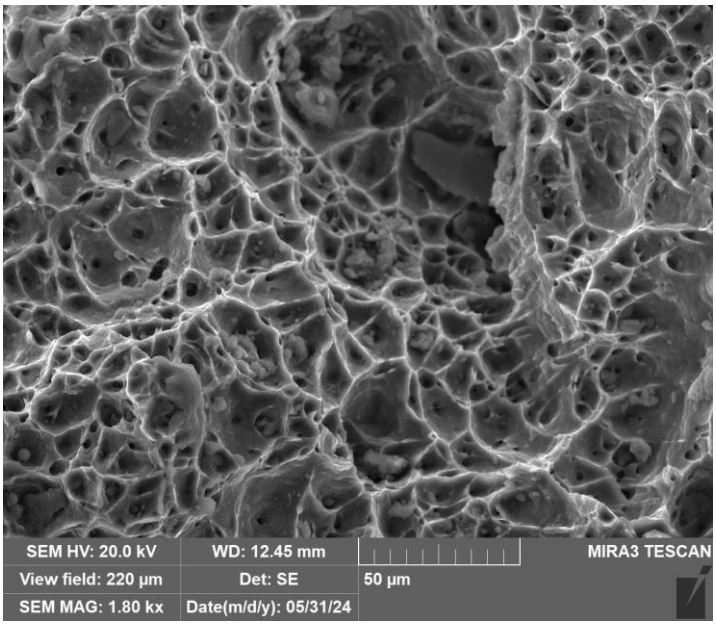


Figure 4-2: High magnification fractographic image within the proximity of the strand centroid shown in Figure 4-1. The image indicates that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site.

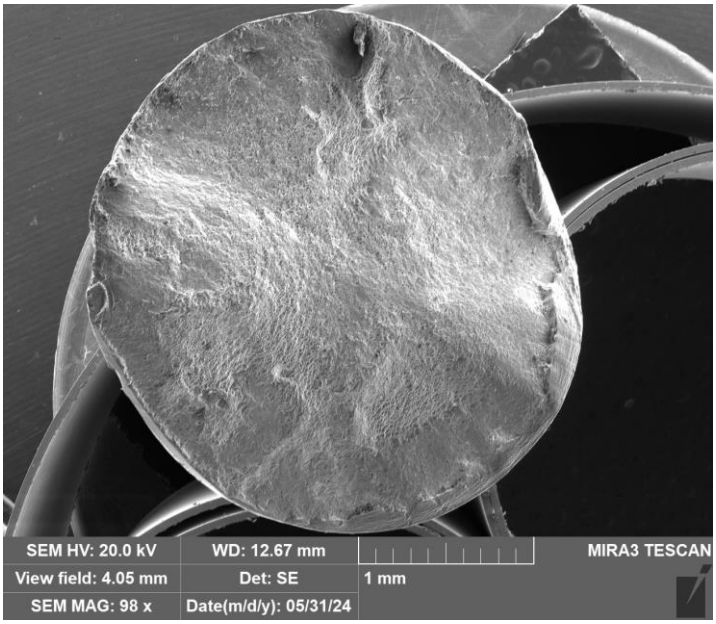


Figure 4-3: Low magnification SEM secondary image of a representative example of the fracture surface associated with the oblique geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-1 (Figure 2-6).

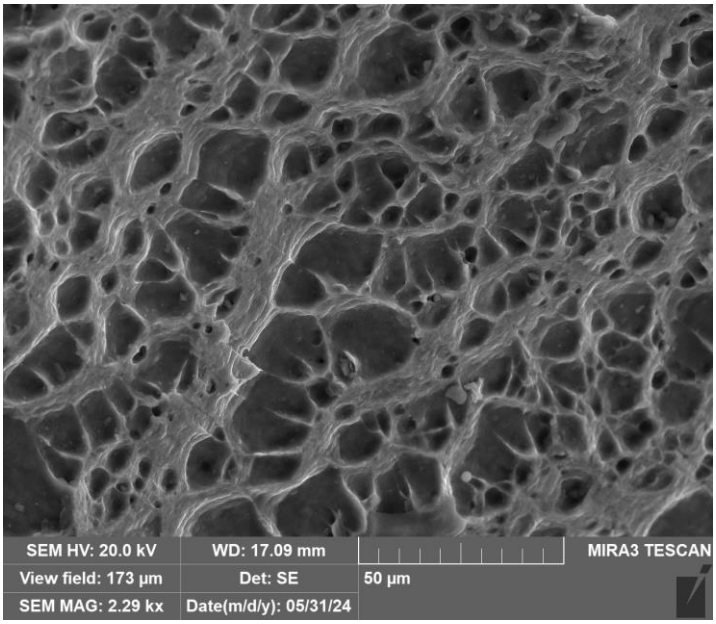


Figure 4-4: High magnification fractographic image within the proximity of the strand centroid showing the topological features associated with the strand fracture mechanism. Similar to Figure 4-2, the image suggests that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site.

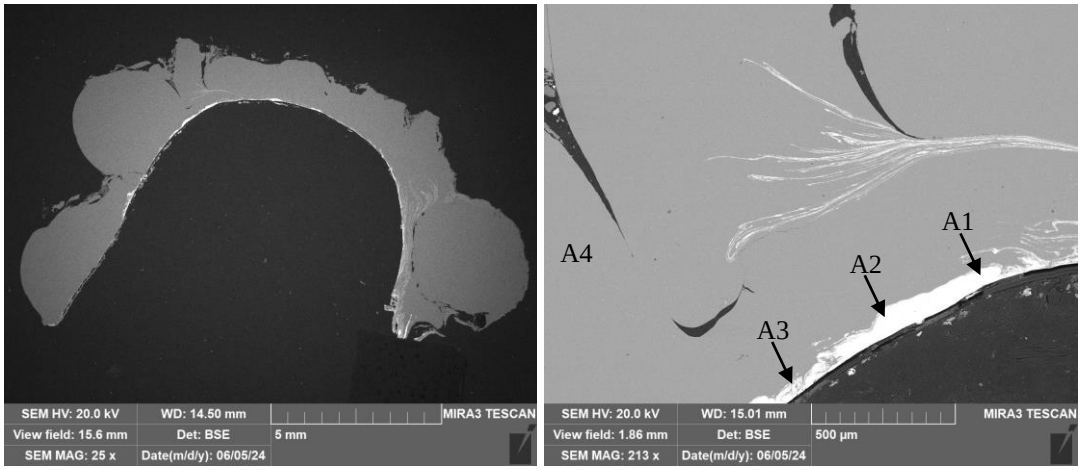


Figure 4-5: Sectional view SEM backscatter image of a representative example of the strand to strand fusing observed in conductor EL-1. The image also shows the location of the SEM EDS analyses conducted to determine the composition of the high density (light) phase observed (results are summarized in Table 4-1).

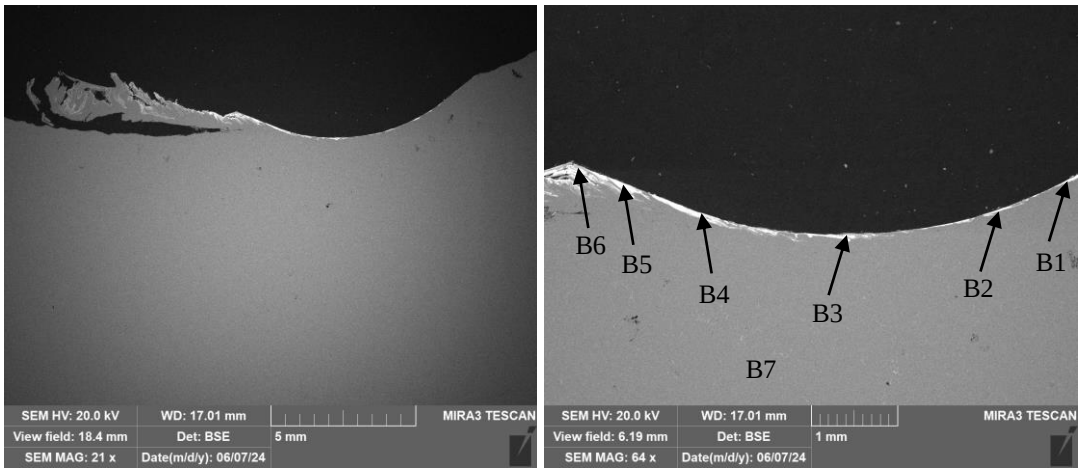


Figure 4-6: Sectional view SEM backscatter image of a representative example of the clamp material immediately adjacent to the site of localized brinelling observed. The image also shows the location of the SEM EDS analyses conducted to determine the composition of the high density (light) phase observed (results are summarized in Table 4-2).

4.2 Metallurgical Characterization of Failed Conductor EL-2

Samples from several of the outer aluminum wire strands, which included the fracture surface associated with the strand failure were removed from conductor EL-2. The samples were prepared for the characterization of the topological features associated with the fracture mechanism using SEM fractographic imaging techniques. Figure 4-7 is a low magnification SEM secondary image of a representative example of the fracture surface associated with the tapered-end geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-2 (Figure 2-17). The image shows the general cup and cone morphology of the failed end of the wire strand. Figure 4-8 is a high magnification fractographic image within the proximity of the strand centroid showing the topological features associated with the strand fracture mechanism. The image indicates that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site. Figure 4-9 is a low magnification SEM secondary image of a representative example of the fracture surface associated with the oblique geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-2 (Figure 2-18). Figure 4-10 is a high magnification fractographic image within the proximity of the strand centroid showing the topological features associated with the strand fracture mechanism. Similar to Figure 4-8, the image suggests that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site.

Several samples were also sectioned from the outer aluminum wire strands at locations where evidence of strand to strand fusing was observed during the preliminary examination of conductor EL-2 (Figure 2-19 and Figure 2-20). The samples were prepared for metallurgical characterization of the damage using a combination of SEM imaging and EDS analyses. Figure 4-11 is a sectional view SEM backscatter image of a representative example of the strand to strand fusing observed in conductor EL-2. The image shows the severe distortion of the wire strands observed, as well as the presence of a higher density phase embedded within the distorted aluminum strands. To determine the composition of the higher density phase, the material was subjected to EDS analyses. The results of the analyses (Table 4-3) indicated that the higher density phase was comprised primarily of zinc (Zn). The analyses suggest that the Zn from the outer coating associated with the steel reinforcing strands was also fusing with the outer aluminum wire strands.

Several samples were also sectioned from the insulator conductor clamp where evidence of localized brinelling was observed during the preliminary examination of conductor EL-2 (Figure 2-22). Figure 4-12 is a sectional view SEM backscatter image of a representative example of the clamp material immediately adjacent to the site of localized brinelling. Similar to Figure 4-11, the image shows the presence of a higher density phase embedded within the aluminum clamp material. The results of the analyses (Table 4-4) indicated that the higher density phase was comprised primarily of zinc (Zn). The presence of Zn embedded within the Al clamp material suggests that the Zn coated steel reinforcing strands (from the inner conductor core) were in contact with the intrados associated clamp housing at the site.

Table 4-3: Semi-quantitative SEM EDS analysis results for the strand to strand fusing observed in conductor EL-2. Figure 4-11 shows the locations of the EDS analyses.

	Chemical Composition (wt%)						
Position	**Fe**	**Si**	**Zn**	**Al**	**O**	**P**	**S**
C1	ND	ND	79.55	10.26	10.20	ND	ND
C2	0.17	ND	32.19	54.49	12.89	0.08	0.18
C3	0.22	ND	95.88	1.28	2.45	0.18	ND
C4	0.26	ND	95.87	1.37	2.50	ND	ND
C5	ND	ND	87.01	7.13	5.75	0.10	ND
C6	ND	ND	35.66	54.43	9.90	ND	ND

Note: ND indicates that the element was not detected.

Table 4-4: Semi-quantitative SEM EDS analysis results for the clamp material immediately adjacent to the site of localized brinelling in conductor EL-2. Figure 4-12 shows the locations of the EDS analyses.

	Chemical Composition (wt%)						
Position	**Fe**	**Si**	**Zn**	**Al**	**Ti**	**Mg**	**O**
D1	ND	ND	96.21	0.98	ND	ND	2.81
D2	ND	ND	96.68	1.63	ND	ND	1.69
D3	ND	ND	97.58	ND	ND	ND	2.42
D4	ND	ND	97.07	1.22	ND	ND	1.70
D5	ND	ND	96.53	1.45	ND	ND	2.03
D6	ND	ND	95.35	1.99	ND	ND	2.67
D7	ND	ND	34.62	62.42	ND	ND	2.96
D8	ND	10.82	ND	86.54	0.19	0.47	1.98

Note: ND indicates that the element was not detected.

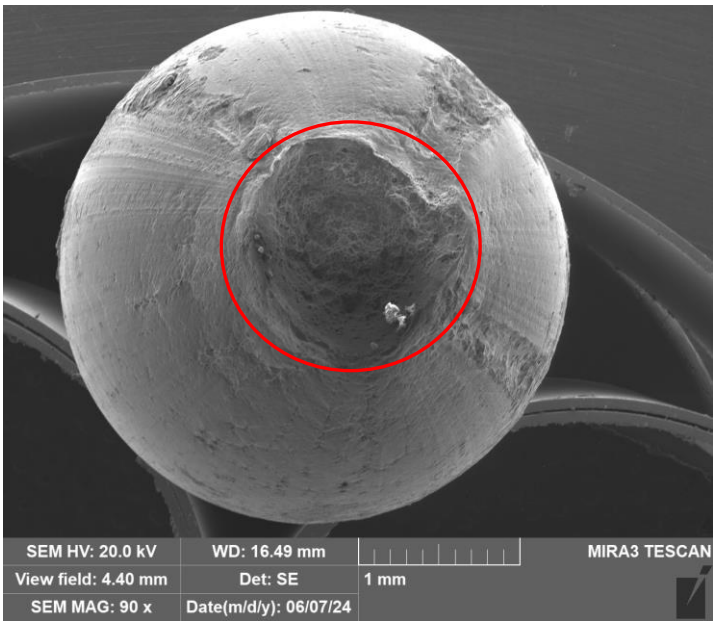


Figure 4-7: Low magnification SEM secondary image of a representative example of the fracture surface (ellipse) associated with the tapered-end (necked) geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-2 (Figure 2-17). The image shows the general cup and cone morphology of the failed end of the wire strand.

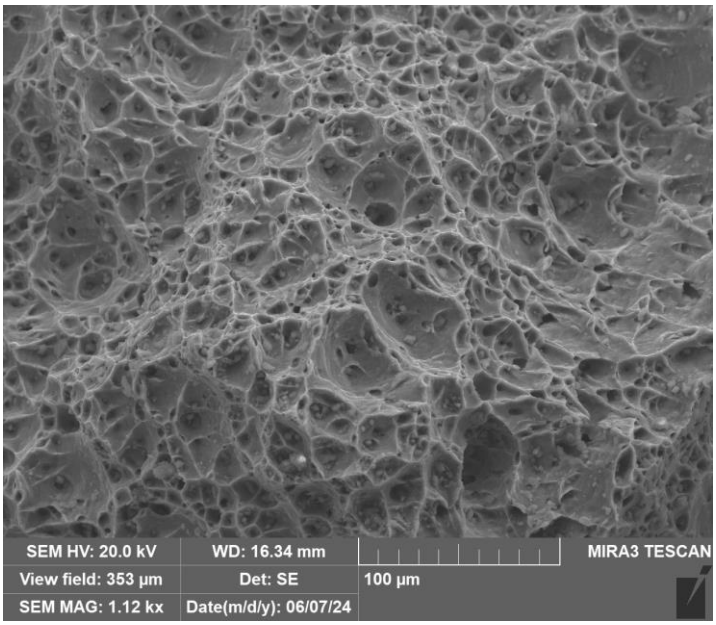


Figure 4-8: High magnification fractographic image within the proximity of the strand centroid shown in Figure 4-1. The image indicates that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site.

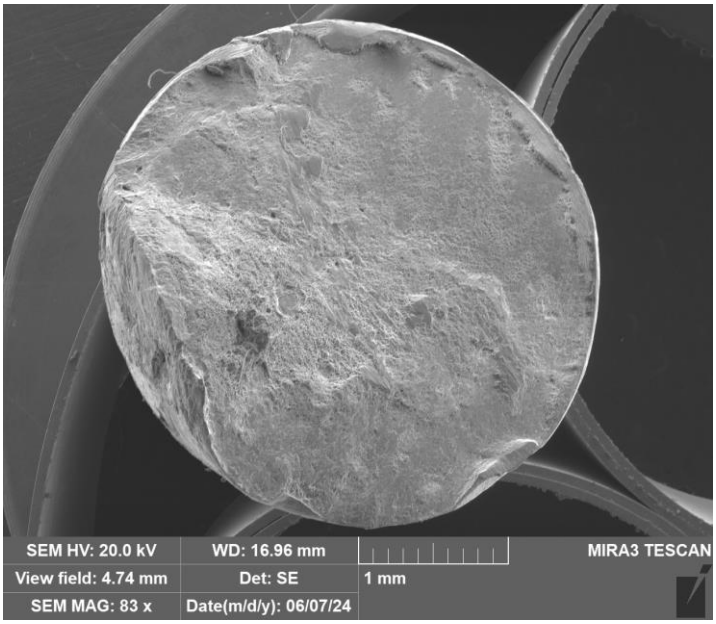


Figure 4-9: Low magnification SEM secondary image of a representative example of the fracture surface associated with the oblique geometry observed terminating the failed aluminum wire strands during the preliminary examination of conductor EL-2 (Figure 2-18).

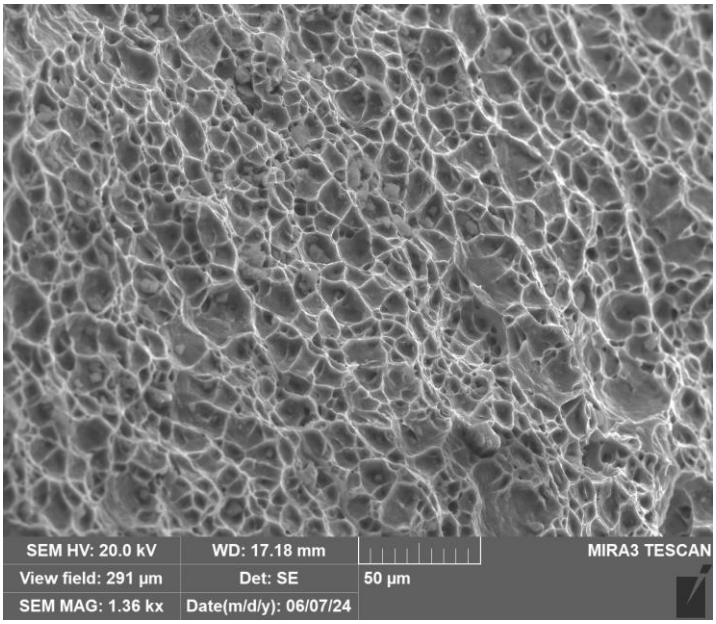


Figure 4-10: High magnification fractographic image within the proximity of the strand centroid showing the topological features associated with the strand fracture mechanism. Similar to Figure 4-8, the image suggests that the strand fracture mechanism was dominated by void coalescence (i.e. ductile fracture) at the site.

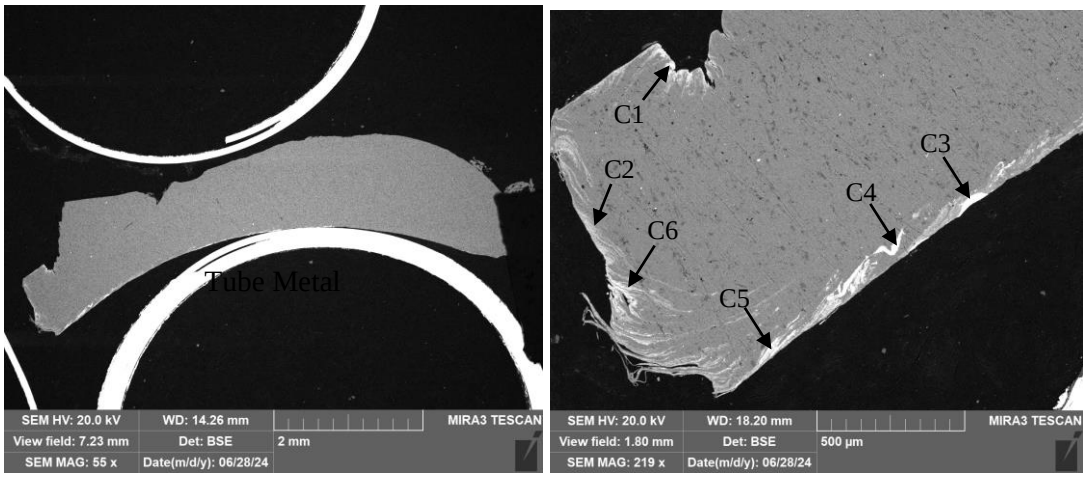


Figure 4-11: Sectional view SEM backscatter image of a representative example of the strand to strand fusing observed in conductor EL-2. The image also shows the location of the SEM EDS analyses conducted to determine the composition of the high density (light) phase observed (results are summarized in Table 4-3).

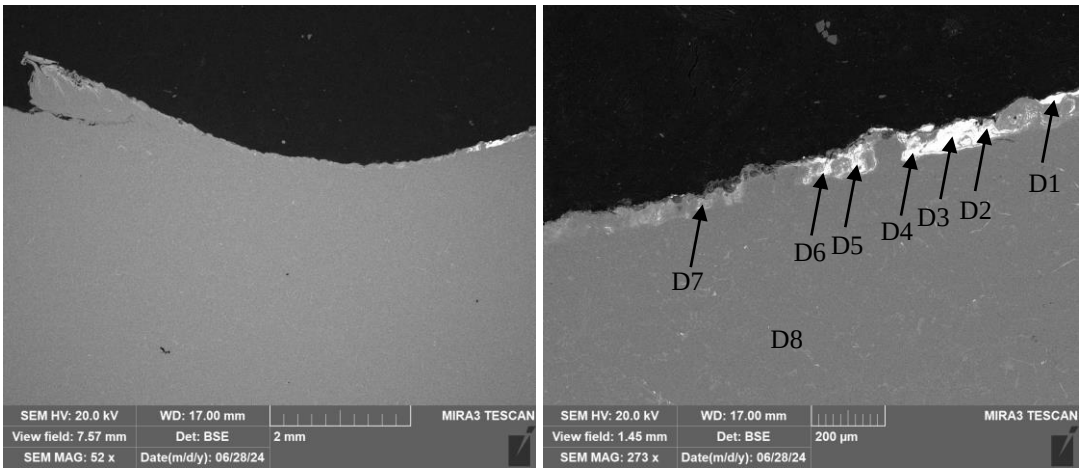


Figure 4-12: Sectional view SEM backscatter images of a representative example of the clamp material immediately adjacent to the site of localized brinelling observed. The image also shows the location of the SEM EDS analyses conducted to determine the composition of the high density (light) phase observed (results are summarized in Table 4-4).

5 SUMMARY AND DISCUSSION OF THE PHYSICAL EVIDENCE

5.1 Summary of the Physical Evidence

The following summarizes the physical evidence generated during the investigation for the failed sections of conductor EL-1 and EL-2 from suspension Tower #1225 provided for evaluation. Given the similarity of the physical evidence generated for conductor EL-1 and EL-2, the items below are relevant to both conductors unless otherwise noted. The physical evidence includes;

- The evidence provided by NL Hydro indicated that at Tower #1225, the line damage consisted of stripped and birdcaged outer conductors, which suggests that the inner steel reinforcing core remained intact at the tower.

- Adjacent to the termination of the insulator wire clamp, on the upper circumferential surface of the conductors, the ends of the aluminum wire strands were generally terminated by fracture failures. SEM fractographic analysis indicated that fracture surfaces associated with the failed wire strands were dominated by void coalescence (i.e. limit load ductile failure).

- Adjacent to the termination of the insulator wire clamp, on the lower circumferential half of the conductors, evidence of either severe distortion of the wire strands or strand to strand fusing was observed. SEM EDS analyses conducted for the fused wire strands detected the presence of zinc from the steel reinforcing strands embedded within the aluminum conductor material.

- Evidence of localized brinelling (plastic deformation) was observed adjacent to the lower, outboard axial end (on the conductor failure side) at the bottom dead center circumferential position of the wire clamp. The sectional profile of the brinelling was characterized by an approximately semi-circular morphology. SEM EDS analyses conducted detected the presence of zinc from the steel reinforcing strands embedded within the wire clamp material adjacent to the brinelling. The presence of the embedded zinc suggests that the steel reinforcing core was in contact with the lower surface of the wire clamp at the site.

- The wire strand diameters were measured for failed conductors EL-1 and EL-2. For conductor EL-1, the diameters of the aluminum conductor strands and the steel reinforcing strands ranged between 3.40 mm to 3.73 mm and 2.06 mm to 2.11 mm, respectively. For conductor EL-2, the diameters of the aluminum conductor strands and the steel reinforcing strands ranged between 3.43 mm to 3.71 mm and 2.16 mm to 2.26 mm, respectively. Measurements of the zinc coating thicknesses for steel reinforcing strands indicated the surface area density of the coating ranges for EL-1 and EL-2 were between 271.9 g/m^2 to 404.9 g/m^2 and between 261.2 g/m^2 to 268.8 g/m^2, respectively.

- The wire strand diameters were also measured for a length of intact service exposed conductor provided for uniaxial tension testing. The diameters of the aluminum

conductor strands and the steel reinforcing strands ranged between 3.71 mm to 3.76 mm and 2.21 mm to 2.26 mm, respectively. Measurements of the zinc coating thicknesses for steel reinforcing strands indicated the surface area density of the coating range was between 171.9 g/m^2 to 332.3 g/m^2.

- Uniaxial tension testing was conducted on a length of intact service exposed conductor. The results of the testing generated a breaking strength of approximately 196.6 kN, which exceeded the rated tension strength requirement of 187 kN [2].

5.2 General Discussion

The physical, chemical and metallurgical evidence indicates that the mechanism responsible for the failure of conductors EL-1 and EL-2 at Tower #1225 is consistent with ductile limit load fracture of the aluminum conductor strands. It was reported that there was significant ice accumulation on the line prior to failure (estimated radial thickness of the ice was in the range between 100 – 125 mm) [1]. The wind velocity was also reported to be approximately 70 km/h and 60 km/h from an easterly direction on the day prior to and during the day of the failures, respectively [1]. It has been indicated that for a radial ice accumulation of approximately 25 mm, the design criterion for the maximum wind velocity reduces to 60 km/h [1]. The combination of the ice accumulation and wind velocities reported suggests that the line was operating in excess of the design criteria both on the day prior to and during the day of the failures. Given ice build-up and the direction of the wind reported, it is also probable that additional cyclic loading from wind induced galloping of the lines was present prior to the failures. Galloping of the conductors has been observed by NL Hydro on multiple occasions in the vicinity of Tower #1225 since the installation of the lines in 2017 [1].

The evidence also suggests that the steel reinforcing core migrated towards, and was in contact with, the lower surface of the insulator wire clamp. The downward bearing force responsible for the migration was sufficient to distort and cold pressure weld (fuse) adjacent aluminum wires together in the lower circumferential half of the conductor. It is reasonable to assume that the distortion and fusing of the aluminum strands would result in a decrease in the overall breaking strength of the conductor where it enters the wire clamp.

The evidence also suggests that the downward migration also resulted in contact between the steel reinforcing core and the bottom dead center surface of the insulator wire clamp, which, in turn, resulted in a localized area of brinelling on the surface of the wire clamp. It has been postulated that one in situ, non-destructive method of detecting steel core migration is radiographic imaging. It should be noted that if radiographic imaging is utilized, it should include a reference marker on the bottom surface of the wire clamp.

6 CONCLUSIONS AND RECOMMENDATIONS

The conclusions and recommendations inferred by the investigation for the failed sections of conductor EL-1 and EL-2 from suspension Tower #1225 include:

- The physical, chemical and metallurgical evidence indicates that the mechanism responsible for the failure of conductors EL-1 and EL-2 at Tower #1225 is consistent with ductile limit load fracture of the aluminum conductor strands.

- The force required to precipitate a ductile limit load fracture mechanism of the aluminum conductor strands was attributed to the combination of ice accumulation and sustained wind velocities on the day prior to and during the day of the failures. It is also probable that wind induced galloping was present in the lines prior to the failures, which generated an additional cyclic force.

- The evidence suggests that the steel reinforcing core migrated towards, and was in contact with, the lower surface of the insulator wire clamp. The downward bearing force responsible for the migration was sufficient to distort and cold pressure weld (fuse) adjacent aluminum wires together in the lower circumferential half of the conductor. It is reasonable to assume that the distortion and fusing of the aluminum strands would result in a decrease in the overall breaking strength of the conductor where it enters the wire clamp.

- It has been postulated that one in situ, non-destructive method of detecting steel core migration is radiographic imaging. It should be noted that if radiographic imaging is utilized, it should include a reference marker on the bottom surface of the wire clamp. It is recommended that in consultation with experts in the field of radiography, that NL Hydro consider investigating the use of radiographic imaging to detect the presence of incipient damage in the conductors.

References

[1] Various E-mails provided by M. Veitch, Newfoundland and Labrador Hydro, June-September, 2024.

[2] ASTM B232, “Standard Specification for Concentric-Lay-Stranded Aluminum Conductors, Coated Steel Reinforced (ACSR)”, ASTM International.

[3] ASTM B230, “Standard Specification for Aluminum 1350-H19 Wire for Electrical Purposes”, ASTM International.

[4] ASTM B233, “Standard Specification for Aluminum 1350 Drawing Stock for Electrical Purposes”, ASTM International.

[5] ASTM A931, “Standard Test Method for Tension Testing of Wire Ropes and Strand”, ASTM International.

Annex A Data Sheet for the ACSR Grackle (Zinc Coated) Conductor

Table A-1 is the manufactures' data sheet summary for the ACSR Grackle conductor with a zinc coated steel reinforcing core.

Table A-1: Manufactures' data sheet for the ACSR Grackle conductor (zinc coated steel reinforcing core).

ISO 9001
ISO 14001
OHSAS 18001
Certified by

MIDAL CABLES LTD. (C.R.:7108)
P.O. Box 5939, Kingdom of Bahrain
Tel.: +973 17 832832 / 17 832833
Fax: +973 17 832932 / 17 832933
E-mail: midalcbl@midalcable.com
Website: www.midalcable.com

شركة ميدال للكابلات المحدودة (س.ت:٧١٠٨)
ص.ب: ٥٩٣٩، مملكة البحرين
هاتف: ٨٣٢٨٣٢ / ١٧ ٨٣٢٨٣٣ +٩٧٣
فاكس: ٨٣٢٩٣٢ / ١٧ ٨٣٢٩٣٣ +٩٧٣
midalcbl@midalcable.com : البريد الإلكتروني
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ITEM	DESCRIPTION	UNIT	REQUIRED	GUARANTEED
1.0	**Manufacturer Name**			Midal Cables
2.0	**Location of Manufacturing Plant**			Bahrain
3.0	**Technical Characterisitics**			
3.1	Type		ACSR	ACSR
3.2	Code name		Grackle	Grackle
3.3	Rated Tensile Strength	kN	187	194
3.4	Unit Weight of Complete Conductor	kg/m	2.28	2.271
3.4.1	Unit Weight of Aluminum	kg/km		1668.5
3.4.2	Unit Weight of Steel	kg/km		597.58
3.5	Coefficient of Thermal Expansion (Aluminum portion)	per °C	23.04×10^{-6}	23.04×10^{-6}
3.6	Modulus of Elasticity (Aluminum portion)			
3.6.1	Final	MPa	49090	49090
3.6.2	Initial Lower	MPa		36600
3.6.3	Initial Upper	MPa		36600
3.6.4	Change of Slope	MPa		NQ
3.7	Coefficient of Thermal Expansion (Steel portion)	per °C	11.52×10^{-6}	11.52×10^{-6}
3.8	Modulus of Elasticity (Steel portion)			
3.8.1	Final	MPa	21580	21580
3.8.2	Initial Lower	MPa		16090
3.8.3	Initial Upper	MPa		16090
3.8.4	Change of Slope	MPa		NQ
3.9	MaximumDC resitance at 20 °C	Ω/km	0.0472	0.0479
3.10	MaximumDC resitance at 25 °C	Ω/km		0.04887
3.11	MaximumDC resitance at 75 °C	Ω/km		0.05852
3.12	Minimum Aluminum Conductivity	% IACS		61
3.13	Emissivity Coefficient		0.5	0.5*
3.14	Solar Absorption Coefficient		0.5	0.5*
3.15	Aluminum Portion Heat Capacity	W.s/m.°C	3206.65	1537.2
3.16	Steel Portion Heat Capacity	W.s/m.°C	570.89	274.9
3.17	Nominal Cross-Sectional Area (Total)	mm^2	680.64	680.07
3.18	Overall Diameter	mm	33.85	33.94
3.19	Number of Conductors per Pole	unit	1	1*
3.20	Number of Aluminum Wires (Stranding)	unit	54	54
3.21	Diameter of Aluminum Wires	mm	3.77	3.77
3.22	Type of Weld for Aluminum Wire Joint			Cold Pressure
3.23	Number of Steel Wires (Stranding)	unit	19	19
3.24	Diameter of Steel Wires	mm	2.26	2.26
3.25	Zinc Coating			
3.25.1	Thickness	g/m^2		230
3.25.2	Class (as per CAN/CSA C60888)		Class A	Class A
3.26	PLS-CADD conductor file (*.wir) provided	Yes/No	Yes	Yes

ISO 9001
ISO 14001
OHSAS 18001
Certified by

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Fax: +973 17 832932 / 17 832933
E-mail: midalcbl@midalcable.com
Website: www.midalcable.com

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ITEM	DESCRIPTION	UNIT	REQUIRED	GUARANTEED
4.0	**Reel**			
4.1	Reel Construction	Wood/Metal	Metal	Metal
4.2	Flange	m	2.13	2.22
4.3	Traverse	m	1.47	1.25**
4.4	Drum	m	0.91	0.78
4.5	Arbor Hole	m	0.127	0.127
4.6	Drive Pin			
4.6.1	Diameter	mm		65
4.6.2	Distance Offset from Center	mm		300
4.7	Maximum Gross Reel Weight	kg		6700
4.8	Empty Reel Weight	kg		550
4.9	Nominal Conductor Length per Reel	m	2700	2700
4.10	Minimum Shipping Lots	lot		222 Reels
5.0	**Lay Ratio**			
5.1	Aluminum Outer Layer	max/min	14/10	14/10
5.2	Aluminum Inner Layers	max/min	16/10	16/10
5.3	12-Wire Steel Layer	max/min	20/14	20/14
5.4	6-Wire Steel Layer	max/min	26/16	26/16
6.0	Length Tolerance	%		-0/+1
6.1	**Lay Direction**			
6.1.1	Outer Strand of Aluminum Layer			Right Hand
6.1.2	Outer Strand of Steel Layer			Left hand

2014D91-09042014 Rev2

*Client given data
** Approx Overall Width Of Reel

Annex B Dimensional Characterization of the Failed Section of ACSR Grackle (Zinc Coated) Conductor EL-1

Table B-1 summarizes the outer aluminum conductor and inner steel reinforcing wire strand diameter measurements for the failed section of conductor EL-1. Figure B-1 though Figure B-3 show representative examples of the thickness of the zinc coating present on the steel reinforcing wire strands.

Table B-1: Summary of the outer aluminum conductor and inner steel reinforcing wire strand diameter measurements for the failed section of conductor EL-1.

Wire Strand No.	Wire Strand Diameter Ranges (mm)					
	Outer Aluminum Strands			Inner Steel Strands		
	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5	Layer 6
1	3.73	F/SD	3.68	2.18	2.08	2.11
2	3.63	3.73	3.68	2.11	2.08	
3	3.40	3.71	3.68	2.24	2.08	
4	3.43	3.56	3.68	2.13	2.11	
5	3.53	3.68	3.63	2.18	2.06	
6	F/SD	3.63	3.66	2.24	2.03	
7	3.68	3.61	F/SD	2.08		
8	3.68	3.63	F/SD	2.08		
9	3.38	3.66	F/SD	2.13		
10	3.66	3.66	F/SD	2.06		
11	3.56	3.63	F/SD	2.18		
12	3.63	3.66	F/SD	2.24		
13	3.63	3.61				
14	3.63	3.66				
15	3.63	3.66				
16	3.68					
17	3.61					
18	3.63					
19	3.63					
20	3.68					
21	3.71					
22	3.71					
23	3.68					
24	3.73					

Note 1: F/SD indicates that the wire strand was either fused to an adjacent strand or that the cross-sectional area of the strand was severely distorted.

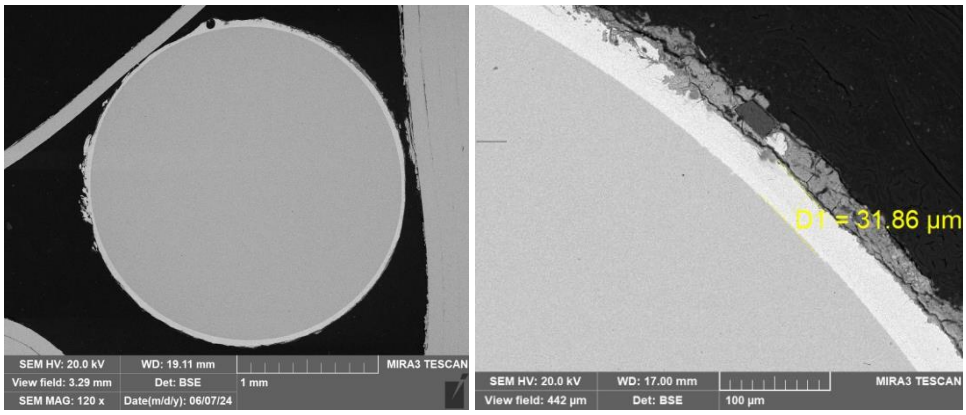


Figure B-1: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-1. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

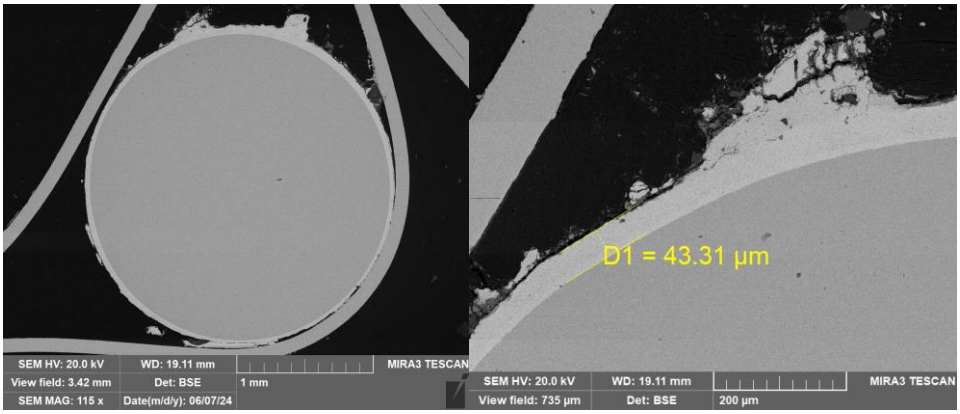


Figure B-2: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-1. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

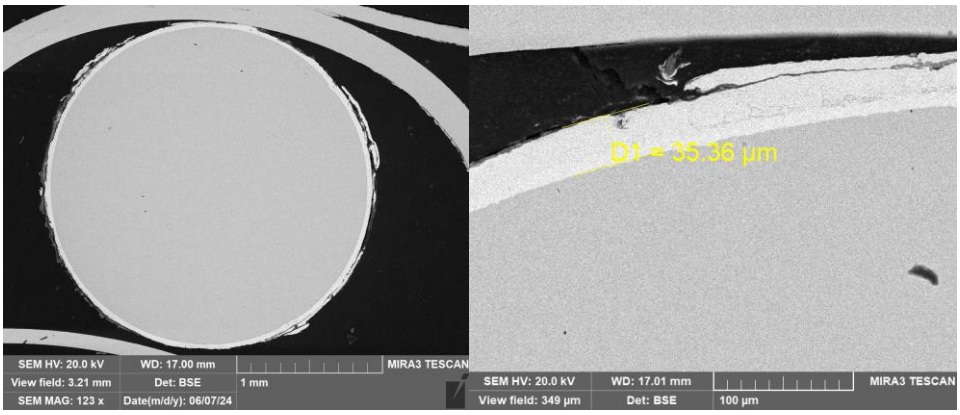


Figure B-3: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-1. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

Annex C Dimensional Characterization of the Failed Section of ACSR Grackle (Zinc Coated) Conductor EL-2

Table C-1 summarizes the outer aluminum conductor and inner steel reinforcing wire strand diameter measurements for the failed section of conductor EL-2. Figure C-1 though Figure C-3 show representative examples of the thickness of the zinc coating present on the steel reinforcing wire strands.

Table C-1: Summary of the outer aluminum conductor and inner steel reinforcing wire strand diameter measurements for the failed section of conductor EL-2.

Wire Strand No.	Wire Strand Diameter Ranges (mm)					
	Outer Aluminum Strands			Inner Steel Strands		
	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5	Layer 6
1	3.68	3.61	3.71	2.18	2.24	2.24
2	3.61	F/SD	3.71	2.26	2.18	
3	3.58	F/SD	3.68	2.26	2.16	
4	3.43	3.66	3.71	2.21	2.21	
5	3.58	3.56	3.71	2.24	2.16	
6	3.68	3.61	3.71	2.24	2.24	
7	3.61	3.66	F/SD	2.24		
8	3.56	3.68	F/SD	2.21		
9	3.61	3.61	3.71	2.24		
10	3.66	3.68	3.66	2.26		
11	3.66	3.61	F/SD	2.26		
12	3.66	3.66	F/SD	2.26		
13	3.66	3.68				
14	3.63	3.66				
15	3.66	3.68				
16	F/SD	3.71				
17	F/SD	3.71				
18	F/SD	3.68				
19	F/SD					
20	F/SD					
21	F/SD					
22	3.68					
23	3.68					
24	F/SD					

Note 1: F/SD indicates that the wire strand was either fused to an adjacent strand or that the cross-sectional area of the strand was severely distorted.

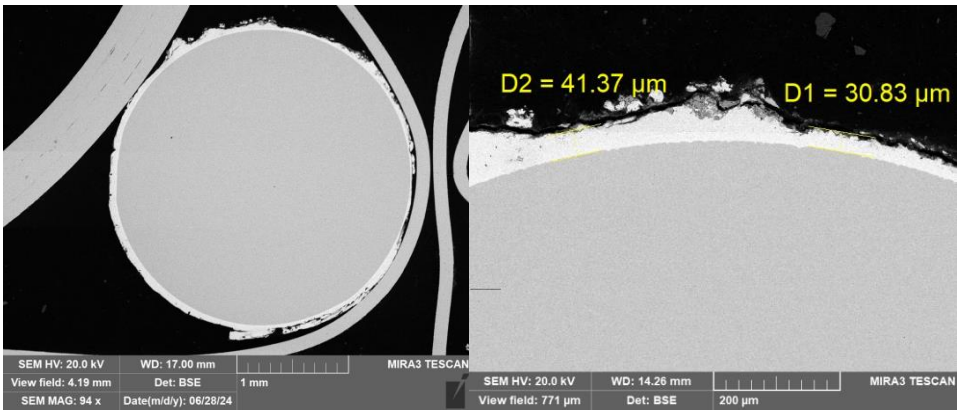


Figure C-1: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-2. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

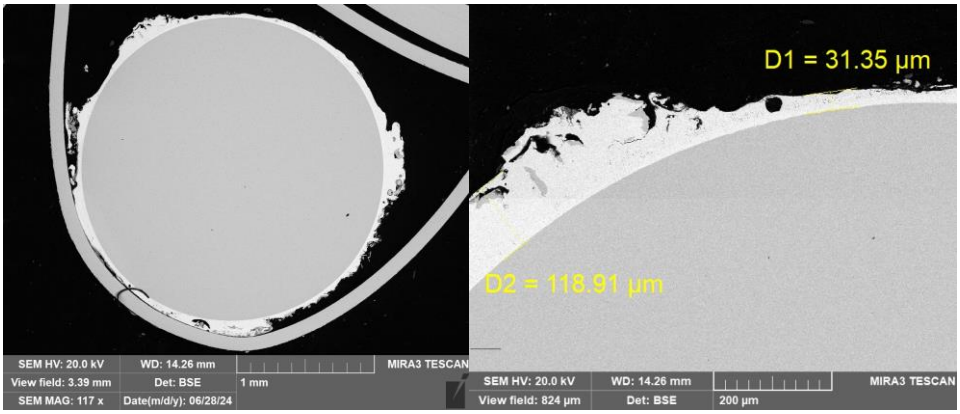


Figure C-2: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-2. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

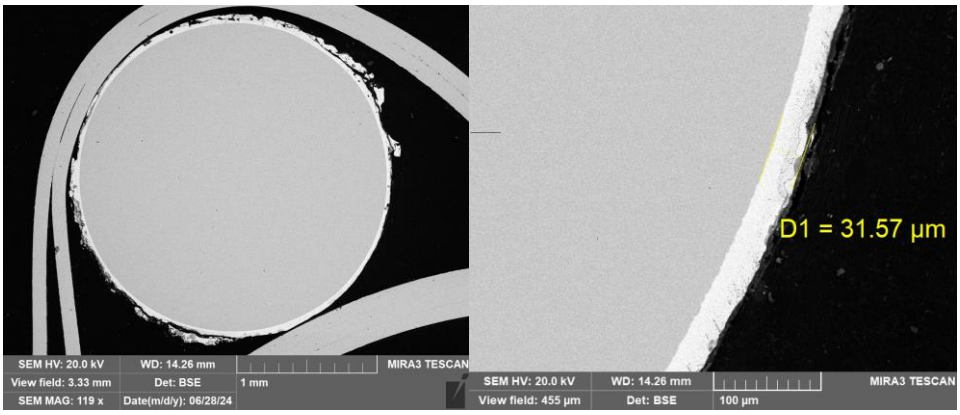


Figure C-3: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for failed conductor EL-2. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

Annex D Dimensional Characterization of the Intact Service Exposed Section of ACSR Grackle (Zinc Coated) Conductor

Table D-1 summarizes the outer aluminum conductor and inner steel reinforcing wire strand diameter measurements for the used intact conductor provided for uniaxial tension testing. Figure D-1 though Figure D-3 show representative examples of the thickness of the zinc coating present on the steel reinforcing wire strands.

Table D-1: Summary of the outer aluminum conductor and inner steel reinforcing wire strand diameter measurements for the used intact service exposed conductor provided for uniaxial tension testing.

Wire Strand No.	Wire Strand Diameter Ranges (mm)					
	Outer Aluminum Strands			Inner Steel Strands		
	Layer 1	Layer 2	Layer 3	Layer 4	Layer 5	Layer 6
1	3.73	3.73	3.71	2.21	2.21	2.21
2	3.71	3.71	3.71	2.24	2.21	
3	3.73	3.71	3.71	2.21	2.24	
4	3.73	3.71	3.71	2.21	2.24	
5	3.73	3.71	3.73	2.21	2.24	
6	3.71	3.73	3.71	2.21	2.21	
7	3.73	3.73	3.73	2.21		
8	3.73	3.73	3.73	2.24		
9	3.73	3.71	3.73	2.21		
10	3.73	3.73	3.73	2.21		
11	3.71	3.76	3.73	2.21		
12	3.76	3.76	3.73	2.24		
13	3.76	3.73				
14	3.76	3.73				
15	3.71	3.76				
16	3.73	3.73				
17	3.76	3.71				
18	3.76	3.71				
19	3.76					
20	3.73					
21	3.76					
22	3.76					
23	3.73					
24	3.73					

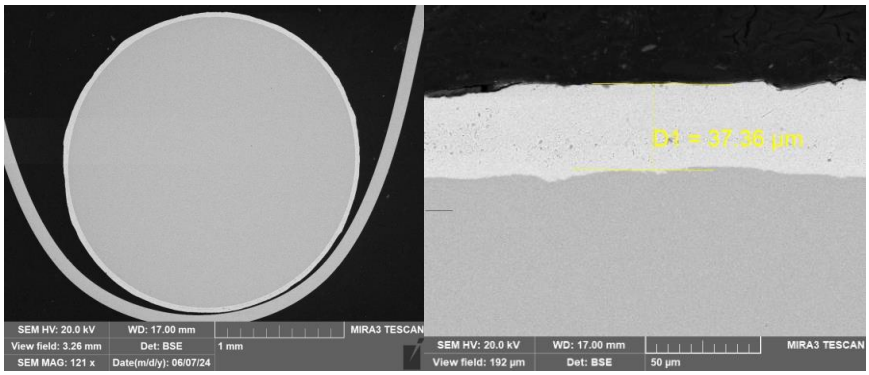


Figure D-1: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the intact conductor. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

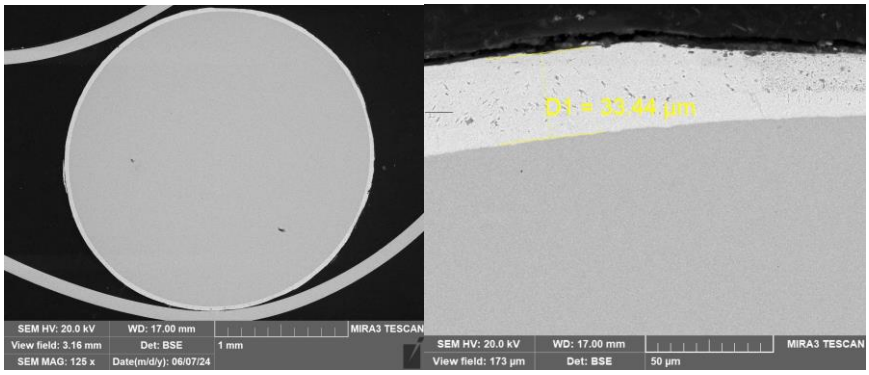


Figure D-2: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the intact conductor. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

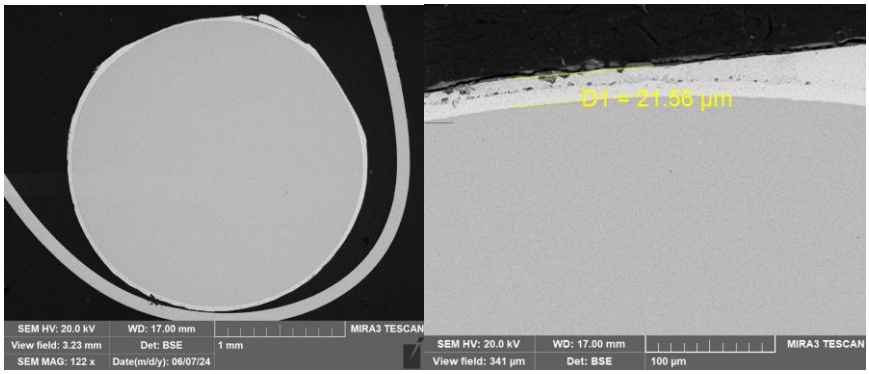


Figure D-3: SEM backscatter image of a representative example of a zinc coated steel reinforcing strand for the intact conductor. The image shows the significant variation in the thickness of the zinc coating observed around the circumference of the steel reinforcing strand.

Request IR-10:

(a) Please confirm what critical punch list or commissioning items, if any, remain outstanding in connection with the NLH transmission facilities as of the date of the Application.

(b) Please confirm what critical punch list items were completed within the Compliance Period noted, and thereafter.

Response IR-10:

a - b)

As remediation of critical items was a precondition to successful commissioning and release to the System Operator for operations, there were no critical punch list items outstanding at the time of LIL commissioning. Of note is the commissioning process was performed under the review and oversight of the Independent Engineer and the NL System Operator, who would have also confirmed no outstanding critical punch list items, as well as the list of non-critical punch list items.

As is typical for complex assets, issues will be identified post commissioning that will require remediation. Any corrective items and non-critical punch list items identified during or subsequent to commissioning would be categorized as appropriate to the applicable contract terms and/or NLH's asset management process and dealt with at an opportunity appropriate to the item in question. Design and installation contracts typically include terms for dealing with deficiencies and corrective items through the life of the various project phases, normally up to the end of the warranty period.

As noted above, in the case of LIL commissioning there were specific critical punch list items that were a prerequisite to commissioning and hand over. These critical items would

have been identified by NLH's project team and its contractors (consultants and those preforming the work) and agreed upon by Canada's Independent Engineer and Newfoundland & Labrador's System Operator.

Request IR-11:

Reference: N-01 Application, page 23, lines 17–19; Section 5.0.
And Reference: Matter M11009, Exh. N-24, NSPML Holdback Compliance Filing.
Preamble: The Application states that in May 2024, a bipole outage was taken to troubleshoot, replace, and test DC current transformers that had been in service for approximately six years and were causing reliability concerns.

a) Please confirm how DC current transformers installed at commissioning in 2018 could have accumulated approximately six years of service by May 2024, given that the LIL was not commissioned until April 2023. Specifically:

i) What was the original installation date of the DC current transformers?

ii) Were they in continuous operation from the Maritime Link's in-service date in January 2018? If not, please explain; and

iii) Please explain what reliability concerns were arising from the transformers that necessitated their replacement, and when those concerns were first realized.

b) When was the need to replace these DC current transformers first identified internally and what were the reasons for the timing of the May 2024 outage?

c) Please provide all engineering reports, root cause analyses, and/or post-event corrective action plans prepared in connection with the bipole outage, including any findings regarding the cause of the outage and any recommendations for addressing the noted reliability concerns.

d) Please confirm whether the DC current transformer replacement was among the

work items that NSPML referenced in its compliance filing in M11009 as a pending multi-day outage planned for the November/December 2023 timeframe (page 19), which at that time was described as relating to replacement of originally installed DC current transformers and noted as presenting "risk that (absent holdback relief) this planned outage will result in a material monthly holdback disallowance and restart of the 12 consecutive months of reliable operations."

i) If so, what was the specific reason this was deferred?

ii) Please provide all internal documentation and communications with NLH, regional system operations and third-party technical resources, relating to the originally planned outage dates for November/December 2023 and rescheduling to May 2024.

e) Does NSPML take the position that this outage and related delivery performance are irrelevant to the Board's consideration of this Application? If so, please explain.

Response IR-11:

a)

i) The original installation date(s) for each of these DC Current Transformers varies by pole and site, however they were installed prior to 2019 when monopole operation of the Labrador Island Link (LIL) was first attempted.

ii) They were not in continuous electrical operation from this date; however, they were physically installed in the system.

iii) The DC Current Transformers measure a relatively large quantity of DC current and transform it into a relatively small amount of current so that it can be in turn measured by the HVDC Control and Protection system. As such, the input current equals the

output current multiplied by a scaling factor. The DC Current Transformers experienced times where their output signal did not match the input signal. It was perturbed by two things: electromagnetic (EM) noise and low ambient temperatures < -20°C which was within their intended manufacturers ratings. These events resulted in both single pole and bipole trips of the LIL which led to operating restrictions and pushed off high power testing given the effect one of these trips has on both Newfoundland and Labrador's power systems and the power systems in the rest of the Atlantic provinces.

b) It was determined that they required replacement in 2022. See (d) below regarding timing of the work.

c) No reports are available.

d)

i) This outage was deferred because the DC Current transformers were not available from GE's manufacturing facility to install.

ii) NSPML does not have records relating to Newfoundland & Labrador Hydro originally planning an outage for November/December 2023 and rescheduling that outage to May 2024.

e) Yes, as the outage is outside the Compliance Period and, additionally, because outages related to replacement of components like this are expected from time to time.

Request IR-12:

Reference: N-01 Application, Section 5.0, pages 23-24.
Preamble: The Application describes a series of outages from July through October 2024, including: single pole outages in July to troubleshoot intermittent system alarms and replace faulty equipment; a bipole outage at the end of July to install, verify, and test a converter station software update; the bipole outage continuing through August to implement and test software; and in September, a bipole outage for software updating, followed by a planned annual maintenance shutdown of the LIL, with the outage extending into early October as planned.

(a) Please confirm whether this outage period related directly, or indirectly to previously reported issues of ground potential, which resulted in approximately six weeks of outages.

(i) If so, please explain what this "ground potential" issue was, the work required to address it, the impact on reliability or otherwise, and the required work to address it.

(ii) Please provide the engineering reports, root cause analyses, and/or post-event corrective action plans prepared in connection with the July-September bipole outage, including any findings regarding the cause of the outage and any recommendations for addressing issues.

(b) Have the discovered ground potential issues been fully resolved? If not, please confirm the current status and the remediation plan with expected completion date.

(c) Please confirm whether the ground potential issues were discovered at

the time of or in connection with attempts to increase the LIL's operating capacity above its then-current level, and if so:

(i) **identify the capacity level at which the LIL was operating at the time the ground potential issues were discovered; and**

(ii) **confirm the target capacity level to which NSPML or NLH was attempting to increase operation;**

(d) Please confirm whether the 900 MW LIL capacity testing that was originally intended to be completed in the winter of 2024–2025 has occurred. If not, confirm the current status and the expected timeline.

(e) Please confirm that the LIL was always intended, from the time of its commissioning, to have a rated capacity of 900 MW.

(f) Please confirm the capacity at which the LIL was operating when it was commissioned on April 14, 2023 (i.e., was it 400 MW, 700 MW, or some other level), and when it ramped up to the current 700 MW capacity.

(g) Please provide the schedule for the ramp-up of LIL capacity to the full 900MW capacity as of the date of commissioning on April 14, 2023, together with any documentation memorializing that schedule.

Response IR-12:

a) The majority of outage hours were not related to the transition station ground potential rise (GPR) mitigations; however, work was performed to mitigate these.

i) The GPR issue at Labrador Island Link transition compounds caused the operation of

the switching sequence itself in combination with the impedance of the ground grid, resulting in higher than anticipated voltages on HVDC Control and Protection interface cards causing them to fail during operation of the cable switching sequence and subsequent trip of the pole.

ii) No reports are available.

b) Confirmed, the issue has been fully resolved.

c) Confirmed, the issue was identified as power levels were being increased along with testing of the associated overload capability.

i) The first overload test uncovering the issue was at 500 MW.

ii) The intention was to perform the set of tests at 500 MW, then continue to 700 MW. 900 MW was to be performed when system conditions would allow.

d) This testing was completed successfully in March 2026.

e) Confirmed.

f) The LIL was commissioned at the 700 MW power level on April 14, 2023.

g) No documentation is available; however, the plan was to test the LIL's operability and overload capability when system conditions would allow at the next opportunity, however system conditions, locally and regionally, prevented this from occurring until March 2026.

Request IR-13:

Reference: N-01 Application, Section 5.0 and Section 6.0, pages 23-27.

Preamble: The Application states that as of the end of 2025, approximately $15.3 million in holdback funds relates to the post-Compliance Period, and that all but $1.1 million are related to planned outages.

(a) Is NSPML asserting that the outages that took place between July 2024-October 2024, were all "planned" outages, including the approximate six-week outage over the entire duration of August 2024 resulting in a $4 million holdback?

(b) Please confirm that none of the outages occurring in 2024 and 2025 that resulted in holdback retention were forced outages. If not confirmed, please explain how that is reconciled with the statement that all of the $15.3 million holdback funds relate to planned outages, aside from the $1.1 million noted.

(c) For all planned outages in 2024 and 2025, confirm whether, in scheduling those outages, NSPML or NSPI considered the potential impact of the outage timing on the monthly holdback calculation, and provide any internal records relating to such consideration.

Response IR-13:

a) Correct, the outages referenced were all planned. As mentioned in NSPML's Application, certain portions of the planned outages took longer than originally anticipated, which is not an infrequent experience for utility outages and does not mean that the planned outage converts to unplanned. During the period there were short-duration forced outages that did not impact the ability to meet the monthly holdback threshold. Please refer to IG IR-07.

b) In the 2024-2025 period there was one unplanned outage in January 2025 that resulted in a $1,084,196 holdback in that month. Holdback amounts retained after the Compliance Period are listed by month in Appendix B of the Application. The January 2025 outage was described on page 25 of the Application, beginning at line 22:

> In terms of unplanned outages since the Compliance Period, there was a bipole icing related outage on January 13, 2025, on NLH's above-ground transmission assets located near Muskrat Falls that lasted several hours before a monopole connection was re-established to facilitate NS Block deliveries. The referenced outage impacted five cross arms and two tower tips, with full remediation of the damage carried out during daylight hours from January 15 to 19, upon which bipole functionality was reestablished.

The unplanned outage portion of this January 2025 event was for a few hours on January 13, 2025, up to the moment when monopole was re-established and the full NS Block was delivered for the day. Once energy could flow, the outage starting on the 15th could be considered a short notice planned outage which was utilized to bring back full bipole functionality. Although the outage that commenced on the 15th of the month had flexibility in terms of timing (due to monopole functionality), it is also reasonable to consider the outage required to bring back full bipole functionality an "unplanned" outage as opposed to a short notice planned outage. The primary difference is that an unplanned outage typically has no flexibility in terms of timing nor an ability to work with regional system operators to coordinate repairs. In this case, the fix to bipole needed to be carried out in a timely manner but had some level of coordination and timing flexibility. For instance, as the original fix on January 13 enabled 450 MW (including full NS Block deliveries), if local or regional conditions required, it would have been normal for the asset to have been operated in its interim condition to satisfy operational requirements. However, as there was not a critical need, regional coordination would have dictated that the impacted utility proceed with the work to bring the asset back to full capability. NLH did so during daytime hours and continued energy deliveries when work was not being undertaken.

Of the $15.3 million in holdback from July 2024 to September 2025, $1.1 million was related to the outage caused by icing in January 2025 and the remainder of the $15.3 million was attributable to planned outages. For further context, $10.2 million relates to the July through October outages where the value of Make-up Energy exceeded the cost of replacement energy by over [redacted] million and [redacted] million related to NLH's annual maintenance (winter readiness) outage in September of 2025 where the estimated value of Make-up Energy also exceeded the cost of replacement energy. Please refer to SBA IR-05. During the period there were short-duration forced outages that did not impact the ability to meet the monthly holdback threshold. Please refer to IG IR-07.

c) NSPML did not schedule any of the applicable planned outages, as they were all undertaken for work on Newfoundland & Labrador Hydro assets. In terms of planning coordination, NSPML did not consider the potential of a holdback. The timing of planned outages is coordinated by the operations team and the System Operators in Nova Scotia and Newfoundland & Labrador, as well as the regional coordinator. Adding holdback considerations to an already complex coordination process would not be appropriate.

Request IR-14:

Reference: N-01 Application, p. 28, lines 23–26.

Preamble: The Application states that any planned outage near the end of a calendar month is likely to result in a holdback disallowance despite the associated energy being subject to redelivery in accordance with the ECA, and that given the scope of assets that can impact deliveries and the expectation of planned outages as part of "Good Utility Practice," there is a scenario where the Holdback lasts until the end of the ECA term.

(a) Please explain in detail the basis for the assertion that any planned outage near the end of a calendar month is *more likely* to result in a holdback disallowance or continuation of the Holdback mechanism, including consideration being given:

(i) **that the Board's 90% threshold provides a 10% grace margin for delivery in any given month; and**

(ii) **that some re-deliveries of shortfalls take multiple months, meaning the timing of an outage within a month does not inherently determine whether the 90% threshold is met.**

(b) Please confirm whether this concern applies equally to outages taken at any point in the month (i.e., is it specifically end-of-month outages that are problematic, or is any multi-day outage of more than approximately 3 days in a given month equally likely to breach the 90% threshold)? Please elaborate.

(c) Please provide quantitative support, by reference to the monthly delivery data in Appendix A and C, for the proposition that an outage near the end of a calendar month creates a materially greater risk of a

disallowance than an outage taken at a different time in the month.

(d) If NSPML's position is that the holdback mechanism structurally creates perverse incentives regarding outage timing, explain how that concern was addressed in the context of the current Application, and the noted outages between May 2023 and now.

Response IR-14:

a – c)

There are several independent but interconnected elements of the nature of the energy delivery obligations as defined in the Energy and Capacity Agreement, and as expected through normal utility and system operations in contrast to the existing holdback mechanism.

Firstly, the delivery performance in the initial years of LIL operations resulted in a volume of owed Nova Scotia Block energy, meaning there was an available pool of owed energy being delivered across the days and months following the successful commissioning of the LIL. Netting out these historical shortfalls was presumably part of (if not the complete) basis for the threshold created by the Board relating to having less than 10 percent owed energy prior to being able to apply to end the holdback mechanism. Such an account of owed energy meant that for every month there was generally sufficient volume of deliveries above the base block obligations that would offset most outages (planned or unplanned) in that measured period. Once the outstanding owed energy was essentially eliminated, it meant there was no such volume of Undelivered Energy available to mitigate an outage period whether planned or unplanned.

The second aspect is that energy contracts do not stipulate minimum volumes of energy in a given month, nor are they delivered based on a value / MWh basis. What is stipulated is

that the volume of Undelivered Energy will be delivered in a timely manner subsequent to the period during which the energy was not delivered. Again, the nature of the pre-commissioning period was that an accumulated volume of energy had pooled and that was all delivered on a first in, first out basis as is generally the case. There is only a requirement to deliver the NS Block in accordance with the agreements and being subject to the normal ebb and flow of utility and system operations. This means that there is no contractual measurement on an hourly, weekly, or monthly basis as it is inherent to the agreements that there should be some flexibility for the system operators to optimize NS Block delivery over these periods while supporting and enabling appropriate maintenance activities to be conducted to ensure the integrity of these and the other interconnected assets within the operational space. Please also refer to BW IR-07 b).

With the depletion of this outstanding volume of energy (Deferred Energy), and the ongoing and anticipated maintenance requirements, the timing of a particular outage will play a material role in whether or not the holdback mechanism value equation can be satisfied for the monthly holdback measurement period. If an outage happens early in a month there is a reasonable likelihood that Make-up Energy can be delivered, however it will depend on a number of operational factors and utility and system operational decisions. Generally, it has been the case that Make-up Energy deliveries have been timely even if they have slipped into subsequent months. Further on this point, the value of this Undelivered Energy can often be higher once delivered as outages are generally taken in lower demand periods with Make-up Energy deliveries following closer to the fall and winter months where intuitively demand and energy value typically increases. The real nuance challenge with the monthly holdback measurement threshold and the ongoing scenario of limited built-up energy is simply that because there is no built-up volume of Undelivered Energy in a month, often there would not be time for reasonable Make-up Energy delivery of even a few days of Undelivered Energy should a planned outage happen nearer the end of the month. And so, even if that Make-up Energy was delivered in the

first week of the subsequent month, it provides no mitigating of the holdback impact for the month in question - despite customers ultimately receiving the full contracted obligated energy aligned and in accordance with both the commercial obligations and the normal course of utility operations.

As has been discussed in relation to the holdback ending requirements, it will be the case that just the annual planned shutdown outages alone will mean that the holdback mechanism requirements will never be met as these outages are expected to be longer than 3 days and will generally fall within a month. As with any asset of any kind in almost any industry, planned and corrective maintenance work is required and a must to ensure the longevity and health of the operational performance of that asset. These maintenance periods are planned when it makes the most sense in coordination with all of the other interconnected assets, the system operator preferences, and the generally most appropriate timeframes for overall grid performance on behalf of customers. They are done when and as needed in reflection of system and sub-system health, as required, by pre-planning and consideration to winter and other asset health.

So it is for this collection of elements that result in the timing of an outage and the prevailing operational circumstances on the day can result in a monthly holdback, despite in the context of a rolling period all outstanding energies being delivered as Make-up Energy in a operationally reasonable timeline, in accordance with the contracted obligations, directed and managed by the interconnected system operators and energy management teams.

In terms of an example that ties to the monthly information in Appendices A and C, the simplest example would be an annual maintenance outage (sometimes referred to as a winter readiness outage) that has typically occurred at the end of September and has resulted in failure to meet the Holdback criteria in each September since 2022.

Given maintenance outages are typically a week or more in length, an example would be a hypothetical outage that spans the last week of September and the first week of October. For recent September outages, as there is no Make-up Energy balance, none of the deliveries above the NS Block amount earlier in the month of September can be used to mitigate the outage that occurs later in the month. Given a seven-day outage is approximately 25 percent of the days in a month, the disallowance would be based on ~20,000 MWh shortfall.

Jumping to October, the Make-up Energy balance would be ~20,000 MWh at the start of the month and is additive with the seven-day outage at the start of October adding another 20,000 MWh shortfall. Although there are many factors that influence the timing of Make-up Energy deliveries, referencing the Total Purchased Energy column in Appendix C of the Application provides some indication of the potential time to deliver, as Make-up Energy, the 40,000 MWh shortfall balance starting on day 8 of the month. Given the owed energy relates to Base NS Block energy, the 40,000 MWh owed are to be delivered as Make-up Energy during the daytime hours and only after the Base NS Block for those hours has been delivered. As such, in order to deliver the 40,000 MWh of Make-up Energy in the remaining three weeks of October it would require an average of 120 MW per hour for 16 hours a day above the Base NS Block amount to make up the full balance. In many months that delivery is likely to happen within the month, while in others the Make-up Energy delivery might carry over into the following month.

Since LIL commissioning (and absent the impact of Make-up Energy deliveries relating to the prior period), the only period where multiple months were taken for delivery of Make-up Energy primarily relates to the impact of NLH planned outages in July through October 2024 where all shortfalls were made up by December 25, 2024. Although the outages during this period were longer than expected, NSPML understood the work that was being undertaken and that such work would continue to augment overall asset performance. Given that the outages were occurring at a lower load period, that there were no issues with respect to system stability and that Make-up Energy deliveries would be closer to (or in) the winter period, NSPML did not push for NLH to undertake accelerated efforts to alter their approach.

In terms of the financial impact to customers relating to the July through October 2024 outages and as set out in greater detail in response to SBA IR-05, the estimated Make-up Energy value provided a benefit to customers of just over [redacted] million.[1] On the other hand, if the present Holdback mechanism is deemed to continue during this same period, NSPML would pay $10.2 million in disallowances – despite there being a benefit to customers of the delay.[2]

Although not guaranteed nor contractually required, it is not unreasonable to expect that the financial impact of outages and deliveries of Make-up Energy will mostly balance out over time – especially given planned outages happen in the lower load periods with deliveries of Make-up Energy potentially occurring closer to higher load periods.

d) NSPML has raised this issue in past Holdback proceedings and provided correspondence to the Board in June of 2024 explaining the issue of the current mitigation mechanism.

[1] Please refer to SBA IR-05.
[2] As previously conveyed, the Energy Access Agreement does not contain make whole provisions but is based on redelivery prior to NLH entering into any new energy sale transactions.

While NSPML does not consider Holdback issues while planning outages, the design of the Holdback mechanism incents altering approaches to outages for reasons such as:

- Timing the outage to span months to not have more than 3 days of outages in a month,
- Timing to occur early in a month to allow for holdback redelivery mitigation,
- With due consideration of safety, conducting as much of an outage as possible in monopole configuration,
- Deferring items to shorten outage length,
- Dividing a longer outage into multiple shorter outages that occur over multiple months, or
- Double shifting to shorten the length of outages.

Aside from the first two items listed, NSPML is not saying that the other items listed should never be taken into consideration when undertaking outages, especially for outages in the high load winter period when the capacity and energy availability is significantly more important in supporting a reliable system.

Although the items listed above and other similar factors could serve to lower the impact of the existing holdback mechanism, NSPML has not and does not intend to influence outages for any reason related to impacts of the design of the holdback mechanism or potential disallowances. The overall outage process is difficult enough in terms of coordinating within and between contractors, internal resources, and regional utilities, that it would be wrong to add irrelevant criteria that would only serve to further complicate this process.

In terms of explaining how the above concern was addressed in the context of the current Application, NSPML has requested termination of the holdback mechanism and, in the alternative if the Board determines that it is appropriate for the holdback mechanism to continue, NSPML has requested a separate process regarding appropriate mitigation.

Request IR-15:

Reference: N-01 Application, Section 6.0; and Appendix B.
And Reference: Matter M11773, N-01 NSPML Holdback Mechanism Letter (June 28, 2024).
Preamble: Appendix B sets out holdback amounts since the Compliance Period totalling $15,352,756 in holdback funds retained and $1,148,502 in WACC, calculated using NSPI's WACC of 6.75% for the period of April 2024 – March 2025 and 6.65% for April 2025 – present. The total amount sought by NSPML is $16,501,258.

(a) Where NSPML has deferred the within application for almost two years since the period it views as having met the compliance requirements, and in light of its representation in Matter 11773, N-1, Letter to the Board dated June 28, 2024, that it was expecting to file this application in August 2024, please explain why NSPML should be entitled to receive approximately $1.1 million in interest?

(b) Please confirm whether the figures in Appendix B have been independently verified by NSPML, or whether they are sourced from NSPI, and if the latter, please provide NSPML's basis for accepting those figures.

(c) Please provide the underlying monthly calculations for each "Holdback Retained" line item in Appendix B.

Response IR-15:

a) Please refer to NSEB IR-01.

b) Please refer to CA IR-03 (c).

c) Please refer to CA IR-03 (c).

Request IR-16:

Reference: N-01 Application, Section 7.0, Request for Separate Process if Holdback is Maintained.

Preamble: In Section 7.0 of the Application, NSPML requests that, should the Board determine that the Holdback mechanism ought to be maintained, a separate proceeding be established to consider the design of a continuing mechanism. NSPML further lists a number of considerations for the Board.

Please confirm that the considerations identified by NSPML in Section 7.0 of the Application are intended solely for the separate proceeding proposed by NSPML, and are not intended to inform, influence, or alter the Board's determination of any issue before it in the present proceeding, including whether the conditions for termination of the Holdback have been satisfied. If not confirmed, please explain.

Response IR-16:

The information is intended to provide the Board context in support of a separate proceeding if complete removal of the holdback is not approved, as NSPML does not believe that the existing mitigation mechanism is appropriate. However, NSPML does not believe the information in and of itself is relevant to the question of whether the conditions for termination of the holdback mechanism have been satisfied.

Request IR-17:

Reference: N-01, Application, pages 6 and 32.

And Reference: Board Decision and Order, February 5, 2024 (M1109).

> ***9. … NSPML may only make an application for such relief if it reasonably believes that, if the relief is granted, the effect will be to immediately terminate the monthly holdback mechanism.***

Preamble: The Application requests the Board "deem the Holdback to have ended effective May 1, 2024" (pdf page 6, line 17) and the "Holdback shall be vacated as at the end of April 2024" (pdf, p. 32, line 6).

(a) Please provide NSPML's interpretation of whether the Board's January 31, 2024 Decision contemplated retroactive termination and if so, what paragraphs?

(b) Please explain how a retroactive termination back to May 2024 satisfies the "immediate termination" upon application condition of the Order.

(c) Provide the date on which NSPML first concluded that the 12-month threshold had been satisfied and all internal analysis supporting that conclusion.

(d) In claiming a "return" of holdback amounts, please confirm NSPML's understanding that there is no surplus of monies held in the FAM balance to be returned to NSPML and that ratepayers owe money to NSPI. If not confirmed, please explain.

(e) Please provide any analysis of FAM-related customer impacts of returning the approximate $15.3 million (plus accrued interest, if granted) to NSPML?

(f) Does NSPML acknowledge that a regulatory option for the Board, if it determines that NSPML has satisfied the conditions to terminate the Holdback, is that termination apply prospectively as of the decision date?

Response IR-17:

a) There are two excerpts from the January 31, 2024, Decision that contemplate the retroactive termination of the holdback mechanism in that termination occurs upon satisfaction of the specified conditions, not the timing of NSPML's application (which will necessarily be brought after those conditions are met).

The first is in Section 2.0, in the quote at paragraph 5 referencing the October 4, 2023, Decision in the same Matter (M11009):

> [4] Having reviewed the evidence and the submissions, the Board finds that $12 million of holdback funds from April 2022 to June 2023, inclusive, shall be credited to ratepayers through the Fuel Adjustment Mechanism (FAM), subject to confirmation in the compliance filing. The monthly holdback will increase from $2 million to $4 million effective December 1, 2023. The holdback **will continue until** at least 90% of the NS Block measured in MWh (excluding Make-up Energy) is received for 12 consecutive months and the net outstanding balance of undelivered energy is less than 10% of the contracted annual amount of the NS Block.
>
> [Board Decision, 2023 NSUARB 175, para. 4]

[Emphasis added]

The words "will continue until" imply that once the two conditions have been satisfied the holdback mechanism will cease to continue. The Boards words do not say that the holdback mechanism will end when NSPML applies for termination of the holdback mechanism or that the holdback mechanism will end when the Board decides on the application.

The second is in Section 3.1 in paragraph 8:

> [8] In its decision, the Board concluded that **the holdback would continue until** at least 90% of the NS Block measured in MWh (excluding Make-up Energy) is received for 12 consecutive months and the net outstanding balance of undelivered energy is less than 10% of the contracted annual amount of the NS Block.
>
> [Emphasis added]

As with the first reference above, the words "the holdback would continue until" imply that once the two conditions have been satisfied the holdback mechanism will cease to continue.

If the Board deems that conditions to end the holdback mechanism had been met as of the end of April 2024, not releasing the $15.3 million holdback amounts that accumulated since the end of the Compliance Period would amount to a penalty against NSPML, or a disallowance, not based on imprudence or harm to customers. The holdback was implemented to offset the cost of replacement energy for delayed NLH deliveries. For the period from May 2024 until December 2025, NS Power did not need to procure replacement energy since all energy contracted for was delivered in the year. Any shortfall in the month was delivered as Make-up Energy in the following weeks. The holdback

exists for specific reasons, and those reasons no longer existed. NSPML submits that retaining the holdback amounts from May 2024 onward would not be consistent with the original intent of the holdback mechanism.

b) The "immediate termination" referenced in the Decision and the Order is not related to the potential retroactive termination of the holdback mechanism. Rather, the reference to immediate termination means, in NSPML's opinion, that the holdback mechanism will be deemed terminated – immediately – if the two conditions are satisfied.

c) NSPML believed it had a strong position that the 12 consecutive months of 90% delivery, considering good utility practice and exceptional circumstances, was satisfied in late May / early June 2024. Please also refer to NSEB IR-01.

d) NSPML understands the FAM is a balancing mechanism that can represent amounts owed to NS Power by customers (current situation) or amounts owed to customers if the BCF forecast was higher than actual fuel costs. The annual balancing process settles these amounts as appropriate. Please also refer to IG IR-18(d).

e) Please refer to NSEB IR-01(a) and IG IR-18.

f) NSPML understands that the NSEB always has discretion to examine the evidence and make whatever decision its feels to be appropriate, regardless of the request of the Applicant. However, given the experience during the Compliance Period and that the financial impact to customers after the Compliance Period is not representative of the holdback amounts (nor the actual ECA remedies), NSPML believes it is appropriate to end the holdback mechanism and release the post Compliance Period holdback amounts.

Request IR-18:

If the Board grants NSPML's application for relief and directs that approximately $16 million in previously held-back amounts be returned to NSPML, please explain in detail:

(a) how those funds would be treated for financial reporting purposes (including whether they would be recognized as current-period revenue, prior-period adjustment, or otherwise, and under which accounting standards);

(b) whether and how the return of these funds would affect NSPML's regulated revenue requirement, return on equity, or WACC-related calculations for the relevant period(s);

(c) any impacts on NSPML's financial statements, debt service coverage ratios, loan covenant compliance, or other financing metrics (including with respect to the federal loan guarantee);

(d) how the return of the funds would be reflected in FAM reporting, audits, or true-ups, and whether any corresponding adjustments or restatements would be required; and

(e) whether NSPML proposes any offsetting regulatory or accounting entries to ensure customers are not adversely affected by the retroactive return of holdback amounts.

Response IR-18:

a) The ~$15 million in holdback has been recorded as a revenue by NSPML in the applicable period with the offset being recorded as a receivable from NS Power. Therefore, there

would be no income statement impact when the funds are released to NSPML, it would be applied against the receivables balance.

The treatment of WACC would be consistent with the prior holdback mechanism decision (M11009) and will be recorded as interest earned for NSPML offsetting NSPML's interest expense; impacting net income in the period in which the decision is received.

b) There would be no impact to NSPML's revenue requirement, return on equity, or NSPML's WACC calculation. The release of the holdback would be treated as a return of equity, reducing NSPML's average equity thickness by ~1 percent, bringing it closer to the target of 30 percent.

c) There would be no impact to NSPML's debt service coverage ratios, loan covenant compliance, or other financing metrics.

d) Holdback retained (as identified in Appendix B of the Application) by NS Power has been recorded as a fuel cost in the FAM within the applicable period, therefore the release of those funds would not impact the FAM balance or FAM reporting. Accounting treatment of WACC would be determined by NS Power's accounting policies. Additionally, the FAM is subject to a biennial audit.

e) Please refer to NSEB IR-01.

Request IR-19:

Reference: N-01, Application, Attachment 1, Concentric Evidence

Preamble: The header on each page of Concentric's evidence states "Rebuttal Testimony of Danielle S. Powers."

(a) When was Concentric retained to prepare this evidence? Please provide a copy of the letter of instruction or retainer.

(b) Please explain why this evidence is characterized as "Rebuttal" evidence.

Response IR-19:

a) Ms. Powers was retained by NSPML in February of 2024 but did not provide NSPML with an updated retainer letter specific to this matter.

b) The evidence of Ms. Powers should be named Direct Testimony, not Rebuttal Testimony.

Request IR-20:

Reference: N-01, Application, Attachment 1, Concentric Evidence, page 3 (pdf page 42), lines 9-14.

> ***I provide my opinion that the period of May 2023 to April 2024 is the appropriate period over which to assess the performance of the Labrador Island Link ("LIL") and that the failure to grant relief to NSPML for the outages taken in July and September of 2023 and March of 2024, and an extreme weather event impacting the LIL in April of 2024, which directly affected the delivery of energy over the Maritime Link, would be inappropriate as a matter of regulatory policy.***

Please identify all documents, data, reports, and other materials that were reviewed or relied upon by Concentric in forming its opinions.

Response IR-20:

Concentric's opinion is grounded in well-established regulatory approaches to performance assessment, under which performance metrics are often designed to account for extraordinary events. In practice, regulators frequently apply exclusions, normalization adjustments, or alternative treatments where outages or events are outside the utility's reasonable control or would otherwise distort the intended purpose of the metric. For example, reliability and service quality frameworks routinely incorporate explicit treatment for major or exogenous events. Distribution reliability indices such as System Average Interruption Duration Index ("SAIDI"), which measures the average total duration of outages experienced by customers over a given period) and System Average Interruption Frequency Index ("SAIFI"), which measures the average number of interruptions experienced by customers) are commonly reported using a "Major Event Day" or similar framework, which separates periods associated with extreme weather or system disruptions

from normal operating conditions. This approach ensures that performance mechanisms remain aligned with the underlying intent of the metric and are not unduly influenced by atypical events.

Request IR-21:

Reference: N-01, Application, Attachment 1, Concentric Evidence, page 4 (pdf page 43), lines 18-21.

It is clear that the facts that existed at the time of the Board adopting the present holdback mechanism no longer exist – it is no longer the case that customers are paying for the Maritime Link but not receiving anything close to the full benefit.

(a) Please confirm the specific date or dates, and the objective criteria and underlying data, that Concentric has relied upon to determine that the conditions underpinning the holdback mechanism — namely, that customers were paying for the Maritime Link while not receiving anything close to the full benefit — ceased to exist. In responding, please:

(i) Identify the specific delivery performance metrics and thresholds Concentric used to determine that "full benefit" was being received, including whether Concentric relied on total NS Block deliveries (inclusive of Make-up Energy and Purchased Energy) or Base NS Block deliveries excluding Make-up Energy;

(ii) Confirm whether Concentric's analysis accounted for the period prior to April 2023 (i.e., before LIL commissioning), during which deliveries were constrained by the absence of a functional LIL, and if so, how;

(iii) Identify the earliest date on which Concentric considers the conditions underlying the holdback to have changed; and

(iv) Produce all underlying data, calculations, spreadsheets, and source materials used to support this conclusion (that have not already been provided).

(b) Please confirm whether Concentric reviewed, or took into consideration, any decisions of the Nova Scotia Energy Board (or its predecessor) relating to the Federal Loan Guarantee (FLG2) and its implications for the alignment of customer costs and Maritime Link benefits. If so, how has that impacted Concentric's analysis?

Response IR-21:

a) i)- iv)

Please see Ms. Powers Direct Testimony on page 6 where she states "for the months of May 2023 to April 2024 (the "Compliance Period"), Nova Scotians received approximately 140% of the contractual volumes agreed to between NSPML and Nalcor Energy ("Nalcor") defined as the Nova Scotia Block ("NS Block"), with winter deliveries being slightly higher at more than 140%. Total deliveries, including Purchased Energy, served approximately 19% of Nova Scotia Power sales and increases total delivery levels to over 170% of NS Block contractual amounts." In addition, please see Appendix C of NSPML's Application to Review the Holdback Mechanism ("Application"), February 3, 2026. Appendix C provides the information that shows that NSPML is meeting the Board's monthly 90 percent threshold, monthly NS Block delivery levels, Make-up Energy status and total energy delivery levels, including Purchased Energy.

As stated by the Company on page 11 of its Application:

- Deliveries of Base NS Block and Make-up Energy exceeded 90 percent of Contract Amounts every month and were over 100 percent in every month but September 2023 which fell short due to a planned outage in advance of the winter period[10]. Over the entire period, customers received NS Block energy equal to 140 percent of the contracted NS Block amount. That figure climbs to more than 170 percent once Purchased Energy is factored in.

- Base NS Block deliveries during the critical winter period (November to March) were 96 percent of the Contract Amount, and more than 140 percent when including Make-up Energy deliveries. These figures include the impact of planned and system operator coordinated outages in March 2024.

- The net balance of Deferred Energy dropped below 10 percent in March 2024 and was essentially eliminated in June 2024.[11]

- With strong delivery levels, NS Power incorporated the NS Block into system planning process prior to LIL commissioning in April 2023 and in the same manner as other generation sources.

ii) Concentric analysis included a review of all delivery data since the LIL was put into service.

iii) The date on which Concentric considers the conditions underlying the holdback to be satisfied is April 2024.

iv) All documents reviewed by Concentric to support the statement referenced in this IR have already been provided.

b) No, Concentric did not take into consideration any decisions involving Federal Loan Guarantees.

Request IR-22:

Reference: N-01, Application, Attachment 1, Concentric Evidence, page 11/36 (pdf page 48) states, "*No harm to customers has been evident since the LIL commissioning in April of 2023.*"

(a) Provide all analyses Concentric performed to assess "harm" to customers, including:

(i) **replacement energy costs during shortfall months;**

(ii) **timing/value differences between expected deliveries and redelivered energy; and**

(iii) **any price-spread analysis for periods of shortfall vs. redelivery.**

(b) If Concentric performed no such analysis, identify the basis on which it concluded "no harm" occurred.

Response IR-22:

Please refer to IG IR-21.

Request IR-23:

Reference: N-01, Application, Attachment 1, Concentric Evidence, page 12 (pdf page 52), line 29.

a) Please provide a copy of FERC's definition of "Good Utility Practice" referenced.

b) Please confirm whether there are any Canadian regulatory definitions of "Good Utility Practice" including those adopted by any provincial regulator, Canadian industry standard, or by the North American Electric Reliability Corporation (NERC) that Concentric considered and rejected as applicable benchmarks, and if so, explain why the FERC definition was preferred.

Response IR-23:

a) The Federal Energy Regulatory Commission ("FERC") has adopted a standardized definition of "Good Utility Practice" through its pro forma tariffs and interconnection agreements, including the Large Generator Interconnection Agreement and Small Generator Interconnection Agreement established in FERC Order No. 2003 and FERC Order No. 2006. Please refer to Attachment 1, page 18 of the PDF.

b) Concentric did not consider and reject an alternate definition of good utility practice. It is important to note that the definition of Good Utility Practice was included in the Joint Operating Agreement, which was provided to and reviewed by the Board as part of the regulatory approval process, and no concerns with that definition were raised in that process. Please refer to the response to IG IR-01 (a).

Revision History*

This version of the *pro forma* Large Generator Interconnection Agreement (LGIA) reflects the following changes:

Updated as of August 20, 2024	
Order No.	**Description of Changes**
2023-A (3/21/2024) & Errata	Revised Article 5.1.3 – Option to Build Revised Article 9.7.3 – Ride Through Capability and Performance
2023 (7/28/2023)	Revised Article 1 – Definitions
	Revised Article 5.4 – Power System Stabilizers
	Revised Article 5.9.2 – Provisional Interconnection Service
	Revised Article 7.1 – General
	Revised Article 8.4 – Provision of Data from a Variable Energy Resource
	Revised Article 9 – Operations
	Revised Article 11.5 – Provision of Security
	Revised Article 13.2 – Obligations
	New Article 17.2 – Violation of Operating Assumptions for Generating Facilities
	Revised Article 22.1.11
	Revised Article 24.3 – Updated Information Submission by Interconnection Customer
	Revised Article 29.1 – Joint Operating Committee
	Revised Appendix A – Interconnection Facilities, Network Upgrades and Distribution Upgrades
	Revised Appendix B – Milestones
	Revised Appendix G – Interconnection Requirements for a Wind Generating Facility
	New Appendix H – Operating Assumptions for Generating Facility
845-A (2/21/2019)	Revised Article 1 – Revised definition of Generating Facility; added definition of Provisional Interconnection Service; added definition of Provisional Large Generator Interconnection Agreement; revised definition of Stand Alone Network Upgrades; added definition of Surplus Interconnection Service.
	Revised Article 5.1 – Options
	Revised Article 5.1.3 – Option to Build
	Revised Article 5.1.4 – Negotiated Option
	Revised Article 5.2 – General Conditions Applicable to

Updated as of August 20, 2024	
Order No.	**Description of Changes**
2023-A (3/21/2024) & Errata	Revised Article 5.1.3 – Option to Build Revised Article 9.7.3 – Ride Through Capability and Performance
	Option to Build
	Revised Article 5.9 – Limited Operation
	New Article 5.9.1 – Limited Operation
	New Article 5.9.2 – Provisional Interconnection Service
842 (2/15/2018)	Revised Article 9.6 – Reactive Power
	Revised Article 9.6.2.1 – Governors and Voltage Regulators
	New Article 9.6.4 – Primary Frequency Response
	New Article 9.6.4.1 – Governor or Equivalent Controls
	New Article 9.6.4.2 – Timely and Sustained Response
	New Article 9.6.4.3 – Exemptions
	New Article 9.6.4.4 – Electric Storage Resources
827 (2/16/2016)	Revised Article 9.6.1 – Power Design Factor
	New Article 9.6.1.1 – Synchronous Generation
	New Article 9.6.1.2 – Non-Synchronous Generation
	Revised Appendix G – Technical Standards Applicable to a Wind Generating Plant
764 (6/22/2012)	Revised Article 1 – Added Definition of Variable Energy Resource
	New Article 8.4 – Provision of Data from a Variable Energy Resource
661-A (12/12/2005)	Revised Appendix G – Interconnection Requirements for a Wind Generating Plant
2003-C (6/16/2005)	Revised 1st Paragraph of Page 1
	Revised Article 5.3 – Liquidated Damages
	Revised Article 12.4 – Disputes
	Revised Article 18.3.6 – Insurance
	Revised Article 19.1 – Assignment
	Revised Article 24.2 – Information Submission by Transmission Provider
	Revised Article 12.4 – Disputes
661 (6/02/2005)	Added Appendix G – Interconnection Requirements for a Wind Generating Plant
2003-B (12/20/2004)	Revised Recitals
	Revised Article 1 – Definition of Force Majeure
	Revised Article 1 – Definition of Network Resource Interconnection Service

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Order No.	**Description of Changes**
2023-A (3/21/2024) & Errata	Revised Article 5.1.3 – Option to Build Revised Article 9.7.3 – Ride Through Capability and Performance
	Revised Article 4.1.2.2 – Transmission Delivery Service Implications
	Revised Article 5.14 – Permits
	Revised Article 5.17.7 – Contests
	Revised Article 5.17.8(ii) – Refund
	Revised Article 11.4.1 – Repayment of Amounts Advanced for Network Upgrades
	Revised Article 18.1 – Indemnity
	Revised Article 18.3.5 – Insurance
	Revised Article 18.3.6 – Insurance
	Revised Article 19.1 -- Assignment
	Revised Article 22.1.10 – Disclosure to FERC, its Staff, or a State
	Revised Article 28.1.2 – Authority
2003-A (3/05/2004)	Revised *pro forma* LGIA **

* This Revision History is for convenience of reference only, is not a part of this *pro forma* Large Generator Interconnection Agreement, and shall not limit or otherwise affect the interpretation of this *pro forma* Large Generator Interconnection Agreement.

** The Order No. 2003-A version is used as the baseline.

Appendix 5 to the Standard Large Generator Interconnection Procedures

STANDARD LARGE GENERATOR

INTERCONNECTION AGREEMENT (LGIA)

TABLE OF CONTENTS

Page

Recitals ..... **- 1 -**

Article 1. Definitions ..... **- 2 -**

Article 2. Effective Date, Term, and Termination ..... **- 12 -**

2.1 Effective Date ..... - 12 -

2.2 Term of Agreement. ..... - 13 -

2.3 Termination Procedures. ..... - 13 -

2.3.1 Written Notice. ..... - 13 -

2.3.2 Default ..... - 13 -

2.4 Termination Costs. ..... - 13 -

2.5 Disconnection. ..... - 14 -

2.6 Survival. ..... - 14 -

Article 3. Regulatory Filings ..... **- 15 -**

3.1 Filing. ..... - 15 -

Article 4. Scope of Service ..... **- 15 -**

4.1 Interconnection Product Options ..... - 15 -

4.1.1 Energy Resource Interconnection Service. ..... - 15 -

4.1.2 Network Resource Interconnection Service ..... - 16 -

4.2 Provision of Service. ..... - 19 -

4.3 Performance Standards ..... - 19 -

4.4 No Transmission Delivery Service. ..... - 19 -

4.5 Interconnection Customer Provided Services. ..... - 19 -

Article 5. Interconnection Facilities Engineering, Procurement, and Construction ..... **- 19 -**

5.1 Options. ..... - 19 -

5.1.1 Standard Option. ..... - 19 -

5.1.2 Alternate Option ..... - 20 -

5.1.3 Option to Build ..... - 20 -

5.1.4 Negotiated Option. ..... - 21 -

5.2 General Conditions Applicable to Option to Build..... - 21 -
5.3 Liquidated Damages..... - 23 -
5.4 Power System Stabilizers. ..... - 24 -
5.5 Equipment Procurement. ..... - 24 -
5.6 Construction Commencement. ..... - 25 -
5.7 Work Progress. ..... - 25 -
5.8 Information Exchange. ..... - 25 -
5.9 Other Interconnection Options. ..... - 25 -
5.9.1 Limited Operation. ..... - 26 -
5.9.2 Provisional Interconnection Service. ..... - 26 -
5.10 Interconnection Customer's Interconnection Facilities ('ICIF')..... - 27 -
5.10.1 Interconnection Customer's Interconnection Facility Specifications..... - 27 -
5.10.2 Transmission Provider's Review. ..... - 27 -
5.10.3 ICIF Construction. ..... - 27 -
5.11 Transmission Provider's Interconnection Facilities Construction. ..... - 28 -
5.12 Access Rights. ..... - 28 -
5.13 Lands of Other Property Owners. ..... - 29 -
5.14 Permits..... - 29 -
5.15 Early Construction of Base Case Facilities. ..... - 29 -
5.16 Suspension..... - 29 -
5.17 Taxes. ..... - 30 -
5.17.1 Interconnection Customer Payments Not Taxable. ..... - 30 -
5.17.2 Representations and Covenants. ..... - 30 -
5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Provider. ..... - 31 -
5.17.4 Tax Gross-Up Amount..... - 32 -
5.17.5 Private Letter Ruling or Change or Clarification of Law. ..... - 33 -
5.17.6 Subsequent Taxable Events. ..... - 33 -
5.17.7 Contests. ..... - 34 -
5.17.8 Refund. ..... - 35 -
5.17.9 Taxes Other Than Income Taxes. ..... - 36 -
5.17.10 Transmission Owners Who Are Not Transmission Providers. ..... - 36 -
5.18 Tax Status. ..... - 37 -
5.19 Modification. ..... - 37 -
5.19.1 General. ..... - 37 -

5.19.2 Standards. ..... - 37 -
5.19.3 Modification Costs. ..... - 38 -

Article 6. Testing and Inspection ..... - 38 -

6.1 Pre-Commercial Operation Date Testing and Modifications. ..... - 38 -

6.2 Post-Commercial Operation Date Testing and Modifications. ..... - 38 -

6.3 Right to Observe Testing..... - 38 -

6.4 Right to Inspect. ..... - 39 -

Article 7. Metering..... - 39 -

7.1 General. ..... - 39 -

7.2 Check Meters..... - 39 -

7.3 Standards. ..... - 40 -

7.4 Testing of Metering Equipment. ..... - 40 -

7.5 Metering Data..... - 40 -

Article 8. Communications ..... - 40 -

8.1 Interconnection Customer Obligations. ..... - 40 -

8.2 Remote Terminal Unit..... - 41 -

8.3 No Annexation. ..... - 41 -

8.4 Provision of Data from a Variable Energy Resource..... - 41 -

Article 9. Operations ..... - 42 -

9.1 General. ..... - 42 -

9.2 Balancing Authority Area Notification. ..... - 42 -

9.3 Transmission Provider Obligations. ..... - 43 -

9.4 Interconnection Customer Obligations. ..... - 43 -

9.5 Start-Up and Synchronization. ..... - 43 -

9.6 Reactive Power and Primary Frequency Response..... - 43 -
9.6.1 Power Factor Design Criteria..... - 43 -
9.6.2 Voltage Schedules. ..... - 44 -
9.6.3 Payment for Reactive Power. ..... - 45 -
9.6.4 Primary Frequency Response..... - 45 -

9.7 Outages and Interruptions. ..... - 49 -
9.7.1 Outages..... - 49 -

9.7.2 Interruption of Service. - 50 -
9.7.3 Ride Through Capability and Performance. - 51 -
9.7.4 System Protection and Other Control Requirements. - 52 -
9.7.5 Requirements for Protection. - 53 -
9.7.6 Power Quality. - 54 -
9.8 Switching and Tagging Rules. - 54 -
9.9 Use of Interconnection Facilities by Third Parties. - 54 -
9.9.1 Purpose of Interconnection Facilities. - 54 -
9.9.2 Third Party Users. - 54 -
9.10 Disturbance Analysis Data Exchange. - 55 -

Article 10. Maintenance - 55 -

10.1 Transmission Provider Obligations. - 55 -
10.2 Interconnection Customer Obligations. - 55 -
10.3 Coordination. - 55 -
10.4 Secondary Systems. - 55 -
10.5 Operating and Maintenance Expenses. - 55 -

Article 11. Performance Obligation - 56 -

11.1 Interconnection Customer Interconnection Facilities. - 56 -
11.2 Transmission Provider's Interconnection Facilities. - 56 -
11.3 Network Upgrades and Distribution Upgrades. - 56 -
11.4 Transmission Credits. - 56 -
11.4.1 Repayment of Amounts Advanced for Network Upgrades. - 56 -
11.4.2 Special Provisions for Affected Systems. - 57 -
11.5 Provision of Security. - 58 -
11.6 Interconnection Customer Compensation. - 59 -
11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. - 59 -

Article 12. Invoice - 59 -

12.1 General. - 59 -
12.2 Final Invoice. - 60 -
12.3 Payment. - 60 -
12.4 Disputes. - 60 -

Article 13. Emergencies ..... - 60 -
13.1 Definition. ..... - 60 -
13.2 Obligations. ..... - 61 -
13.3 Notice. ..... - 61 -
13.4 Immediate Action. ..... - 61 -
13.5 Transmission Provider Authority. ..... - 61 -
13.5.1 General. ..... - 62 -
13.5.2 Reduction and Disconnection. ..... - 62 -
13.6 Interconnection Customer Authority ..... - 63 -
13.7 Limited Liability. ..... - 63 -
Article 14. Regulatory Requirements and Governing Law ..... - 63 -
14.1 Regulatory Requirements. ..... - 63 -
14.2 Governing Law ..... - 63 -
Article 15. Notices. ..... - 64 -
15.1 General. ..... - 64 -
15.2 Billings and Payments. ..... - 64 -
15.3 Alternative Forms of Notice ..... - 64 -
15.4 Operations and Maintenance Notice. ..... - 64 -
Article 16. Force Majeure ..... - 64 -
16.1 Force Majeure. ..... - 64 -
Article 17. Default ..... - 65 -
17.1 Default ..... - 65 -
17.1.1 General. ..... - 65 -
17.1.2 Right to Terminate. ..... - 66 -
17.2 Violation of Operating Assumptions for Generating Facilities. ..... - 66 -
Article 18. Indemnity, Consequential Damages and Insurance ..... - 66 -
18.1 Indemnity. ..... - 66 -
18.1.1 Indemnified Person. ..... - 66 -
18.1.2 Indemnifying Party. ..... - 67 -
18.1.3 Indemnity Procedures. ..... - 67 -
18.2 Consequential Damages. ..... - 68 -

18.3 Insurance. - 68 -

Article 19. Assignment - 70 -

19.1 Assignment. - 70 -

Article 20. Severability - 71 -

20.1 Severability - 71 -

Article 21. Comparability - 71 -

21.1 Comparability. - 71 -

Article 22. Confidentiality - 71 -

22.1 Confidentiality - 71 -
22.1.1 Term. - 72 -
22.1.2 Scope. - 72 -
22.1.3 Release of Confidential Information - 72 -
22.1.4 Rights. - 73 -
22.1.5 No Warranties. - 73 -
22.1.6 Standard of Care - 73 -
22.1.7 Order of Disclosure. - 73 -
22.1.8 Termination of Agreement. - 74 -
22.1.9 Remedies. - 74 -
22.1.10 Disclosure to FERC, its Staff, or a State - 74 -

Article 23. Environmental Releases - 75 -

Article 24. Information Requirements - 76 -

24.1 Information Acquisition. - 76 -

24.2 Information Submission by Transmission Provider - 76 -

24.3 Updated Information Submission by Interconnection Customer - 76 -

24.4 Information Supplementation - 77 -

Article 25. Information Access and Audit Rights - 77 -

25.1 Information Access. - 77 -

25.2 Reporting of Non-Force Majeure Events. - 78 -

25.3 Audit Rights. - 78 -

25.4 Audit Rights Periods. - 78 -

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. ..... - 78 -
25.4.2 Audit Rights Period for All Other Accounts and Records ..... - 79 -
25.5 Audit Results. ..... - 79 -

Article 26. Subcontractors ..... - 79 -
26.1 General. ..... - 79 -
26.2 Responsibility of Principal. ..... - 79 -
26.3 No Limitation by Insurance. ..... - 79 -

Article 27. Disputes ..... - 80 -
27.1 Submission. ..... - 80 -
27.2 External Arbitration Procedures..... - 80 -
27.3 Arbitration Decisions. ..... - 80 -
27.4 Costs. ..... - 81 -

Article 28. Representations, Warranties, and Covenants ..... - 81 -
28.1 General. ..... - 81 -
28.1.1 Good Standing. ..... - 81 -
28.1.2 Authority. ..... - 81 -
28.1.3 No Conflict. ..... - 82 -
28.1.4 Consent and Approval..... - 82 -

Article 29. Joint Operating Committee..... - 82 -
29.1 Joint Operating Committee. ..... - 82 -

Article 30. Miscellaneous..... - 83 -
30.1 Binding Effect. ..... - 83 -
30.2 Conflicts. ..... - 83 -
30.3 Rules of Interpretation..... - 83 -
30.4 Entire Agreement. ..... - 84 -
30.5 No Third Party Beneficiaries. ..... - 84 -
30.6 Waiver. ..... - 84 -
30.7 Headings. ..... - 84 -
30.8 Multiple Counterparts. ..... - 84 -

30.9 Amendment. ..... - 85 -
30.10 Modification by the Parties. ..... - 85 -
30.11 Reservation of Rights. ..... - 85 -
30.12 No Partnership. ..... - 85 -

Appendix A - Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Appendix B – Milestones

Appendix C – Interconnection Details

Appendix D – Security Arrangements Details

Appendix E – Commercial Operation Date

Appendix F – Addresses for Delivery of Notices and Billings

Appendix G – Interconnection Requirements for a Wind Generating Plant

Appendix H – Operating Assumptions for Generating Facility

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this ____ day of _____ 20__, by and between _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Interconnection Customer" with a Large Generating Facility), and _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Standards shall mean the requirements and guidelines of the Electric Reliability Organization and the Balancing Authority Area of the Transmission System to which the Generating Facility is directly interconnected.

Balancing Authority shall mean an entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Balancing Authority Area shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Cluster shall mean a group of one or more Interconnection Requests that are studied together for the purpose of conducting a Cluster Study.

Cluster Restudy shall mean a restudy of a Cluster Study conducted pursuant to Section 7.5 of the LGIP.

Cluster Study shall mean the evaluation of one or more Interconnection Requests within a Cluster as described in Section 7 of the LGIP.

Clustering shall mean the process whereby one or more Interconnection Requests are studied together, instead of serially, as described in Section 7 of the LGIP.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Contingent Facilities shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the

Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Electric Reliability Organization shall mean the North American Electric Reliability Corporation (NERC) or its successor organization.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows Interconnection Customer to connect its Generating Facility to Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device(s) for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility or the aggregate net capacity of the Generating Facility where it includes more than one device for the production and/or storage for later injection of electricity.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not

intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which Interconnection Customer reasonably expects it will be ready to begin use of Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean Transmission Provider's Interconnection Facilities and Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by Transmission Provider or a third party consultant for Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Cluster Study), the cost of those facilities, and the time required to interconnect the Generating Facility with Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of the LGIP.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the LGIP, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by Transmission Provider associated with interconnecting Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Cluster Study, the Cluster Restudy, the Surplus Interconnection Service Study, the Interconnection Facilities Study, the Affected System Study, Optional Interconnection Study, and Material Modification assessment, described in the LGIP.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

LGIA Deposit shall mean the deposit Interconnection Customer submits when returning the executed LGIA, or within 10 Business Days of requesting that the LGIA be filed unexecuted at the Commission, in accordance with Section 11.3 of the LGIP.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with an equal or later Queue Position.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows Interconnection Customer to integrate its Large Generating Facility with Transmission Provider's Transmission System (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 4 of the LGIP for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where Interconnection Customer's Interconnection Facilities connect to Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to Transmission Provider's Transmission System.

Proportional Impact Method shall mean a technical analysis conducted by Transmission Provider to determine the degree to which each Generating Facility in the Cluster Study contributes to the need for a specific System Network Upgrade.

Provisional Interconnection Service shall mean Interconnection Service provided by Transmission Provider associated with interconnecting Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Provisional Large Generator Interconnection Agreement and, if applicable, the Tariff.

Provisional Large Generator Interconnection Agreement shall mean the interconnection agreement for Provisional Interconnection Service established between

Transmission Provider and/or the Transmission Owner and the Interconnection Customer. This agreement shall take the form of the Standard Large Generator Interconnection Agreement, modified for provisional purposes.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, established pursuant to Section 4.1 of this LGIP.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of Interconnection Customer(s) and Transmission Provider conducted for the purpose of discussing the proposed Interconnection Request and any alternative interconnection options, exchanging information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, refining information and models provided by Interconnection Customer(s), discussing the Cluster Study materials posted to OASIS pursuant to Section 3.5 of the LGIP, and analyzing such information.

Site Control shall mean the exclusive land right to develop, construct, operate, and maintain the Generating Facility over the term of expected operation of the Generating Facility. Site Control may be demonstrated by documentation establishing: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size to construct and operate the Generating Facility; (2) an option to purchase or acquire a leasehold site of sufficient size to construct and operate the Generating Facility; or (3) any other documentation that clearly demonstrates the right of Interconnection Customer to exclusively occupy a site of sufficient size to construct and operate the Generating Facility. Transmission Provider will maintain acreage requirements for each Generating Facility type on its OASIS or public website.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that are not part of an Affected System that Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement. If Transmission Provider and Interconnection

Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, Transmission Provider must provide Interconnection Customer a written technical explanation outlining why Transmission Provider does not consider the Network Upgrade to be a Stand Alone Network Upgrade within fifteen (15) Business Days of its determination.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in Transmission Provider's Tariff.

Substation Network Upgrades shall mean Network Upgrades that are required at the substation located at the Point of Interconnection.

Surplus Interconnection Service shall mean any unneeded portion of Interconnection Service established in a Standard Large Generator Interconnection Agreement, such that if Surplus Interconnection Service is utilized the total amount of Interconnection Service at the Point of Interconnection would remain the same.

System Network Upgrades shall mean Network Upgrades that are required beyond the substation located at the Point of Interconnection.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on Transmission Provider's Transmission System or on other delivery systems or other generating systems to which Transmission Provider's Transmission System is directly connected.

Tariff shall mean Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Withdrawal Penalty shall mean the penalty assessed by Transmission Provider to an Interconnection Customer that chooses to withdraw or is deemed withdrawn from Transmission Provider's interconnection queue or whose Generating Facility does not otherwise reach Commercial Operation. The calculation of the Withdrawal Penalty is set forth in Section 3.7.1 of the LGIP.

Article 2. Effective Date, Term, and Termination

2.1 Effective Date. This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 Term of Agreement. Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by Interconnection Customer after giving Transmission Provider ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Either Party may terminate this LGIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this LGIA. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, Transmission Provider shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Provider shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as

practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Provider to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Provider has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection. Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 Survival. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this LGIA or

other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing. Transmission Provider shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this LGIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

4.1.1 Energy Resource Interconnection Service.

4.1.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Attachment A.

4.1.1.2 Transmission Delivery Service Implications. Under Energy Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Large Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System on an "as available" basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for Energy

Resource Interconnection Service have been constructed. Where eligible to do so (e.g., PJM, ISO-NE, NYISO), Interconnection Customer may place a bid to sell into the market up to the maximum identified Large Generating Facility output, subject to any conditions specified in the interconnection service approval, and the Large Generating Facility will be dispatched to the extent Interconnection Customer's bid clears. In all other instances, no transmission delivery service from the Large Generating Facility is assured, but Interconnection Customer may obtain Point-to-Point Transmission Service, Network Integration Transmission Service, or be used for secondary network transmission service, pursuant to Transmission Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Large Generating Facility Point of Interconnection or to improve its ability to do so, transmission delivery service must be obtained pursuant to the provisions of Transmission Provider's Tariff. Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

4.1.2 Network Resource Interconnection Service.

4.1.2.1 The Product. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission

Provider shall construct the facilities identified in Attachment A to this LGIA.

4.1.2.2 Transmission Delivery Service Implications. Network Resource Interconnection Service allows Interconnection Customer's Large Generating Facility to be designated by any Network Customer under the Tariff on Transmission Provider's Transmission System as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Large Generating Facility in the same manner as it accesses Network Resources. A Large Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Large Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Large Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or firm Point-to-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the

capability to physically deliver the output of its Large Generating Facility to any particular load on Transmission Provider's Transmission System without incurring congestion costs. In the event of transmission constraints on Transmission Provider's Transmission System, Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer's Large Generating Facility be designated as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Large Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Large Generating Facility within Transmission Provider's Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Large Generating Facility be undertaken, regardless of whether or not such Large Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Large Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Large Generating Facility outside Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 Provision of Service. Transmission Provider shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 Performance Standards. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 No Transmission Delivery Service. The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 Interconnection Customer Provided Services. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

Article 5. Interconnection Facilities Engineering, Procurement, and Construction

5.1 Options. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either the Standard Option or Alternate Option set forth below, and such dates and selected option shall be set forth in Appendix B, Milestones. At the same time, Interconnection Customer shall indicate whether it elects to exercise the Option to Build set forth in Article 5.1.3 below. If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days. Upon receipt of the notification that Interconnection Customer's designated dates are not acceptable to Transmission Provider, Interconnection Customer shall notify Transmission Provider within thirty (30) Calendar Days whether it elects to exercise the Option to Build if it has not already elected to exercise the Option to Build.

5.1.1 Standard Option. Transmission Provider shall design, procure, and construct Transmission Provider's Interconnection Facilities and Network

Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option. If the dates designated by Interconnection Customer are acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable RTO or ISO refuses to grant clearances to install equipment.

5.1.3 Option to Build. Individual or Multiple Interconnection Customers shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2, if the requirements of this Article 5.1.3 are met. When multiple Interconnection Customers exercise this option, multiple Interconnection Customers may agree to exercise this option provided (1) all Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades constructed under this option are only required for Interconnection Customers in a single Cluster and (2) all impacted Interconnection Customers execute and provide to Transmission Provider an agreement

regarding responsibilities and payment for the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades planned to be built under this option. Transmission Provider and the individual Interconnection Customer or each of the multiple Interconnection Customers must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option. If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives, or the procurement and construction of all facilities other than Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades if Interconnection Customer elects to exercise the Option to Build under Article 5.1.3). If the Parties are unable to reach agreement on such terms and conditions, then pursuant to Article 5.1.1 (Standard Option), Transmission Provider shall assume responsibility for the design, procurement and construction of all facilities other than Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades if Interconnection Customer elects to exercise the Option to Build.

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Provider;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider;

(5) at any time during construction, Transmission Provider shall have the right to gain unrestricted access to Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider for claims arising from Interconnection Customer's construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Provider's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Provider;

(10) Transmission Provider shall approve and accept for operation and maintenance Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

(12) If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.3, Interconnection Customer shall pay Transmission Provider the agreed upon amount of [$ PLACEHOLDER] for Transmission Provider to execute the responsibilities enumerated to Transmission Provider under Article 5.2. Transmission Provider shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

5.3 Liquidated Damages. The actual damages to Interconnection Customer, in the event Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Provider to Interconnection Customer in the event that Transmission Provider does not complete any portion of Transmission Provider's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades for which Transmission Provider has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Provider to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for Transmission Provider's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission

Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Transmission Provider's delay; (2) Transmission Provider's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure; (3) Interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 Power System Stabilizers. Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Electric Reliability Organization. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 Equipment Procurement. If responsibility for construction of Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by Transmission Provider, then Transmission Provider shall commence design of Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Interconnection Facilities Study pursuant to the Interconnection Facilities Study Agreement;

5.5.2 Transmission Provider has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 Construction Commencement. Transmission Provider shall commence construction of Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Provider has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 Work Progress. The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, Interconnection Customer determines that the completion of Transmission Provider's Interconnection Facilities will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of Transmission Provider's Interconnection Facilities will be required.

5.8 Information Exchange. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Other Interconnection Options.

5.9.1 Limited Operation. If any of Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. Transmission Provider shall permit Interconnection Customer to operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.9.2 Provisional Interconnection Service. Upon the request of Interconnection Customer, and prior to completion of requisite Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities Transmission Provider may execute a Provisional Large Generator Interconnection Agreement or Interconnection Customer may request the filing of an unexecuted Provisional Large Generator Interconnection Agreement with Interconnection Customer for limited Interconnection Service at the discretion of Transmission Provider based upon an evaluation that will consider the results of available studies. Transmission Provider shall determine, through available studies or additional studies as necessary, whether stability, short circuit, thermal, and/or voltage issues would arise if Interconnection Customer interconnects without modifications to the Generating Facility or Transmission System. Transmission Provider shall determine whether any Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities that are necessary to meet the requirements of the Electric Reliability Organization, or any applicable Regional Entity for the interconnection of a new, modified and/or expanded Generating Facility are in place prior to the commencement of Interconnection Service from the Generating Facility. Where available studies indicate that such, Interconnection Facilities, Network Upgrades, Distribution Upgrades, and/or System Protection Facilities that are required for the interconnection of a new, modified and/or expanded Generating Facility are not currently in place, Transmission Provider will perform a study, at Interconnection Customer's expense, to confirm the facilities that are required for Provisional Interconnection Service. The maximum permissible output of the Generating Facility in the Provisional Large Generator Interconnection Agreement shall be studied and updated [on a frequency determined by Transmission Provider and at Interconnection Customer's expense]. Interconnection Customer assumes all risk and liabilities with respect to changes between the Provisional Large Generator Interconnection Agreement and the Large Generator Interconnection Agreement,

including changes in output limits and Interconnection Facilities, Network Upgrades, Distribution Upgrades, and/or System Protection Facilities cost responsibilities.

5.10 Interconnection Customer's Interconnection Facilities ('ICIF'). Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 Interconnection Customer's Interconnection Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Transmission Provider's Review. Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider.

5.10.3 ICIF Construction. The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the

layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Transmission Provider's Interconnection Facilities Construction. Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Provider shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Provider's Interconnection Facilities [include appropriate drawings and relay diagrams].

Transmission Provider will obtain control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, Transmission Provider or Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Interconnection Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred

in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Provider for the installation of Transmission Provider's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Provider for Transmission Provider's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty

(20) years, and (iii) any portion of Transmission Provider's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Provider's request, Interconnection Customer shall provide Transmission Provider with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Provider represents and covenants that the cost of Transmission Provider's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon Transmission Provider. Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Provider from the cost consequences of any current tax liability imposed against Transmission Provider as the result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Provider.

Transmission Provider shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Transmission Provider has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Provider should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation; provided, however, that Transmission Provider may require Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Provider (such as a parental guarantee or a letter of credit), in an amount equal to the cost

consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Provider of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Provider upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 **Tax Gross-Up Amount.** Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Transmission Provider, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Provider ("Current Taxes") on the excess of (a) the gross income realized by Transmission Provider as a result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Provider to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Provider's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Provider will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Provider's anticipated tax depreciation deductions as a result of such payments or property transfers by

Transmission Provider's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 Private Letter Ruling or Change or Clarification of Law. At Interconnection Customer's request and expense, Transmission Provider shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Provider under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Provider and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Provider shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Provider shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 Subsequent Taxable Events. If, within 10 years from the date on which the relevant Transmission Provider's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Transmission Provider retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the

cost consequences of any current tax liability imposed on Transmission Provider, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 **Contests.** In the event any Governmental Authority determines that Transmission Provider's receipt of payments or property constitutes income that is subject to taxation, Transmission Provider shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Provider may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Provider shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Provider may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Provider, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the

current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Provider for the tax at issue in the contest.

5.17.8 **Refund.** In the event that (a) a private letter ruling is issued to Transmission Provider which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Provider in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not taxable to Transmission Provider, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Provider are not subject to federal income tax, or (d) if Transmission Provider receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Provider pursuant to this LGIA, Transmission Provider shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Transmission Provider for such taxes which Transmission Provider did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Provider refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Provider, any refund or credit Transmission Provider receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission

Provider for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Provider to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Provider will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Provider has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Provider's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which Interconnection Customer may be required to reimburse Transmission Provider under the terms of this LGIA. Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Provider for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Provider.

5.17.10 Transmission Owners Who Are Not Transmission Providers. If Transmission Provider is not the same entity as the Transmission Owner, then (i) all references in this Article 5.17 to Transmission

Provider shall be deemed also to refer to and to include the Transmission Owner, as appropriate, and (ii) this LGIA shall not become effective until such Transmission Owner shall have agreed in writing to assume all of the duties and obligations of Transmission Provider under this Article 5.17 of this LGIA.

5.18 Tax Status. Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this LGIA is intended to adversely affect any Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 **Modification Costs.** Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Provider makes to Transmission Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Provider's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

Article 6. Testing and Inspection

6.1 **Pre-Commercial Operation Date Testing and Modifications.** Prior to the Commercial Operation Date, Transmission Provider shall test Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 **Post-Commercial Operation Date Testing and Modifications.** Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 **Right to Observe Testing.** Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 Right to Inspect. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review the other Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

Article 7. Metering

7.1 General. Each Party shall comply with the Electric Reliability Organization requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 Check Meters. Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 Standards. Transmission Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 Testing of Metering Equipment. Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 Metering Data. At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 Interconnection Customer Obligations. Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone

system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 Remote Terminal Unit. Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 No Annexation. Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 Provision of Data from a Variable Energy Resource. Interconnection Customer whose Generating Facility contains at least one Variable Energy Resource shall provide meteorological and forced outage data to Transmission Provider to the extent necessary for Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide Transmission Provider with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide Transmission Provider

with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. Transmission Provider and Interconnection Customer whose Generating Facility contains a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. Interconnection Customer whose Generating Facility contains a Variable Energy Resource also shall submit data to Transmission Provider regarding all forced outages to the extent necessary for Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by Interconnection Customer to Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

Article 9. Operations

9.1 General. Each Party shall comply with the Electric Reliability Organization requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Balancing Authority Area Notification. At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider in writing of the Balancing Authority Area in which the Large Generating Facility will be located. If Interconnection Customer elects to locate the Large Generating Facility in a Balancing Authority Area other than the Balancing Authority Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Balancing Authority Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Balancing Authority Area.

9.3 Transmission Provider Obligations. Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. Interconnection Customer shall operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Balancing Authority Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this LGIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this LGIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Large Generating Facility to Transmission Provider's Transmission System.

9.6 Reactive Power and Primary Frequency Response.

9.6.1 Power Factor Design Criteria.

9.6.1.1 Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all synchronous generators in the Balancing Authority Area on a comparable basis.

9.6.1.2 Non-Synchronous Generation. Interconnection Customer shall design the Large Generating Facility to maintain a

composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Balancing Authority Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

9.6.2 Voltage Schedules. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Large Generating Facility to produce or absorb reactive power within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the Balancing Authority Area in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 Voltage Regulators. Whenever the Large Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its voltage regulators in automatic operation. If the Large Generating Facility's voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's

system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Balancing Authority Area on a comparable basis.

9.6.3 Payment for Reactive Power. Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.6.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved Electric Reliability Organization reliability standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Large Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are

outside of the deadband parameter; or (2) based an approved Electric Reliability Organization reliability standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Large Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved Electric Reliability Organization reliability standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with the provisions specified in Articles 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities.

9.6.4.1 **Governor or Equivalent Controls.** Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved Electric Reliability Organization reliability standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service,

Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Large Generating Facility's governor or equivalent controls to a minimum whenever the Large Generating Facility is operated in parallel with the Transmission System.

9.6.4.2 **Timely and Sustained Response.** Interconnection Customer shall ensure that the Large Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Large Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved reliability standard with equivalent or more stringent requirements shall supersede the above requirements.

9.6.4.3 **Exemptions.** Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Articles 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Large Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load

and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Article 9.6.4, but shall be otherwise exempt from the operating requirements in Article 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

9.6.4.4 **Electric Storage Resources.** Interconnection Customer interconnecting a Generating Facility that contains an electric storage resource shall establish an operating range in Appendix C of its LGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Articles 9.6.4, 9.6.4.1, 9.6.4.2 and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Article 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity

to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 Outage Schedules. Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining

Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 **Outage Restoration.** If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 **Interruption of Service.** If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 Ride Through Capability and Performance. The Transmission System is designed to automatically activate a load-shed program as required by the Electric Reliability Organization in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the Electric Reliability Organization to ensure frequency "ride through" capability of the Transmission System. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. Interconnection Customer shall also implement under-voltage and over-voltage relay set points, or equivalent electronic controls, as required by the Electric Reliability Organization to ensure voltage "ride through" capability of the Transmission System. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the Transmission System during system

disturbances within a range of under-frequency, over-frequency, under-voltage, and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other Generating Facilities in the Balancing Authority Area on a comparable basis. For abnormal frequency conditions and voltage conditions within the "no trip zone" defined by Reliability Standard PRC-024-3 or successor mandatory ride through reliability standards, the non-synchronous Large Generating Facility must ensure that, within any physical limitations of the Large Generating Facility, its control and protection settings are configured or set to (1) continue active power production during disturbance and post disturbance periods at pre-disturbance levels, unless reactive power priority mode is enabled or unless providing primary frequency response or fast frequency response; (2) minimize reductions in active power and remain within dynamic voltage and current limits, if reactive power priority mode is enabled, unless providing primary frequency response or fast frequency response; (3) not artificially limit dynamic reactive power capability during disturbances; and (4) return to pre-disturbance active power levels without artificial ramp rate limits if active power is reduced, unless providing primary frequency response or fast frequency response.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 **System Protection Facilities.** Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Provider's Interconnection Facilities or the Transmission System as a result of the interconnection of the Large Generating Facility and Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection. In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment

if conditions on the Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality. Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 Switching and Tagging Rules. Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other

mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 Transmission Provider Obligations. Transmission Provider shall maintain the Transmission System and Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 Interconnection Customer Obligations. Interconnection Customer shall maintain the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 Coordination. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems. Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays

for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

Article 11. Performance Obligation

11.1 Interconnection Customer Interconnection Facilities. Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 Transmission Provider's Interconnection Facilities. Transmission Provider or Transmission Owner shall design, procure, construct, install, own and/or control Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by Interconnection Customer.

11.4 Transmission Credits.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating

Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 Special Provisions for Affected Systems. Unless Transmission Provider provides, under the LGIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by

Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment, as specified in Appendix B of this LGIA, shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes. Transmission Provider must use the LGIA Deposit required in Section 11.3 of the LGIP before requiring Interconnection Customer to submit security in addition to that LGIA Deposit. Transmission Provider must specify, in Appendix B of this LGIA, the dates for which Interconnection Customer must provide additional security for construction of each discrete portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and Interconnection Customer must provide such additional security.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.6 Interconnection Customer Compensation. If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this LGIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to an RTO or ISO FERC-approved rate schedule. Interconnection Customer shall serve Transmission Provider or RTO or ISO with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this LGIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. Transmission Provider or RTO or ISO shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

Article 12. Invoice

12.1 General. Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits,

shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 Definition. "Emergency Condition" shall mean a condition or situation: (i) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (ii) that, in the case of Transmission Provider, is imminently likely

(as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (iii) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to**,** the Large Generating Facility or Interconnection Customer's Interconnection Facilities' System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

13.2 Obligations. Each Party shall comply with the Emergency Condition procedures of the applicable ISO/RTO, the Electric Reliability Organization, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 Notice. Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.4 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission System.

13.5 Transmission Provider Authority.

13.5.1 **General.** Transmission Provider may take whatever actions or inactions with regard to the Transmission System or Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Provider's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 **Reduction and Disconnection.** Transmission Provider may reduce Interconnection Service or disconnect the Large Generating Facility or Interconnection Customer's Interconnection Facilities, when such, reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection

Customer and Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority. Consistent with Good Utility Practice and the LGIA and the LGIP, Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Provider's Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, neither Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices.

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default

17.1.1 **General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act or omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this LGIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this LGIA.

17.2 Violation of Operating Assumptions for Generating Facilities. If Transmission Provider requires Interconnection Customer to memorialize the operating assumptions for the charging behavior of a Generating Facility that includes at least one electric storage resource in Appendix H of this LGIA, Transmission Provider may consider Interconnection Customer to be in Breach of the LGIA if Interconnection Customer fails to operate the Generating Facility in accordance with those operating assumptions for charging behavior. However, if Interconnection Customer operates contrary to the operating assumptions for charging behavior specified in Appendix H of this LGIA at the direction of Transmission Provider, Transmission Provider shall not consider Interconnection Customer in Breach of this LGIA.

Article 18. Indemnity, Consequential Damages and Insurance

18.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

18.1.1 Indemnified Person. If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 **Indemnifying Party.** If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 **Indemnity Procedures.** Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of

the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. Each party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined

single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) Business Days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) Calendar Days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

Article 19. Assignment

19.1 Assignment. This LGIA may be assigned by either Party only with the written consent of the other; provided that either Party may assign this LGIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that Interconnection Customer shall have the right to assign this LGIA, without the consent of Transmission Provider, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer

pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is

conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 **Term.** During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 **Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 **Release of Confidential Information.** Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of

Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 **Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties.** By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this LGIA or its regulatory requirements.

22.1.7 **Order of Disclosure.** If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance

that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 **Termination of Agreement.** Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 **Remedies.** The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 **Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this LGIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other

Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Balancing Authority Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no

later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 Information Acquisition. Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 Information Submission by Transmission Provider. The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer. The updated information submission by Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Transmission Provider for the Cluster Study and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on Transmission Provider Transmission System based on the actual data submitted

pursuant to this Article 24.3. Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to Transmission Provider for each individual generating unit in a station.

Subsequent to the Operation Date, Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Provider shall provide Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may affect Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

Article 25. Information Access and Audit Rights

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is

necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Transmission Provider's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Provider's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to either Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Provider be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes

27.1 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on

the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

Article 28. Representations, Warranties, and Covenants

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located**;** and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 **No Conflict.** The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 **Consent and Approval.** Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 **Joint Operating Committee.** Except in the case of ISOs and RTOs, Transmission Provider shall constitute a Joint Operating Committee to coordinate operating and technical considerations of Interconnection Service. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Interconnection Customer shall notify Transmission Provider of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this LGIA. Each Party shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Large Generating Facility and other facilities that impact the normal operation of the interconnection of the Large Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect. This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such

Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement. This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this LGIA.

30.5 No Third Party Beneficiaries. This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have executed this LGIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: _____ By: _____

Title: _____ Title: _____

Date: _____ Date: _____

[Insert name of Interconnection Customer]

By: _____

Title: _____

Date: _____

Appendix A to LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. **Interconnection Facilities:**

   (a) [insert Interconnection Customer's Interconnection Facilities]:

   (b) [insert Transmission Provider's Interconnection Facilities]:

2. **Network Upgrades:**

   (a) [insert Stand Alone Network Upgrades]:

   (b) [insert Substation Network Upgrades]:

   (c) [insert System Network Upgrades]:

3. **Distribution Upgrades:**

Appendix B to LGIA

Milestones

Site Control

Check box if applicable [ ]

Interconnection Customer with qualifying regulatory limitations must demonstrate 100% Site Control by {Transmission Provider to insert date one hundred eighty (180) Calendar Days from the effective date of this LGIA} or the LGIA may be terminated per Article 17 (Default) of this LGIA and Interconnection Customer may be subject to Withdrawal Penalties per Section 3.7.1.1 of Transmission Provider's LGIP (Calculation of the Withdrawal Penalty).

Appendix C to LGIA

Interconnection Details

Appendix D to LGIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Appendix E to LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between Transmission Provider and Interconnection Customer.

[Date]

[Transmission Provider Address]

Re: _____ Large Generating Facility

Dear _____:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. ___. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Large Generating Facility, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Appendix F to LGIA

Addresses for Delivery of Notices and Billings

Notices:.

Transmission Provider:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Billings and Payments:

Transmission Provider:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

APPENDIX G

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Appendix G sets forth requirements and provisions specific to a wind generating plant or a Generating Facility that contains a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer(i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static

VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall

remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAR Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. <u>Power Factor Design Criteria (Reactive Power)</u>

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a Facilities Study Agreement as of the effective date of the Final Rule establishing the reactive power requirements for non-synchronous generators in article 9.6.1 of this LGIA (Order No. 827). A wind generating plant to which this provision applies shall maintain a power factor within the range of 0.95

leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's Cluster Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability 606 (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Cluster Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from Transmission Provider to protect system reliability. Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Appendix H to LGIA

Operating Assumptions for Generating Facility

Check box if applicable [ ]

Operating Assumptions:

[insert operating assumptions that reflect the charging behavior of the Generating Facility that includes at least one electric storage resource]

Request IR-24:

Reference: N-01, Application, Attachment 1, Concentric Evidence, pages 13-16 (pdf pages 53-55).

Preamble: Concentric provides its opinion in relation to what "Good Utility Practice" consists of in relation to maintenance of generation and transmission assets and confirms that both planned and unplanned outages can be part of good utility practice.

(a) Please confirm whether, in Concentric's view, the following factors are relevant considerations in evaluating whether a planned outage falls within Good Utility Practice:

(i) **The adequacy of planning and coordination in advance of the outage, including the timing and sufficiency of outage requests filed with the applicable system operator, and whether the minimum 30-day coordination period was observed;**

(ii) **The selection of outage timing, including whether the outage was scheduled to minimize system impact and replacement energy costs, and whether alternative timing was considered;**

(iii) **The nature of the work scope performed during the outage — specifically, whether the work constituted preventive maintenance, corrective maintenance arising from known deficiencies, residual commissioning or early-operation corrective work, or reliability enhancements — and whether each work item reasonably required a full bipole outage;**

(iv) **Whether the outage was taken on schedule or was deferred from an earlier planned date, and if deferred, whether the deferral contributed to a longer or more extensive outage than would otherwise have been required; and**

(v) **Whether the planned duration of the outage was reasonable in light of the work scope, and whether any extensions to the outage duration were justified by conditions discovered during the outage, with appropriate documentation supporting the decision-making at the time.**

(b) Please identify any other factors that Concentric considers relevant to the evaluation of whether a planned outage falls within Good Utility Practice, within the context of this Application.

(c) Please confirm whether, in Concentric's view, the following factors are relevant considerations in evaluating whether an unplanned outage falls within Good Utility Practice:

(i) **Whether an appropriate preventive maintenance program, inspection schedule, and condition monitoring**

regime existed for the affected assets and was consistently adhered to prior to the failure;

(ii) **Whether there were any known deficiencies, deferred maintenance items, or prior failure events relating to the affected equipment that were outstanding at the time of the failure, including any items documented in commissioning punch lists, failure investigation reports, or corrective action plans;**

(iii) **Whether the design standards and material specifications of the affected equipment were appropriate for the climatic conditions and geographic location of the assets, including compliance with applicable Canadian Standards Association (CSA) or equivalent standards at the time of construction and commissioning; and**

(iv) **Whether the protective and operating actions taken in response to the unplanned event (including trips, deratings, and isolation) were consistent with Good Utility Practice and applicable reliability standards.**

(d) Please identify any other factors that Concentric considers relevant to the evaluation of whether an unplanned outage falls within Good Utility Practice, including what contemporaneous documentation Concentric would expect to exist to support such a determination.

Response IR-24:

a) Yes. While every situation must be assessed based on individual circumstances, in Concentric's view, the factors listed in subparts (i) through (v) are relevant considerations in evaluating whether a planned outage falls within good utility practice. Concentric's evidence shows that planned outages consistent with good utility practice are prudently coordinated in advance with system operators, scheduled during periods of lower system need and generally lower replacement energy costs, and undertaken for preventive, corrective, testing, or reliability-related work reasonably tied to maintaining reliable service. Concentric did not, however, present these factors as an exhaustive checklist or opine separately on every sub-element identified in the interrogatory, such as whether each individual work item independently required a full bipole outage or whether specific extensions were supported by particular documentation.

b) In addition to the factors identified in part (a), Concentric considers the following additional factors to be relevant in evaluating whether a planned outage falls within good utility practice:

- Consistency with reliability objectives - whether the outage was undertaken to maintain or enhance the safe and reliable operation of the bulk power system, including addressing identified deficiencies, implementing necessary updates, or completing preventative maintenance required for continued asset performance.
- Regional system operator coordination and system needs - whether the outage was coordinated with the relevant system operators and scheduled at times when the associated facilities were not required to maintain reliable service, reflecting broader system conditions rather than solely asset-specific considerations.

- Minimization of customer and system impacts - whether the outage was planned and executed in a manner intended to minimize impacts on customers, including avoiding periods of peak demand and limiting exposure to higher replacement energy costs.
- Nature of the assets and operational complexity - recognition that complex, large-scale transmission assets require periodic planned outages as part of normal operations, particularly in early years following commissioning or during primary maintenance cycles.
- Prudent operational judgment at the time. Whether decisions regarding the outage were made based on reasonable engineering and operational judgment in light of the information available at the time, rather than through hindsight evaluation.

Concentric's evidence reflects that these considerations, taken together, inform whether a planned outage is consistent with good utility practice, and that no single factor is determinative in isolation.

c) Yes, in Concentric's view, the factors identified in subparts (i) through (iv) can be relevant considerations in evaluating whether an unplanned outage falls within good utility practice. However, consistent with Concentric's evidence, these factors are not applied as a rigid checklist and must be considered in the context of the specific facts and circumstances, including the nature of the assets and the conditions at the time of the event.

d) In addition to the factors identified in part (c), Concentric considers the following additional factors to be relevant in evaluating whether an unplanned outage falls within good utility practice:

- Nature and foreseeability of the event - whether the outage was caused by conditions reasonably within utility control (e.g. maintenance) versus external

or exceptional events (e.g. extreme weather) that may exceed design assumptions and occur despite prudent practices.

- Timeliness and appropriateness of response and restoration - whether the utility acted promptly to diagnose the issue, restore service (including interim configurations such as monopole operation where applicable), and implement repairs in a manner consistent with maintaining system reliability.
- Coordination with system operators during the event - whether actions taken during and after the outage were coordinated with system operators to ensure reliable system operation and appropriate use of alternative resources.
- Impact on system reliability and customers: whether the outage and the response actions avoided or minimized broader system reliability impacts, including customer outages, consistent with prudent utility operation.
- Timely redelivery of energy consistent with contractual obligations - whether any delivery shortfalls resulting from the outage were subsequently redelivered in accordance with the governing agreements, consistent with normal utility and commercial practice.
- Post-event evaluation and corrective actions - whether the utility undertook appropriate root cause analysis and implemented corrective actions, where necessary, to support future reliability and performance.

Concentric's evidence reflects that these considerations, taken together, inform whether an unplanned outage is consistent with good utility practice, and that no single factor is determinative in isolation.

CONFIDENTIAL (Attachment Only)

Request IR-25:

Reference: N-01, Application, Attachment 1, Concentric Evidence.

Preamble: In responding to Q38, Concentric relies on NERC outage statistics and HVDC benchmarking to support the view that outages are normal and planned outages should be expected annually.

(a) Provide copies of all benchmarking sources relied on (including the specific NERC/IEEE references cited) and the portions relied upon.

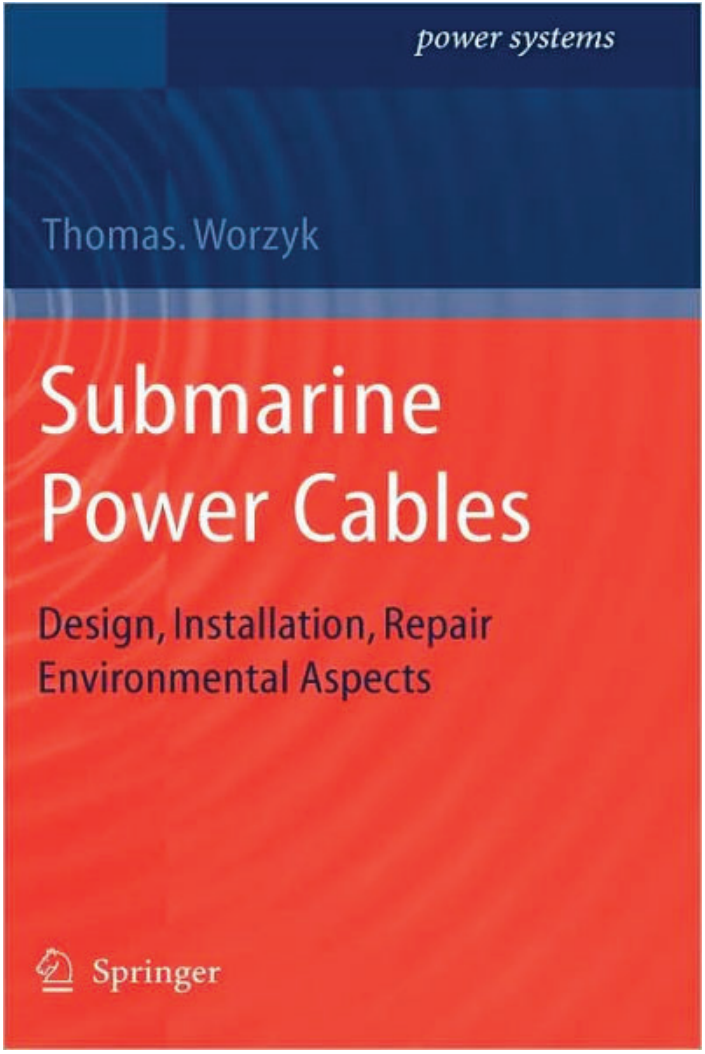
(b) Explain how these benchmarks are relevant to the Board's monthly performance threshold for NS Block deliveries, as distinct from general asset reliability.

Response IR-25:

a) Please refer to Confidential Attachment 1 (in particular Part III) and Attachment 2 (in particular section 9.2).

b) The cited benchmarks are relevant because they support Concentric's opinion that planned outages are a normal and expected aspect of operating complex transmission assets and that the monthly threshold should be applied with allowance for outages attributable to good utility practice.

IG IR-25 Attachment 1
has been removed due to confidentiality


power systems
Thomas. Worzyk
Submarine
Power Cables
Design, Installation, Repair
Environmental Aspects
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Thomas Worzyk

Submarine Power Cables

Design, Installation, Repair, Environmental Aspects

Springer

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Preface

Submarine power cables have always been the unknown cousins of the submarine telecom cables. Telecom cables encircle the globe through all oceans in an enormous mesh, and have attracted public attention since the first Channel cable was laid in 1850. While the heroes of the first Atlantic telecom cable have been sung in numerous books, the feats of submarine power cable technology were rarely respected outside a small community.

However, submarine power cables have their own characteristics and peculiarities. Cable design has developed during the decades. The evolution of manufacturing and installation technology allows for projects that, 20 years ago, were considered impossible. New performance records in system length, water depth, transmission power, or profits from the operation of submarine power cables are set every few years. Owing to this development, more submarine power cable projects are economically viable, or even possible. New applications for submarine power cables appear while known applications are pursued on a larger scale.

Submarine power cables draw the attention of larger circles. Ten years ago only power utility engineers and cable ship crews were interested in submarine power cables. Possibly some fishermen uttered unprintable comments on them when they had entangled their fishing gear. Today, in the wake of new applications, submarine power cables have come into the focus of larger groups. The engineers of oil-and-gas companies have been interested a while, and increasing offshore activities, as well as the need for more power supply from shore to platform have promoted their involvement in the field. Most of all the fast development of offshore wind power brought submarine power cables to the attention of new quarters outside the power utilities. Investors and project developers need knowledge on the subject in order to analyse the technical and economical feasibility of offshore wind farms, as the cable costs can make up to forty per cent of the project costs, and cable installation can have a substantial impact on the overall schedule. Great commercial opportunities in power trading triggered the curiosity of Transmission System Operators (TSO) and power traders about opportunities and limitations of submarine power transmission lines. Regulators and authorities are getting more involved into submarine power cables, as permit applications continue to roll in. Also environmental groups and organisations now have to deal with submarine power cables, which sometimes are installed in sensitive areas. Satisfying enough, more students of all levels are

getting involved into submarine power transmission as they study the possibilities of renewables. Even lawyers have developed an occupational interest in these cables.

The idea to prepare this book actually came when I received many questions from the new audience, which demonstrated that there was need for a comprehensive introduction into the matter. For those who want to dig deeper into the issue it is not always easy to find relevant information. Much needed information about design and installation is scarce. Most textbooks on cables deal with land cables and leave only little space to submarine power cables, sometimes relegating them into their "Miscellaneous" chapter. Other cable textbooks are simply outdated neglecting state-of-the-art manufacturing and installation techniques.

When I put this book together, I had to face several difficulties. Evaluating published reports and peer discussions, it became clear that the willingness for sharing experiences has decreased strongly. Information on submarine power cable operations have been shared in journal papers quite openly until the 1990s, while reports about recent projects rarely address "lessons learned". At a time when investor relations, quarterly reports, and insurance issues prevail, few cable operators like to go public with accounts of detailed technical issues, problems, and fixes. However, the entire community of investors, grid operators, manufacturers, installers etc. would profit from an openhearted dialogue.

This book aims at conveying a basic knowledge on the design, manufacture, and installation of submarine power cables. In 1903, cable engineer Dr. C. Baur wrote in the preface to his cable book: "the amount of knowledge related to the electric cable is so large that no single man can comprehend it". This must be even more correct for submarine power cables. I must most humbly admit that I could only grasp and compile a fraction of the knowledge on the subject, relying on the assistance and help of many colleagues. For those who want to go further the reference lists may be helpful.

I owe a lot of gratitude to those who assisted in the development of this book. Most of all, at this prominent place of the book, I want to take the opportunity to thank my dear wife for her enormous patience and my sons for their valuable input from their point of view.

Acknowledgments

I am indebted to many people and companies who helped me to bring this book on its way and into a reasonable form. I want to make a point of thanking all of them at this occasion.

Although the production of this book was my private adventure, my employer ABB/Sweden provided me with a grant for literature and xerox copies. My colleagues let me participate in their enormous and priceless knowledge and experience, just to contribute to this book. Peter Sunnegardh, Anders Gustafsson and Johan Karlstrand supported me with their most valuable comments.

Other cable manufactures gave me indepth information. I want to express my gratitude to Prysmian/Italy, Norddeutsche Seekabelwerke NSW/Germany and NKT Cables/Denmark for their generous assistance.

The power utilities Statnett/Norway, Long Island Power Authority/USA, and Baltic Cable/Sweden contributed with information on cable service experiences and other. HT Suen, John Savio and Jan Brewitz were ever so cooperative.

A book cannot be completed without the involvement of certain individuals who are conducive with illustrations, knowledge, anecdotes, good advice, or something else – or a bit of all of this. I would like to thank Lars Aksel Solberg and Janne Stark for a good story, Bill Burns for background info, Walter Paul and Jaeyoung (Jay) Lee for most interesting facts.

Lydia Stark and Stephen Wigginton helped me to improve the writing language.

The challenging task of transforming my writing into readable English was performed by Jochen U. Frankl, of Keryx Translations/Germany.

A number of other companies helped me out with much needed photographs. Commercial and non-commercial marine organisations, from all around the world, have played a decisive role in the improvement of this book. The list is here:

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Contents

1 Applications of Submarine Power Cables 1
1.1 Power Supply to Islands 1
1.2 Connection of Autonomous Grids 3
1.3 Offshore Wind Farms 4
1.4 Supply of Marine Platforms 5
1.5 Short-Haul Crossings 6
1.6 Other Applications of Submarine Power Cables 6
References 7

2 Submarine Power Cables and Their Design Elements 9
2.1 The Conductor 10
2.1.1 Solid Conductor 10
2.1.2 Conductors Stranded from Round Wires 11
2.1.3 Profiled Wire Conductors 12
2.1.4 Hollow Conductors for Oil-Filled Cables 13
2.1.5 Milliken Conductor 13
2.1.6 Conductor Resistance 15
2.1.7 Watertightness of Conductors 16
2.1.8 Superconducting Conductors 16
2.2 The Insulation System 17
2.2.1 Polyethylene 17
2.2.2 Cross-Linked Polyethylene 18
2.2.3 Conductor and Insulation Screen 19
2.2.4 The Influence of Ageing and Humidity on XLPE Insulation 20
2.2.5 Applications of XLPE Insulation 22
2.2.6 Extruded HVDC Cables 22
2.2.7 Other Extruded Insulation Systems 23
2.2.8 Paper-Insulated Oil-Filled Cables for a.c. or d.c. 23
2.2.9 Paper-Mass Insulation for HVDC 26
2.2.10 Gas-Filled Submarine Cables 28
2.2.11 Other Insulation Systems 29
2.3 The Water-Blocking Sheath 30

2.3.1 Lead Sheath . . . 30
2.3.2 Aluminium Sheath . . . 32
2.3.3 Copper Sheath . . . 32
2.3.4 Polymeric Sheaths . . . 33
2.4 Armoring . . . 33
2.4.1 Corrosion Protection . . . 37
2.5 Outer Serving . . . 39
2.6 Three-Core Cables . . . 40
2.6.1 Choice Between One Three-Core and Three Single-Core Cables . . . 42
2.7 Two-Core Cables . . . 43
2.8 Coaxial Cables . . . 44
2.9 Optical Fibres Inside Submarine Power Cables . . . 45
2.10 Five Generic Cable Types . . . 47
References . . . 48

3 Design . . . 51
3.1 Thermal Design . . . 51
3.1.1 Single-Core HVDC Cables . . . 52
3.1.2 a.c. Cables . . . 59
3.1.3 Other Factors for the Thermal Design . . . 64
3.1.4 The 2 K Criterion . . . 73
3.1.5 Economic Aspects of the Thermal Design . . . 75
3.2 Design of Mechanical Properties . . . 78
3.2.1 Tensional Forces During Laying . . . 79
3.2.2 The Cigré Test Recommendation . . . 81
3.2.3 Distribution of Mechanical Stress Between Conductor and Armoring . . . 83
3.2.4 Other Forces and Impacts . . . 85
3.2.5 Vortex Induced Vibrations . . . 88
3.3 Electric Design . . . 90
3.3.1 The Concept of Electric Strength . . . 90
3.3.2 The Weibull Distribution . . . 91
3.3.3 Dielectric Design of a.c. Cables . . . 94
3.3.4 Dielectric Design of d.c. Cables . . . 97
3.3.5 Dielectric Design of Mass-Impregnated Cables . . . 100
3.3.6 Impulse Stress . . . 101
3.3.7 Availability and Reliability . . . 102
References . . . 103

4 Accessories . . . 105
4.1 Submarine Cable Joints . . . 105
4.1.1 Factory Joints . . . 106
4.1.2 Offshore Installation Joints . . . 108
4.1.3 Miscellaneous Joint Designs . . . 113
4.1.4 Beach Joints . . . 114

4.2 Cable Terminations . . . 116
4.2.1 On-Shore a.c. Cable Terminations . . . 116
4.2.2 On-Shore d.c. Cable Terminations . . . 116
4.2.3 Offshore Cable Terminations . . . 118
4.3 Other Accessories . . . 118
4.3.1 J-Tubes . . . 118
4.3.2 Hang-Off . . . 119
4.3.3 Bending Protection . . . 120
4.3.4 Holding Devices . . . 120
References . . . 120

5 Manufacturing and Testing . . . 123
5.1 Manufacturing . . . 123
5.1.1 The Conductor . . . 124
5.1.2 XLPE Cables . . . 125
5.1.3 Paper-Insulated Cables . . . 126
5.1.4 Sheathing . . . 129
5.1.5 Lay-up . . . 130
5.1.6 Armoring . . . 131
5.1.7 Storage of Submarine Cables . . . 134
5.2 Testing . . . 136
5.2.1 Development Tests . . . 136
5.2.2 Type Tests . . . 137
5.2.3 Routine Tests . . . 144
5.2.4 Factory Acceptance Tests (FAT) . . . 145
5.2.5 After-Installation Test . . . 146
5.2.6 Non-electrical Tests . . . 148
References . . . 148

6 Marine Survey . . . 151
6.1 Scope of the Marine Survey . . . 152
6.2 Bathymetry . . . 153
6.3 Sub-bottom Profiling . . . 156
6.4 Visual Inspection . . . 157
6.5 Soil Sampling . . . 157
6.6 Soil and Water Temperatures . . . 158
References . . . 159

7 Installation and Protection of Submarine Power Cables . . . 161
7.1 Installation . . . 161
7.1.1 Cable Laying Vessels . . . 162
7.1.2 Other Vessels . . . 171
7.1.3 Loading and Logistics . . . 173
7.1.4 Laying of Submarine Power Cables . . . 174
7.1.5 Landing of Submarine Cables . . . 177

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 11 of 306

7.1.6 Jointing of Submarine Power Cables . . . 181
7.1.7 Weather . . . 186
7.1.8 Organisation . . . 193
7.2 Protection of Submarine Power Cables . . . 194
7.2.1 Selection of a Suitable Cable Route . . . 195
7.2.2 Design of a Suitable Cable Armoring . . . 196
7.2.3 External Protection . . . 198
7.2.4 After-Installation Protection . . . 205
7.3 Appendix: The Catenary Line . . . 206
References . . . 208

8 Damages and Repair . . . 211
8.1 Damages . . . 211
8.1.1 Causes of Damages . . . 212
8.1.2 Statistic Distribution of Damages . . . 213
8.1.3 Damage by Fishing Equipment . . . 213
8.1.4 Damage by Anchors . . . 215
8.1.5 Damage During the Installation . . . 218
8.1.6 Other Damage . . . 219
8.1.7 Spontaneous Damage . . . 220
8.1.8 Failures of Joints . . . 221
8.2 Repair . . . 222
8.2.1 Spare Cable . . . 222
8.2.2 Repair Vessel . . . 223
8.2.3 Repair Crew . . . 223
8.2.4 Repair Operation . . . 224
8.3 Fault Location . . . 225
8.3.1 TDR . . . 225
8.3.2 Bridge Measurements . . . 228
8.3.3 Fine Localisation . . . 229
8.3.4 Optical Time Domain Reflectrometry . . . 230
8.3.5 Other Methods . . . 231
8.4 Repair Example . . . 232
References . . . 235

9 Operation and Maintenance: Reliability . . . 237
9.1 Operation of Submarine Cables . . . 237
9.1.1 Common Measures for All Kind of Submarine Power Cables . . . 237
9.1.2 Instrumentation . . . 238
9.1.3 Mass-Impregnated Cables and XLPE Cables . . . 240
9.1.4 LPOF, SCOF and SCFF Cables . . . 240
9.1.5 Cable Terminations . . . 241
9.2 Reliability of Submarine Cables . . . 241
9.2.1 The Cigré Studies . . . 241

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 12 of 306

9.2.2 Failure Statistics for Large HVDC Cable Projects 242
9.2.3 Definition of Reliability Terms 244
9.2.4 Reliability of Some Specific Submarine Power Cables . . 244
References 247

10 Environmental Issues 249
10.1 Environmental Assessment 249
10.2 The Influence of Cable Losses 251
10.3 Environmental Aspects Related to Cable Design 252
10.3.1 Conductor Materials 252
10.3.2 Choice of Other Cable Materials 252
10.4 Environmental Aspects of Cable Installation 255
10.5 Environmental Impacts from the Operation of Submarine Power Cables 258
10.5.1 Thermal Impact 258
10.5.2 The 2 k Criterion 258
10.5.3 Electromagnetic Impact 261
10.5.4 Chemical Impact 266
10.6 Recycling of Submarine Power Cables 266
References 267

11 Anecdotes 269
11.1 The Floating Hospital S/S Castalia 270
11.2 HVDC Cable Between Lydd, UK and Boulogne, F 270
11.3 The Pilot 271
11.4 S-Lay and Coiling Direction 271
11.5 Edible Insulation 273
11.6 Flipper 273
11.7 Stamps 274
11.8 Unusual Cable Ships 274
11.9 Master Teredo 276
11.10 Krauts at War Searching for a Cable Break 276
11.11 Even More Damages 277
11.12 Loops 277
11.13 Cable Ship Reefs 277
11.14 Poetry 278
11.14.1 The Journey of Mrs. Florence Kimball Russel 279
References 280

12 Useful Tables 281
12.1 Dielectric Properties of Cable Insulation Material 281
12.2 Lead Alloys 282
12.3 Non-metric Conductor Size: kcmil 283
12.4 Non-metric Wire Diameter 283
12.5 The Galvanic Series of Metals and Alloys in Seawater 285

12.6 Classification of Submarine Soil in Different Countries 286
12.7 Non-metric Units 287
12.8 Tidal Terms 288
References 288

Index 289

About the Author

Thomas Worzyk, born in Germany in 1957, received his M.Sc. degree in Physics from the Leibniz Universität Hannover, Germany in 1983. He joined one of the largest electric power product companies in Sweden, in 1984. After some years in the circuit-breaker R&D department, he moved on into the field of high-voltage cables, when a new cable factory was set up in the town of Karlskrona, Sweden.

Worzyk has acquired a deep knowledge in research and design aspects of power cables, especially submarine. He has been the Chief Engineer in several large cable projects, both underground and submarine. He spent almost a decade with the development and implementation of the longest power cable link of all classes, which was inaugurated in 2008.

During the work with this book, Worzyk has discovered his inclination to the history of submarine power cables. “From history, we sometimes can learn things cheaper and faster than from research projects,” he concludes.

Worzyk has published a number of journal articles and is holder of patents in his field.

Abbreviations

3C	Three-Core Cable
1C	Single-Core Cable
AHT	Anchor Handling Tug
AIS	Automatic Identification System
CDVC	Cable Depending Voltage Control
Cigré	Conseil International Des Grands Réseaux Électriques
CLPS	Cable Load Prediction System
DTS	a) Distributed Temperature Measurement System b) Desktop Study
EIA	Environmental Impact Assessment
GIL	Gas Insulated (Transmission) Line
GIS	Gas Insulated Switchgear
IEC	International Electrical Committee
LCA	Life Cycle Assessment
LIWL	Lightning Impulse Withstand Level
LPOF	Low Pressure Oil Filled
MBR	Minimum Bending Radius
MI	Mass-Impregnated
OTDR	Optical Time Domain Reflectometry
OWP	Offshore Wind Park
PD	Partial Discharge
PLGR	Pre-Lay Grapnel Run
ROV	Remote Operated Vehicle
RTTR	Real Time Thermal Rating
SC	Single-Core Cable
SCADA	Supervisory Control And Data Aquisition
SCFF	Self-Contained Fluid Filled
SCOF	Self-Contained Oil Filled
SIWL	Switching Impulse Withstand Level
STRI	Swedish Transmission Research Institute
TD	Touch Down
TDR	Time Domain Reflectometry
TSO	Transmission System Operator
VIV	Vortex Induced Vibration
VMS	Vessel Monitoring System
WTG	Wind Turbine Generator
XLPE	Cross-Linked Polyethylene

Chapter 1
Applications of Submarine Power Cables

Contents

1.1 Power Supply to Islands 1
1.2 Connection of Autonomous Grids 3
1.3 Offshore Wind Farms 4
1.4 Supply of Marine Platforms 5
1.5 Short-Haul Crossings 6
1.6 Other Applications of Submarine Power Cables 6
References 7

Submarine power cables have been around for more than a century and the major use has shifted through the decades. In the early times, submarine power cables were used to supply isolated offshore facilities such as lighthouses, infirmary ships, etc. Later, the power supply of near-shore islands was the main objective of submarine power cables. The connection of autonomous power grids for the sake of better stability and resource utilisation has been pursued since the sixties of the last century. In modern days, the connection of offshore facilities is again in the focus. Oil and gas production units ask for shore-generated power, while offshore wind parks (OWP) need to bring their precious green power to the onshore grids.

1.1 Power Supply to Islands

Islands located closely to the mainland can be connected to the mainland grid by submarine power cables. This is normally done with medium-voltage a.c. cables ($\leq$52 kV) and a transmission power of 10–30 MW per cable. The submarine power cables replace island-stationed, often-inefficient power generation such as diesel generators. The maximum economic length of these cables is 10–30 km. In response to increased power demand of the island, additional cables are often laid in different routes to reduce risks and increase the power availability on the island. The island supply can be secured by other cables even in the case of a cable failure. The archipelago of the North Frisian Islands in Northern Germany was connected to

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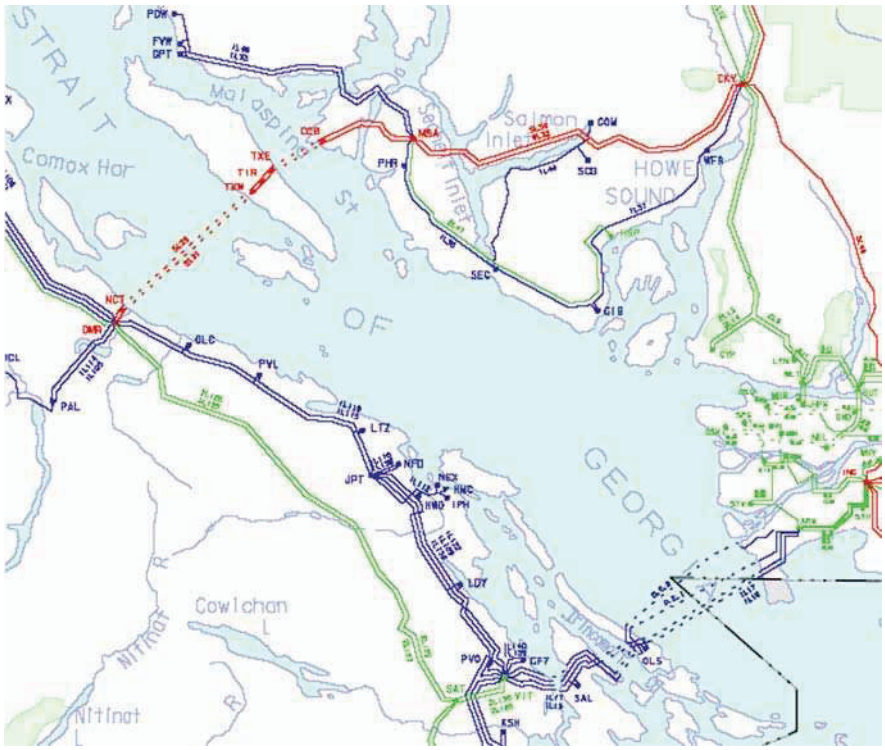


Fig. 1.1 Submarine power cables supplying Vancouver Island, Canada. The island (*down left*) was first connected to the mainland (*upper right*) with a 138 kV system (*down right*). Increasing power demand necessitated more cable systems, both a.c. and d.c. [2]

the mainland by a grid of 20 kV submarine cables starting in 1944 [1]. Other islands like Vancouver Island, Canada, and Long Island, NY, USA, have a large population and massive power demands requiring a number of extra high voltage submarine power cables circuits (Fig. 1.1).

The supply of distant islands is difficult as losses in a.c. cables increase dramatically with distance. Islands located more than 50 km from the mainland have not been connected for a long time. The German tourist island of Heligoland will be connected to the mainland only later this year (2009). The Swedish island of Gotland is some 100 km off the Swedish mainland and had to rely on inefficient diesel power generation for a long time. The island wasn't connected to the mainland grid until 1954, when the first submarine HVDC cable was installed. The canal islands of Jersey and Guernsey were connected to the French mainland in 1987 and again 2000, and the Italian islands of Sicily and Sardinia were connected to the Italian mainland by submarine power cables.

Islands with an autonomous power supply are sometimes connected to the mainland or neighbour islands in order to increase the power availability. The submarine

cable has the function of a spare power plant providing emergency power in case of a local generator outage.

Owing to the geographical character, some countries, such as Norway, the Philippines, Japan, and other countries, have a long tradition of installing submarine power cables between their numerous islands.

1.2 Connection of Autonomous Grids

Since the advent of powerful submarine cables many grids have been interconnected, using different techniques. Submarine cables connect grids of different countries (To name a few: UK – France, Sweden – Germany, Denmark – Sweden, Morocco – Spain, Greece – Italy). Using HVDC techniques, regions with different frequency control can be linked (Store Belt in Denmark, Sweden – Germany, Norway – the Netherlands). In the mentioned cases, both sides have a 50 Hz grid but the frequency is controlled in different ways, rendering asynchronous grids. The interconnection of national grids is a prime objective of the European Community.

The connection of autonomous grids can have various purposes and objectives:

- The load peaks of the connected countries/grids occur at different times of the day due to different time zones or due to different habits of electricity use. With the submarine cable transmission it is possible to share generation capacities to meet the power demand.
- The connected countries/grids may have different electricity generation mixes with differences in availability and pricing patterns. Many HVDC cables connect the NordEl grid system with its abundant hydropower to the European continental power grid (UCTE), which mostly relies on fossil and nuclear power. “Green power” can be traded across borders.
- Each power grid needs a certain amount of “spinning reserve”, that is generation capacity that can be switched to the grid within minutes. Traditionally, generators (hydro or thermal) provide spinning reserve while running idly. It is obvious that a submarine power cable making a connection to another grid is a more efficient and maintenance-free spinning reserve, which can be used to dispatch power flow in either direction within minutes.
- Since the deregulation of the power markets, the pricing pattern is highly volatile. Power traders can use submarine power cables to earn money by exploiting the price difference in the connected countries/grids. Sometimes they change the direction of power flow several times a day responding to the price fluctuations [3].

Submarine HVDC power cables of extreme length have been used to connect distant autonomous grids: The longest existing HVDC submarine cable system is a pair of 580 km cables (NorNed), and a number of 200+ km systems are in successful operation (Baltic Cable, Swepol, Bass Link) or under construction (BritNed, SAPEI).

1.3 Offshore Wind Farms

Offshore wind farms (OWP) consists of a number of wind turbine generators (WTG). The distance between the WTGs is 300–800 m. A grid of submarine cables interconnects the WTG and bring the power to shore. The in-field cables are three-phase medium-voltage cables (10–36 kV) with polymeric insulation. The connection to shore can be achieved with medium-voltage cables for distances up to about 10 km.

For OWP with many turbines, large output power, or large distance to the shore, the losses in a medium voltage transmission to land would be quite high and a high-voltage connection to land would be more economic. In larger offshore parks the WTG are connected to an offshore platform that carries a step-up transformer. From the transformer platform, a submarine power cable (export cable) sends the power to shore. Three-phase cables with >100 kV operating voltage serve most often as export cables for distances exceeding 30 km (Fig. 1.2).

Export cables may also operate with HVDC, which requires converter stations both offshore and onshore. The erection of an offshore converter station on a platform is expensive and can be motivated only when large amounts of power must be transmitted over a long distance.

The use of a.c. frequencies lower than 50 Hz for WTG has been considered, in order to reduce capacitive losses in the cables, and mechanical requirements for the WTGs.

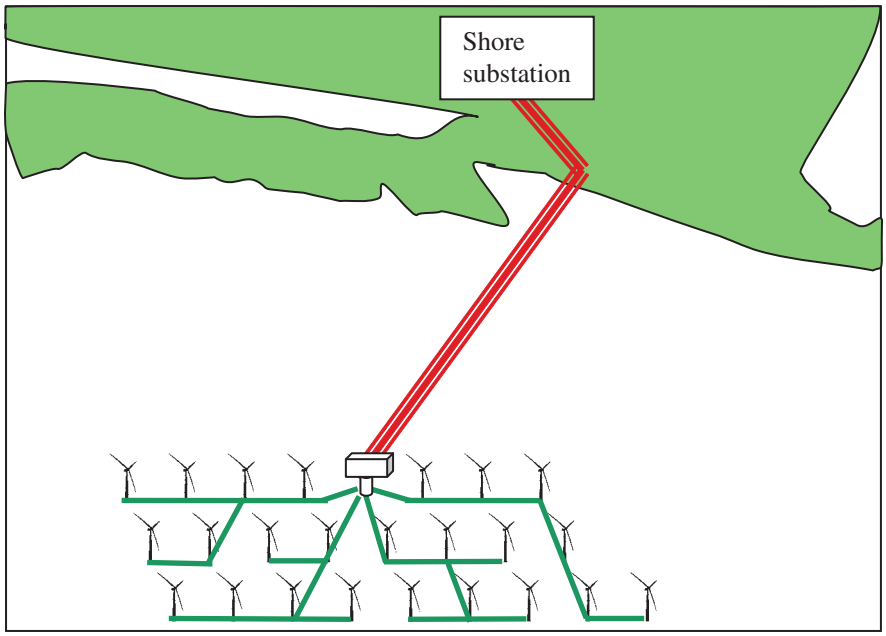


Fig. 1.2 Layout of an offshore wind farm with 34.5 kV in-field cables and 138 kV export cable between the OWP and the shore line

1.4 Supply of Marine Platforms

Production platforms in the offshore oil and gas business have a large power demand to extract hydrocarbons from wells. Energy use covers a range of activities including driving pumps to extract hydrocarbons and to re-inject water for enhanced oil recovery, heating the output stream to allow separation of the oil, gas and water, powering compressors and pumps for transporting oil and gas through pipelines to processing plants or to shore, and supply of the electricity needed for on-site operations and living quarters.

Energy needs vary widely according to local circumstances and operational conditions. The electric power for many platforms is generated from locally produced gas in steam plants or gas turbines at rather low efficiency. The power plants require precious space while their operation and maintenance staff needs additional accommodation and transport. All this makes the onboard power production expensive. As the power need increases, it becomes viable to connect the platform to onshore grids by submarine power cables.

In Norway, the offshore industry produced a quarter of the country's total CO_2 emission in 2006. As Norway has vast resources of hydropower, there is a large potential to reduce the country's CO_2 emission by connecting platforms to the onshore grid (Fig. 1.3).



Fig. 1.3 The Norwegian gas platform "Troll A" receives its electric power supply from a pair of HVDC cables (Courtesy of ABB, Sweden)

For these reasons, an increasing number of platform operators invest in submarine power cables for the power supply of offshore platforms. The supply of floating platforms is a special challenge as the repeated movements, induced by wind and waves, require certain design considerations.

1.5 Short-Haul Crossings

Hundreds of submarine power cables have been installed to transport power across rivers, channels, straits, fjords, or bays. Though overhead lines can be used for crossings up to 3 km (e.g. Messina Strait, Italy) in many cases submarine cables have been chosen instead of overhead lines. The invisibility of cables is important in tourist resorts and natural resources. Allegedly, for the crossing of a 500 kV d.c. power transmission over the St. Lawrence River, Canada, a 5.1 km submarine cable system was used to avoid optical impact. Cables do not restrict the height of ships passing the river or strait. The overhead lines over the Ems River in Germany have to be shut down each time when an upstream shipyard transports its new mega-size cruising ships to the North Sea. When the lines were switched off the grid in 2006 for the passage of the "M/S Norwegian Star" a galloping instability blacked out millions of households in Europe. Sub-river cables have been discussed for this river crossing but were not yet realized.

Also the lifetime costs of a maintenance-free cable can be lower than that of an overhead line threatened by storms, salt and ice deposition, etc.

In short-haul applications, submarine cables with very high voltage can be used when no joints are required. Often cables are available at higher voltages than the corresponding joints.

Crossings of some 1400–1800 m can be realized with trenchless horizontal directional drilling methods from the shoreline. The bore is lined with pipes and the cables would simply be pulled through the pipes. Longer crossings would require ordinary submarine cable laying techniques.

1.6 Other Applications of Submarine Power Cables

There are many niche applications of submarine power cables that cannot be covered in this book. The submarine cables used here are in the medium-voltage or low-voltage range. Here are mentioned a few:

Oil and gas production cables. As production wells are established in ever larger depths of water, more sophisticated equipment such as submersible pumps and compressors of all kind is placed on the seafloor. Figure 1.4 illustrates different oil and gas installations all requiring submarine power cables.

Umbilicals are armoured flexible assemblies containing anything from power cable cores, signal cables, fluid conduits, hydraulic lines etc in the same

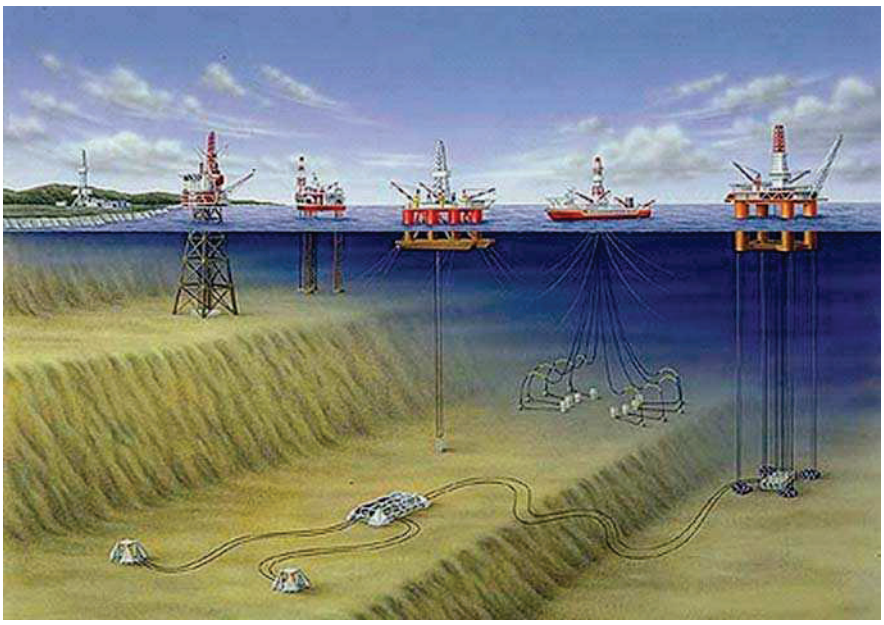


Fig. 1.4 Various oil and gas installations requiring submarine power cables. (Courtesy of Minerals Management Service, US Department of the Interior, www.mms.gov)

cable. They serve oil and gas equipment on the seafloor and remotely operated subsea vehicles (ROV).

Pipeline heating cables. Submarine pipelines sometimes need electric heating to prevent the formation of wax and hydrate deposits. The pipe itself is used as the heating element, and the power supply is accomplished by XLPE-insulated power cables with large conductor size and without metallic water barrier [4].

Subsea observatories. Tsunami pre-warning systems and military reconnaissance arrays require underwater power. The increasing focus on oceanographic research has triggered the installation of subsea automatic research stations to collect data. All these must have reliable submarine power supply [5].

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Chapter 2
Submarine Power Cables and Their Design Elements

Contents

2.1 The Conductor 10
2.1.1 Solid Conductor 10
2.1.2 Conductors Stranded from Round Wires 11
2.1.3 Profiled Wire Conductors 12
2.1.4 Hollow Conductors for Oil-Filled Cables 13
2.1.5 Milliken Conductor 13
2.1.6 Conductor Resistance 15
2.1.7 Watertightness of Conductors 16
2.1.8 Superconducting Conductors 16
2.2 The Insulation System 17
2.2.1 Polyethylene 17
2.2.2 Cross-Linked Polyethylene 18
2.2.3 Conductor and Insulation Screen 19
2.2.4 The Influence of Ageing and Humidity on XLPE Insulation 20
2.2.5 Applications of XLPE Insulation 22
2.2.6 Extruded HVDC Cables 22
2.2.7 Other Extruded Insulation Systems 23
2.2.8 Paper-Insulated Oil-Filled Cables for a.c. or d.c. 23
2.2.9 Paper-Mass Insulation for HVDC 26
2.2.10 Gas-Filled Submarine Cables 28
2.2.11 Other Insulation Systems 29
2.3 The Water-Blocking Sheath 30
2.3.1 Lead Sheath 30
2.3.2 Aluminium Sheath 32
2.3.3 Copper Sheath 32
2.3.4 Polymeric Sheaths 33
2.4 Armoring 33
2.4.1 Corrosion Protection 37
2.5 Outer Serving 39
2.6 Three-Core Cables 40
2.6.1 Choice Between One Three-Core and Three Single-Core Cables 42

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NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 25 of 306

2.7 Two-Core Cables 43
2.8 Coaxial Cables 44
2.9 Optical Fibres Inside Submarine Power Cables 45
2.10 Five Generic Cable Types 47
References 48

Many different shapes and styles of submarine power cables have been invented, developed, manufactured, tested, and installed during more than hundred years. The showrooms of the cable manufacturers display a fascinating variety of designs, all made with contemporary engineering art and entrepreneurship. There are success stories, and there are sad stories. This book concentrates on cable types that are produced and installed today (2009). Other cable types, which still might be in operation and maybe subject to repair operations are mentioned and described briefly. This chapter tries to describe different submarine cable types and their construction elements without going too deep into formulae.

Five very typical submarine cable designs and their application are portrayed in Sect. 2.10 at the end of this chapter.

2.1 The Conductor

The current-carrying conductors of submarine power cables are made of copper or aluminium. Even though copper is more expensive than aluminium in relation to the current-carrying capability, the majority of submarine power cables have copper conductors. Copper allows a smaller cross section and hence requires less material for the outer layers such as lead and steel wires. However, there are occasions where aluminium is the better solution. There is no given best choice as the costs vary strongly with a volatile metal market. The limited corrosion resistance of aluminium is sometimes quoted in favour of copper for submarine power cables. However, when seawater can cause corrosion in the conductor, it has already penetrated the insulation, and the cable must be repaired or replaced, regardless of the conductor material.

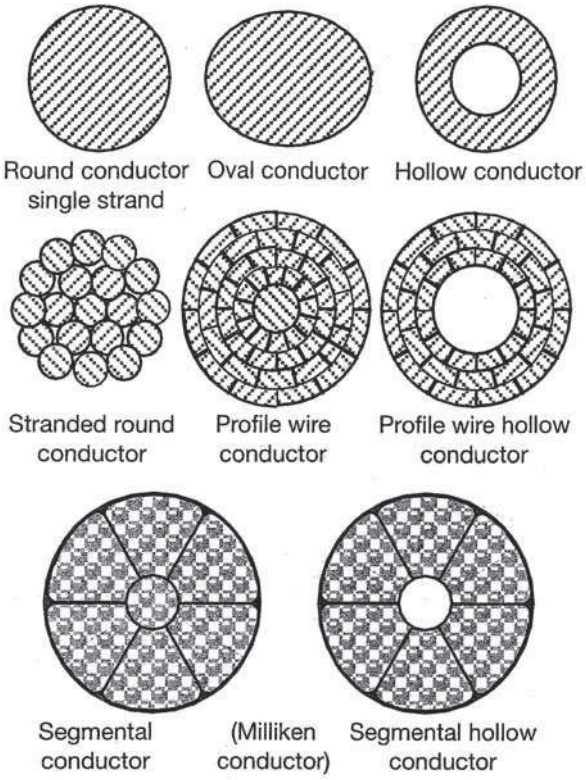
For some cable projects it makes sense to use copper for some parts of the route, and aluminium for others. The HVDC cables of the Estlink project have copper conductors in the submarine part and aluminium in the land section [1]. It is also possible to use submarine cables with aluminium conductor for the deeper cold part of the submarine cable route and "copper ends" for the warmer parts buried close to the beach [2]. Copper and aluminium conductors can be jointed together.

Conductors of submarine power cable are made in various shapes (cf. Fig. 2.1). The most common shapes are explained below.

2.1.1 Solid Conductor

The conductor consists of a single massive wire. This design is used for cross sections up to about 400 mm^2. The manufacturing is easy and the conductor has

Fig. 2.1 Conductor design



naturally good longitudinal water tightness, a property most often required for submarine cables. Sometimes an extruded insulation tends to slip on the smooth conductor surface thus creating a shrink-back tendency of the insulation when cutting the cable for termination or jointing. This phenomenon depends largely on the extrusion technique for the insulation. Knurling or similar surface treating methods on the conductor can enhance friction and reduce shrink-back problems.

As the cross-section of solid conductors is limited to about 400 mm^2, they are not used for cables >150 kV, which usually have larger cross sections. For low voltage cables with three or four cores in one cable, also segment-shaped solid conductors are used.

2.1.2 Conductors Stranded from Round Wires

Most conductors for submarine power cables are stranded from round wires. The wires are laid up in the stranding machines in layers. The conductor is compressed by the action of dies or roller sets, either after each layer or at the end of the stranding machine. The compressing reduces the interstices between the strands. Conductors from compressed round wires can achieve a filling factor of 92%. Since the wires are cold worked by the compression, the electric conductivity of the material is reduced.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 27 of 306



There are two different stranding directions: righthand or left hand. Sometimes they are denominated as Z-lay or S-lay, depending on the visual impression of the spiralled strands. Imagine that the letter is projected onto the lay and find out if the central line of the letter goes in parallel with the strand lay. The sketch shows a Z-laid conductor. Most often, the layers of stranded conductors have alternatively S- and Z-lay, but it is possible to use any mixture of lay directions for better stability of the conductor or other production reasons. For any practical reason, the conductivity of the conductor is not depending on the sequence of S- and Z-lay. If the cable is to be coiled in clockwise direction the outer conductor layer should be laid right-hand (Z-lay) so that the conductor contracts during coiling [3]. A conductor expanding under the influence of the coiling stress would possibly infringe with the insulation. In paper-insulated cables the innermost paper layers can burst.

Conductors with compressed round wires are equally useful for a.c. and d.c. applications. Most often, they are designed according to the industrial standard IEC 60228, Class 2. For large cross sections or transmission power, d.c. cables would be more economic with profiled wire conductors, and a.c. cables would be more economic with Milliken conductors which are described later.

In large conductors for a.c. cable additional magnetic losses can be generated reducing the ampacity[1] of the cable. The "proximity effect" in a conductor is caused by the magnetic field of neighbour cables and tends to "push" the current flow lines into a certain part of the conductor. Individual wires or groups of wires can be insulated electrically to reduce the "proximity effect". The insulation can be accomplished by paper or plastic strips, or by varnish coatings of the wires. Another magnetic effect, the "skin effect" cannot be reduced by this method in normal stranded conductors.

Tinned copper wires have been used frequently for conductor manufacturing in earlier times, but this concept has not been pursued in the recent years.

2.1.3 Profiled Wire Conductors

The conductors are composed from cake-piece-shaped wire cross sections, sometimes also called keystone wire conductors. In the stranding machine, the wires (strands) combine perfectly to a circular conductor. Filling grades up to 96% can be achieved, probably even more. The conductor surface is very smooth, which is extremely useful during the further production process. Large HVDC submarine cables are most often produced with profiled wire conductors. The standard IEC 60228 does not cover conductors with profiled wires.

[1]The word ampacity denotes the current carrying capability of a cable and has been coined by W. A. DelMar of Phelps Dodge Wire&Cables in 1951 [31]

Profiled copper wires can be produced in almost any shape using the Conform method, which is a type of extruding. The shaping is done without cold working and the resulting wire has the excellent conductivity of annealed copper.

2.1.4 Hollow Conductors for Oil-Filled Cables

Oil-filled or fluid-filled cables (also called LPOF, low-pressure oil-filled, or SCFF, self-contained fluid-filled) are filled with low-viscosity oil. They contain a central duct in the conductor to allow for oil flow in connection with thermal expansion and pressure supply from the cable terminations.

Some designs have a central metallic support helix, which prevents the conductor wires from collapsing into the central duct. The helix is visible in Fig. 2.2.

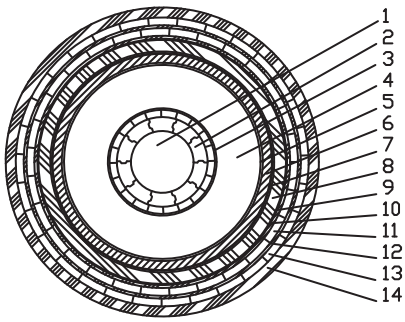
Hollow conductors can also be made from profiled wires. Slot-and-key shaped profiled wires engage when stranded to form a self-stabilizing vault (cf. Fig. 2.3). In this case, the central helix can be omitted. A grooved surface between the wires helps to allow for sufficient oil flow between insulation and central duct.

2.1.5 Milliken Conductor

The alternating magnetic field from the a.c. current in a conductor produces an electromagnetic force (emf) that concentrate the current flow lines into the peripheral parts of the conductor (the “skin”). The current squeezes into the outer part



Fig. 2.2 LPOF cable made by Taihan



Item	Component	Item	Component
1	Oil Duct	8	Anti-corrosion PE jacket
2	Conductor, self supporting segmental strips of copper	9	Antiteredo protection, Cu tapes
3	Conductor screen	10	Bedding
4	Insulation, paper tapes impregnated with low viscosity fluid	11	Copper flat wires wire armor
5	Core screen	12	Bedding
6	Lead sheath	13	Copper flat wires wire armor
7	Reinforcement, bronze tapes	14	Serving

Fig. 2.3 Hollow conductor with slot-and-key shaped wires (Courtesy of Prysmian, Italy)

of the conductor. The current density in the inner conductor part decreases and the inner part of the conductor is less useful for the current transport. The skin effect reduces the ampacity of large conductors for alternating current substantially. H. Milliken filed two patents in the 1930s describing a conductor design with reduced skin effect [4, 5]. For the manufacturing of a Milliken conductor, the factory starts with standard stranded sub-conductors from round wires. These sub-conductors are now rolled into a triangular cake-slice shape, and then are pretwisted. Finally, a number of these sub-conductors are laid up into a round conductor. The result is obvious from Fig. 2.2. A Milliken conductor may or may not have a central duct or a central wire. Milliken conductors are also known as segmental conductors.

In a standard conductor, the distance to the conductor axis of each individual wire is constant along the conductor. The individual wire accumulates the emf induced at its particular distance to the conductor axis. In contrary, in the Milliken conductor each individual wire changes its radial position from close to the centre to far from the centre as the wire proceeds along the conductor. The emf at the centre and the emf at the periphery have opposite signs and cancel each other partly. This reduces the skin effect considerably. The larger the number of segment strands in the Milliken conductor, the better the reduction of the skin effect. In practice, segment numbers of 5 up to 6 are common. However, cables with up to nine segments have been designed [6].

For the full exploitation of the intricate current flow pattern in a Milliken conductor, it is important that the current cannot "jump" between the wires rather than following the wire. The insulating oil film between the individual wires helps reducing the skin effect. The application of extra insulation between the individual wires can reduce the skin effect even further [7]. This insulation can be applied between the individual segments, between the wire layers within each segment, between individual wires or any combination thereof. It is also known to insulate only a fraction of all individual wires. The insulation can be made with thin paper strips or lacquer on the wires.

The higher production costs of Milliken conductors motivate their use only for large cross sections ($\geq$1200 mm^2 copper).

2.1.6 Conductor Resistance

The electric resistance is the most important property of the cable conductor. The specific resistivity of the conductor material is temperature dependent:

$$R_\theta = R_{20} \cdot (1 + \alpha(\theta - 20))$$

with these symbols:

- R_θ specific resistivity at temperature θ (°C)
- R_{20} specific resistivity at 20°C
- α Temperature coefficient of the electric resistivity

The specific resistance and the thermal coefficient for copper and aluminium are given in Table 2.1. Both the specific resistivity and the temperature coefficient are depending on the purity of the metal. The effective resistance of a given conductor is not only depending on the conductor cross-section but also on the lay length of the strands because the current has to travel a longer path in a laid-up conductor. The number of strands and the compression during lay-up also influences the resistance. The presence of water-blocking compounds in the conductor can increase the resistance as contact points between individual wires vanish. During the manufacturing, the wires are subjected to different degrees of cold working. Cold worked copper and aluminium have a higher specific resistivity than annealed metal. Power cable specifications usually not only specify the conductor cross-section but also the

Table 2.1 Specific resistivity and its temperature coefficient

	Copper	Aluminium
R_{20}: Specific electric resistivity @20°C, Ωmm^2/m	0,01786	0,02874
α: Thermal coefficient of the specific electric resistivity @20°C, 1/K	0,00392	0,0042

conductor resistance. The standard IEC 60228 lists conductor resistance values that include the influence of the strand lay length (cf. Table 3.1 in Chap. 3).

With the Conform® Extrusion process, shaped wires can be made without cold working resulting in better conductivity values than those for compressed round wires. The resulting profile wire conductor may have a smaller conductor than a compressed wire conductor to achieve a specified resistance.

The purchaser of a power cable is not primarily interested in a particular cross section, but in obtaining a cable with a certain resistivity (or conductivity). Ordering a cable with 1600 mm^2 copper, the purchaser actually wants to have a cable with a resistance not more than 0.0113 Ω/km according to the IEC60228. This value is the basis for the system owner's loss and ampacity calculations. However, it is up to the skills of the manufacturer to achieve the resistance requirements with as little copper as possible, using the best art of choosing wire production method, lay length, compression factors, raw material grade, etc.

Standardized conductor sizes have been tabulated both in the IEC60228 standard and many national standards. However, submarine cables are often tailor-made products for a specific project. It is quite common to determine a suitable cross section area from the actual needs rather than from the standard values. Odd values such as 790, and 1410 mm^2 have been chosen to meet real needs. Only in very rare cases, submarine power cables can be purchased from stock at standardized cross section values.

2.1.7 Watertightness of Conductors

Longitudinal water tightness is often required for submarine power cables to prevent water from migration into the cable after a cable fault. Also, water ingression from defect end caps during transport or installation must be prevented. For this purpose, swelling agents in the shape of powder, tapes or yarns are inserted in between the conductor layers. Upon contact with water they swell considerably and block the passage for water efficiently. Most swelling agents work much better in contact with fresh water rather than salt water. Other hydrophobic compounds are used, too, to stop water migration. Petrojelly is a vaseline-based material serving the same purpose. It has been discussed to extrude a polymeric matrix accommodating the conductor wires and providing high longitudinal water tightness. Oil-filled and mass-impregnated cables are considered having longitudinal water tightness without additional measures to be employed.

2.1.8 Superconducting Conductors

No other conductor materials than copper or aluminium are used for commercial submarine cable manufacturing today. Research institutes investigate the possibility to make conductors with very high conductivity from carbon nano-tubes.

After the discovery of high-temperature superconductivity in 1986, a number of oxide compositions have been found with a critical temperature for superconductivity over 77 K, which is the lowest temperature for liquid nitrogene. Superconductivity came into reach for many practical applications. Material systems like Y–Ba–Cu–O, Bi–Sr–Ca–Cu–O und Tl–Ba–Ca–Cu–O are in the frontline. Very soon, laboratory samples of cryogenic superconducting cables were devised. For cable applications, the superconducting materials are shaped into thin ribbons to be applied onto a copper substrate. At the end, the ribbons can be crafted into cable conductors with enormous ampacity when under the critical temperature. Experimental cables have been produced and a large effort of dielectric research on cryogenic materials is done. Still, there are some major drawbacks: The power needed for the cooling process is only little less than the saved losses. For submarine applications there is still no suitable cryogenic cable available.

2.2 The Insulation System

The cable insulation provides an effective barrier between potential surfaces with an extreme potential difference. It is of utmost importance that the insulation system is absolutely clean and even. Furthermore, the insulation wall must be mechanically robust, and resistant to temperature and aging. During more than 150 years of submarine electric cables (telecom and power) many different insulation materials have been tried, developed, rejected or approved. Insulation materials for submarine cables are in no way different to insulation materials for land cables; however, conditions of production and application might be different. Today, submarine power cables for medium and high voltage are manufactured with only a few different insulation materials. In-depth information on the dielectric properties and chemical structure of cable insulation materials can be found elsewhere [8]. Here the most important characteristics of some insulation materials are described. Some properties of relevant insulation materials are compiled in tables in Chap. 3.

2.2.1 Polyethylene

Polyethylene is a hydrocarbon consisting of long chains of $CH_3–(CH_2)_n–CH_3$ molecules. It contains nothing but carbon and hydrogen. The chains may be branched or not. The material is nonpolar and semicrystalline. It is thermoplastic and can theoretically be re-melted. For electric insulation it is available in different density ranges such as LDPE (low density), MDPE (medium-density), and HDPE (high-density). The density of all these varieties is between 0.9 and 0.97 g/cm^3. PE has lower dissipation factor and lower dielectric losses than paper insulation and was used for 63 kV cables since the early 1960s. In France, LDPE was used successfully for up to 500 kV cables in the 1990s. However, the author does not know if thermoplastic PE cables have been manufactured for submarine application. Because of the

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 33 of 306

Table 2.2 Operational temperature of cable insulation materials

	Operating temperature	Short-circuit temperature
LDPE	70°C	125°C
XLPE	90°C	250°C
EPR	90°C	250°C
Mass-paper	50–55°C	
Oil-paper	85–90°C	

limited conductor temperature in PE cables (70–80°C), PE has subsequently been replaced by cross-linked PE (XLPE) which stands 90°C and short-circuit temperatures well above 200°C. However, as cable operators today try to avoid large losses associated with a hot conductor the thermoplastic PE insulation might experience a revival (Table 2.2).

2.2.2 Cross-Linked Polyethylene

Cross-linked polyethylene (XLPE) has been used for submarine cables since 1973, and even earlier for land cables. Starting with polyethylene, XLPE is made by cross-linking the long molecular chains of LDPE to form a three-dimension network. The cross-linking is irreversible and prevents the polymer from melting at elevated temperatures. Thermoplastic polyethylene (PE) is getting soft and eventually melts when heated to 80–110°C depending on the density. In the contrary, XLPE is stable at far higher temperatures. Instead of by melting, it is destroyed by pyrolysis above 300°C.

Organic peroxides are being used as process initiators for the cross-linking process. They are added to the raw material already at the compounder's factory. The raw material is extruded around the conductor in the extruder head. The cross-linking takes place in a tube under inert atmosphere with high pressure and high temperature immediately after the extrusion head.

The gaseous by-products tend to form bubbles inside the still soft XLPE in the cross-linking zone of the extruder. To suppress the generation of gas bubbles, the extruded cable must be transported further in a pressurized tube until the cooling XLPE has gained sufficient strength. The cooling must be slow to relieve internal stress. The total travel length of the XLPE cable in the cross-lining zone, the cooling zone and the relaxation zone can be more than 150 m.

In vertical extrusion lines and in catenary lines, the contact between the tube wall and the XLPE insulation can be avoided, which leads to a very high surface quality. A vertical line prevents also the forming of excentrical insulation under the influence of gravity. In less common processes the cross-linking can be achieved by silane agents or electron ray irradiation.

XLPE is a first-choice insulation material for submarine cables. In the early days of XLPE cable manufacturing, the material got a bad reputation due to its perceived sensitivity for water. Under the combined influence of water, electric field and

impurities, water-treeing could be initiated, a phenomenon involving tree-like damage structures inside the insulation. The "trees" would grow and finally cause an electric breakdown in some cases. Water-treeing has been investigated widely in the 1980s and 1990s, and has been documented in many impressive pictures, underpinning the reputation of XLPE cables as being water-sensible. However, many of these experiences were made with XLPE cables produced with steam-induced cross-linking, and extrusion of screens and insulation in subsequent operations, thus paving the road for water and dirt into the insulation. Worse still, in the first excitement on the new insulation material, some cables were laid directly into water with bare insulation. Today, all premium manufacturers produce XLPE cables with triple-extrusion and dry curing tubes. By these and other improving steps, the quality and breakdown voltage of XLPE insulation has improved dramatically since the 1980s. A comprehensive survey on water-tree phenomena and a large reference list for further reading can be found in [9]. Water-treeing is a problem not reported anymore. In contrary, XLPE has developed to be the insulation material of choice for both land and submarine power cables.

XLPE suppliers offer a number of cable materials with different properties. A well-composed formulation of base resin and additives can have excellent dielectric values, good processability, water-tree-retarding, and anti-aging properties. For a high-performance high-reliability insulation system, it is recommended to use a well-defined material combination of XLPE insulation material and semiconducting screen material recommended by an experienced cable manufacturer.

The dielectric properties of XLPE vary between different species and brands. The dielectric strength that is perhaps the most important property in cable design is not a constant fixed value. It depends not only on the material formulation but also on manufacturing conditions, sample preparation, temperature, test voltage shape, and much more. The concept of dielectric strength is based on a statistical distribution of experimental breakdown voltages on samples of a given insulation design (Weibull distribution). The details of the Weibull distribution of the dielectric strength are described in most cable textbooks and are needless to be repeated here. In a Cigré paper the application of Weibull distributions to cable insulation is described along with a comprehensive bibliography on the subject [10].

The use of XLPE cables for submarine application is limited by the availability of suitable joints. While XLPE cables per se are available for voltages up to 550 kV for land cables, there are no joints available for this voltage levels. While flexible joints have been made occasionally for 245–345 kV, higher voltages remain the realm of unjointed cables. This restricts the maximum reach of XLPE submarine cables to lengths, which can be produced in one piece. Submarine power cables for 170 kV a.c. can be produced with factory lengths of 50 km or more.

2.2.3 Conductor and Insulation Screen

If we would extrude the XLPE insulation layer right away onto the conductor, the grooves, ridges and irregularities of the conductor would generate local stress enhancement and would reduce the dielectric strength of the insulation considerably.

To avoid this, a layer of semi-conductive XLPE is extruded onto the conductor resulting in an extremely smooth dielectric surface towards the insulating XLPE. As the semi-conductive inner layer is completely circular and has a smooth surface, there will be no stress enhancements.

The surface of the inner conductive layer can be made visible using hot-oil bath methods. XLPE becomes transparent at 130°C and reveals in detail the surface structure of the inner semi-conductive layer.

The triple-extrusion-method also provides a semi-conductive layer outside the insulation layer in order to form a stable dielectric surface not being affected by the outer screen layers. The three layers "conductor screen – insulation wall – insulation screen" make up the cable dielectric system. For high-quality insulation the three layers should always be manufactured simultaneously in a triple-extrusion system.

Semi-conductive XLPE-layers are made of PE-based co-polymers blended up with 40% carbon-black. According to international relevant standards, the volume resistivity shall be lower than 250 Ωm (CENELEC) or lower than 500 Ωm (AEIC, IEC). If the resistivity of the screen materials is too high, impulse voltages in the cable system can induce large stresses in the semi-conductive materials, eventually generating an insulation breakdown. Most modern carbon-black formulations meet the requirements with great margins. The resistivity of carbon-black filled XLPE in practical life is strongly dependent on temperature and mechanical stress, as the contact bridges between the carbon-black particles can close or open under the influence of strain in the polymeric matrix [11].

There are different varieties of carbon-black, such as furnace-black and acetylene-black with different particle size distribution and purity. Extruding parameters are strongly affected by the carbon-black content and character. Peelable screen systems with reduced adhesion between the insulation wall and the outer XLPE semi-conductive screen are sometimes used for medium-voltage cables. During the preparation of joints or terminations, the outer screen can be peeled off like a banana skin saving working hours.

The semi-conductive layers are applied with 1–2 mm nominal thickness. For long cables, the cost for a thick semi-conductive layer can add up to a considerable sum, as the raw material is fairly expensive.

2.2.4 The Influence of Ageing and Humidity on XLPE Insulation

"Ageing" is the deterioration of insulation material properties under the influence of temperature, electric and mechanical stress, chemical aggression, or any combination of these. Under ageing, the dielectric strength is decreasing gradually. When the dielectric strength has decreased to a degree that it is in the range of the operating stress the cable has reached the end of its useful life. Due to the statistical nature of the dielectric strength, some sections of a cable route will reach "pension age" and experience breakdown while the rest of the route still has years of service life. For statistical reasons, a longer cable route will face a larger risk of breakdown

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 36 of 306

than a short route, everything else being equal. An analysis of the accumulated and expected repair costs helps the cable owner to decide when the economical end of useful life of the cable route will be reached.

Thermal ageing of insulation materials is described as a result of chemical reactions in the insulation. According to the classical Arrhenius model the life time can be expressed as:

$$\tau = A \cdot e^{(U/T)} \tag{2.1}$$

with: τ: relative life time, A: constant, U: Activation energy for the chemical process in question, T: absolute temperature (K). Equation 2.1 can be set up for each of the chemical processes contributing to ageing when the activation energy and the Arrhenius constant are known.

Another equation has been established for the ageing as a result of electric stress:

$$\tau \cdot V^n = Const \tag{2.2}$$

with: τ: relative life time, $Const$: constant, V: applied voltage, n: coefficient depending on material and manufacturing process. For XLPE cables n=9. . .12.

Neither Eq. 2.1 nor 2.2 deliver an exact calculation of the lifetime of a specified cable system. The value of the equations is the visualization of how the lifetime depends on the temperature and voltage. In most cases, the operating voltage of high-voltage cables is quite constant within narrow limits. It becomes obvious from the equations how much temporary overvoltages or overtemperature "eat up" the cable's lifetime. For certain cable installations (e.g. off-shore wind farms), it should be evaluated if there is the risk of long-time overvoltages in certain conditions.

For easy understanding and practical purposes, there are two fundamental rules for the lifetime of most organic insulation materials (polymers, paper, oil) [12]:

1. Increase the operating temperature by 8–10°C and you'll cut the life time by half.
2. Increase the operating voltage by 8–10% and you'll cut the life time by half.

Rule 1, known as the "Montsinger rule", has been proposed already in the 1930s. The rule can also be applied to modern insulation materials [13, 14]. According to this rule, a cable declared having a 30-years life at 90°C conductor temperature, would have a service life twice as long at 80–82°C conductor temperature. The 8–10° temperature step quoted in Rule 1 might have different values in other applications of insulation materials. For cable systems with varying load, a cumulative ageing calculation can take temporary thermal or electric stresses into account.

Many more ageing models have been proposed in the recent decades. Also the complicated process of multi-stress ageing under the simultaneous influence of thermal and electric ageing has been investigated thoroughly. References [13] and [15] provide a comprehensive compilation of this issue and list further references.

Copper has the potential to accelerate catalytically the ageing of polyolefinic (XLPE, PE) insulation materials. In modern cable designs the semi-conductive screen materials constitute an effective barrier for copper ions.

Humidity is the prime enemy of all electric insulation. It is a well-known fact that the dielectric strength and ageing resistance decrease under the influence of humidity. The insulation of the submarine cable must be protected from water and humidity by a purposeful design. It should be noted that polymeric materials are often completely water-tight but still allow for diffusion of humidity. If a complete humidity bloc is not possible for economic or other reasons, the water barrier should at least retard the water diffusion/intrusion so much that the humidity level inside the insulation stays under the critical limit during the economic life time of the cable. According to one strategy, the cable has a polymeric layer preventing direct water intrusion. Swelling tapes absorbs the humidity diffusing into the cable through the polymeric layer. The swelling tapes have sufficient capacity to absorb all humidity during the economic life of the cable [16].

Ageing by sun irradiation and UV can usually be excluded for submarine cables. The cable owner should provide a sun protection where the submarine cables come up to the surface on shore or on platforms/wind turbines.

2.2.5 Applications of XLPE Insulation

XLPE submarine cables are available for very long lengths (>50 km) in 3C fashion up to 170 kV from selected cable manufacturers. As voltage grows, the number of cable manufacturers is getting smaller. SC cables up to and including 500 kV can be manufactured in limited length. 400–500 kV flexible joints for XLPE cables are not available today (2009), which makes 400/500 kV extruded submarine cables difficult for extended sea routes.

2.2.6 Extruded HVDC Cables

Standard XLPE is not suitable for HVDC applications because of space charge phenomena in the insulation. Under the influence of a direct voltage, space charges would accumulate at certain places in the insulation wall. These accumulations would create unfavourable peaks of the electric field in the insulation. This phenomenon had rendered XLPE unsuitable for HVDC for a long time.

Today, special XLPE formulations have been developed that can cope with the problem. One manufacturer has gained more than 15 years of commercial experience with extruded HVDC cables. The first submarine extruded HVDC cable (“Cross Sound Cable”) was installed in 2002 between Long Island, New York, and Connecticut in the US [17]. Since then, other extruded HVDC submarine cables from one supplier have been installed (“Troll A”, “Estlink”, “NordE.ON”). Extruded HVDC cable systems are now offered for 320 kV operating voltage. Given the

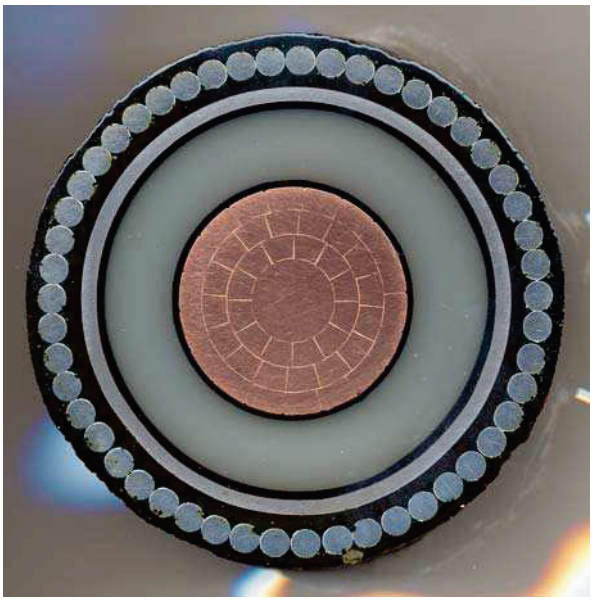


Fig. 2.4 Submarine HVDC cable with extruded insulation, used for the "Estlink" link (Courtesy of ABB, Sweden)

conditions of submarine installation and operation, the mechanical sturdiness of extruded power cables is advantageous. Figure 2.4 illustrates a typical submarine HVDC power cable with extruded insulation.

2.2.7 Other Extruded Insulation Systems

Ethylene propylene rubber (EPR) is an extruded dielectric used by some manufacturers mainly for underground cables.

Compared to XLPE, EPR has a rather high tanδ and ε_r making it less suitable for the highest voltages. At least three manufacturers offer EPR medium-voltage submarine cables today. The latest known high-voltage submarine installation of EPR is the Venezia-Murano-Mestre 150 kV cable in Italy (2001). A comprehensive comparison of EPR vs. XLPE and relevant references can be found in [18].

An extruded PE d.c. cable was included in the Cross Channel HVDC installation already in 1963 [19].

2.2.8 Paper-Insulated Oil-Filled Cables for a.c. or d.c.

This classical cable design is filled with low-viscosity oil. The cables are known under several names:

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 39 of 306

LPOF, low-pressure oil-filled,
SCFF, self-contained fluid-filled,
SCOF, self-contained oil-filled,

and possibly even more. There are also high-pressure type oil filled cables but these are not used for submarine applications. Mass-impregnated paper-insulated cables must not be confused with oil-filled cables. They are treated in the next section.

The insulation paper of oil-filled cables is made from conifer pulp (Kraft paper). To improve the dielectric losses especially for ehv a.c. cables, the pulp is sometimes washed with de-ionized water. Low-density paper (0.7–0.8 kg/dm^3) is being used to keep the dielectric losses low and the permeability for oil flow high. The insulation is often composed of paper tapes with different thicknesses, from 50 up to 180 μm. Thin paper, having a higher dielectric strength than thicker paper, is used close to the conductor where the electric stress is higher. In the outer parts of the insulation, the stress is lower and the required insulation thickness can be achieved with less layers of thicker paper tapes. An insulation wall with stacked paper thickness also provides good bending properties.

For decades the impregnation compounds for fluid-filled cables have been low-viscosity mineral oils. Since the early 1980s, synthetic cable fluids have been used in fluid-filled cables, predominantly linear alkylbenzene mixtures (LAB). As LAB is compatible with mineral oils it is also suitable for refilling and refurbishment of existing oil-filled cables.

During operation, the oil is pressurized. The dielectric strength of paper-oil insulation for a.c. voltage is depending on the pressure. The solubility of gases in the oil decreases with deceasing pressure. If the pressure falls too low, gases dissolved in the oil may be released and form bubbles. The electric field can create partial discharges in the bubbles, which can erode the insulation and cause an electric breakdown.

The necessary pressure in submarine oil-filled cables is maintained from pressure feeding units on the shore station. The cable must have sufficiently large oil channels to provide hydraulic communication from the land-based feeding units to all parts of the cable for the following cases:

- Thermal expansion and contraction. Responding to load changes the cable can change its temperature. The oil contracts/expands and the pressure variation must be equalized by oil transport to/from the land feeding units. Due to the flow resistance, there is a pressure drop from the centre of the cable to the land ends. The pressure variations are the largest in the middle of the cable route. It must be avoided at all costs that vacuum-like low-pressure conditions arise as these may cause electric breakdown.
- Positive overpressure against the seawater must be maintained at all locations to prevent water ingress in case of a damage of the metal sheath. Seawater is heavier than oil so that the pressure balance changes in favour to the water pressure as the laying depth increases. This must be compensated for by a larger oil pressure in the land-based feeding units.

The oil channel can be provided by different measures depending on the cable design. Single-core paper-oil cables have hollow conductors providing pressure equalization and hydraulic communication to the on-shore feeding units. In vintage cable designs the centre channel has been assisted by longitudinal grooves in the inside of the lead sheath. In three-core cables with common lead sheath, the interstices between the cores form oil channels. Today, only single-core oil filled cables are used for higher voltages (>150 kV). These rely on oil channels in the conductor centre.

Practical considerations show that the maximum length of fluid-filled cables is 30–60 km. For longer length, a sufficient oil flow in the cable can not be guaranteed. Only a lower coefficient of thermal expansion of the fluid, or a lower operating temperature would change this. The hydraulic design is discussed in detail e.g. in [20].

The Möllerhöj-cable is an exception to the rule of limited length of LPOF submarine cables (cf. Fig. 2.5). Comprising two or three fully insulated cable cores in a flat, untwisted formation, the thermal expansion of the oil can be absorbed by a slight deformation of the oval lead sheath which is supported by an intricate metallic structure acting as a spring-loaded cushion [21]. Möllerhöj submarine cables do not need external oil feed and can be installed in seemingly unlimited lengths. The latest submarine cable of this kind was the Kontek link between Denmark and Germany with 600 MW d.c. power in 1996. The cable will be replaced by a conventional mass-impregnated HVDC cable in 2010.

Oil-filled cables could be improved by using paper strips reinforced with polymeric films. Laminates composed of paper layers and polypropylene (PP) layers have been used as insulation matrix for oil-filled cables since the 1980s for voltages up to 800 kV a.c. (cf. Fig. 2.6). The material has a better dielectric strength for a.c.



Fig. 2.5 Möllerhöj-type cable for the Kontek HVDC link (Courtesy of NKT Cable A/S, Denmark)

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 41 of 306

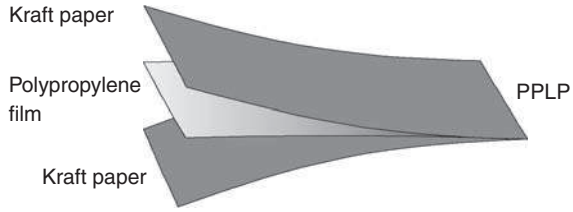


Fig. 2.6 Layers of PPLP

and lower losses than Kraft paper which makes it attractive for high-performance EHV a.c. cables. The basic principle has been used with different sandwich schemes (paper-PP-paper, PP-paper-PP) in double, triple and quadruple layers. The insulation is known under the names PPL, PPP, or PPLP. More information and references on the development of PPLP cables can be found in [6].

Fluid-filled cables have a longer operational record for EHV a.c. cable links compared to XLPE cables. A well-proven range of joints and cable terminations is available. The high conductor temperature of 90°C allows for large ampacities, and the low losses of PPLP make longer cable lengths possible. On the negative side, there is the rather complicated production process, the complicated feeding stations, and, more important, the doubtful environmental behaviour with outpouring oil in case of a submarine damage. The positive properties resulted in the cable type still being used successfully for shorter submarine cable routes with high transmission power demands. The Strait of Gibraltar cable system, the Hainan-China Mainland Strait cable system, and the Jordan-Egypt (Gulf of Aqaba) connection are modern examples of a technique that has been used worldwide for distances of up to 40–50 km. Today, XLPE cables are qualified for very high voltages and leave little room for fluid-filled cables. Still, a system with four oil-filled submarine cables with only 138 kV rated voltage was installed in the Philippines by a Japanese manufacturer as late as 2000, although oil-related accessories such as feeder tanks and pumps could not even be transported to site by road [22].

2.2.9 Paper-Mass Insulation for HVDC

This insulation type has been used for HVDC cables since more than 100 years [23]. Mass-impregnated cables have been used for medium-voltage a.c. transmission, but today, they are only being used for submarine d.c. applications for large transmission power at the highest d.c. voltage. Mass-impregnated cables are available for up to 500 kV d.c. For this voltage, there is no alternative to the well-proven mass-impregnated cables. The longest route length today is 580 km (NorNed, 2008) but this type of cables can be used for virtually infinitive lengths. As cables with paper-mass-insulation have many similarities with cables with extruded insulation, they are also called “solid-insulation cables”. Figure 2.7 shows an 450 kV HVDC cable with mass-impregnated insulation, in comparison to a 150 kV cable from 1954.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 42 of 306



Fig. 2.7 Mass-impregnated HVDC cables: 450 kV "Baltic Cable", left, and 150 kV "Gotland cable" from 1954 (Courtesy ABB, Sweden)

Mass-impregnated d.c. cables require different insulation paper than oil-filled a.c. cables. As d.c. cables are not subject to dielectric losses, one can chose high-density paper ($\approx$1.0 kg/dm^3) to achieve best possible dielectric strength. Specialized paper makers are able to keep the porosity high in order to enable lower flow resistance through the papers. The paper used for submarine HVDC cables is made from conifer cellulose pulp (Kraft paper). Sometimes manufacturers use different paper tape thickness in the insulation to accomplish a better mechanical flexibility. For high-performance cables, the lapping process must be done under controlled humidity and requires scrupulous cleanliness.

The conductor screen in paper-insulated cables is made from semi-conducting carbon-black paper. The insulation screen consists of carbon-black paper combined with metal-laminated papers or thin-wire copper nets. Sometimes also duplex-paper (one side insulating, the other side carbon black) is used as screen. Both screens provide a smooth dielectric surface towards the paper insulation. Metal-laminated paper is also known as "Höchstädter Papier" since its introduction in 1914.

After lapping of all paper tapes, the cable core is put into giant vessels for further treatment. A vacuum-heat-drying phase is followed by hot impregnation with high-voltage grade impregnation compound. One certain mineral-oil based compound with non-Newtonian rheological behaviour has established itself as material of choice with European mass-impregnated cable manufacturers. The high viscosity is achieved by poly-isobutylene additives.

Mass-impregnated HVDC cables with high-viscosity compounds can be used for indefinite route length because they are not depending on external pressurization from on-shore feeding stations [27].

Mass-impregnated cables have small voids in the butt gaps of the insulation when the insulation is cold. Under the influence of the electric field partial discharges might occur in the voids. Under a.c. voltages the voids would ignite in every half-cycle. Many repeated partial discharges at the same location can lead to paper disintegration and eventually to breakdown. For this reason mass-impregnated cables cannot be used for high voltage a.c. In a d.c. field a different charge transport mechanism allows for partial discharge to ignite only very rarely. When the cable is getting warm due to conductor current the impregnation compound expands filling all possible voids. The dielectric strength of a warm mass-impregnated cable is much higher than that of a cold cable.

Thanks to the layered structure, the mass-impregnated insulation can tolerate small impurities and/or defects. Scattered defects and foreign particles smaller than the thickness of a paper layer, can be regarded as harmless as long as they do not emit ions.

Attempts to replace the paper in mass-impregnated cables by paper-propylene-laminate have been made. One manufacturer using PPLP together with the standard impregnation compound (with altered viscosity) reported no significant improvements compared to standard paper-mass insulation [24]. A more recent publication by another manufacturer reported better power rating but this seems to be achieved by using low-viscosity impregnation oil and a higher current rating [25] which resembles an LPOF cable. The use of PPLP for mass-impregnated dc cables seems to require further development. Furthermore, the authors suggest the change of relevant test standards before PPLP can unfold its possible advantages.

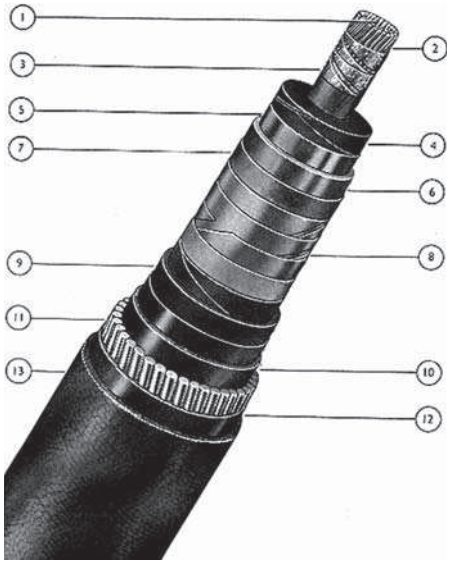
Cables with mass-impregnated insulation do not leak oil to the environment when they get damaged [26]. This property is important for submarine cables to be installed in sensitive environments.

2.2.10 Gas-Filled Submarine Cables

Lapped cable insulation with a gas filling rather than an oil filling was developed by C. J. Beaver and E. L. Davey of W. T. Glover & Co already in 1937. Having the same or similar design elements as a standard oil-filled cable, the insulation was constructed from pre-impregnated paper tapes. After installation the cable was vacuum-treated and pressurized with nitrogen from the cable ends. The pressurized gas filled the band gaps between the paper tapes suppressing the formation of partial discharges. The gas filled cable can be used for a.c. or d.c. voltages despite the voids in the insulation.

Submarine 138 kV single-core gas-filled cables with gas-filled insulation were installed between British Columbia and Vancouver Island in 1956–1958 (Fig. 2.8). One system has been removed in 2007, and the other is expected to serve ten more years [28].

Three gas-filled submarine cables for an HVDC scheme (one spare cable) were laid under the 40 km wide Cook Strait between the two islands of New Zealand in 1962.



1. Gas channel
2. Copper conductor
3. Conductor screen
4. Paper insulation
5. Dielectric screen
6. Lead-alloy screen
7. Bedding
8. Reinforcement
9. Reinforcement protection
10. Bedding
11. Steel wire armoring
12. Cotton tapes
13. Serving

Fig. 2.8 Vancouver Island 138 kV gas-filled cable [28]

2.2.11 Other Insulation Systems

Since the first days of cable industry all kinds of material were tested for their suitability as insulation material. In the beginning, fibrous vegetable products such as cotton, jute, flax and hemp were examined. Very early, it was detected that hydrophobic impregnation compounds could improve dielectric or breakdown properties. Mineral or vegetable oils, their combination, derivatives and by-products all were tested in great varieties. The Scottish physician William Montgomery exhibited samples of a Malaya plant sap called gutta-percha at a meeting of the London Royal Society of Art in 1843. In 1845, the samples found William Siemens's interest, and he sent them to his brother Werner in Berlin for further evaluation. The material was extrudable and served as cable insulation for at least 3 decades. The next widely used insulation material was vulcanized rubber. These insulation materials had an important roll in the development of submarine cables, but today, they do not even "surface" in repair cases.

In modern days insulation systems employing nano-systems are being considered. Cigré has prepared a summary report on this item [29], providing comprehensive further readings. Another more recent update can be found in [30]. In nano-insulation materials, the insulating matrix is enriched with inorganic nanoparticles. Some insulation material properties such as pd-resistance, space-charge properties, water-tree-resistance etc, could be improved. Before a deployment in the field of submarine cables will be possible, this concept will have to prove itself in underground applications ashore.

Gas-insulated lines (GIL) have been installed in a few occasions for the transmission of very high power values onshore. They consist of a conductor hold in place by polymeric spacers inside a metallic tube. The space between the central conductor and the tube is filled with pressurized insulation gas such as SF_6, nitrogen or a mixture of these gases. Gas insulation of this type has a long successful record for switchgear installations. Designed for voltages of 245 kV and above, GIL can transmit enormous power. Gas insulation relies on extreme cleanliness of the gas volume. There are a few onshore GIL installations already, comprising a length of a few hundred meters each. GIL have been suggested for submarine links to transmit the enormous power flow from planned offshore wind farms in Northern Germany. Although the installation of welded pipelines is a well-known technology, a submarine application of GIL would require the mastering of extreme cleanliness during the assembly on-board. A possible ingress of seawater in case of a leakage would contaminate an enormous length of the GIL requiring a complete new installation. It remains to see if this type of transmission can be installed and operated safely in the harsh submarine environment.

2.3 The Water-Blocking Sheath

The dielectric insulation must be protected against undue water ingression to maintain the dielectric strength. Most high-voltage submarine cables have a metallic sheath to provide protection against water ingression. Aluminium, lead, copper, and other metals can be used for this purpose in a variety of shapes. Medium-voltage cables often can do without metallic sheaths or with a simpler design of sheath because of the low electric stress in the insulation. One strategy is to equip the cable with some water-absorbing agent under a polymeric sheath. The polymeric sheath would be watertight but would allow little humidity to diffuse through the sheath in the vapour phase. The absorbing agent has sufficient capacity to keep the insulation dry enough for the entire economic life of the cable and beyond [16].

Most metallic sheaths also provide a good protection against the Teredo, a family of aggressive “shipworms” (actually, they are mussels) feasting not only on sunken pirate ships but also on submarine cables. It is abundant in most saltwaters. In recent years there are indications that the Teredo has invaded also the brackish Baltic Sea as an alien species. They can be kept at bay also by copper or brass tapes.

2.3.1 Lead Sheath

Wheatstone and Cooke suggested lead sheaths for telegraph cables already in 1845. Lead extrusion was known since 1797, but it took the relentless efforts of some known and countless unknown cable engineers to arrive at the lead sheath quality of today. Before 1900, most of the large cable manufacturers were using a ram

press to produce lead-covered cables [31]. Well-produced lead sheaths are completely impermeable for water ingression and humidity diffusion. For oil and mass-impregnated cables, they provide an enclosure to protect the environment outside the cable. Furthermore, the lead adds to the cable weight, which in certain cases is important for the stability of the cable on the sea floor. With screw extruders, submarine cables of 100 km length can be lead-covered in a single uninterrupted length at reasonable costs. Long term stability, creep, and extrusion properties can be improved substantially by using lead alloys with alloy elements such as antimony, tin, copper, calcium, cadmium, tellurium, and others. The standard EN 50307 lists a number of lead alloys for cable use. Table 2.3 shows the composition of lead alloys, which have been used successfully for the extrusion of long submarine cable lengths. A longer table is given in Chap. 12.

Lead and lead alloys are very soft and must be protected against mechanical damages during manufacturing, cable transport, installation, and beyond. In early times, it happened far too often that the lead sheath was ripped open by misaligned cable rollers or protruding edges. Also, early lead sheathing machines (before extrusion, a discontinuous ram press was often used) delivered sheaths with wrinkles, air intrusions, holes, etc. The risk of damaged lead sheaths was so high that many cables were produced with a double lead sheath.

Modern submarine cables are often lead-covered in extruders with high reliability providing lead sheaths with narrow thickness tolerances and good alloy stability. When screw-extruders are used for lead covering, a PE extruder can apply a PE sheath immediately after the lead extruder, thus protecting the lead during the subsequent manufacturing. On-line thickness measurements of the lead sheath and the plastic sheath contribute to a high-quality sheathing system.

The lead sheath is subject to fatigue processes. Vibrations, repeated bends, and thermal cycling can result in a recrystallisation of the lead alloy. Crystal boundaries can develop to micro-cracks and deteriorate the water-tightness of the lead sheath. Wave induced movements of the cable-laying vessel can subject the cable that hangs down from the vessel to many repeated bendings. Depending on wave characteristics, amplitude, number of bends, and bend radius, this might cause premature fatigue in the lead sheath. Eventually, the lead sheath can break.

In order to mitigate risks of fatigue due to thermal cycling, lead-covered cables have been used with an oval conductor-insulation-lead sheath system (e.g. SACOI

Table 2.3 Lead alloys and their constituents suitable for submarine cables. The table shows the designation according to EN 50307, and the conventional names for the nearest related alloy

Alloy designation acc. to		Alloy elements and percentage (by weight). Min and max values				
EN50307	Convention	As	Bi	Cd	Sb	Sn
PK012S	½C			0.06–0.09		0.17–0.23
PK021S	E				0.15–0.25	0.35–0.45
PK022S	EL				0.06–0.10	0.35–0.45
PK031S	F3	0.15–0.18	0.08–0.12			0.10–0.13

1967 200 kV d.c. cable, Vancouver Island 138 kV gas-filled cable [28]). The idea is that thermal expansion of the cable would result in a deformation from an oval shape into a circular shape of the cable rather than a strain and re-compression of the lead sheath.

2.3.2 Aluminium Sheath

Aluminium sheaths come in different shapes: extruded, welded, or laminated.

For the welded sheath, aluminium strips in the range of 0.5 up to 4 mm thickness are folded around the cable with a set-up of rolls. The strip edges are trimmed to correct dimensions and welded longitudinally forming a tube. The welding can be made with laser welding methods. The tube-like sheath can be corrugated after welding to improve the flexibility. The weld seam must be checked carefully for pinholes. Welded corrugated cable sheaths can be made from more corrosion resistant alloys than extruded.

The extruded aluminium sheath has been employed for many decades in straight and corrugated shapes. Extruded aluminium sheaths in a thickness of 2 up to 4 mm have been used occasionally for submarine cables, but heavy corrosion problems occurred. Today, extruded aluminium sheaths are not used for submarine cables anymore.

Laminated aluminium sheaths consist of a thin aluminium foil (0.1–0.3 mm thick) pre-laminated with a layer of PE-copolymers. During the cable production, this laminate is formed around the cable core with the polymeric layer outside. The edges of the laminate strip are glued together with overlap. In the same operation, a PE sheath is extruded directly onto the PE layer of the aluminium laminate. The laminate is thus firmly bonded to the outer PE sheath. Only by this bonding, the aluminium sheath is able to withstand the cable bending without wrinkles or creases. In most cases, there is a copper wire screen directly under the laminate to carry the short-circuit current. Laminated aluminium sheaths have an excellent track record from land cables. While the aluminium foil is absolutely impermeable for water and humidity, tiny amounts of humidity might diffuse into the cable through the glued seam. The amount is much depending on the seam geometry and the used materials. Z-folds can increase the diffusion path and bring down the diffusion rate considerably. Water adsorbing agents inside the cable keep the humidity level down to an acceptable level for the safe use of aluminium laminate cables in submarine medium-voltage applications.

2.3.3 Copper Sheath

Copper sheaths from welded and corrugated copper strips are sometimes used in submarine power cable applications. The corrugation machine can provide a wave structure with annular or helical gaps. For submarine cables, the annular gaps struc-

ture is preferred because it provides a better barrier against longitudinal water migration in case of damage. The profile of the corrugation "waves" may be sinusoidal, trapezoid, or another shape. These shapes have different properties regarding internal or external pressure resistance, and bending and fatigue properties. Copper sheaths are corrosion resistant and, at proper sizes, even able to carry short-circuit currents. Separate copper wire screens are dispensable. Copper properties can be improved by using alloy elements such as beryllium.

A copper sheath is considered to be very resistant against fatigue phenomena, which can demolish a lead sheath after a large number of bends. For this reason, a copper sheath can be used for dynamic power cables, which are suspended freely from floating oil and gas platforms and are subject to repeated bends due to waves.

2.3.4 Polymeric Sheaths

Polymeric cable sheaths have different functions depending on where they are located in the cable construction. A polymeric sheath usually protects the underlying lead sheath from corrosion and abrasion. For this purpose, mostly HDPE or LDPE sheaths are used. They provide excellent chemical and mechanical stability over a long life at moderate costs. Other materials used for sheathing are PVC, polyamide ("Nylon"), and polyurethane. Polyamide has even better mechanical properties than HDPE.

If there is no metallic sheath, a polymeric sheath can provide a radial water barrier. Polymeric materials are water impermeable, but water vapour can diffuse through them. For medium-voltage submarine cables, the small amount of water vapour diffusing through the polymeric sheath can be accepted as the electric field strength in medium voltage cables is small. The most common cable-sheathing polymer, HDPE, has a rather low water vapour permeability (145 gμm/(m^2·d), @38°C, 90% r.h., according to a resin supplier). Both PVC and polyamide (Nylon) have higher diffusion rates. Specialty polymers such as PVDC have much lower diffusion rates than HDPE but have not been used for power cable sheathing yet.

Small scratches or even small holes of the plastic sheath do normally not constitute any danger for the corrosion protection, as the access of oxygen-rich water is very limited.

Polymeric sheaths are sometimes made from semi-conducting PE materials loaded with carbon-black. They provide voltage equalization between the metallic sheath inside and the armoring outside.

2.4 Armoring

The most prominent construction element of submarine cables is the armoring, which provides both tension stability and mechanical protection.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 49 of 306

For every submarine cable project the armoring should be designed with respect to the tension stability, external threat pattern and protection requirements for each sector of the planned cable route.

Submarine cables are exposed to tensional forces during the installation not only by the weight of the hanging cable, but also to additional dynamic forces from the vertical movements of the vessel. The total force during installation can dramatically exceed the static force of a cable hanging down to the seafloor. Tensional forces and tensional stabilities are discussed in Chap. 3.

The armoring must also provide sufficient mechanical protection against expected external aggression by installation tools, fishing gear, and anchors.

Submarine power cable armoring is built from metal wires wound around the cable with a certain lay length (also called pitch). The lay length, i.e. the length of cable in which the armoring wire completes one turn around the cable, is between 10 and 30 times the cable diameter under the armoring. Round armoring wires have a diameter of 2–8 mm.

The design of the armoring has a strong influence on the cable properties such as bending stiffness, tensional stability, torsion balance, and on the choice of handling and installation methods. Some relations are given in Table 2.4.

A helical armoring translates a tensional force into a torsional force trying to twist the cable. In a long lay-length armoring, the wires run almost parallel to the cable axis and can take up tensional forces without building up too much of torsional forces. The tensional stability of the cable is very large. At the same time, a long lay-length increases the bending stiffness of the cable, which is undesirable.

Submarine cables with short lay-length in the armoring have generally a lower bending stiffness. Subject to tensional forces, the short lay-length armoring is tightened up inwards without taking up much of the tensional force. Much of the force is transferred to the conductor instead.

Table 2.4 Properties of some armoring concepts

Properties of armoring of single-core cables with single-layer armoring		
	Long lay-length (pitch)	Short lay-length (pitch)
Tensional stability	++	0
Bending stiffness	–	+
Torsional stiffness	+	0
Possibility to coil the cable	++	+

Properties of armoring of single-core cables with double-layer armoring				
	Unidirectional lay		Counter-helical lay	
	Long lay-length (pitch)	Short lay-length (pitch)	Long lay-length (pitch)	Short lay-length (pitch)
Tensional stability	+	–	++	o
Bending stiffness	–	+	–	+
Possibility to coil the cable	+	0	–	–

The armoring lay-length must be optimized with respect to the expected tensional forces, the tension stability of the conductor and the torsional requirements of the cable and its installation.

A cable with a unidirectional armoring can absorb torsions in one direction only: the direction where the armoring layer is opening up. This allows laying up the cable by coiling it on a storing area or fixed cable tank.

A double layer of armoring wires (DWA) provides a much stronger protection against external force than a single layer. When the two layers have different lay direction, they can prevent intrusion of sharp edges from anchor flukes, cable ploughs, rocks, etc. In a counter-helical DWA, the torsional forces of each layer counterbalance or even cancel out each other. Therefore, submarine power cables for large depths of water are equipped with torque-balanced counter-helical armoring layers.

A special combination of armoring layers is called “rock armor” and comprises an outer wire layer with very short lay length (cf. Fig. 2.9). This layer with short lay does not contribute to the tensional strength but improves significantly the crush resistance properties of the cable and results in a lower bending stiffness than a long-lay armoring [11]. This design gives a better protection against external damage caused by impacts from rocks, dropped objects and towed equipment such as fishing gear.

Counter-helical armored cables require turntables for storage and installation. With the two layers having the same lay-up direction, the cable still can be twisted and coiled. However, the necessary twisting forces can become very high. During



Fig. 2.9 Three-phase submarine cable with double-layer round wire rock armoring (Courtesy of ABB, Sweden)

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 51 of 306

laying, high tensional forces in connection with unidirectional lay create considerable torsional forces.

Flat armoring wires rather than round wires have been used successfully. They provide the necessary steel cross section with less outer diameter, saving some material and space on the laying vessel. Flat wires are more expensive than round wires. In early times of cable manufacturing, even slot-and-key wires have been used for the armoring. The wires interlock and provide a closed yet flexible armoring where no single wire can be removed [32].

For shallow water with low tensional requirements, open armoring with spaced wires can be used. The spaces can be left open or filled with spacer wires made from plastics, ropes, or something similar. Open armoring not only reduces weight but also, in case of a.c. cables, can reduce the eddy current losses. Open armoring is used but seldom as it offers less mechanical protection than a closed armoring.

In most cases, the armoring is made from mild steel, which is a magnetic material, concentrates the magnetic field around the conductor, and generates unwanted losses and extra heat in a.c. submarine cables. In single-core a.c. submarine cables, the losses in the steel armoring can reduce the ampacity substantially. Some strategies have been developed to reduce these losses:

1. Armoring made from non-magnetic materials, such as bronze, brass, copper or aluminium. Table 2.5 lists the tensile strength of some non-ferrous metals. Copper-based alloys are an expensive choice for an armoring. Aluminium is much cheaper but can easily be attacked by seawater corrosion. Armoring made from copper wires combines low resistivity with good corrosion resistance, but the mechanical strength is less than steel. Hard-drawn copper wires have a substantially better mechanical strength but slightly lower conductivity than annealed copper. A double counter-helical flat wire copper armoring has been used down to 400 m for the 500 kV a.c. submarine cables between British Columbia and Vancouver Island in the early 1980s [33].
   A superior yet expensive solution is the use of stainless steel wires for the armoring. They provide a low-loss non-magnetic armoring with high tensile strength and very good seawater corrosion resistance (valid for stainless steel with high alloy element content).

Table 2.5 Composition and tensile strength of non-ferrous armoring materials

Material	Designation	Tensile strength (MPa)	Composition
Copper	Cu−ETP	200–400	Cu 99.9%
Brass	CuZn40	340–500	Cu 59.5–61.5%, Zn: remainder
Phosphor bronze	CuSn6	340–1000	Sn: 5.5–7.0%, Zn: a few % Cu: remainder

2. Reduction of magnetic induction. The single-core a.c. cable can be provided with a massive copper screen, which is firmly grounded on both ends of the cable. A screen current is generated almost as large as the conductor current. These two currents run in opposite directions inside the armoring and virtually cancel their magnetic fields. The magnetic losses vanish almost completely but losses in the copper screen will arise instead. To achieve this goal the copper screen needs to have a cross section similar to the conductor. A counter-helical double armoring, the inner layer being of copper, the outer of steel, can make up a low-loss, high-strength armoring for single-core a.c. cables.

In three-core-cables, the magnetic fields of the three cores cancel each other to a great extend, and the magnetic losses are reduced to a lower level.

The tensile strength of steel armoring can also be achieved with modern aramid or polyester fibres (trade names: Kevlar, Vectran, Twaron, etc). Lightweight aramid fibres have been used to reinforce special submarine cables for the offshore industry since the 1970s [34]. Cords or wires made from these fibres provide only little protection against side impacts such as anchoring or fishing gear aggression. One manufacturer developed an armoring based on fibreglass-reinforced plastic (FRP) in 1985 and installed a three-core cable with one layer of polymer-sheathed FRP threads and one conventional steel wire layer between two islands in the Japanese Okinawa prefecture in 2000 [35]. The creep behaviour of ultra-high molecular-weight polyethylene fibres (trade names *Spectra* or *Dyneema*) render them not being useful for submarine cables under sustained load [36].

The armoring is applied on a bedding which protects the underlying surface (often an extruded inner sheath) from undue located press from the armoring wires. Beddings are made from fabric tapes, which offer a certain amount of compressibility. A special type of bedding tapes is known under the name Hessian tape.

2.4.1 Corrosion Protection

Marine salt water is a corrosive environment. In the open oceans the salt content is 33 through 39‰ by weight. In marginal seas, inland seas and coastal areas the salt content can vary considerably due to freshwater admixture from rivers, or evaporation under solar irradiation. The open North Sea has a salinity of 32 up to 36‰, decreasing to 15 up to 25‰ close to shore. The Baltic Sea holds 3 up to 25‰. In tropical waters the local salt content can vary largely due to strong evaporation and/or large amounts of tropical rain. Salinity also varies through the annual seasons, and with depth. Sometimes the unit *psu* (Practical Salinity Unit) is being used, with 35 $psu = 35‰$ by weight.

Corrosion must be considered seriously when designing submarine power cables. There are several corrosion mechanisms each deserving close attendance. General corrosion occurs by the impact of salt seawater onto the armoring wires. The armoring wires are in most cases made from zinc-coated steel wires. A zinc layer of 50 μm

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 53 of 306

or more is the primary corrosion protection of steel wires. The secondary protection is made by flushing the armoring with hot bitumen during manufacturing. The lifetime of the bitumen protection is much depending on the mechanical impacts on the cable. The bitumen layer can be eroded during installation or later during service when the unburied cable is hit by water currents laden with sand. Where the bitumen layer is damaged, the zinc layer takes over the corrosion protection. The corrosion rate of zinc coatings in seawater is depending on many factors such as salinity, temperature, water exchange around the cable, etc. Reference values of the corrosion rate of zink layers are 5–50 μm/year [37, 38]. Investigations of retrieved cables after decades of exposure in the Baltic Sea have shown a zinc layer corrosion rate of about 1 μm/year. When the zinc is gone, the steel may be consumed at rates of 10 μm/year [39]. An important role for the corrosion plays the free access to fresh sea water containing dissolved oxygen. If the water exchange around the cable is inhibited by soil or protecting layers, the existing oxygen close to the cable is not replenished and the corrosion rate will decrease considerably.

Electric corrosion has been identified as a possible strong effect. The corrosion is associated to electric currents entering and leaving the steel wires from the ambient. Tidal flows in combination with the earth's magnetic field are alleged to cause these currents [35]. Also stray currents from onshore railways, nearby cathodic protection systems of pipelines, or strong welding operations have been identified as sources of electric corrosion [39].

Sacrificial zinc wires are sometimes used to protect steel wires from corrosion, much similar to the anti-corrosion zinc anodes used in naval applications. This anti-corrosion protection method works only if the sacrificial zinc anodes have a sufficient good galvanic contact to the protected steel wires. Given the bitumen flushing during the manufacturing process, the electric contact between the wires is only random and the zinc wire method is not considered to be very successful.

Also semiconductive polyethylene can be involved into electric corrosion. It may act as a galvanic agent connecting two metals with different electrochemical potential leaving the lower rated metal to corrosion. Also, the semiconductive polyethylene can suffer from decarbonisation and eventually punctuation as a result of a d.c. stray current over a certain density [39].

The armoring wires can also be corrosion-protected by an individual polymeric sheath. The direct contact to salty seawater is excluded, as long as the sheath is not washed away by sand abrasion. The method can avoid much of the troublesome bitumen layer. The method has been used occasionally and might be considered for OWP in-field cables. When preparing cable ends for terminations on offshore wind turbines, the brittle bitumen will crack from the cable ends and soil down the place. Here, plastic-coated armoring wires could be a better alternative. However, when damaged, the individually extruded sheaths could lead to an adverse effect, when pitting corrosion occurs from localised current going into the wire.

Corrosion affects but a fraction of armoring wires at singular spots. The remaining wires still offer a protection against external forces even if the tensile force of the cable has decreased.

The armoring can also be constructed from more corrosion-resistant metals. Copper, bronze, and brass wires have been used as armoring. However, aluminium

should not be used in seawater. The 1970 Long Island cables suffered severe seawater corrosion of its armoring made of Al—Mg—Si "Aldrey" alloy [40]. Aluminium armoring has been used in brackish waters [41] with doubtful results, but can be considered for freshwater.

The use of an outer extruded plastic sheath over the complete cable as a corrosion protection is useful as long as the sheath is undamaged. Local damages in the sheath can concentrate corrosion-enhancing galvanic currents.

2.5 Outer Serving

Scratches can deteriorate the anti-corrosion effect of bitumen and zinc layers. To avoid this, an outer serving protects the corrosion protection of the cable armoring during loading, laying, and burying of the submarine cable. Modern submarine power cables have either extruded polymeric outer servings or servings made from wound yarn layers. Cables with wound yarn layers are designed for the seawater penetrating into the armoring wires to the plastic inner serving (semi-wet design). The water exchange in the narrow interstices under the yarn layers is very limited and reduces corrosion rates considerably. The yarn layers play a sacrificial role, and small damages during handling or laying are not considered harmful. For power cables intended to be coiled for storage or installation, the lay direction of the yarns should be the same as for the armoring wires. Otherwise the yarn layers can easily be exploded by the opening of the underlying steel wires.

An extruded outer serving provides a neat appearance of the submarine power cable and most often a dry environment for the armoring wires. Still, the armoring system must be designed for water exposure in case of damage in the extruded serving. The damage could soak the complete armoring with seawater and enhance local corrosive stray currents.

The friction coefficient of the outer serving must be taken into account for the design of the installation procedure. Wound yarn layers provide a good grip for cable pulling engines on board the CLV, while extruded servings are more slippery.

The outer serving usually has markings to make the cable visible for ROV cameras and to distinguish the cable from other cables on the seafloor. Extruded outer servings can be provided with a longitudinal strip in a different colour. In wound yarn servings, some of the outer yarn threads are usually replaced with threads of different colours generating a helical pattern. White, yellow and orange strips provide a good contrast to the black background colour. When laying more than one cable on a confined space, a different marking of the cables can help to identify the cables on the seafloor. For a pair of HVDC cables, it makes sense to identify one cable with one stripe, the other with two.

The inner serving layer of submarine cables is often soaked with bitumen in order to corrosion-protect the underlying steel armoring. The bitumen can cause some problems during the cable installation. In warm weather, the bitumen may exude from the cable on-board of the cable ship and aggregate on the cable rollers and cable engines to thick disturbing layers. Also, when preparing cable ends for

termination on offshore installations, such as offshore wind turbines, the brittle bitumen will crack from the cable ends and soil down the place. For these cases, plastic-coated armoring wires could be a better alternative. The sticking of bitumen-soaked cables on the turntable can be relieved by coating the outer serving with lime wash.

2.6 Three-Core Cables

Modern medium-voltage submarine cables ($\leq$52 kV) are usually designed as three-core (3C) cables with XLPE insulation.[2] The cable cores are similar to those of land cables. Many different design alternatives are used for this class of submarine cables. Many cable constructive layers can be applied either to each single core, or to the three cores in common. Furthermore, many different screen/sheath configurations can be found.

Depending on the specifications submarine medium-voltage cables can be produced with or without a metallic sheath. The low electric stress in extruded medium-voltage cables allows for a cable design without total lock-out of water. An extruded plastic sheath provides a secure water barrier while water-absorbing agents inside the plastic sheath can take care of the minute amount of water vapour, which can diffuse through the extruded plastic sheath.

Another common system is the aluminium laminate for water protection combined with a copper wire screen. The aluminium laminate constitutes a radial water barrier, while the copper wire screen is designed to carry fault currents.

The non-metallic sheath of three-core submarine cables can be produced from semi-conducting polymeric materials. The capacitive currents of the three phases can balance each other, which can increase the cable ampacity. Many different combinations of sheath, screen, and corrosion protection are possible. Manufacturers have their own "recipes" to meet the very different conditions and requirements of submarine power links.

High-voltage cables are available in 3C design up to and including 170 kV. The first 245 kV 3C submarine cable has been installed in a moderate length of 7.8 km in Canada in 2008. This system voltage is possible for short cables without the requirement of flexible joints, which are not available yet for higher voltages. Almost all modern high-voltage 3C cables are produced with XLPE insulation.

Once the cable cores are manufactured and tested, they are laid-up to provide the flexibility of the cable. Beside standard S and Z lay-ups, there is also a S-Z-lay-up for mv cables, where the cable cores are twisted right-hand and left-hand in sequence. After lay-up, the diameter of the 3C cable over the core binder is 2.16 times the diameter of the individual cores. Four interstices are generated during the lay-up, three in the periphery and one central. To provide a stable circular base for the armoring, the outer interstices are normally filled with fillers. Ropes of different

[2]Some manufacturers still offer medium-voltage submarine cables with mass-impregnated insulation. They may have shaped individual cable cores providing a circular base for the lead extrusion.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 56 of 306

sizes or tailor-made extruded polymeric profiles are used to fill the space. Extruded profiles from PE or PVC provide an excellent support for the armoring wires and can accommodate small optical cables. PE requires more complicated extruding dies but lower material costs per unit length of the cable, compared to PVC. For very long submarine cables, the use of PE is more economic, and for short length, PVC is the cheaper alternative. Even lead profiles have been used as filler profiles, when the cable needs additional weight for an installation in streaming water.

Filler ropes can be made from recycled polymeric material of any kind. A combination of three ropes of two sizes can fill the interstices reasonably well.

The central space of the cable usually does not need a filler for stability. The three cable cores support each other so they do not collapse into the central space. It is not suitable to include an optical cable into the central space because it might be exposed to tensional forces as the central line is not the neutral line in cable bending.

After lay-up, or sometimes in the same operation, the cable is fed into the armoring machine. In 3C a.c. cables, the magnetic fields from the conductor currents cancel each other to a large extent. Therefore, the armoring can be made from steel wires without excessive magnetic losses. 3C cables for high voltage can easily reach a diameter of 200 mm and more. As the number of spools in the armoring machine is limiting the number of armoring wires on the cable, sometimes very thick steel wires must be used to cover the entire circumference of the cable. For a cable with 200 mm diameter (under the armoring) and an armoring machine with a capacity for 84 wires, the combined steel cross section of a single armoring layer would be about 3700 mm^2. This massive armoring would be sufficient for more than 300 m laying depth. Flat armoring wires can offer sufficient steel cross section for shallow waters and still cover the complete cable circumference. However, the protective effect against external aggression of armoring wires goes down with the square of the wire diameter. Many cable operators think that the better protection of round wires justify the increased material costs compared to flat wires.

3C cables have been produced also with oil-filled insulation for up to at least 170 kV. These cables are always equipped with a lead sheath, either a common lead sheath for all three cores, or individual lead sheathes for each core. In a common lead sheath, the interstices between the cable cores provide conduits for the oil transport to and from the “breathing” cable under the influence of load changes. An oil conduit in the centre of the conductor is not necessary. Filler ropes in the interstices give some support to the extruded lead sheath. However, a common lead sheath over three cable cores plus some filler ropes is not a very stable design. These cables are sensitive to fatigue, and external forces or movements can damage the lead sheath. Also, these cables can be manufactured only in a short length and require many joints for long installation lengths. The 150 kV Java-Madura 3C oil-filled cable (commissioned 1987) has a common lead sheath and was produced in short drum lengths. These were transported to a jointing facility at the port where the cable pieces were jointed and loaded on-board the vessel [42].

3C-cables with individual lead sheath (denominated “S.L.” for “single lead”) have been used since many decades ago as submarine cables. Especially 3C cables with extruded insulation are almost always made with individual lead sheaths.

The individual lead concept has some important advantages over the common-lead concept:

- larger flexibility in the factory to joint individually sheathed cable cores
- better stability of lead sheaths because they are smaller in diameter and have a circular core underneath
- better stability during installation.

The advantage of a 3C cable with common lead sheath is the large oil channel provided by interstices in-between the individual cores. But for all practical applications these systems can be replaced by XLPE systems today without the need of oil channels or oil feeding.

Oil-filled submarine cables are still being produced for the EHV level – 500 kV and higher. Cables at this voltage levels are so massive that they cannot be produced as 3C cables.

As 3C oil-filled submarine cables are not produced anymore, this subject is not further elaborated here.

2.6.1 Choice Between One Three-Core and Three Single-Core Cables

In some cases, the customer has the choice between one 3C cable and three 1C cables for the selected route. The best choice is not always obvious but depends on a large number of factors including cable route characteristics, installation and protection methods, factory facilities etc. The following considerations apply only to a.c. cables.

The armoring losses in 3C cables are significantly lower than in 1C cables because the magnetic fields from the three conductor currents cancel each other to a large extent. Therefore, 3C cables can be equipped with armoring of mild steel wires where 1C cables require more sophisticated armoring solutions. The lower losses in a 3C cable may allow for a smaller conductor to achieve the required ampacity. On the other hand, the heat transfer from a 3C cable is inferior to that from a group of spaced 1C cables. A detailed thermal calculation of both concepts will reveal the required conductor size for the 1C and 3C solution.

A 3C cable is in principle more expensive than the sum of three 1C cables on account of the additional factory step of lay-up of the three cable cores. The largest lay-up machines today can handle continuous cable core lengths of a few kilometres. For longer 3C cables, the lay-up machines need to be reloaded with new cable core making flexible factory joints necessary and thus adding to the costs.

Whereas 20 years ago 3C cables could be delivered only in short lengths, making many joints necessary, the situation is much different today. Depending on the equipment of the supplier, 3C cables for 100–170 kV can be delivered in continuous lengths of 50 km and beyond. A 50 km 115 kV 3C XLPE cable was supplied and installed in one piece in Saudi Arabia in 2004. The limitation today is set by the capacity of factory turntables and cable laying vessel (approx. 3000–7000 t).

The choice of 3C vs. 1C cables has a strong influence on the cable installation. A 3C cable can be installed in a single run, provided the vessel could load sufficient cable for the entire cable route. A group of 1C cables would require multiple installation runs including foregoing route survey and route clearing. 1C cables can often be installed and buried with lighter equipment than 3C cables because the cable's unit weight, bending stiffness, and bending radius are smaller.

It has been suggested to use 1C cables and install them simultaneously bundled in the same trench. Here, the drawbacks of both concepts (large armoring losses in 1C cables, bad cooling of 3C cables) are combined. Furthermore, cable laying vessels equipped for the simultaneous laying of three power cables are not easily available.

Another important aspect is the availability of the cable systems. It is common practice to install a group of 1C cables with some distance (up to several hundred metres) to avoid multiple damages. Also, it is common practice to install four cables for a three-phase circuit, or seven cables for two circuits, in order to have one spare. In case of a cable fault, the circuit can be restored within hours using the spare cable. The cable fault can then be repaired whenever practically possible. Loss of revenue can be avoided to a large extend. To achieve a similar redundancy for a 3C cable only a second 3C cable would do at considerable costs.

The question of single-core cable vs. three-core cables is further discussed in reference [43].

2.7 Two-Core Cables

Two-core cables have been used for HVDC systems where two conductors naturally occur. A development of the Mollerhoj cable has two fully insulated cable cores in a common lead sheath and has been used for the Danish part of the KontiSkan link. The pressurised oil filling provides a cavity-free paper insulation and can be operated at 70°C conductor temperature. Both cable cores are operated at the same voltage, and the return current goes through the sea electrodes. The latest submarine cable of this kind was the Kontek link between Denmark and Germany with 600 MW d.c. power in 1996.

The NorNed HVDC cable between the Netherlands and Norway has two cable cores with individual lead sheaths inside a common armouring (cf. Fig. 2.10). The cable cores are operated with opposite voltages, and there is no need for a sea electrode. The advantage of two-core HVDC cables with opposed currents is the almost total cancelling of the external magnetic field. This effect, however, can be achieved easier by a tight bundling of two single-core cables during laying.

A novel use of two-core submarine power cables may arise from suggestions to install 6-phase a.c. cable systems to bring massive offshore wind farm power to shore [44]. According to these suggestions, two cable cores with opposite phase would be combined into a two-core cable with common armoring. Magnetic losses in the steel armoring would be minimised.



Fig. 2.10 Two core 450 kV HVDC cable for the NorNed project

Flat two-core cables can be bent easily but in one direction. This property makes manufacturing, loading, and installing difficult and requires considerable investments in equipment.

2.8 Coaxial Cables

Coaxial cables have been used in earlier times to achieve concentric cables even in multiphase (two or three) systems (Fig. 2.11). Due to the difficulties of jointing and termination, they have been considered as impractical already more than 60 years ago [45]. Still, coaxial HVDC cables were installed in the Moyle Interconnector between Scotland and Ireland, in 2002.



Fig. 2.11 Early two-conductor coaxial cable on display in Les Renardiers Research Center, Moret-sur-Loing, France

2.9 Optical Fibres Inside Submarine Power Cables

Optical fibres can be integrated into submarine power cables for several purposes:

1. Distributed measurement of temperature (DTS)
2. Data transmission
3. Measurement of cable strain or vibrations
4. Fault detection and location
5. Detection of changes in the cable route, e.g. changes in sediment cover over the cable.

Temperature measurement is based on short laser impulses launched into the fibre, and the back-scattered light (Raleigh scattering). The back-scattered light contains not only the original laser light wavelength but also faint side bands in the wavelength spectrum. The temperature can be determined from the ratio of the intensity of the spectral bands. As the back-scattered light from different distances in the fibre arrives at different times in the monitoring unit, a spatially resolved temperature measurement can be achieved. Different spectral phenomena can be used for temperature measurements. The temperature measurement unit provides a temperature profile along the length of the submarine cables. Some systems allow matching the profile into a map of the cable route for easier identification of hot-spots.

For a submarine power cable equipped with a DTS, a temperature profile of the cable route can be recorded some weeks after the cable commissioning, taking into account the initial warm-up. This reference temperature profile reflects the thermal characteristic along the cable route, such as soil cover, ambient temperature, etc. and can be used as a reference profile for comparison of subsequent measurements. The seafloor topography can change considerably due to tidal or other currents in the water, storms or human activities. Unwanted thick soil sediments above the cable, as well as unwanted de-burial of the cable result in changed thermal conditions, which can be detected by DTS when the cable is loaded. The data help the cable operator to decide on necessary corrective actions on the seafloor to restore cable protection or improve heat transfer from the cable.

Unfortunately, the DTS system suppliers use different terms to describe the accuracy of the temperature measurement systems. It is not always easy to compare the performance of different systems. Today, the largest length of temperature monitoring is about 30 km. Depending on the measurement system, the DTS needs one or two fibres, and there are different requirements on the need of connecting the far end of the fibres. If the far end is on shore, the loop can be made within a standard fibre joint box. However, if the monitored cable length ends somewhere *en route* in the sea, the connection of the far end can require the use of a joint box deep in the water. Sometimes very long lengths of DTS monitoring are stated, but this requires relay or amplifying boxes *en route*, which is rarely an option in submarine power cables.

Optical fibres can also be used for fault location. Standard OTDR (Optical Time Domain Reflectometry) methods use the attenuation of back-scattered laser impulses to determine the location of fibre damages. The measurement can easily

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 61 of 306

be done from shore with standard instruments available at any fibre network installation company. Attenuation abnormalities and fibre breaks can be located with high accuracy (a few meters up to a few tens of meters). However, optical fibres can detect and locate power cable faults only to a certain extend. In a ruptured power cable, the fibre break will be clearly visible in the OTDR. But an anchor can damage the fibre (mostly laying in the cable armoring) without damaging the power cable core. A fibre break does not necessarily mean a broken power cable core, and a breakdown in the power cable insulation will not necessarily cause a detectable damage in the fibre.

The primary purpose of optical fibres, data communication, is also pursued in the combination with submarine power cables. Enormous submarine telecom cable networks embrace the planet. Extremely long hauls are covered, assisted by active or passive amplifier units. Though submarine power cables have been equipped with datacom fibres, a combination of submarine power cables and repeatered (=with amplifiers/repeaters) fibre-optical lines have not been tried yet. The reach of unrepeatered data transmission in increasing steadily. At standard data transmission rates of 5 or 10 GB/s for each fibre, repeater-less links can cover 200 km and more.

In-field cables in OWP's are made as three-core medium-voltage cables with integrated optical cables for monitoring and control of the turbines. The fibre cable sits inside the interstices between the cable cores. The short length of these cables (typically 200–1000 m) allows for unspliced optical cables with high fibre counts. The fibre attenuation is often less important in these short lengths. Optical cables with welded steel or copper sheaths and a diameter of 10–20 mm are commercially available with high fibre counts (96 fibres or more), and can be integrated into the interstices between the cable cores. However, the data flow between offshore WTG could easily be handled by a handful of fibres. Large fibre counts require high efforts for testing and splicing. In case of failure, the complete cable would be replaced rather than jointing both fibre and power elements.

Longer three-core cables for a.c. for high-voltage, too, can be equipped with optical cables in the interstices between the cores.

In single-core submarine cables, the optical fibres can be accommodated in the armoring. The fibres are housed in a stainless steel tube of 0.9–4 mm diameter. A plastic sheath on the stainless steel tube has a diameter equal to or slightly under the diameter of the armoring wires so that the element can be placed instead of one of the armoring wires (cf. Fig. 2.10). The plastic sheath prevents galvanic corrosion between the stainless steel tube and the armoring wires, and gives protection against squeezing of the tiny tube.

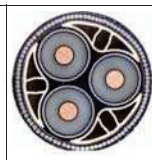
In the tough environment of a cable armoring machine, the metallic tubes must be handled with great care. Undue strain and bending of the tubes result in increased attenuation or even break of the fibres long before the steel tube is being damaged. By its own Young modulus, the plastic sheath can increase the maximum allowed tension by up to 25% depending on the sheath thickness and material specification. PVC, PE, PP, PA can be used for the sheath. Tiny armoring wires around the centre steel tube, embedded into the plastic sheath, can provide additional tensional strength.

Optical fibres located in the armoring of rather long single-core submarine cables are at risk of damage by external force. Damages would require the jointing not only of the optical element but also of the power cable core. Fibre and power cables are very different in characteristics and repair conditions so it might be prudent to separate the systems and lay separate power and fibre cables (maybe in one single operation).

2.10 Five Generic Cable Types

The large number of different submarine power cable species and their varieties may be confusing to those not deeply involved in the subject. It is one of the main tasks of this book to create a better understanding of possibilities and constraints of submarine power cables. To do so, five generic cable types are presented here in tabular form.[3] Application and prominent characteristics are summarised.

Table 2.6 Five generic submarine power cable types

					
Cable Type No.	1	2	3	4	5
Rated voltage U_0	33 kV a.c.	150 kV a.c	420 kV a.c.	320 kV d.c.	450 kV d.c.
Insulation	XLPE, EPR	XLPE	Oil/paper or XLPE	Extruded	Mass-impregnated
Typical application	Supply of small islands, connection of offshore WTG	Connection of islands with large population, OWP export cables	Crossing of rivers/straights with large transmission capacity	Long-distance connections of offshore platforms or wind parks	Long-distance connection of autonomous power grids
Max. length	20–30 km	70–150 km	< 50 km	>500 km	>500 km
Typical rating	30 MW	180 MW	700 MW/ three cables	1000 MW/ cable pair	600 MW/ cable

[3]The pictures in Table 2.6 are courtesy of NSW, Germany (cable no. 1), ABB, Sweden (cables no. 2, 4, 5) and Prysmian, Italy (cable no. 3).

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 63 of 306

The selected five cable types represent the majority of submarine power cables installed today. Other designs of course exist. Some of them are of historical interest, or have been used only in few cases. Others are highly specialised niche products such as power supply cables for subsea installations of the oil and gas industry.

Voltages and ratings are given for the five generic cables. That does not imply that these cables are standard cables. Submarine power cables are no off-the-shelf products. Most cable investments have different conditions that require variations of the cable design data. Multi-buyers, however, would gain from defining cable standards in order to reduce costs for redesign and type-testing.

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NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 64 of 306

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Chapter 3
Design

Contents

3.1 Thermal Design 51
3.1.1 Single-Core HVDC Cables 52
3.1.2 a.c. Cables 59
3.1.3 Other Factors for the Thermal Design 64
3.1.4 The 2 K Criterion 73
3.1.5 Economic Aspects of the Thermal Design 75
3.2 Design of Mechanical Properties 78
3.2.1 Tensional Forces During Laying 79
3.2.2 The Cigré Test Recommendation 81
3.2.3 Distribution of Mechanical Stress Between Conductor and Armoring 83
3.2.4 Other Forces and Impacts 85
3.2.5 Vortex Induced Vibrations 88
3.3 Electric Design 90
3.3.1 The Concept of Electric Strength 90
3.3.2 The Weibull Distribution 91
3.3.3 Dielectric Design of a.c. Cables 94
3.3.4 Dielectric Design of d.c. Cables 97
3.3.5 Dielectric Design of Mass-Impregnated Cables 100
3.3.6 Impulse Stress 101
3.3.7 Availability and Reliability 102
References 103

3.1 Thermal Design

The aim of thermal design of submarine power cables is to devise a conductor size, which transports the required power without exceeding design temperature limits of the cable or the environment. The thermal design of power cables has been described in many textbooks [1–3] and industrial standards [4] and shall not be repeated here in all details. Instead, this book is supposed to convey an understanding for the

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principles of thermal design. Items particular to submarine cables are also touched. Project planners and decision makers may learn about some aspects of the thermal design and especially the aspects related to submarine power cables. For detailed calculations of a particular case, the "cookbook recipes" can be found in the textbooks or obtained from submarine power cable manufacturers.

The basis of all thermal design is a thermal model of the cable. During operation, heat is generated in parts of the cable construction (heat sources), which is transported to the outside of the cable and disappears into the ambient (heat sink). On its way from the source to the sink the heat is traveling through various layers in the cable and in the ambient. The thermal model tries to describe the real situation by a system of equations. With a better knowledge on the cable design and the ambient conditions, a more precise model can be generated. The thermal model must be able to describe continuous and transient conditions.

The cable operator wants to use his assets to achieve maximum benefit without jeopardizing the reliability or useful life of the asset. The benefit from a power cable lies in the accumulated transmitted energy and in the maximum power transmitted at any time. This must be achieved without exceeding the maximum operational limits of the cable.

The cable operator expects answers from the thermal model to at least the following questions:

- Which conductor cross section is necessary for the required transmission power under the given ambient conditions?
- Which short-term overload can I transmit, if the cable already has reached at a certain temperature?
- How does the maximum load change during the annual temperature variations?
- Which regular load pattern can be used under given thermal conditions?
- What happens if other cable operators install cables nearby?

Thermal models with various complexity are available for different purposes. Some simple cases, the dimensioning of a single-core HVDC cable and a pair of HVDC cables in a homogeneous seafloor, are described here to illustrate the basic idea. The symbols are corresponding to those used in the well-known industrial standard IEC 60287 [4].

3.1.1 Single-Core HVDC Cables

The ohmic losses in the conductor are the only heat source in an HVDC cable.[1] The loss P_L can be described as

[1] Most HVDC links have a harmonic spectrum of overtones laying on top of the d.c. current. These overtones create some extra losses which however most often are very small, and are neglected here.

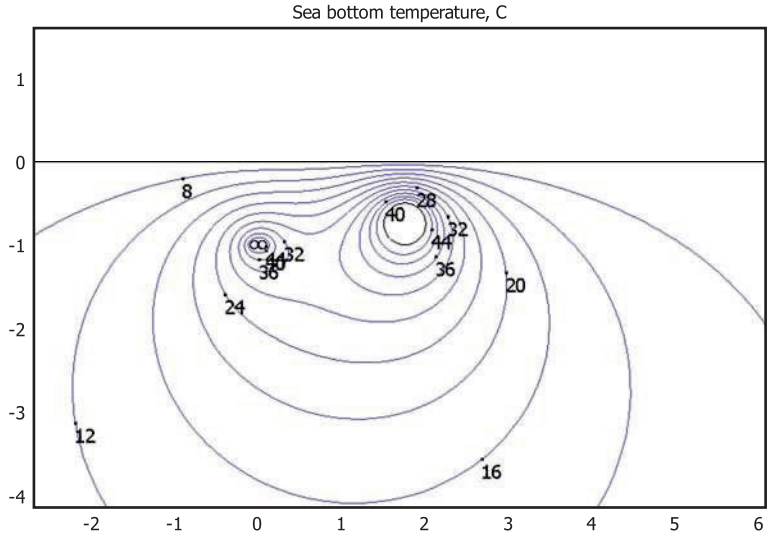


Fig. 3.1 Equithermal lines in an installation of a pair of buried submarine cables (*left*) close to a pipeline (*center*) with 50°C surface temperature. The seafloor temperature at level 0 is assumed to be 4°C

$$P_L = I_C^2 \cdot R' \tag{3.1}$$

where the conductor resistance R' is depending on the temperature:

$$R' = R_{20°C} \cdot (1 + \alpha(\Theta_C - 20°C)) \tag{3.2}$$

Both ohmic losses P_L (W/m) and conductor resistance R' (Ω/m) are given as per-unit-length of the cable. The conductor resistance at 20°C for various conductor sizes is given in Table 3.1. The values apply to conductors made from compressed round wires (IEC 60228 class 2).

Other conductor designs may have, with identical cross section, different resistance values due to other lay length, the presence of water-blocking compound, etc. HVDC cables with Conform-produced profiled conductor wires have often lower resistance values than those in Table 3.1. However, the values above may be used for the thermal design of HVDC cables as they constitute a conservative approximation.

Under steady-state conditions, all the heat generated in the conductor must flow to the outside of the cable. First the heat flows through the cylindrical dielectric insulation. The equation

$$\Delta\Theta = P_L \cdot T_1 \tag{3.3}$$

describes the relation between the temperature drop $\Delta\Theta$ across the insulation wall and the thermal resistance T_1 of the cylindrical insulation wall. For T_1:

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 69 of 306

Table 3.1 Resistance values for copper and aluminium conductors according to IEC 60228, class 2

	Copper	Aluminium
Specific electric resistivity@20°C, $\Omega mm^2/m$	0.01786	0.02874
Thermal coefficient of the specific electric resistivity @20°C, 1/K	0.00392	0.0042
Conductor resistance according to IEC 60228, Class 2. 20°C	Ω/km	Ω/km
240 mm^2	0.0754	0.125
400 mm^2	0.0470	0.0778
500 mm^2	0.0366	0.0605
630 mm^2	0.0283	0.0469
800 mm^2	0.0221	0.0367
1000 mm^2	0.0176	0.0291
1200 mm^2	0.0151	0.0247
1600 mm^2	0.0113	0.0186
2000 mm^2	0.0090	0.0149

$$T_1 = \rho_T/(2\pi) \cdot \ln(D_o/D_i) \tag{3.4}$$

where D_o is the outer diameter of the insulation screen and D_i the diameter of the conductor. Although the semicon layers of the screens and the insulation have completely different electric properties they have similar thermal properties and therefore they are combined into T_1. The symbol ρ_T denotes the thermal specific resistivity of the insulation material. Table 3.2 lists the specific thermal resistivity for some materials.

In a similar way, the thermal resistance of other cylindrical layers in the cable can be determined. For an arbitrary layer n:

$$\Delta\Theta_n = P_L \cdot T_{(n)} = \rho_T/(2\pi) \cdot \ln(D_o/D_i) \tag{3.5}$$

Table 3.2 Thermal resistivity of cable design materials according to IEC 60287

Insulation	Specific thermal resistivity K·m/W
Paper insulation, oil-filled cables	5.0
Paper insulation, mass impregnated	6.0 (according to IEC 60287)
PPL	5.5
Polyethylene, XLPE or PE thermoplastic	3.5
Polyethylene for extruded HVDC cables	3.5
EPR for cables above 3 kV	6.0
Outer serving	
PE	3.5
PVC	6.0
Polypropylene yarn immersed in water	3.7 (estimated)

with $\Delta\Theta_n$ being the temperature drop over the nth layer. $T_{(n)}$ is the thermal resistance of the nth layer, D_o the outer diameter and D_i the inner diameter of the layer. In our cylindrical single-core cable the total temperature difference between the conductor and the cable surface now is

$$\Delta\Theta = \sum\nolimits_n (P_L \cdot T_{(n)}) = P_L \sum\nolimits_n T_{(n)} = I_C^2 R' \sum\nolimits_n T_{(n)} \tag{3.6}$$

where I_C is the conductor current. The sum runs over all layers in the cable. The thermal model of IEC 60287 defines four thermal layers T_1 to T_4 for the cable and its ambient soil as follows:

T_1: Thermal resistance of the dielectric insulation as defined in Eq. 3.4.
T_2: Thermal resistance between metallic screen/sheath and armoring. This layer also includes bedding layers under the armoring.

$$T_2 = \rho_T/(2\pi) \cdot In(1 + 2\,t_2/D_s). \tag{3.7}$$

where t_2 is the layer thickness and D_s is the outer diameter of the metallic screen/sheath. The extruded plastic sheath over the lead sheath of submarine cables is accounted for in T_2. The bedding is often bituminized fabric tape, sometimes arranged with overlap so that their thermal behavior is difficult to describe. Fortunately the bedding is less than 1 mm in thickness and contributes so little to the total thermal resistance that possible errors in the assumed thermal resistivity are acceptable.

T_3: Thermal resistance of the outer sheath (serving) over the armoring.

$$T_3 = T/(2\pi) \cdot In(1 + 2\,t_3/D'_a). \tag{3.8}$$

where D'_a is the outer diameter of the armoring and t_3 is the layer thickness of the serving/outer sheath. The ρ_T values for some serving materials can be found in Table 3.2.

Metallic screens covering the complete cable can be neglected, as their thermal resistivity is negligible in comparison with that of other cable construction materials. In this context we assume: ρ_T (metal) = 0, $T_{(n)}$ (metal) = 0.

Flat wire armoring with dense laying acts as a consolidated metallic layer and has virtually no thermal resistance compared to other cable layers. An armoring made from round wires, however, is a mixture of metal with low thermal resistivity and air/water/bitumen having a higher thermal resistivity. A detailed differential analysis shows that the composed thermal resistance of a layer of densely packed round wires is at the most 1.5 times the thermal resistance of a solid metal layer of the same thickness. Given the low thermal resistance of metals in the cable construction, we can neglect the thermal resistance of densely packed wire armoring no matter if the interstices between the wires are filled with air or water.

Now, the thermal resistances of all cable layers have been computed. For buried submarine power cables the heat flow continues through the seafloor soil. The accumulated thermal resistance between the buried cable and the sea floor is designated T_4 according to the symbols used in IEC 60827.

3.1.1.1 Single Buried Cable

For a single cable buried in homogeneous sea bottom soil at depth L the thermal resistance T_4 between the cable surface and the seafloor is:

$$T_4 = \rho_T/(2\pi) \cdot In(2\,u) \tag{3.9}$$

where $u = 2L/D_e$, relating the burial depth L to the cable diameter D_e. The burial depth L is defined as the vertical distance between the seafloor and the cable axis (cf. Fig. 3.2). Equation 3.9 is a good approximation for $u > 10$ and applies for most buried cables. For a shallower burial depth of the cable, IEC 60827 suggests more complicated formulae. Typical values for the thermal resistivity ρ_T of the seafloor soil are given in Table 3.6 in Sect. 3.1.3.1.

3.1.1.2 A Pair of Buried Cables

For two identical equally-loaded HVDC cables laid in the same depth, T_4 can be calculated as:

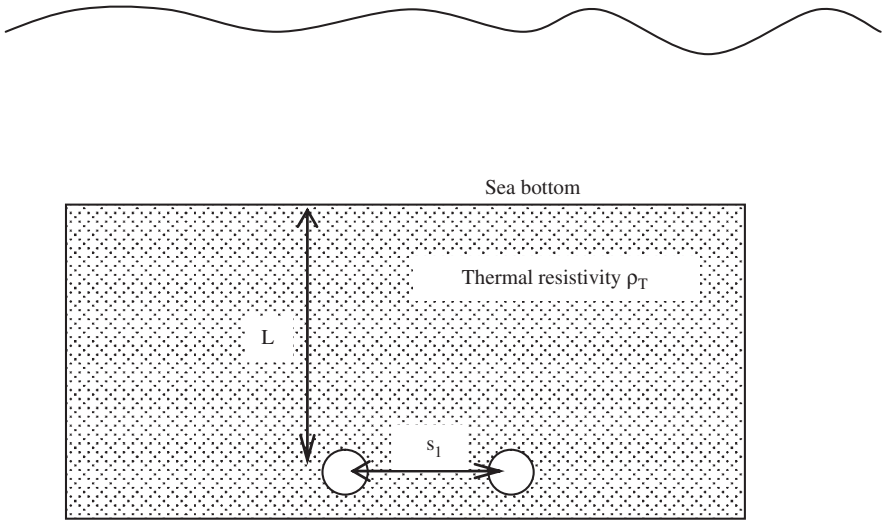


Fig. 3.2 Symbols used for the calculation of T_4

$$T_4 = \frac{\rho_T}{2\pi}\left(\ln\left(u + \sqrt{u^2 - 1}\right) + \frac{1}{2}\ln\left(1 + \left(\frac{2L}{s_1}\right)^2\right)\right) \tag{3.10}$$

For $u > 10$ (which is most often true in submarine installations) the term $(u + \sqrt{(u^2 - 1)})$ can be replaced with *(2u)*.

D_e outer Diameter of the cable/s
L laying depth, as measured from the sea floor surface to the cable axis
s_1 axis distance of the cable pair
ρ_T specific thermal resistivity of the soil material.

The important T_4 value for a pair of identical equally loaded cables can also be found from Fig. 3.3. The figure shows the ratio of T_4 normalized for ρ_T as a function of L/D_e, i.e. the relation between burial depth and the cable diameter. The parameter is the ratio between the burial depth and the cable spacing s_1. Knowing the laying parameters and the cable diameter, the value T_4/ρ_T can be found from the graph. Finally T_4 is obtained by multiplying with ρ_T. Most submarine HVDC cable links can be assessed with Eq. 3.10 as both cables of a HVDC pair are equally loaded and buried at the same depth.[2] Local moderate differences in the burial depth have only little influence on T_4.

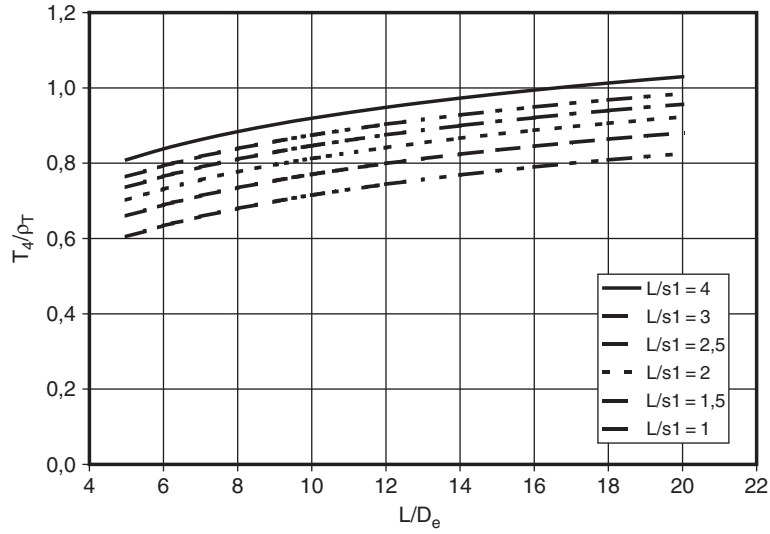


Fig. 3.3 Thermal resistance T_4 of the soil (related to ρ_T) vs. the laying geometry. Denotations are explained in the text

[2]Monopolar HVDC systems with one pole cable and one metallic return cable should be calculated with different equations, as the cables are not identical.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 73 of 306

Now we have calculated the thermal resistances T_1 to T_4 and can continue to calculate the ampacity[3] of the HVDC cable as follows:

$$I = \left[\frac{\Delta\Theta}{R'\,(T_1 + T_2 + T_3 + T_4)}\right]^{0.5} \tag{3.11}$$

Here $\Delta\Theta$ is the maximum allowable temperature difference between the conductor temperature Θ_c and the undisturbed ambient soil temperature Θ_{amb}:

$$\Delta\Theta = \Theta_c - \Theta_{\text{amb}}$$

As an example the ampacity of a pair of extruded HVDC cables (Cable type 4) is determined (Table 3.3 and Table 3.4):

The thermal design of most submarine HVDC cables and cable pairs can be performed according to the simple model of Eqs. 3.9 and 3.10. A more detailed calculation is required when both conductors of a HVDC link are combined into one cable, such as in the Kontek, NorNed and Moyle Interconnector.

Table 3.3 Thermal properties of a pair of extruded HVDC cables

Cable design data	
Conductor 1200 mm^2 Cu	$D =$ 39.9 mm
Conductor resistance at 70°C	R(70°C) = 0.0182 Ω/km
Maximum allowed conductor temperature	70°C
Insulation system (1.2 mm semicon, 12 mm insulation, 1.2 mm semicon)	$T_1 = 0.328$ K·m/W
Lead sheath, thickness 2.5 mm	
Plastic sheath, thickness 2.5 mm	$T_2 = 0.036$ K·m/W
Armoring round wires, 5 mm wire dia	
Outer serving yarn thickness 4.0 mm	$T_3 = 0.087$ K·m/W

Conductor tapes, bedding tapes etc are not mentioned but included in the calculations.

Table 3.4 Thermal rating of a pair of extruded HVDC cables

Cable installation data	
Laying depth under the sea floor	1.5 m
Spacing between the cables	5 m
Thermal resistivity of the sea floor	0.8 K·m/W
T_4	0.5423 K·m/W
Ambient temperature in the sea floor	8°C
Current rating	1854 A per cable

[3]The word ampacity denotes the current carrying capability of a cable and has been coined by W. A. DelMar of Phelps Dodge Wire&Cables in 1951 [2].

Mainly two strategies are used to increase the ampacity of the cable system to meet the project requirements: changing the laying parameters (depth and spacing), and changing of the conductor resistance. The use of a larger conductor in order to reduce the conductor losses will cause minor changes in the T_1 to T_4 values. Therefore, the calculation of the optimum cable system is an iterative process.

3.1.2 a.c. Cables

The calculation of a.c. ampacities is much more complex compared to d.c. cables. Additional losses are created in the conductor and the armoring as a result of the alternating current.

3.1.2.1 Conductor Losses

The magnetic alternating field around the conductor current causes the skin effect, by which the current density is low in the centre of the conductor, and high in the outer regions of the conductor. The useful conductor area is reduced, and the effective conductor resistance is increased. The skin effect is more pronounced with increasing conductor areas. Furthermore, the skin effect is depending on the resistivity of the conductor material, the conductor design, and the power frequency. These influences are summarized into the skin effect factor y_s. Since the skin effect adds to conductor losses, the cable ampacity is decreased. Skillful but expensive conductor design can reduce the skin effect considerably especially for large cross section conductors.

Another magnetic effect, the proximity effect, is caused by the proximity of the conductors in a three-phase system. Under the influence of a neighbor conductor, the current strives to concentrate in current paths as far away as possible from the disturbing neighbor. The current density in the conductor becomes inhomogeneous, rendering the conductor portions nearest to the neighbor less useful for current transport. This effect is mostly pronounced for closely spaced large ampacity conductors such as three-phase a.c. cables. The resulting apparent resistance is expressed:

$$R = R'(1 + y_s + y_p) \tag{3.12}$$

where

R is the a.c. resistance of the conductor at maximum operating temperature
R' is the d.c. resistance of the conductor at maximum operating temperature
y_s is the skin effect factor
y_p is the proximity effect factor.

The a.c. resistance R (Ω/m) must be used for the calculation of the conductor losses. The factors y_s and y_p depend on the conductor material and design (stranding, lay-length, segmental or not), impregnated or not, and the power frequency.

Elaborate formulae to calculate y_s and y_p for various cable configurations are given in [2, 3], and shall not be repeated here. For the practical purpose of project planning, it is often enough to know that $(1 + y_s + y_p)$ for small cross section (500 mm^2) most often is below 1.1, i.e. skin and proximity effect increase the effective a.c. resistance of the conductor by less than 10%. Given the uncertainty of the thermal resistivity of the soil, it may be considered to neglect the skin and proximity contribution with small conductors. For very large conductor sizes ($\geq$2000 mm^2), however, skin and proximity effect may enlarge the a.c. resistance with more than 30%.

3.1.2.2 Dielectric Losses

The cable insulation is a dielectric material and can be modeled as combination of a capacitance and a resistance in parallel between the conductor and the grounded screen. Applying a voltage to the conductor results in a capacitive and a resistive current. The resistive current is in phase with the voltage while the capacitive current is shifted with 90°. The resistive current is a loss current generating heat in the insulation. The ratio between resistive and capacitive current is called the loss angle tan δ:

$$\tan\delta = \frac{|I_r|}{|I_c|} = \frac{1}{R_i C\omega} \tag{3.13}$$

where R_i is the resistance of a 1-m-piece of cable insulation (Ω**.**m) and C is the capacitance per meter (F/m). $\omega = 2\pi f$ is the angular frequency of the a.c. voltage. The cable capacitance C can be calculated as:

$$C = \frac{\varepsilon_0 \varepsilon_r}{18 \ln\left(\frac{D_i}{d_c}\right)} \tag{3.14}$$

where D_i is the diameter of the insulation, d_c the diameter of the conductor screen, and ε_r is the relative dielectric constant of the insulation material (Table 3.5).

Now, the dielectric losses in the insulation can be calculated as:

$$W_d = \omega C U_0^2 \tan\delta \tag{3.15}$$

Table 3.5 Dielectric properties of high-voltage cable insulation materials. tan δ is depending on the temperature. A more comprehensive list is in Chap. 12.

IEC 60287	Dielectric loss factor tan δ	Dielectric constant ε_r
XLPE > 18/30 kV	0.001	2.5
EPR	0.005–0.020	3
Oil/paper > 87 kV	0.0033	3.6
Mass-impregnated	0.01	4

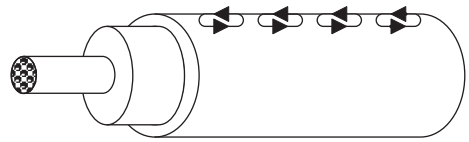
The dielectric losses grow with the square of the cable voltage and are relevant only at higher voltage levels. According to IEC 60287, they can be neglected for XLPE cables under 127 kV. For oil-filled submarine power cables being used predominantly for high and extra high voltages, the dielectric losses must not be neglected because of the higher ε and tan δ values. The dielectric losses are not depending on the arrangement of the conductors in single-core or three-core cables, nor on the design of the conductor.

3.1.2.3 Screen Losses

The alternating magnetic field around the conductor generates circulating and eddy currents in the metallic screen and armoring. These currents contribute to heat generation and reduce the cable ampacity. Four different types of induced current losses are considered according to the terminology of IEC 60287:

λ'_1 denotes the losses due to circulating currents in the screen/sheath.[4] Circulating screen/sheath currents occur when the screen/sheath is grounded on both sides of the cable. The losses are depending on the screen/sheath resistance, the screen/sheath inductance, and the arrangement of the phases in relation to each other. Circulating screen/sheath currents can achieve high amplitudes (up to the value of the conductor current) and add a heat source in the cable. The ampacity is reduced considerably. Especially single-core a.c. submarine cables suffer from screen/sheath losses. Loss-reducing measures such as cross-bonding or single-side bonding which are common in onshore cable installations can hardly be arranged for submarine cables.

λ''_1 denotes the losses due to eddy currents in the screen/sheath. The alternatingconductor current generates an emf in the metallic screen or sheath. The emf drives eddy currents locally inside the metallic screen/sheath. The amplitude of the eddy currents is strongly dependant on the thickness of the screen/sheath. The specific resistivity of the materials involved and geometric factors play an important roll. In many cases λ''_1 can be neglected in comparison to the λ'_1 losses. However, λ''_1 should be taken into account for a.c. cables with large segmental conductors, and cables where the λ'_1 losses have largely been reduced by cross-bonding or single-side bonding.



λ'_2 denotes the losses due to circulating currents in the armoring and metallic protection pipes, if applicable.[5] λ'_2 is strongly depending on the total resistance of the armoring layer. Not only the specific resistivity of the armoring material but

[4] "Screen/sheath" includes metallic wire screens (most often Cu wires) and extruded or welded metallic sheathes, but not the armoring.

[5] Sometimes parts of the cable are protected with cast iron half-pipes or similar after installation. This should be taken into account for the cable design.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 77 of 306

also the lay-length and contact points between individual wires influence the eddy current losses. Steel wire armorings are particularly affected by eddy current losses as the magnetic material attracts and concentrates the magnetic induction.

An a.c. cable with a low-resistance metallic screen/sheath has a rather high induced screen/sheath current opposite in direction to the conductor current. The magnetic fields from the conductor and the opposite screen current partly cancel each other. For this reason the magnetic effects on the armoring and external pipes are strongly reduced. Single-core a.c. submarine cables sometimes have a large copper screen able to carry the full screen current. As the screen current is opposite to the conductor current, the resulting magnetic field outside the screen is very low allowing for the use of a magnetic steel armoring without excessive armoring losses.

In three-phase a.c. cables the magnetic fields from the individual phases cancel each other to a large extend, which leads to low magnetic losses in the common armoring. Still, the armoring losses cannot be neglected.

λ''_2 denotes the losses due to eddy currents in the armoring and metallic protection pipes, if applicable.

All loss factors λ'_1, λ''_1, λ'_2 and λ''_2 are expressed as a factor relating the losses to the conductor losses. The calculation of the factors is explained for many different cable configurations in [2]. A concise tabular summary is found in [3], all based on the industrial standard IEC 60287, which is commonly accepted as the basis for the thermal design. However, the IEC formulae and factors are sometimes based on empirical values and can be subject to reviews.

For the common type of submarine a.c. power cables having three cores with individual lead sheath and common armoring, the loss factors λ'_1 and λ''_1 are as follows:

$$\lambda'_1 = \frac{R'_S}{R'} \cdot \frac{1.7}{1 + \left(\frac{R'_S}{X'}\right)^2} \tag{3.16}$$

where X' is the reactance of the sheath:

$$X' = 2\omega \cdot 10^{-7} \cdot \ln\left(\frac{2s}{d}\right), \Omega/m \tag{3.17}$$

R'_S is the resistance per meter of the lead sheath, and R' is the resistance per meter of the conductor, s is the axial distance of the conductors and d the average sheath diameter. Unless we deal with large segment conductors (which rarely are used in three-core cables), we can assume

$$\lambda''_1 = 0. \tag{3.18}$$

For the same cable type (≤ 400 mm^2) with common steel wire armoring the losses in the armoring can be summarized as:

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 78 of 306

$$\lambda'_2 + \lambda''_2 = \lambda_2 = 1.23 \cdot \frac{R'_B}{R'} \cdot \left(\frac{2c}{d_B}\right)^2 \cdot \frac{1}{1 + \left(\frac{3.48 R'_B}{\omega \mu_0}\right)^2} \cdot \left(1 - \frac{R'_S}{R'} \cdot \frac{1}{1 + \left(\frac{R'_S}{X'}\right)^2}\right) \tag{3.19}$$

where:

- c distance between cable axis and conductor axis
- d_B average diameter of the armoring layer
- R_B resistance per meter of the armoring
- R'_S resistance per meter of the lead sheath
- R' resistance per meter of the conductor
- s axial distance of the conductors
- d average sheath diameter.

3.1.2.4 a.c. Cable Ampacity

Three-core a.c. cables have no coaxial geometry, which makes the calculation of the thermal resistivity between conductor and cable surface more complex. While the cable cores (conductor, insulation system, and screen/sheath) are coaxial and can be treated as in single core cables, thermal resistance between the cable core and the common armoring cannot be treated correctly with IEC 60287 methods. The materials in the interstices between the cable cores play an important roll for the heat transport to the ambient. Assemblies of circular polymeric filler ropes, extruded plastic profiles with hollow cores, or even lead profiles are put into the interstices, having much different thermal properties. Extruded plastic profiles with hollow cores are air-filled during manufacturing, but they might fill with water after installation. In these cases, the heat flow and temperature field inside and outside the cable can easily be calculated with commercial FEM software. The mesh generating routines in most FEM software is adaptive with sufficiently high dynamic so that both the temperatures in the small cable details and in the wide cable surrounding can be calculated.

Now the elements necessary to calculate the ampacity of a.c. cables have been collected. The ampacity is expressed as:

$$i = \left[\frac{\Delta\Theta - W_d \left[0.5\, T_1 + n \left(T_2 + T_3 + T_4\right)\right]}{RT_1 + nR\left(1 + \lambda_1\right) + nR\left(1 + \lambda_1 + \lambda_2\right)\left(T_3 + T_4\right)}\right]^{0.5} \tag{3.20}$$

where n is the number of conductors in the cables (one or three). The a.c. resistance R is calculated according to Eq. 3.12. In three-core cables the proximity effect is more accentuated and the a.c. resistance is affected accordingly. The thermal resistances T_1 and T_3 can be calculated according to Eqs. 3.4 and 3.8. The calculation of T_2 for single-core cables can be done according to Eq. 3.7, while the same value for three-core cables is depending on the design of the metallic sheath.

Again, conductor losses and the thermal ambient of the cable are the most dominant factors in the thermal design. Additionally, for a.c. cables the control of losses in screen/sheath and armoring is important to achieve a high ampacity, especially at higher transmission power.

3.1.3 Other Factors for the Thermal Design

3.1.3.1 Transient Conditions

The calculation models shown so far are used to calculate ampacities for steady-state conditions reflecting the case of continuous constant load over long time. In real life, cables are rarely operated at constant load over a longer time. Knowing that, the thermal design of a given submarine cable project can be reconsidered. For this, it is important to know how fast the cable temperature increases after the load is switched on, and after which time the cable reaches a steady-state condition under the impact of a constant load. Taking into consideration the load variations over time, one can perform a transient cable rating.

The mathematical challenge is to express the temperature response of the different cable layers and its surrounding on a step function representing the power switch-on. In the 1950s, when computers were not commonly available, many researchers suggested analytical solutions before Neher/McGrath published their famous papers in 1964 [5, 6], which subsequently influenced the IEC standard 60287.

The thermal models of power cables represent the various layers of the cable by thermal resistances and thermal capacitances. The heat dissipated in the conductor travels through the thermal resistance of the insulation and the outer layers towards the ambient soil.[6] The analogous network shown in Fig. 3.4 is called a Cauer-type RC ladder network. Cauer networks are often used to calculate heat flow phenomena in semiconductor devices.

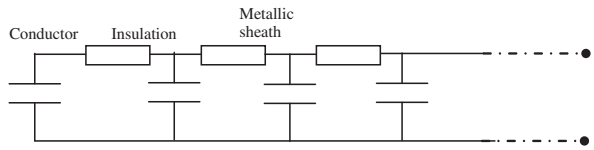


Fig. 3.4 Cauer-type ladder network representing a cable construction

The ladder network consists of the thermal resistances R of the various cable layers and the ambient soil, and capacitances C, which represent the thermal capacities of the different cable layers and the ambient soil. The thermal capacitance of a given volume V of a material with the specific heat c_p is:

[6] In the electric analogy the conductor loss corresponds to a current source, the heat flow from the conductor outwards corresponds to an electric current, the thermal resistance of each layer corresponds to an electric resistance, and the thermal capacitance of each layer corresponds to an electric capacitance.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 80 of 306

$$C = c_p \cdot V \cdot \rho_G$$

where ρ_G is the density of the material.

Let us consider a simplified fictitious cable, only consisting of a 1200 mm^2 copper conductor and a 12 mm polymeric insulation, directly submersed into water. The outer surface of the cable is kept at 10°C by ambient water. At $t = 0$ the load is switched on, generating a constant conductor loss of 30 W/m irrespectively the conductor temperature. The conductor losses heat up the thermal capacitance representing the conductor (solid line in Fig. 3.5), and the conductor temperature follows a logarithmic curve until a steady-state condition at about 18°C. The increasing temperature difference between the conductor and the ambient causes an ever-increasing heat flux (dotted line in Fig. 3.5) through the thermal resistance representing the insulation. The increasing heat loss through the insulation reduces the thermal power available for heating up the conductor, and the steepness of the temperature rise curve declines. A classical thermal time constant $\tau = R \cdot C$ can be defined for this simple system. The time constant of this system is 1220 s as indicated by an arrow. After 1220 s, the temperature rise has reached 63% of its final value.

In a real cable installation, there are more thermal resistances and thermal capacitances coupled into a ladder network. Some layers, such as a lead sheath, can simply be represented by a thermal capacitance, while their thermal resistance can be neglected due to the high thermal conductivity of the metal. Insulation layers of a few millimetres thickness can be modelled by a single thermal resistance and a single thermal capacitance. Thicker insulation layers must be subdivided in a number of "onion shells" each of them with its own resistance and capacitance. Many computer-based models of the thermal ladder comprise 20 layers or more. A further complication is that in many high-voltage a.c. cables heat sources exist outside

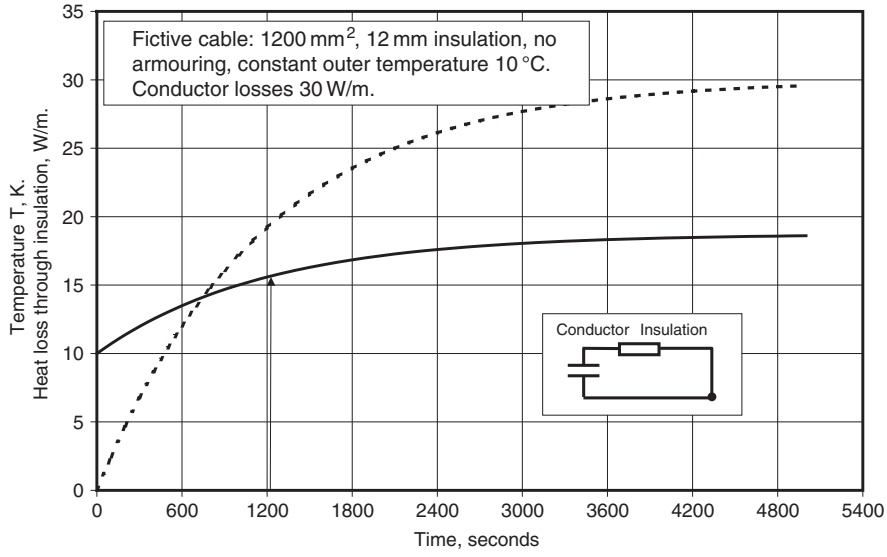


Fig. 3.5 Temperature evolution (*solid line*) and heat flow through the insulation (*dotted line*) in a fictive simplified single-core cable

the conductor, such as dielectric losses and sheath/screen/armoring losses. It is not possible to define a classical thermal time constant for these complicated systems, as the step response is not longer a simple logarithmic rise such as in Fig. 3.5.

The ambitious reader may find exhaustive reading on the subject in [2, 7]. However, a few further considerations are important for the understanding of the cable behaviour and rating.

3.1.3.2 Temporary Overload

Today, submarine power cables are usually buried 1–3 m down in the seafloor. The seafloor temperature will rise slowly, heated by the cable losses. The constant ambient temperature assumption in the simple model of Fig. 3.5 is not valid anymore. Since the seafloor has a large thermal capacitance and a large thermal resistance due to its sheer size, it can take weeks or months to warm up the seafloor around the cable to steady-state conditions. Although a time constant in a classical sense can no longer be defined, it can be useful to use two "quasi"-time constants to characterize the complex system of cable and surrounding soil. The thermal time constant τ_c of the cable describes the response of the conductor temperature to a step-formed load change, while the soil time constant τ_s describes the response of the soil temperature to a long-term load in the cable. Even for the most massive submarine cables, τ_c is in the order of 0.5–2 h. In contrary, τ_s is in the order of weeks or months. This dual time response behavior has some important consequences.

The evolution of temperature in and around a submarine cable is illustrated in Fig. 3.6. It starts with the "all-cold" situation (curve No. 1) where the cable and

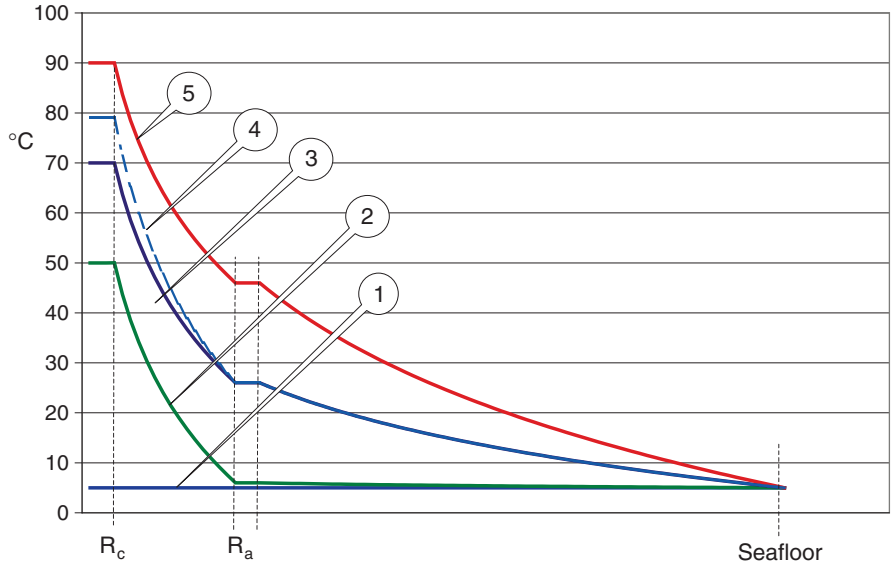


Fig. 3.6 Temperature profile in a single-core cable and surrounding soil

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 82 of 306

the seafloor have the same undisturbed temperature, being 5°C in our example. The x-axis of Fig. 3.6 indicates the distance from the conductor, where R_c denotes the conductor radius, R_a the radius of the armoring, and the label "Seafloor" indicates the position of the surface of the sea bottom.

Now we put full rated load on the cable from "all-cold" condition, and the cable will reach a first steady-state after 3–4 times τ_c, i.e. a few hours. This situation is indicated in curve 2 of Fig. 3.6. It is also visible that the temperature curve inside the conductor is flat because the metal equalizes all internal temperature gradients. The conductor temperature reaches 50°C in this example. During this time, the ambient soil (between R_a and "Seafloor") changes its temperature only very little.

Under continued rated load, the soil temperature rises slowly as a result of the dissipated heat from the cable. At the same pace as the soil temperature next to the cable surface rises, the cable conductor follows suit. An intermediate situation is depicted as curve no. 3 in Fig. 3.6. As the soil and thus the cable armoring (at R_a) slowly increase in temperature, the conductor temperature keeps pace by always holding 45 K over the cable armoring. The temperature difference between armoring (at R_a) and the conductor stays constant, as this is only dictated by the conductor heat losses, which are assumed to be constant.[7] Finally, still under constant rated load, the system arrives at a steady-state indicated by curve no. 5 in Fig. 3.6. In the steady-state value the conductor temperature has arrived at 90°C and the cable surface (armoring) temperature is at 46°C.[8]

Let us go back to the situation of curve no. 3 in Fig. 3.6. The cable had been operated at full nominal load for days or even some weeks. Temperatures have not reached their final steady-state value yet. It is obvious from the graph that the conductor temperature is below the maximum temperature that it is designed for (90°C), and that it would reach only some weeks later. Meanwhile, we could use the thermal reserve to run temporary overload on the cable. Higher current means larger ohmic losses in the conductor, a larger heat flow through the insulation, and a larger temperature drop over the insulation. This renders a steeper temperature curve between R_c and R_a as indicated in curve no. 4 in Fig. 3.6. The overload can only be run 0.5–2 h until the conductor temperature reaches the design limit and must be reduced subsequently. Different restrictions may apply for HVDC cables as they usually have a maximum allowed temperature difference across the insulation.

A different starting case for a possible temporary overload occurs when the cable has been run with reduced load for a long time. In the following section, the possible overload for short periods is estimated with some easy equations. Recall the calculation of the maximum continuous current I_{cont} according to Eq. 3.21:

$$I_{\text{cont}} = \left[\frac{\Delta\Theta}{R'\,(T_1 + T_2 + T_3 + T_4)}\right]^{0.5} \tag{3.21}$$

[7]For the sake of simplicity, we neglect here that the conductor resistance and hence the losses increase with the conductor temperature.

[8]This value is only valid for this example. Cable surface temperatures are depending strongly on the specific case.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 83 of 306

The steady-state conductor temperature Θ_c is according to Eq. 3.21:

$$\Theta_c = \Theta_{\text{amb}} + I_{\text{cont}}^2 \cdot R' \cdot \sum \cdot T_i \tag{3.22}$$

When the same cable had been running at 75% load ($I_{75\%} = 0.75\ I_{\text{cont}}$) the steady-state temperature, accordingly, would have been:

$$\Theta_{75\%} = \Theta_{\text{amb}} + I_{75\%}^2 \cdot R' \cdot \sum \cdot T_i = \Theta_{\text{amb}} + 0.75^2 I_{\text{cont}}^2 \cdot R' \cdot \sum \cdot T_i \tag{3.23}$$

The steady-state temperature $\Theta_{75\%}$ at 75% load is lower than the full load temperature and the difference is $\Theta_c - \Theta_{75\%}$. Now, we switch on the overload current I_{overload}. For a short-term overload (say 10 min), we may assume a quasi-adiabatic situation where the excess heat is only used to heat the conductor but the heat flow through the insulation is maintained at the level of the 75% constant load prior to overload. For an overload time of 10 min = 600 s, we can establish:

$$(I_{overload}^2 \cdot R' - I_{75\%}^2 \cdot R') \cdot 600\,s = c_p \cdot m_{Cu} \cdot (\Theta_c - \Theta_{75\%}) \tag{3.24}$$

The left side of the equation is the difference between the loss power $I^2{}_{\text{overload}}\%R'$ and the power outflow $I^2{}_{75\%}{}'R'$ through the insulation, multiplied with the duration of the overload current. This is the excess energy that is consumed by the heating of the conductor. c_p=393 J/(kg K) is the specific heat of copper, and m_{Cu} is the mass of one meter of the copper conductor. For a cable with a 1200 mm^2 Cu conductor we find that I_{overload} (10 min) = 3513 A. This is indeed an amazing figure of overload after a long continuous load of 75% of nominal load.

The temporary overload calculation according to Eq. 3.22 may be applied to a.c. cables where the electric stress in the insulation is not depending on temperature gradients. The same algorithm can be applied to overload durations shorter than 600 s, to different pre-overload load factors (instead of 0.75), or to aluminum conductors by accordingly adjusting the parameters.

For d.c. cables an additional restriction applies. The temperature difference over the insulation must not exceed a specified value in order to stay below a specified electric stress in the insulation. Equation 3.24a would thus transform for d.c. use:

$$(I_{\text{overload}}^2 \cdot R' - I_{75\%}^2 \cdot R') \cdot 600\,s = c_p \cdot m_{Cu} \cdot (\Delta_{\max} - \Delta\Theta_{75\%}) \tag{3.24a}$$

with $\Delta_{\max}$ the maximum specified insulation temperature drop, and $\Delta\Theta_{75\%}$ the insulation temperature drop at 75% load.

For longer overload periods, the time-dependent heat outflow through the different layers must be taken into account.

From the situation depicted in curve no. 3 of Fig. 3.6, another overload scenario is also possible. If only a little overload is run, e.g. 15% over full load, the temperature difference over the insulation would soon (within 3–4 times τ_c) assume a new value somewhat larger than the difference at full load. But the conductor temperature would not reach the limit in the first place. Now, we have a non-adiabatic

process where the excess heat from 15% overload has time enough to flow outwards through the different layers. It slowly heats up the surrounding soil. As the soil slowly increases in temperature, the conductor temperature keeps pace. When it arrives at the limit (=90°C in Fig. 3.6), the load must be reduced to 100% load to avoid overheating.

Power cables with direct contact to the free sea water (unprotected, laid directly onto the seafloor or in spans) cannot use the benefits of the thermal capacitance of the surrounding soil. The surface temperature of these cables follows the seawater temperature, which is changing only very slowly through the year. The exposed cables will reach steady-state conditions after only a few hours. The overload capability of exposed un-buried cables is much lower compared to buried submarine power cables.

3.1.3.3 Cyclic or Variable Loads

Most submarine power cables are operated with varying load, which is often below the rated power transmission. These cables are under-utilized during certain periods, and the operator might be interested in extra transmission power during peak demand.

Some cables, predominantly those feeding populated islands, may have a daily cyclic load pattern. IEC 60853 has developed algorithms to calculate possible overload due to cyclic cable utilization. The methods are based on the calculation of an average loss factor through the day, such as indicated in Eq. 3.25. The fact that the cables have a daily load pattern can be exploited in two different ways:

1. A higher short-term ampacity can be offered during and past the periods of lower load.
2. A smaller conductor size can be chosen if the load pattern is guaranteed.

Another actual case of variable loads is the submarine connection of OWPs. Most of the time the load in wind-farm cables (both in-field connectors and export cables) is below rated OWP output power. The duration of peak loads is counted in few days at each time. The short-time peak loads are efficiently equalized by the large time constant of the sea soil. A statistical analysis of the expected wind conditions can result in lower cable load requirements and appreciable investment cost reductions [8]. For the unlikely case of long-lasting full-power wind generation, on-line cable temperature monitoring can advise the operator to shut down some turbines if necessary.

However, it must be remembered that unburied submarine cables have no thermal reserve from the ambient soil; they offer very little overload capabilities.

3.1.3.4 Thermal Resistivity of the Seafloor

For good reasons, one of the prime objectives of any cable design is to avoid hotspots as they can jeopardize the availability of the link. It is therefore extremely

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 85 of 306

important to have a detailed knowledge of the thermal surrounding of the cable, i.e. the thermal resistivity of the seafloor and the ambient temperature. Actually, the precise knowledge of these parameters along the cable route can save investment money and/or increase availability and lifetime.

The thermal resistivity of soil is a function of the soil base material, the dry density, the distribution of grain size, the compaction, the humidity and the content of organic materials. The influence of humidity, one of the most important factors for land based soils, can be disregarded in subsea soils because the soil is completely soaked. This is also valid for seafloors of tidal flats which fall dry during low water tide. The German Maritime Authority (BSH, Bundesamt für Seeschiffahrt und Hydrographie) assumes a thermal resistivity of 0.7 K·m/W or less for soil saturated with water [9]. Values up to 1.03 K·m/W have been found in in-situ measurements in the North Sea [10]. Other measurements show values as low as 0.5 K·m/W [11]. Further values are shown in Table 3.6.

The large distribution of these values and those found in Table 3.6 implies that it is one of the most important objectives of the marine survey to measure the thermal resistivity of the soil along the cable route. The measurement of thermal resistivity values for soil is rather delicate. Soil samples taken from the intended installation site can represent the soil base material, grain size distribution, and, in case of submarine soil samples, the humidity content. However, the in-situ degree of compaction is difficult to reproduce in the laboratory. The degree of compaction might be different in virgin soil and in soil after cable laying and burial.

The soil conditions in the vicinity of the submarine cable can be inhomogeneous due to geomorphologic or anthropogenous factors. As an example, the cable is perhaps installed in layered soils or in trenches, which are being filled with non-local material. Also the protection of submarine cables with rock-dumping or concrete slabs creates inhomogeneous thermal ambient conditions. Commercial FEM software can solve the task to find out the effective thermal insulation of an inhomogeneous cable cover that is composed of different soils/rocks/items.

It is important to create a complete picture of the soil conditions along the entire cable route before doing the cable design. The locations of the limited number of soil samples should be chosen so that the thermal properties of the cable route can be mapped in sufficient accuracy.

Table 3.6 Thermal properties of some submarine soils

	Heat capacity per volume $\rho \cdot c_p$, MJ/(m^3·K)	Thermal Resistivity ρ_T	
References	[12]	[12]	[13]
Gravel	2.4	0.55	0.33–0.5
Sand	2.2–2.9	0.2–0.59	0.4–0.67
Clay/silt	1.6–3.4	1.0–2.5	0.56–1.11

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 86 of 306

3.1.3.5 Ambient Temperature

The ambient temperature is a critical value in all thermal design calculations, no matter which method is used, or which load cases are considered. The ambient temperature for the cable is defined as the temperature at the *locus* of the cable if the cable would *NOT* be there, i.e. the undisturbed ambient temperature.

For unburied submarine cables, the ambient temperature is simply the temperature of the seafloor water. Even when the surface water temperature may change considerably over the year the water temperature at seafloor level can be quite constant but that is not the case everywhere. At some locations in the North Sea, the seafloor water temperature fluctuates between 8 and 17.5°C during the year. Relevant data for a specific submarine cable project can often be obtained from the national hydrographical institute or commercial survey companies. The highest summer temperature of the seafloor water is different in different years. Statistics list 10-years-high, or 100 years-high values. It is up to the decision of the cable owner/operator which of these values should be used in the context of the overall asset management.

When the unburied cable is carrying load, its surface temperature is only a few degrees over the ambient water temperature. Flowing water provides a better assimilation of temperatures compared to calm water. However, a thermal cable design should not be based on the assumption of the beneficial effects of flowing water.

For the thermal design of buried submarine cables, the ambient temperature at the burial depth must be taken into account. The annual variation of the water temperature at the sea floor penetrates down into the sea bottom until it reaches the intended cable position and beyond. In deeper depths under the seafloor, the amplitude of the seasonal variation becomes smaller and the peak value occurs later in the year. The schematic course of the temperature is shown in Fig. 3.7. Assuming an annual average temperature T_a on the seafloor and a sinusoidal course of the seafloor temperature, the annual variation of the temperature in the depth z can be described as [14]:

$$T(z,t) = T_a + A_0 e^{-z/d} \sin\left(\frac{2\pi(t - t_0)}{365} - \frac{z}{d} - \frac{\pi}{2}\right) \tag{3.25}$$

T (Z,T) Temperature at time t in the depth z
T_a Average temperature at the seafloor averaged over the year
A_0 Amplitude of the annual variation of the seafloor temperature
d penetration depth of the annual temperature variation
t_0 Constant reference time.

The penetration depth is $d = (2\, D_h/\omega)^{1/2}$ with D_h being the thermal diffusity (cf. table 3.7). $\omega = 2\pi/365$ is the angular frequency of the annual variation, denoted in 1/day.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 87 of 306

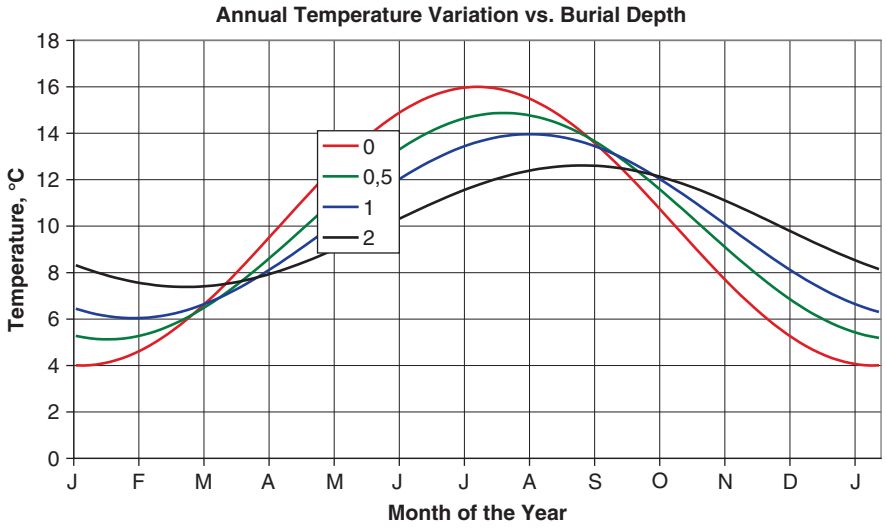


Fig. 3.7 Schematic course of the temperature as a function of time and depth. The depth parameter is given in *metres.* Assumed thermal diffusity $D_h = 0.05$ m^2/day

Table 3.7 Empirical relationship between thermal diffusivity and thermal resistivity for homogenous and moist soils, according to IEC 60853-2 App. D

Thermal resistivity (m×K/W)	Thermal diffusivity (m^2/day)
0.35	0.0864
0.45–0.54	0.0691
0.55–0.64	0.0605
0.65–0.84	0.0518
0.85–1.04	0.0432
1.05–1.24	0.0389

The parameters of Eq. 3.25 can be determined by plotting the annual variation of seafloor temperature. From this, the average temperature at the seafloor T_a, the amplitude of the annual variation A_0, and the reference time t_0 can be determined. For all further calculations at various depths the same t_0 is used.

In the example of Fig. 3.7, the soil temperature at 1 m burial depth reaches a peak of 14°C. The cable that will be buried here can be designed for 14°C ambient temperature instead of 16°C which is the maximum temperature at the seafloor. Note that Fig. 3.7 is just an example showing the principal course of temperatures. For every submarine power cable project the values T_a and A_0 should be identified. If they cannot be retrieved from long-term measurements the estimated values should have sufficient safety margins.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 88 of 306

3.1.3.6 Conditions Changing with Time

Seafloor conditions, which have been charted by survey operations, may alter during the cable's lifetime. While water temperature hopefully increases only slowly with the climate change, other parameters may change faster.

Coastal waters exposed to tidal currents are subject to strong and fast changes of the bathymetric structure. Spring tides and storms can cause erratic changes. A cable buried at the –2 m level might be exposed to water, or covered underneath 10 m of sediment. These unpredictable changes have nevertheless to be taken into account for the cable design.

The thermal ambient of submarine cables can also be changed by human activities such as dredging, dumping, etc.

Submarine cables can be subjected to marine growth. The submarine fauna/flora may create extensive layers of organic material over buried cables, which has the effect of thermal insulation and consequential overheating of the cable. Cables on a free span, covered with a thick layer of subsea dwellers, may constitute dangerous hot-spots in the cable route.

3.1.4 The 2 K Criterion

The prospective of a massive installation of offshore wind parks triggered a discussion of the heating of the seafloor. Environmentalists and authorities mainly in Germany advocate a limitation of the expected warming of the seafloor above the submarine power cable (cf. Chap. 10). According to this discussion, the seafloor above the cable must not be warmed up more than 2 K over the undisturbed temperature. The warm-up is calculated for a reference location straight above the cable, at a depth of 0.2 or 0.3 m under the seafloor surface.[9] By means of FEM software the situation can be calculated easily. This chapter provides a simpler method to determine the warm-up for many cases. We use the following terminology.

$\Delta\Theta_{0.2}$ is the temperature rise over the undisturbed sea soil, at a depth of 0.2 m under the seafloor. $\Delta\Theta_{0.3}$ is the corresponding value for a depth of 0.3 m under the seafloor. Both values are valid for steady-state conditions, which are reached only after weeks of continuous constant full load. We consider two representative types of cable installation configurations:

1. A pair of cables laid touching. HVDC cables are sometimes installed in this configuration.
2. A single cable. This represents the case of a three-phase a.c. cable, or one single-core cable in a group of cables laid with distance. In submarine installations, cables are installed either in a bundle (cf. case 1) or with a lateral distance of 5 m or more due to installation restrictions. In the latter case, each cable of the group can be considered as a single cable.

[9] Different authorities and environmental groups use either 0.2 or 0.3 m.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 89 of 306

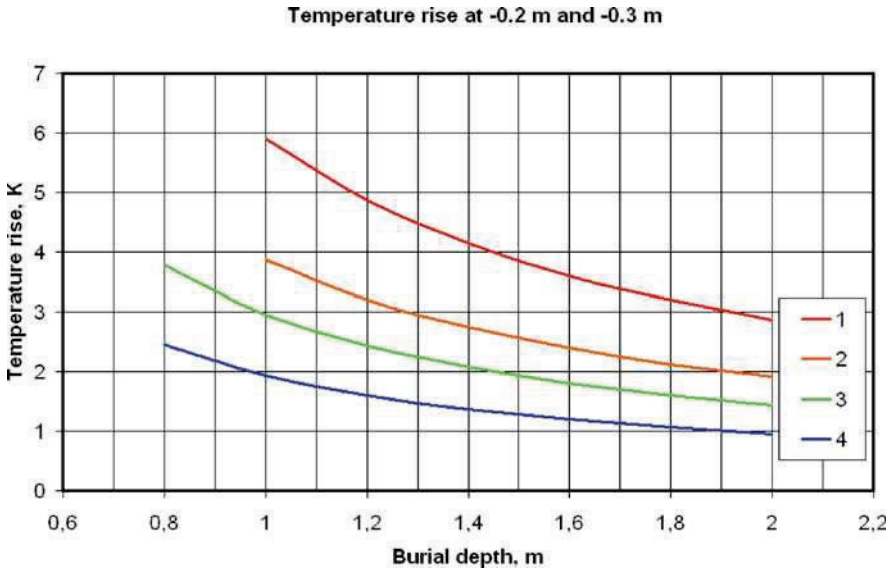


Fig. 3.8 Temperature rise over the undisturbed seafloor. Curve 1: A pair of HVDC cables, touching, cable diameter 100 mm, –0.3 m; Curve 2: A pair of HVDC cables, touching, cable diameter 100 mm, –0.2 m; Curve 3: A single cable, diameter 150 mm, –0.3 m; Curve 4: A single cable, diameter 150 mm, –0.2 m

The curves in Fig. 3.8 are calculated for a cable loss of $P_{\text{loss}} = 30$ W/m in each cable, and a thermal resistivity of $\rho_T = 1.0$ K·m/W. The temperature rise in a specific project can be calculated as follows:

To find out the temperature increase $\Delta\Theta_{0.2\text{ m, project}}$ at the –0.2 m level for any project the following equation shall be used:

$$\Delta\Theta_{0.2\,\text{m,project}} = \Delta\Theta_{0.2\text{m}} \cdot \rho_T \cdot \frac{P_{\text{loss,project}}}{30\,W/m} \tag{3.26}$$

where $P_{\text{loss, project}}$ is the total cable loss in the actual project. $\Delta\Theta_{0.2}$ is taken from Fig. 3.8. The actual thermal soil resistivity goes in as ρ_T.

Accordingly, the temperature increase $\Delta\Theta_{0.3\text{ m, project}}$ at the –0.3 m level can be calculated from the values in Fig. 3.8 and the actual cable losses and thermal resistivity.

The cable diameter has only little influence on the resulting temperature rise. A case with a single cable with 190 mm diameter has been calculated. The results differ from the values of the 150 mm cable only in the second decimal place.

The results presented in Fig. 3.8 are strictly spoken valid for steady-state conditions only. However, they can also be used for cases where the cable load is subject to daily cyclic patterns. The large thermal inertia of the seafloor equalizes the daily variations. Starting from the daily load pattern an average cable loss value can be calculated from the mean square I_{24} of the current during the day:

$$P_{\text{loss,average}} = R \cdot s \cdot \frac{1}{24\ \text{h}} \cdot \int_0^{24} I^2(t)\, dt \tag{3.27}$$

where

I(t) the conductor current as a function of time. The integral adds up one current value for each hour for the day.
R resistance of each phase.
s number of phase conductors in the system.

The average loss during a 24-h period is often considerably smaller than the cable losses at full rated load. This should be taken into account when using Eq. 3.26 for the calculating of the soil warm-up.

3.1.5 Economic Aspects of the Thermal Design

When designing a power cable it is attempting to reduce the conductor size as much as possible in order to reduce the tender price. This design method results in the smallest conductor meeting the ampacity requirements and the smallest initial costs. Indeed, for longer submarine cable links, the slightest reduction of the conductor size can save appreciable amounts of investment. For a 100 km link the cross section reduction with only 10 mm^2 copper can save some 36.000 US$ in copper costs per conductor.[10] However, it became clear decades ago that the costs of losses must not be neglected. A larger conductor cross section reduces the losses and associated costs over many years ahead. A comprehensive cost analysis includes not only the up-front investments (Capex) but also the cost of losses during the cable lifetime. Here, we try to sort out what the loss evaluation factor is, and how it can translate to the conductor size with the lowest lifetime costs for the investor.

The total lifetime costs of a cable system include the investment and the accumulated future costs of losses and maintenance. The future operational costs (Opex) can be projected to the present time with "present value" methods. The question is whether or not the smallest conductor size from the thermal point of view generates the smallest lifetime costs.

The assessment of the present value of future cable losses starts with the calculation of the losses Q_L in one year. The accumulated losses over a year in the cable system are:

$$Q_L = I_0^2 \cdot R \cdot s\mu \cdot 8760\, h \tag{3.28}$$

where

I_0 nominal maximum conductor current
R equivalent resistance of each phase

[10] Assumptions for the calculations in this chapter: Copper price 4000 US$/ton.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 91 of 306

s number of phase conductors in the system
μ load loss factor of the cable link

The equivalent resistance includes all load-depending losses such as ohmic conductor losses, the contribution of skin and proximity effects, and the contribution of armoring/screen/sheath losses. Dielectric losses are neglected here. The load loss factor μ is the normalized mean square of the current over time.

$$\mu = \frac{1}{8760\ \text{h}} \cdot \int_0^{8760} \frac{I^2(t)\,dt}{I_0^2} \tag{3.29}$$

I(t) is the average conductor current in each hour of the year. For a cable system running on full power over the year $T\mu = 1$. For a cable link to be built in the future, it is not easy to determine the integral in Eq. 3.29. Meanwhile some rough assumptions can be made:

$$\mu = p \cdot m + (1 - p) \cdot m^2 \tag{3.30}$$

with $p = 0.3$ for transmission lines and $p = 0.2$ for distribution lines [2]. m is the load factor, i.e the normalized average current (not square) over time.

We can reduce the future loss costs to the present value C_L at the time of investment:

$$C_L = \frac{C \cdot Q_L}{i} \cdot \left[1 - \left(\frac{1}{(1+i)^n}\right)\right] \tag{3.31}$$

where

C Cost of 1 kWh of electricity to cover the losses ($/kWh)
i Rate of interest on the capital market
n Cable lifetime (years).

This formula can be used both for a.c. and d.c. cables. It is valid under the (uncertain) assumption that C, L, and i are constant over the n years of lifetime, which is a strong simplification. Calculation procedures including variable load schemes and variable loss unit costs C over the years are given in [2]. With the equations given above the present value C_L of future loss costs can be calculated. This value is often given to the cable manufacturer in the cable system specification in "dollar per kW" units. Each kW of cable losses is penalized with a sum of money reflecting the accumulated C_L costs of the losses over the entire cable lifetime.

Figure 3.9 illustrates the conditions under which it is profitable to increase the copper cross section, depending on the combination of copper price and energy price during the lifetime of the cable. The assumptions are:

- Cable design (1200 mm^2 HVDC) according to Table 3.4
- Ampacity 1854 A rated maximum current

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 92 of 306

- Lifetime 30 years
- 7% capital costs
- Cable price increases linearly with the LME copper price times a factor 1.5 for manufacturing
- The calculation is made for an upward step from 1200 to 1210 mm^2.

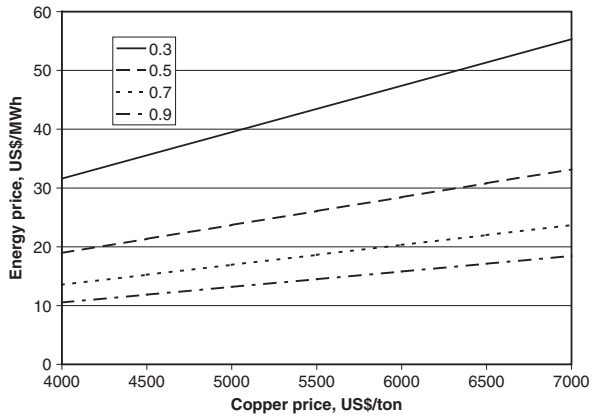


Fig. 3.9 "Break-even" values for the cable described in Table 3.4. At energy prices over the curve it is profitable to increase the copper cross section

The load loss factor μ is the curve parameter. It is profitable to increase the copper cross section if the energy price is higher than the value stated in the diagram. The incremental cable price indicated above is nothing but an assumption for incremental cable price changes and must not be taken as an indication for cable prices based on LME copper values.

By nature, all theories are based on assumptions on the future value of some parameters, which tend to be very volatile:

The technical lifetime of a cable system can be anything between 10 and 40 years.[11] The lifetime is a statistical number. Most manufactures would agree on a 30–40 years expected lifetime for a well-protected submarine cable.

Capital market terms will vary largely during this time, and so will the rate of interest. Since an investor would probably finance the investment with a mix of loans with different terms it is not possible to put a single rate of interests into the formulae. The often used Eq. 3.34 is not very useful in these cases.

Generation costs for losses are often equal to the electricity price on the upstream side of the cable link. This price changes by the hour for trading links. For OWP the loss costs can be assessed from different viewpoints as explained in Chap. 10. In any case, the costs for losses are not constant or even known over the cable lifetime.

Installation criteria. If there are requirements to keep a certain low sediment temperature over the buried submarine cable, it could be advantageous to reduce

[11] Some submarine cable installations have had lifetimes below 10 years or over 40 years, and may be considered as statistical outliers.

Table 3.8 Estimated utilization of submarine power cable links

Type of submarine link	Link utilization
Supply of islands with residential demand	According to island demand, 4380/8760 h
Supply of G&O platforms	90% 7884/8760 h
OWP	25% 2190/8760 h
Power trading between autonomous grids	70% 6130/8760 h

the cable heat losses by extra conductor copper. A larger conductor emits less heat and can be buried shallower for less money to meet the 2 K criteria. At the end, the larger conductor might induce lower costs.

Cable utilization. The utilization of a submarine cable link depends largely on the type of the application (cf. Table 3.8). For a specific cable link the utilization may vary largely from week to week and over the years.

Recycling costs/benefits after the cable lifetime. Regulators today sometimes require that cable systems must be recovered after the end of life. If this is the case, the conductor copper is not a write-down investment. In contrary, increasing metal prices can turn the cable copper into a valuable asset. Extra copper in the conductor would not only reduce costly losses but also would contribute to late income when recovering the cable.

All these imponderables make the standard economic evaluation methods little useful. Some trends are visible:

- For a short expected lifetime the Capex are more important than the Opex. Select the conductor area as small as possible with respect to thermal conditions.
- For a long expected lifetime the Opex may outweigh the Capex. It might be attractive to put in more copper to reduce costly losses.
- High energy prices bring the focus to the loss reduction. Losses must be paid for somewhere, and the value of some extra copper in the cable becomes more attractive with increasing energy prices.
- An OWP owner might consider investing into a larger conductor size. To bring the same amount of power to shore, it is better to invest in a maintenance-free increase of cable cross section compared to another turbine needing annual maintenance.
- If the cable is to be recovered after life, the investment in extra copper is even more attractive due to future metal prices.

3.2 Design of Mechanical Properties

Submarine power cables must be designed to withstand all mechanical stresses during manufacturing, handling, transport, installation, and operation. The stresses imposed to submarine power cables are much different from those imposed to underground cables. An inappropriate mechanical design has the potential to leave the

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 94 of 306

cable vulnerable to damages with the possible consequence of higher unavailability and large repair costs. As a result of poor mechanical design, some cable systems had to be abandoned or replaced by new ones long before their electrical lifetime was over.

The first challenge is to bring the cable safely into the water. The armoring has to provide sufficient tensional strength. The required tensional strength for a submarine power cable project is primarily a function of the water depth. Dynamic forces during the installation may impose much stronger requirements, and conditions during the operation, such as strong currents or forces in cables hanging in free spans, may add to the tensional strength requirements.

3.2.1 Tensional Forces During Laying

When the cable is being laid from a cable ship there are at least four components that contribute to the tensional forces at the laying wheel:

- Static weight of the cable between the laying ship and the seafloor.
- Residual bottom tension, which translates to an extra tensional force at the laying wheel.
- Extra weight of the catenary line between the laying wheel to the touch-down point (TD) on the seafloor.
- Dynamic forces when the laying wheel is moving up and down.

The static tensional force is $T_s = w{\cdot}D$, with w being the unit weight of the cable in water and D being the water depth. The small length of cable between the water surface and the exit point on the laying wheel[12] is neglected here.

During laying the cable is not just let down vertically. Instead, the cable must be positioned in a well-defined catenary line from the laying wheel to the TD by application of a certain tension in an on-board cable break device. Under these circumstances the cable hits the sea floor asymptotically.

The shape of the catenary is associated to a certain bottom tension. The length of the catenary line is longer than the water depth resulting in a larger weight of cable hanging in the laying wheel as if the cable would hang down vertically (cf. Fig. 7.28). The top tension T , i.e. the tension in the cable at the laying wheel, is expressed as:

$$T = \sqrt{T_0^2 + w^2 s^2} \tag{3.32}$$

where T_0 is the bottom tension and s is the length of the catenary line. At zero bottom tension, the catenary length becomes $s = D$ and the equation reduces to $T = w{\cdot}D$.

[12]The expression "laying wheel" stands here also for a laying chute or similar overboarding arrangements.

A complete mathematical treatment of the catenary line is given in the appendix to Chap. 7.

The vertical movement of the laying sheave caused by wave-induced vessel motion adds a dynamic force to the weight of the cable in the catenary line. We assume that the vertical movement of the laying sheave is sinusoidal and find the maximum vertical acceleration $b_{\max}$:

$$b_{\max} = h/2 \cdot (2\pi/P)^2 \tag{3.33}$$

where h is the vertical movement amplitude (measured peak to peak) and P is the movement period (time between subsequent wave peaks). The maximum force on the hanging cable is now

$$T_{\max} = T_s + m \cdot b_{\max} \tag{3.34}$$

where m is the mass of the hanging cable. Since the force due to acceleration is an inertia phenomenon, the cable mass must be used for the calculation rather than the weight in water or air. Each cable laying ship has different sea-keeping characteristics describing how the vessel reacts on different waves from different directions. What matters for the cable top tension, is the vertical acceleration of the laying wheel. Predominantly pitch and heave movements influence the wheel vertical movements. A more detailed treatment of wave statistics and the relation between wave movement and wheel movement is given in Chap. 7.

Real waves sometimes do not obey the sinus equation. Instead, they are, in parts of the wave silhouette, steeper than a sinus curve. In other cases, waves from different directions and different causes can be superimposed, which leads to very steep wave fronts. In these cases the vertical acceleration $b_{\max}$ and hence the dynamic forces may be substantially larger than indicated by the sinus calculation.

The tensional forces on the cable are results of waves with a statistically distributed wave height. Even if the significant wave height of the weather forecast seems to be acceptable, a few waves of exceptional amplitude can cause tensions big enough to damage the cable. The installation engineer must always keep this in mind.

It is evident that the simple sinus representation of the vessel movement is sometimes not adequate to describe statistically rare events. To take into account even unexpected events, guidelines for cargo stowing recommend lashing dimensions fit for vertical acceleration of up to 1 g (=9.81 ms^{-2}) at the aft and bow of a vessel ([9], in Chap. 7). If no detailed values about the cable ship's vertical movements are known, a value of $b_{\max} = 6\ \mathrm{ms}^{-2}$ shall be assumed.

It is rather easy to estimate the contribution of the catenary and the wave dynamics to the top tension separately. The results give us an idea on the augmentation of the tensional forces due to both effects. It is much more complex to calculate the combined effects on the tensional forces of a catenary line and the vertical acceleration dynamic.

The entire length of the suspended catenary, also the cable portion close to the TD, must be accelerated vertically. However, the inclined cable can transmit forces only in its own axial direction. For this reason, large tensions along the cable have to be transmitted to create the vertical forces for the cable acceleration close to the TD. A complete laying analysis with resulting tensional and bottom tension values can be performed with specialised commercial software. Some of the software tools also can take the vessel's response to various sea-states into account. Engineering companies working for the offshore industry, and submarine installation companies, often have such tools.

It is a straight-forward task to design the armoring of a submarine power cable for the tensional forces in a catenary line in calm weather. It is more difficult to determine for which sea state the cable should be designed during installation. The selection of the maximum considered sea-state is a matter of attitude rather than engineering. The sea-state statistics for the installation area and the intended installation season can be found out in a desktop study. It must subsequently be decided which range of sea-states the cable should be designed for. If the cable is designed only for the stresses occurring in moderate sea-states, the number of suitable weather windows for installation will be small. If the cable design allows for higher sea-states during installation, more and longer laying opportunities will appear. The costly risk that a laying operation has to be terminated due to adverse weather is reduced.

3.2.2 The Cigré Test Recommendation

The only known mechanical test recommendation for submarine power cables is the Cigré test recommendation for submarine cables [15], referred to as Electra 171 in the following. The most prominent test of the recommendation involves simultaneous bending and pulling of the cable, resembling the stress during pay- out of the cable over the laying wheel. The test arrangement is shown in Fig. 5.9 in Chap. 5. Electra 171 suggests tension values as follows (cf. Fig. 3.10):

For a laying depth up to 500 m:

$$T = 1{,}3 \cdot w \cdot d + H \cdot \tag{3.35}$$

where w and d are as explained above. The additional force H reflects the bottom tension of the cable during installation. H is:

$$H = 0{,}2 \cdot w \cdot d_1 \tag{3.36}$$

with d_1 being the laying depth but 200 m at minimum.

For depth greater than 500 m, Electra 171 suggests another tensional force:

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 97 of 306

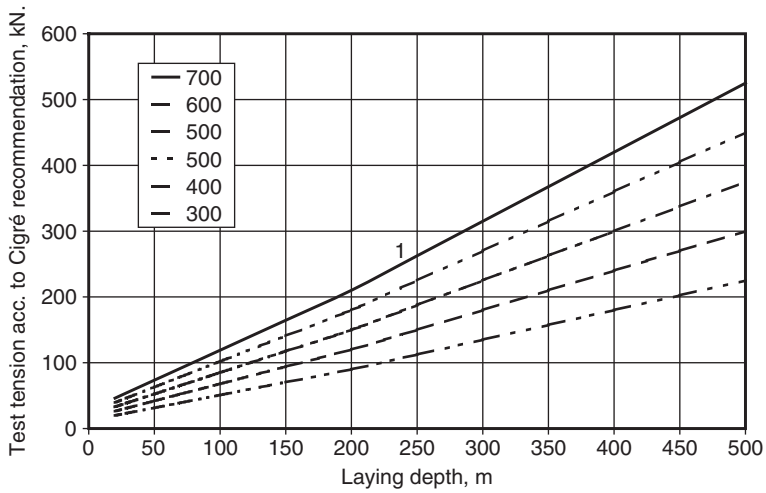


Fig. 3.10 Tensional force for testing according to the Cigré recommendation. The curve parameter is the weight of the cable in water (N/m)

$$T = 1{,}3 \cdot w \cdot d + H + 1{,}2 \cdot |D| \tag{3.37}$$

where $|D|$ represents the dynamic tensions (in N) calculated as:

$$D = \pm {}^{1}/_{2} \cdot b_h \cdot m \cdot d \cdot \varpi^2 \tag{3.38}$$

b_h the vertical movement, crest to crest, of the laying wheel
m mass of cable in air, kg/m
ϖ $2\pi/t$, circular frequency of the vertical movement of the laying wheel, 1/s
t movement period, in seconds.

This formula does not take into account the cable catenary shape but reflects simply the inertial force of the hanging cable under the acceleration during ship movements.

The Electra 171 test values cover most cases of submarine laying operations. In tough weather conditions, however, the resulting tensional forces can be substantially higher. Table 3.9 illustrates this for a typical single core 1200 mm^2 extruded HVDC cable. While the Electra 171 test value is 78 kN, expected values in tough weather can reach 106 kN. This value still does not include any allowances for the dynamic forces in the catenary nor any safety margins. With sinusoidal wave shapes a vertical acceleration of 6 ms^{-2} occurs under quite rough sea-states only. However, irregular wave shapes and interfering waves can generate vertical acceleration of this size in the laying wheel at the stern of the vessel.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 98 of 306

Table 3.9 Comparison of tensional test values of Electra 171 and estimated maximum tensional forces in heavy weather

Mass of the cable	29 kg/m
Weight in water	209 N/m
Laying depth	250 m
Force attributed to bottom tension (H in Eq. 3.35)	10.450 N
Static force $w{\cdot}d$	52.250 N
Tensional test force according to Electra 171 (Eq. 3.35)	78.375 N
Assumed vertical acceleration $b_{\max}$	6 ms^{-2}
Dynamic force $m{\bullet}b_{\max}$	43.500 N
Total tensional force $T{=}\ w{\cdot}d{+}\ m{\bullet}b_{\max}{+}H$	106.200 N

3.2.3 Distribution of Mechanical Stress Between Conductor and Armoring

In the following, the response of a single-core DWA submarine cable with steel armoring and copper conductor is discussed. The equations can easily be adapted to other armoring and/or conductor materials. When a tension is applied on the cable the elongation and the tensions in the armor wires and the conductor is given by

$$\varepsilon = \frac{F_A}{E_A \cdot A_A} = \frac{F_L}{E_L \cdot A_L} \tag{3.39}$$

$$F = F_A + F_L \tag{3.40}$$

where

F Total tension (N)
F_A Tension in the armoring (N)
F_L Tension in the conductor (N)
E_A Young's modulus of steel (N/mm^2)
E_L Young's modulus of the copper conductor (N/mm^2)
A_A Total cross section of the armoring wires (mm^2)
A_L Conductor cross section (mm^2).

The tension in the conductor can be calculated as follows:

$$\frac{F - F_L}{E_A \cdot A_A} = \frac{F_L}{E_L \cdot A_L} \Rightarrow F_L \left(1 + \frac{E_L \cdot A_L}{E_A \cdot A_A}\right) = F \cdot \frac{E_L \cdot A_L}{E_A \cdot A_A} \Rightarrow$$

$$F_L = \frac{E_L \cdot A_L}{E_A \cdot A_A + E_L \cdot A_L} \cdot F \tag{3.41}$$

The conductor stress σ_L is as follows:

$$\sigma_L = \frac{E_L \cdot A_L}{A_L \left(E_A \cdot A_A + E_L \cdot A_L\right)} \cdot F \tag{3.42}$$

The tension in the armoring wires is:

$$F_A = F - F_L \Rightarrow F_A = F \cdot \left(1 - \frac{E_L \cdot A_L}{E_A \cdot A_A + E_L \cdot A_L}\right) \tag{3.43}$$

The total armoring tension is divided between the inner armoring layer (F_{AI}) and the outer armoring layer (F_{AO}):

$$F_A = F_{AI} + F_{AO} \tag{3.44}$$

$$\frac{F_{AI}}{F_{AO}} = \frac{A_{AI} \cdot E_A}{A_{AO} \cdot E_A} \tag{3.45}$$

where

A_{AI} Total cross section of the inner layer (mm^2)
A_{AO} Total cross section of the outer layer (mm^2).

Now the tension in the inner and the outer armoring layer can be calculated from Eqs. 3.43, 3.44, and 3.45:

$$F_{AO} = F \cdot \frac{A_{AO}}{A_{AO} + A_{AI}} \cdot \left(1 - \frac{E_L \cdot A_L}{E_A \cdot A_A + E_L \cdot A_L}\right) \tag{3.46}$$

$$F_{AI} = F \cdot \frac{A_{AI}}{A_{AO} + A_{AI}} \cdot \left(1 - \frac{E_L \cdot A_L}{E_A \cdot A_A + E_L \cdot A_L}\right) \tag{3.47}$$

Finally, the mechanical stress in the inner (σ_{AI}) and outer (σ_{AO}) armoring layer is:

$$\sigma_{AO} = \frac{F}{A_{AO} \cdot \cos\varphi_O} \cdot \frac{A_{AY}}{A_{AO} + A_{AI}} \cdot \left(1 - \frac{E_L \cdot A_L}{E_A \cdot A_A + E_L \cdot A_L}\right) \tag{3.48}$$

$$\sigma_{AI} = \frac{F}{A_{AI} \cdot \cos\varphi_I} \cdot \frac{A_{AI}}{A_{AO} + A_{AI}} \cdot \left(1 - \frac{E_L \cdot A_L}{E_A \cdot A_A + E_L \cdot A_L}\right) \tag{3.49}$$

φ_O is the lay angle of the outer layer (in degrees)
φ_I is the lay angle of the inner layer (in degrees).

For many submarine cable projects, in particular in shallow waters, an armoring with thin wires would be sufficient to comply with the tensional bending test according to Electra 171. However, as the maximum number of wires that can be handled in the armoring machine in one run is limited, manufacturers often use thicker wires to achieve a complete coverage of the cable circumference. In doing so, the cable is

Table 3.10 Guide values for mechanical properties of copper and steel. Steel grade values from European Standard EN 10257-2:1998

Wire material	Breaking stress (N/mm^2)	Yield point (N/mm^2)
Copper wire	220–240	120
Copper wire – welding zone	170–210	70–80
Mild steel (grade 34)	340 . . . 540	min 210
Steel grade 65	650 . . . 850	
Steel grade 85	850 . . . 1050	
Steel grade 105	1050 . . . 1250	
Steel grade 125	1250 . . . 1450	

equipped with a stronger armoring than the Electra 171 test would require. But the additional steel also provides additional lateral protection, a property much needed in certain projects as the next chapter explains.

In cases where the additional protection of an oversized armoring is not necessary or wanted, some of the steel wires may be replaced by plastic filler wires. This reduces weight, magnetic losses, and possibly costs.

The armoring wire length is longer than the power cable length. Table 3.11 gives the overlength as a function of the lay-length.

One should not conclude that a long lay-length (20 or 25 times the diameter) would save material because of the short overlength in Table 3.11. A long lay-length simply requires more wires to cover the complete cable circumference.

Table 3.11 Armoring wire overlength as a function of the lay-length

Lay-length as multiple of the diameter of the armoring layer	Ratio of armoring wire length to cable length
10	1.048
15	1.022
17.5	1.017
20	1.012
25	1.008

3.2.4 Other Forces and Impacts

The armoring must withstand all forces that can be reasonably expected during installation and operation. The tensional forces that occur during installation can be predicted with a certain degree of accuracy. Other forces and impacts during installation and operation have an accidental nature and hence are indifferent in their character, amplitude and frequency. Many types of external forces and stresses might attack the cable during installation and/or operation:

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 101 of 306

- Overbending, mostly during installation because of inadequate equipment or insufficient control
- Impact from edges or rocks may happen during burial operations
- Squeezing from cable engines or inadequate roller arrangements
- Impacts from anchors and fishing tackle.

It is difficult to quantify the magnitude of external violence from the accidental events listed here. The design of cable armoring should be based on a compilation of the expected dangers and threats along the cable route, including the hazards arising during the installation. The history and experience from previous submarine cable installations is another valuable source of knowledge. Unfortunately there is no general design rule for the thickness and number of the armoring wires because impacts, threats, and peak tensions are statistic events. Most manufacturers consider the design data as property, not suitable for publishing. Still, there are a few self-evident rules of thumb:

- more steel provides better protection
- harder wires provide a better protection
- double wire armoring is tougher than single wire armoring
- a short-lay rock armoring provides a better protection against lateral impacts at the expense of tensional force.

The optimum armoring wire thickness is depending on several factors. First of all there must be a minimum wire thickness to withstand the external threats such as fishing gear and anchors. On the other hand, most cable manufacturers can apply only a limited number of wires onto the cable. In order to reach a complete cover of wire armoring they must apply thick dimensions of wire for a complete coverage. The thickness of the armoring wires has a large impact on both weight and diameter of the cable. Hence, the cable length in each shipload and the laying schedule are influenced noticeably by the wire thickness.

The American standard ICEA No. S-57-401/NEMA Standards Publication No. WC2 determines the required wire thickness for paper-insulated submarine cables

Table 3.12 Thickness of armoring wires according to US standard

Calculated diameter of cable under the armoring bedding mm	Size of armoring wires, mild galvanized steel BWG	mm
0–19.05	12	2.77
19.08–25.40	10	3.40
25.43–43.18	8	4.19
43.21–63.50	6	5.16
63.53 and larger	4	6.05

according to Table 3.12. However, the standard does not tell if this is valid for single or double-layer armoring, or both.

The side-wall pressure impact (SWP) value is often required to know for the planning of the installation. Literally, SWP is the maximum allowed lateral squeezing force, which the cable can stand without serious damage. The name SW-pressure is misleading as it describes a force per unit length (N/m) rather than a pressure (N/m^2). The SWP can best be described as the lateral force onto a cable, which is bent around a wheel under a tensional force. SWP can be expressed by:

$$SWP = F_T/R \tag{3.50}$$

where F is the pulling force and R the wheel or bend radius. There are no literature values for the maximum permissible SWP of submarine power cables. However, for some cable projects the tensional force used during tensional bending tests have been reported. The results are summarized in Table 3.13.

Table 3.13 SWP in some cable projects

Link	Armoring	Insulation	Test tension kN	SWP kN/m	References
Morocco – Spain	DWA copper	LPOF	353	70.6	[16]
Italy – Greece	DWA steel	MI	471	94.2	[16]
Gulf of Aqaba	DWA	LPOF	500	100	[17]
Troll A	DWA	Dc XLPE	375	75	

It is expected that double-wire armored cables have a substantially higher permissible SWP than single-wire armored cables. A short-lay rock armoring provides probably even higher SWP.

It must be kept in mind that the SWP refers to a distributed lateral force on the cable. The effects of concentrated impacts or lateral forces cannot be treated with the concept of SWP.

Submarine cable producers often are asked for data on the bending stiffness of submarine power cables. A critical parameter for bending stiffness calculations for cables is the friction between the cable layers. Submarine cables are constructed from a variety of different materials. Friction data are known only with limited accuracy, in particular the friction in the armoring layers. For the steel wire armoring layer, coated to a certain extend with bitumen, a complicated mixture of static and dynamic friction coefficients is applicable. Furthermore, the friction and hence the bending stiffness, is strongly depending on the temperature, which influences the bitumen properties, and the amplitude and radius of the bending. For this reason, technical data on the bending stiffness of submarine power cables of standard design are prone to large inaccuracies. The bending stiffness has no influence on the value of the top tension during laying, but can critically change the bending radius at the TD when the laying wheel moves down in heaving.

A few examples of armored cables and their fate might be interesting to know about:

Two mass-impregnated HVDC cables were installed between Denmark and Norway in the mid-70ties. After full-size tests of the resistance of the cable against external aggression, it was equipped with two layers of armoring, 7.0 and 5.6 mm thick, respectively. These cables were put out of service by very heavy fishing gear in 1976 and 1977, and by a dragged towing weight in 1981 [18]. Until 1984, the cables survived the hits from about 30 anchors and fishing trawls which had got entangled with the cables in waters between 160 and 300 m.

The Baltic Cable with two layers 5.0 mm steel wire armoring did survive some violent anchor entanglements but was damaged seriously by the ferryboat "Nils Holgersson" that lost rudder control outside Travemünde/Germany and hit ground and cable. Another outage was caused by an emergency anchoring. At another incident, the cable survived the encounter with a heavy anchor.

Another submarine power cable with two layers of 6.3 mm wires was damaged during the trenching operation, probably by an unsuitable trenching plough.

The notorious Fox Islands Cables between Rockport, Maine, and the islands of North Haven and Vinalhaven, which suffered a large number of mechanical faults (due to anchors, fishing gear, mistreatment during installation and repair, and unsuitable installation over a steep seafloor outcrop) had #4 BWG galvanized wires (=6.054 mm).

3.2.5 Vortex Induced Vibrations

Irregular seafloors and steep underwater slopes can cause free spans of the cable. Submarine cables hanging in free spans are exposed to oscillations when water currents strike them. The water current creates Karmán-vortices, which separate from the cable alternating on the upper and the lower "edge" of the cable. Such vortices can also be observed in the wake of bridge posts in a streaming river. The dispersal of vortices from the cable is called vortex shedding. Each time a vortex is leaving the cable, a force is exerted on the cable. If the cable is horizontal and the water current also is horizontal but perpendicular to the cable, the forces from the vortex shedding point vertically alternatively up and down. The frequency (Hz) of the vortex shedding is

$$f_s = St\frac{u}{D} \tag{3.51}$$

with f_s the vortex shedding frequency (Hz), u the velocity of the streaming water (m/s), D the diameter of the cable (m), and St the Strouhal number [19]. For submarine power cables and relevant current velocities St can be assumed 0.2.

A cable hanging in a free span has a number of natural frequencies with which it can vibrate like a guitar string. The natural frequencies f_n are multiples of the basic natural frequency:

$$f_n = \frac{n}{2} \cdot \sqrt{\frac{T_a}{m' \cdot L^2}} \tag{3.52}$$

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 104 of 306

Table 3.14 Basic natural frequency and minimum flow velocity for the establishment of VIV

Cable span data	Large cable	Small cable
Cable mass per meter, kg/m	40	20
Length of free span, m	20	40
Tension in the span, kN	10	2
Cable diameter, mm	110	80
Frequency of the basic natural frequency, Hz	0.40	0.125
$V_{\min}$, m/s	0.22	0.05

with n the mode number, T_a the tension of the cable, m' the mass per length unit of the cable, and L the length of the free span [20].

The cable in free span is excited by the force from the leaving Karmán vortices with an oscillating frequncy f_s. When the exciting frequency f_s is close or equal to one of the natural frequencies f_n the cable may start vibrating in resonance. This phenomenon is called "lock-in". Combining Eqs. 3.51 and 3.52 results in a minimum flow velocity for the lock-in and the establishement of vibrations:

$$u_{\min} = \frac{D}{2 \cdot St} \cdot \sqrt{\frac{T_a}{m' \cdot L^2}} \tag{3.53}$$

According to [20], this simple relation can be used to make a first assessment of the risk for vortex-induced vibrations (VIV) in a given cable installation situation. Table 3.14 shows the calculated results for two typical cable designs.

It should be noted that the diameter of the cable could change drastically by marine growth. The density of marine growth may be set to 1325 kg/m^3. If site-specific information is not available the thickness of marine growth can be assumed as indicated in Table 3.15.

As soon as the cable starts vibrating, its natural frequencies are changed. This is partly due to the inertial force of the water, which is pushed by the moving cable. In hydrodynamics, this is addressed by the added-mass coefficient describing a virtual increase of the mass of the accelerating cable due to the dense medium around it (the water). The added-mass coefficient decreases the natural frequencies, more for cables with low own density (such as aluminium cables or three-phase cables) but only little for cables with high density (such as single-core copper cables). Furthermore, the added-mass coefficient is depending on the actual flow velocity [19].

Table 3.15 Thickness of marine growth on submarine structures [19]

	Latitude	
	56–59° N	59–72° N
Water depth	Thickness of marine growth (mm)	
+2 . . . –40 m	100	60
Below –40 m	50	30

The bending stiffness of the cable may change the natural frequency to higher values. The influence of the bending stiffness can be estimated from the value φ:

$$\varphi = \left(\frac{n\pi}{L}\right)^2 \cdot \frac{E \cdot I}{T_a} \tag{3.54}$$

where $E{\cdot}I$ is the dynamic bending stiffness of the cable. If $\varphi << 1$, the influence of the bending stiffness can be neglected [20].

Once lock-in has established, the vortex shedding frequency is dictated by the actual oscillating frequency of the cable rather than Eq. 3.51.

In long spans, the higher order natural frequencies lie close together. A certain vortex shedding frequency f_s with its associated bandwidth can strike excitation of many natural frequencies or modes simultaneously. However, as the energy included in each mode is small the risk for lock-in is reduced.

An additional complication arises when the flow speed is not uniform along the span of the cable. The response of cables on non-uniform flow fields has been described e.g. in [21, 22]. In the first place, project planners should try to avoid free spans by any means such as route diverting or seafloor leveling.

Some design changes can contribute to reduce the risk of VIV. The cable mass per meter can be changed by a thicker lead sheath, or, in case of three-phase cables, by lead profiles in the interstices between the cable cores [23]. Increased mass-per-length reduces the cable's natural frequency and the minimum necessary flow velocity, but can also reduce the amplitude of the oscillation. VIV suppression strakes can be mounted onto the cable to break up the laminar flow necessary for the vortex creation and shedding. The severity of a given installation situation can be assessed with commercial software packages in use in the offshore oil and gas industry. Reference [19] provides a comprehensive bibliography on the subject.

3.3 Electric Design

The electric design of submarine power cables follows the same design principles as those for underground cables. Since submarine cables are often more remote and less accessible for repair, it should be considered to increase the safety margins. The task of this chapter is not to repeat the well-documented principles of the electric design of a.c. power cable [1, 23, 24]. Instead, a very short overview is presented. A little more attention is dedicated to the dielectric properties of d.c. submarine cables as these have not been treated in reference literature to the same extent.

3.3.1 The Concept of Electric Strength

The electric strength of an insulation material is the ability to withstand an applied voltage without a breakdown. If the voltage is higher than the electric strength, an electric breakdown occurs. No matter which mechanism initiates the breakdown, the

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 106 of 306

result is a sudden discharge of the voltage through the insulation. In cable insulation, such an event inevitably leads to a complete failure and an outage of the power line. The cable insulation must be designed such that it can withstand all expected voltages during the lifetime of the cable.

The electric strength is a material property given in kV/mm. There are no fixed values for solid insulation materials, even if tables with electric strength values can be found in many textbooks and journal articles. The electric strength of a given material is depending on a number of parameters under which the electric strength has been measured. Sometimes, the concept of "intrinsic dielectric strength" of a material is used. The expression describes the electric strength of an ultra-pure sample in a laboratory without any deteriorating influences. The published "intrinsic dielectric strength" values of insulation materials are many hundred kV/mm. Those experiments are conducted on very thin layers of insulating material between extremely smooth electrodes. The electric strength of insulation material depends on the volume of the stressed dielectric. Even if the breakdown voltage of a thick layer of insulation material is higher than that of a thin layer, the dielectric strength as expressed in kV/mm is usually smaller. The reason for this is the increased number of impurities and other irregularities in a thick insulation layer compared to a thin layer. These irregularities can act as starting points for a breakdown. For this reason, the electric strength in industrial insulation systems, such as cables, is usually one or two orders of magnitude lower than those that can be achieved in small laboratory materials samples.

Furthermore, the actual dielectric strength is depending on temperature, voltage shape and duration, ageing etc. All these factors should be considered when consulting tabulated dielectric strength values for the electric cable design.

3.3.2 The Weibull Distribution

Electric breakdown is a statistic process. Repeating the same experiment with equal samples and test conditions will result in a statistic distribution of results. The Weibull distribution is widely used to describe the results of electric breakdown experiments. The 2-parameter Weibull distribution can be expressed as:

$$f(E) = \frac{\beta}{\eta}\left(\frac{E}{\eta}\right)^{\beta-1} e^{-\left(\frac{E}{\eta}\right)\beta} \tag{3.55}$$

where *f(E)* is the probability that the sample suffers a breakdown under the application of the electric stress *E*. η is called the scale parameter and β the shape parameter of the Weibull distribution. Very interesting is the accumulated probability F(E) for a breakdown:

$$F(E) = 1 - e^{-\left(\frac{E}{\eta}\right)\beta} \tag{3.56}$$

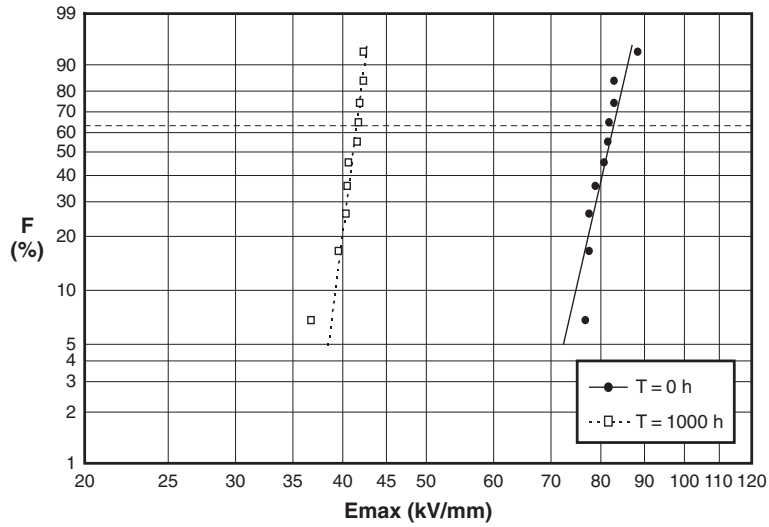


Fig. 3.11 Results of breakdown experiments plotted on Weibull paper. Explanation in the text (Courtesy of Borealis, Sweden)

For a group of samples, *F(E)* returns how many of these samples will have failed when tested with an increasing electric stress up to *E*. Figure 3.11 shows a Weibull plot of two experiments with insulation material. The test electric stress is on the x-axis, and the probability of failure is on the y-axis. Plotted on "Weibull paper" with its particular axis formation, Weibull-distributed experimental data should lie on a straight line. From the Weibull plot of experimental data, the scale parameter η and the shape parameter β can be determined. The scale parameter η in Eqs. 3.55 and 3.56 can be interpreted as a measure for the dielectric strength of the material under the given test conditions. The shape parameter β tells us something about the statistical scatter of breakdown values over the electric stress scale. A high β value indicates a material where the most samples fail within a narrow range of electric stress. A small β value indicates a material where samples fail within a large range of stress values. Such a material seems to be less predictable.

The Weibull plot can be used to compare an insulation material in different ageing stages, or different insulation materials. In Fig. 3.11, two sets of breakdown data are plotted into the same diagram. The solid dots represent the results of breakdown experiments on fresh material, while the open dots result from tests on aged material. In spite of the scatter of breakdown voltage as a result of the statistic nature of electric breakdown, it can be seen clearly that the material represented on the right side of the diagram performs better than the left material [25].

Weibull can do more than this. In Eq. 3.56, the variable is the electric stress *E* and the Weibull distribution describes the failure probability with respect to the applied electric stress. The Weibull statistics can also be used to assess the influence of other parameters on the breakdown behaviour of insulation materials. It is known

that the breakdown strength is depending on temperature and the duration of applied voltage. Experiments can be carried out where the breakdown probability is tested as a function of temperature at constant electric stress. The distribution is expected to follow Eq. 3.56 with temperature θ substituted for the electric stress:

$$F(\Theta) = 1 - e^{-\left(\frac{\theta}{\eta}\right)\beta} \tag{3.57}$$

In this case, *F(θ)* describes the accumulated risk of failure for breakdown experiments at temperature θ. The parametersη and β of this Weibull distribution are naturally different from those for the stress-related Weibull distribution in Eq. 3.56. The parameters can only be established by experiment.

In a similar way, the basic Eq. 3.56 can be used to describe how the electric strength of insulation material depends on the duration of applied electric stress. If E in Eq. 3.56 is substituted with the time duration T of applied voltage, a statistical analysis of the influence of time on the electric strength can be made.

$$F(T) = 1 - e^{-\left(\frac{T}{\eta}\right)\beta} \tag{3.58}$$

Again, *F(T)* describes the probability that a sample fails before or at the time T of voltage exposure. This probability distribution is valid for a certain experiment set-up in terms of temperature, voltage, electrode shape, etc. And again, the parametersη and β of this Weibull distribution are different from those for the stress-related Weibull distribution in Eq. 3.56.

A utility operating a network of identical cables can plot the cables' lifetime in a Weibull diagram to evaluate the scale parameter η and the shape parameter β. From this evaluation, the mean-time-to-failure (MTTF) of a new cable circuit can be calculated:

$$\bar{T} = \eta \cdot \Gamma\left(\frac{1}{\beta} + 1\right) \tag{3.59}$$

where Γ is the gamma function evaluated at $(1/\beta + 1)$. The shape parameter β can help to estimate if all cables in a circuit will fail approximately during a few years around the MTTF, or if the failures (and repair costs) will be scattered over a longer time period. However, the empirical evaluation of η and β from the failure data of installed cables is very difficult and probably unreliable. The operation data of the cables such as temperature, magnitude, and duration of overvoltages etc., use to differ so much that no homogeneous cable population can be found for the statistics.

The application of Weibull statistics for power cables is described in detail in [26]. The reference also contains a bibliography on the subject.

Relevant lifetime tests can be made in the laboratory with elevated voltage. The evaluation makes use of the fact that applied stress and lifetime are related:

$$(V - V_0)^n \cdot t = \text{const.} \tag{3.60}$$

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 109 of 306

where V is the applied voltage (representative for the electric stress, which easily can be deducted from V), V_0 is a threshold value, and t is the time to failure. The exponent n is a material constant. Test samples from laboratory tests performed under controlled conditions are suitable for statistical treatment [27].

Experimental data can be plotted into a Weibull diagram in order to assess different insulation materials. The Weibull distribution is a valuable tool for researchers to compare different insulation materials in terms of electric strength.

3.3.3 Dielectric Design of a.c. Cables

While the thermal design of a.c. cables is a complex matter due to the extra losses generated by the alternating magnetic field, the electric design of a.c. submarine power cables is so much easier. The cable insulation must be designed in such a manner that the electric stress caused by all expected voltages in the cable system do not exceed the breakdown strength of the insulation, allowing for a safe margin also after reasonable ageing of the insulation.

For a.c. and transient voltages, the stress distribution in the insulation is capacitive. It can be calculated using the Laplace equation $\nabla^2 \Phi = 0$ for space-charge free dielectrica, where ∇^2 is the Laplace operator and Φ the electric potential. In cables, cylindrical coordinates are useful. The Laplacian operator ∇^2 applied to the function f reads in cylindrical coordinates:

$$\nabla^2 f = \frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial f}{\partial r}\right) + \frac{1}{r^2}\frac{\partial^2 f}{\partial \theta^2} + \frac{\partial^2 f}{\partial z^2} \tag{3.61}$$

For the axi-symmetric case of a cable insulation the two last terms of the right side of Eq. 3.61 vanish. After integration of the remaining equation and proper setting of the boundary conditions the electric stress in the a.c. cable insulation can be expressed as:

$$E(r) = \frac{U}{r \ln\left(D_o/D_i\right)} \tag{3.62}$$

with the following symbols:

U applied voltage
r radius in the insulation
D_o Outer diameter of the insulation = insulation diameter under the insulation screen
D_i Inner diameter of the insulation = diameter over the conductor screen.

The applied voltage in Eq. 3.62 is the phase-to-ground voltage $U_0 = U_r/\sqrt{3}$ where U_r is the phase-to-phase system voltage. The stress distribution in the insulation of

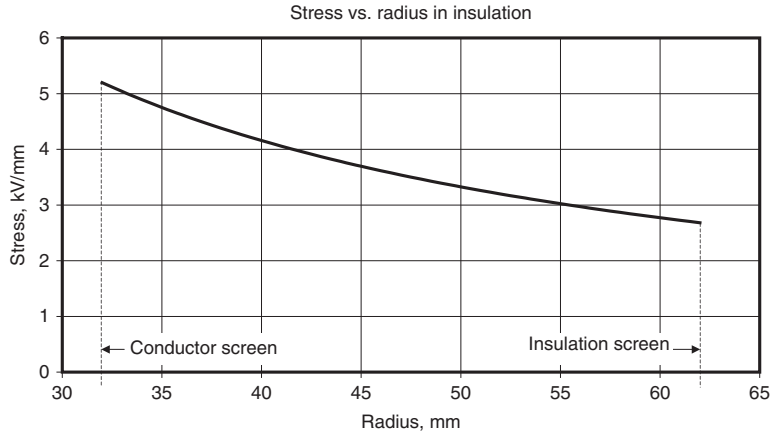


Fig. 3.12 Electric stress in a 110 kV a.c. XLPE cable

a 110 kV 630 mm^2 XLPE cable is shown in Fig. 3.12. The 15 mm insulation wall has $D_o = 62$ mm and $D_i = 32$ mm.

The stress distribution given in Eq. 3.62 and Fig. 3.12 postulates that the relative dielectric constantε_r has the same value in the entire insulation.ε_r is practically independent on temperature and power frequency. Hence the stress distribution formula 3.62 is valid for all a.c. cables, no matter if it is a three-core cable, a single core cable, cold or loaded.[13] The concentration of electric stress at the conductor screen imposes high requirements on material cleanliness and a smooth interface without defects.

Equation 3.62 is also valid for the calculation of stresses under transient voltages such as lightning or switching impulses but must not be used for the calculation of stresses in d.c. cables.

Equation 3.62 can also be used to determine the required insulation thickness for the cable to withstand the expected voltages. The crucial task is to establish the highest acceptable stress for power frequency voltage, switching impulse and lightning impulse taking into account system overvoltages.

3.3.3.1 Overvoltages

During testing and operation of submarine power cables a number of different voltage shapes can occur. Power frequency overvoltages can occur during a single-phase-to-ground cable failure until the fault is cleared. Depending on the system earthing concept, the overvoltage over the insulation of the healthy phases can be

[13]Only some low-voltage cables without insulation screens maintain non-circular stress distributions.

3 times the rated phase-to-ground voltage. This overvoltage, though not very long lasting, can result in extra ageing or even breakdown.

Other overvoltages can be caused by abnormal operation conditions such as incorrect generation/load balance, especially when the submarine cable is used to connect a remote isolated load or generator to the shore grid. A detailed system study can clarify the expected overvoltages in the particular project, and suggest suitable protection measures.

With respect to the strong correlation between overvoltages and ageing, it should be avoided to operate submarine power cables at the maximum design voltage U_m during the greater part of the operational time.

Voltage impulses with high magnitude and very short duration may occur in power transmission systems as a result of switching operations and atmospheric lightning. The duration of these voltage peaks is in the range of micro- or a few milliseconds. The electric stress in the insulation during impulse voltages can be calculated using Eq. 3.62. Fortunately, the dielectric strength of insulation materials under impulse stress is much higher than under power frequency voltage.

Test standards recommend test voltage level for Lightning Impulse tests (LIWL) and Switching Impulse tests (SIWL), cf. Table 3.17. Test levels for a.c. routine tests are summarized in Table 5.5.

3.3.3.2 Design Rules

Scientific books and research articles can provide dielectric strength values for different materials and experimental conditions but they can hardly provide design rules. In addition to laboratory results, the experience and safety policy of power utilities influence the selection of safety factors for the dielectric cable design. National or international standard committees, power utilities and each cable manufacturer have developed own attitudes concerning safety factors and design rules. Given the "minority" role of submarine power cables compared to land-based power cables, almost all cable standards refer to underground cables, leaving the field of submarine cables with little regulation.

The USA industrial standard AEIC CS9-06 lists maximum stress values and the corresponding insulation thickness (Table 3.16)

The European International Electric Commission (IEC) does not recommend any particular insulation wall thickness for high-voltage cables. Instead, test procedures both for power frequency and impulse withstand tests are specified, and a cable design is approved if the relevant type tests are passed (cf. Chap. 5).

Power utilities may have their own cable design standards. Major German TSO's have agreed on a common standard for the insulation thickness of 110 kV XLPE cables: 18 mm. Most cable manufacturers would support a thinner insulation such as 15 mm.

For medium-voltage cables ($\leq$ 36 kV) with an insulation thickness of 4–8 mm, the maximum design stress in the insulation is only between 2 and 4 kV/mm. Modern XLPE insulation has a much higher breakdown strength than this. However, the thin insulation wall renders this insulation more sensitive to production irreg-

Table 3.16 Stress limits and insulation thickness for extruded cables according to [28]

Rated voltage (kV)	Conductor size, (mm^2)	Nominal internal ac stress limit (KV/mm)	Corresponding generic insulation thickness (mm)
69 wet	240–2000	4	16.5
69 dry	240–2000	6	12.0
115	400–2000	8	15.0
138	400–2000	8	18.0
161	400–2000	9	20.0
230	500–2500	11	23.0
345	500–2500	14	26.0

Note. The nominal internal stress is the electric stress at the conductor screen at rated phase-to-ground voltage. A "wet" design is a cable without impermeable metallic sheath. The limits given in the standard are valid unless proposed otherwise by the manufacturer or purchaser.

ularities. Higher design stress and thinner insulation would be possible but would require a more definite and costly production and the use of higher grades of insulation material.

For higher rated cables ($\geq$ 150 kV), higher design stresses are generally accepted as a result of better polymer grades and a higher relative thickness stability of the insulation. This can be achieved despite the fact that the specific breakdown strength in thicker XLPE layers is lower than in thin XLPE layers [29].

3.3.4 Dielectric Design of d.c. Cables

Direct current high-voltage power transmission is more than a century old, and paper-insulated submarine cables have been used for submarine d.c. transmission since more than 50 years [30]. Extruded d.c. cables have been introduced commercially more than a decade ago by ABB and are now used as submarine cables in a large scale. The increasing need for long-haul submarine power transmission fuels a large interest in the properties of d.c. cable insulation materials.

The d.c. voltage of normal operation creates a field distribution in the cable dielectric that is controlled by the specific conductivity σ of the insulation material. The specific conductivity $\sigma = \sigma(E, T)$ is a function of local electric field and temperature. For this reason, a simple analytic solution of the Laplace equation, as in the case of a.c. cables, cannot be applied.

Various expressions for the dependence on E and T of $\sigma(E, T)$ have been published, such as the following for polymers:

$$\sigma\ (E,T) = A \exp\left(\frac{-\phi \cdot q}{k_B T}\right) \frac{\sinh\left(B\,|E|\right)}{|E|} \tag{3.63}$$

where A and B are constants, ϕ is the thermal activation energy in eV, q is the elementary charge, T the temperature in Kelvins and E the electric field in V/m

[31]. According to other references $\sigma(E, T)$ can be expressed as:

$$\sigma = \sigma_0 \cdot e^{(\alpha(T-273)+\gamma|E|)} \tag{3.64}$$

where σ_0 is the conductivity at 0°C and 0 kV/mm, α is the temperature dependency coefficient, γ is the field dependency coefficient, and E is the local electric field strength [32]. For mass-impregnated cables, we can assume the following:

$$\sigma_0 = 1 \times 10^{-16}\Omega^{-1}\mathrm{m}^{-1}, \quad \alpha = 0.1\,K^{-1}, \quad \gamma = 0.03\,\mathrm{mm/kV}.$$

It is difficult to measure the dependence of σ of E and T as the probes usually need a very long time to stabilize.

Although Eqs. 3.63 and 3.64 are different, they describe two fundamental properties of cylinder-symmetrical d.c. insulation:

1. The higher the electric field at a particular radius r in the insulation, the higher the local conductivity σ(r).
2. The higher the temperature at a particular radius r in the insulation, the higher the local conductivity σ(r).

These properties have far-reaching consequences. Consider a d.c. cable which has just been put under d.c. voltage. In the first instant, the field distribution is according to the green dotted line in Fig. 3.13. The distribution resembles that of an a.c. cable such as shown in Fig. 3.12, with the highest stress at the conductor screen. The relatively high electric field close to the conductor results in a higher specific conductivity in the innermost cylindrical shell of the insulation. As a result, the voltage drop over the shell and the gradient in the same place decrease. After a while, the cold cable d.c. stress distribution has established. This process is called relaxation, and the resulting stress distribution is depicted in Fig. 3.13 as the blue solid line. The distribution represents the situation in a not-loaded cable wich has been under operational d.c. voltage for some hours. The positive effect of the field depending conductivity is to reduce the stress where it is the highest, i.e. next to the conductor. How much the stress peak at the conductor screen is reduced, is depending on the σ(E) function, which is slightly different for different materials.

The next step would be to switch on the current. Once conductor current is flowing, a temperature gradient over the insulation is established, and the situation changes dramatically. As the temperature rises in the insulation close to the conductor, the local conductivity increases further; and this in turn decreases the local stress. The influence of the temperature gradient is much stronger than the influence of the electric field previously was. As a result the stress on the conductor screen decreases considerably, while the stress close to the insulation screen accordingly increases. With large temperature gradients over the cable insulation, the stress profile can actually reverse leaving the cable with the highest stress at the insulation screen. Figure 3.13 shows the electric stress in a d.c. insulation also for full power (red dashed curve) and fully developed thermal gradient.

To describe the d.c. stress distribution the Laplace equation $\nabla^2 \Phi = 0$ of the a.c. distribution is replaced by the more general Poisson equation:

$$\nabla^2 \Phi = \rho \cdot \varepsilon_r$$

where ρ is the local space charge density. Now the insulation layer is no longer space-charge free as in the case of a.c. cable insulation. The transition between the initial transient stress distribution, as depicted by the green dotted line to the no-load d.c. distribution (blue solid) and to the full-load d.c. distribution (red dashed), is associated with the creation and relocation of space charges in the insulation to fulfil Poisson's equation. As space charges have a limited mobility it takes some time to establish a stable stress distribution (a process sometimes called relaxation). The charge mobility is strongly depending on the temperature [33, 34] so that the relaxation speed is different in cold and warm cables. In d.c. submarine cables at 6°C (the seafloor temperature often found in waters in moderate climate zones), it can take many hours to achieve a stable stress distribution. For the design of submarine d.c. cables, it is important to calculate the time-dependant stress distribution under the influence of all expected operational conditions.

The curves of Fig. 3.13 depict the global stress distribution in the d.c. cable insulation. However, this is only a part of the total picture. Many measurements have demonstrated that space charges also accumulate in the immediate vicinity of the dielectric surfaces of the insulation, i.e. close to the extruded conductor screen and close to the extruded insulation screen. These space charges can be caused by charge injection from the semi-conducting surfaces. Sometimes they are homo-charges (same polarity as the neighbouring semi-conductor), sometimes hetero-charges. This space-charge accumulation has led to many failures in the develop-

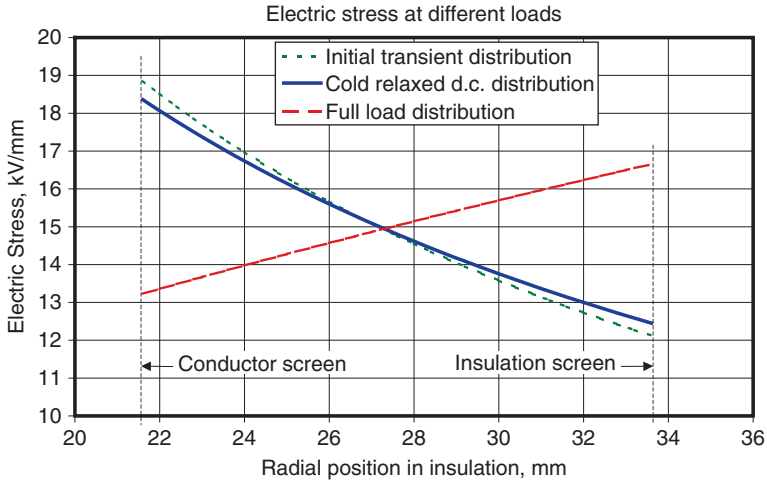


Fig. 3.13 Electric stress in d.c. cable insulation under different load conditions

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 115 of 306

ment of extruded d.c. cable insulation systems. Only by orchestrated properties of the insulation material and the screen material the problems of space charge related field distortion can be overcome. Today, at least one manufacturer has succeeded and installed more than thousand of kilometres of extruded HVDC cable.

A comprehensive bibliography on space charge phenomenon in polymeric d.c. cables is given in [35].

3.3.5 Dielectric Design of Mass-Impregnated Cables

For practical considerations, the steady-state stress distribution in a mass-impregnated d.c. cable can be calculated analytically according to [36]:

$$\beta = \frac{\alpha \cdot W_C}{2\pi\lambda} \qquad \gamma = \frac{k \cdot U}{r_S - r_C} \qquad \delta = \frac{\beta+\gamma}{\gamma+1}$$

$$E(r) = \frac{\delta \cdot U}{r_S} \cdot \frac{\left(\frac{r}{r_S}\right)^{\delta-1}}{1-\left(\frac{r_C}{r_S}\right)^{\delta}} \quad \text{kV/mm} \tag{3.65}$$

with the following symbols (partly different from [36]):

α [1/K] = conductivity dependence of the temperature
k [mm/kV] = conductivity dependence of the electric stress
U [kV] = voltage conductor – sheath (screen)
r_c [mm] = radius of conductor screen
r_s [mm] = radius of insulation
r [mm] = radius where E is calculated
W_c [W/m] = conductor losses
λ [W/K×m] = thermal conductivity of insulation.

The factor β may also be written:

$$\beta = \frac{\alpha}{2\pi\lambda} \cdot W_C = \frac{\alpha}{2\pi\lambda} \cdot \frac{\Delta\theta \cdot \lambda \cdot 2\pi}{\ln \frac{r_S}{r_C}} = \frac{\alpha \cdot \Delta\theta}{\ln \frac{r_S}{r_C}}$$

The dielectric behaviour of mass-impregnated cables is governed by a particular effect. In contrary to an oil-filled cable, which has an external pressure supply, the mass-impregnate cable has no inner pressure when it is not carrying a load current. Small voids exist in the gaps between the paper tapes, limited in the radial extension by the thickness of the adjacent paper tape. When the cable is loaded with transmission current, the expanding impregnation compound fills up all voids and creates finally an overpressure inside the insulation. Under full load, the dielectric strength of the cable insulation is much higher compared to the no-load situation. For this reason, the cable could be operated at higher voltage under full load conditions compared to no-load conditions. Experience has shown that the dielectric

strength undergoes a minimum during the first one-three hours after reducing the current and, hence, the temperature.

The relevant type tests for mass-impregnated d.c. cables stipulate load cycles with 8 h loading and 16 h cooling ([7], in Chap. 5). The recommended test voltage during the entire load cycle test is $1.8 \times U_0$. According to experience, the cooling phase of the load cycle is the limiting challenge for a given cable design. In practice the mass-impregnated submarine d.c. cable is designed to fulfil the requirements of the Electra 171 type test requirements rather than the challenges of real cable life.

Initially the rated voltage of the tested cable is set such that the cooling phase of the type test will be passed. Doing so, the additional dielectric strength during the full load period cannot be used for real cable operation. In order to utilize the cable in a more economic way, a voltage regulating algorithm has been installed in some HVDC links, which increases the operational voltage on the cable whenever possible using the higher dielectric strength of the insulation under load conditions. The continuous transmission power can be increased by about 25% using this voltage regulation ("CDVC").

Historically, an operational dielectric stress of up to 40 kV/mm has been considered possible for mass-impregnated d.c. insulation [37]. Today, a d.c. design stress of 25–35 kV/mm has been established. The design impulse strength is usually in the range 80–95 kV/mm for impulse tests superimposed on a d.c. voltage with opposite polarity, as stipulated by the Cigré test recommendation. It should be mentioned that the required impulse test levels of mass-impregnated submarine d.c. cables could be lowered noticeable if converter station manufacturers and cable manufactures agreed on closer protection levels for the cable terminations.

3.3.6 Impulse Stress

For all cable types, there are test standards to demonstrate the impulse withstand level. Often, a Switching Impulse Withstand Level (SIWL) and a Lightning Impulse Withstand Level (LIWL) are defined. Table 3.17 lists test levels for LIWL and SIWL

The electric cable cores of submarine power cables are developed and tested according to the same principles as land cables. Therefore, they have to comply with the impulse test requirements given in the applicable land cable standards. Knowing the impulse test voltage, the electric stress in the cable during the test can easily be calculated with Eq. 3.62.

The design impulse stress of power cables can unfortunately not be found in tables. Impulse breakdown voltages are strongly depending on sample size, material purity, manufacturing quality, temperature, electrode structure, etc. Paper insulation tends to have a narrower statistical distribution of breakdown voltage than extruded insulation. For mass-impregnated HVDC cables Electra 189 requires the same peak voltage ($=2.0 \times U_0$) for both Lightning (LI) and Switching Impulse (SI) tests, while the SI test level is lower than the LI level in IEC test standards. In real life, HVDC

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 117 of 306

Table 3.17 Impulse test levels for a.c. cables

Rated voltage Kv a.c.	Lightning impulse test voltage, kV	Switching impulse test voltage, kV
According to IEC 60840		
20	125	42
30	170	63
45	250	65
66	325	90
110	550	160
132	650	190
150	750	218
220	1050	318
275	1050	400
330	1175	420
400	1425	440
According to British Electricity Boards Engineering Recommendations		
76/132	640	380
160/275	1050	850
230/400	1425	1050

cables of any kind would hardly ever experience overvoltages of the magnitude tested in IEC impulse tests.

Extruded d.c. cables for VSC use are terminated indoors and do not suffer any lightning overvoltage in the classic sense at all. Neither the classic switching overvoltage is experienced for these cables.

3.3.7 Availability and Reliability

The choice of the insulation wall thickness is as much an asset management task as it is an engineering task. Considering the Weibull plots of the cable insulation material, the cable designer will chose an insulation wall thickness which guarantees that the probability of a cable breakdown within the required life time of the cable is below an acceptable level, given the operation temperature and the electric stress on the cable. It must be noted that the statistical risk for breakdown cannot be eliminated completely unless the cable is not being used.

Given the difficulty of submarine cable installations/repairs, it can be prudent to apply conservative design rules for submarine power cables. The large expenses for submarine cable repair might motivate the use of thicker an insulation than it is used for land-based cables, with the purpose of reducing the electric stress and hence the statistic risk of electric failure. On the other hand, experience from submarine power cable operation demonstrates that there are almost no spontaneous electric failures in submarine power cables (cf. Chap. 9).

A thicker insulation would also increase the costs for lead and steel. In the worst case, the larger cable weight and volume would require a larger cable ship or more laying campaigns.

Rather than adding extra insulation the cable should be protected against overvoltage and excess temperature, in order to comply with the rules of thumb (cf. Chap. 2):

- Increase the operating temperature by 8–10°C and you'll cut the lifetime by half.
- Increase the operating voltage by 8–10% and you'll cut the lifetime by half.

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Chapter 4
Accessories

Contents

4.1 Submarine Cable Joints 105
4.1.1 Factory Joints 106
4.1.2 Offshore Installation Joints 108
4.1.3 Miscellaneous Joint Designs 113
4.1.4 Beach Joints 114
4.2 Cable Terminations 116
4.2.1 On-Shore a.c. Cable Terminations 116
4.2.2 On-Shore d.c. Cable Terminations 116
4.2.3 Offshore Cable Terminations 118
4.3 Other Accessories 118
4.3.1 J-Tubes 118
4.3.2 Hang-Off 119
4.3.3 Bending Protection 120
4.3.4 Holding Devices 120
References 120

4.1 Submarine Cable Joints

The manufacture of a submarine power cable joint[1] requires valuable vessel time, specialised equipment for the manufacturing and deployment of the joint, highly specialized teams on board, and a sufficient long period of suitable weather conditions. The failure of some early installation joints during service shaded the reputation of submarine power cable joints. Failures in the joints were usually caused by poor engineering or inadequate installation procedures. As an example, all shore joints in the first Cook Strait cable connection failed or needed repair. The failures were blamed to inadequate engineering of the transition joints connecting different conductor sizes [1]. However, submarine power cables of today deserve a better

[1] The expression “splice” is sometimes used.

T. Worzyk, *Submarine Power Cables*, Power Systems,
DOI 10.1007/978-3-642-01270-9_4, © Springer-Verlag Berlin Heidelberg 2009

reputation. In a 1986 Cigré study on the reliability of submarine power cables, the joints account for 18% of the failures, the cables for 82%. Improved engineering methods, better route survey methods, and more sophisticated installation procedures have changed the picture during the past twenty years. With these improvements, the major submarine power cable manufacturers can provide joints of high quality and reliability. Assembled by well-trained teams and supported by adequate vessel equipment, the joints meet all requirements and do not have to be regarded as a weak point anymore. Still it is prudent to reduce the number of cable joints as much as possible because the joint assembly requires extra good weather time.

Submarine power cable joints come in a row of different shapes, which can cause some confusion. There are factory joints, installation joints, repair joints, flexible and stiff joints, both for 1C and 3C cables. The following paragraphs try to eradicate some of the confusion.

4.1.1 Factory Joints

A factory joint connects semi-finished pieces of cable before the armoring is applied. Factory joints are also used when production mishaps require that the production cable length must be cut to remove damaged parts. The flexibility of the joint allows for application of a continuous armoring over the joint in the ordinary armoring machine in the factory.

The manufacturing of a factory joint (cf. Fig. 5.2) starts with the connection of the conductors of the two cable ends. Different welding methods such as TIG, MIG, etc. are used. Friction welding can be used to connect aluminium to copper. Stranded conductors are welded either with a single welding seam across the entire diameter, or wire-by-wire. The choice of an appropriate welding process and suitable filler materials is critically important to producing conductor joint with sufficient mechanical properties. Welding defects such as discontinuities, cracks, porosity, incomplete fusion or penetration, and nonmetallic inclusions must be avoided. Sometimes, the weld quality is checked by X-rays. The tensile strength of the welded joint is of great importance for the installation of submarine power cables. The conductor portion adjacent to the welding is weaker because it is annealed by the welding heat. The strength is often only 70% of the strength of the original conductor. Less frequently, other methods of conductor joints are used, such as flush ferrules to be crimped on the conductor ends, or soldering processes [2].

The electric conductivity of the weld must be sufficiently high to avoid a hotspot in the cable. Still, a local moderate increase of the specific resistivity of the weld materials is uncritical as the heat generated from the excess losses is dissipated efficiently into the adjacent conductor.

Screw connectors are not used for factory joints because they would add up to the diameter and obstruct further manufacturing.

After the conductor joint, the insulation is built up, normally comprising the same structure as the cable insulation. The insulation of the two cable ends is tapered to form conical surfaces. New insulation material is applied between the two tapered

cable ends now. A longer interface cone provides a lower axial electric field along the sensitive interface. In most cases, the joint insulation is somewhat thicker than the cable insulation in order to reduce the electric stress.

Factory joints according to the described generic design can be used both for paper-insulated and polymeric cables.

The joint insulation for polymeric insulated cables (XLPE, PE, EPR) is made from tapes of similar material, which are lapped in the gap between the cables. The screens are made from carbon-black loaded polymeric tapes. The joint insulation is cured under heat and pressure so that the tapes melt together and form a homogeneous continuous material without voids. If XLPE tapes are used, the curing time is longer for the cross-linking process. The applied pressure helps to suppress the formation of gas bubbles when the XLPE tape is cross-linking. The interface between cable insulation and joint isolation must not have any voids, gaps, cracks, or contaminations. The preparation of the conductor screen and the transition between the conductor screen in the cable and the screen in the joint is a delicate task and requires the highest carefulness (cf. Fig. 4.1). The adhesion of the joint insulation to the cable insulation is of great importance for the electric strength of the joint.

For voltages up to and including 110 kV also self-amalgamating tapes can be used as joint insulation. These tapes must be applied with well-defined tension. The self-amalgamating process results in a compact insulation material after a few days.

With paper-insulated cables, the insulation of the flexible joint has a similar structure as the cable itself, comprising a conductor screen, the electric insulation, and an insulation screen. The screens are made from carbon-black paper tapes. The paper tapes are pre-impregnated and are applied either manually or with a semi-automatic lapping machine (Fig. 4.2). The joints should be manufactured in humidity-controlled and temperature-controlled rooms.



Fig. 4.1 Application of XLPE joint insulation under clean conditions (Courtesy of ABB, Sweden)

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 123 of 306



Fig. 4.2 Application of paper insulation for a flexible joint using a semi-automatic lapping machine (Courtesy of ABB, Sweden)

The factory joint also includes a lead sheath over the jointed insulation. The lead sheath is applied as a wide lead tube, which is slid over and parked on one side of the factory joint before the conductor jointing. After the insulation is finished, the lead tube is pushed over the factory joint, swaged down to a tight fit over the joint insulation, trimmed, and soldered to the cable's lead sheath. In case of mass-impregnated cables, the insulation inside the lead sheath can now be treated again to achieve fully saturated paper-oil insulation. Finally, a protective polymeric shrink tube is applied over the lead or other outer layers. Now, the factory joint constitutes an integral part of the power cable core and is ready for further steps in the production line such as armoring. The slight oversize of the factory joint does not impose any obstacle for the further production.

4.1.2 Offshore Installation Joints

The notion "installation joint" or "field joint" describes a joint of the complete submarine power cable including conductor, insulation system, armoring and all intermediate layers.

Installation joints are manufactured on-board of a sea-going vessel, or in the beach area. Depending on the cable and joint design, the manufacturing of offshore installation joints takes between one and ten days after both cable ends are laid up in the jointing shack on-board the vessel. No matter if this is the laying vessel or a separate jointing barge, the joint should be designed to keep the offshore jointing time as short as possible. During the jointing, at least one of the cables is hanging down from the vessel over a laying wheel or a laying chute.[2] In heavy weather this imposes a risk for the jointing crew and the cable. If the required jointing time

[2]One of the cables to be jointed may still be on the turntable on the cable laying vessel.

is short, there are better chances to find a sufficiently long weather window with suitable sea-state. Once the jointing process is started it can be interrupted only by cutting the cable.

4.1.2.1 Flexible Installation Joints

Flexible joints can be used with advantage when a long cable route requires the offshore jointing of subsequent delivery lengths. After the first laying campaign, the vessel would fetch the next cable length at the manufacturer's premises or a storage port. It returns to the cable route and pulls up the end of the first cable over the laying wheel to a jointing shack onboard the vessel. There, the second cable length, which is still onboard the vessel, is jointed to the first cable by means of a flexible installation joint.

The basis of a flexible repair joint is the same procedure as for the factory joint, including the jointing of conductor, insulation, and lead sheath as described for the factory joint. The joint may be slightly thicker than the corresponding cable diameter. Finally, and this is the special attribute of submarine power cable joints, the armoring over the installation joint must be arranged with high tensional strength, yet flexible.

For flexible joints a wire armoring covering the joint section is necessary. The gap between the armoring of the two cable ends can be closed with pre-spiralled wires. These wires are welded to the wires on one side of the joint, twined around the joint, and then connected to the armoring wires on the other side of the joint. A pretension of the joint armoring wires is necessary to maintain the tensional forces in the armoring. The armoring wires can be welded to each other wire by wire, or in various welding patterns to achieve the best possible tensional strength between the cable armoring and the joint armoring. The wires of the joint and the cables can be connected also by screw connectors [3] or by what is known as turnbuckle, a left/right-threaded sleeve to tighten the connection between armoring wires [4]. The use of ring-shaped welding sleeves to connect the wires from the joint to the cable armoring wires provides a good distribution of tensional forces. A welding sleeve makes it also possible to connect cables with different numbers, diameters or shapes of armoring wires. A Swedish manufacturer uses a patented [5] semiautomatic portable armoring machine to provide the joint armoring.

A picture or illustration of a flexible repair joint would not be very informative as the joint has the same appearance as the adjacent cables.

The completed joint can now be transferred through the ordinary laying equipment of the vessel and passes over the stern laying wheel down into the water. The jointed new cable length is following and the laying operation can be continued. Depending on the cable design, the manufacturing of a flexible joint requires a jointing shack of 4 up to 18 m length on-board, located between the storage turntable and the stern laying wheel.

Flexible cable joints can be made for single-core mass-impregnated cables of any rated voltage. For polymeric single-core cables, flexible installation joints have been

used for voltages up to 245 kV. Flexible joints have also been used for three-phase cables up to 150 kV [6].

Cable factories without their own sea harbour can produce submarine cables only in short drum lengths fit for road transport to the next port. In these cases, flexible joints are used to connect a number of drum lengths to the desired submarine cable delivery length, which is an inconvenient and tedious method [4, 6].

4.1.2.2 Rigid Joints

Rigid joints (or "stiff joints") are very different to flexible joints. The name denotes that the joint has a rigid outer casing, most often in the shape of a steel tube (Fig. 4.3). The steel tube serves as a connecting point for the cable armoring wires of each cable end, and as an outer protection to the cable joint inside.

The jointing of the electric systems inside the outer casing can be accomplished in different ways. The cable core ends may be connected with the flexible jointing method as described above. The outer steel casing provides additional mechanical strength and tensional force. In another method, the steel casing allows to use pre-moulded joint sleeves for the electrical parts of the cable. The pre-moulded joint design employs an elastomeric sleeve containing both semi-conducting and insulating layers. This sleeve is bridging the gap between the cable insulation on each side (cf. Fig. 4.4).

The concept of pre-moulded or pre-fabricated joints has become the method of choice for polymeric land cables because of many advantages:

– short assembly time
– accommodates all types of conductor connections such as welding, compression sleeves and screw connectors according to client specifications
– can be pre-tested in factory

The steel casing makes it possible to use pre-fab joints also in submarine applications. Sometimes, an inner casing made of copper or brass is used which encloses

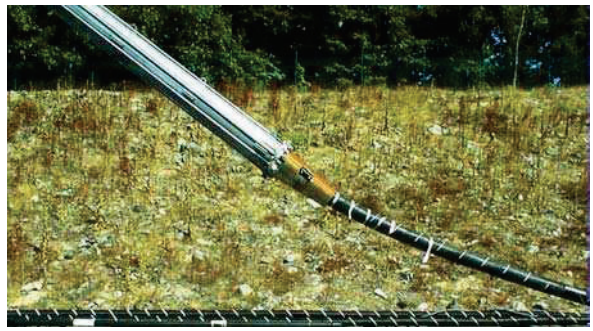


Fig. 4.3 Rigid submarine installation joint in a steel casing for a 1C cable during an on-shore bending test

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 126 of 306



Fig. 4.4 Pre-moulded polymeric cable joint. The elastomeric joint sleeve on *top*. Conductor connected and insulation prepared for application of insulation sleeve on *bottom*

the pre-fab joint and is soldered to the lead sheath for complete water tightness. Before jointing the conductors of the two cable ends, the pre-fab sleeve is expanded radially and "parked" on an auxiliary support tube on the nearby power cable end. After conductor jointing and preparing the insulation according to the instructions of the supplier, the "parking" sleeve is slid over the insulation gap. The support tube is removed, and the joint sleeve collapses over the insulation gap in a pre-determined position. In this final position, the sleeve keeps a radial pressure onto the underlying insulation surfaces. The radial pressure between the interface surfaces is of critical importance for the dielectric strength of the joint over the total lifetime. In some designs, external spring-loaded elements help keeping that radial pressure up.

In contrast to the taped or tape-moulded joint, the pre-fab joint sleeve can be pre-tested at the manufacturer's premises. The high-voltage factory test, often with partial discharge recording, can detect possible flaws, voids, or particles in the insulation material and confirms the intrinsic dielectric strength of the tested joint sleeve. Naturally, this test cannot unveil a poor installation job.

The core joint is equipped with its own water barrier system (very often a lead sheath). If the pre-fab joint sleeve is very bulky, a copper or brass casing can be used to encapsulate the joint. The copper casing can easily be soldered to the cable lead sheath in order to provide a completely watertight cover for the joint.

For some medium voltage cables, a polymeric water protection is considered adequate and the joint can be covered with a shrink tube.

The jointed core(s) are now encased into the outer metallic casing. The casing has a central cylindrical portion and two conical ends. The partition line of the steel casing may run in parallel with the cable axis connecting two half-shells, or may run around the ensemble connecting two funnel-like parts. The outer casing can also be assembled from more than two parts. The different parts of the steel casing are connected to each other by welding or nuts and bolts. The wire armoring on each side of the joint casing is connected mechanically to the casing by means of clamping flanges or welding (cf. Fig. 4.5).

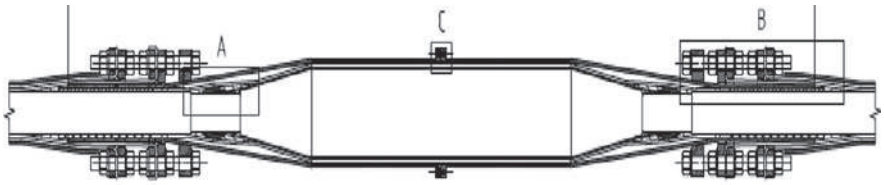


Fig. 4.5 Copper and steel casing for a pre-moulded joint

In Fig. 4.5, the soldering of the copper casing to the cable lead sheath can be seen at "A", and the partition of the steel casing at "C". The casing constitutes a strength member connecting firmly the armoring layers of each cable side (at "B"). For less demanding applications such as shallow waters, a casing made from polymeric materials may be used. Special attention must be paid to the transition between the layers of the cable and the corresponding layers of the joint as the manufacturing, transport, installation, and service can impose high mechanical stresses on all parts of the joint.

In order to avoid sharp cable bends at the transition between the stiff joint casing and the flexible armoring of the submarine cable, bend restrictors in the shape of conical rubber sleeves enclose the cable at the exit of the steel casing (cf. Fig. 4.3).

Rigid joints cannot be transported through the ordinary cable gantries or deployed with the ordinary vessel laying equipment because of their stiffness and increased diameter. Complicated crane arrangements are necessary for the deployment of rigid joints.

All these facts seem to make the rigid joint the inferior choice of installation joints for submarine power cables. Indeed, the flexible joint as outlined in the previous chapter has the advantage of simple design and easy installation. But the advantages of pre-fab joint sleeves and the good mechanical protection provided by the steel casing may outweigh the use of extra components. At the end, assembly time on board the vessel is very precious.

While rigid joints have been used for submarine LPOF cables, they are not being used for today's MI d.c. cables. As there are no pre-fab MI cable joints available, the joint insulation must be made by on-site lapping anyhow. Rigid joints can therefore not provide the advantage of quick assembly and factory pre-testing for mass-impregnated cables.

Rigid installation joints are used for almost all 3C cables (cf. Fig. 4.6). Inside the joint case, the three cable cores are split and jointed individually. Each cable core joint is encapsulated in its own water-proof inner casing, which can be made from pre-formed copper tubing to be soldered to the lead sheath of the cable. The functional separation of inner casing (water protection) and outer steel casing (tensional forces, armoring) allows for more possibilities in the design process. The outer casing also can accommodate a splice box for optical cables, which might be incorporated into the power cable.

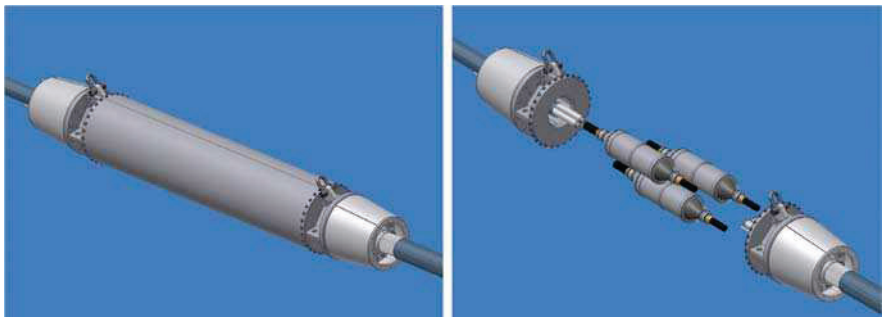


Fig. 4.6 Rigid joint casing with three pre-moulded joints inside (Courtesy ABB, Sweden)

4.1.3 Miscellaneous Joint Designs

Fluid-filled submarine power cables require joints with a continuous fluid duct in the hollow conductor. A tubular sleeve is often included into the duct to provide support before welding. The cable cores are frozen down by liquid nitrogen to prevent oil outflow.

Under certain circumstances, the free flow of impregnating fluid through the joint is not wanted, e.g. in steep passages of the submarine cable. In these cases, stop joints can be devised, which have a solid conductor weld, closing both the central oil duct and the inter-wire spaces. Conical epoxy resin spacers inserted into the insulation wall stop the oil passage in the insulation. These stop joints can also prevent unwanted movements of copper particles with the oil [4].

Many transition joints have been designed to connect submarine cables of different kinds. Submarine cable links sometimes comprise different conductor sizes to match different thermal conditions along the route. Small size differences can be jointed with flexible joints. For large size differences, the use of a rigid joint is preferred because it provides a protection against mechanical stress, which can be detrimental to the sensitive transition of the highly stressed conductor screen.

Some submarine 150 kV HVDC projects with extruded cables have copper conductors in the submarine portion and aluminium conductors in the land section (Estlink, NordE.ON). The transition between the different cables was accomplished by purpose-made pre-fab joints with two-metal screw connectors. The transition joint connected a 1000 mm^2 Cu submarine cable conductor to a 2000 mm^2 Al land cable conductor.

In some submarine HVDC cable links the near-shore cable is a fluid-filled cable, while the submarine cable is a mass-impregnated cable [7]. Also here transition joints can be constructed to connect cables with different insulation systems and different conductor design. Transition joints between paper-insulated cables and extruded cables are known from on-shore applications but no case of submarine use is known.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 129 of 306

Table 4.1 Application and properties of various joint concepts

	Flexible joint	Rigid joints, tape-insulated	Rigid joints, pre-fab
1C mass-impregnated	Yes, all voltages	Yes, but no advantages	No
1C paper-insulated	Possible	Possible	No
1C extruded cables	Up to 145 kV. In few cases 245 kV.	Common up to 110 kV	Yes
3C paper-insulated	Possible	Yes, but no advantages	No
3C extruded cables	Possible	Yes, but no advantages	Yes
Conductor joint	Welded only	Welded only	Welded, compression or screw
Need for special deployment arrangement on cable vessel	No	Yes	Yes
Space for optical joint box	1C cable: No	3C cable: Yes	3C cable: Yes

Trifurcation joints connecting a three-core cable to three single-core cables are known for land applications but no submarine use is known. Probably trifurcation joints have been used as beach joints to connect 3C submarine cables to 1C land cables.

A bifurcation joint has been manufactured for the NorNed project; it connected a two-core HVDC cable in the southern part of the cable route to two single-core cables in the northern part.

The large variety of submarine cable joints may cause some confusion. Table 4.1 lists those joint concepts described here and their most important properties.

4.1.4 Beach Joints

Sometimes, the submarine cable can be connected to an overhead line or a substation directly at the landing point, but in many cases the cable route continues onshore. A beach joint between the submarine and the land cable can be necessary for different reasons:

- The cable termination is too far from the shoreline to pull in the submarine cable all the way.[3]
- Thermal conditions require a larger conductor size onshore than offshore. It would be imprudent to dimension a long submarine cable for the thermal needs of a short beach section.

[3]The longest pull hitherto has been made when the Swedish end of the Baltic Cable was pulled from the sea more than 4 km onshore to the cable-to-air transition yard.

– In many projects the submarine cable is 3C while the land cable system consists of three single-core cables. The transition joint is usually erected in the shoreline

The design and installation of beach joints may require special attention. The location for the beach joint should be selected carefully if there is a choice. A dry jointing house or tent offering protection from wind and airborne sand, salt, and droplets, is necessary for the assembly of a joint. The safest place is on dry land, sufficiently far away from the splash zone. The higher the location over the water table, the easier it is to keep the joint pit dry. A location beside a road would facilitate transport of equipment and minimize impact on the environment.

The manufacturing of the beach joint in the splash zone generates further difficulties. The jointing pit must be excavated into the near-shore seafloor, secured by a cofferdam and pumped dry. The cable ends must be guided through the cofferdam walls. Equipment and crew must be given a dry clean environment. Alternatively, the joint can be erected on a lofty platform. In either case, the work preparations are even worse when tidal current threaten the stability of the arrangements twice a day.

Figure 4.7 illustrates the beach joint area for a double HVDC extruded cable circuit. Two pairs of HVDC cables are pulled in from offshore through pipes into land. The protection pipes are terminated in beach holding devices that are bolted into the concrete floor of the joint pit.



Fig. 4.7 Beach joints of two pairs of extruded HVDC cables

4.2 Cable Terminations

The submarine cable, when landed onshore, is normally connected (jointed) to an underground cable close to the beach. The underground cable continues to a substation, where it is terminated with a standard onshore cable termination. The substation can be a few meters or many kilometres from shore.

The onshore cable termination is not specifically designed for submarine cables but for underground cables.

4.2.1 On-Shore a.c. Cable Terminations

Onshore a.c cable terminations are equal for submarine and underground cables in most respects. Standard terminations for a.c. submarine cables are available from a row of manufacturers:

- *Open-air terminations* to connect the cables to overhead lines or the busbars of an air-insulated substation. The insulator may be of porcelain or polymeric. The creepage length over the insulator sheds is specified between 25 and over 40 mm/kV depending on the expected salt and pollution load. Expected salt storms close to shore also require special attention to the corrosion protection of the metal work of the termination. It is recommended to replace standard aluminium grades to highly corrosion resistance grades. Also, specified wind loads for near-shore terminations might be more stringent.
- *GIS terminations* to connect the cables to gas-insulated switchgear. This type of cable terminations is well-known from land cable applications up to the highest voltages. GIS terminations have standardised sizes in order to make them compatible to switchgear from other manufacturers. GIS terminations are based on a stress relief cone on the extremity of the cable insulation. The stress cone is inserted into a conical receptacle inside the GIS compartment. In some GIS terminations, the stress cone matches the inside of the conical receptacle perfectly (plug-in type), and these terminations are completely oil-free. Other designs contain a small amount of dielectric fluid to fill the gap between the stress cone and the inside of the conical receptacle.
- *Transformer terminations* are generally identical or very similar to GIS terminations. However, for submarine cables they are rarely used, as substation planners want to have circuit-breakers between the submarine cables and the transformer.

4.2.2 On-Shore d.c. Cable Terminations

So far, only cable-to-air terminations have been devised for submarine d.c. cables. The stress control in d.c. termination must rely at least partly on resistive elements,

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 132 of 306



Fig. 4.8 Indoor HVDC cable terminations for mass-impregnated cable (*left*) and extruded cable (*right*). Small oil reservoir cylinder is attached to the stand of the left termination

as pure capacitive elements would be not suitable with d.c. The design is adapted to the type of submarine d.c. cable.

The terminations used for extruded submarine HVDC cables up to 150 kV are identical to on-shore cable terminations for the same cable technology. They have a polymeric insulator and are completely oil-free. Terminations for extruded HVDC cables are erected indoors.[4] The termination shown in Fig. 4.8 has a field-grading element that is made of a resistive material with non-linear resistivity. This material becomes more conductive when subject to higher electric stress. Owing to this property the field grading element has the ability to relieve highly stressed parts inside the termination.

LPOF cable terminations for d.c. use are designed very similar to their sisters for a.c. use. However, the stress cone and the external insulator might have a different design to control the d.c. stress. The stress cone is made from impregnated paper, which is either pre-formed in the factory or shaped on-site during the erection of the termination. The termination also constitutes the oil-feeding entry point into the cable.

The terminations for mass-impregnated HVDC cables are similar to the LPOF cable terminations except the oil-feeding system. While the LPOF cable termination must take care of the thermal "breathing" of the entire cable (or at least half of the length of it), in the mass-impregnated system only the expansion of the small oil

[4]It is yet not known how the cable terminations for the Trans Bay HVDC project (under construction) will be arranged.

volume inside the termination must be taken care of. For this purpose, a relatively small oil expansion vessel of a few hundred litres is enough and can be mounted on the termination stand without external pipework (cf. Fig. 4.8).

4.2.3 Offshore Cable Terminations

Submarine power cables connected to offshore installations such as oil and gas production platforms, or OWP must be terminated in a harsh environment. The adverse climate and restricted space allow the use of open-air terminations only for moderate voltage levels. The cables are often terminated directly into encapsulated switchgear by means of GIS terminations, polymeric plug-in connectors, or transformer terminations.[5] Again, these components are standard components from land cable applications. However, they must be corrosion proof and comply with the product and safety standards that rule onboard the platform. These standards may be more stringent than equivalent standards onshore. Also, the erection and installation of the terminations may be subject to much stricter rules compared to those that apply for onshore work.

4.3 Other Accessories

A number of accessories are used for the structural integration and safe fixation of submarine power cables. The following lines give but a rough overview on the large variety of products.

4.3.1 J-Tubes

It is industrial practice to guide power cables up to stationary platforms through J-tubes, named for their J-like shape. The bow of the J is down on the seafloor and the upper end of the J is beneath or above the lowest platform deck. The lower opening is called bellmouth for its shape and is normally directed outwards from the platform legs. The bellmouth can be underneath or slightly above the seafloor. During the installation, the cable is pulled through the bellmouth up to the platform by means of a pulling wire. In order to guarantee a smooth installation, the bow radius should be noticeably larger than the minimum bending radius of the cable, and the tube diameter at least 2.5 times the cable diameter. It is cheaper to add some material to the construction than to get stuck with a cable and an expensive cable vessel scheme during the installation. Normally, there is one power cable in each J-tube, but numbers of two and four have been used.

[5]The terminations of extruded HVDC cables on offshore platforms are usually placed inside the valve cubicles.

While most J-tubes are left open at the bottom, some are plugged around the cable in order to keep anti-corrosion fluid inside.

The thermal conditions of the power cable inside the tube should be given special attention. In the water-filled J-tube, convection contributes to the heat flow between the cable and the tube wall. Convection is depending on the size of the annular gap and is difficult to grasp mathematically. The conditions get worse in the upper air-filled part of the J-tube where the air can get trapped inside the tube. Sufficiently large openings on top and bottom of the air column create a chimney effect and improve the situation considerably. However, openings close to the splash zone are not liked by corrosion specialists.

Some central platforms in OWP's have giant J-tubes that accommodate a large number of incoming cables from the individual chains of turbines. It can get crowded and warm inside.

4.3.2 Hang-Off

The gravity weight of vertically suspended cables on stationary or floating platforms is carried by hang-offs. A hang-off is a sophisticated connection flange between the cable armoring and the platform structure (cf. Fig. 4.9). The flange contains a clamping device for the armoring wires of the power cable to carry the mechanical load. The cable core with lead or copper sheath and protective plastic sheath is extending through the hang-off and continues upwards towards the cable termination.



Fig. 4.9 Hang-off for a three-phase cable connecting an offshore wind turbine

4.3.3 Bending Protection

As any flexible product, a submarine power cable is sensible for overbend and fatigue where there is a discontinuity in bending stiffness. This situation can be found at a cable entrance into a rigid joint enclosure cable, entrances to fixed structures such as hang-off, or cable glands into floating structures. Overbends may occur, or repeated bending may cause severe fatigue in the cable construction. Bending stiffeners are elastomer sleeves that engulf the power cable close to the entrance into a rigid structure. The conical shape of the bending stiffener provides a gradual increase of bending stiffness and defines a gentle bending curve for the flexible cable (Fig. 4.10). The bending stiffener must be designed for the specific case.

A bending restrictor consists of a number of interlocked polymeric or metal shells around the cable allowing for a certain bending angle for each interlocked shell. The bend restrictor defines a minimum bend radius regardless of the cable load. As it has a stepwise bending stiffness adding to the cable bending stiffness, there may be a discontinuity of bending stiffness anyhow. With improper design, the sharp-bend problem will just be re-located to the end of the bend restrictor.



Fig. 4.10 Bending stiffener (*right hand*) together with a diverless subsea cable connector (*left side*). (Courtesy of Trelleborg, UK)

4.3.4 Holding Devices

Various clamping devices can be used to secure submarine power cables in beach areas, along steep underwater slopes, in areas of strong currents, and elsewhere.

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Chapter 5
Manufacturing and Testing

Contents

5.1 Manufacturing 123
5.1.1 The Conductor 124
5.1.2 XLPE Cables 125
5.1.3 Paper-Insulated Cables 126
5.1.4 Sheathing 129
5.1.5 Lay-up 130
5.1.6 Armoring 131
5.1.7 Storage of Submarine Cables 134
5.2 Testing 136
5.2.1 Development Tests 136
5.2.2 Type Tests 137
5.2.3 Routine Tests 144
5.2.4 Factory Acceptance Tests (FAT) 145
5.2.5 After-Installation Test 146
5.2.6 Non-electrical Tests 148
References 148

5.1 Manufacturing

The manufacturing of land cables is a straight-forward consecutive row of adding layer by layer to the conductor. The short production length (typically a drum length) allows for moving the cable between the different production steps on drums until the final layer has been applied and the cable drums can be put to the final acceptance test.

Submarine power cables on the contrary are often shipped in extreme lengths only limited by the capacity of the cable-laying vessel, which can be several thousand tons of cable. To avoid a large amount of joints, all production steps must be performed on lengths as long as possible. The maximum continuous production length of each production step depends on the cable size and type. Most often

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NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 138 of 306

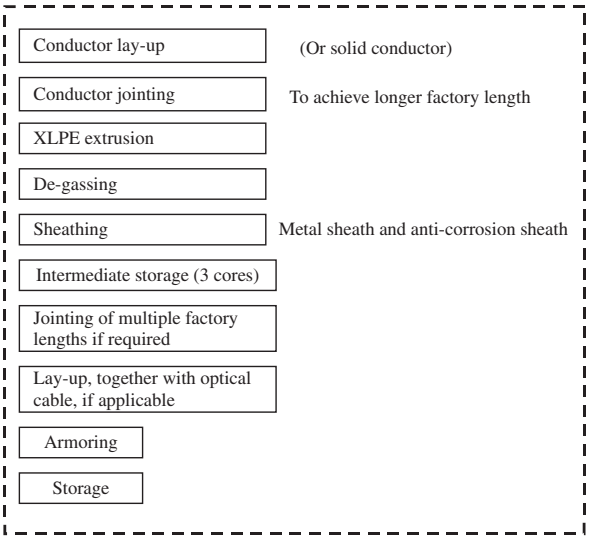


Fig. 5.1 Flow chart for the production of three-core submarine cables with extruded insulation

the production lengths of the different steps cannot be harmonized completely. This results in an intricate planning of the use of production assets. Only a well-orchestrated factory can exploit the advantage of long shipping length.

Figure 5.1 is a flow chart of the manufacturing of a three-core extruded submarine cable.

The core of a cable consists of a conductor, the electric insulation system, and protecting sheathes such as lead and PE sheath. The manufacturing of submarine cable cores is almost identical to the manufacturing of land cable cores and is described here but briefly. More detailed descriptions of cable core manufacturing can be found in [1, 2]. In this chapter the focus is on those manufacturing steps that are characteristic for submarine power cables.

5.1.1 The Conductor

All cable manufacturing starts with the conductor. Conductor making methods are identical to those for underground cables. However, the conductor made from pre-shaped profiled Cu or Al wires is used almost exclusively for submarine HVDC cables where a very compact conductor has a larger advantage than in an a.c. cable. For mass-impregnated cables it is essential that the wires lay closely together not leaving any space for extra impregnation compound [1]. Wire design and manufacturing process must be matched carefully to avoid gaps between the wires, or stepping, which is a misalignment of the profiled wires leading to a saw-teeth like surface on the conductor. A well-adjusted conductor stranding line makes a perfect smooth conductor. Conductor sizes up to around 3000 mm^2 have been achieved.

Some factories can produce conductors in continuous lengths up to 20–30 km but most factories produce the conductor on cable drums in lengths of only a few kilometres. Conductors can be jointed before entering the next production step by a multitude of jointing technologies:

- Solid welding in one piece through the cross section
- Wire-by-wire welding
- Soldering or brazing techniques
- Flush compression sleeve.

Conductor joints for fluid-filled cables (not mass-impregnated) require an oil passage in the centre. All conductor joints must be performed very carefully to provide sufficient mechanical strength and a smooth flush surface. In particular, "cold" soldering must be avoided as the wire ends might snap apart during later bending of the cable and perforate the conductor screen from the inside. The conductor joint must also meet the stringent tensile requirement imposed on submarine cables for larger depths. The area on both sides of the welding is often softer than the weld or the conductor itself on account of the annealing effect of the heat.

A frequent requirement for submarine power cables is longitudinal water tightness in the conductor. This can be achieved by the introduction of various water-blocking agents such as swelling powder, swelling yarns, hydrophobic compounds or gels. They are inserted between the wire layers.

The conductor resistance should be checked on a regular basis according to the quality assessment system of the manufacturer.

The next step in the manufacturing process is the application of the insulation. In modern submarine power cables, only extruded XLPE or lapped paper insulation is being used. These two processes are completely different in material, equipment and production properties.

5.1.2 XLPE Cables

XLPE extrusion is a continuous process. The raw material is a highly sophisticated compound of base polyethylene resin with well-defined distribution of molecular weight, antioxidants and cross-linking agents. The compound is supplied as granules and comes in different purity classes. In general, a higher voltage class requires a higher purity. The properties of the semiconducting compound forming the conductor screen and the insulation screen are tailor-made to fit the insulation compound. There are smooth and ultra-smooth varieties regarding the smoothness of the highly stressed inner semi-conductive surface.

Virtually all modern m.v. or h.v. cable extrusion lines employ a triple-extrusion concept. Three extrusion screws supply the constituent materials to a common extrusion head, which extrudes all three layers concentrically in the same process. Catenary or vertical extrusion lines are used to manufacture the insulation system. While

an extrusion length of 2000 m is sufficient to produce underground cables in drum lengths, the long delivery length of submarine cables call for much longer uninterrupted extrusion length in order to reduce the number of joints. Lengths of over 20 km can be extruded in a single run. The long extrusion time requires a faultless supply of resin granules under super-clean conditions. In the best cable extrusion lines there are closed systems for the handling of the granules to avoid any contact with factory air or human hands.

Any interruption in the process causes a cut of the cable rendering shorter cable lengths than anticipated.

Extrusion lengths, whether limited by extruder limitations or by unintended cable cuts, can be jointed together using flexible factory joints to achieve long delivery lengths. Flexible factory joints are provided with a conductor connection of one of the types outlined above. The conductor joint must be flush with the cable conductor. After the conductor connection is made the insulation of the adjacent cable ends are tapered. The gap is filled with lapped XLPE tapes and cured under heat and pressure. The added insulation material melts together with the surface of the tapered cable insulation. Figure 5.2 shows such a flexible factory joint. Some factories produce injection-moulded factory joints. The flexibility of the joint is crucial for the subsequent path of the cable core through the cable gantries of the factory.



Fig. 5.2 Factory joint of an extruded cable core (Courtesy of ABB, Sweden)

Gaseous byproducts that are dissolved in the XLPE matrix must be removed by degassing. If not degassed properly, the cables would emit these gases during operation later on resulting in unwanted gas volumes in the conductor or under the lead sheath. The degassing of long lengths of submarine cable cores requires large heated and ventilated vessels.

The insulation material must be protected against humidity already in the factory. Condensing water can be found on resin pellets cold from the transport. At cable cutting surfaces humidity may enter the conductor and contaminate the insulation from inside. The manufacturer's QA system defines when and where during storage time the cable must be equipped with suitable end caps.

5.1.3 Paper-Insulated Cables

The paper insulation is applied on dedicated paper lapping lines consisting of a row of lapping heads. In each lapping head, typically 12–16 reels with paper tapes revolve around the cable conductor as it passes through.

The paper tapes are applied according to an intricate pattern. Each single paper tape is wrapped around the cable in an open helix (it does not overlap itself in

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 141 of 306



Fig. 5.3 Lapping of carbon-black paper and insulation paper onto a copper conductor (Courtesy of ABB, Sweden)

subsequent turns). There must be a small gap (1–4 mm) between consecutive turns. This gap is called butt gap. When the cable is bent, the butt gaps in the inner curve accommodate the relative movement of the individual paper tapes.

The paper tension is controlled for each paper tape by brake devices on each reel. The lapping heads rotate in alternate directions to produce a torque-balanced insulation. Figure 5.3 shows the cable core in a lapping head. A layer of semi-conducting carbon-black paper is lapped onto the conductor before the insulating paper is added. High-performance power cables require the use of pre-dried cable paper and a lapping line in a controlled dry atmosphere.

Many cable types use staggered paper thicknesses throughout the insulation, each layer having a well-defined paper tension. The paper thickness ranges between 40 μm and 180 μm.[1] The insulation can have as many as 270 individual paper tapes to be put on the conductor in a single run.

The paper lapping process can be stopped and started at will. Reloading of the paper reels consumes a considerable part of the production time, and it is an appreciable logistic effort to supply sufficient paper reels of the correct type in time. After completion of the insulation including the screen the cable core is guided to the receiving turntable. This can be an intermediate storage turntable, or the cable is being stored directly into the rotating impregnation vessel. In either case the cable must be kept under very dry air.

It is, drawing on sufficient experience, and obeying strict quality standards, possible to produce a firm regular insulation without wrinkles or creases over very long lengths. The process is virtually unlimited as the next conductor length can be welded to the previous one upstream of the lapping line. Only the hold capacity of the receiving turntable limits the uninterrupted lapped cable core length.

While paper in equilibrium with the open air holds a water content of 6–12% the accepted level for paper insulation is only within the range of 1–2%. The

[1] Paper suppliers prefer to specify the paper "thickness" in grams per square metres (g/m^2).

lapped insulation must therefore be dried before impregnation. Today, major cable makers have very large drying vessels to process up to 50 km of cable core in a batch.

Once the lapped cable is in the impregnation vessel the lid is closed and the cable inside is subjected to a heat/vacuum treatment as the final drying step.

So far, the process is identical for mass-impregnated and for LPOF cables. The subsequent impregnation and sheathing processes differ between the two insulation concepts owing to the very different viscosity of the impregnant.

The impregnation compound for mass-impregnated cables (today almost invariably used for HVDC cables) becomes rather liquid at the impregnation temperature of 120°C (Fig. 5.4). The compound is heated and de-gassed in a dedicated oil treatment plant in the cable factory before it is released into the closed impregnation vessel. The vessel is filled completely, and under pressure. Owing to the lower viscosity of the hot compound the impregnation is finished after a few days. However, the cable cannot be processed yet. The cooling of mass-impregnated d.c. cables must be controlled carefully as the contracting compound in the insulation must be completed by new compound from the free vessel volume. As the temperature decreases, the compound viscosity increases, and makes the replenishment more time-consuming. If the cable is taken out to the lead sheathing too early the subsequent cooling would render unwanted voids in the insulation. The cooling time for mass-impregnated cables can sum up to several weeks. Once the cooling criteria have been met the vessel lid can be lifted and the cable can carefully be pulled to the lead sheathing machine. The short-time contact to the free air does not harm the cable insulation since the high viscosity of the compound prevents the diffusion of soluble nitrogen or humidity into the insulation.

LPOF (or SCFF) cables will be impregnated with very low viscosity mineral oil synthetic impregnation fluids. The fluid is degassed and prepared before it is pumped into the vessel to soak the dried cable core. Thanks to the low viscosity the impreg-

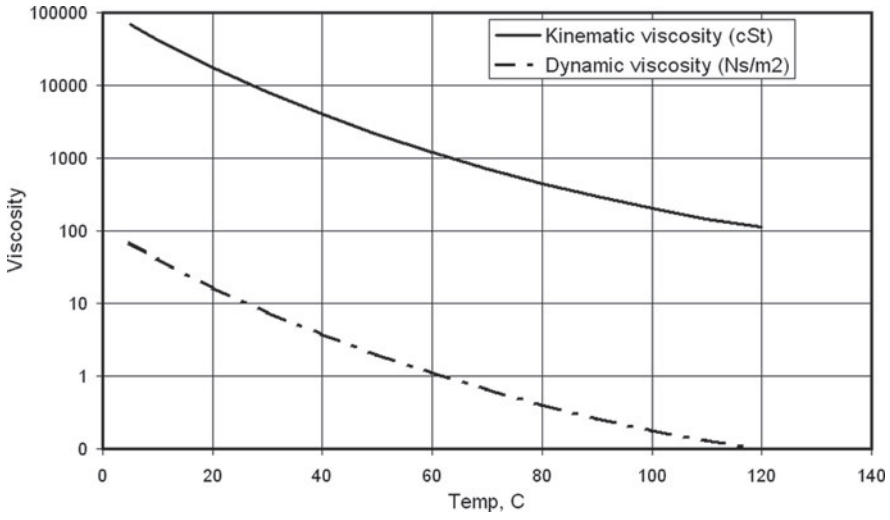


Fig. 5.4 Viscosity vs. temperature of a HVDC cable impregnation mass [3]

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 143 of 306

nation and cooling process is much faster than for mass-impregnated cables. The impregnated cable core of oil-filled paper-insulated cables cannot be transported from the impregnation vessel to the lead-sheathing machine through open air as the low-viscosity oil would eagerly adsorb air humidity. Instead, an oil-filled tube carries the insulated conductor from under the oil level of the impregnation vessel over the rim and into the lead extruder. The tube is continuously flushed with degassed impregnation oil.

5.1.4 Sheathing

Most submarine power cables have a radial water barrier in form of a metallic sheath.[2] Shorter medium-voltage cables often have an aluminium laminate sheath consisting of aluminium foil coated with a thermoplastic layer. The aluminium laminate is folded longitudinally around the cable core and glued together, sometimes with a Z-fold. The subsequent plastic sheathing provides mechanical support to the laminate.

The lead sheath for submarine power cables is applied in uniform thickness between 2 and 5 mm with a lead press, or an extruder. In the press, also known as ram press, molten lead is being filled into a chamber and cooled down to the correct temperature under the melting point. Then the lead is pressed by hydraulic force through a die forming a seamless tube around the cable, which travels slowly through the press. When the lead chamber is emptied, the process stops and the chamber is being refilled with molten lead. The intermittent process causes change marks in the cable sheath each time the press stops [1]. Another lead sheathing machine is the Hansson-Robertson continuous lead extruder, which was commercialised in 1949. Basically it is a screw extruder fed with lead from a melting pot. Today Hansson-Robertson extruders can deliver 50 km and more of uninterrupted high-quality lead sheath. Continuous extruders have replaced the ram-press as the most common and economical means of producing lead sheathed power cables. Different lead sheathing technologies require different lead alloys for best performance and process stability. The development and properties of different lead alloys in connection with ram press and screw extruder is described in [4].

Long term stability, creep, and extrusion properties can be improved substantially by using lead alloys with alloy elements such as antimony, tin, copper, calcium, cadmium, tellurium, and others. The standard EN 50307 lists a number of lead alloys for cable use (cf. table of lead alloys in Chap. 11).

The lead sheath is vulnerable for mechanical damages and should be protected by additional layers as soon as possible. The use of a continuous lead extruder allows for the extrusion of a rugged plastic oversheath in a tandem process directly after the lead extruder. When the cable has been lead sheathed in a stop-and-go ram press, it must be stored on an intermediate turntable before the plastic oversheath can be applied in the next operation.

[2] In older books on the subject, the word “sheathing” is used for “armouring”.

If the cable should be stored temporarily in a bare lead sheath it can be useful to brush the lead sheath with a bituminous solution to prevent the lead sheath from sticking together.

Although it is possible to produce aluminium sheaths by extrusion or strip welding this material is, due to its poor corrosion resistance, hardly ever used for submarine cables. In some cases the sheath is made from copper. A copper strip is folded longitudinally around the cable, and the edges are trimmed and welded continuously. Then the formed copper tube is corrugated to increase the flexibility. So far this process has been used only for shorter cable lengths in the range of a kilometre. As a perfect welding seam is fundamental for a watertight copper sheath, the seam is checked in-line after welding, e.g. by eddy current measurements.

5.1.5 Lay-up

For the production of three-phase cables, the three cable cores must be laid up to form a coherent cable. Just taking three cores in parallel into a common armoring would render a very stiff design without flexibility. Horizontal lay-up machines have three (or more) pay-off drums containing the cable cores, and a take-up drum to receive the laid-up cable. The cable cores travel through a common die where they are put together and secured with a binder tape. The take-up drum is inserted in a drum-twister, which spins the drum axis around the cable axis while the take-up drum rotates and takes up the three-core cable. The lay-up is caused by the drum-twister movement. Also, the pay-off drums rotate in drum-twisters, providing the back-twist that is necessary to keep the three cable cores together. This is the same process as being used when making ropes.

This method is sufficient for short cables to be delivered on drums (probably less than 1000 m per length). For longer submarine cables it would be tedious to manufacture the cable in drum lengths and then joint the cables to achieve delivery lengths of 20–40 km. Such long lengths of three-phase submarine cable can be produced in vertical lay-up machines. The pay-off reels (drums or baskets) are mounted onto a turntable rotating around a vertical axis. The cable cores are fed vertically upward into a collecting die many meters above the turntable centre. The cable cores are pulled through the die, then over a sheave and then placed onto a take-up turntable. Figure 5.5 shows a vertical lay-up machine with rotating baskets as pay-off.

The baskets for the cable cores can accommodate some kilometres of cable core depending on the core diameter and basket size. When the baskets run empty, they are reloaded with the next cable core, which is jointed into the foregoing cable cores by means of flexible factory joints. The turntable carrying the baskets can also carry additional baskets or reels for optical cables and/or filler elements, which would be arranged in the interstices between the cable cores. Vertical cable lay-up machines are the most versatile lay-up machines.

Some of the difficulties caused by the three-phase lay-up topology can be overcome with SZ-lay-up. In this method the lay-up direction (right-handed or left-handed) is altered regularly. This method requires no drum twisters or rotating take-up reels.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 145 of 306

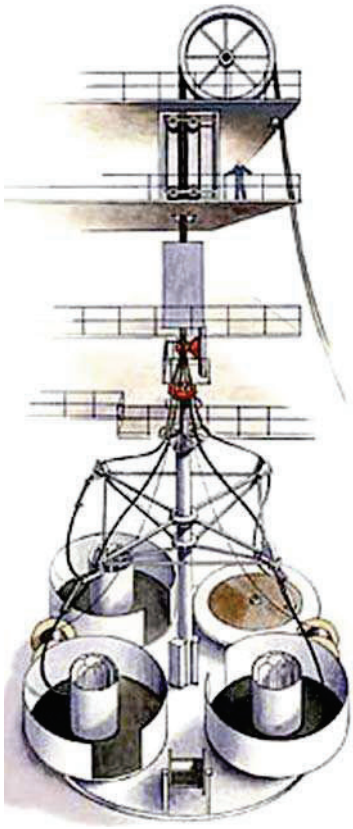


Fig. 5.5 Vertical lay-up machine with three rotating pay-off baskets and a fourth rotating pad for an optical cable. Additional small drums can accommodate filler ropes (Courtesy of ABB, Sweden)

The diameter of the envelope circle of the three-core cable is 2.16 times that of the individual cable cores.

5.1.6 Armoring

The most prominent attribute of submarine power cables is the armoring. Basically, submarine cable armoring is the winding of metal wires around the single core or a multicore cable. The most common wire is galvanized steel wire, but copper, brass, bronze, and aluminium wires sometimes also are used. The beautiful engraving in Fig. 5.6 from 1898 illustrates the working principle of an armoring more clearly than most photographs [5]. Today's armoring machines are very similar except for electronic drives and computerized monitoring equipment. Armoring machines carry a number of wire bobbins arranged on a rotating cage. The cable is travelling through the centre axis of the armoring machine. As the cage rotates the wires are drawn off the bobbins into a collecting bellmouth die at the exit of the armoring machine. In the bellmouth the wires are laid around the cable in the centre. The rotating speed of the machine and the cable travel speed must be synchronized to maintain a correct

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 146 of 306

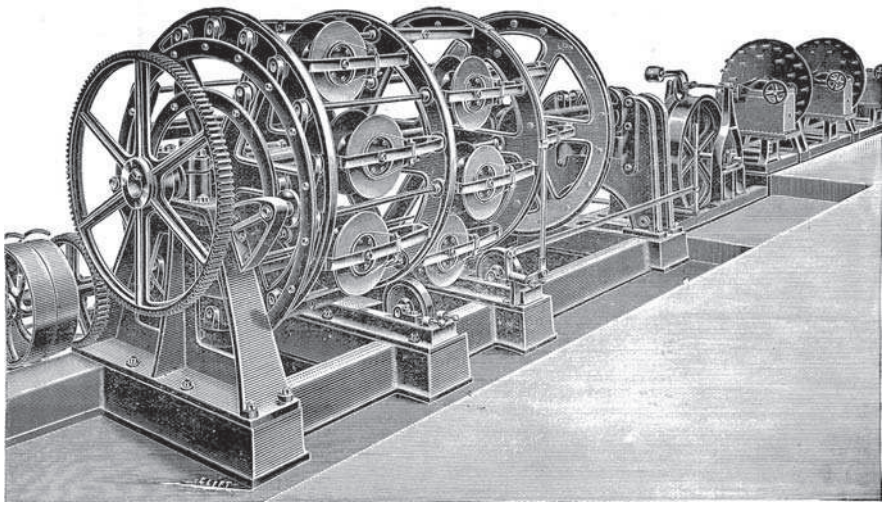


Fig. 5.6 Armoring machine with planetary movement of the wire bobbins. Six bobbins in two groups are visible. The eccentric ring in front of the first rim keeps all bobbins in the same orientation during their rotation (Machine designed and produced by Johnson & Phillips, London)

lay length. Some submarine cable factories have two armoring machines in line to produce submarine cables with double armoring, often with opposite lay direction.

In "rigid" armoring machines the bobbin axles are set up rigidly in the cage frame which means that the axles turn around with the cage. Each wire receives a 360° twist for each rotation of the cage. This can be difficult with heavy wires and a short lay-length. In most large armoring machines the bobbins are guided by a planetary gear, which gives them the same global orientation on their travel around the cable (cf. Fig. 5.6). By this means, the armoring wires will not receive a twist as they are being laid around the cable. However, when flat armoring wires are to be used, the armoring machine must have no planetary movement. There are armoring machines where the planetary movement can be switched on/off at will. Each bobbin has a breaking device that keeps the wires straight, and provides a smooth laying onto the cable core.

Cable caterpillars or other linear cable engines situated downstream pull the cable through the armoring machine. Considerable forces are required to draw off the cable from the armoring machine since a multitude of armoring wires have to be drawn off the bobbins and wound around the cable. For large armored cable the necessary pulling force can be 5 tons or more.

The lay length of the armoring is determined by the ratio of cable speed through the machine and the rotation speed of the cage. The pull-of engine can be coupled mechanically to the rotation drive by means of gearboxes. Modern armoring machines with electronic d.c. drives can achieve any desired lay length with high accuracy.

Large armoring machines for submarine cables have often two rotating cages in a row. Very large submarine power cables can be covered with a complete layer

of wires using both cages in tandem operation. The cages are rotated in the same direction with identical lay length, and the wires are combined to a single wire layer. For the production of a double layer uni-directional armoring the cages are rotated at different speeds so that the layers have different lay lengths. Much more common is a double-layer counter-helical armoring using the two cages in opposite rotation direction.

At regular intervals the armoring process must be stopped to swap the empty bobbins for refilled ones. The new wires are butt-welded to the trailing ends of the previous ones. This is a rather quick process, completed by de-burring and zink-coating of the weld. Swapping all bobbins of a machine cage at the same time keeps the downtime shorter. For cables intended for large depth it may be considered to spread the welds over a longer distance.

One or more bobbins can carry optical fibre (OF) cables to be integrated into the power cable. OF cables are more delicate than the rugged steel wires and require more attention, more sophisticated braking units and gentler internal guiding in the armoring machine.

Tape winder units are often situated at the entrance of the armoring machine to apply bedding tapes. Often also metallic tapes are applied under the armoring wires. They provide pressure reinforcement for paper-insulated cables, or a teredo protection where it is required.

The corrosion protection of the armoring is applied in the same process. Most often the corrosion protection is accomplished by flushing the armoring with fluid bitumen. The heated bitumen is showered over the armoring wires right before they are collected into the die, and again after the die. Using this arrangement the wires are covered with bitumen from all sides. The flow of bitumen must be cut off when the armoring machine is halted for wire change or other service, otherwise the cable under the bitumen shower would be overheated.

An outer serving of polypropylene threads (yarns) is finally wound over the armoring wires, one layer right-hand and one left-hand. The rotating stand for the thread spools is shown in Fig. 5.7. The bituminised armored cable can be seen entering into the centre orifice. The serving threads are immersed into the adhesive bitumen. The bitumen under the outermost serving layer, if any, should be applied sparsely, in order to avoid the bleeding of the cable during storage and laying.

Long submarine power cables often consist of a number of factory lengths, which are shorter than the shipping length. When a factory length of unarmored cable core is used up in the armoring process, the next factory length is pulled to a jointing room. The next length is then jointed to the previous one under controlled humidity conditions and high cleanliness requirements. Upon completion the joint is pulled through the armoring machine, and is covered by an uninterrupted wire armoring. The factory joint is only a few millimetres larger in diameter than the cable and is considered an integral part of the cable. Depending on the particular factory jointing technique this may require a 1–5 days break.

It is not possible to combine the cable armoring with the manufacturing of an extruded outer sheath as extrusion lines cannot be stopped easily.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 148 of 306

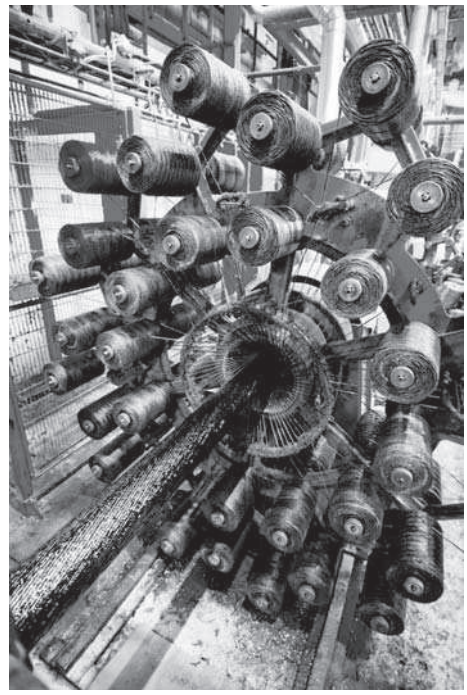


Fig. 5.7 A serving of polypropylene threads is applied on an armored cable covered with hot bitumen (Courtesy of ABB, Sweden)

5.1.7 Storage of Submarine Cables

It can be worthwhile to make some comments on the storage of submarine cables because it may involve the storage of a single product of 7000 tons in weight, without having the means of lifting the entire thing.

Cable drums can carry some hundred meters of armored submarine cables, supersize drums possibly 1–2 km. This storage form is suitable for in-field cables for OWPs, for shorter beach cables and limited water crossings. Cable drums with armored cable can have a weight of 30–50 tons and require suitable lifting and transport gear, and driveways with sufficient stability.

Longer lengths would be stored on turntables or fixed coiling pads. A coiling pad is a flat round or oval surface on the factory premises or in a storing tank on-board of the cable ship. The cable is guided down onto the pad from an elevated position, the guiding mechanism often equipped with a linear cable engine (cf. Fig. 5.8).

Coiling of armored cable can only be done if the armoring is unidirectional. Each turn of the cable around the coiling pad will cause a 360° twist in the cable. Therefore a minimum coiling diameter is required to enable the cable to absorb the twisting generated in each turn. The minimum diameter of the coiling ring should be no less than 60 times the cable diameter [6]. The exact minimum coiling diameter is depending on the armoring lay-length, the bedding under the wires and other design parameters.

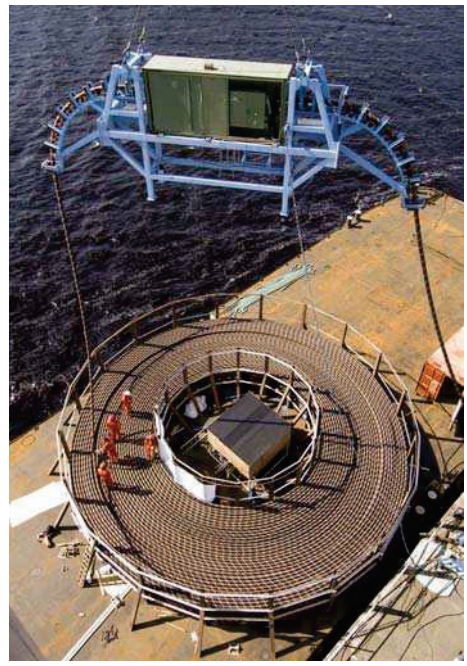


Fig. 5.8 Coiling of submarine power cable

A cable with uni-directional (single layer or double layer with the same lay direction) armoring can absorb torsions only in one direction. Coiling is only possible if the cable is twisted in the direction where the armoring is opening up. Coiling in the wrong direction will inevitably lead to kinks and loops in the cable and the entire procedure will fail.

For an S-lay cable the coiling direction must be clockwise. Under clockwise coiling the armoring can open up a little under the influence of the twist in the cable. Choosing the wrong direction of coiling (counterclockwise for a cable with S-laid wires) would provoke a closing-in of the armoring wires. Under these forces the cable would tend to form kinks or loops. However, as an exception to this rule, 3C-cables with single wire armoring and the cable core lay-up in opposite direction can be laid up counterclockwise (cf. Table 5.1).

The coiling pad should be flat. A high fence around the coiling pad provides protection to the coil staff that walks around the coil to direct the cable in position. The cable is fed to the coil from a point some 6–15 m above the coil. It is of advantage to have a caterpillar or wheel engine on the top. A fenced coiling pad with five coilers is shown in Fig. 5.8. The quadrant (roller guide arc) is suspended from a crane and contains a wheel-pair cable engine.

Direct solar radiation on the stored cables can develop high temperatures that easily can unpleasantly bleed out the bitumen.

Cables on coiling pads, outdoor turntables, trailers or cable laying vessels are frequently showered by rain, seawater spray, overflows and similar. In these situations

Table 5.1 Coiling direction depending on armoring lay orientation

	Armoring lay orientation	Coiling
Single core cables with unidirectional armouring	S-lay	Clockwise
Single core cables with counter-helical armouring	S or Z	No coiling
3C cables with core unidirectional armoring, core lay-up in S-orientation	S-lay	Clockwise
3C cables with core unidirectional armoring, core lay-up in Z-orientation	S-lay	Clockwise or counterclockwise

cable ends must always be capped with suitable end caps recommended by the cable supplier. Shrink-on end caps are in most cases not advisable.

5.2 Testing

Submarine power cables are subjected to comprehensive tests during development, qualification, manufacturing and installation. The various tests serve different purposes with the single overall goal – to ascertain a trouble-free operation under specified conditions.

The large variety of cable related tests can be categorised according to their purpose and stage during qualification, manufacturing and installation of the cables.

5.2.1 Development Tests

The development of new cable types, or the extension of existing cable types to new sizes or ratings, may require comprehensive testing of materials, components, and production processes. Many of the new materials and concepts have been developed for underground cables before they were being employed for submarine cables. The reason is simply that possible failures in submarine cables cause much higher repair costs and longer outage time compared to identical failures in underground cables.

The polymeric components of cables are subject to continuous improvement. New polymer formulations proposed by material suppliers need to be evaluated under the specific conditions of submarine power cables. Tests of dielectric strength, loss angle, leakage current, and dielectric response test, are used to characterize and screen insulation materials. These tests can often be performed on samples or model cables avoiding the expensive manufacturing of full-size cables. The ageing performance is being tested under different temperature and ambient conditions. The processing of cross-linked materials can be evaluated with methods determining the cross-linking degree.

Polymeric sheath materials in submarine cables are sometimes tested for their water vapour permeability, stability in salt water, abrasion resistance, carbon-black content, etc. However, in most cases manufacturers use their well-proven sheath materials without the need for change.

Even if most properties of metallic constituent materials are listed in textbooks, some properties need to be evaluated. The fatigue properties of lead sheathing alloys must be assessed by testing very thoroughly, taking the manufacturing method into account. Other metallic sheathing materials are also subjected to fatigue tests to secure trouble-free performance during the cable lifetime.

Another group of development tests addresses the corrosion performance of all metallic materials in submarine cables. Metals are tested separately, but also in relevant combinations to investigate galvanic behaviour.

Mechanical tests on complete submarine cables are designed to demonstrate their ability to withstand all stresses and incidents, which can be encountered during installation and operation of the cable. These tests include tensioning, bending, pinching, impacts, etc. Also the behaviour under the influence of external hydrostatic pressure is important for submarine cables.

Knowing the strong and sensitive points of the cable design, and knowing which tests will be required for a successful qualification, every manufacturer has his own set of tests to be pursued during development programs. For a speedy screening, sometimes short-cut tests are designed that can deliver reasonably reliable results in short time. This is of particular interest for tests for the ageing behaviour of cable materials. The cable maker would subject the newly developed cable design to these pre-tests, before he brings it to the standardised qualifying long-term test.

5.2.2 Type Tests

Once a cable type has been developed or adopted to new applications, it will be subjected to a type test. As many large submarine cable projects require a tailored unique design, many purchase contracts also require the performance of type tests. However, as type tests add considerably to costs and project execution time it should always be considered if the proof that a certain cable design is suitable for the intended project, could be deducted from previous type tests on similar cable types.

The purpose of the type test is to "qualify the design and the manufacturing of the cable system against the conditions of the intended application" [7]. Type-testing of electric equipment is generally regulated by test standards issued by national authorities or professional organisations such as IEEE, AEIC, ANSI, or Cigré. Most power cable testing standards cover underground land cables only, and some standards explicitly exclude submarine power cables from their scope.[3] Therefore test standards for submarine power cables are scarce (Table 5.2).

In practical life, type-tests on submarine power cables are often performed according to test standards applicable to underground cables with the same insulation design and conductor size. These type tests include material tests and electric tests, and in some cases mechanical tests such as bending tests over a cable drum.

[3]Cables for submarine applications are explicitly excluded from the scope of IEC 60502-2. However, it can be considered to use IEC 60502-2 for informational tests in medium voltage submarine cables.

Table 5.2 Type test standards usable for submarine power cables

	Published in	Title or content
Cigré	Electra No. 171 April 1997	Recommendations for Mechanical tests on sub-marine cables Referred to as Electra 171 in the following
Cigré	Electra No. 189 April 2000, pp. 29ff [8]	Recommendations for testing of long a.c. submarine cables with extruded insulation for system voltage above 30 (36) to 150 (170) kV Referred to as Electra 189a in the following
Cigré	Electra No. 189 April 2000, pp. 39ff [7]	Recommendations for tests of power transmission dc cables for rated voltages up to 800 kV (all insulation types excl. extruded) Referred to as Electra 189b in the following
Cigré Technical Brochure TB 219	Cigré Technical Brochure 219, Working group 21.01, February 2003 [9]	Recommendations for testing DC extruded cable systems for power transmission at a rated voltage up to 250 kV (scope includes submarine cables)
IEC 60840		Power cables with extruded insulation and their accessories for rated voltages above 30 kV ($U_m = 36$ kV) up to 150 kV ($U_m = 170$ kV) – Test methods and requirements
IEC 62067		Power cables with extruded insulation and their accessories for rated voltages above 150 kV ($U_m = 170$ kV) up to 500 kV ($U_m = 550$ kV) – Test methods and requirements

The Cigré recommendation published in Electra 171 is the only known test standard describing relevant mechanical tests on submarine power cables. Sometimes the type test specifications include mechanical tests according to the Electra 171 followed by applicable type test elements from IEC standards (for a.c.) or Cigré recommendation (for d.c.). It shall be noted that type tests are normally not mandatory by legal means. The test conditions are sometimes part of the contract negotiations.

Table 5.3 lists the applicable type test standards for the five generic cable types as described in Chap. 2. These standards are adhered to in most European submarine cable projects. Different type test standards may be applicable in other markets.

5.2.2.1 Mechanical Tests

The Cigré test recommendation published in Electra No. 171, April 1997, suggests a few test procedures especially designed for submarine power cables. It is at the discretion of the purchaser to determine which tests to be done.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 153 of 306

Table 5.3 Electric type tests for five generic cable types

Cable type No	1	2	3	4	5
Rated voltage U_0	33 kV a.c.	150 kV a.c.	420 kV a.c.	150 kV d.c.	450 kV d.c.
Insulation	XLPE	XLPE	Paper/oil	Polymer	Mass-impregnated
Mechanical tests			Electra 171[4]		
Electrical type test	Electra 189a with reference to IEC 60840	IEC 60840	IEC 62067	Cigré Technical Brochure TB 219	Electra 189b
Test sequence	TB PD Tan δ HC PD LI AC (PD) (same as in IEC 60502)	TB PD Tan δ HC PD LI AC (PD)	TB PD Tan δ HC PD SI (for $U_m \geq 300$ kV) LI AC (PD)	TB LC SI LI & DC DC	TB LC PR LI SI

Abbreviations: TB, Tensile bending test; WP, Water penetration test; PD, Partial discharge test; HC, Heating cycle voltage test; LI, Lightning impulse test; SI, Switching impulse test; LC, Load cycle test; PR, Polarity reversal test; DC, High-voltage test with d.c.; AC, High-voltage test with a.c.

The first suggested test is a coiling test, to be performed only on those cables that are intended to be coiled during manufacturing, loading, or installation. The test confirms the suitability of the cable for coiling according to the parameters encountered in cable handling. The coiling diameter is not specified in Electra 171 but the test shall confirm the value given by the manufacturer. The test cable must be long enough to achieve a sufficient number of turns to exclude end effects.

The tensile bending test according to Electra 171 demonstrates the cable's ability to withstand tensional forces in combination with bending over the laying wheel during installation. The test is to be performed on a piece of cable before the electric tests are performed on the same piece of cable. A flexible joint can be qualified when included in the test cable. The test cable is laid halfway around a large sheave, which represents the laying wheel of the cable-laying vessel. A pulling force is applied to the cable ends while they are moved three times back and forth around the wheel. The wheel diameter is often 6 or 10 m representing typical laying wheel diameters of existing cable ships (cf. Fig. 5.9).

[4]Electra No. 171 is "primarily meant for cables having a rated voltage U_0 higher than 36 kV a.c. or 100 kV d.c.". However, Electra 189a covering 33 kV cables refers to Electra 171.

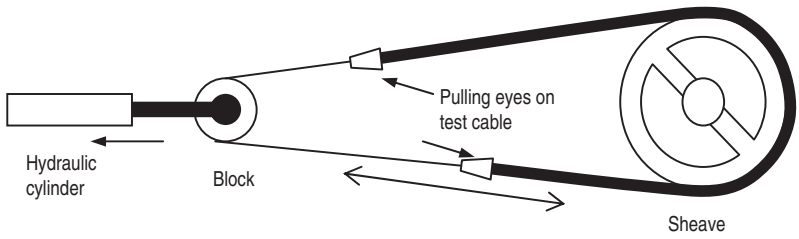


Fig. 5.9 Test arrangement for tensional bending test according Electra No. 171. *Top view*

The test pulling force is given in Electra 171 depending on the cable weight in water and the water depth (cf. Chap. 3). For a depth over 500 m, also the dynamic forces caused by wave movements are included. Experience has shown that actual pulling forces on the laying wheel can considerably exceed the forces given in Electra 171, depending on the weather situation during laying.

For many submarine transmission projects the laying depth is below 100 m, which leads to rather moderate test forces according to the Cigré recommendation. Sometimes the required pulling force is so small that the heavy cable is not even straight but has considerable sag during the test. Tests with the Cigré-recommended forces for laying depth under 100 m often have no practical relevance. Purchaser and manufacturer should consider an agreement to omit the test to save costs.

The tensional bending test confirms the design values of tensional strength and side-wall pressure (SWP), i.e. the uniform lateral force onto the cable side per unit length.[5] Other mechanical stresses might be experienced during installation, such as localized side impact by caterpillar pads or wheeled cable engines, or stresses caused by trenching machinery. Also the transport of cable over curved roller tracks or cable gantries is not covered by the Cigré test recommendations, unless the rollers in the gantry are very close together and the roller diameter is sufficiently large. No type tests have been devised yet for this type of impacts. As installation conditions and gear vary largely between projects, it would not be possible to construct type tests covering all type of impacts. Instead the manufacturer, purchaser and installer should agree on the necessity and character of additional confirming tests.

The Electra No. 171 also recommends an internal pressure test for oil-filled and gas-filled submarine cables.

A very particular test recommended in Electra No. 171 is a sea trial test for cases where laying conditions differ from previously performed operations. For a sea trial test the anticipated laying spread (vessel, on-board equipment and crew if possible) should be established to lay and recover a substantial length of the submarine cable on a seafloor representative for the target area. The tests are very expensive but can reveal possible flaws in cable design and installation equipment. Poor equipment or a cable design that is not appropriate for the installation method can cause immense costs when discovered during the cable installation. In the worst case, the instal-

[5]The established expression “side-wall pressure” actually does not denote a pressure (N/m^2) in a classical sense but a force per unit length. The unit of SWP is kN/m.

lation must be interrupted and the equipment upgraded or refurbished. It is by far less expensive to do this in a well-planned manner after a sea trial test prior to the installation campaign. Acknowledging this, many major submarine power projects have performed sea-trial tests and used the results for the benefit of the project.

5.2.2.2 Load Cycle Test

Load cycle tests are part of the type tests for all submarine power cables. The a.c. cables are usually subjected to electric tests according to the same specifications as underground cables. The load-cycle test procedures for d.c. cables are less well-known and shall be described in the following.

The recommended load cycle test for mass-impregnated HVDC cables is described in Electra 189b. A 24-hours load cycle is combined from an eight-hour period of full cable load, followed by a 16-hours period of natural cooling. The Electra 189b load cycle test comprises ten load cycles with a constant negative voltage of $-1.8 \times U_0$. After this, another ten cycles will be performed with positive voltage of $1.8 \times U_0$. The ambient temperature during the test is subject to agreement between manufacturer and purchaser. Depending on the conditions in the seafloor, the tests may be specified with cold and warm ambient to reflect different thermal conditions and seasons. For a cable installed in the seafloor in moderate waters, the lowest expected ambient is around 6°C when the cable has not been used for a while, and possibly over 30°C after a long uninterrupted period of power transmission. In tropical waters, the ambient temperature would be specified differently. The ambient temperature of the test cable can easily be adjusted if the cable is installed in hoses or pipes with temperature-controlled water. The heating current amplitude should reflect the rated load of the cable and is also subject to agreement.

The limiting factors for the operation of mass-impregnated HVDC cables are the conductor temperature and the temperature drop across the insulation. During type test, only three of the four following parameters can be set independently:

- Conductor temperature
- Temperature drop over the insulation
- Conductor current
- Ambient temperature.

The 8/16 h rhythm of the cycles is widely accepted as it fits well into the working day. As the thermal time constant of this type of cables is 1 to 2 h, a shorter cooling/heating cycle would also achieve appropriate heating of the cable. For development tests, a 4/8 h sequence is an acceptable short-cut.

The test voltage deserves some extra comments. Although the load cycle test for mass-impregnated HVDC cables is described in Electra 189b, its conditions are often altered during contract negotiations. Electra 189b specifies a test voltage of $1.8 \times U_0$, where U_0 is the operating voltage of the HVDC cables. In recent years manufacturers and cable purchasers have often agreed on lower test voltage factors, in particular for the cooling part of the load cycle test. The reason is simply that the dielectric strength during the load phase of the type test (with full current), and

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 156 of 306

in most operational situations is much higher than in the type test cooling phase. It would be uneconomic to oversize an HVDC cable just in order to comply with a single test parameter. For mass-impregnated HVDC cables of the past 15 years a test voltage of $1.55 \times U_0$, $1.6 \times U_0$, or $1.7 \times U_0$ have been specified by purchasers for the cooling phase.

The test cable is terminated with oil-filled pressurized cable terminations. Oil inflow from these terminations into the cable must be prevented during the type test, as this would assist the cable to pass the type test, a situation not available in real life at some distance from the termination. Means to prevent this oil flow must be provided in order to assure relevant type-test conditions. This can be achieved by extra long cable connections between the terminations and the test cable portion, by freezing the cable between the terminations and the test cable portion, or by sealing arrangements inside the terminations.

The next step, after negative and positive voltage load cycles, is the polarity reversal test. The load cycle (8/16 h) is maintained but the voltage is periodically reversed between $+1.4 \times U_0$ and $-1.4 \times U_0$ every 4 h. This is repeated during ten complete load cycles. The recommended reversal speed specified in the Electra 189b is under 2 min, but real tests have been performed with longer reversal times, due to laboratory equipment reasons, or due to transmission system aspects not requiring such short reversal times [10]. After the polarity reversal tests the cable is subjected to impulse testing.

For extruded HVDC cables, which have conquered a reasonable portion of the submarine HVDC cable market, a load cycle test is specified in Cigré Technical Brochure 219 [9]. For cables to be qualified for voltage source converters, i.e. without polarity changes, TB 219 recommends the following load cycle test sequence (Table 5.4):

Table 5.4 Load cycle test sequence for extruded HVDC submarine cables according to Cigré TB 219

Load cycle characteristics	Number of cycles
8/16 h load cycles at $-1.85 \cdot U_0$	12
8/16 h load cycles at $+1.85 \cdot U_0$	12
24/24 h load cycles at $+1.85 \cdot U_0$	3

For extruded HVDC cables to be qualified for line-commutated converters (so called “Classic”), a different suite of load cycles is defined, including polarity reversal tests. Owing to the characteristics of extruded d.c. insulation, a reduction of test voltage in the cooling phase as in the case of mass-impregnated HVDC cables has not been advocated yet.

TB 219 requires the performance of a row of non-electric tests before the load cycle tests. These tests comprise bending tests (depending on submarine or underground application) and water integrity tests, with reference to other IEC or Cigré test standards. After the load cycle tests the cable is subjected to impulse testing.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 157 of 306

5.2.2.3 Impulse Tests

Impulse tests are a part of most type test standards. It became clear very early in power engineering that a.c. and d.c. tests alone do not cover all events in the life of a component in the power system. The dielectric strength of any insulation is very much depending on the shape and duration of a voltage wave. Impulse tests are necessary to demonstrate the behaviour of components under temporary overvoltages. The tests are performed according to IEC test standards, which apply in principle to all high-voltage power transmission equipment. As for other high-voltage cables, the test standards specify lightning impulse tests and often also switching impulse tests for submarine cables. Despite their names, the tests do not necessarily resemble real life switching or lightning impulses. The distinction of switching and lightning impulses may be made on the basis of wave shape rather than their origin [11]. The impulse shapes are specified in IEC 60060-1 in terms of front steepness and tail time to half value. The standard lightning impulse (LI) has 1.2 μs front time (t_1) and 50 μs time to half value (t_2) after the crest. For the standard switching impulse (SI) these values are 250 and 2500 μs, resp. IEEE defines 1.4/40 μs as LI wave shape parameters. IEC and IEEE use slightly different formulae as how to determine t_1 and t_2 from the wave shape. Figure 5.10 shows the ideal impulse shape. However, laboratory records usually do not look like this and the evaluation of the test parameters of a specific test (front time, time to half value) is all but easy. Computer-assisted algorithms help to identify parameters from corrupted records with distortions and overlaid ghost oscillations [12, 13].

Impulse test parameters were originally conceived to resemble phenomena in air-insulated power grids and substations. Today, the situation for many submarine cable terminations is different. HVDC cables are connected to converter stations where certain types of overvoltages cannot occur at all, or only with lower amplitude compared to air-insulated a.c. substations. Other modern submarine power cable applications, e.g. in HVDC converters or offshore, have their terminations indoors.

Type tests for a.c. submarine cables comprise impulse tests according to standards for land cables with corresponding rating. For d.c. cables the Cigré recommendations specify impulse tests with superimposed d.c. voltage.

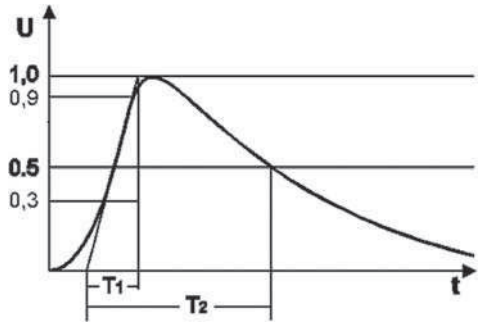


Fig. 5.10 Standard impulse voltage shape

For paper-insulated HVDC cables ten positive lightning impulse shots superimposed over negative d.c. voltage are performed, then ten negative lightning impulse voltage shots superimposed over positive d.c. voltage. The same sequence is done with switching impulses. This concludes the electric type test for paper-insulated HVDC cables.

According to the Cigré TB 219, extruded submarine HVDC cable systems have to undergo a complicated pattern of switching impulse tests with opposite or parallel polarity. Lightning impulse testing may be omitted under certain circumstances.

5.2.3 Routine Tests

Routine tests are performed on all manufacturing lengths and/or delivery lengths. In the various test standards applicable for submarine power cables, different sequences of routine tests are prescribed. Almost all standards require testing of conductor resistance, insulation capacitance, and loss angle tan δ. Resistance and capacitance can be measured either on the complete cable (e.g. on a drum length), or on end pieces cut from a long length of cable. The resistance measurement requires the knowledge of the conductor temperature. For short test pieces, a four-point resistance measurement should be used. The distance between current source contacts to the conductor and the voltage probes should be sufficiently long to allow for a uniform current distribution in the conductor. Should the resistance test for a manufacturing length in a long cable exceed the required value, it should be checked if there are expected hotspots in the cable route sector for which the manufacturing length is destined. If not, the total resistance of the cable route can be adjusted by adding a little to the conductor area of the remaining manufacturing lengths.

The capacitance test is a check that the insulation is not too thin. According to IEC standards the specified value must not be exceeded by more than 8%.

The loss angle tan δ is conveniently measured on a piece of cable cut from a manufacturing length. The IEC standards require the measurements under a.c. voltages corresponding to an electric stress in the insulation of 2 and 8 kV/mm, resp. The measurement can be performed e.g. with a high-voltage Schering bridge. An elaborate description of tan δ measurement methods and their theory can be found in [1]. Limit values are specified both for tan δ at both voltages, and for the difference between both results. The American AEIC standards specify the ionisation factor, IF, being the difference between tan δ at 100 V/mil (=3.9 kV/mm) and 20 V/mil (=0.8 kV/mm). The IF value must not be higher than 0.1% for LPOF cables.

High tan δ values can hint on contaminated insulation, which leads to high ohmic leakage currents through the insulation. The tan δ value can also be increased by partial discharges in the insulation, resulting in an integral current.

5.2.3.1 High-Voltage Routine Tests

Manufacturing lengths are often given a high-voltage routine test either by standard requirement, by agreement, or as an internal test of the manufacturer (Table 5.5). The obvious reason is to exclude faulty cable core from further costly manufacturing

Table 5.5 a.c. test voltages for routine and after-installation tests on a.c. cables

	Rated voltage kV	U_0 kV	Routine test voltage (phase-to-ground), kV	After installation test voltage (phase-to-ground), kV
IEC 60605	30	18	63	30 (5 min) *or* 18 (24 h)
IEC 60840	45–47	25	65	52
	60–69	36	90	72
	110–115	64	160	128
	132–138	76	190	132
	150–161	87	218	150
IEC 62067	220–230	127	318	180
	275–287	160	400	210
	330–345	190	420	250
	380–400	220	440	260
	500	290	580	320

steps. The voltage factors given in standards are different for different cable types, and can also be altered in agreement with the client.

Modern submarine power cable cores can be manufactured in appreciably long length of 20 km or more. Factory testing of these long cable cores with a.c. voltage requires considerable testing power to provide the charging current. In many cases, this is beyond the possibilities of a.c. test voltage generators. More testing power can be achieved with resonance circuits where an inductance is tuned to form a resonance circuit with the test cable capacitance. The testing frequency of resonance systems is between 30 and 300 Hz.

Testing with d.c. voltages (e.g. HVDC cables) requires the charging of the capacitance of the cable up to the specified voltage. The charging current of d.c. test voltage generators is limited and it may take a considerable time to reach the desired voltage. The charged cable capacitance stores a large amount of energy. Strict fencing of the test range should be provided for the case that the energy is released in a breakdown. Should a test termination fail the amount of stored energy can easily explode a porcelain insulator.

5.2.4 Factory Acceptance Tests (FAT)

FAT is the last test program to be performed at delivery. The performance of FAT is often connected to the issuing of client certificates and project milestones. What has been said about testing methods in the routine tests, also applies to the FAT. As delivery lengths can be much longer than the included manufacturing lengths the charging time for d.c. tests are even longer. Also the discharge of the tested cable after the FAT takes considerable time. In case of a.c. FAT on long submarine cables a sizeable set-up of resonance circuit has to be employed (cf. Sect. 5.2.5). Often only specialized submarine power cable makers can provide this type of FAT.

The American standard ICEA No. S-57-401/NEMA Standards Publication No. WC2 recommends a high-voltage a.c. test for armored cables employing 80% of the test voltage for an equivalent un-armored cable.

The FAT for long submarine cables may even include a TDR (Time Domain Reflectometry). The test comprises sending a short voltage impulse into one cable end and recording the echoed impulse. The travelling impulse is partly reflected by changing of *Z*, the impedance per unit length of the cable. The most prominent change of impedance is of course the far end of the cable where the impulse is being reflected. Also factory joints sometimes constitute a local change in *Z* causing a faint partial reflection of the travelling impulse. The idea behind the TDR test is to create a reference curve, which can help localising possible future cable faults. There are no pass/fail criteria for the TDR test.

5.2.5 After-Installation Test

A damage-free installation of the submarine cable is confirmed by a successful after-installation test of the entire cable link including joints and terminations (Table 5.6). As in FAT, the tests are performed as high-voltage test with either a.c. or d.c. It is not always easy to bring high-voltage sources to the installation site.

d.c. test voltage generators can be transported quite easy in a truckload. Since the test voltage generators are mostly designed for indoor laboratory use, they must be used only indoors or under dry weather conditions. Fog and dew can degrade the internal insulation of the test equipment. Sometimes temporary shelters can be erected to protect the equipment. Especially with long cable links the testing time can be long due to the cable charging. In one of the recent very long HVDC projects the specified testing time at $1.4 \times U_0$ was only 30 min, but the complete testing took 11 hours due to charging/discharging time. About five hours of this time the voltage was above U_0.

Table 5.6 Test voltages for routine tests and after-installation tests

Cable type No	1	2	3	4	5
Rated voltage U_0 Insulation	33 kV a.c. XLPE	150 kV a.c. XLPE	420 kV a.c. Paper/oil	150 kV d.c. Polymer	450 kV d.c. Mass-impregnated
Applicable standard	Electra 189a with reference to IEC 60840		IEC 62067	Cigré TB 219	Electra 189b
Routine test voltage	–	218 kV	440 kV	$1.85 \times U_0 =$ –278 kV d.c.	$1.8 \times U_0 =$ –810 kV d.c. 15 min
After-installation test voltage	–	150 kV	260 kV	$1.45 \times U_0 =$ –218 kV d.c. 15 min	$1.4 \times U_0 =$ –630 kV d.c. 15 min

Testing long cable links with high-voltage a.c. requires substantial charging currents. The required power for the test circuit is proportional to the cable capacitance and the square of the test voltage. For many cable links, the a.c. testing would require a test power exceeding the capacity of most high-voltage test transformers. Another strategy to test a.c. cables is to connect them to the power grid for 24 h. Obviously, this method is independent on heavy test transformers. The method is also called soak test and is applied frequently to h.v. a.c. cables. The test method has also been recognized in IEC 60840. However, the soak test does not provide testing at elevated voltages. Another strategy is using d.c. voltage also for testing of a.c. cables. This enables the use of simpler test equipment. However, it is not sure that hidden flaws in the cable system can always be detected by d.c. voltage. Even worse, many specialists agree that the d.c. voltage can do more harm than good, and deteriorate the insulation. Today, d.c. testing on a.c. submarine cables is used only to a lesser extend.

Long and very long cable links can be tested at elevated voltages with series resonance circuits. In these test circuits an inductance is connected to the cable capacitance to form a resonance circuit. An exciting transformer supplies the voltage to the resonance circuit in which an a.c. voltage can be maintained by resonance action between the cable capacitance C_{cable} and the external inductance L_{external}. The resonance criterion is:

$$C_{\text{cable}} \cdot L_{\text{external}} = \frac{1}{(2\pi f)^2}$$

where f is the power frequency. In some commercial series resonance circuits the resonance criterion is met by a tunable external inductance at constant frequency, while other systems employ a tunable frequency at constant external inductance. The tunable frequency systems are said to have a better power/weight ratio, a fact that can be very important given the weight of the necessary inductance [14, 15].

The power frequency is in the range of 30–300 Hz. Some commercial resonance testing systems are built modular, i.e. more inductances can be added in order to meet the larger cable capacitance of very long cable links. A wider frequency range is being discussed for future test standards.

The resonance circuit made up of the cable and the external inductance is lossy. In every oscillation of energy between the capacitance and the inductance, a certain amount of energy is dissipated in the ohmic components of the circuit, mainly the cable conductor and screen. This ohmic loss must be replenished by the exciter transformer, and can limit the maximum length of the test cable circuit. A cable length of well above 100 km can be tested, depending of cable capacity, test voltage, system configuration, and desired test duration. Suppliers of test systems can provide exact data in their system specifications.

Depending on the needed a.c. test voltage and the capacitance of the cable, one or more truckloads of equipment must be shipped to the testing site. The method is feasible for submarine cable links where at least one end is accessible easily from a landing site. However, very large submarine cable would require unreasonable amounts of combined inductances to perform the task.

The American standard ICEA No. S-57-401/NEMA Standards Publication No. WC2 recommends a high-voltage after-installation test for armored cables employing 80% of the test voltage used for the test on the armored cable in the factory according to Sect. 5.2.4, i.e. 64% of the factory test voltage for an equivalent un-armored cable.

5.2.6 Non-electrical Tests

The various test standards stipulate, beside the electric tests, also a number of non-electric tests. The tests are performed as sample tests on a defined share of the entire production, as routine tests on the entire production for a certain order, or as a part of the type test. The purpose of these tests is generally to confirm that the physical properties of the produced cable comply with the specifications.

A large spectrum of different non-electric tests is specified in the various test standards, to be performed at very different frequencies and occasions. It is almost impossible to compile a comprehensive summary on this item.

Many non-electrical tests are dimensional checks such as layer thickness or eccentricity. Other test specifications deal with the electric resistivity of semi-conducting materials, or simply the counting of the wires in the conductor. Material properties are checked before and after ageing. Hot-set tests on cross-linked materials check the quality of cross-linking.

Some of these tests are specified in the international test standards, others are specified by utilities, or just common practice in certain countries. The non-electric tests are often in the shadow of the more prominent electric tests. Because of this and the fact that the large number of different test specifications is somewhat confusing, it is recommended to define the bouquet of non-electric tests very clearly in the project contract.

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Chapter 6
Marine Survey

Contents

6.1 Scope of the Marine Survey 152
6.2 Bathymetry 153
6.3 Sub-bottom Profiling 156
6.4 Visual Inspection 157
6.5 Soil Sampling 157
6.6 Soil and Water Temperatures 158
References 159

A sufficiently detailed marine survey is one of the most important activities during the planning and preparation of a submarine power cable project. The survey can deliver critical input data for the choice of the best cable route, the cable design, and the design of the cable installation procedure. These parameters do not only have an important impact on cost and schedule. A comprehensive survey can also make a substantial difference for the future cable link availability and repair costs. The profitability of the cable link can critically depend on the survey.

Based on the survey data of the submarine area between the landing points, the best possible cable route can be suggested in order to avoid submarine obstacles and hazards, such as:

- Existing cables and pipelines
- Fishing and trawling
- Shipping lanes, harbour entries, anchorages
- Dumping and dredging
- Seabed contamination
- Oil and gas fields
- Military activities
- Ammunition dumping grounds
- Ship wrecks and other submarine junk, abandoned cables
- Areas of sand or gravel extraction.

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Troublesome areas should be avoided, since every major obstacle to a smooth laying operation can generate large costs. Avoiding these areas can be an important piece in the protection concept for the cable project.

The best cable route is also depending on the knowledge of the seafloor conditions and properties. In particular, the following data are necessary to know:

- Bathymetry, i.e. the water depth along the entire cable route
- Seafloor structure, existence of boulder fields, outcrops, crevices, canyons, steep slopes, rocky irregular sea floor
- Areas with risk for free spans of the cable
- Seafloor morphology, i.e. the structure of the soil beneath the seafloor
- Geophysical data such as grain size, hardness, thermal conductivity
- Sediment movements.

A thorough knowledge of the seabed conditions helps the project engineers to identify and locate potential hazards to operations. The data has impact on the cable design and the choice of the installation spread. If the seafloor conditions are too severe along the suggested cable route, this might be reason enough to change it.

Hydrological data also have a strong influence on cable design and installation procedures:

- Water temperature (surface and seafloor) over the year
- Wave patterns
- Tides and currents
- Wind patterns over the year.

Wind, waves, and tides have the ability to seriously hamper or interrupt an installation campaign so it is good to know in advance where the limitations are.

Other items may not endanger the cable but may be disturbed by the cable laying action:

- Bird and fish nurseries
- Sensible natural resources
- Tourist resorts.

The laying operation in or close to these locations is usually restricted or regulated by authorities. In some countries, the authorities might be weak or do not care. It is a matter of corporate ethics and environmental policies to decide what to do and not to do.

6.1 Scope of the Marine Survey

There are no strict general rules for the needed scope of a marine survey. It should be clear to the submarine cable project planner that a more comprehensive survey can help the installing contractor to perform a more precise tender and a better installation job. On the other side, the investor who is evaluating the economic feasibility of

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 166 of 306

a certain submarine cable project does not want to spent money on a fully-fledged marine survey just to provide data for a bidding process.

In any case, the project planner should perform a comprehensive Desk Top Study (DTS). An amazing large amount of data can be retrieved from public sources, marine authorities, and commercial vendors. Bathymetric charts, seafloor temperatures, marine soil maps, currents, weather, waves, tides, hydrological data, other seabed users, and much more can be compiled without leaving the office [1]. The exact positions in an agreed geodetic reference system are important when compiling the data from different sources. The World Geodetic System 84 (WGDS84) is a standard in the field. The DTS also should evaluate the need for permits both for the subsequent on-site marine route survey and for the cable installation itself. Neglecting the DTS will most probably lead to increased survey and installation costs. A complete DTS is a good base plate for a bidding process except for very complicated projects.

Marine route survey means to leave the office and go on-site. Commercial survey companies would perform one or more survey runs with dedicated survey vessels to provide any wanted data along the suggested cable route. For simpler cases, vessels of opportunity (VOO) are mobilized with the equipment needed for the particular job. Either case, the quality of the used equipment and the skills of the crew are pivotal for the outcome of the effort. It is insufficient to merely identify the existence of a rock outcrop or a shipwreck, but it is essential to determine its exact position. Inaccuracies from the surface positioning system (often DGPS) and the underwater detection system may add up to intolerable values leaving the seafloor topographic data less useful for the cable installation.

The marine route survey run with the survey vessel can be amended by the sampling of seafloor material. Also, a visit on the landing site for the submarine cable is considered mandatory.

6.2 Bathymetry

The marine equivalent of a topographic land map is a bathymetric map of the sea bottom, indicating the depth at any point. The cable design engineer needs to know the water depth in order to determine the mechanical properties of the submarine cable. Slopes can be dangerous terrains, as cables might have a tendency to skid down the slope, or as soil movements may destruct the cables.

Bathymetric data have been used for navigation for more than 3000 years. They can be obtained from various sources with changing quality and accuracy. Only national or government hydrographical offices (HO) provide official charts and their latest updates. Commercial sea charts are available from different vendors, mostly as electronic charts (EC). In the best case, these products are a digitalized form of the official HO charts. Only a few EC systems meet the requirements of the IMO "Safety of Life at Sea" (SOLAS) code. In spite of their fancy appearance, electronic charts are in no way more accurate than the paper charts they often are compiled from. For the desk-top-study, HO charts or EC products derived from HO data can be a nice start.

The project planner should be aware of the accuracy limitation of bathymetric data. Depth soundings have been made for centuries, and one should thoroughly check the source of bathymetric data. As of 2002, over 50% of the depth information found on US charts were based on hydrographic surveys conducted before 1940. But coastlines might have changed since. Construction activities can alter the coastline considerably within a few years, in particular in harbour areas and close to densely populated areas. Also, natural erosion/aggregation has the potential to reshape coastlines and the bathymetry. Seafloors in or close to tidal waters or other water currents are particularly affected by fast changes of the seafloor bathymetry.

All bathymetry refers to a water surface reference level called chart datum (CD). Since 2005, the North Sea states adopt the "Lowest Astronomical Tide" (LAT) as CD. This is obviously lower than the mean sea level. Germany, Spain, UK, and France have adopted LAT as CD for the North Sea. In Belgium, parts of the Netherlands and Denmark (W of Skagen), the mean Low Water Springs Level is used as CD. In the Baltic Sea and Denmark E of Skagen, the CD is usually defined as the mean sea level [2]. The chart datum may have changed since the date of measurements, either due to administrative/legal changes or due to real changes out on the seafloor.

The differences on CD in relation to the on-shore levels matter little in the open sea. However, in the coastal and splash zone the tidal and level conditions can affect the cable laying operations critically.

Early chart makers could only sound the depth at distinct points. They may have interpolated between the sounded spots, allowing for the negligence of ridges and outcrops in-between [3]. Between the spotted and charted soundings, there may exist natural ridges, outcrops, shipwrecks, and other disturbing features.

A very useful source for desktop-studies in North-American waters is the service provided by the National Oceanic and Atmospheric Administration (NOAA) at http://www.nauticalcharts.noaa.gov/mcd/OnLineViewer.html. An annoying detail, however, is that the depth information of the provided charts sometimes are given in feet, sometimes in fathoms.[1] Fathom-data can be affected with a truncation error of up to 1 m. Correct bathymetric data are important both for the design of the cable and for the choice of suitable laying vessels with respect to their draught. Mistaking the sounding units can have expensive consequences.

Today, sonar-based systems are routinely used to provide a high-resolution bathymetric contour of the cable route. The method can be compared with radar, but uses high frequency sound pulses with frequencies up to 500 KHz instead of electromagnetic pulses. The systems transmit sound "pings" and analyse the return signal that has bounced off the seafloor or objects on the seafloor.

Several bathymetry methods are industry standard and can be used for the marine route survey. A multi-beam echo-sounder (MBES) with high frequency has a high resolution, relatively small transducers, and can thus be mounted on VOO mobilized

[1] 1 fath equals 6 ft. Conversion information is given in the Useful Tables chapter.

for the task. This advantage has to be paid for with a short range. Long range full ocean depth systems require large transducer arrays underneath dedicated survey vessels (=high day-rate). For the rather shallow waters of most submarine power cable projects the high-frequency systems might be good enough. In any case, the specification for the subcontracted marine survey should specify accuracy and coverage data. The accuracy is about 0.5–1% of the water depth in the beam centre (vertically down) and somewhat less at the beam edges. In deeper water the beam spread can monitor a wider corridor. Often, the cable corridor can be surveyed in a single pass, but in very shallow waters only a narrow corridor can be charted in one pass. With MBES, major obstacles in the cable route such as shipwrecks, large boulders, etc. can be identified. Large power cables and pipelines can be seen if the water is not too deep (cf. Fig. 6.1).

The measurement sensors of side-scan sonar are located in a towfish, a torpedo-shaped device pulled through the water at mostly constant height above the seafloor. It sends sonar detecting signals down and side-way and can provide an excellent imagery of the seafloor and all objects on it. The towfish is not influenced by the survey vessel roll and pitch. The detection ability of seafloor features is depending on the operating range, the vessel speed over ground, and the ping rate. According to IHO specifications, three pings per object are required in order to detect the object. Side-scan systems can also provide some information on the seafloor texture and boulder fields (cf. Fig. 6.2).

An insufficiently detailed survey may have serious consequences. A trenching plough was pulled over a seafloor where the maximum slope angles had been calculated to be 5°. However, the real slopes were much steeper. The plough was pulled over sandwaves with larger steepness, eventually rolling over on a 17° slope, and the plough was lost [5].

During the route survey for the new Wolfe Island cable in the St. Lawrence River both boulders, debris and intake pipes for a nearby plant have been discovered. Furthermore, an existing power cable was found 60 m away from its supposed position [6]. The findings helped to readjust the route for the new cable to avoid hazards.

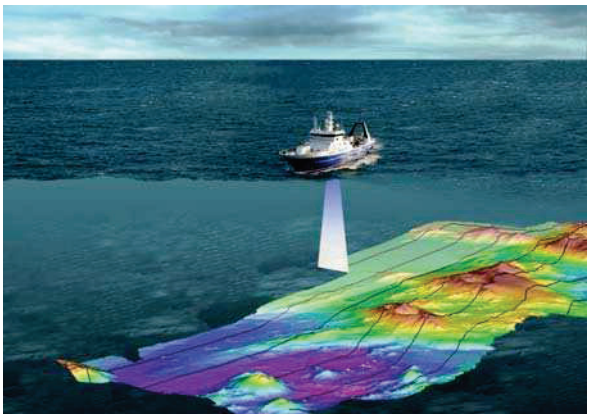


Fig. 6.1 Survey vessel charting the bathymetry by sonar (Courtesy of National Institute of Water & Atmospheric Research Ltd, New Zealand)

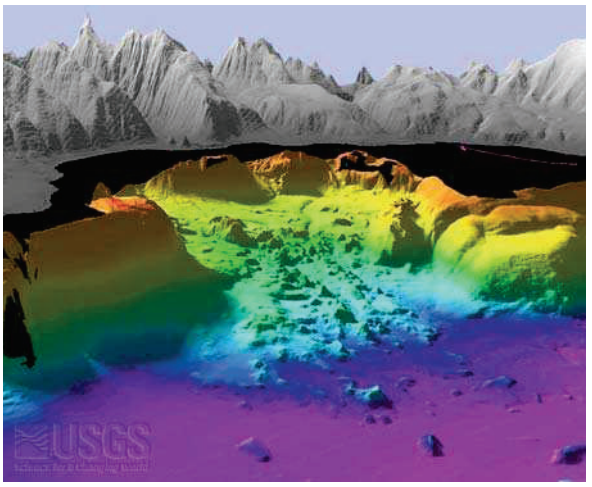


Fig. 6.2 3D-processed bathymetric pictures from Lake Tahoe, US. The black area is the unsurveyed coastal area. Vertical exaggeration is ×2. The debris tongue is 7.5 km wide and 9 km long. The large blocks within the debris tongue are up to 20 m high [4]

Some of the worst enemies of submarine cables are free spans where the cable hangs between outcrops, peaks, boulders and ridges.

6.3 Sub-bottom Profiling

If the submarine cable is to be protected, the knowledge of the seafloor bathymetry is not enough. Especially for cable burying it is necessary to know what is hidden below the sea bottom. The character, hardness, and thickness of various sub-bottom layers are decisive for the choice of the cable protection method, as well as for the assumption on the thermal parameters of the soil. Sub-bottom profiling can provide useful information on the depth and character of the strata existing under the seafloor.

The sub-bottom profiling unit is vessel based (shallow waters) or towfish based (deep waters) and is able to investigate the sub-seafloor profile vertically under the unit. Chirp-profilers produce a frequency-modulated signal providing both large soil penetration and depth resolution [1].

The sub-bottom profiling should be performed as comprehensive as possible. The sub-bottom morphology can change significantly even when the seafloor surface is not changing. Insufficient knowledge about the sub-seafloor characteristics may cause serious problems during burying of cables. All of a sudden, the cable trenching equipment might encounter a bedrock layer only a foot under the nice-looking sandy seafloor. This situation would lead to a costly variation of the cable protecting operation. Another example of insufficient survey depth: a sub-bottom profile had been performed down to the design burial depth of 2 m in a large offshore wind farm power cable project showing no problems. It turned out that the seafloor bathymetry had changed since survey. The cable plough hooked eventually into a pipe, which had been slightly under the –2 m level, such invisible for the inappropriate survey.

6.4 Visual Inspection

In complicated waters a survey performed from the sea surface may be too insensitive to reveal all underwater features. In order to achieve a complete picture on the subsea conditions before cable laying, manned submarine boats have been employed, e.g. during the survey for the Messina Strait (Italy-Sicily) cable system [7]. Today, similar operations can be performed rather easily by Remote-Operated Vehicles (ROV) or Autonomous Underwater Vehicles (AUV). Both types are able to carry camera systems down to the laying depth for a detailed inspection of critical route sections.

A site visit to the landing points is a must. The experienced cable installation engineer would gather valuable information on soil conditions, best locations for winches, trucks, supply, storage lots, etc. Interviews with people knowing the site under different weather, tidal, and seasonal conditions would complement the data collected in the DTS. All this helps to decide on the best possible installation technology and to foresee potential hazards.

6.5 Soil Sampling

Sometimes, the sub-bottom profiling has no sufficient resolution to provide data for a burial assessment survey [8]. Soil sampling can deliver additional data from selected locations to support decisions on burial tools. The hardness and character of the seafloor in different sub-seafloor depths can be investigated by taking "cores". In contrast to remote survey techniques, coring delivers tangible samples for further laboratory evaluation (Fig. 6.3).

Beside the hardness/strength, also the thermal resistivity ρ_T of the seafloor can be measured on cored samples. The thermal resistivity ρ_T in the cable route is an important parameter for the design of the power cable. Although ρ_T does not vary very much for many known subsea soil types, there can be spots of unusual soil with different characteristics. Especially soil types with high content of organic contents may have a high ρ_T value leading to a poor cable cooling [9]. It can save a lot of money to perform a comprehensive determination of ρ_T en route by soil sampling. Good knowledge on ρ_T en route enables the cable design engineer to fine-tune the conductor cross-section and save money.

Soil sampling may also reveal the existence of chemical contaminations in the seafloor. Waste or ammunition dumping, or aggregation of contaminated sediments in river estuaries may have caused contaminations. The contaminations can be released during the cable installation.

The hardness of the seafloor is an important factor for the specification of the burial method.

The costs of sampling along the cable route depend on the number of sample points, i.e. the required distance between sampling points. The results of the desktop study and possibly from the sub-bottom profiling provide valuable inputs for the determination of the necessary sampling frequency. If the sub-bottom profiling



Fig. 6.3 Core sampler

survey indicates long stretches of uniform seafloor the sample points can be 2–20 km apart. The more the seafloor properties vary along the cable route the closer the sample points must be located. Usually the survey and installation companies have the knowledge to make recommendations.

6.6 Soil and Water Temperatures

The variation of subsea soil and water temperatures over the year is one of the first data the cable design engineer asks for. For many waters, comprehensive data sets are available, taking annual variations and many years' statistics into account. For the submarine cable engineer the water temperature at sea bottom level is interesting, which can differ significantly from the water surface temperature.

In most submarine power cable projects, the thermal conditions at the landfalls are most onerous. High summer temperatures, large virtual burial depth in underbores and dike crossings, or interference with industrial activities must be listed before the cable design is settled. For power cables connecting offshore facilities, the ambient temperatures in the J-tubes and on the topside are necessary for a suitable cable design.

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Chapter 7
Installation and Protection of Submarine Power Cables

Contents

7.1 Installation 161
7.1.1 Cable Laying Vessels 162
7.1.2 Other Vessels 171
7.1.3 Loading and Logistics 173
7.1.4 Laying of Submarine Power Cables 174
7.1.5 Landing of Submarine Cables 177
7.1.6 Jointing of Submarine Power Cables 181
7.1.7 Weather 186
7.1.8 Organisation 193
7.2 Protection of Submarine Power Cables 194
7.2.1 Selection of a Suitable Cable Route 195
7.2.2 Design of a Suitable Cable Armoring 196
7.2.3 External Protection 198
7.2.4 After-Installation Protection 205
7.3 Appendix: The Catenary Line 206
References 208

7.1 Installation

The installation of submarine cables has developed substantially in many respects during the past 20 years. Cable manufacturers are able to deliver very long lengths of submarine power cables, up to 160 km in one piece. Powerful cable laying vessels with more than 6000 t turntables can operate in heavy sea-states using satellite-based navigation systems and modern propulsion systems. A lot of experience from the oil & gas industry can be used also for the installation of submarine power cables. Also, the booming industry of submarine fibre-cables fuelled the technical progress in submarine cable laying. Remote-operated-vehicles (ROV) have developed amazing skills today, which nobody could imagine only two decades ago. Also, the seafloor

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NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 174 of 306

survey can be performed so much easier than it could 20 years ago, today providing a close-up look onto the seafloor and, thus, avoidance of any adverse condition for the cable.

Still, the installation of submarine power cables is not an easy game. Meticulous planning is necessary, taking into account the properties of the cables, the characteristics of the cable route, and the abilities of the installation machinery. The circumstances differ so much from case to case that planning of costs and schedules must provide room for slippage, even if a good knowledge of all prerequisites exists. A successful submarine cable installation requires a carefully selected and integrated assembly of vessels, crews, and auxiliary equipment. An inappropriate cable-laying vessel, undersized equipment on board, or an inexperienced crew have devastated more than one cable laying campaign. Furthermore, a suitable determined installation management must be included. Clear and powerful authorisations for all parties on board should be agreed on.

7.1.1 Cable Laying Vessels

The cable-laying vessel (CLV) is the heart of each cable laying campaign. CLVs are available at all sizes and with all kind of equipment. Worldwide there are a few fully equipped and highly specialised CLVs for large power cables, such as C/S “Skagerrak” and C/S “Guilo Verne” with payloads exceeding 6000 t of cable (Fig. 7.1).

These high-capacity CLVs have a respectable day rate, particularly in times of high demand. There is also a number of cable laying vessels with very large tonnage



Fig. 7.1 C/S “Skagerrak” DP2 vessel with over 6000 t turntable, suitable for all kinds of power cable installation and repair

built for the installation of telecom cables. Most of these vessels are not suited for the installation of power cables as the cable handling equipment onboard is designed for light-weight small-diameter telecom cables. Some of these vessels can be used for power cable installation after considerable refurbishments.

Apart from dedicated CLVs many other vessel types can be temporarily converted for cable laying purposes. Barges and supply vessels can be equipped with suitable gear for cable laying tasks. Barges do not have own propulsion but rely on tug boats for transfer travel. During cable laying, they can be towed by tugs and/or anchors that are carefully placed along the cable route. Barges for this purpose come in all sizes and shapes.

Factors to be considered when selecting a cable laying platform (vessel or barge) are load carrying capability, manoeuvrability properties, deck space for cable handling equipment and jointing shack, crew quarter size, etc. Good sea-keeping properties, i.e. stability of the vessel in wind and waves, are essential for operations in the open sea. The bollard pull is important when a cable plough is to be used.

The barge in Fig. 7.2 has no own propulsion and must be towed to the destination. During cable laying she is pulled by anchor moorings and winches. The following features are visible: Towing chains at the left, central turntable for heavy cables, anchor winches in each corner, blue accommodation containers in three floors, white A-frame in the aft for launching rigid joints and other structures.

The barge in Fig. 7.3 is able to sit on the seafloor during low tides. The cable is coiled into a fixed cable tank. Another, rather unusual barge with a 1700 tonnes-turntable and a 6 m-laying wheel is the “H P Lading” (Fig. 7.4). She is the chopped-off foreship of the once-proud 1930 Exxon tanker “Esso Köbenhavn” after this was broken up in 1963. She has accommodation for 25 people.



Fig. 7.2 Large cable laying barge (Courtesy of Oceanteam Power and Umbilicals, UK)



Fig. 7.3 Flat bottom barge mobilised for cable laying in tidal flats (Courtesy of Oceanteam Power and Umbilicals, UK)



Fig. 7.4 Cable laying barge "H.P. Lading". Tow barge with turntable for up-and-down spooling on the conical hub (Courtesy of NKT Cables A/S)

A new fleet of high-capacity purpose-built CLVs is under construction. Figure 7.5 shows one of the new CLVs. Important features are:

- Turntable with 6000–7000 t cable capacity
- Space aft of the turntable for a jointing house and cable tensioners
- Large wheel or chute on the aft of the vessel for deploying the cable
- High deck strength to add more cable laying facilities or temporary turntables
- Crane over the cable track to handle rigid joints
- Helipad for easy crew transfer.



Fig. 7.5 Latest generation cable laying vessel (under construction). (Courtesy of Oceanteam Power and Umbilicals, UK)

Load capacity. Each laying campaign should transport as much cable as possible to reduce the number of costly and sometimes risky joints at sea. The largest CLVs for power cables have a turntable with an outer diameter of about 30 m and a load capacity exceeding 6000 MT. The load capacity is marginally dependant on the seawater temperature and salinity, i.e. the location and the time of year. Depending on the cable design, volume or weight can be limiting factors when determining the load capacity.

Turntables. The turntable (or carousel) has a vertical axis and is able to store even the largest of power cables, which cannot, due to their torsional stiffness, be stored in a fixed tank by coiling. Most turntables are being loaded in horizontal layers starting from the bottom layer. According to another "school", turntables have a conical inner hub and the cable is wound onto this hub in concentric layers up and down this hub under constant tension. The CLV "H P Lading" and some new vessels are built according to this design. This method requires a continuous cable tension during loading and laying. If the continuous tension is interrupted, this method can cause disorder in the cable turns as they slide down from the center.

Some vessels are or can be equipped with two independent turntables. With this equipment, two cables can be laid simultaneously. If the CLV is equipped with two spaced laying wheels[1] at the stern or bow, the two cables can be laid at a constant distance to each other. Preferentially, the cables are laid closely, bundled to each other. The bundling is accomplished as the cable pair leaves the CLV by means of suitable tape wrapping or cable straps. This is the preferred method for a pair of HVDC cables in shallow waters (up to 250 m water depth.). In the latter case, the pair of cables can be buried later in a single operation.

[1]The laying wheel represents all type of laying gear such as wheels, chutes etc.

Turntables can be divided into an inner and an outer partition. Two cables can be loaded into these partitions independently, either one after the other, or into both partitions at the same time (Fig. 7.6). This method requires a uniform-lay-direction cable armoring. Basically, both cables can be wound into their respective partition of the turntable independently by using individual feeding speeds out from the factory. A better method is, though, to wind up the cable into the outer partition and to coil down the other cable into the inner partition over a hanging coil spreader. Since the turntable is rotating to wind up the first cable, the second cable goes through a semi-coiling where the cable is twisted less than one time per turn. During laying, the process is reversed and the cables can be laid at the same common speed onto the seafloor without residual torsion. The pair of cables can be laid and bundled so that they can be buried in a single run later on. If the cables are not bundled, they might diverge on their way to the seafloor and thus jeopardize the subsequent burial.

For smaller submarine cable projects or repair jobs, small turntables can be mounted temporarily on the decks of barges or supply vessels.

Fixed cable tanks. Circular or oblong holds for cables are common for telecom cables and can be used for power cables, which are not torsion-stiff. The cable is loaded via a coiling spreader that is hung or fixed in considerable height above the tank. While loading, it is important to maintain a minimum inner coiling diameter specified by the cable manufacturer. Supports must be provided to prevent the cable from sliding down from the growing cable stack. A gang of coilers walking on top of the coiled stack must put the cable in place. For the sake of their safety, the coil



Fig. 7.6 Turntable with inner and outer partition for simultaneous laying of two cables. Here, a submarine power cable (outer partition) and a fibre-optic cable (inner partition) are stored on the turntable (Courtesy of ABB, Sweden)

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 179 of 306

stack should be fenced as it grows in height. The laying is the reverse operation of the loading, and the cable should land on the seafloor without internal torsion. Fixed tanks can be used for cables of moderate diameter with uniform-lay-direction armoring. Single-core cables with single wire armoring are good candidates for the use of fixed tankes. Medium-voltage three-phase submarine cable can also be loaded in a similar technique in oblong holds in vessels.

Cable drums. For many submarine cable projects with short cable length, it is not necessary to employ a dedicated CLV. Submarine cables connecting offshore wind turbines have a length of 400–800 m. They can be installed from barges or supply vessels equipped with cable drum pay-offs and suitable breaking and tensioning engines (Fig. 7.7). Extremely large drums with horizontal axis can be found on some pipeline laying vessels and, basically, may be used for cables.

Positioning. Every cable-laying vessel must be able to position itself very accurately on the prescribed cable corridor and move in desired directions without loosing positioning control. Even slight deviations from the planned position and heading can adventure the health of the cable or the accuracy of cable laying. The cable may end up in a subsea position different from the anticipated one. Maybe the cable goes down beside a pre-dredged trench, outside a licensed corridor, or in a hazardous seafloor area.

Anchoring systems. The classical method to keep the CLV in position is the use of anchoring systems. The CLV, often a propulsionless barge, is manoeuvred between the holds of numerous anchors fanning out in all directions. The anchors are handled by independent AHT (anchor handling tugs). Cable laying barges employ four to



Fig. 7.7 Laying with cable drums on a barge

eight anchors. They are placed some hundred or even thousand metres away from the barge into the water and connected to winches onboard the barge. The barge controls its position, speed, and heading by operating the winches. In very shallow waters it can be advantageous to use flat barges and anchoring methods and tugs because large CLVs often have large draught and protruding propulsion devices. The anchoring method is risky in waters where other cables or pipelines exist. These lines are hooked easily by the numerous anchors, resulting in costly repair jobs. Also, the anchors must not damage the cable already laid. The anchoring method is a tedious and time-consuming method but it avoids the high day-rates of a self-propelled CLV.

Dynamic positioning systems (DP). These systems keep the vessel on a determined position by means of high-sophisticated navigation systems and various ship propulsion devices. DP systems can move the vessel along a pre-determined course over ground. DP systems can also keep the vessel on station with any desired heading. Within certain limits, this is possible even when wind, waves, or currents try to carry the vessel off course. Conventional screw propellers provide forward thrust and, in combination with rudders, also directional control to a certain degree. A number of other propulsion systems are available to provide directional control, even without rudders and at low or no speed. Tunnel thrusters in bow and stern can push the vessel sideway and turn it on the spot. Azimuth thrusters are screw propellers, suspended in pivotable pods under the vessel (Fig. 7.8). They can turn 360° in most cases, and provide excellent manoeuvrability at any speed. Two independent azimuth thrusters can keep the vessel on station or turn it into the required



Fig. 7.8 Azimuth pods (Courtesy of ABB Oy, Marine, Finland)

heading. The pod propellers can be powered mechanically from an engine in the hull (Schottel drive), or with an electric motor in the pod powered from a generator in the vessel hull. Some vessels have retractable azimuths to improve the ability to navigate shallow waters.

Voith-Schneider propulsions consist of rotating vertical blades mounted under the vessel. They can generate thrust in all directions. Azimuth drives and Voith-Schneider propellers provide excellent manoeuvrability and can move the vessel in all directions (back/forth, sideways), which can be necessary during complicated cable laying or repair operations. In contrast to conventional propulsion, they do not need a minimum speed to maintain direction and control. The vessel is able to lay the cable along a well-defined corridor and still to keep the heading into the weather to reduce roll. For stationary jobs such as jointing or ROV operations the vessel is able to keep station and direction also under rough conditions.

DP systems use different navigation systems such as GPS-supported navigation systems, taught wire systems, and acoustic beacons. Most of modern vessels have GPS based systems. They are classified into DP-classes DP0 through DP3 depending on the redundancy of subsystems according to an International Maritime Organisation (IMO) classification. Redundancy requirements include not only propulsion and navigation systems but also features such as independent power generation systems and other auxiliary systems separated by firebreaks. A higher DP class on the vessel increases the safety of the cable operation. The DP class should be carefully selected with respect to the requirements and risk profile of the project. Sometimes, insurance companies require the use of vessels with a defined DP class. Many large submarine cable projects employ DP2 vessels.

Jointing house. The jointing of submarine power cables can only be performed in specially equipped jointing houses. They must be designed according to the specifications of the jointing company and need to have sufficient size. For a recent submarine power cable project, the on-board jointing house had a size of 4×17 m. The jointing house must be equipped with electric power supply, air condition, and air dryer. It must be fixed sea-worthily on an appropriate place in the cableway on deck. It is of advantage if the jointing house is splitable so it can be removed from the cable after jointing. For safety reasons, the jointing house should have redundant direct radio communication to the vessel bridge, and an alarm bell commanded from the bridge.

Cable tensioners. Also called linear machines, they are necessary for any moving of cables on board and for applying tension during laying. Many linear machines comprise pairs of wheels. The wheel pairs can be opened and closed with controlled pressure to grip the cable. Individual opening is necessary when bulky joints must be deployed. Wheel drive is most often hydraulical. The linear machine in Fig. 7.9 has eight wheel pairs and is installed close to the laying wheel at the vessel stern. The first end of the cable is being passed through the linear machine, which is in pulling mode. When the cable is being deployed into the water, the linear machine can be operated in braking mode. Many machines can be operated in speed- or tension-controlled mode. Linear machines are also available with belts instead of wheels, so called caterpillars. A good friction between the wheels and the cable surface is



Fig. 7.9 Cable tensioner with eight wheel pairs taking grip of the leading cable end

necessary without undue pressure on the cable. Not unlike car tyres, the wheels on the linear machine need to have a sufficient grip for efficient braking/pulling power, and the cable surface must not be too slippery. Some cable layers advocate the use of sand between cable and wheels when the grip slips.

The need for sufficient power in the linear machines must not be underestimated. The cooperation of linear machines, turntables and the vessel must be orchestrated carefully.

Emergency cutter. As described below in the weather chapter, a situation may arise when the cable must be cut in emergency situations. The cutting must be performed rapidly. The preferred solution is a hydraulic cutting head close to the aft wheel with remote control (cf. Fig. 7.10). A simpler device is a movable disc cutter with petrol or electric motor to be operated by a man. The emergency cutting device should be able to cut the cable within 60–90s.

Cableways, rollers, laying and pick-up arms, chutes, and laying wheels are other devices necessary for the cable installation. For each specific installation job, the ensemble of machinery must be selected to meet the requirements and allow for a safe and successful operation. Especially the specified bending radii under defined tension values should be taken into account. It is wise not to try to save money when specifying the equipment for an installation job. Many operations suffered painful delays because of weak cable rollers that have been blown away under heavy loads, or because of too weak linear engines.

It has been discussed to design aft laying wheels or chutes with dynamic heave compensation, in order to facilitate cable installation in higher sea-states. Another

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 183 of 306



Fig. 7.10 Hydraulic emergency cable cutter

means to reduce the vertical movement of the laying wheel is to arrange it midships, in order to reduce the effects of heave and pitch.

ROV equipment. Many activities in cable laying operations are possible only with the help of ROV (remote operated vehicle, Fig. 7.11). The ROV is a submersible powered tool carrier, which can be equipped with different manipulators and tools. Cameras are valuable to inspect difficult route sections, boulders, outcrops, or man-made leftovers such as wrecks or containers. Also, in easy waters, the ROV can provide valuable data for the as-built documentation. The ROV can handle submarine pick-up operations, inspections of possible damages, and close-ups of questionable areas. ROV are highly complex systems and are available in all sizes. The vessel should have sufficient space for a complete ROV system, comprising the vehicle and its parking space, launch crane, umbilical drum, container for control room and supplies, accommodation for the ROV operating crew, etc.

Helicopter landing pad. For the crew change or transport of specialists like jointers or fault locators a helicopter transfer can be an economic or even the only possible option.

7.1.2 Other Vessels

Apart from the CLV, other vessels are often needed for a submarine cable installation. In strong winds or currents, the CLV may need the assistance of one or more tugs to keep position. During landing operations, a fleet of smaller vessels

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 184 of 306



Fig. 7.11 ROV with grip manipulators and cameras

is often busy with the handling of pull wires, anchors, floating devices, and the cable. Anchor handling vessels are needed when the cable installation is performed by a propulsionless CLV. For complicated routes, the use of a survey ship during installation can be essential.

For post-lay cable protection a mother vessel for the trenching or jetting equipment is necessary. Before completed protection a fleet of guard vessels is useful to chase away fishing boats and protect the cable from unauthorized access.

Installation jobs far away from the coast require accomodation for the crew. If the CLV does not have sufficient accommodation a separate hotel vessel must be employed. Accommodations must be approved by authorities and insurance companies.

Manned submersible vessels have been used occasionally for cable related jobs [1]. Today, highly sophisticated ROV′′s can perform almost any underwater job without risk.

A 123 kV three-phase cable was installed in 2006 between the two Thai islands of Koh Samui and Kha Nom over a distance of 24 km. Five vessels were participating:

- one laying barge (85×24 m) equipped with 6-point-mooring system, cable tank, LCE, diving spread, jetting spread.
- two AHT (anchor handling tugs)
- one accomodation vessel
- one shallow water jetting sledge support vessel.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 185 of 306

7.1.3 Loading and Logistics

Submarine cables with short length can be handled and transported on standard or oversize drums. Most standard and all oversized drums require flatbed trailers making the onshore transport expensive.

When the submarine cable factory is located next to a harbour, the cable drums can be transported to the destination by a cargo vessel. Oversized drums can be shipped in this way avoiding the troublesome and expensive heavy road transports. Some cable manufactures ship long cables in coils laying on a group of rail cars [2], (cf. Fig. 7.12).

The length of in-field cables in offshore wind parks is often in the range of 400–800 m. There are two concepts for the supply of the cables:

1. Supply of pre-cut lengths on drums. Loading and installation require but rather simple machinery and barges with low day rates. However, the correct lengths must already be known in the factory. The requirement of relatively large safety margins in length results in large amounts of scrap cable during installation. Also, the empty drums must be either disposed of or returned, which can be a



Fig. 7.12 Transport of submarine cable on railway cars (Coutesy of NKT Cables A/S, Denmark)

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 186 of 306

costly activity. Another disadvantage can be a possible client requirement for individual factory acceptance tests on each cable drum.
2. The submarine cable can be shipped in a large coil or on a turntable. On-site, the lengths are cut from the coil as needed during laying. With this concept, less scrap cable and no drums need to be disposed of. However, more complicated equipment is needed both in the factory and on-site.

For the loading of a long cable length, the CLV is mooring directly at the cable factory to take up the cable in one piece. From the factory turntable, the cable runs over cable rollers to the CLV over a laying arm onto the ship turntable. Depending on cable size and equipment capacity, the loading speed is 3–20 m/min. The complicated loading operation requires the synchronised action of turntables and linear machines continuously over days or even weeks. Failures in synchronisation of speed can render kinks, bends, or buckling of the cable. This kind of damages may require costly and time-consuming repairs. Any possible measure to reduce the risk of loss of synchronisation must be considered prior to loading.

Other methods to load long cable lengths manufactured in factories at some distance from the harbour have been used in few cases: Cable roller tracks have been used by a Swedish company, and a British company shipped many drum lengths to a jointing ground at the harbour site. Both methods are tedious and risky.

The loop time for the CLV (load, transfer to site, manufacturing of connecting joint to previously laid cable, laying of the new cable, return to factory harbour) is most often much longer than the laying time. When the installation site is far away from the cable factory, the speed of the transportation vessel can be important. CLVs are relatively slow. Separate cargo vessels can speed up the cable transport, but this scheme requires a transfer of cable from the cargo vessel to the CLV at a port close to the installation site.

The ends of the cable must always be sealed properly to avoid intrusion of water or even humidity. The use of inadequate capping methods or equipment may result in water intrusion, which may require a cut-away of a considerably long length of cable. In the worst case, the cut-away of water-damaged cables requires the use of extra spare cable and extra joints. The end caps are manufactured according to the manufacturer's specifications. Shrink-on end caps often are not appropriate.

The water and humidity barriers in the submarine cable must not be damaged during transport, laying and burying. Too small bending radii, large side wall pressures, shear forces, etc. can destruct metallic laminates and metallic sheathes.

7.1.4 Laying of Submarine Power Cables

Submarine cables on drums, e.g. for in-field cables, can be installed from barges with simpler navigation equipment. A drum pay-off and a linear machine with brake are necessary. The cable runs over a chute or a laying wheel into the water. The chute or wheel must have sufficiently large a diameter to maintain the MBR. The barge normally has no propulsion and must be manoeuvred by tugboats or a set of anchors and winches. Stabilizing the position of a barge requires at least four anchors, one on each corner. Once the anchors are set, the barge can move by hauling in and paying

out the anchor lines in an orchestrated manner. The anchors need to be relocated from time to time by specialized anchor handling vessels. To keep the vessel on station at all times, it takes therefore more than four anchors, possibly up to eight or even more. This method is risky to other cables or pipes in the area, and it has actually happened that anchors from the laying barge have damaged cables already installed in the same project. Altogether, this is a very slow method, making 1–2 km a day as a maximum. However, in some waters, the use of barges able to rest on the seafloor at low tides might be the only way to get the job done. In these waters, ROV cameras are often useless as the visibility can be very little or zero.

A linear machine is necessary also for the installation of cables from a turntable. The cable runs from the motorized turntable over a movable pickup arm with cable rollers, through the linear machine, and then over the chute or wheel. The pickup arm normally has the shape of a gooseneck. In the gap between the turntable and the gooseneck, the cable can hang loose. This slack is useful to absorb possible temporary speed differences between turntable and linear engine. The gooseneck is pivotable and often also adjustable in height. Its position is moved according to the point where the cable leaves the turntable. Operators try to keep the slack always in the same curvature. This can turn out difficult, if the turntable drive works depending on load or position of the turntable, or if the linear machine has slippage or wheelspin. The cable runs further towards the laying wheel or chute before departure into the water. Close before the wheel or chute, another linear machine can be installed, working in breaking or pulling mode. For greater laying depth, a Capstan wheel may be used to amplify the cable breaking force from the linear cable engine.

When designing the installation, one of the machines is defined as the “master”. This machine defines the laying speed and all other machines, including the vessel propulsion, must follow the master speed.

If the cable would be let down to the sea floor vertically, there would be a risk of looping and instability of the laying direction. The heaving, pitching, and rolling movement of the aft sheave can cause cable damages at the touch down (TD) point, as the cable might be compressed longitudinally. Instead, the cable must be positioned in a well-defined catenary line from the laying wheel to the TD by application of a certain forward tension by means of the vessel. Under these circumstances, the cable hits the sea floor in a flat angle. A fully equipped CLV has the possibility to monitor the catenary parameters. Sensors to monitor the departure angle and the lay tension provide information to calculate the other catenary parameters. Equations relating water depth, bottom tension, top tension, departure angle, and the horizontal distance between aft sheave and TD are given in the Appendix at the end of this chapter.

An inappropriate catenary line or bottom tension can be corrected by a temporary extra pay-out from the turntable, or by a temporary acceleration of the vessel speed. At critical passages of the cable route, the TD should be monitored by ROV.

The bottom tension is considered a critical parameter for the laying. Too low a bottom tension can cause the cable to build loops or to snake, especially if the cable is laid from a fixed tank, which generates twisting in the cable. Many cable laying “pilots” consider that a high bottom tension results in a cable on the seafloor carrying a highly residual tension. The residual cable tension is thought to impede

later burying for protection. Figure 7.28 in the Appendix of this chapter shows the main parameters of the catenary line.

Misalignment of the various speeds (vessel, turntable, linear machines, tensioners, etc.) can cause a cable kink, loops or damages of the deck equipment. Submarine power cables that break out from their roller guides during laying may cause serious damages and hazards for the deck crew.

A power cable stored in a fixed cable tank can be paid-out using a fixed or movable pick-up arm over the tank. During loading in the factory, the cable has captured one torsional turn for each turn it was laid around the cable tank. This residual torsion is now released when the cable enters the fixed cable guide on the vessel. The rest of the laying from a fixed tank is equal to laying from a turntable.

Single-wire armored cables are not torsional-balanced. As the cable tension at the laying wheel and the bottom tension are unequal, there will be a resulting torsion in the cable as it goes down to the seafloor. At great depths especially, this may lead to cable loops. The catenary of these cables should be monitored by ROV – if possible – to detect any irregularities.

When a pair of cables is installed simultaneously, the cables can be stored in two independent turntables. A double set of cable handling equipment transports the cables to the laying wheel. Before departing, the cables are bundled together using steel straps, tape wrapping heads, or something similar. Bundled cables can be buried later in a single run. For the Cross Sound and the Estlink HVDC projects, the two HVDC cables and a fibre-optical cable were bundled and laid simultaneously.

For cables stored on inner and outer partitions of a turntable, different pay-off equipment is necessary. Most often, the outer cable has been spooled onto the turntable in the cable factory without torsion. It will be taken up as described with a movable pick-up arm, and paid out. The inner cable must reach the laying wheel with the same speed as the outer cable. Independent from the turntable speed, it will be taken up with a gooseneck and pulled by a tensioner with a speed that corresponds to the laying speed of the outer cable. However, as the turntable is actually turning to pay out the outer cable, only part of a torsional turn is released in the inner cable for each turn it is uncoiled from the turntable. For this, the method is called "semi-coiling".

There is a large difference in cable laying complexity, if a plain feature-less seafloor allows for a "simple" reel-out of the cable, or if the seafloor structure requires that the cable be laid between and around obstacles such as boulders, rocks, or outcrops. Free spans should be avoided under all circumstances. Sometimes, ROV-supported monitoring is necessary in order to direct the cable into the best possible line between the obstacles. This is also valid for pipe and cable crossings. Sometimes, special laying techniques must be developed and engineered for critical cable routes.

ROV monitoring of the TD is recommended even for other reasons:

1. An inappropriate TD angle can damage the cable seriously. Using ROV on-line monitoring can alert suitable action at an early stage.
2. Equipped with positioning device the ROV can supply very precise position data of the cable route for the as-built documentation.

7.1.4.1 Laying of Cable Around a Curve

When laying the cable around a bend with too small a bending radius, the residual bottom tension tends to drag the cable laterally over the seafloor. The minimum required bending radius can be calculated as

$$R_s = L_s = \frac{FT_H}{W_s \mu} \tag{7.1}$$

where (cf. Fig. 7.13)

F, Safety factor (suggested: 2.0);
T_H, Horizontal bottom tension;
W_s, Cable unit weight in water;
μ, lateral friction coefficient cable-soil.

After passing an obstacle, a straight line of length L_s should be laid before the curve is initiated. This is to avoid the cable being dragged against the obstacle as a result of lateral displacement. For cables with smooth extruded outer sheath, the following friction coefficients μ may be assumed: clay 0.2, sand 0.6, and gravel 0.8 [3]. Slightly higher values can be used for cables with yarn serving.

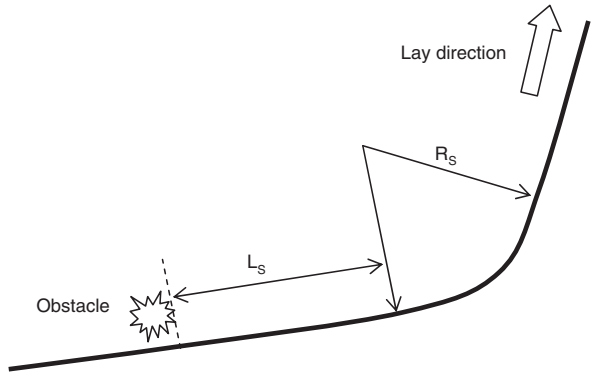


Fig. 7.13 Laying the cable in a curve

7.1.5 Landing of Submarine Cables

The landing of submarine power cables sometimes requires the most engineering, the most equipment and often the most time of all efforts of the cable project. The majority of all submarine cable projects have at least one landing point. Regularly, the laying operation is started here. A number of methods for the cable landing

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 190 of 306

have been used, but new projects may require new methods. The method to be used depends much on the shore conditions, equipment abilities and authority requirements. In cable installation jargon the coastline is called beach even if nobody wants to spend a single day of vacation there.

Sometimes it is possible to establish an open trench through the beach. The entrance point can be stabilised by cofferdams. The open trench goes from the sea entrance to the most appropriate land site for the joint pit between the submarine cable and the connecting land cable, called beach joint. The beach joint can be located inside the real sand beach, behind a dike, or as far away as some kilometres from the beach (e.g. the Baltic Cable project). The trench routing should be as straight as possible in order to avoid undue pulling forces and curves. During pull-in, the cable is guided on roller guideways inside the trench or outside; in the latter case, the cable will be pushed into the trench afterwards. The trench profile must be engineered with respect to thermal properties. Despite the fact that dikes along the European North Sea coast are very sensitive areas and normally must not be penetrated under any conditions, the NorNed cable could be landed through the Dutch protection dike system in open trench thanks to a well prepared operation (Fig. 7.14). Only one year after the operation the dike appears in pristine conditions.

In some areas, the only acknowledged method to cross the beach zone is the use of closed pipes. The method of choice is Horizontal Directional Drilling (HDD), where a drilling station is erected on the land side of the dike or beach. The drilling station drills a hole with a pre-determined curvature under the beach area and/or dike into the open water. The drilling path can be controlled in all directions. After drilling, the hole is lined with steel or plastic pipes for the later pull-in of cables. The pipe sections must be welded without leaving any internal welding beads, which could obstruct the cable pulling through the pipe. The longest possible length for



Fig. 7.14 Landing of a submarine power cable (NorNed) in open trench over the protection wall. In the splash zone, an open pit was created with cofferdam walls to receive the cable. The cut in the dike is visible in the distance in the *right* picture. Cable winch is in the foreground

HDD for cable applications is today in the range of 1400–1800 m. The length is limited not only by the drilling technique but also by the maximum pulling length of cables. The latter depends on:

- cable properties like weight, stiffness and maximum allowed pulling forces
- friction coefficients
- bending radii
- lubrication methods
- possibility of employing cable pushing, e.g. at river crossings.

The risk of failure increases more than linearly with the pulling length. For long pull length, the internal diameter of the pipe should be 2.5 times the cable diameter, for a short pull length, a factor of 1.5 is sufficient. Pulling two or three cables in the same pipe increases the pulling forces substantially and is recommended for very short length only (e.g. road crossings). The necessary pulling force for a straight pipe can be estimated by the following equation:

$$\text{Pulling force} = \text{cable weight} \cdot \text{friction coefficient} \tag{7.2}$$

With a pulling length of 400 m, a cable weight of 400 N/m and a friction coefficient of 0.4, the necessary pulling force is 64 kN (~6.4 MT). This is valid for a straight pipe without internal obstructions such as weld beads. The maximum pulling force can be decreased when the pipe is water-filled to obtain bouyancy for the cable. Proper choice of materials for cable sheath and pipe walls can decrease the friction coefficient. Friction coefficients for various material pairings are depending on the explicite composition of the polymeric materials. Tabulated values are of little use in practical life as the properties often are influenced by temperature and dirt on the cable surface. For engineering purposes, the friction coefficient can be set to 0.4 for unlubricated cable pulls, and 0.25 for lubricated cable pulls. Lubricating agents can be mineral slurries, gels, or bio-degradable oils. A slight bend, such as a gentle curve under a river crossing, does not change the figure very much. However, pipe bends increase the necessary pulling force substantially and should be avoided with all methods. Any bend contributes strongly to the resulting pulling force, especially if the bend is located close to the target end of the pulling route. If possible, cable pulling always starts from the difficult bends.

When all land preparations are concluded, the CLV approaches the landing spot as close as possible and stays there by means of its DP system. On shore, a winch is installed and a pull wire from the winch is transported to the CLV and connected to the cable end. The power cable can now be paid out over the laying wheel or the chute. Floating devices (air-filled bags) are being attached to the cable, while more cable is being paid out. Water currents e.g. due to tidal changes and wind may interfere strongly with this operation. The curvature in the cable in Fig. 7.15 was caused by tidal longshore currents.



Fig. 7.15 Floating of a submarine power cable during landing (NorNed). Crew members wear safety harness

Auxiliary boats may be necessary to keep the cable in position, while the shore winch hauls in the pull wire and the power cable to the beach and further to its destination. When the cable end has reached the destination on shore, it can be anchored there and the air-bags can be removed starting from the beach. The cable is now sinking down to its predetermined position. The maximum pulling length on land is much depending on the route. The Baltic Cable, a 450 kV HVDC cable, was pulled for about 5 km from the beach onto land, using a large number of small synchronised cable pulling machines along the route. The above-mentioned methods can be applied for the starting end of the cable. After landing the cable with the above-mentioned method, the CLV can start laying the cable. At the destination beach, different methods must be employed. There, the CLV arrives with the end piece of the submarine cable, which must be brought onto land. The CLV would move towards the beach as close as possible. From now on, the cable would be equipped with floating devices such as air cushions. Then the CLV would turn into a heading in parallel to the beach or even back. It is important that the floating devices are attached to the cable before the CLV starts changing its direction. The CLV now pays out the remainder of the cable, or at least as much as is necessary to reach the beach jointing pit. Since many cables are produced with spare or excess length there will be a remainder of cable onboard the vessel. A pulling eye is attached to the properly cut tailing end of the cable when it leaves the CLV. The floating cable can now be pulled from a shore pulling winch, when necessary assisted by working vessels. Cable layers, pray to your God that it is long enough!

Should weather conditions get worse, threatening the finalization of the destination beach approach, the CLV may reel out the remaining cable quickly in parallel to the shore line and put the cable end on the seafloor with suitable capping. In a later operation, it would recover the cable and complete the installation within a suitable weather window.

The landing of submarine cables to offshore platforms (or offshore windturbines, OWT) is somewhat different. Offshore structures with fixed foundations usually carry J-tubes that reach from the seafloor up to the top-side of the platform. The J-tubes are made from steel or polymeric materials. Above the top opening of the J-tube, there is a winch to be used for cable pull-in. The lower opening of the J-tube is bellmouth-shaped and points away from the platform or OWT foundation. The opening may be at, under, or above seafloor level. To install the start end of the submarine power cable, the CLV would approach the J-tube until it reaches a distance corresponding to the water depth or more. A pulling wire is sent from the topside winch down through the J-tube, and further on to the cable end onboard the vessel. The cable is paid out from the stationary vessel, while the pulling wire is hauled in. Ideally, the cable approaches the bellmouth horizontally. The pull-in of the submarine power cable is only successful when some conditions are fulfilled:

- The bending radius of the J-tube must be sufficiently high. It is most advisable to design the J-tube with a bending radius substantially larger than the MBR of the cable in order to avoid undue friction and high tensional loads on the topside winch
- The J-tube interior must be clear of obstacles and welding beads. The J-tube should be camera-inspected before cable pull-in. The internal diameter of the J-tube should be 2.5 times the cable diameter
- The winch is sufficiently strong
- An ROV or a diver shall be provided to camera-monitor the bellmouth.

The landing of the second end of the cable at the next OWT or platform can be performed in a similar way. The difference to the fore-end is that the tail of the cable must be taken off the CLV and parked somewhere, before it can be pulled into the J-tube. The “parking-lot” should be as close to the receiving J-tube as possible to reduce the length of pulled cable. The parked cable can rest on the seafloor when the water depth is in the range of 10–30 m and the seafloor is free of boulders, outcrops, and other obstacles. The parked cable can then be pulled into the J-tube from its “parking-lot” on the seafloor. In greater depths, or when movement over the seafloor is being hindered, the cable end must be parked with floating devices.

7.1.6 Jointing of Submarine Power Cables

Although modern cable laying vessels can store and handle enormous lengths of cable, it is sometimes unavoidable to joint cables on open sea because the length of

the cable route cannot be covered with a single shipload of cable. Other applications of submarine cable joints include the jointing of different cable designs along the route. The design of submarine cable joints is treated in Chap. 4.

The assembly of submarine power cable joints on open sea is a challenge that requires meticulous planning, suitable and reliable equipment, and a highly specialised and well-trained crew. With these preconditions, and a sufficiently long period of favorable weather, the joint can be manufactured and deployed safely. The manufacturing of the joint inside the jointing shack is described in Chap. 4. Here, the positioning of cables before jointing and deployment of the completed joint is to be discussed. The deployment of a manufactured joint on the seafloor can be a complicated operation, as the two jointed cables must be handled simultaneously with the joint. No overbending or overtensioning must occur, nor must the cable arrangement get stuck in A-frames or other structures on board. The cable laying circumstances decide which type of sea joint can be used.

Power cable joints must be prepared in purpose-built jointing houses onboard the CLV. A simple tent might be acceptable for the jointing of medium-voltage cables in calm waters. The jointing of high-voltage submarine cables requires jointing houses with air-conditioning, air-drying facilities, hoisting, and cable handling equipment. Outside the jointing house, additional space might be required for the air-conditioning units, storage, and waste boxes.

When laying long lengths of submarine cables in subsequent campaigns it is sometimes not possible to joint the next length immediately to the previous length. It is possible to sink a cable end into the water for an indefinite time and later recovery if the cable end is capped carefully according to the manufacturer's instructions. The use of inadequate methods or equipment may result in water intrusion, which requires a cut-away of a considerably long piece of cable. In the worst case, the cut-away of water-damaged cables requires the use of extra spare cable and extra joints.

7.1.6.1 In-Line Joints

In the simplest laying scheme, the CLV is laying cable **A** first. The end of Cable A is provided with a cable seal with pulling eye, a ground wire, and a hooking arrangement before it is lowered to the seafloor. The hooking arrangement should be ROV friendly for later recovery. Buoyancy links at the end of the ground wire can be useful, should sediment movements bury the ground wire.

After the first laying campaign, the vessel returns to port to fetch the next length, Cable B. The CLV returns to the cable route at the end of cable **A**. The ground wire of cable **A** is hooked with an ROV or a grapnel and pulled onboard over the laying wheel to a jointing shack onboard the vessel. There, the second cable length, which is still onboard the vessel, is jointed to the first cable. If the joint is a flexible joint (cf. Chap. 4), the completed joint can now be transferred through the ordinary laying equipment of the vessel, and passes over the stern laying wheel down into the water. The vessel is keeping a suitable cable tension and layback in order to preserve the joint from undue bending at the touchdown point. The jointed new

Cable B is following, and the laying operation can be continued. This arrangement requires that the complete second cable runs through the jointing shack unless the shack is a split design and can be removed after jointing. If the joint design is rigid, it cannot be pulled through the ordinary cable route and over the stern wheel. Instead, the rigid joint body must be hauled over carefully with cranes. At the same time, sharp bends of the cables must be avoided where they are connected to the rigid joint body. A carefully orchestrated operation of deck cranes, vessel positioning, and winches is necessary to deploy the joint, bring Cable B fully into the cable laying machinery, and lay the joint correctly onto the seafloor. It should be avoided that the joint position on the seaflor is affected by sharp bends, boulder fields, and free spans.

In-line joints are comparatively easy to handle, particularly if flexible joints can be used. The cables lie straight on the seafloor and can later be buried in a single uninterrupted run (precaution is needed when a rigid joint body is too bulky for the trenching equipment). However, the method requires a long period of good weather for the jointing operation and the subsequent laying of Cable B.

A different approach is to lay Cable B without jointing it to cable A in the first place. Cable A and B will later be connected by a so-called hairpin joint.

7.1.6.2 After-Installation Joints

Sometimes it is necessary to lay down both Cables A and B onto the seafloor without jointing. A possible reason might be a short weather window not allowing for both jointing and subsequent laying in one go. Also, it can be less costly to use the high day-rate CLV only for laying, and use a cheaper vessel for the jointing job. The post-lay jointing can be done in different configurations. One post-lay cable configuration is depicted in Fig. 7.16. Both Cable ends A and B are lying on the seafloor with straight overlap, each hopefully equipped with seal, pulling eye, ground wire, and ROV-friendly hooking devices.

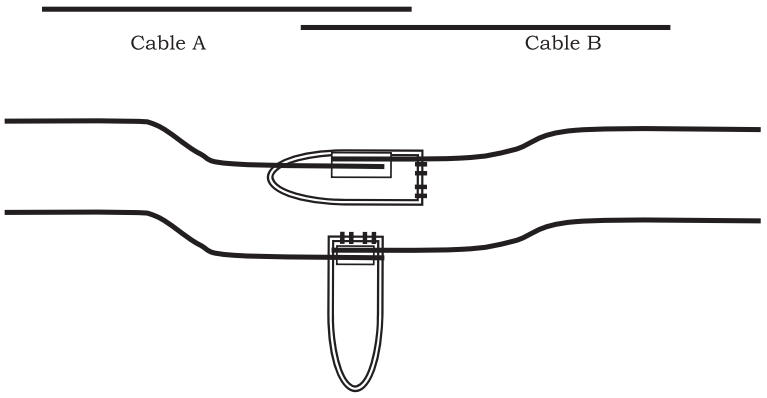


Fig. 7.16 Two cables laid with overlap, and positioned in a jointing shack (symbolized by a rectangle on the vessel) parallel to the bulkward or across the aft deck

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 196 of 306

For the final jointing, the two cable ends can be pulled up to a jointing shack arranged along the deckside and the bulkward. The ground wires of the cable ends are hooked by ROV or grapnel, pulled up and guided to the jointing shack over wheels, chutes, and suitable cable guides. The length of the overlap in Fig. 7.16 must be two times the water depth, plus the length of the desired catenary lines during jointing, plus 100–150 m depending on the length of the cable guides on-board. It can be prudent to have an extra length to provide cable for a second try if the first joint must be redone.

Another similar set-up is to have the jointing shack transversely across the aft deck of the jointing vessel (cf. lower part of Fig. 7.16). The Cables A and B would be pulled up over chutes or wheels protruding laterally from the vessel, and guided into the jointing shack using winches, linear machines, or other suitable equipment. The ends are positioned inside the jointing shack with overlap according to the joint manufacturer's instructions. The cables must be secured firmly outside the jointing shack so they cannot move under any conditions.

The vessel must keep station during the subsequent jointing operation. If the DP system cannot keep the vessel on station in difficult weather tug boats can assist to stabilize the position of the CLV. After jointing the jointing shack must be removed or opened so that the jointed cables can be deployed into the water.

Another configuration for a post-lay jointing is shown in Fig. 7.17.

The cable ends are laid departing from the straight cable route. The distance between the two cables in the spur route may range between 5 and 20 m. The length of the spur route must be sufficient in order to keep the cable in a stable position on the seafloor even if the CLV keeps pulling in order to maintain a proper catenary line during the jointing. The minimum length L_S for stability is given in Eq. 7.1 in this chapter. Further allowance must be made for 100–150 m on board of the CLV. If provisions shall be made for a second try of joint manufacture, the spur cable

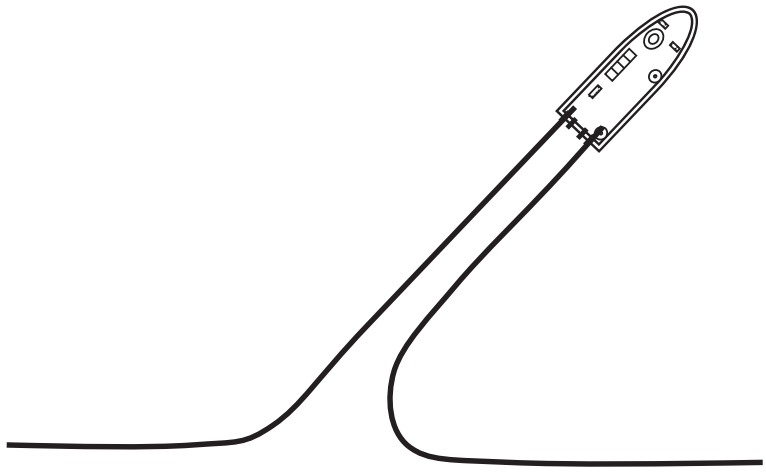


Fig. 7.17 Two cables laid for a hairpin joint

length must be even longer. The spur cable route may be laid in a sharper angle to either side in order to provide an advantageous CLV heading into the waves for the jointing operation to come.

For the preparation of the hairpin joint, both cable ends are pulled up to the vessel aft deck simultaneously, while the CLV travels backwards along the spur route. One cable is being pulled up over the ordinary stern wheel, the other over a provisional wheel or chute. Well onboard the vessel, both cable ends are guided to the jointing shack using winches, linear machines, or other suitable equipment. The ends are positioned inside the jointing shack with overlap according to the joint manufacturer's instructions. The cables must be secured firmly outside the jointing shack in a way that they cannot move under any conditions. The CLV must keep station during the subsequent jointing operation. After jointing the jointing shack must be removed or opened so that the jointed cables can be moved. The jointed cables **A** and **B** form a loop or hairpin-shaped open bend which now must be deployed into the water. The deployment of the joint is possibly the trickiest part of the operation. The excess length of the two jointed cables must be organized to form gentle curves on the seafloor. A welded steel arc ("quadrant") is used to support the cable in the loop and provide the correct bending radius (cf. Fig. 7.18, and the description of an example repair operation in Chap. 7). During the deployment, the vessel moves along the spur route to maintain suitable cable tension.

In the trade, the hairpin that is deployed on the seafloor is also known as "loop", "omega", or "final bight". More nicknames are probably being used.

Suitable vessel equipment provided, a hairpin joint can be installed with both flexible and rigid cable joints. The advantage of hairpin joints is that it can be pro-



Fig. 7.18 The quadrant, a steel support frame, goes into the water (Courtesy of ABB, Sweden)

duced independently of the cable laying operation, maybe on a later occasion with more favorable weather. The hairpin joint can also be manufactured using a different vessel with appropriate equipment for the operation. This vessel can have a lower dayrate than a top-of the-line CLV. A hairpin joint provides no straight cable corridor and post-lay trenching must take special measures to protect the spur route and final bight.

7.1.7 Weather

Weather is the cable crew's worst enemy. Countless are the hours during which an armada of cable laying vessels and working boats has been rolling idly in waves and wind for hours, days, or even weeks until useful weather appeared from the skies. Weather can demolish any working plan and any schedule. Neptune is still invincible if it were with the fanciest technology. Waiting on weather ("WoW") is a very costly way of doing nothing.

Unfortunately, it is almost impossible to list weather limits for a safe laying operation. Neither wind nor waves per se constitute obstacles for cable laying. What matters is only the movement of the laying wheel when the cable is hanging down from it. This movement is caused by waves, which in turn are caused by winds. Each step in this causal chain involves statistical relations and local parameters making things difficult.

7.1.7.1 Winds

Wind generates waves. The wind distribution can be very different for different places and is subject to strong seasonal variations, which may create weather windows of different length for the cable laying. The wind speed is given in the classical Beaufort scale or other speed units such as km/h, m/s or knots (1 kn = 1852 m/h). Relations are listed in Table 7.1 together with the characteristics of related sea-states.

7.1.7.2 Wave Properties

Waves originate from wind blowing over a water surface. Fresh wind waves usually have a short time period and can be rather steep. The longer the length of the route where wind can attack the water ("fetch") the higher the waves can build up. In parts of the North Sea, westerly winds have a longer fetch and build up much higher waves than easterly winds. In the Baltic Sea, parts of the Mediterranean, and other marginal seas the fetch is limited and the wave height is often smaller than with similar wind forces over the Ocean.

The size of waves that wind of a given strength can generate depends also on the wind duration and the water depth. Empirical formulae for the calculation of wave characteristics from wind speed are given in [4] for the Baltic and North Sea. Table 7.2 summarizes some of the results with the condition of constant wind speed in constant direction over the entire area.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 199 of 306

Table 7.1 Wind speed and sea-states

Beaufort	Wind speed			Description	Sea conditions
	Kn	km/h	m/s		
0	0	0	0–0.2	Calm	Flat
1	1–3	1–6	0.3–1.5	Light air	Ripples without crests
2	4–6	7–11	1.6–3.3	Light breeze	Small wavelets. Crests of glassy appearance, not breaking
3	7–10	12–19	3.4–5.4	Gentle breeze	Large wavelets. Crests begin to break; scattered whitecaps
4	11–15	20–29	5.5–7.9	Moderate breeze	Small waves
5	16–21	30–39	8.0–10.7	Fresh breeze	Moderate longer waves. Some foam and spray
6	22–27	40–50	10.8–13.8	Strong breeze	Large waves with foam crests and some spray
7	28–33	51–62	13.9–17.1	Near gale/ Moderate gale	Sea heaps up and foam begins to streak
8	34–40	63–75	17.2–20.7	Fresh gale	Moderately high waves with breaking crests forming spindrift. Streaks of foam
9	41–47	76–87	20.8–24.4	Strong gale	High waves with dense foam. Wave crests start to roll over. Considerable spray
10	48–55	88–102	24.5–28.4	Whole gale/storm	Very high waves. The sea surface is white and there is considerable tumbling. Visibility is reduced
11	56–63	103–119	28.5–32.6	Violent storm	Exceptionally high waves
12	64–80	120	32.7–40.8	Hurricane	Huge waves. Air filled with foam and spray. Sea completely white with driving spray. Visibility greatly reduced

The values given here serve for an approximate overview and must not be taken for engineering purposes. It is highly recommended to use wave spectra for the actual location of a proposed submarine cable project.

Waves generated by winds can travel a far way over the oceans. Travelling over hundreds of miles, the waves become less steep, having longer periods, but can

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 200 of 306

Table 7.2 Wave height at different wind speeds

	Wind speed			
	20 kn 10.3 m/s 37 km/h 5 Bft	30 kn 15.4 m/s 56 km/h 7 Bft	40 kn 20.6 m/s 74 km/h 9 Bft	46 kn 23.7 m/s 85 km/h 10 Bft
Baltic Sea				
Significant wave height H_s, m	1.6	3.3	5.3	6.3
Highest of 100 waves $H^{1/100}$, m	2.4	5.0	8.0	9.5
North Sea and Mediterranean (west of 21°E)				
Significant wave height H_s, m	1.9	4.8	8.6	10.3
Highest of 100 waves $H^{1/100}$, m	2.9	7.2	13.0	16.0

conserve much of the wave height. These waves, which are generated far away are called "swell", and may prevail for days after they have been generated. Travelling waves can be reflected from coastlines. In some spots, travelling waves from different origins can interfere and build up to larger wave heights than those from each contributing wave train. Refraction and interference of waves can build up complicated wave patterns particularly between coastal islands and the mainland, or in waters where sand banks can impact wave train directions [4]. For this reason, the waves at a certain location are composed of waves with different characteristics and height. Wave direction can be different from and even opposite to wind direction. Waves can be existent in the absence of wind, as a result of earlier winds/storms.

Each sea-state comprises a spectrum of waves with different wave height. The wave height distribution is often described as a Raleigh distribution. In many sea-state forecasts the term "significant wave height" is used. The significant wave height H_s is defined as the average wave height of the highest third of all waves [5, 6]. In practice, one would measure the height of 10,000 subsequent waves and take the average of the highest 3333 waves to obtain H_s. The definition of H_s is independent of the statistical distribution of the wave heights. If the Rayleigh distribution is used the probability of various wave heights can be related to H_s:

$H^{1/10}$ (one wave out of ten in the upper third) $= 1.27 \cdot H_s$
$H^{1/100}$ (one wave out of hundred in the upper third) $= 1.67 \cdot H_s$
$H^{1/1000}$ (one wave out of thousand in the upper third) $= 1.86 \cdot H_s$
H^{max} (Max wave height expected) $= 2 \cdot H_s$

Figure 7.19 shows Raleigh-distributed wave heights for a significant wave height of 4.4 m (indicated by a vertical line).

Other researchers prefer other statistical distributions (e.g. Gauss distribution) to represent the wave spectrum. This disagreement reflects the fact that the wave spectrum differs between locations. A comprehensive treatment of wave theories and a related bibliography can be found in [7]. Freak waves (also called "monster

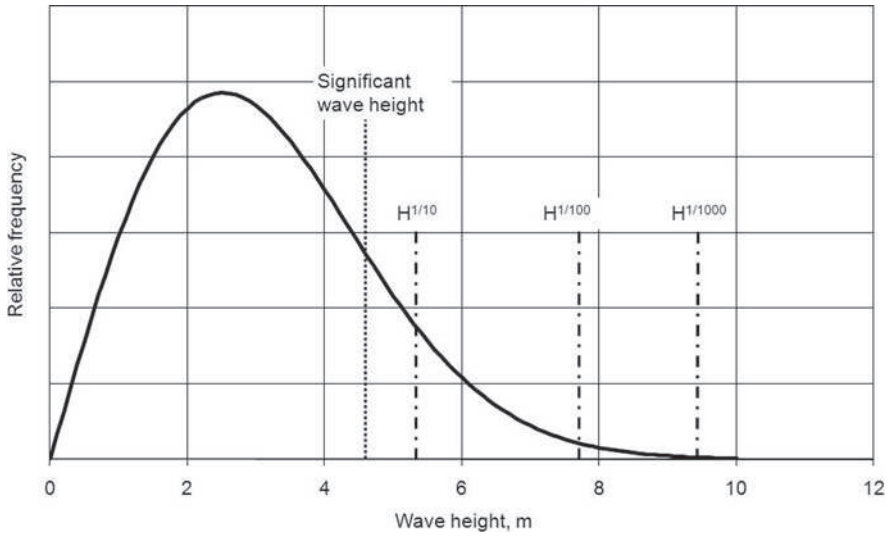


Fig. 7.19 Wave height of a Rayleigh-distributed wave spectrum. Significant wave height is indicated by a *vertical line* at 4.4 m

waves" or "rogue waves") are not part of these statistics. Today the existence of freak waves is widely acknowledged [4, 8].

For the cable installation engineer, it is important to know that the maximum wave height can be roughly twice the significant wave height given in sea-state forecasts, and that waves with $2 \cdot H_s$ are expected to occur a few times in each eight-hour interval. As the accuracy of sea-state forecasts decreases for longer forecast horizons, the cable installation engineer should consider increasing the safety margins for cable installation operations with long duration.

7.1.7.3 Vessel Movement

The next question is how different vessels react to a given wave spectrum. The response is not only depending on vessel size but also on its design and equipment. For each CLV a RAO (Response Amplitude Operator) can be established that takes into account an individual vessel's size, mass distribution and other parameters reflecting the seakeeping properties of the vessel.

The movement of a cable laying vessel (CLV) has six degrees of freedom (Fig. 7.20):

The RAO (Response Amplitude Operator) for the vessel in question translates wave characteristics to vessel movements. In particular, the heading of the waves with respect to the vessel is an important factor to determine the vessel heave, pitch, and roll from the wave characteristics. For laying operations, pitching and heaving have the largest influence on the vertical movement of the laying wheel. Still, rolling cannot be totally neglected if the aft laying wheel is off the vessel centre line.

Lateral movements	Heave (up and down) Surge (back and forth) Sway (right-to-left)
Rotational movements	Roll (rotation around the longitudinal axis) Pitch (rotation around the beam axis) Yaw (rotation around the vertical axis

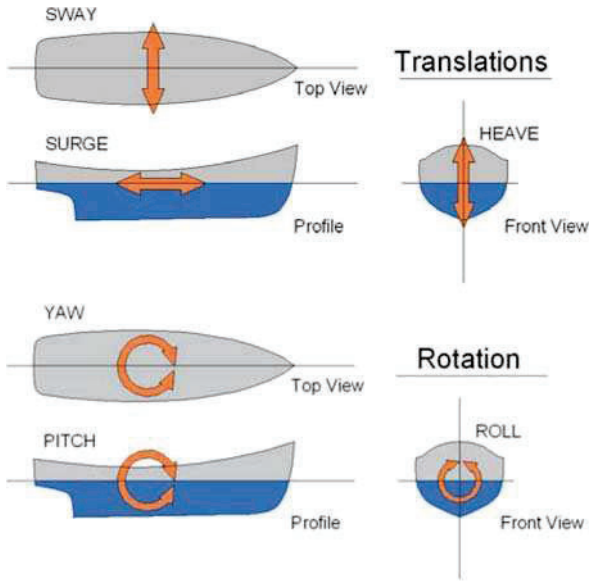


Fig. 7.20 Six basic movements of a ship. Source: Wikipedia, http://en.wikipedia.org/wiki/Ship_motions

Figure 7.21 shows the RAO factor for a specific cable-laying vessel in the 6000 t payload class. The period time of the (sinusoïdal) wave is represented on the *x*-axis. The *y*-axis is the RAO factor for heave. The factor is given in m/m, and describes the relations between the resulting heave amplitude to the causing wave amplitude. A RAO heave factor of 0.6 means that the heave of the vessel is 0.6 times the wave height. Seven curves are given for different wave headings related to the vessel. 180° means head-on waves, 90° are beam waves. Some interesting observations can be deducted from Fig. 7.21:

- The vessel response on waves is very much depending on the wave direction and the wave period time.
- Waves with short period time usually do not cause large heave since the wave length is smaller than the vessel length.
- Beam waves can cause large heave even at relatively short period time.
- In very short and very long waves the wave direction is less critical for the heave.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 203 of 306

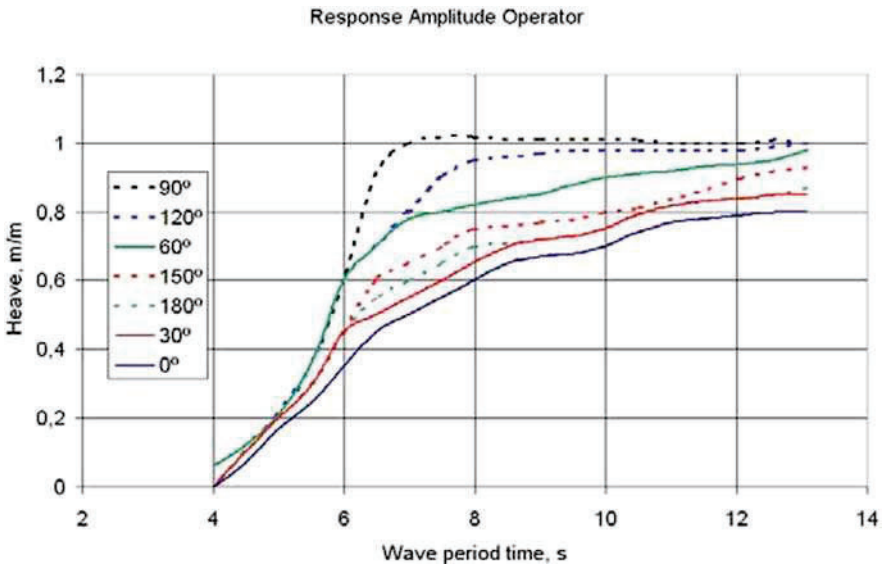


Fig. 7.21 RAO for heave for a 6000 t payload CLV

During cable laying, the vessel heading is dictated by the cable route. If the cable route is S–N and the prevailing winds are NW, the CLV receives the waves from a quarterly direction, which often results in the most onerous movements.

The cable that is hanging down from the laying wheel in a catenary line is subjected to a number of forces. Let us first consider a simple case when the cable hangs down almost vertically. Assume that the cable has a weight w per meter in water (that is the weight in air minus the cable's buoyancy). The water depth is D. The vessel stands still. The weight of the hanging cable is now

$$F = D \cdot w \tag{7.3}$$

Now, we assume that the laying wheel is moving up and down in response to waves. To make it easy, we assume that the vessel floats on the waves like a wine cork, i.e. the laying wheel movement is identical to the wave movement. The movement has a sinusoidal shape. The movement amplitude (measured peak to peak) is h, and the movement period (time between subsequent upside peaks) is T. The laying wheel movement can now be described as:

$$y = h/2 \cdot \sin(2\pi/T \cdot t) \tag{7.4}$$

The largest acceleration of such a movement can be found by twofold derivation with respect to time and amounts to:

$$a_{\max} = h/2 \cdot (2\pi/T)^2 \tag{7.5}$$

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 204 of 306

As an example, a vertical laying wheel movement with 4 m peak-to-peak and a 6 s period time reaches a maximum acceleration of about 2.2 m/s^2. The maximum force on the hanging cable is now

$$F_{\max} = F + m \cdot a_{\max} \tag{7.6}$$

where m is the mass of the hanging cable. Since the force due to acceleration is an inertia phenomenon, the cable mass must be used for the calculation rather than the weight in water or air.

Actually, this value can be larger still. Especially high waves with short period can cause substantial acceleration values. In addition, waves can interfere, which leads to sudden vertical movements. Stowing guidelines published by the International Maritime Organization (IMO) and International Labor Organization (ILO) of 02.05.1997 state that vertical acceleration of up to 1 g (=9.81 ms^{-2}) can be observed at the aft and bow of a vessel [9]. However, these high acceleration values are encountered on vessels under speed into head waves, which results in shorter wave periods. The speed of CLVs is rather low (mostly under 1 kn) so the contribution of vessel speed can mostly be neglected. Still it is prudent engineering to consider an appreciable vertical acceleration when estimating the cable tension.

During cable laying with a departure angle of 25°–30°, the suspended cable length is considerably higher than the water depth. The entire cable must be accelerated following the vertical movements of the laying wheel. The cable portion far away from the wheel, close to the TD, is moving up and down with, in comparison to the laying wheel, lower amplitude. The necessary force to accelerate the cable must be vertical. The cable can only transmit forces along its own direction. For this reason, large tensions along the cable have to be transmitted to create the vertical forces for the cable acceleration close to the TD.

The tensional forces on the cable are results of waves with a statistically distributed wave height. Even if the significant wave height of the weather forecast seems to be harmless, only a few waves of exceptional amplitude can cause tensions big enough to damage the cable.

7.1.7.4 Other Impacts of Wind and Waves

Vessel movements can introduce adverse effects on cable laying beyond the tensional force on the cable:

Crew work ability. Many seamen suffer from seasickness. In heavy weather, 10–30% of the crew might be sick and unable to work [10]. The healthy part of the crew might be unable to work for safety reasons.

Danger to the crew. The cable jointing crew inside the jointing shack can be subjected to danger from moving equipment. All equipment in the jointing house must be lashed to the walls or the floor, and working can be very difficult when the jointers

need one hand to secure themselves all the time. The power cable must be anchored firmly on board to keep it in place. The greatest danger comes from the cable in the jointing shack. In very strong heaves, the cable hanging in the water is exposed to forces so strong that it might be overtensioned. The grip of cable tensioners might slip or the cable securing devices on board might break.[2] The situation is out of control, when the heavy cable starts now moving unfastened in the jointing shack and over deck areas. This is seriously dangerous for the crew, the equipment, and the vessel. It calls for immediate crew clearance of the area and possibly emergency cut of the cable in order to save health or life of the deck crew. Emergency cutting is a safety measure and causes normally large economic losses in form of costly repair operations and schedule slippage. Should the Master or the charterer of the vessel, in order to save consequential costs, put the crew's safety at risk, he can be subject to criminal prosecution.

Loss of position. The CLV keeps station by means of thrust engines. In heavy weather, the thruster capability can be overwhelmed by side winds, strong currents and/or waves. The vessel is driven from its determined position. The cable is still in its hanging position and may act as an anchor chain. It can be subject to additional tensional strength and also to other forces, when the direction of drift is not along the cable route. This has happened in a number of cable installation projects. When the CLV is been driven back over the cable, there is a risk of twisting and kinking of the cable.

7.1.8 Organisation

In 1964, a report on a submarine cable laying operation declared: "Captain and crew of the boats shall be cooperative with the cable laying work and, if possible, having experience in cable handling" [11]. The insight behind this statement was not new. However, more than one project manager wished that everybody had read this report. Today, the installation of a major submarine link is a considerable industrial construction project. Only with meticulous planning, appropriate resource allocation and thorough contingency preparedness the project can succeed.

A number of different companies can be engaged in a cable installation such as the following parties:

- The client, represented by the client rep on board
- Nautical crew of the vessel from Master to maid
- Cable laying and handling crew onboard, perhaps from another company
- Cable manufacturer representative

[2]Cable tensioners must never be used alone to secure the cable during jointing.

- Survey company responsible for staying in the cable corridor, making fresh in-situ surveys, and preparing the as-built documentation
- Owners and operators for the ROV equipment, guard vessels, auxiliary vessels
- Insurance companies.

These companies can be contracted independently by the client, or can have a subcontractor hierarchy, or anything in-between. In many projects, the different tasks of the cable laying operation are organised by a single contractor who is using subcontractors. The single contractor is the only interface to the client, and the coordination responsibility is put on the single contractor. This is a convenient structure for the client as he has only one contractor to talk to. It is fair, when the single contractor is claiming extra compensation for his efforts of interface coordination and increased risk exposure.

In a different business plan, the client goes shopping for all different supplies and services in separate contracts. This gives the client the opportunity to procure the best offer for each of the contracts and to avoid paying coordination surcharges to a general contractor. In this case the interface coordination is an effort to be performed by the client (or an external company hired for that purpose).

In any case, there must be clearly defined responsibilities, order flow and mandates, and communication paths between the participating parties.

It can be of advantage for the client to hire contractors who have been working together successfully in previous projects.

Coordination and planning meetings involving the parties should be conducted repeatedly and long before the operation starts. Flaws in the project organisation or/and the installation equipment can be detected during these personal meetings. People meet, people accept the other's roll, and people know whom to talk to. The importance of a mutual understanding of the role and competence of each party can't be overestimated. Costs for early coordination meetings pay back manyfold.

During the cable installation, daily operation meetings are conducted involving representatives for all relevant parties. Apart from the HSE (Health, Safety, Environment) topics, the progress of the last 24 h and the planned work for the next 24 h are to be discussed then and there. In separate tool-box-meetings, the details of certain work activities are organized with the relevant crew.

7.2 Protection of Submarine Power Cables

Submarine cables are precious assets and need to be protected from external hazards. The 1986 Cigré study [14] presents a comprehensive compilation of submarine cable faults and protection methods. The protection constitutes a considerable part of the total investment.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 207 of 306

There are four principle steps of submarine cable protection:

1. selection of a suitable cable route
2. design of suitable cable armoring
3. protection on the seafloor e.g. by burying
4. active after-installation protection.

It is widely accepted that a well-designed cable protection enhances the reliability and, hence, the availability of the cable system. The operational costs for repair and maintenance can be reduced by a proper protection.

7.2.1 Selection of a Suitable Cable Route

After a desktop study a provisional cable route can be selected. As far as possible, hazardous areas should be avoided, such as:

- Shipping lanes, anchorages, harbour entrances
- Fishing grounds
- Boulder fields, outcrops, submarine canyons and steep slopes
- Wrecks, ammunition-dumping grounds, debris
- Areas with strong water currents.

Shipping lanes should be avoided because the presence of heavy ship traffic can impose restrictions on the installation operations. Also, the risk of anchor damages is higher where ships travel. If shipping lanes have to be crossed somewhere, it is advisable to do this at right angle to keep the interference low. Anchorages, ammunition-dumping grounds, and military exercise areas are strict no-go's for submarine cable installation.

Fishing grounds exercise a direct threat to the cable's health. Not only fishing nets but also ancillary gear such as mooring points can do harm to the cable.

Landing points for the cable link must be selected carefully. Shorelines have very different characters and are sometimes stable in their position, sometimes very volatile and prone to changes. The shoreline and the adjacent bathymetry may change rapidly due to tidal current, longshore currents, wave patterns, seasonal storms, and more. Even if many coastal communities try to preserve the coastline as it is by various costly measures, there are voices advocating the acceptance of natural changes of the shorelines.

Shorelines may also be disturbed by man-made interference such as breakwaters, harbour entrances, beach protection, etc. When selecting a cable route, also future near-shore developments should be taken into account.

Electric stray currents from on-shore activities (electric trains, welding, etc.) have reportedly caused cable damages. Therefore, the route selection should also include possible effects from onshore activities.

Many other obstacles may be hidden in the water or even under the seafloor. The following list has a few of these, and many more different things have been found by the survey crews: ship wrecks, abandoned cars and trucks, lost containers, dumped construction materials, active or defunct subsea installations, military installations, garbage dumps, intake or outflow pipes, etc. Most often it is not possible to avoid the crossing of cables and pipelines but one should select suitable crossing points at a distance from shore.

OWP installations define a safety zone of 500 m for their own protection but it is strongly recommended to keep away from OWP at least 2000 m, unless the cable in question runs to that OWP. This is to enable possible future repair activities, which may require some space outside the cable corridor. Also, future OWP must be taken into account. The laws of the High Seas do not grant a safety zone around the submarine cable.

Great care should be devoted to the selection of the best seafloor topology and morphology for the cable route. Not only boulder fields, outcrops, submarine canyons, and steep slopes threaten the cable or call for trouble during installation. A smooth sandy seabed might seem suitable for laying and installation, but there might be a ridge of rock just some feet below, making the subsequent trenching very difficult.

Sand waves on the seafloor might constitute considerable risks for the cable life. Sand waves can move on unpredictable paths creating unexpected patterns through the years. As a result, the cable can be buried much deeper than previously expected, or the cable can ly exposed and without protection in the valleys between the sand waves. In worst cases, free spans may be generated, or the exposed cable may be sand-blasted by the sand-loaded current.

It can be more economic to run the cable in a detour rather than spend money for a higher degree of other protection in a dangerous area.

Route selection also includes fine adjustment during cable laying where ROV can monitor the detailed cable route and helps laying the cable between rocks rather than over them. In a Norwegian project, the cable was allowed to follow the “valleys” between seafloor elevations, rather than a “blind” straight laying (Fig. 7.22). Actually, hiding the cable between natural elevations might give it a good protection without burying it, but it requires meticulous control of the cable touchdown during laying.

7.2.2 Design of a Suitable Cable Armoring

The armoring of submarine cables (power or telecom) must be designed to meet the tensional forces during laying and the protection requirements during the lifetime of the cable. The telecom submarine cable industry has developed an armoring

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 209 of 306



Fig. 7.22 The initially planned route (*straight line*) would have implied several ridge/valley crossings with risk for free spans. Detailed route survey enabled to lay the cable along the *curved* route avoiding strong undulations [12] (Courtesy of Submarine Telecom Forum)

philosophy according to Table 7.3. According to this philosophy, the shallow water cables are protected with heavy armoring against external violence, while the deep-sea cables have a lighter armoring because there is little threat from human activities down there.

Submarine power cable projects in the 1950–1980s have often followed a similar concept providing a heavier armoring for the beach section as external dangers are

Table 7.3 Types of cable armoring for submarine telecom cables [13]

Water depth	Armoring	Characteristics
< 200 m	Rock Armor (RA)	Double armor with short lay in the outer armoring layer, improved impact resistance and better flexibility to follow seafloor undulations
<500 m	Double Armor (DA)	Protected cable for areas with little or no burial depth
<1500 m	Single Armor (SA)	Used for areas with limited burial depth

expected to be more frequent in shallow waters and in the splash zone. The open sea cable was covered with a lighter protection. The principle is very easy: more massive steel wire armoring provides a better protection against fishing gear and anchors.

As submarine power cable dimensions and weight have grown considerably during the last two decades, manufacturers are less keen to provide extra heavy armoring for the beach zone. In many cases, the armoring is designed only to meet the requirements of tensional forces during laying. As most power cables are installed in shallow to moderate depths (< 300 m), the armoring can be designed rather simple. Often, this allows for a thin-wire armoring, which is not prepared to cope with external threats. Unfortunately, the protection against damages is sometimes neglected when manufactures try to submit the lowest bid. However, there are good examples as well. The Channel Island cable between France and Jersey/Guernsey was equipped with an extra-strong steel wire "rock armor" in 2000. A double-layer counter-helical armoring provides a much better protection against external violence than a single-layer armoring. In many encounters of submarine power cables with installation gear, anchors, etc., the outer wire layer was damaged but not the inner layer.

It should be considered carefully if the circumstances of the cable route (shipping lanes, fishing grounds, etc.) or the installation method may call for additional reinforcement of the cable. Often, the manufacturer can offer armoring with higher protection level as an option.

The choice of the appropriate armoring is a difficult balance between up-front capital costs and expected (better: feared) costs of future cable damages including repair and income losses. The initial costs for extra heavy armor are known but the future costs can only be projected estimates. It should be taken into account that the armoring cannot be upgraded after a few years of project experience.

Shorter parts of the cable can be equipped with additional protection by attaching plastic shells during laying of the cable (cf. Fig. 7.23). This method is often used to strengthen the protection at cable and pipeline crossings.

7.2.3 External Protection

Many submarine cables have been laid unprotected on the seafloor except for the immediate beach zone until the 1980s and 1990s. Until then, it was almost taken as inexorable fate that submarine power cables are being damaged from time to time. When appropriate subsea burial equipment became available in the 1980s, the burial protection of longer cable stretches became more common. Existing cables such as the Baltic Cable were buried afterwards to upgrade the protection level. When the Cigré study on mechanical damages to submarine cables [14] was compiled in 1986, only a small fraction of submarine power cables were externally protected. The study also accounts for the fate of the Kontiskan link between Denmark and Sweden. The first cable there was laid unprotected in 1964, designed to withstand all what was known of fishing gear at that time. Fishing gear grew heavier with time, and during the early 1970s, the cable was damaged too many times by trawls. It was

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 211 of 306



Fig. 7.23 Protective plastic shells are attached to two HVDC cables and an FO cable before the cable group leaves the vessel (Courtesy of ABB, Sweden)

decided to replace a piece of the cable by a cable with heavier armoring, and to bury the new cable piece. The new cable piece had no failures until the report was written, while the remaining unburied cable suffered another 14 failures during the same time.

Today, almost all submarine power cables have an external protection (burial or covered). This protects the cable not only against accidental damages but also against sabotage. For over 100 years, submarine cables have been the target of war-related assaults; today evil forces might try to attack unprotected submarine power supply. Having this in mind, the insurance companies would probably reward suitable protection efforts with a lower premium, or even require complete cable protection prior to issuing an insurance policy.

7.2.3.1 Trenching

The most common protection method today is trenching, i.e. the burial of the cable under the seafloor.

There is a variety of different trenching methods, and new equipment is being developed as the amount of submarine infrastructure increases.

Ploughing down submarine cables has been known and practised for many decades. A underwater cable plough has a horizontal framework that can travel over the seafloor either on four sledges, one in each corner, or on wheels, or caterpillars (Fig. 7.24). In the centreline of the frame there is a plough share reaching down into the seafloor. In contrary to an agricultural plough, the cable burying plough is not designed to turn over the soil but to cut a narrow slit with as little resistance as possible. While the ploughshare is cutting this slit the cable is guided down directly behind the ploughshare or through a hollow slot inside the ploughshare. The ploughshare must have a shape and inclination such that it is not pressed upwards



Fig. 7.24 Cable plough. The tiltable plough share to the right is now horizontal, ready for tilting down to the vertical position (Courtesy of IHC Engineering Business Ltd., UK)

over the seafloor while moving. The backward inclination of the ploughshare adds vertical forces that keep the plough in the soil [15].

Ploughs are towed after the surface vessel and can require high tow forces. In deeper water, the plough requires long heavy tow cables and the position control of the plough becomes difficult [16].

More sophisticated plough systems employ vibration or water jets to support the ploughing process. These systems require power supply from the surface. The plough depth is up to 3 m depending on the seafloor stiffness.

The ploughing has some inherent risks when the plough meets rocky soil conditions. Rocks and boulders encountering the course of the plough are sometimes able to derange the heading direction and misalign the plough with respect to the cable. This has the potential to squeeze and damage the cable. Another risk is that boulders or debris can enter the entrance bellmouth together with the cable and develop enormous side impacts on the cable.

Rocks and boulders may misalign the plough in relation to the cable that in some cases can be damaged. In soft seafloor soils (sand, silt, mud, clay) a plough can be used to open a temporary furrow into the seafloor.

Ploughing down cables is a brute force method suitable for soft to medium strong soils and shallow waters. Many ploughs are passive systems with a fairly good reliability, which makes ploughing to one of the most economic cable burial methods.

7.2.3.2 Jetting Methods

Another group of burial equipment relies on water jetting action. A sword carrying a row of water nozzles is pushed down into the seafloor (Fig. 7.25). The high-pressure

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 213 of 306



Fig. 7.25 Cable jetting device. The sword carrying water nozzles is visible to the *right*, tilted up (Courtesy of LD Travocean, France)

water flow from the nozzles fluidises the seafloor (Fig. 7.25). While the water-jetting unit is moved along the cable, the cable sinks down into the slurry. Soon after, the slurry re-solidifies. Often, there are two swords travelling on each side of the power cable. Different carrier systems are available for the water-jetting unit. The simplest carrier is a sledge that slides on the seafloor much similar to a plough. A support vessel tows the sledge. These machines often feature a combination of plough and water jetting. Submersible pumps mounted on the sledge can create a water flow of 1100 m^3/h at 5.5 bar pressure. One particular sledge carries six of these powerful pumps, plus a long row of monitoring instruments.

The water-jetting unit can also be assembled into a purpose-built ROV with own propulsion. This ROV is a large truck crawling on the seafloor on wheels or caterpillars. The vehicle carries high-power water pumps to create large water flows at high pressures, the jetting swords, wheel drives, cable tracking equipment, process monitoring sensors, and positioning systems. Other water-jetting ROV are free-flying over the seafloor. An umbilical cable connects the ROV to the surface vessel in order to provide power supply and data communication. The ROV-based water-jetting system is complex and requires auxiliary systems (power supply, crane, deck space, control cubicle, etc.).

7.2.3.3 Simultaneous or Post-Lay Burial?

Ploughs and water-jetting equipment can be used for simultaneous laying and burial of the cable, or for post-lay burial (PLB). A PLB operation can be performed at convenient occasion after the cable has been laid by the CLV. A smaller vessel can

be hired at lower day rates for the burial operation. In a PLB operation the burial equipment (plough or water-jet of any kind) moves along the cable route, guided by joystick in an on-board control room. ROV cameras provide an overview over the situation to take measures in case not only the cable but also rocks or debris are going to enter the cable entrance of the equipment, which could lead to damages on the cable. The cable is, however, at risk in the time window between laying and protection. Despite the deployment of guard vessels patrolling the cable route to chase away fishing boats, it has happened that submarine cables waiting for burial protection have been hooked.

In a simultaneous laying and burial operation, the plough or water-jetting would follow the CLV immediately. The cable can be fed into the burial equipment directly from above, which leads to a better cable guiding and reduced risk for encounters with rocks. Also, the guiding of the burial equipment on the seafloor is fairly easy. A simultaneous laying and burial operation slows down the laying operation considerably because the burial equipment is the slowest of the entire spread. This is particularly costly when a high day-rate specialized CLV must be used for the laying operation. Also, the weather window for the slow operation must be much longer than for the laying operation without simultaneous burial. Many cable installation specialists advocate the opinion that the cable should be brought into the water as quickly as possible without the retarding effect of simultaneous trenching.

The economic situation is different when the laying is performed with a less expensive laying barge. The progress of a laying barge is much slower than that of a CLV due to the time-consuming anchor handling procedures of the laying barge. Therefore, the simultaneous use of trenching gear would not have the same retarding effect as with a self-propelled CLV.

Laying barges are often used to install cables in shallow waters or tidal flats, where large CLV cannot operate. In these cases, the operation of the trenching equipment can be synchronised better with the laying equipment. The trenching gear (plough or jet) can be towed equidistantly behind the barge as she moves. Another solution would be the laying of cable during high tides when the barge can swim and the subsequent trenching at low tides when the barge lies on belly and can serve as hold point for the trenching equipment.

Another method developed for the installation of pipelines in tidal flats is the “bathtub” method [17]. A dredger prepares a wide flotation ditch for the laying vessel, which follows directly after the dredger. The laying vessel can float all the time in the ditch regardless of the tides. The laying vessel is directly followed by another floating barge, which refills the ditch. The leading dredger pumps its excavation soil by pipe to the tailing refill barge. The cable-laying vessel has always a pond of water to swim in.

7.2.3.4 Trenching Depth

There is always a discussion about the ideal trenching depth providing sufficient protection at reasonable cost. While it is obvious that a deeper trenching provides

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 215 of 306

a better cable protection, the relationship between trenching depth and protection level is not linear, though. In some cases, the protection level would not increase below a certain trenching level.

While a large burial depth can offer a better protection (up to a certain degree), it comes with some important disadvantages.

Slower process, need for heavier equipment, considerably higher costs, higher risk for equipment failure and cable damage, less efficient cable cooling, larger difficulties when the cable must be retrieved for repair, or decommissioning.

The optimum burial depth can vary considerably along the cable route depending on protection requirement and soil conditions. A mathematical model for the detailed planning of the degree of protection for cable route sections with different properties and risk patterns is suggested in [18]. The burial depth is discussed further in Chap. 8. It should be noted that the designed trenching depth not always can be achieved. Unexpected sub-bottom soil conditions can render the chosen trenching equipment insufficient.

The best protection for the cable is sub-bottom burial out of the reach of fishing gear. A burial depth of 1–1.5 m is a good protection against most of fishery threats. Trawling and fish dredging equipment do seldom reach depths exceeding 1 m. However, as sea bottoms can be volatile, a good sand cover might disappear after years or even months leaving the cable exposed and vulnerable for fishing gear aggression.

The choice of trenching depth might be influenced by the knowledge of future developments in the cable route such as planned harbour dredging, ship lane dredging, or future pipe installation.

7.2.3.5 Other Protection Methods

There are also pre-laying trenching methods using dredging or excavating. The cable trench is prepared before the laying vessel brings the cable. The necessary furrow in the seafloor can be prepared by different machinery. Cutter-suction dredgers can work in a wide range of soils from mud to soft rock [17]. They can even cut an access ditch for themselves in shallow waters or mudflats. Here, also backhoes mounted on a small barge can operate.

If the seafloor is rocky or otherwise too hard for ploughing/jetting, the cable trench can be prepared before laying by cutting wheels, cutting chains, or other mechanical disintegrators. This is costly, slow, and only suitable for limited length of the cable route (Fig . 7.26).

In many cases, none of the methods mentioned here is feasible for one of the following reasons:

- Long rocky stretches which cannot be avoided
- Crossing of the cable over other cables or pipes
- The sand layer is too thin to achieve the specified burial depth
- Beach area does not allow for access with large vessels.



Fig. 7.26 Wheel cutter for rocky seafloor. Cable trench cut into calcarite seafloor (Courtesy of LD Travocean, France)

For these cases, some other protection methods have been developed: an artificial cover protects the cable. The cover can consist of:

- Cast iron half pipes to be assembled onto the cable after laying. Mostly used in near-shore waters and applied by divers
- Concrete slabs
- Cement bags or mattresses
- Rock dumping.

Concrete slabs, cement bags, and mattresses can be applied from the sea level though for some projects purpose-built ROV have been developed to deploy mattresses over longer lengths.

Rock dumping is a technology well-known from protection of submarine pipelines of any kind and size. Purpose-built vessels carry a shipload of rocks over the laid cable and discharge the load. On some barges, the rocks are simply pushed over the side of the barge (side-dump). In a bottom-door vessel or split-barge the hold is opened underneath, and the load of rocks is falling down altogether. For the protection of cables, this method is simple and quick but wasteful. Better control and a more beautiful protection job can be achieved with discharge through a flexible fallpipe. Modern rock-dumping vessels are equipped with high-sophisticated control and monitoring instrumentation, e.g. DP systems.

A peculiar protection method was used for the 1967 SACOI HVDC cable between Italy and Corsica. After too many encounters with fishing gear, a number of heavy steel ropes were run next to the cable, resting on blocks at a certain height above the seafloor [14]. Their purpose was to prevent fishing gear from entangling with the power cable.

The strangest heard-of protection method, the alignment of scrapped busses along an Istanbul submarine power cable, could, however, not be confirmed.

7.2.4 After-Installation Protection

Even after the successful and completed installation of submarine power cables, the protection can be maintained and improved by active measures. Unfortunately, the after-installation protection measures are neglected in many submarine power cable projects.

Since the overwhelming majority of cable damages are caused by human activity, it is a good idea to keep people away from the cable. This is an information task. People must be told that there is a cable, and that it is dangerous or at least inconvenient to get in touch with it.

Beach warning signposts should be erected where applicable. Also, information on the cable position must be given to all issuers of sea charts, be it national marine agencies, fishing authorities, etc. National sea chart authorities would issue "Notices to Mariners" alerting on newly installed submarine cables. It is important to entry the submarine power cable into any sea chart and registry imaginable. The cable information should be disseminated to pipeline operators, harbour authorities, meteorological, and hydrographical agencies. Military authorities should be informed in any case even if their present operational zone does not include the cable route. London-based "International Cable Protection Committee" (www.iscpc.org) keeps cable registers mainly for the telecom cable industry but would also include submarine power cables into their charts.

The dialogue with fishermen and their organisations is crucial. Fishery authorities and fishermen's professional organisations are usually willing to help to spread information on submarine power cables. Every fisherman and mariner should know that it is a bad idea to try to recover an entangled gear or anchor from a cable by brute force. Mariners should know that it could be very dangerous to encounter a submarine power cable. The loss of at least three fishing vessels and several men of their crew has been attributed to hooking of submarine cables [19]. Every fisherman should also know that the cable owner would happily compensate him for a lost fishing gear rather than to repair a cable that has been damaged when the fisherman tried to recover that gear. It is also advisable to circulate information and education to fishing exhibitions and schools for fishermen and future mariners. In less developed areas, it can be profitable to provide local fishermen with easy-to-understand charts, free of charge, showing the position of the cable.

The Long Island Power Authority has hired local fishermen to guard their cable installation works. By this the local fishing community got aware of the cable existence.

Another way to protect the cable after laying is to monitor ship movements close to the route. The Vessel Monitoring System (VMS) specially designed for fishing vessels, or the AIS for all vessels, provide live data on ship identity and movements. By action of a marine authority or a specialized security company, the vessel can be warned upon approach to the cable corridor. Active ship movement monitoring can also be incorporated into harbour surveillance and other systems. Position and

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 218 of 306

movement data may even be used in court proceedings when cable damages are dealt with. Many useful tips for the after-laying protection of submarine cables are given in [20].

Sea and air patrol of the cable route are efficient methods to keep possible hazards out. At least at times, the Cook Straight HVDC cable and other cable routes have been guarded regularly by sea patrols. Still, this service is expensive. Instead of establishing an own patrol service, the cable operator might enrol on other existing patrol services. Possible offenders can be identified and warned prior to cable damage. In case of damage, the offender can be identified for further claiming.

7.3 Appendix: The Catenary Line

When the CLV lays cable in calm waters with constant speed over a horizontal seafloor, the cable is following a catenary line from the exit point on the laying wheel down to the touchdown (TD) point on the seafloor. Actually some more simplifications are necessary to achieve a catenary line:

1. The cable has no bending stiffness
2. The cable does not experience any drag while moving through the water
3. The cable has a uniform weight per meter.

The bending stiffness of submarine power cables can be neglected in most cases except for very shallow waters. Given the slow laying speed the drag forces exerted onto the cable may also be neglected (in contrast to telecom cables, which are paid out at much higher speed).

In the coordinate system of Fig. 7.27 the catenary line can be expressed as:

$$y = a \cosh\left(\frac{x}{a}\right) \tag{7.7}$$

where a is the catenary parameter

In Fig.7.28, the real laying situation is included in the diagram. Note that the seafloor is not at y=0 but at the vertical coordinate y=a. The angle ϕ is expressed by the derivative of Eq. 7.7:

$$\cot \varphi = \frac{\partial y}{\partial x} = \sinh\left(\frac{x}{a}\right) \tag{7.8}$$

The coordinates of the point where the cable leaves the laying wheel are x=L and y=H+a. From Eq. 7.7 follows:

$$y = H + a = a \cosh\left(\frac{L}{a}\right) \tag{7.9}$$

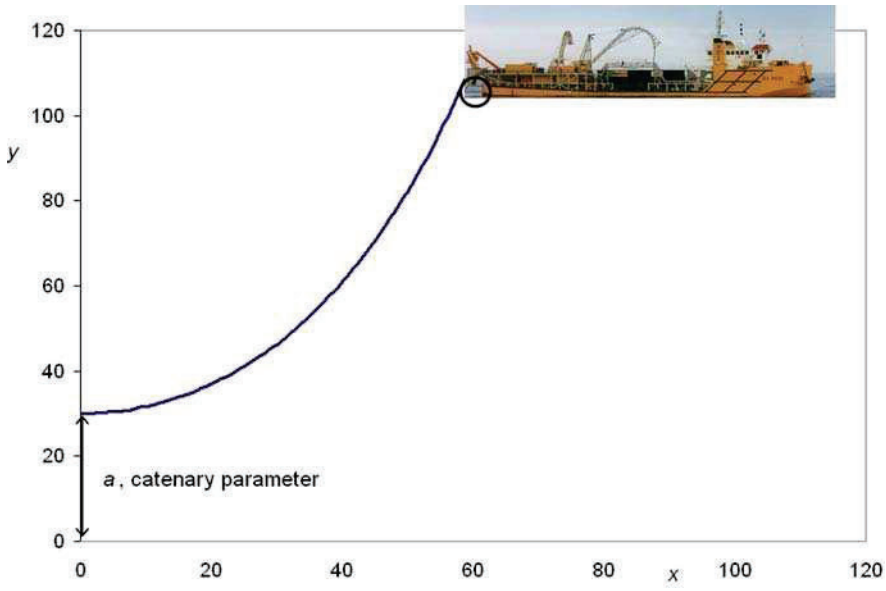


Fig. 7.27 Catenary curve of the cable under the laying vessel. Here the catenary parameter a has the value $a=30$

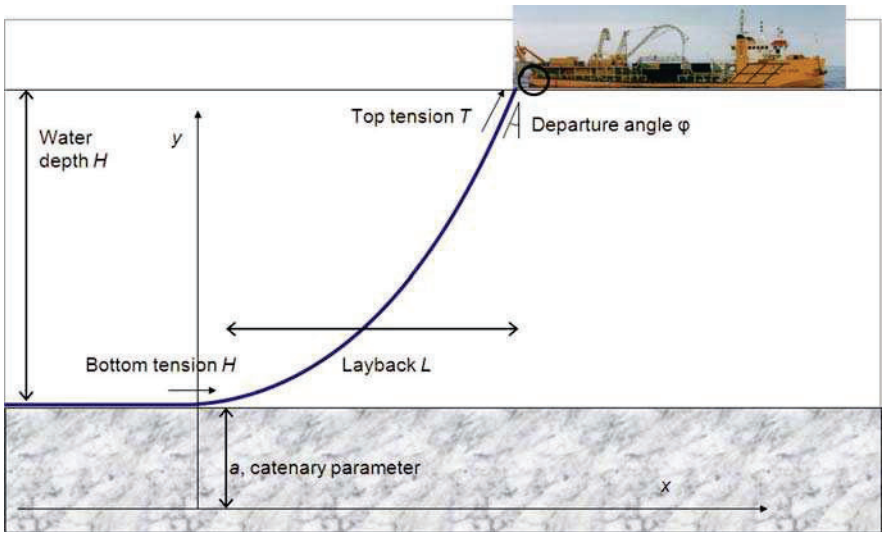


Fig. 7.28 Catenary curve of the cable under the laying vessel

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 220 of 306

The inclination of the curve at the same place is equal to the departure angle ϕ. During laying of the cable, the departure angle ϕ can be monitored and the water depth H is known. In the following we calculate all relevant entities from the known values. From Eq. 7.7 follows:

$$\cot\varphi = \sinh\left(\frac{L}{a}\right) \text{ or } \frac{L}{a} = \operatorname{arcsinh}(\cot\varphi) \tag{7.10}$$

That means that L/a can be calculated from the observed departure angle. Now, we put L/a into Eq. 7.9 and solve for a:

$$a = \frac{H}{\cosh\left(\frac{L}{a}\right) \quad - 1} \tag{7.11}$$

Now, the catenary parameter a is calculated, and we can continue calculating the other important entities.

$$T_0 = w \cdot a$$

where T_0 is the bottom tension and w the cable weight per metre in water. The layback L can be calculated from Eq. 7.10. The total length s of the suspended cable (from wheel to touchdown) is:

$$s = a \sinh\frac{L}{a} \tag{7.12}$$

The important top tension T is:

$$T = \sqrt{T_0^2 + w^2 s^2} \tag{7.13}$$

Finally the bending radius at touchdown is:

$$R_o = a \cosh^2\frac{L}{a}. \tag{7.14}$$

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Chapter 8
Damages and Repair

Contents

8.1 Damages 211
8.1.1 Causes of Damages 212
8.1.2 Statistic Distribution of Damages 213
8.1.3 Damage by Fishing Equipment 213
8.1.4 Damage by Anchors 215
8.1.5 Damage During the Installation 218
8.1.6 Other Damage 219
8.1.7 Spontaneous Damage 220
8.1.8 Failures of Joints 221
8.2 Repair 222
8.2.1 Spare Cable 222
8.2.2 Repair Vessel 223
8.2.3 Repair Crew 223
8.2.4 Repair Operation 224
8.3 Fault Location 225
8.3.1 TDR 225
8.3.2 Bridge Measurements 228
8.3.3 Fine Localisation 229
8.3.4 Optical Time Domain Reflectrometry 230
8.3.5 Other Methods 231
8.4 Repair Example 232
References 235

8.1 Damages

Submarine cables have been stricken with damage and failures since the early days. Although one may think that submarine cables, in their depth, are hardly accessible for human activities, experience from 150 years of submarine cable history has shown that most cable breaks are caused by humans. It started when a French

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fisherman caught the first Dover-Calais submarine telegraph cable in 1850, only days after its installation. According to some accounts, he believed it was a delicious new sort of seaweed; according to others, he took the conductor for gold.

The reader of this chapter should not conclude that the installation and operation of submarine power cables is an unpredictable gambling with unavoidable incidents beyond control. In contrary, a thorough analysis of the installation and operation conditions gives the preconditions to

(a) take measures to reduce the operational risk substantially
(b) arrive at a correct perception of the character of the remaining risks
(c) enjoy a high availability of the submarine cable system.

During the history of submarine cables, strategies were developed to protect submarine cables from damages. Today, submarine power cables belong to the most reliable components of electric power systems. Still, utilities need to be prepared for the unlikely case of a submarine power cable failure. Unfortunately they cannot just go there and replace the faulty piece of cable. Or can they?

8.1.1 Causes of Damages

Fishing gear and anchor damages are accused for most of submarine cable failures, both for telecom cables and power cables. Figure 8.1 shows the cause of damages to telecom cables in the Atlantic [1].

The distribution of damage causes can change considerably in different waters, and for different cable types. Cables in shallow coastal waters have a higher risk of damages by fishing gear than cables in harbour areas. Power cables will not be affected by fish bite as much as slim telecom cables. However, Fig. 8.1 can illustrate the variety of damage causes. Beside the causes given in the figure, others have

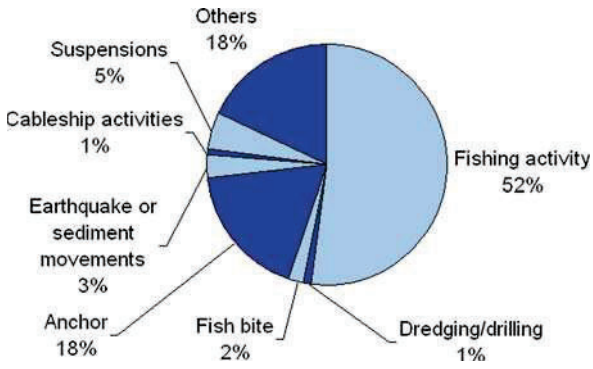


Fig. 8.1 Cause of damages to telecom cables in the Atlantic

been reported, including cable damage by dynamite fishing off the Philippines and elsewhere. In the following, some hazards to submarine power cables are discussed.

8.1.2 Statistic Distribution of Damages

The statistical assessment of submarine cable damages is of great interest for cable designers as well as forcable operators and insurance companies. Cable link availability and the risk of repair costs are critically depending on the expected frequency of cable damages along the specific submarine cable route. Knowing the largest hazard for the submarine cable, the design engineer can optimise the design of the cable armouring and an appropriate protection of the cable. Using the expertise of the cable manufacturer and the installation company, the cable operator can balance the costs for different levels of armouring and protection against the economic risk of cable damage. The repair of submarine cable fault is costly, and often takes considerable time because repair vessels are not always available, and weather conditions may impede repair attempts for weeks or months. The possible loss of income is another reason for a better cable protection.

Comprehensive studies on statistics of submarine cable damages are available from the telecom cable industry as they install vast amounts of submarine telecom cables. Only between 1997 and 2001, 350,000 km of submarine telecom cables have been installed [2]. The annual failure rate of submarine telecom cable networks can vary considerably between years [3].

It is not quite clear if this variation also applies to submarine power cables that tend to have a larger diameter and greater strength than telecom cables, and hence are less vulnerable to minor aggression. But as fishing industries employ larger units, and ship anchors grow larger, even the biggest submarine power cable may be at risk.

The Cigré study on submarine power cable damages published in 1986 [4] does unfortunately not specify the type of external violence that caused the investigated cable failures. The most important factor, altering a bad failure statistics into a good one, is the improvement of the cable protection.

8.1.3 Damage by Fishing Equipment

To understand the risks of damages to submarine cables some words should be mentioned about the most common fishing techniques, which may affect submarine cables.

The speed of Otter trawling (Fig. 8.2) is about two up to four knots. The trawl doors (= otter boards) are large flat pieces of steel, designed to keep the net open horizontally, while it is towed over the seafloor by the trawler. The trawl doors slide over and below the seabed in order to keep the net down, and thus cut – in soft grounds up to 30–40 cm deep – into the seabed. The weight of the trawl doors can be

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 225 of 306

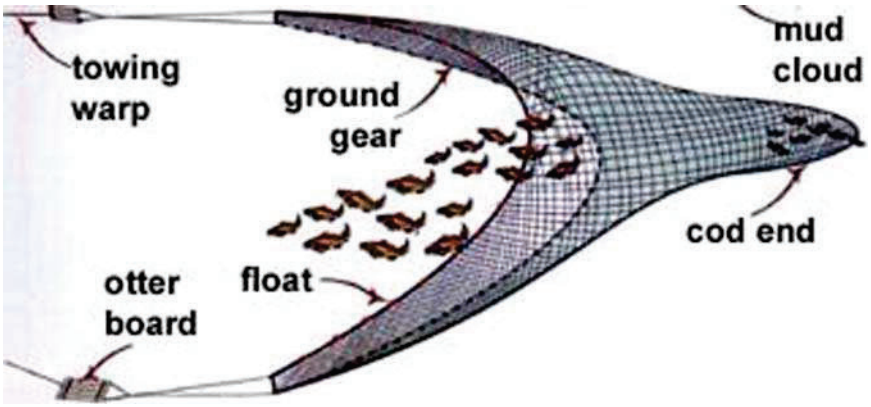


Fig. 8.2 Otter trawl net configuration
Source: Wikipedia/public domain

up to 3.5 MT. Some trawlers tow two or three nets at the same time. Under unusual conditions (break of the connection bridle between trawl door and net, or badly rigged set-up) the door can cut down into the seafloor much deeper than normal.

Beam trawling involves a horizontal beam to keep the net open, rather than trawl doors. The beam heads also can entangle with cables. Beam trawls caused over 100 telecom able faults in the North Sea between the mid-1960s to mid 1970s [5].

The force impact on a cable when hit horizontally by a 1900 kg trawl door at a trawler speed of 2.9 kn, has been estimated to 11 t [5]. Other components of the trawling gear, such as bridles, shackles, and rockhopper discs also have the potential to fault the cable. However, the largest hazard for the cable comes up when the trawler crew tries to recover the entangled fishing gear. Modern large trawler can develop high winch and bollard pull forces which can destroy almost every hooked submarine power cable.

Dredge fishing is designed to stir up the bottom sediment in order to harvest shellfish. The search for clams, scallops, and crabs may involve dredging equipment going 450 mm deep into the seabed. Even here, unusual conditions (such as rocks ahead) can push the dredging equipment deeper into the sediment.

Under normal conditions neither trawling nor dredge fishing is expected to disturb the seabed more than 0.5 m in depth. For a submarine cable, that is buried deeper than 1 m into the seabed, the risk of interference is low. However, the bathymetry is not always stable. The seabed can move with time and expose the cable for external threats.

Another fishing method, bottom set fixed fishing, uses stationary nets to catch fish in the move, driven by either fish migration or fish in streaming waters, e.g. in tidal currents. The nets are fixed to the sea bottom by anchors or weights. With stow net fishing, a method often used in Korean and Japanese waters, anchors up to 1.5 t are used to keep both the net and the attending vessel at station. These anchors can penetrate a sandy sea bottom down to –1.5 m, or a soft sea bottom down to

–2.7 m [3]. The nets are positioned in places where the tidal currents are strong in order to catch large fish swarms. If the anchors hook into the submarine cable, the strong tidal current can subject the cable to considerable forces. Tired of many cable damages from fishing activities in the Japanese Seto Inland Sea, the local power utility Chugoku Electric Power Co. installed a new heavily armed 66 kV submarine cable in 1992. When it was hooked later, the outer armouring suffered some damage, but, after testing, the cable was considered fit for further operation [6].

Fishing is a billion-Dollar industry and makes a living for many millions of fishermen all around the world, who would just not easily accept being told: Please don't fish close to my cable! Methods to protect submarine power cables from fishing gear damages are described in Chap. 7.

8.1.4 Damage by Anchors

According to Fig. 8.1, anchor damages account for the second largest single cause of submarine cable damages. Given the larger diameter and strength of submarine power cables in contrast to the telecom cables that Fig. 8.1 was compiled for, the anchor damages most probably are at level with fishing gear damages or even exceed them.

At first sight, it seems incomprehensible that a commercial vessel is able to drop anchor onto a cable that is depicted in sea charts. Any commercial vessel should be equipped with the latest charts and avoid cable areas when mooring. However, reality is different.

A large category of anchor damages is caused by mishaps. Anchors are being dropped involuntarily. Reasons can be badly secured anchors, which go down unintended. Master and/or crew affected by alcohol or other drugs might be responsible for anchor dropping. Reportedly, vessels have sailed along with their anchors dragging behind.

Another category of anchor aggression stems from emergency anchoring. Ships, large or small, can loose control of manoeuvrability by electric power black-out, engine malfunction, drop of rudder function, leakage, or for other reasons. Then the ship Master or Commander-on-Duty can drop anchor to save life or ship. Saving life has the highest priority under any circumstances. On other occasions, anchors have been dropped into cables because the harbour tugs were on strike and the vessel had to stop somehow. Ironically, anchors from cable laying barges have cut into cables being laid by the same barge only a little earlier. Drop of anchor has happened, and will happen, everywhere where ships manoeuvre: in harbour basins, in ship lanes, or in open seas (Fig. 8.3).

A number of different anchor types are being used with weights up to 30 t for the largest ships. The anchors of "Queen Mary 2" weigh 23 t. Different anchor shapes have different efficiency and behave different in their contact to the sea bottom.

The risk of anchor damages of a given cable in a given cable route can only be assessed with statistical methods. The assessment starts with the analysis of ship traffic in the investigated cable area. National shipping authorities often can provide

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 227 of 306



Fig. 8.3 Anchor damages on the 120 mm Baltic Cable (Courftesy of Baltic Cable AB, Sweden) [7]

statistics on the number of vessel crossings over the investigated cable route, and the size distribution of the ships. The next step would be to determine the anchor size distribution. From the compilation of a large number of ships and their anchor weight, Luger [8] proposed the following empirical relation between anchor size and ship dead-weight:

$$y = 7e-3 \cdot x^3 - 6e-7 \cdot x^2 + 0.1635 \cdot x + 2162.2 \tag{8.1}$$

where x is the ship's dead-weight in metric tons and y is the anchor mass in kg.

Using this relation, one can establish an anchor size distribution from the ship size distribution in the cable route. Figure 8.4 shows the expected accumulated anchor size distribution, calculated for the Kadetrenden strait between Denmark and Germany [7]:

It appears that about 98% of anchors are at 8000 kg or below, and more than 60% are below 4000 kg. The ability to damage a buried submarine cable increases with anchor weight by three reasons: A large mass has a larger damage capability at direct hits. A heavier anchor can penetrate the sea bottom deeper than a lightweight anchor. Finally, a heavy anchor belongs to a heavier vessel which can drag and damage with greater force than a smaller ship with a smaller anchor. Not all anchors are equally dangerous. In sand or clay, anchors usually can dig down only as much as a fluke length; while in soft mud, they can go down 3–5 fluke lengths (Table 8.2).

Another source [9] quotes relationships between ship size, anchor weight, and penetration depth for Japanese waters. Unfortunately, the authors do not specify which ship tonnage unit is meant. The anchor weights from Table 8.1 and Eq. 8.1

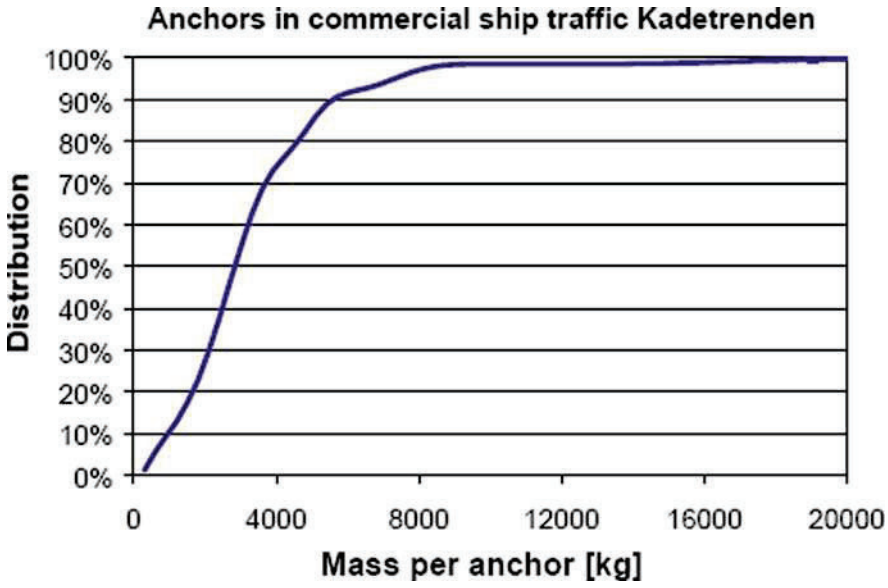


Fig. 8.4 Accumulated frequency of anchor size in the Kadetrenden strait

Table 8.1 Relationship between ship size, anchor weight and penetration depth according to [9]

Ship weight (tons)	Anchor weight (tons)	Penetration depth in mud	Penetration depth in sand
1000	1.0	~ 1.0 m	~ 0.5 m
5000	2.8	~ 2.0 m	~ 1.0 m
15,000	4.6	~ 3.0 m	~ 1.5 m
50,000	8.2	~ 4.0 m	~ 2.0 m
100,000	12.4	~ 5.0 m	~ 2.5 m

Table 8.2 Relationship between ship size and penetration depth in firm ground (sand/clay) according to [3]

	Anchor type	
Ship weight (Gross tonnes)	Danforth/Moorfast penetration depth	Stockless/AC 14 penetration depth
2000	~ 1.5 m	~ 1.2 m
4000	~ 1.7 m	~ 1.35 m
70,000	~ 1.9 m	~ 1.45 m
100,000	~ 2.1 m	~ 1.5 m
130,000	~ 2.2 m	~ 1.5 m

correlate quite well, but underestimate the real anchor weight of “Queen Elizabeth II” by a factor of three.

Using some further probability figures, Christensen summarizes his results in Fig. 8.5:

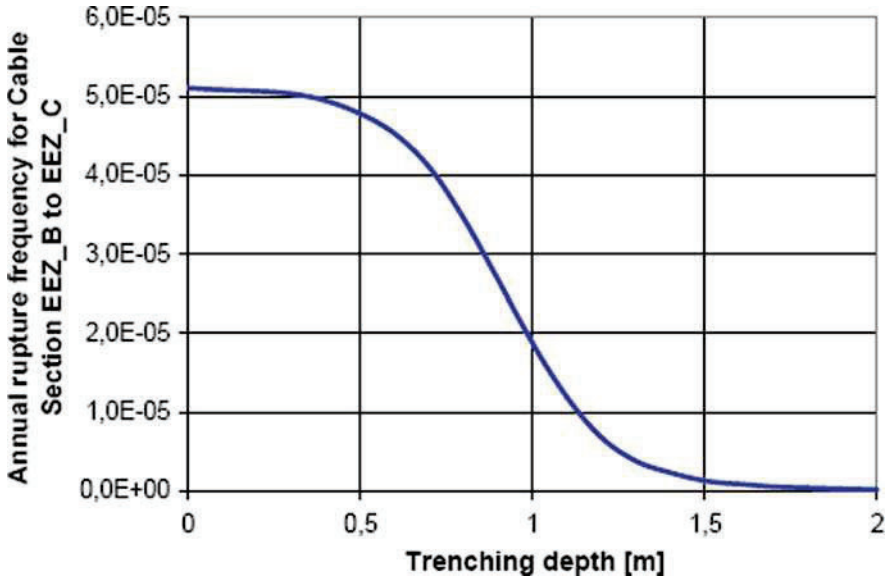


Fig. 8.5 Annual rupture frequency for a submarine cable in the Kadetrenden [7]

It becomes clear that a burial depth of 1.5–2 m is a very good measure to avoid anchor damages in these particular waters. A similar curve can be expected for most shipping areas. Similar risk assessments for other cable routes should be performed, based on the local traffic pattern and density.

8.1.5 Damage During the Installation

While many failure statistics account for failures during operation, they usually do not include damage to the cable that happens before commissioning. Cable damages during the installation might call for expensive and time-consuming repair operations.

Experience has shown that almost anything imaginable and unimaginable can happen during installation. The following lists some incidents known from various submarine power cable installations. The list aims by no means at scaring cable owners but at helping them to prevent some sources of trouble.

Loss of DP. The CLV is may be unable to keep position due to storm, waves or currents. The uncontrolled vessel movements can introduce inappropriate strain, bending, or choking of the cable. A case where the laying barge moved backwards unintendedly introducing backwards overbending into the already laid cable, belongs to this category.

Anchoring damages. It so happened that the anchors used for the mooring of cable laying barges damaged cables that have been laid in previous runs.

Kinks. Insufficient coordination of CVL forward motion and cable pay-out may cause kinking of the cable at the seafloor or over the seafloor. In the best case, the cable can remain as it is laid and only the subsequent protection by plough or jetting is rendered impossible.

Loading/re-loading. Cables can be damaged during loading onto the cable vessel, or during transfer between a transport vessel and the cable laying vessel.

Protection. Inappropriate trenching equipment or methods are able to damage the cable by squeezing, deformation or overbending.

Emergency cut. Extreme situations may emerge during laying/jointing that call for immediate emergency cutting of the cable on-board the CLV in order to avert situations dangerous for crew or vessel. An emergency cable cut usually necessitates time-consuming repair operations.

8.1.6 Other Damage

Anchors and fishing activities account for the largest portion of submarine cable damages. A minor share is caused by other factors, this portion being smaller for submarine power cables since they are stronger than telecom cables.

Many damages are induced in cables installed with free spans. Sometimes difficult submarine areas with rocky areas and large outcrops cannot be avoided. Even with the most suitable installation and protection methods being used, the cable may end up hanging in free spans over submarine obstacles. This situation combined with water currents can easily lead to oscillations induced by vortices, a phenomenon known as vortex-induced vibrations (VIV), or, somewhat misleading, "vortex shedding". The oscillations can cause strong chafing at the contact points of the cable to fixed ground, and premature fatigue of the lead sheath. The water currents that may cause harmful oscillations might stem from [10]:

- atmospheric pressure gradients, storms
- tidal currents
- circulation currents (e.g. Gulf Stream and spin-offs of the large marine current systems)
- longshore currents – run in parallel to the coast line and are driven by diffracted waves.

Currents up to 7 kn in cable routes have been measured, e.g. in the Öresund strait between Denmark and Sweden [11]. The first cable system laid between the North and South New Zealand islands was damaged several times in free spans where the cable was suspended between outcrops. A more detailed description of vortex-induced vibrations is given in Chap. 3. The advice "do not install cables in free spans" is given in many accounts on submarine cable projects.

Not only anchors, but also direct hits by ships have damaged submarine cables. The ferryboat "Nils Holgersson" ran aground outside Travemünde / Germany due to a loss of power on March 16th, 2002. The 450 kV HVDC "Baltic Cable" was

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 231 of 306

damaged by the keel and the power link was interrupted. When the freighter "Roy A. Jodrey" sank with 20,000 t of iron ore under the eyes of the Coast Guard in the St. Lawrence River, she cut off the submarine power cable supplying the Coast Guard station, leaving them in the dark [12].

Oceans and peripheral seas are subject to geo-hazards implying potentially damaging phenomena such as landslides, volcanic activities, gas hydrate destabilisation, etc. Movements of the sea bottom due to submarine landslides or earthquakes can destroy submarine cables by direct impact or by land slide induced turbidity currents (Suva 1953 [13], Taiwan 2006). Volcano activities destroyed submarine power cables at the Heimaey eruption (Island, 1973) and elsewhere. Landslides and other movements of the seafloor can even be caused by annual formation/deformation of gashydrates, a material that can exist only in certain waters under certain pressure and temperature conditions below approx 200 m [14]. Gashydrates have the potential to change structure and mechanical strength during the seasons and over the years. Their change may impose a hazard to subsea installations.

Shark bite has caused frequent outages on early submarine telecom cables in the Canary Island region but is not believed to be a serious problem to armored submarine power cables today.[1]

A charting of the estuary of the river of Thames shows a large number of shipwrecks, many of them from famous sea battles of the past centuries. Some of the wrecks are painted red in the chart, indicating that they are carrying unexploded ammunition. This is not a good place for submarine cables.

8.1.7 Spontaneous Damage

Electric insulation systems have a limited lifetime. A number of ageing phenomena affect the insulation where temperature and electric stress are the dominant factors. Different ageing mechanisms are discussed in references [11, 13] of Chap. 2. Spontaneous damage, or internal failure, occurs extremely rarely in submarine power cables. The typical lifetime for cable insulation ranges from a few years (cables manufactured or installed with inappropriate methods) up to well over 50 years for some paper-insulated cables.

The proper function of the insulation is sometimes obstructed by other causes than ageing. Fatigue cracks in the lead sheath can result in loss of oil or ingression of water. A pressure drop in the oil-feeding station ashore easily detects larger oil losses in oil-filled cables. Small leaks can exist over weeks before the oil loss is noticed. Water intruding into the insulation deteriorates the insulation properties and will eventually cause a breakdown. The hydrophobic properties of impregnating oils/compounds in paper-insulated cables delay the propagation of the water

[1] The lethal encounter of a Great White with a submarine power cable in the movie *Jaws II* was not voluntary, nor realistic.

considerably. Laboratory tests with mass-impregnated d.c. cables have demonstrated that it can take weeks or even months from the first ingress of water until the breakdown finally occurs. However, the insulation of low and medium-voltage submarine cables can be made tolerant against intruding water because of the low electric field and purpose-made insulation resins.

Another failure mechanism observed in older mass-impregnated cables is caused by the depletion of the impregnation compound in elevated parts of the cable, e.g. on the top of a ridge. Under unfavourable conditions, the compound is suspected to migrate "downhill" leaving unfilled insulation behind. However, to the knowledge of the author, no such case has been reported within the last 10 years. Mass-impregnated cables are not suitable for vertical installation, and manufacturers have different opinions on the maximum allowed inclination angle for their mass-impregnated cables.

In most HVDC cables, the lead sheath is electrically connected to the armouring in regular distances, the connections being made through the plastic sheath over the lead sheath. At least in some cases, faulty designed ground connections are suspected to have caused internal sparks in the sheath area eroding the lead sheath and leading to breakdown.

The new Cigré investigation (2009) on service experience with submarine cable systems embraces 7000 reported circuit kilometres of submarine power cable [15]. Of 49 faults reported in total for the time span 1990–2005, only four faults were identified as "internal", i.e. spontaneous faults. Three of these faults struck the same cable installation.

8.1.8 Failures of Joints

According to the 1986 Cigré study, a noticeable part of the damages were located in submarine or beach joints. Unfortunately the study does not specify the exact failure causes. Three major fault causes for submarine cable joints are known:

- inadequate design
- poor joint assembly work on-board
- adverse weather condition during assembly.

Many of the cables evaluated in the study were oil-filled cables. The joints of these cables are more complicated and demanding than joints of solid-type cables (XLPE or mass-impregnated). The first Cook Strait cable suffered a number of failures in transition joints between different conductor sizes, so that the new Cook Strait cable was specified to have only one conductor size. In the past decade submarine cable accessories have become much more reliable because of better understanding of mechanical stresses, better design, and more sophisticated installation practice. The 2009 Cigré study [15] reports only four joint failures out of 49 failures in total in 7000 km submarine cable.

8.2 Repair

The repair of submarine cables is one of the most demanding tasks of submarine cable engineering. Not only must the fault be found and identified in water depths often inaccessible to divers, also the damaged cable must be made accessible for repair. Attempts were made to repair damaged cables on the seafloor. Leaking lead sheaths in the 138 kV Long Island cable system were repaired using external sealing cassettes, which were attached to the cable by divers [16]. Another submarine repair attempt was made using submersible workshops to repair oil-leakage from submarine power cables [17]. Also, for the IFA 2000 HVDC link between France and UK, repair methods based on manned submarine vehicles were devised [18]. Neither method had been pursued further.[2] In general, the damaged cable must be brought to the surface safely. Once it is onboard of the repair vessel, the cable must be cut back to undamaged fresh cable and jointed on a possibly rolling and pitching repair deck when the heavy cable hanging over board may expose the equipment to too strong a tension. Adverse conditions have forced some repair operations to terminate in emergency.

Submarine cable repair requires good preparation. “Red alert” plans should be available for each cable link including repair method descriptions, service/maintenance contracts, vessel and crew availability plans, etc.

8.2.1 Spare Cable

Almost every repair job requires that the cable would be lifted on board the repair vessel. In most cases, the cable lays on the sea floor on a straight line and must be cut before lifting the ends. For the repair, a spare cable must be jointed between the two recovered cable ends. The length of the spare cable must at least cover the double water depth, an additional length to establish the catenary lines for the cable, plus the amount needed on board of the vessel in the cable gantries, plus the length cut away during jointing, plus safety margins. Before jointing, the ends of the damaged cable would be checked for further damages and/or water ingression, which might require additional cut-back of the cable. If the jointing has to be re-done for any reason, further length of spare cable is required. The experienced repair operation manager will bring a long spare cable to the repair site rather than finding himself short of spare cable before the final joint is finished.

Few submarine power cables are standard products that can be procured within a week’s time. Producing new spare cable takes months, at unit costs much higher than the original production. Therefore, the most cable operators/owners have a stock of spare cable, which has been produced together with the original submarine cable.

[2]The following question has been passed on in this context: Is it easier to train a diver to be a jointer, or to train a jointer to be a diver?

Should the cable operator wish to increase his stock of spare cable he sometimes can place an order at the supplier to be produced as "hang-on" to another cable manufacturing order. Spare cables are usually stored in quay warehouses for easy loading to repair vessels. Spare cables for submarine power cables can even be stored on the seafloor at suitable locations.

8.2.2 Repair Vessel

The repair vessel may differ very much from the laying vessel, as there are different needs for load capacity and deck arrangements. A load capacity of a few hundred tons can be enough to carry the spare cable and all handling equipment. Also, the requirements for a repair joint and an installation joint are different even if the joints per se are equal.

The repair vessel has preferentially a large open deck with sufficient space for the jointing house, cable engines, winches, cranes, etc. It is quite common to mobilise a supply vessel or barge with the appropriate equipment for the job. A turntable or cable hold for the spare cable must be installed on the vessel as well as chutes to deploy the cable and joint over board. For more complicated repair operations, an ROV might be necessary. Other specialised vessels before the repair operation usually perform the de-burial of damaged cables.

For the insertion of a piece of spare cable into a broken cable, two different types of deployments are needed. The first joint would be made between one recovered cable end and the spare cable on-board. The joint and spare cable can then be paid out over the chute. The final joint between the other recovered cable end and the spare cable creates a loop of cable on-board that must be deployed in a different arrangement. A possible repair vessel lay-out is shown in the example at the end of this chapter.

As it is the case for the CLV, the repair vessel needs suitable DP and other navigational equipment depending on the character of the task. Repairing a 600 MW HVDC cable 100 km out in the raving sea requires a different set-up than the repair of an 11 kV cable in a calm bay of a subtropical archipelago.

8.2.3 Repair Crew

Apart from the nautical crew of the repair vessel, also a specialist team of cable jointers is necessary. While there are many companies providing cable repair for land cables, there is only a limited number of teams skilled in the art of submarine cable repair. Most reputable submarine cable manufacturers have their own trained jointer teams. Given the large day rates of repair vessels, it is advisable to hire a sufficient number of jointer teams to get the work done on a 3-shift basis.

Many vessel operators require that jointer crews produce medical certificates and/or certificates on relevant safety and survival training before embarking.

8.2.4 Repair Operation

There is no standard cable repair operation for submarine power cables. Sad exemptions from this rule are those few cables that are affected by similar faults over and over again. However, there is a generic sequence of activities that can serve as a basis to design a specific repair task.

The generic repair sequence is the following:

- cut the cable at the fault site
- take up one cable end and joint it to the spare cable carried on-board
- lay spare cable and proceed to the location of the other cable end
- bring up the other cable end and joint it to the spare cable
- put everything back down to the seafloor.

A possible repair operation is described in a section at the end of this chapter.

Upon occurrence of a cable fault, a number of activities would start. As losses of income may be high for each day, it is an all-out effort:

- Fault location. The position of the cable fault can have strong influence on the required repair spread. The coarse location can be performed from shore sites with sufficient accuracy to plan the repair job. Faults in the splash zone, in shallow waters or in deep waters would require different repair equipment. Fine location requires the use of a search ship.
- Securing of repair vessel contract.
- Planning of repair operation. Repair methods are depending on water depth, weather and current conditions, cable dimension, joint design, and much more. The planning will result in the identification of necessary equipment and vessel modification.
- Mobilisation of repair vessel and equipment. Often the vessel needs to be modified with extra cable handling equipment, chutes, roller guides, etc.
- De-burial of the faulty cable portion
- Loading of spare cable and jointing kit
- Jointer crew embarks.

After all this, the repair vessel is ready to go. It is presumed that the cable jointing per se has been engineered and trained before the fault occurred. Experienced installation engineers will have prepared detailed repair plans including HAZOP (Hazard and Operability) studies. Daily meetings during the repair operation summarize achieved progress and coordinate next activities.

The duration of the repair operation depends critically on the availability of a repair vessel with suitable equipment, and the time needed to bring spare cable to the site. Small cables in calm waters can be repaired within a week or two, available spare cable provided. Large cables require heavier equipment and access to specialized vessels. If spare cable is available the downtime of the system can be between a few weeks and four months. Procurement of new spare cable can delay the repair

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 236 of 306

operation by many months. In the 2009 Cigré study on submarine cable experience 19 of 49 reported faults could be repaired within one month [15].

Also, the weather conditions have a strong influence on the cable repair. Adverse weather conditions prohibit repair operations even with the largest repair vessels. Storm seasons can make it difficult to find suitable weather windows that hold up long enough.

8.3 Fault Location

A number of methods for fault location are available, each having its own possibilities and limitations. Depending on the characteristics of the fault and the design and configuration of the cable, the methods will have different prospects to successfully localize the fault. In case of a submarine cable fault, the cable operator often mobilises different methods simultaneously in order not to lose time, should some of the methods fail to identify the fault location.

Although there is a wide range of commercial fault-location equipment with ever more simplified user guidance available, the need for experienced engineers for the task must not be underestimated. The cable operator can make a prudent investment by sending some of his engineers to fault-location training courses.

Most often, a cable failure is being noticed by a voltage breakdown. This indicates a breakdown of the cable insulation and renders the cable inoperable. The damages range from a high-ohmic fault to a low-ohmic insulation damage or possibly a complete rupture of the cable.

In two- or three-core cables, the first step would be identifying the faulty cable core by a simple insulation test.

8.3.1 TDR

The acronym TDR stands for “Time domain reflectometry” and is based on an electric impulse, which is sent into the faulty cable conductor. The easiest fault to detect is a complete cable break. The impulse travels down the conductor until it reaches the cable break. Here, most of the impulse energy is drained into the water, but a fraction is reflected with opposite polarity. The reflected impulse is travelling back to the shore cable termination, where the instrument records the impulse and shows it on a graphic display. Knowing the impulse propagation velocity, one can calculate the distance to the fault by measuring the travel time. Figure 8.6 shows a typical trace from a TDR measurement. The impulse propagation velocity v can be calculated as follows:

$$v = \frac{1}{\sqrt{\varepsilon_0 \varepsilon_r \cdot \mu_0 \mu_r}} \tag{8.2}$$

with the symbols according to standard conventions. For mass-impregnated cables with $\mu_r = 1$ and $\varepsilon_r = 4$, the resulting propagation velocity v is 150 m/μs, that

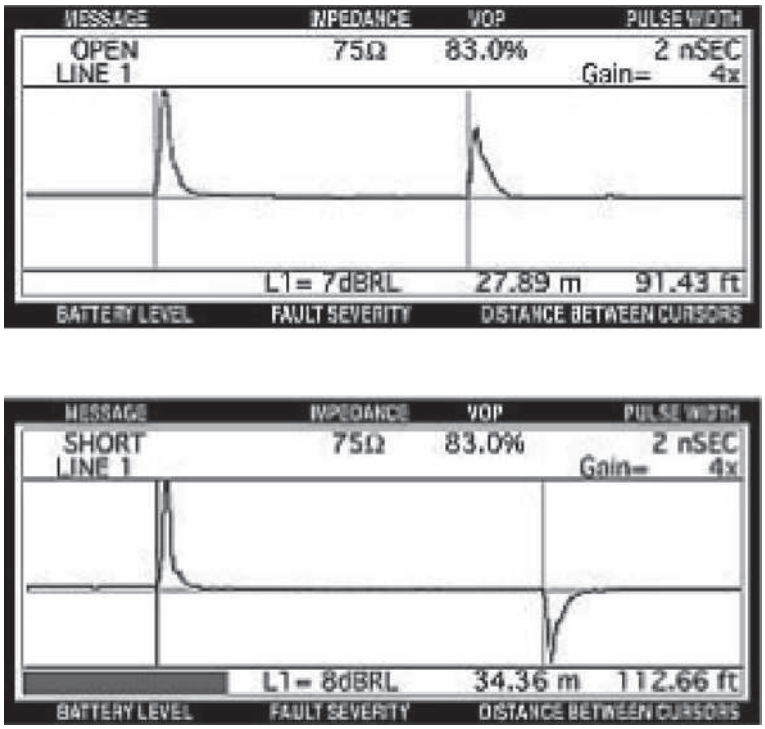


Fig. 8.6 TDR reflections. Upper diagram: a reflection with the same polarity indicates a fault with OPEN (high impedance) tendencies. The reflection shown at the 2nd cursor is a COMPLETE OPEN. Lower diagram: a reflection with the opposite polarity indicates a fault with SHORT (low impedance) tendencies. The reflection shown at the 2nd cursor is a DEAD SHORT [19]

is half the speed of light. This value is independent of the dimensions of the actual cable. For one recently produced delivery length of mass-impregnated cable, a value of 141.26 m/μs has been measured, reflecting a $\varepsilon_r = 3.9$ rather than 4.0. Confusingly enough, in some publications and pamphlets, the value v/2 is specified as wave velocity because it is more convenient for the fault-locating engineer to multiply $v/2$ directly with the total travel time (forth and back) to find the fault distance.

As the real propagation speed of an impulse in a cable can be different from the theoretical speed according to Eq. 8.2, it can be prudent to determine the true velocity in the actual cable. This can be done directly after laying, by sending an impulse into the cable conductor and recording the reflection from the far-end cable termination if the far end is in the reach of TDR measurements. When the exact cable length is known, the propagation velocity can be calculated from the travel time. Also, v can be determined by using TDR on an identical, healthy cable core with known length. Test engineers have reported that the propagation speed is different before and after installation. This has been attributed to different temperatures but the constants in Eq. 8.2 normally are not or very little temperature dependent. The

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 238 of 306

difference in propagation speed has also been explained by the fact that the cable is reeled before installation and straight after installation.

Usually, rectangular impulses are sent out into the cable. The pulse length and the steepness of the pulse front are important for the spatial resolution, i.e. the accuracy of the location. An impulse with 10 ns pulse length at a propagation velocity of $v = 150$ m/µs can resolve distances down to $\Delta x = 1.5$ m. The impulse shape and impulse length is changing during the travel through the cable. This phenomenon is known as dispersion and is caused by wavelength-depending propagation speed of impulses. As a result, the rectangular impulse shape with a steep front, which has been sent into the cable, turns into a broader impulse with soft edges. The spatial resolution ability of this dispersed impulse is reduced. For this reason, distant cable faults can be located with lower accuracy than near faults. A longer impulse length from the TDR instrument brings more energy into the cable with better chance to record long-distance faults, at the expense of spatial resolution.

TDR actually measures impedance changes along the cable. These can also be generated by joints and defects.

TDR equipment is available in a large variety. Hand-held or desktop instruments with an impulse amplitude of a few volts are available. Other systems include impulse generators with some kilovolts of impulse voltage.

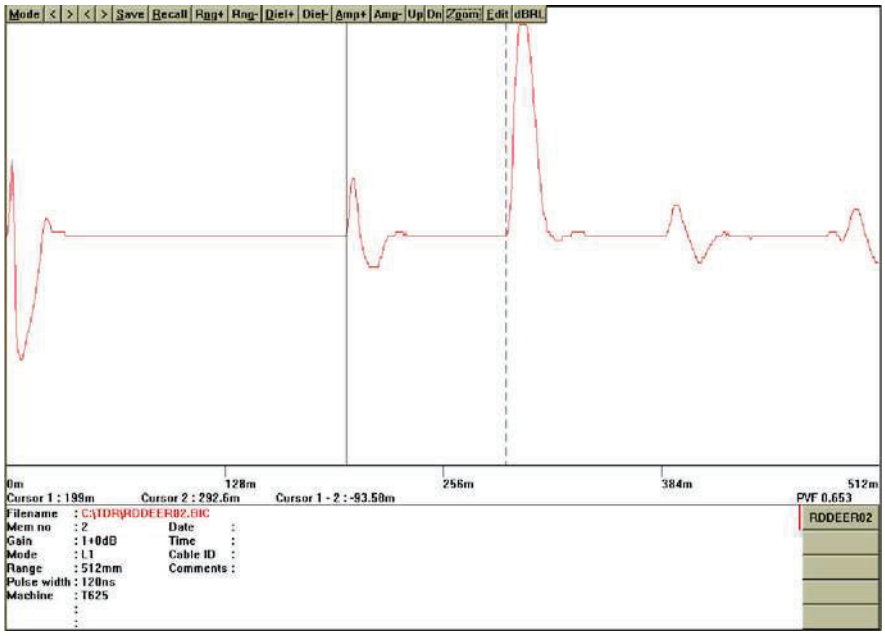


Fig. 8.7 Analysis of a land cable TDR waveform [19]: Perfect trace, cable features are easily visible. The cable is disconnected at the next substation at 292 m (*dashed cursor*). This allows calibrating distances. *Solid cursor* is at joint at 199 m (93.5 m back). Features on the *right side* of the open cable end are the same reflections just bouncing back and forth (distances are all multiples)

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 239 of 306

TDR performs best on clear cable breaks and low-ohmic short circuits between conductor and earth. High-ohmic faults are more difficult to detect. These faults can be burnt down with special “thumpers”, which send high-energetic pulses into the cable. The impulses discharge through the fault, increase the devastation and decrease the fault resistance for better fault detection. The possible fault detection distance is depending on the cable design and instrument characteristics. Sharp events like the far end of the cable can be detected over hundreds of kilometres.

The example in Fig. 8.7 is taken from a land cable TDR measurement to illustrate some TDR features. Submarine cable measurements, especially on long length, are more obscured. Multiple reflexions can occur as well as ghost features of unknown origin.

8.3.2 Bridge Measurements

Another useful fault location principle is based on resistance measurements in the conductor from one cable end to the fault. Using variations of resistance bridges, many different bridge measurement schemes are known since the 1880s [20]. A bridge measurement can be done if there is a healthy return conductor from the distant cable link station to the station where the measurement is performed. This second conductor forms one of the legs of a bridge measurement and must have a well-known resistance. In case of a three-phase submarine cable, another conductor in the same three-phase cable can be used if it is healthy. Also, a parallel cable can be used for the bridge measurement.

Figure 8.8 shows the Murray scheme for a bridge cable fault location. The cable has the length L and the distance to the fault is x. At R_f the insulation fault has contact to ground or seawater. For the purpose of measurement, the faulty cable core is connected to a healthy cable core in the same cable or a parallel cable at the far end (right end in the diagram). A battery voltage is fed to the circuit. The two tuneable resistances $R1$ and $R2$ are adjusted until the voltage meter G shows zero (G stands for “galvanometer” as these things were used in the 1880s to perform this

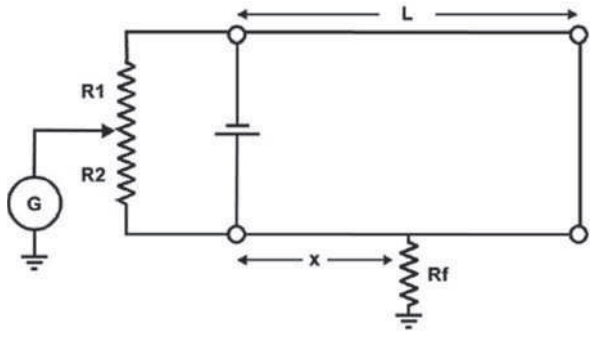


Fig. 8.8 Murray loop for bridge measurement of cable fault location. Explanations to be found in the text

type of measurements). When G is balanced to zero, the distance x to the cable fault can be determined as

$$x = \frac{R_2}{R_1 + R_2} \cdot 2L \tag{8.3}$$

The Murray test loop is essentially an application of the Wheatstone bridge known from secondary school. Many other bridge applications have been developed within 150 years of fault location. Today, bridge measurement equipment for fault location with a high degree of operation convenience is commercially available. The bridge measurement instruments usually display the fault location in percent of the distance from the measurement place to the far-end station. Actually, this displayed value is the percentage of resistance-weighted distance. The displayed result must be compensated for possible conductor resistance differences along the route. These differences can be caused by differences in conductor size or temperature *en route*. Also, the resistance of the jumper cable between the power cable terminations at the far end has to be taken into account. This is a neat calculation task for the junior cable engineer. The bridge measurement is simple and can localise a fault within 0.5–1% of the cable length, which is good enough to start planning the repair work.

8.3.3 Fine Localisation

The methods mentioned above are able to find the fault within a few percents of the total cable length. This can still be a few kilometres, too much for excavating the cable and searching with a ROV for the fault. Instead, there must be a fine localisation to pin-point the failure.

The fine localisation cannot be done from shore alone but requires an offshore visit to the suspected area. Fortunately, the localisation equipment is rather small and can be carried by small vessels.

With all modern fine localisation, a signal current is sent into the conductor of the faulty cable phase from shore. At the cable fault, the signal current exits through the insulation damage, which creates a difference of magnetic field on both sides of the fault location. A search coil on-board of the search vessel records the characteristics of the magnetic field from the signal current. Passing over the fault location, the search coil records a significant change in signal intensity. For a search coil on-board, the accuracy is about twice the water depth, provided a straight unburied cable.

In calm shallow waters, the search coil can be suspended from something like a fishing boat. More often, this is not enough. The search coil must be lowered towards the sea floor, requiring a winch. In many cases, an ROV is very useful to position a search coil closer to the cable, especially when the cable is buried. The use of an ROV requires vessels with specially trained teams and hoisting facilities. ROV-mounted cable-tracking equipment is very useful to locate buried cables.

Signals for fine localisation must be provided from land-based signal generators. Sinusoidal currents can be impressed onto the cable conductor. To avoid disturbances from the vessel's own power system the signal frequency should be different from 50 and 60 Hz. Sometimes very good results can be achieved when an impulse generator is used sending hv impulses into the faulty cable. These impulses can be "heard" by the search coil travelling along the submarine cable. Again, at the fault location the registered signal change its characteristics. Depending on the circumstances the fault can be found within a hundred meters. An ROV equipped with a search coil and which is flying close above the cable has a good chance of tracking down the fault location to a very short range.

If the fault location is located within a range of a few hundred meters, another method can be used. The cable is cut at the suspected damage location or in the middle of the suspected area. Both ends can be retrieved (one by one) to the vessel and a TDR measurement can be performed into each end. As the fault must be pretty close to one end, it will be easily detected and localised by the TDR.

8.3.4 Optical Time Domain Reflectrometry

If the damaged submarine power cable contains optical fibres, OTDR (Optical Time Domain Reflectometry) can be used to localise damages of the fibres. Modern OTDR methods are well developed from telecom cable applications and are easy to use. Similar to TDR, OTDR is based on pulse travelling in the optical fibre. Fibre defects scatter a portion of the impulse light back to the monitoring unit, where the engineer can detect the fault location. Some special characteristics of OTDR methods should be kept in mind.

Most OTDR instrument cannot monitor the first hundred or so metres of optical fibre next to the optical unit. This area is called the blind spot. To compensate for this, OTDR engineers connect an optical launch cable (up to a thousand metres) between the instrument and the optical fibre in the tested cable. The length of the launch cable must be taken into account for the length evaluation.

The impulse travel velocity in the fibre is $V = c/n$ where c is the speed of light in vacuum (300,000 km/s) and n the refraction index of the glass fibre. It is obvious that the exact knowledge of the fibre refractive index is a prerequisite for good accuracy. Table 8.3 gives approximate values for the refractive index n of fibres [21]. The fibre cable manufacturer should be able to produce exact values.

The OTDR method can only detect optical distances within the fibre. To translate the evaluated distances to power cable length, it is necessary to take into account

Table 8.3 Refractive indices of optical fibres to be used in OTDR measurements

Fibre type	Wavelength (nm)	Refractive index n
Multimode	850	1.481–1.495
Multimode	1200	1.476–1.490
Single-mode	1310/1550	1.467

1. the excess length of fibre within the optical cable
2. the excess length of the optical cable within the power cable due to the lay length.

The optical cable manufacturer should be able to specify the excess length of the fibre within the optical cable which is in the range of 0.05–1%. Then the optical fibre is incorporated into the power cable with a certain lay length. The lay length determines the fibre length in relation to the power cable length. Usually, the optical fibre is 2–8% longer than the power cable.

8.3.5 Other Methods

If the damaged cable connects two transmission substations, the first information about the possible location of a cable fault can sometimes be obtained from the fault recorders. A precondition for this is that both stations have recorded the voltage shape during the breakdown and used exact time stamps on the voltage records. This is often the case in modern HVDC converter stations. The voltage breakdown at the fault location travels towards the cable ends with the wave group velocity, which in a mass-impregnated cable is around 150 m/μs. A rough estimation of the fault location can be obtained from the time difference between the arrivals of the breakdown signal at the two stations. The group velocity of the actual cable can be obtained by methods described in the TDR chapter.

Recently, a new cable fault location method has been suggested depending on the measurement of the complex cable impedance for different frequencies [22]. The group, which developed the method, claims that it also can detect global or local cable insulation degradation as there is, e.g., ageing. However, it is not known if it has yet been used for successful cable fault detection.

A rather unwanted fault location method has been used when searching for faults in oil-filled submarine cables.

The oil slick from the damaged leaking oil cable can sometimes be observed at the surface over the cable damage. At calm weather, this observation can be made from the air with a good chance to find the fault [17]. This method helped to localise a fault in the 400 kV a.c. cable between Denmark and Sweden in August 1979. Also after the damages striking the a.c. cable between the islands of Leyte and Luzon (the Philippines) the oil slick could be observed from the air.

Still another fault locating method is using the galvanic effect of a d.c. current. When a strong d.c. current is sent into the damaged cable core, a galvanic reaction can occur at the fault location, which makes gas bubbling into the water just above the fault. The gas development can be observed with ROV cameras.

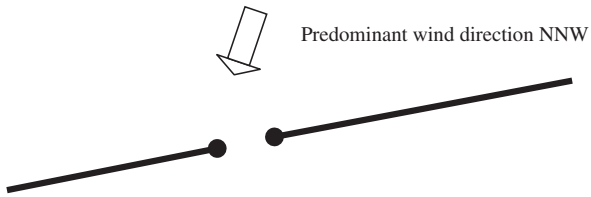
A quite simple, still effective method was used to find some of the many cable faults in the notorious Fox Island cables. As the cable route was not known exactly, TDR or a similar method would have revealed the fault distance to land but not it's exact position. Instead, the repair vessel picked up the cable at shore and let it travel over wheels in the bow and aft. The vessel underruns the cable while travelling out to sea. Guided by the emerging cable, the vessel progressed with on-board specialists who searched the cable for the breakdown [22]. This method has been used already in 1853 when a telegraph cable off the Netherlands had to be repaired [23].

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 243 of 306

8.4 Repair Example

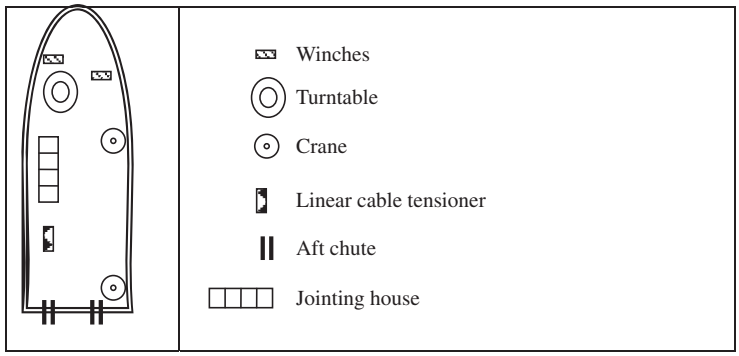
The following example illustrates step by step how a submarine cable repair operation can be done. It should be kept in mind that the described case is just one possibility, taken from a real situation. For each task, the experienced installation engineer will devise a tailor-made repair scheme, taking into account the particular conditions of the cable, the equipment, the location, and the weather.

The damaged cable runs from east to west at 50 m water depth. A flexible repair joint is available for the cable type. The crew of the fault location vessel has cut out the damaged portion (about 200 m of cable). The cable ends have been sealed properly and deployed on the sea floor. The cable ends have been provided with transponders, a ground wire, and rings and hooks to enable retrieving with an ROV.

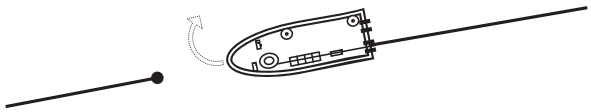


The repair vessel arrives on site with about 1000 m of spare cable on the turntable. Now it is important to plan the repair works so that the repair vessel will head into the wind during the delicate jointing work as much as possible to attain the largest possible stability.

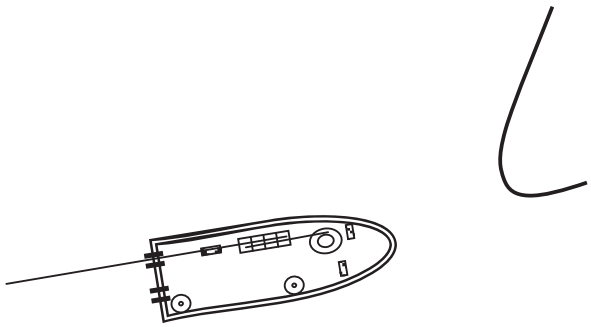
The next sketch describes the repair vessel arrangement.



1. The east cable end is retrieved by ROV and pulled on board via the port side winch[3] over the port side aft chute. About 300 m of the cable are retrieved and stored on the turntable on top of the spare cable.



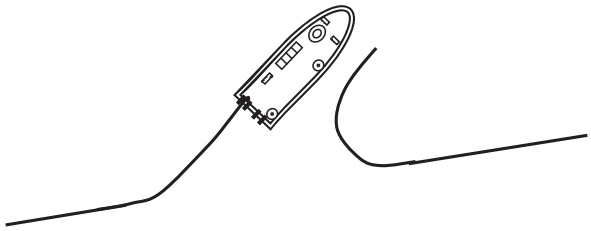
2. The repair vessel is moving in a curve towards a northerly direction, while the retrieved cable is laid out again over the port side chute. About 200 m of cable are now laid on the sea floor heading towards NNW. Transponders, ground wire, and ROV-friendly grip rings are attached to the cable end before it is put back down.



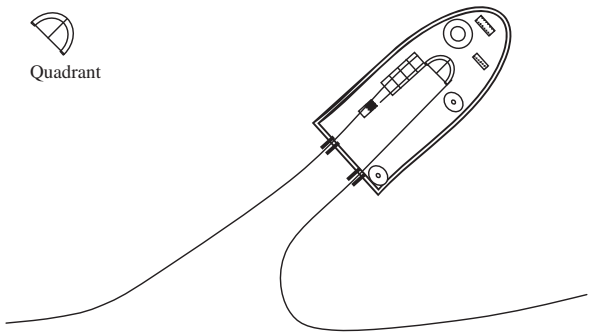
3. After laying down the end of the east cable towards NNW, the repair vessel is positioning itself so that the port side chute stands over the end of the west cable. The west cable is connected to a pull wire from the port side winch. The west cable is pulled onboard until the cable end is in the joining house. During the pulling the repair vessel moves backwards. The west cable is fixed aft of the jointing house by lashing or “chinese fingers”. The spare cable is now pulled from the turntable into the jointing house.
4. The cable ends (west cable and spare cable) are now placed in the jointing house with overlap. Both ends are inspected with respect to damages or water ingress. If necessary, damaged pieces can be cut away and new cable can be pulled in from both the turntable or the sea floor. After the approval of the cable ends, they can be jointed in the jointing house. During this operation, the repair vessel can head up into the wind if necessary.

[3]Port side is the left side of the vessel when looking towards bow (front end). Starbord is the right side. The use of these terms is practical as they are non-ambiguous regardless of the ship direction on situation plans.

5. Once the joint is manufactured, the repair vessel is moving forward while paying out the flexible repair joint over the aft chute. The spare cable follows. When the joint and a short length of the spare cable have been laid safely onto the sea floor, the repair vessel is heading up in parallel to the end of the east cable, with a lateral distance of about 10 m. To reduce strain and forces on the flexible joint, it is advisable not to head up before the joint is in position on the sea floor. The two cable ends are now in parallel with a 10 m distance to each other.



6. After passing by the end of the east cable on the sea floor, the repair vessel stops to pick up the end of the east cable, placing it over the starboard aft chute. Moving backwards, both cable ends are pulled back on board. On the port side chute, the spare cable is being pulled back onto the repair vessel and spooled onto the turntable. On the starboard chute, the east cable is being pulled up onto the vessel towards the vessel's bow.



Now the quadrant is being introduced (cf. sketch, and Fig. 7.19 in Chap. 7). The 180-degree steel frame can hold half a turn of the cable and will later be used to deploy the cable into the water. The sketch shows the position of the quadrant on the vessel. While the vessel moves backwards taking in more cable, the eastern cable is being put around the quadrant and pulled into the jointing house until it lies there overlapping with the spare cable. The repair vessel is now positioned in the predominant wind direction and provides the best possible stability for the next jointing operation. During the jointing operation, the cables on the chutes must always be kept under tension so that the cables do not depart vertically from the chutes.

7. After jointing the cable link is restored, and can be tested from the cable ends on shore or on platforms if so desired. The cable loop is still on the repair vessel kept in place by the quadrant. Now, the jointing house must be removed. While the repair vessel is moving head-on slowly, the quadrant and cable loop are moved backwards on the vessel deck. The quadrant can be supported by rails, cranes, slipways or similar. The quadrant must be stabilized against tilting or warping. When the quadrant arrives at the aft chutes, it must be lifted carefully over the chutes by a crane (cf. Fig. 7.19). During this process, the repair vessel must maintain the cable tension by travelling forward. The quadrant goes down in the water suspended from the aft crane or the A-frame. As the repair vessel slowly travels ahead, the quadrant descends into the water and finally lands on the sea floor. An ROV can now unlash the cable from the quadrant. The repair is finished, and the cable can be protected. Depending on the joint manufacturing time and other circumstances, the described procedure can take 4–12 days.

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Chapter 9
Operation and Maintenance: Reliability

Contents

9.1 Operation of Submarine Cables 237
9.1.1 Common Measures for All Kind of Submarine Power Cables 237
9.1.2 Instrumentation 238
9.1.3 Mass-Impregnated Cables and XLPE Cables 240
9.1.4 LPOF, SCOF and SCFF Cables 240
9.1.5 Cable Terminations 241
9.2 Reliability of Submarine Cables 241
9.2.1 The Cigré Studies 241
9.2.2 Failure Statistics for Large HVDC Cable Projects 242
9.2.3 Definition of Reliability Terms 244
9.2.4 Reliability of Some Specific Submarine Power Cables 244
References 247

9.1 Operation of Submarine Cables

After commissioning, submarine power cables are expected to work troublefree for decades. The cable operator can contribute to a long useful life and a high reliability of the cables by some maintenance actions. This chapter explains what the cable operator can do to improve the availability.

9.1.1 Common Measures for All Kind of Submarine Power Cables

The cable operator must protect the cable from a number of hardships, such as overvoltage, overheating, external violence, fatigue, etc. This requires an active involvement and the establishment of maintenance plans for the cable system. In most cases, a simple instrumental monitoring is sufficient.

Overvoltage can be avoided by a system analysis prior to system design. Surge arresters with appropriate protection levels should be used, especially when the

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submarine cable is connected to overhead lines. Surge counters should be checked regularly in order to detect anomalies in the power system behavior. Temporary system overvoltage due to strong generation (e.g. in OWP) should be monitored carefully and mitigation strategies considered.

The risk of overheating can arise even if the cable is run within its design limits. Seafloor conditions can alter within months, and the cable route can be covered with additional thick layers of sediment. This reduces the heat flow from the cable, which leads to cable temperatures higher than expected. Also, other services such as pipelines, flow lines, other power cables, etc., may suddenly turn up in the vicinity of the power cable. The cable operator should develop strategies to detect this type of thermal hazards:

- Disseminating knowledge of the existence of the cable to authorities, infrastructure developers, utilities etc.
- Watch out for construction activities at the cable sites
- Study bathymetric updates from survey companies, marine authorities and professional associations
- Check and compare satellite photographs in regular intervals.

The thermal conditions along the cable route can be monitored with a DTS (Distributed Temperature measurement System). Adverse conditions can be detected, and relieving action can be launched.

Free spans in the cable route should be checked from time to time to detect a possible enlargement. Too long free spans can easily cause vibration, chafing, fatigue, and cable failures. Free spans can be stabilized with additional rock-dumping, or with mid-span guy lines. Another possibility to improve the vibration characteristics of free spans is the subsequent application of VIV suppression strakes.

A number of active measures can be taken to avert external damage to the cable. In Chap. 7, measures for the active post-lay cable protection are described. They range from information campaigns for the fishing community to repeated share of cable position data to authorities, nautical agencies, etc. Active ship traffic monitoring allows for warning of vessels, should these come too close or try to anchor too close to the cable route.

The cable operator can monitor the character and frequency of vessel traffic and fishing activities along the route of the cable. If the vessel traffic increases in size or numbers, the cable operator may consult marine authorities in order to discuss methods to divert traffic from the area.

9.1.2 Instrumentation

Taking active control of the operation of a submarine power cable may increase the availability and profitability of the cable link. Suitable instrumentation is available to do this.

9.1.2.1 DTS

The Distributed Temperature Measurement System (DTS) is an optical fibre-based temperature sensor incorporated into the power cable, or installed alongside the power cable. Such a system is able to monitor the temperature along the power cable. A land based monitoring unit evaluates the optical signals and displays a temperature profile over the cable length.

Hot-spots and cold-spots, and other irregularities along the cable route can be detected with DTS. By comparing DTS printouts from subsequent years, it is possible to detect sediment wash-away at the particular location. If a submarine cable is exposed in free spans or by wash-away of sediment it should be considered to take advantage of the situation and fly an ROV along the cable to inspect it for damages and corrosion. Submarine power cables that are not buried should be inspected regularly by divers or ROV to confirm their status or changes in their environment.

Most DTS have built-in ODTR capabilities to detect and localize fibre damage. But DTS can be used even if everything is running smoothly.

The temperature profiles recorded from this system can be evaluated to perform a dynamic cable rating. In contrast to the conventional static “Rated Power”, the system is able to calculate the ampacity of the link by taking into account the actual ambient conditions. The cable operator can take advantage of the ampacity changes over the seasons of the year. Furthermore, dynamic rating can exploit thermal reserves in the cable system for temporary overloads. The operator of links designed for the purpose of power trading may use this system to generate extra income without putting the cable integrity at risk. Dynamic rating systems are also known under the acronyms CLPS or RTTR.

If the power cable is equipped with optical fibres for data transmission, these can be used for ad-hoc distributed temperature measurements.

9.1.2.2 CDVC

The Cable Dependent Voltage Control, designed for mass-impregnated d.c. cables, is a control function resident in the HVDC converter station. At reduction of power demand, the system reduces temporarily the system voltage without limiting the transmission capacity. Doing so, the electric stress in the cable insulation is reduced when the cable is cooling down. The voltage reduction has the potential to increase the electric life of the cable. When full power is required again, the voltage returns to rated.

9.1.2.3 Partial Discharge Monitoring

Partial discharge (PD) monitoring of power cable systems has achieved a sophisticated level. Defects, inhomogenities and other flaws can be evaluated with on-line PD detection systems. PD activities on a particular spot in the cable link may indicate the presence of a small damage in the cable insulation system or in a cable joint.

Modern PD measurement systems are getting increasingly powerful in discrimination of PD signals and their relevance for the future cable life. Still, it is extremely difficult to monitor a longer stretch of submarine power cables from the shoreline as PD signals tend to be attenuated after only a few kilometres of travel through the cable.

Furthermore, there is the great question about what happens if the system detects an increased PD activity in a particular joint or cable location out there. Would the TSO manager decide the interruption of the cable link for repair of a suspicious cable portion? Or would he/she prepare a repair operation but wait for the breakdown that may not happen?

9.1.3 Mass-Impregnated Cables and XLPE Cables

Mass-impregnated and extruded cables, also called solid cables (cf. Chap. 2), are maintenance-free. This is also valid for the submarine joints belonging to these cable types. Cables with solid insulation have no free oil volume that needs to be pressurized from the shore stations. The terminations require only a small pressure vessel to accommodate the oil expansion inside the termination. The monitoring sensors for pressure and oil level can be connected to the substation SCADA system. Too low or high pressure would cause a tripping of the link.

XLPE insulated a.c. cables are sometimes terminated directly into GIS substations. Not all, but some GIS cable terminations have small amounts of insulation oil (mineral oil, polyisobutene oil or silicone oil) calling for level/pressure monitoring. The maintenance requirements are identical to those applicable for equivalent terminations for land cables.

9.1.4 LPOF, SCOF and SCFF Cables

Fluid-filled (FF) and oil-filled (OF) cables require the monitoring of the oil-pressure feeding system. Since the performance of these cables is critically depending on the prevailing oil pressure, it must be monitored on-line. A loss of oil pressure indicates a cable damage calling for immediate attention. The pressure monitoring can be connected to the substation SCADA system. The cable link will be tripped if the pressure falls under a certain limit.

Sufficient amounts of degassed dielectric fluid must be available in the feeding station in order to maintain a positive oil pressure also in the case of a cable leakage. As leaks may be large and weeks may elapse until the cable can be sealed, it should be considered to keep an extra stock of cable oil not too far from the termination. Cable operators of one region can cooperate in this issue, as cable oils from different cable systems usually are compatible.

9.1.5 Cable Terminations

The proximity of many submarine power cable terminations to the sea may cause severe salt layer deposits on the insulators calling for a regular cleaning schedule. Some cleaning can be done under energized lines. Some termination insulators rely on the hydrophobicity of polymeric materials or coatings. The remaining hydrophobicity should be tested regularly, e.g. according to visual tests suggested by STRI [1] and set forth in an IEC specification [2].

All terminations erected close to shore or on marine platforms must be checked regularly for corrosion. Especially galvanic corrosion between different metals can be onerous.

9.2 Reliability of Submarine Cables

Submarine power cables are often a special asset in the basket of TSOs and might deserve closer attention. The operating utilities are very much interested in a trouble-free operation because repair is expensive and can be cumbersome. Also, submarine power cables are often not a part of a meshed network with large redundancy. On land, the power flow blocked by a cable failure can most often be rerouted through other paths of the grid. In contrary, submarine power cables often have no redundant grid for back-up. A submarine cable failure can darken islands or oil/gas production platforms, or cut the revenues from offshore wind farms. A failure in submarine cables connecting self-sustaining grids (such as HVDC links between countries) would not black-out cities, but would deprive the owners of large revenues from power trading. For this reason, the reliability of submarine power cables is an important aspect of each business model and has strong influence on the cable design.

Unfortunately cable operators are somewhat reluctant about reporting failure statistics. A number of journal articles were published in the 1970s and 1980s reporting on experiences from large submarine cable links including accounts of failure modes and repair methods. In the last decade reports of this kind have become astonishingly scarce. Owing to the excellent work of the Cigré Study Group B1 (erstwhile SC 21), cable operators have the possibility to report cable experiences and failures confidentially without annoying the shareholders.

9.2.1 The Cigré Studies

The Cigré organisation (Cigré=Conseil International des Grands Réseaux Électriques) has established a working group that regularly collects data on submarine power cable reliability. In 1986 it published an often-cited compilation on experiences from thousands of kilometres of submarine power cables [3]. The

Table 9.1 Failure rates for submarine power cables > 60 kV expressed in (failures/(year×100 circuit kilometres))

	Internal origin failures	External origin failures	All failures
a.c. HPOF cables	0	0.7954	0.7954
a,c, LPOF cables	0	0.1189	0.1189
a.c XLPE cables	0	0.0706	0.0706
d.c. MI cables	0	0.1114	0.1114
d.c. LPOF cables	0.0346	0	0.0346

study covers experience from 1950 to 1980. It arrives at a failure rate of 0.32 failures/year/100 cable kilometres. Only a small fraction of the cable kilometres considered in this failure rate are protected. Today, since the protection rate of submarine power cables is considerably higher, and survey methods, cable design, and installation methods have developed enormously, the failure rate is expected to be much lower.

According to the 1986 Cigré study 82% of the failures occurred in the cables and 18% in the joints. The dominant majority of the cable faults were caused by external violence, while the joint failures mostly were caused by poor engineering, installation or maintenance.

The failure rates reported in the 2009 Cigré study [4] are summarized in Table 9.1. Except for HPOF submarine cables (which are used very rarely today), all failure rates are much lower than the 1986 values. The values are related to circuit kilometres. As circuit often comprises two, three or four individual cables, the rate as per cable kilometre would be even lower.

While the ratio of joint failures to cable failures was 0.22 in the 1986 study, this relation changed to 0.095 in the 2008 study. This indicates a much higher relative safety of cable joints in the recent time.

It should be noted that calculated failure rates can be warped by a few notorious cable links, which account for a significant share of the reported failures.

9.2.2 Failure Statistics for Large HVDC Cable Projects

The failure rate calculated from the data given in Table 9.2 is 0.264 failures/year/100 cable kilometres for mechanical faults and 0.0143 failures/year/100 cable kilometres for other failures. “Other faults” means internal faults, such as the failure of the insulation system. It is evident that a few cable systems contribute largely to the failure statistics. In particular, the 1964–1988 Kontiskan 1 suffered many mechanical failures. Without the contribution of the Kontiskan 1 link the failure rate would be only 0.1 failures/year/100 cable kilometres. It is obvious that badly engineered cables or unsuitable installation methods account for the majority of cable failures.

Table 9.2 Failure in some large HVDC cable links as per 1998[5]

Cable project	V [kV]	P [MW]	L [km]	Max depth [m]	Cables [#]	In service year	Service time years	Technical service [km*years]	Mech faults [#]	Other faults [#]
Kontiskan 1	285	300	88	80	1	91	4	352	0	0
Cook Strait	350	185	41	260	3	91	4	492	0	0
Fenno Skan	400	500	200	120	1	89	6	1200	1	0
Konstiskan 2	285	300	88	80	1	88	7	616	0	1
Cross-Chn. 2	250	200	48	60	8	86	9	3456	0	0
Hokkaido-Hon.	250	200	43	550	2	78	17	1462	0	0
Vancouver 2	280	100	32	200	2	76	19	1216	1	0
Skagerrak ½	250	250	128	550	2	76	19	4864	6	0
Vancouver 1	260	100	32	200	3	69	26	2496	3	0
Sardina-Cor.	200	100	118	450	2	67	28	6608	12	0
Kontiskan 1	285	250	87	80	1	64–88	24	2088	44	2
Gotland 1	150	30	93	170	1	54–89	35	3162	7	1
Total			998		27		198	28012	74	4

9.2.3 Definition of Reliability Terms

Reliability terms can be expressed in many different terms. For a correct comparison of information from different sources, it is important to use a well-defined terminology.

Reliability	The probability that a cable is fulfilling its purpose adequately for the period of time intended. The reliability can be described as: $1-(\lambda \times r)/8760$
Availability	A measure of a system's performance in terms of its reliability and maintainability: $1-(\lambda \times r + c)/8760$
Where	λ = number of failures per year r = repair time after failure [hours] c = scheduled outage (e.g. maintenance) [hours/year]
Outage	Period of non/functioning of the system
Forced outage	Involuntary outage as a result of a failure
Failure rate	The annual rate of forced outages associated with failures in the cable
Scheduled maintenance	Annual preventive maintenance as specified by supplier or according to operators own standards
Unscheduled maintenance	All maintenance required that can not be termed annual preventive maintenance

9.2.4 Reliability of Some Specific Submarine Power Cables

A few reports on reliability and availability data can be found in the literature. However, cable operators today are less prone to publish such data. This is a disadvantage to the industry, as investors and insurance companies might need a clearer picture for a fair risk assessment. Here, a few examples are given.

9.2.4.1 Skagerrak HVDC Scheme

The first Skagerrak HVDC cable between Norway and Denmark was installed 1976–1977. The base data are as follows:

Rated voltage	250 kV d.c.
Number of cables	2
Year of commissioning	1976, 1977
Submarine distance	128 km
Largest depth	550 m

The operation statistics for the interval between 1978 and 1984 is reported in [6]. For this pair of cables the availability was always better than 93% during this time

span, despite forced outages due to cable failures in two of seven years. In five of seven years the availability was over 95%.

9.2.4.2 Windfarm Export Cable

For a hypothetic OWP export cable the reliability of five different a.c. cable configurations is compared in [7]. Three-core and single-core systems have been investigated for a fictive 60 km 1000 MW power export system. A 275 kV single-core system with seven individual cables (two circuits and one spare cable) was found to have the lowest expected failure rate (0.15 failures per year and cable) (Table 9.3):

Table 9.3 Failure rates for different cable schemes to connect a large OWP

Voltage (kV) cable type	132 3-core	220 3-core	400 3-core	275 SC	400 SC
No of cables for 1000 MW transmission	6	4	2	7 (1 spare)	4 (1 spare)
Failures/year and cable	0.25	0.46	0.67	0.15	0.22

Taken into account the number of cables, the 400 kV system with three single-core cables seems to have the lowest expected number of repairs over lifetime.

9.2.4.3 Fox Islands

Four SC submarine cables were laid between Rockport, Maine, USA, and the Fox Islands in 1976. The 10.4 miles of 34.5 kV circuit replaced on-island diesel generation. The cable system was stricken by 45 faults until decommissioning in 2005 [8]. While the Cigré failure statistics for submarine power cables [1] quote a rate of 0.32 faults per year and per 100 km of cable system, the Fox Island cable counts nine faults per year and per 100 km, and has perhaps the worst reliability record in the world.

9.2.4.4 Long Island

Seven single-core high-pressure oil-filled 138 kV cables were installed under the Long Island Sound and commissioned in 1969. At that time it was the longest oil-filled submarine cable in the world [9]. Eighty percent of the cable route was installed freely on the seafloor, with 275 m spacing between individual cables [10]. Unfortunately, the cable system (called “1385 cable”) had an exceptionally bad availability. The operator Long Island Power Authority reports:

> Since being energized in 1969, the existing 1385 Cable had experienced 36 incidents with 58 damages to cables that have resulted in either limited capacity operation or total electrical failures. The causes for incidents included chafing from rock and corrosion, and bottom dragging of grappling hooks or anchors from both small and large vessels. As a result, frequent and extensive maintenance was required for the existing 1385 Cable. Since 1990 alone, the cost of cable repairs has exceeded $45 million.

In spite of the extra spare cable and the spaced installation multiple damages caused 50% capacity drop in extended periods (2–9 months) in the 1970s. The outages were caused mostly by external damages affecting a system already weakened by damages that were caused by severe corrosion. No less than four cables were damaged by a single anchor attack 17 November 2002.

The unlucky cable system is now replaced by a system of three 3C cables with 138 kV rating. Since the new cables are protected by burial six feet under the seafloor, they have much better chances to serve without trouble during many years.

9.2.4.5 Baltic Cable

The Baltic Cable is a HVDC cable connecting Sweden and Germany. The return current is conducted by sea electrodes.

Rated voltage	450 kV d.c.
Number of cables	1
Year of commissioning	1994
Submarine distance	250 km
Largest depth	40 m

The performance data of the Baltic Cable link are summarized in Table 9.4 (Courtesy of Baltic Cable AB, Sweden).

Three failures were reported, one in 1999, 2002 and 2009, resp. This figure calculates to 0.08 failures per year and 100 cable kilometres, which is better than the reported average in both the 1986 and 2009 Cigré studies. The 1999 cable failure led to 3374 h of outage[1] in 1999 and 2000 reducing the availability figure for 2000 drastically. The 2002 failure could be repaired within 8 weeks [11].

Table 9.4 Failure rates for different cable schemes to connect a large OWP

Year	Scheduled unavailability (%)	Forced unavailability (%)	Availability (%)
1995	3.14	0.82	96.04
1996	6.00	1.24	92.76
1997	1.49	1.40	97.11
1998	1.50	2.29	96.21
1999	1.29	7.67	91.04
2000	1.23	30.76	68.01
2001	1.23	0.78	97.99
2002	0.96	14.08	84.96
2003	1.23	0.01	98.76
2004	8.88	0.04	91.08
2005	1.23	0.61	98.16
2006	1.23	1.52	97.24
2007	1.23	0.14	98.63

[1] The cable repair was delayed by vessel unavailability, unsuitable weather and other factors.

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Chapter 10
Environmental Issues

Contents

10.1 Environmental Assessment 249
10.2 The Influence of Cable Losses 251
10.3 Environmental Aspects Related to Cable Design 252
10.3.1 Conductor Materials 252
10.3.2 Choice of Other Cable Materials 252
10.4 Environmental Aspects of Cable Installation 255
10.5 Environmental Impacts from the Operation of Submarine Power Cables 258
10.5.1 Thermal Impact 258
10.5.2 The 2 k Criterion 258
10.5.3 Electromagnetic Impact 261
10.5.4 Chemical Impact 266
10.6 Recycling of Submarine Power Cables 266
References 267

10.1 Environmental Assessment

For all industrial projects, the environmental impacts must be considered, the relevance of these impacts must be evaluated, and possibilities to reduce these impacts must be discussed. The delicate state of our planet, the industry's responsibility for its activities, and the public attention require a serious and honest assessment. Those who want to erect an industrial project such as a submarine power cable must perform regulated Environmental Impact Assessments (EIA). Within the EU, the directives 97/11/EG and 85/337/EEG regulate the legal background for the EIA process. Furthermore, authorities call for compliance with laws and rules.

The installation of a submarine power cable requires permits to be obtained in sometimes lengthy processes. Steps to be taken, and authorities to be approached, differ from country to country, and are subject to legislation, that sometimes is volatile. A treatment of permit issues would be insufficient in the framework of this book. Instead, some basic technical issues on the environmental aspects of

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NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 260 of 306

submarine power cables are discussed here in order to facilitate a fact-based fruitful discussion between project developers, authorities, and the public.

The environmental impacts of submarine power cables have to be considered "from cradle to grave", i.e. all aspects of raw material production, transports, manufacturing, installation, operation, recovery, and recycling add to the overall impact of a submarine cable. Various LCA (Life Cycle Assessment) models are available. LCA models work with various categories of environmental impact. For a given product, the LCA can compute and compile the aggregate environmental impacts starting from the needed amounts of constituent and auxiliary materials, consumables, and energy. LCAs do not create new data; they just compile appropriate data from the underlying database. The quality of an LCA is hence depending on the quality of the data base entries. As an example, for the assessment of the influence of the use of copper, it is essential to make correct assumptions on the share of recycled and virgin material, as well as the mining and refining site on the globe. The skills of the LCA engineer are critical to assemble a correct model of the product and its peripheral processes, and to interpret the results. Various LCA tools are available on a commercial basis. The EIME tool has been developed by 6 major electronic companies 10 years ago, and has been adopted by "la Fédération des Industries Electriques, Electroniques et de Communication" (FIEEC) [1]. This tool has the following categories of environmental impact:

RMD	Raw material depletion
ED	Energy depletion
WD	Water depletion
GW	Global warming
OD	Ozone depletion
AT	Air toxicity
POC	Photochemical ozone creation
AA	Air acidification
WT	Water toxicity
WE	Water eutrophication (too much nutrients in water bodies)

Other tools have also Hazardous Waste Production as a category.

LCAs can support decision making on submarine power cables in different levels:

1. On the lowest level, the design engineer may apply LCA on different cable design solutions meeting the functional specification of the submarine power cable. Based on the result, the engineer may select the environmentally best solution.
2. If the purpose of a submarine power cable is to transmit power between two given points A and B, the LCA can help to rank possible routes with respect to their environmental impact. Alternative routes can sometimes also include overhead lines or land cables. In this case also demographic and socio-economic factors need to be taken into consideration.

3. Sometimes permission authorities require an environmental comparison between the planned project and the "zero alternative", i.e. the situation when nothing is being built. For submarine power cables, the zero alternatives could be continued operation of Diesel generators on unconnected islands, or the need of costly spinning reserve in autonomous grids. For wind farm export cables, the zero alternative would be that the harvested wind energy would not be available and must be produced in a different way, possibly with fossil fuels.

Unfortunately, LCA results are sometimes being used by various parties to promote their own agenda. Green groups, NGOs, and industrial lobbyist groups work with LCAs to proof their statements. Also, political parties, companies, and investment funds promoting "green" investments often present fragmentary LCA graphs or tables.

The task of this chapter is not to present the results of complete LCAs. This should be performed using individual data for each project. Here, we want to discuss some features specific to submarine power cables, which may help the LCA analyst to fine-tune models and assumptions. The factors related to the production and transport of raw materials are not listed here because they are highly depending on specific project circumstances, and would be outdated after only a few years. Commercial LCA tools hopefully provide updated databases.

10.2 The Influence of Cable Losses

A standard LCA includes the impact from the operation of a product/asset. The transmission losses of a power cable during service generate a much higher environmental footprint than the energy used for raw material production and manufacturing. In fact, the transmission losses and the environmental impact from their generation obscure almost all environmental impacts from raw material production, manufacturing and transport of the submarine power cable [2]. This leads to the unfortunate situation that the cable design engineer can put almost any questionable material in the cable without affecting the cradle-to-grave analysis. Only if the environmental impact from the cable operation losses is excluded for the moment, the environmental difference between design solutions becomes visible.

The environmental impact of transmission losses can only be assessed correctly with the knowledge of how the power for these losses is generated. Even if all facts and figures are firmly available, the conclusion is far from being unambiguous. As an example, the impact of transmission losses from an OWP submarine cable can be evaluated in at least four different manners:

1. The transmission losses are generated by clean wind power, hence the impact is zero.
2. The losses eat up some of the wind power arriving onshore and decrease the possibility of replacing fossil power generation. The impact of losses is the same as of an equivalent amount of fossil-generated power.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 262 of 306

3. The wind power does not replace fossil power alone, but a typical power-mix in the country where the wind power is landed. This can be fossil, nuclear and sustainable power.
4. The losses are compared to an international power-mix of the future.

Table 10.1 illustrates the difference in CO_2 emission per kWh depending on the choice of reference power production [3]:

Table 10.1 CO_2 emission per kWh for different system borders

System borders for electrical power production	Average CO_2 emission Kg CO_2/kWh (2005)
Sweden	10
Scandinavia	58
EU (25)	415
Marginal power production from coal-fired plants	400–750

In any case, the reduction of losses improves the environmental impact of a submarine power cable more than any other detail.

10.3 Environmental Aspects Related to Cable Design

10.3.1 Conductor Materials

Within the framework of the project specification, the design engineer often has little possibilities to choose materials from an ecologic point of view. Submarine power cables can be designed with aluminium or copper conductor. The conductivity of copper is by 64% better than that of aluminium.

Table 10.2 shows the required amount of energy for the production of copper and aluminium conductors with equal conductance. It is obvious that a larger cross section is necessary for the aluminium conductor to achieve the same conductance, but a lower mass because of the low density of aluminium. With the base data and method used here, the energy required for the production of equivalent copper or aluminium conductors is almost equal.

A cable with aluminium conductor, however, requires more insulation and armoring material due to the slightly larger conductor diameter.

10.3.2 Choice of Other Cable Materials

The choice of insulation material is determined by the intended use of the cable and the state-of-the-art. Only sometimes there is a free choice.

Most modern submarine power cables have an insulation made from XLPE. The peroxide-based crosslinking process in the factory releases gaseous by-products such as acetophenone, alpha-methylene-styrene and cumyl-alcohol. These exhaust

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 263 of 306

Table 10.2 Energy vs. conductance needed to produce conductor material

	Cu-conductor, 1200 mm^2	Al-conductor, 2000 mm^2
Conductor resistance at 20°C	0.015 mΩ/m	0.015 mΩ/m
Conductance	66.666 m/Ω	66.666 m/Ω
Mass of conductor	10.7 kg/m	5.4 kg/m
Energy used for raw material production [4]		
Primary raw material (freshly mined)	60 GJ/t	164 GJ/t
Recycled raw material	20 GJ/t	20 GJ/t
Share of recycled material α	0.9	0.8
Energy used to produce raw material from mix virgin/recycled	24 GJ/t	48.8 GJ/t
Energy used for raw material for 1 m of conductor (MJ/m) with equal conductance	256.8	263.5

gases from the manufacturing are taken care of in the factory according to local regulations but might contribute to air toxicity. Later, during operation, no more by-products will be released into the atmosphere or water.

XLPE cannot be recycled by melting to new products. Instead, its energetic content can be used in suitable incineration plants releasing water and carbon dioxide. XLPE does not contain halogenides. However, some additives are used in the compounding of XLPE resin to improve production and electrical properties.

Thermoplastic polyethylene is an alternative extruded insulation material. The absence of cross-linking has some important environmental advantages. First, cross-linking by-products are not being generated. Second, less process energy is used in manufacturing. Third, thermoplastic polyethylene can be recycled easily.

The semiconducting layers of the conductor and insulation screen are made from carbon-black filled polymers that are compatible to the insulation material. Due to the cross-linking and the inseparable carbon-black filling these materials can hardly be recycled. The amount of these materials is in the range of 100 g/m of cable core. Replacement materials for carbon-black filled polymers are not known.

Most submarine power cables, especially those for rated voltages of 52 kV or above, are equipped with a metallic sheath. Lead alloy sheaths contain minute amounts of one ore more of the alloying elements antimony, tin, copper, calcium, cadmium, etc. Due to the large amounts of lead it constitutes a high value in the category “raw material depletion” in the environmental assessment. When enclosed in a plastic over-sheath the lead sheath will not release material into the ambient. Watertight sheaths made from aluminium or copper consume less material than lead sheaths, so they achieve better RMD scores. The environmental impact in different categories can be visualised in polar coordinate diagrams such as Fig. 10.1. The impact categories are distributed around the circle and the impact in each of these categories is shown by the distance to the centre. Figure 10.1 shows such a “radar plot” of two different land cable types [1]. The diagram is normalised, so that the values for the 1200 mm^2 Cu cable with Pb sheath are set to “1”. Therefore,

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 264 of 306

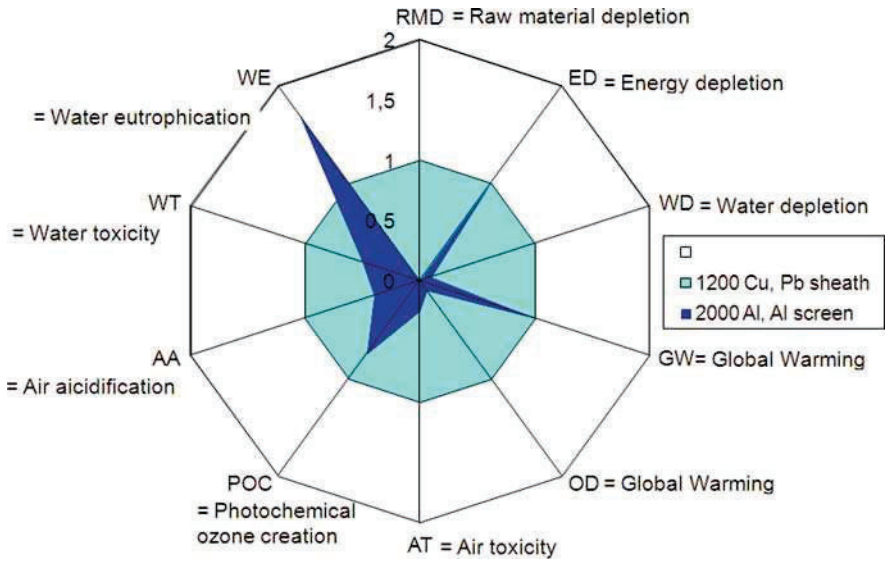


Fig. 10.1 Radar plot over the environmental impact in various categories of two cable types

the profile curve for the Cu/Pb cable is at "1" around the circle. In most categories the Al/Al cable has much lower environmental impact than the Cu/Pb cable. The two cable types are on a par in the categories Energy Depletion and Global Warming, and almost on a par in Photochemical Ozone Creation. Only in the category Water Eutrophication the Cu/Pb cable is more environmentally friendly than the Al/Al cable.

The radar plot of Fig. 10.1 has been established for underground cables and may illustrate the assessment method. Similar plots, comparing submarine high-voltage a.c. and HVDC cables, however, could not be found in literature.

The armoring is most often made from wires of steel or non-ferrous metals. Design and cost considerations usually dictate the choice of material. All metallic armoring can in principle be recycled. Anticorrosive materials, such as bitumen, or plastic coatings, can render the recycling difficult. Some anticorrosive agents contain large amounts of solvents that contribute to the total emission of volatile organic matter during manufacturing.

The interstices of multi-core submarine power cables contain filler materials. These materials are most often polymeric ropes or extruded profiles made from PVC or PE. These materials are functionally almost equivalent so that the cable designer can make a choice from cost and ecological criteria.

Table 10.3 lists the content of some materials in two typical submarine power cables. In the HVDC case, the listed material amounts refer to a pair of single-core cables. The pair of HVDC can transmit more than twice the power compared to the a.c. cable. It becomes clear that HVDC cables can transmit much more power per invested material than three-phase ac cables.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 265 of 306

Table 10.3 Mass content of various materials in two types of submarine power cables. All mass figures in kgs

	170 kV a.c. 3 × 400 mm^2 Cu	HVDV 150 kV 1 × 1200 mm^2 Cu
Copper	11	22
Lead	22	13
Steel	20	16
XLPE	8.3	3.8
Other polymers	5.9	2.2
Tapes	0.8	0.8
Optical cables	0.2	–
Anticorrosion agents	<0.5	<0.5

10.4 Environmental Aspects of Cable Installation

Like any construction activity, the installation of submarine cables affects the environment. Encouraged by the requirements of the authorities and the public opinion, the client will follow rules and standards in order to minimize the environmental impact.

All cable installation starts with the transport of the cable. As most submarine cable factories have an own port, cargo vessels offer a cost-efficient transport method even for short drum lengths. Cargo ships are known to have the best fuel economy per payload unit of all transport methods. Transport by truck has a larger environmental impact than sea transports.

It is taken as a prerequisite that the contracted transport and installation companies comply with industrial environmental standards also for their offshore activities. It is recommended to subject contractors to an HSE (Health, Safety, and Environment) audit. An established HSE incident reporting system enables a close follow-up.

The installation of submarine cables may comprise a few separated activities along the cable route. The first thing to do, after the desk-top studies, is a marine survey. In most cases, this is performed using minor survey vessels that do not impose a greater environmental impact than any other equally sized vessel. There are no reported indications that the used high-frequency sonar methods with low audible amplitude affect cetaceans or other marine mammals.

After survey, the cable route sometimes needs to be cleared of obstacles. Different methods can be used:

Pre-Lay Grapnel Run (PLGR): A hooking device (grapnel) is pulled along the seafloor prior to the installation operation. The hooking device is much smaller than most commercial fishing gear. If existent, seafloor vegetation can be uprooted in a very narrow corridor defined by the grapnel size. The PLGR is considered non-invasive to the seafloor.

Singular actions can be taken where abandoned cables or lines are cut; wrecks or other man-made obstacles are removed. Abandoned anchors and fishing gear *en route* are removed to tidy up the seafloor.

Rectification of the cable route. When the seafloor is littered with outcrops, boulders or other obstacles it can be difficult to find a manageable cable route between these obstacles avoiding free spans and other hazards. A close-up optical survey can be done by non-disturbing ROV operation. In earlier times the cable route was rectified by blasting a clear "road" through the debris on the seafloor. This method would not be accepted today in most waters.

The cable laying per se is a quite slow and calm activity. The CLV is travelling slowly along the cable corridor (at 0–3 knots) emitting the typical noise of vessels of similar size. Cable laying equipment such as capstan wheels, linear cable engines, etc. are installed on-board and do not contribute to noise outside the hull. No chemicals or gases are released during the laying except for the normal exhaust fumes from the vessel engines. The waste from normal vessel operation is stored and processed according to vessel standard. If the CLV is travelling along close-to-beach routes, where large vessels normally not operate, the beach-side dwellers might sense some low-frequency engine noise and exhaust smell during the duration of operation. The CLV also can disturb marine fauna especially during reproduction periods. Usually the permitting authorities will restrict the laying time frame avoiding periods of animal mating and breeding.

The cable is fed out from the CLV in a slow pace and moves down to the seafloor while the CLV is moving forward. Often the laying is monitored by ROV. ROVs use electric thrusters and bright lights that may frighten off animals and may disturb their behaviour for a short time. Some fish however seem to be very curious and look straight into the cameras of the ROV. Other animals can be observed while continuing with feeding under the close-up eyes of the ROV.

During the laying or afterwards ("post-lay trenching") most submarine power cables are buried into the seafloor. The burial by plough or waterjetting involves a vehicle moving on the seafloor either pulled by a surface vessel or by own propulsion. The trenching gear usually stirs up a lot of sediment in a narrow corridor (0.5–2 m) along the cable. Although most of the sediment settles back within short time, the sediment plume can, depending on sediment character and water currents, move hundreds of meters from the origin. Also, a local disorder in the natural layers can occur in the trenching zone. The degree of impact is depending on the trenching method and the soil conditions. The seafloor vegetation, if existent, will be disrupted in parts of this corridor. Benthos organisms[1] will be disturbed during laying operation, either by mechanical impact, or by scaring away. Animals living on these benthic organisms may leave the place with them.

Soft seafloors such as in the North Sea, or Baltic Sea, start to reorganize rather quickly after the burial operation. The trench refills itself unless it was cut in rocky soil. Mobile organisms like zoo benthos return to the area above the cable, and the vegetation recovers after a few growing seasons. In most cases the cable route is indiscernible within a year after burial. In the case of the SwePol HVDC cable in the Baltic Sea the zoo-benthos had returned completely within one year

[1] "Benthos" is the collective term for organisms living close to and in the seafloor.

after trenching [5]. The disturbances from the cable laying and burial are considered as temporary and small-size. Cable laying and burial is a singular event and should be evaluated in relation to other repeated disturbances by fishing gear ripping up the seafloor regularly. In the seafloors of the North Sea or the Baltic Sea that are being ruptured by trawling repeatedly, a single cable trenching would not make a difference. Comprehensive analysis and evaluation of the disturbances from cable laying can be found in the permits issued by the German marine authority BSH (Bundesamt für Seeschifffahrt und Hydrographie) for cable links to North Sea OWP [6].

However, there may be exceptions from this. Cable laying and burial in coral reefs and mangrove forests may cause irreversible damages. Every new cut can endanger the integrity of these biotopes. Other sensitive habitats such as sanctuaries for fish, mammals, amphibiae and waterfowl, might suffer damage, especially when the operation is being done during mating or nesting seasons.

Hazardous waste from hidden burdens, such as chemical dumps, ammunition dumps, also dumps of chemical warfare, can be stirred up and released into the sea water in critical areas during trenching. It is often not feasible to trench the cable in rocky seafloors. In that case, the cable can be protected by rock dumping or covering with concrete mattresses or something similar. The used materials must be compatible with salt water, neither must they leach out adverse substances.

Waterfowl react differently on the presence of the installation vessels. Some species are repelled for the time of installation, while others are attracted, as they would be by any other vessel. There is no obvious danger for waterfowl as long as the installation does not infringe their nesting habitat.

Concerns have been expressed for the noise impact on marine animals by submarine construction works. The sensitivity to noise of marine mammals is extremely difficult to access. The mammals live in environments that are not silent even in the absence of human activity. Marine mammals represent an extreme example of not only habitat adaptations but also adaptations in ear structure and hearing capabilities. Audiograms are available for only a few out of 119 different species of marine mammals, and these audiograms were recorded from captive individuals [7]. Marine mammals as a group have functional hearing ranges of 10 Hz–200 kHz. They can be divided into infrasonic balaenids (probable functional ranges of 15 Hz–20 kHz; good sensitivity from 20 Hz to 2 kHz), sonic to high-frequency species (100 Hz–100 kHz; widely variable peak spectra), and ultrasonic dominant species (200 Hz–200 kHz general sensitivity; peak spectra 16–120 kHz) [8]. Mammals use their voice and hearing capability for communications in the lower frequency range and for echolocation in the ultra-high frequency range. Most pinnipeds, such as seals, have their best hearing sensitivities at 10 kHz or above. Many documented examples show that cetaceans react on anthropogenic sound. Sound sources were sonar pingers, seismic equipment, vessel engines, industrial sounds etc. Behavioural changes in the presence of sounds range from shorter diving intervals, decrease or cessation of calls, avoidance of the place or escape. However, there is no evidence that these behavioural changes are biologically significant. Massive whale stranding has been associated to the use military of high-energy

mid-frequency sonar. A clear demonstration of the causal relation is still to be done. Very little is known about the hearing capabilities of fish, marine invertebrates or marine reptiles.

For the case of noise generation, submarine cable installation should not be confused with other offshore activities involving hammering down poles into the seafloor.

10.5 Environmental Impacts from the Operation of Submarine Power Cables

10.5.1 Thermal Impact

Power cables transmitting electric power dissipate losses in form of heat. The amount of heat losses at full transmission power is 10–100 W per metre of cable, which is corresponding to the heat from a household light bulb every metre. Inevitably the heat is transferred into the surrounding ambient. Cables installed on the seafloor do not heat up their surrounding as the water washes away almost all heat. However, the cable surface of the freely installed cable might be some degrees warmer than the surrounding water. Buried cables warm up the surrounding soil in the long run. Figure 10.2 shows the isothermal lines of temperature rise around a typical HVDC cable installation under the seafloor. It is a pair of 100 mm dia HVDC cables buried 1.0 m under the seabed. Each cable has a heat loss of 30 W/m. For the sake of clarity the isothermal lines are drawn only up to 26 K. The cable surface temperature is approx. 32 K above the seabed temperature.

The temperature rise in the immediate vicinity of the cable may alter the conditions for deep-dwelling cold-adapted organisms. In most cable projects this limitation is of no great concern as submarine power cables are designed to eliminate excessive losses. From subsea inspections and recovery operations it is known that many submarine power cables are colonialized by molluscs, starfish and other species. Probably submarine power cables, similar to artificial reefs made by OWP foundations or sunken ships, constitute new habitats in otherwise featureless seafloors.

10.5.2 The 2 k Criterion

The losses in buried submarine power cables generate a temperature rise in the surrounding soil. If the cable is fully loaded over months the cable surface can reach a temperature of 40–50°C. This is, however, an extremely rare situation. Most submarine power cables have an average load much lower than the maximum rated load. The temperature decreases with the distance to the cable. A few meters from the cable there is practically no sediment warm-up (cf. Fig. 10.2). The

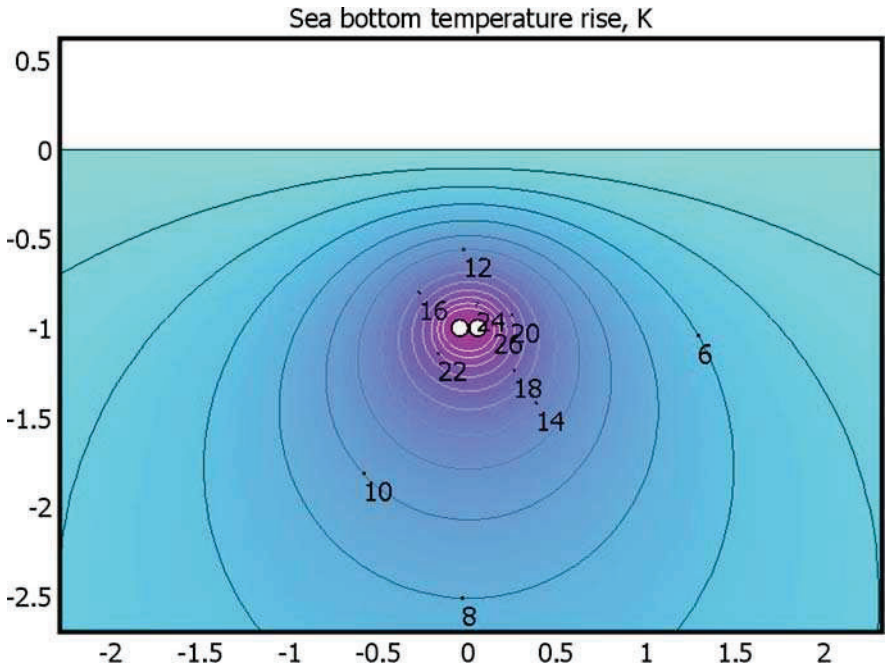


Fig. 10.2 Isothermal lines around a pair of submarine HVDC cables. The horizontal line at "0" represents the seabed. The *y*-axis is the vertical position and the x-axis the horizontal position, expressed in m. The numbers in the diagram express the temperature rise above the temperature of the seabed, expressed in K. Spacing between isothermal lines is 2 K

changed temperature situation in the soil close to the cable alters the living conditions for *benthos.* Most of sub-seafloor dwellers live in the upper few centimetres of the seafloor. There are concerns that the temperature change could change the metabolism and reproductive behaviour of the zoo-benthos. Psychrophilic (cold-loving) organisms within the benthos might be expelled from the cable corridor, while new, foreign species may be attracted to the new "warm" habitat. Neither of this is wanted. Also, the contents of nutrients and oxygen can possibly be changed by altered temperature profiles. Still, there is no scientific evidence for any of these concerns. If there is a measurable impact of the local heat generation on marine life, it is limited to a very narrow corridor along the cable.

The question was discussed in greater detail when a number of submarine cable projects were filed for permission in the Wadden Sea off the German North Sea coast. The Wadden Sea is a national park and biosphere reserve recognized by UNESCO. Naturally, environmental issues came into focus when cable project applications arrived at authorities. To cope with the situation and to prevent possible damages to the environment, a German environmental authority (Nationalparkverwaltung Niedersächsisches Wattenmeer) has issued a recommendation that

the temperature rise over a buried submarine power cable should not exceed 2 K[2] at a depth of 0.3 m below the seafloor, compared to the undisturbed seafloor. Another German environmental authority (Bundesamt für Naturschutz) has recommended a 2 K limit for a depth of 0.2 m, valid for the German Exclusive Economic Zone outside the 12-sm national zone. The German marine authority (BSH), which is in charge for the permits for submarine power cables in the EEZ, also defines a 2 K limit for a depth of 20 cm under the sea bottom [9]. Empirical support for this recommendation is not available. Perhaps the defined limits will be changed when evidence condenses.

The temperature rise at the –0.2 and –0.3 m levels, respectively, can easily be calculated with FEM software. Another simplified calculation method is described in Chap. 3, which can be performed with a simple pocket calculator. No matter which method is used, a good knowledge of the thermal resistivity of the seafloor and the expected cable load scheme is necessary.

What happens if a cable project does not meet the 2 K criterion as formulated above? A strategy to reduce the warm-up at the –0.2 and –0.3 m levels, respectively, is a deeper burial depth. Deeper down the cable has a smaller impact on the reference levels, everything else unchanged. For a single cable with 50 W/m losses and a burial depth (BD) of –1.0 m the temperature increase at –0.2 m would be 3.23 K.[3] To meet the 2 K criterion at –0.2 m the BD must be increased to –1.6 m. However, this strategy also has negative impacts on the environment. As outlined above, all benthos will be disturbed in a small corridor during the burial operation. Burying the cable down to –1.6 m would affect more benthos than a –1.0 m burial, both due to the larger depth and due to the wider corridor associated with a greater burial depth. Also, since a deep burial operation is more complicated than a shallow, the duration of the construction work is prolonged. The same applies for the recovery of the submarine cable after end of life.

Furthermore, the cable operation temperature (both on the cable surface and the cable conductor) increases. In the example above, the cable temperature is expected to increase with 4 K. At higher temperatures, the cable losses increase and destroy valuable electric energy. Using a greater burial depth to meet the 2 K criterion would result in extra environmental impacts, such as more seafloor disturbances, higher cable temperature, larger energy losses, and a larger volume of seafloor being subjected to cable heating. These effects should be accounted for when discussing the 2 K criterion in environmental assessments.

Another strategy to meet the 2 K criterion is the reduction of cable losses. For the situation described in the previous paragraph the cable at –1.0 m should have losses of 31 W/m rather than 50 W/m to meet the 2 K criterion. Loss reduction in submarine power cables can be achieved by different design measures. The most prominent is the investment in a larger conductor. In HVDC cables, the reduction from

[2] 1 K is one degree step on the Celsius scale.

[3] This has been calculated for a seafloor thermal resistivity of 1.0 K**.**m/W. To adopt the result to a real situation just multiply with the actual thermal resistivity.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 271 of 306

50 to 31 W/m would require a conductor area growth by 61%. Increased conductor area would benefit the environment also by reduced energy loss, but is difficult to negotiate with investors. Furthermore, the environmental footprint of the production of the large conductor cable is obviously much larger than for the smaller cross section.

It is not the task of this book to argue the reasonability of the 2 K criterion. However, for the sake of better understanding, it could be useful to put the temperature rise of 2 K into perspective. The annual variation of the seafloor temperature can be as much as 15 K in shallow waters. It is also known that the seafloor temperature can vary considerably between different locations in the same area. That means that a seafloor which is 2 K warmer than another place in the neighbourhood, is probably not a "disturbed" environment. It seems that the environmental concerns would benefit from a wider view on the matter. Maybe a narrow corridor of 5 K warm-up (from a shallow cable) makes less harm than a wide corridor with 2 K warm-up and a larger heated soil volume (which would be the case with a deeper cable).

10.5.3 Electromagnetic Impact

The nature of electromagnetic phenomena is not easy to grasp for non-electric engineers. The public is concerned about the exposure to all kinds of electromagnetic fields in daily life. Sometimes things are confused and pre-mature conclusions are drawn. Fortunately, the issue is not as complicated as it might seem. To start with, two properties of the electric and magnetic fields from power cables should be mentioned:

- Due to the low frequency, the fields around the cable do not constitute a "radiation" such as radiation from cell phones, antennas etc. The intensity decreases very strongly with distance.
- The fields from the cables contain so little energy that any ionising or cell disruptive effects are excluded.

For the consideration of power cables, electromagnetic fields can be separated into electric fields and magnetic fields. In the cable case, these fields are independent from each other except a few cases.

Electric fields are confined between conductive surfaces with a potential difference in-between. This is the case in power cables. The electric field exists between the high-voltage conductor and the grounded screen/armoring. As the screen/armoring is on the same electric potential as the ambient outside, there is no electric field outside the cable. The screen/armoring efficiently confines the electric field to the inside of the cable. This is valid for any power cable, regardless the design, rating, single-core or three-core cable, a.c. or d.c.

A secondary electric field effect is caused in the vicinity of a.c. cables. The a.c. current in the conductor creates a magnetic field outside the cable. This alternating B-field generates, according to the Maxwell laws, an alternating electric field

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 272 of 306

with very tiny amplitude within the range of a few μV/m. This is much less than the electric field produced by the battery in the LED-lit key chain in our pocket. Some *elasmobranch* fish species such as sharks, rays, and skates, can sense these extremely small electric fields. They are assumed to use electric field sensation for orientation in the electric fields generated by water movement in the geomagnetic field, and for detection of prey. The *elasmobranch* detection level is within the range of 0.5 . . . 1000 μV/m, the avoidance limit being assumed at >100 μV/m.

The magnetic field is somewhat different. Any conductor is surrounded by a magnetic field generated by the current. The intensity of the magnetic field at a certain distance from the linear conductor is according to the Biot-Savart law:

$$B = \frac{\mu_0 \cdot I}{2\pi \cdot d}$$

where B is the magnetic field[4] at distance d from the conductor, I is the conductor current,[5] μ_0 is the magnetic constant $\mu_0 = 4\pi\ 10^{-7}$ T·m/A, where T (Tesla) is the unit for the magnetic field (also called magnetic flux density).[6] As an example, the magnetic field at 1 m distance to a conductor carrying 1000 A would be $2{\cdot}10^{-4}$ T = 200 μT. Most often HVDC cables are installed in pairs with currents flowing in opposite direction. Therefore their magnetic fields are also anti-directional and cancel each other to a large extent, depending on the distance between the conductors. As a result, the magnetic field decreases very rapidly as a function of distance from the cable pair. Figure 10.3a shows the magnitude of the magnetic field vector over a pair of HVDC cables carrying 1000 A each. The cable pair is installed at the level –1.0 m under the seafloor. The axial distance between the two cables is 0.1 m, i.e. they are laid touching each other, or close to. The lateral distance from the centre axis between the cables is drawn on the x-axis. The upper curve illustrates the B-field on the seafloor. The next curve is the B-filed at the +5 m level and the lowest curve represents the B-field 10 m above the seafloor. Here the B-filed is far below 1 μT. Figure 10.3b shows the magnitude of the magnetic field vector over a pair of HVDC cables laid with 10 m distance to each other. Again, both cables carry 1000 A in opposite direction. The sequence of the three curves is equivalent to that in Fig. 10.3a. At the seafloor, 1 m above the cables, the B-field reaches values of 200 μT. At 10 m above the cable pair the B-field has decreased to 10 μT.

Most countries have developed recommendations or limitations for human exposure to electromagnetic fields. In 1992, the International Commission on Non-Ionizing Radiation Protection (ICNIRP) was established to investigate possible

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[4]Strictly spoken, the symbol B stands for the magnetic induction with the SI unit Tesla, while the magnetic field is denoted H with $B = \mu_0 H$. However, in power engineering context B is called magnetic field.

[5]The Biot-Savart formula assumes that the current flow is confined into a filament with zero diameter. For some distance from the cable conductor (>10 × conductor diameter) the Biot-Savart law can be used without any practical restrictions.

[6]The "Tesla" is a unit of the magnetic induction. Another unit is "Gauss". 1 T = 10,000 G = 1,000,000 μT.

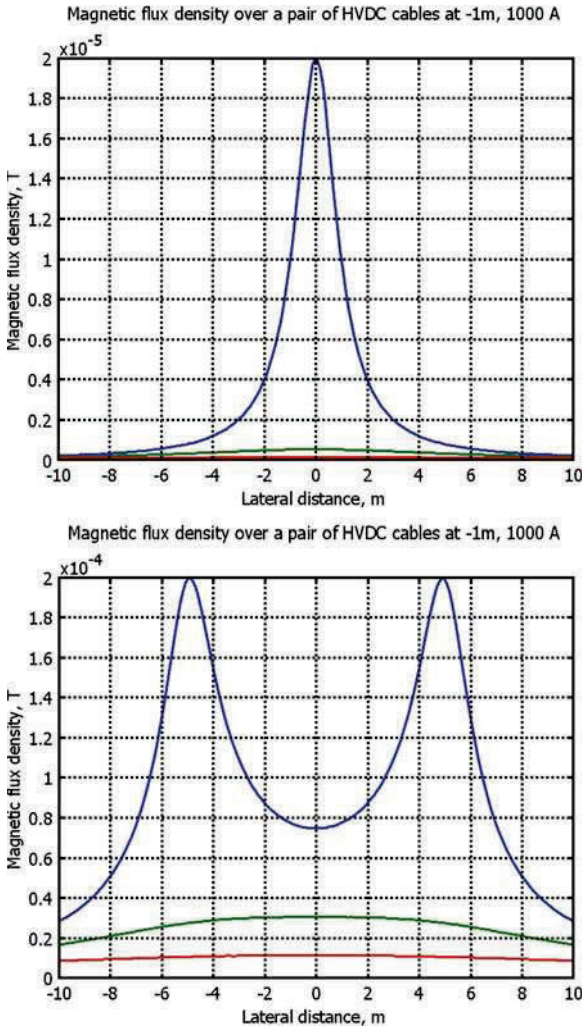


Fig. 10.3 Magnetic field around a pair of submarine HVDC cables carrying 1000 A. As the magnetic field is proportional to the current, the results can easily be scaled up or down for other current values. Upper diagram: cable pair installed touching. Lower diagram: cable pair installed with 10 m distance

hazards from electromagnetic fields, and develop international guidelines in radiation exposure. This work resulted in the "Guidelines for limiting exposure to time-varying . . . electromagnetic fields. . ." [10]. The guidelines cover frequencies up to 300 GHz (radio signals, mobile phones etc.), but for submarine power cables only two frequency ranges are relevant: 0 Hz (d.c.) and 50/60 Hz (a.c.). The recommended limits for human exposure for these frequencies are given in Table 10.4. Most European countries and Singapore, South Africa, South Korea, and Taiwan have adopted the ICNIRP values.

It is obvious from the diagrams that the magnetic fields emitted from d.c. cables are far below all known limits, even in close vicinity. Therefore no risks for human life or health can be anticipated from the magnetic field of HVDC cables. Concerns

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 274 of 306

Table 10.4 ICNIRP Guidelines for magnetic fields

	Occupational exposure	Public exposure
0 Hz (d.c. cables)	200,000 μT	40,000 μT
50 Hz (a.c. cables)	500 μT	100 μT
60 Hz (a.c. cables)	417 μT	83 μT

have been raised on the impact of d.c. magnetic fields from HVDC cables on submarine organisms, in particular fish relying on geomagnetic orientation during reproductional migration. Investigations carried out by the Swedish Fishery Authority demonstrated that some fish species obviously are not affected by the magnetic field of the SwePol cable, one of the highest rated submarine HVDC cables. Eel, known for its ability to navigate using the geomagnetic field, showed no abnormal behaviour when crossing HVDC cables.

Sometimes the magnetic field from HVDC cables is compared to the geomagnetic field, which is considered harmless to organisms. The intensity of the geomagnetic field is different at each location on earth but it is within the range of 0–50 μT. More serious than the impact on animals of magnetic fields from d.c. cables is their possible influence on the function of magnetic compasses. Magnetic compasses rely on the geomagnetic field and can be disturbed by other magnetic sources. Magnetic compasses can suffer a deviation in the immediate vicinity of powered submarine HVDC cables. The amount of deviation is depending on:

- Distance between the conductors of a cable pair
- Magnitude of the d.c. current
- Vertical distance between cable pair and compass localisation. The distance is the sum of burial depth, water depth, and height of the ship's bridge over the water surface. On large vessels, the bridge can be some 10–30 m over the water surface
- Magnitude and orientation of the local geomagnetic field
- Cable route heading. An East–West cable produces magnetic fields in N–S direction, which add to the geomagnetic field but do not alter the direction. The impact on magnetic compasses is much less than from a N–S cable under similar conditions.

For a small vertical distance between cable pair and the compass, considerable deviations (30° and more) can be observed directly over the cable pair. The corridor of noticeable disturbance along the cable is only a few tens of meters m wide.

It could be demonstrated that ships steered by autopilots based on magnetic compasses may suffer considerable route changes when passing over a single-pole HVDC cable [11]. When the vessel travels towards an HVDC cable the increasing deviation may trigger the magnetic autopilot to take action to correct for the perceived erroneous heading. In the worst case, the autopilot will steer the vessel so that it follows the cable route; the vessel is "captured" by the cable. Tests with a 17 m vessel with non-metallic hull were conducted over the Kontiskan cable in

monopolar operation at 1200 A and 20 m depth [11], and confirmed the risk of "capturing". This risk is larger if the vessel heading at small angle to the cable route before crossing. In less onerous cases the autopilot steers the vessel over the cable route with unchanged heading but with a lateral displacement. Vessels are affected in different ways depending on their size.

Small vessels such as leisure vessels navigate shallow waters where the vertical distance between cables and compass can be very small. The magnetic compass of these vessels may suffer large deviations in the immediate vicinity of the HVDC cables. Normally, these vessels are navigated also by visual orientation and/or GPS based systems, which are not affected by magnetic disturbance. In a risk evaluation, the additional risk due to compass deviation seems small compared to risks from ignorance and bad seamanship. The consequences of a vessel accident are quite small.

Medium size vessels (draught 2–4 m) can normally not navigate into the shallowest waters. The magnetic compasses of these vessels can still be affected by magnetic deviations. The result can be a lateral set-off of the vessel′s position. This would be serious in a ship separation lane, where the vessel, involuntarily, could be steered into the lane of opposite direction. But in ship separation lanes the water depth is large enough to provide a sufficient vertical distance between the HVDC cables and the magnetic compass.

Large vessels (draught < 5 m) have usually a large vertical distance between the compass position and the cable pair. These vessels have a long response time for course changes. They travel through the influence corridor before the magnetic autopilot can turn the vessel very much. The risk for these vessels is considered very low.

Only magnetic compasses and magnetically controlled autopilots can be affected by cable's magnetic field. Almost all commercial vessels have redundant gyrocompass or GPS based navigation and steering systems, which are not affected by magnetic fields.[7] HVDC cables do not impose a risk to marine traffic. Still, some countries require that commercial vessels have magnetic compasses as back-up systems.

In a.c. cables the current in each conductor is changing its direction 50 or 60 times a second, and so is the magnetic field. In three-phase cables the three magnetic fields from the conductors are superimposed to each other. For an observer at large distance (called "far-field", e.g. 25 times the cable diameter) all three conductors seem to have the same distance and direction. Hence the three magnetic fields cancel out each other almost perfectly. To a near-field observer close to the cable, the conductors are not exactly at equal distance and hence their magnetic field does not cancel out each other's perfectly. A minute residual magnetic a.c. field can be measured.

[7]Some GPS use incorporated magnetic compasses to detect global directions when the vessel is not moving and the NSWE direction cannot be determined from incremental positioning.

Single core cables often have a much larger distance between the conductors resulting in a poor cancelling of magnetic field at least in the near-field range. However, in single-core a.c.cables the conductor current induces a counter-directional current in the screen of the cable, resulting in a largely decreased external magnetic field.

10.5.4 Chemical Impact

Under normal operation conditions submarine power cables do not release chemicals, consumables, or other agents to the ambient. The materials are designed to be stable under the influence of seawater for decades. Cables with solid insulation (XLPE, EPR, mass-impregnated) do not contain fluids that can leak in case of cable damage or rupture. The impregnation compound in mass-impregnated HVDC cables is so viscous (thick-flowing) that there is practically no outflow from the cable even if it is cut [12].

A different situation arises for oil-filled cables with low-viscosity insulation oil. These cables are now installed only for the highest voltages (230 kV and above) as they have a long operational record. The oil inside these cables is pressurized from onshore feeder stations, and pours out into the sea when the cable is damaged. In case of damage the cable owner tries to counteract the intrusion of water by pumping in more oil into the cable. It can take days and weeks before the cable leakage can be localised, and the cable can be picked up and sealed. A damage on a 420 kV Öresund cable between Sweden and Denmark in 1979 could be localized only after observations of the oil plume [13]. When an oil-filled cable on the Oslo fjord was damaged in April 2008, oil leaked out from the cable initially at a rate of 80 l/h. When one of the 138 kV Long Island cables was damaged by a ship anchor, the initial outpour of cable oil was 450 *l* a day; it took 10 days to seal the faulty cable [14]. The good thing is that the cable insulation oils have so low viscosity that they usually evaporate rather quickly from the water surface. The cable insulation oils used to be low viscosity mineral oils. Since the 1980s synthetic cable oils have been used both for refurbishment and production of cables. Most of the synthetic oils are linear alkylbenzenes (LAB) with varying molecular weight composition. LAB is miscible and compatible with mineral oils. LAB is biodegradable, but little is known on the rate of degradation under the exclusion of air. The toxicity of LAB has been demonstrated by tests showing that the LC_{50} mortality concentration in soil for a nematode species is less than 1% [15]. A study on the subject and further references have been published in [16].

10.6 Recycling of Submarine Power Cables

There are few options to proceed after the useful life of a submarine power cable. It is easy to leave the defunct submarine cable in place and announce it as "abandoned" to authorities. It is difficult to pull up buried cables, and the scrap value might not

pay the salvage costs. Abandoned cables continue to be an obstacle for fishermen (a late revenge of the cable owner perhaps?) and must be cleared before new cables are being laid. If it is decided to leave the cable in place, it is possible to remove the insulation oil by subsequent flushing the cable with solvents and fill it finally with water [17].

Another solution, sometimes also required by permit authorities, is the recovery of the cable from the sea floor. Recovery of buried cables can be difficult. Even heavy-armored cables can break under the load of a pull-up operation, but recovery is possible. As an example, 76 km of 138 kV submarine power cable were removed from the Georgia Straight between Vancouver Island and the Canadian mainland in 2007 after 51 years of service [18]. Once the cable has been recovered from the seafloor, it can be recycled in a number of different ways. The first step of every recycling is the separation of materials. The metal fraction in the cable (steel, copper, lead, and other non-ferrous metals) can be separated easily by mechanical disintegration and separation using the large difference in specific gravity of metals versus other materials. The value of the metals can partly pay for the cost of the cable recovery. A promising method to cut open long lengths of cable is the use of water-jets running along the cable.

The clue to a successful recycling of polymeric components (polyethylene, XLPE, polypropylene, PVC, EPR, EPDM, etc.) is the separation of the cable constituents into clean material streams. A sink-and-swim separation in water creates a polyolefin stream with PE, XLPE, PP, and the "PVC" stream containing conductive materials, PVC, EPR, polyester, etc. A material recovery (using it for production of new materials) is only possible with very clean homogeneous streams. The chemical recycling of silane-linked XLPE has been demonstrated in Japan [19]. The most cost-efficient and environmentally wise methods seem to be the use of the cable polymers as fuel in thermal power plants normally fuelled with waste or biomass. A comprehensive overview on recycling possibilities can be found in [20].

No methods have yet been reported to re-use paper insulation. Paper insulation makes up a good fuel for biomass fuelled power plants or district heating plants.

The third solution is the use of submarine cables to build habitats for marine life, or artificial reefs. It has been observed many times that organisms, such as molluscs, algae, starfish, corals, crustaceans, etc., settle or live on submarine cables. Marine organisms are in general attracted to items different from a flat seafloor, so artificial reefs have been built from all sort of structures. Of course, the materials must be cleaned from all residual fluids and other hazardous items. Both defunct cables and defunct cable laying ships have been used for this purpose [21].

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Chapter 11
Anecdotes

Contents

11.1 The Floating Hospital S/S Castalia 270
11.2 HVDC Cable Between Lydd, UK and Boulogne, F 270
11.3 The Pilot 271
11.4 S-Lay and Coiling Direction 271
11.5 Edible Insulation 273
11.6 Flipper 273
11.7 Stamps 274
11.8 Unusual Cable Ships 274
11.9 Master Teredo 276
11.10 Krauts at War Searching for a Cable Break 276
11.11 Even More Damages 277
11.12 Loops 277
11.13 Cable Ship Reefs 277
11.14 Poetry 278
11.14.1 The Journey of Mrs. Florence Kimball Russel 279
References 280

The professional life of the cable engineer seems to be boring, maybe even desolate. The product he (in rare occasions: she) is working with has reached great technical maturity with no high-tech appeal whatsoever. Submarine power cables have no aesthetic value as no manufacturer so far has spent money to print small fish or sweet little anchors on the outer sheath. The product is invisible in the public life – like a sewage pipe. May be even lesser known to the great public. In contrast to the rocket scientist and the TV talk show leader the cable engineer would speak rather quiet about his/her profession in the dancing hall or in the flirt line.

T. Worzyk, *Submarine Power Cables*, Power Systems,
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NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 280 of 306

Still, sometimes laughter can be heard during coffee breaks in the cable factories, the electro-technical institutes, or during expert conferences. The reason might be a funny story from the strange world of submarine cables. Some anecdotes and little tales are printed in this chapter. All this material is compiled from rumors and tales, sometimes from printed matter[1]. The author hopes to receive more and better stories from the vast treasure out there, for the next edition of this book.

11.1 The Floating Hospital S/S Castalia

The steamship S/S Castalia was built in order to facilitate the Dover-Calais traffic in the 1880s. After a few trial tours it was decided to de-mobilise her and commit her to other duties. Laid off, she was intended to serve as a pest hospital vessel near Dartford, England.

For matters of convenience the vessel should be equipped with electrical illumination. Four submarine cables with extra heavy armoring and an insulation made from vulcanised bitumen were produced by the "Callender Bitumen Telegraph and Waterproof Company". The year is 1889. Vulcanised bitumen had been patented in 1881 and had been used successfully in land cables.

The cable laying was successful onshore. But when the workers got to know that the cable was to be laid to a pest carrying ship, they terminated the work and preferred to attend the near-by "Long Reach Tavern". The duty engineer, George Barnard, soon realised that all attempts to persuade the crew to continue working would be futile.

He rowed the pull wire to the pest hospital vessel, and let the hospital staff pull in the cables. It is untold if also the sick were told to pull. The engineer himself concluded the cable termination work onboard alone [1].

11.2 HVDC Cable Between Lydd, UK and Boulogne, F

> "*C/S Dame Caroline Haslett" left Woolwich Cable Works at 24 May (probably 1961) for laying the English part of the cable. She made preps and test runs at the mooring position off shore. At the same time a shore gang made final preps to pull the cable inshore.*
>
> *The weather which had been perfect for the French operation, turned worse. It delayed the whole thing and added to the difficulties.*
>
> *On 7 June the ship was fixed on a mooring point 1400 yards offshore. The cables were pulled out with pull wires towards the beach (winch on beach). Cables supported by air cushions (rubberized canvas air cushions). Cable pull out at 40 ft/min. Suddenly (when 360 yards were out) one air cushion and then two more broke away from the cables.*
>
> *Chain reaction: Under the increasing weight of the cable all the other cushions were dragged under water and the whole cable pair disappeared.* [2]

[1] Text in *Italics* is reproduced directly from the cited references.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 281 of 306

11.3 The Pilot

I had overseen the design, testing, and part of production of this powerful submarine cable. Now I was on board one of the largest cable ships of the world with more than 6000 t capacity, to watch the installation. After years of woes and whoops in manufacturing and testing I would observe how “my” cable would go smoothly into the water.

I sat on the bridge and watched the “pilot”. The pilot is the cable laying chief. He/she commands the speed of all cable laying machinery, the vessel speed, and all other things relevant for the cable laying. By radio he/she controls all the slave cable engines and has the full responsibility for the cable laying operation. As always, the night shift included a certain amount of tiredness and sleepiness. To keep blood pressure positive people on the bridge usually start telling stories and fairy-tales. So I started to talk about an anecdote connected to the Leyte-Cebu cable system, which has been delivered by my company and another one. The Leyte-Cebu system included four single-core cables. Rated 230 kV, the cables were big guys. They were laid in parallel corridors about 1 km apart to make service possible if one cable should brake.

Shortly after laying, all four cables were reported broken and possibly disrupted. Disbelieve and incredulity were the main tempers in the offices of the cable factories. To prevent water from ingress, oil was pumped into the cable from the shore stations at a rate making necessary the air-borne import of new cable oil. It was a terrible mess altogether. During coffee breaks the possible cause of the breaks was discussed, ranging all between dynamite fishing and foreign sabotage. My eight-year-old son suggested a submarine volcano outburst as an explanation.

Later on the real cause became known. Another cable ship, laying a telephone cable for the Philippine Long Distance Telephone Co. across the power cable route had actually fresh sea charts but no information about the newly installed 230-kV cables. The tension curve from the laying displayed four neat peaks with one kilometre or so distance while the telephone cable was ploughed through the power cables.

The pilot listened to my narration with little interest while he watched the data monitors. “My” cable continued to roll out smoothly, and I felt in safe hands. He said, “And do you know who was the pilot on that telephone ship? It was me!”

11.4 S-Lay and Coiling Direction

Each trade has its own unwritten laws. Young engineers entering a design department of a radio manufacturer learn very early that volume knobs on the stereo always are to be turned clockwise to increase the volume. Why is that so? Is there a technical raison-d’être? The junior often does not dare to ask, anxious to avoid disparaging answers.

But why is it as it is? Why do we usually put an S-lay armouring on the cable so that it must be coiled clockwise? Can we do the other way round? Many things come

in a left-hand and a right-hand appearance, e.g. screw threads, electric guitars (after Jimi Hendrix), or road lane use. Left-hand driving empires and right-hand driving empires have risen and fallen no matter what.

The S-lay (or left-handed lay) armoring has been described as standard already in 1898 [11.3]. The notable Messrs. R. S. Newall & Co. and Messrs. Glass & Elliot, the first to apply iron wire armouring to electric cables, were in the wire rope business, where right-handed lay was tradition. No question, they produced the first armoured telegraph cables with right-handed lay. However, this lay direction soon led to some unexpected inconveniences. The coiling method of the day was to start coiling from the outer rim of the tank towards the inner hub. Once arrived there the cable would be laid straight outward again, only to start the next flake also from the outside. The guys in the coiling tank, the coilers, now were told to lay the cable clockwise, to accomplish for the armouring lay direction. The coilers found this very inconvenient as they were forced to guide the cable with their *left* hand while they were running around the coiling tank. The only way to overcome this inconvenience was to change the lay direction of the armouring.

Some cable makers listened to their workers later than others. The first transatlantic telegraph cable was made partly by Newall (right-handed lay) and partly by Glass & Elliot (left-handed lay). A splice between these cables would result in undesired untwisting under the influence of strain. This was a major engineering glitch, today possibly called Insufficient Interface Coordination. We do not know what was said in the board room when the mismatch was discovered but I and my fellow

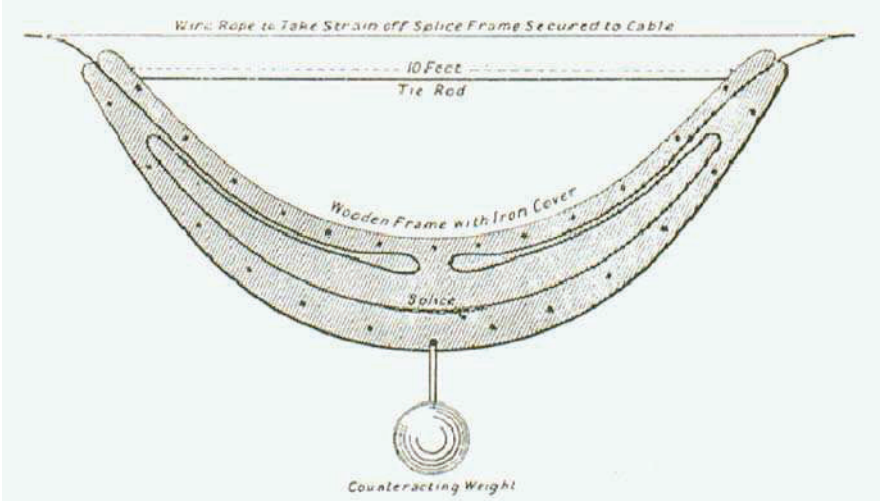


Fig. 11.1 Transition joint between *left-hand* and *right-hand* armoured submarine telegraph cable of 1856 [4] (Courtesy of Bill Burns)

cable engineers only can bow our heads to the ingenious solution conjured up in these days (Fig. 11.1).

11.5 Edible Insulation

There were no given insulation materials in 1875 when the students of the Cornell University wanted to install electric illumination on the Campus. They were in search of a good yet affordable insulation material. It was the time when photography was brought forward by "kitchen chemistry" to find ever better development processes. Under the guidance of their electrical professors the students decided to build up the cable insulation from muslin, a fine fabric. The cable core was impregnated in beef drippings obtained from the local butcher [1]. Unfortunately, no records on the success of this strategy have been found yet.

11.6 Flipper

The North Sea is not always a cosy place for vacation. Many are the cable technicians who have fed the fishes during cable installation campaigns, especially during winter storms. The waves roll in relentlessly under the vessel, making even simple moves on board difficult. Not only easy tasks, such as balancing egg and bacon to the breakfast table, require full concentration but also cable work on deck or in the jointing house can be close to impossible when the vessel is rolling and swaying along.

J. S. and his team had finished a beautiful jointing job on the North Sea. The vessel was about to lay the next length of the power cable. It was decided to transfer the jointing team to shore for other duties. The vessel had no helicopter platform, so a transfer vessel was called in for taking up the jointers team. It is always a tricky thing to enter a rather small transfer vessel from a large vessel. The transfer vessel would approach the large vessel from the lee side, positioning its bow as close as possible to the large vessel. The man to be transferred would hang on a rope ladder outboard of the large vessel, watching the heaves of the bow of the small transfer vessel. The trick is to jump over to the transfer vessel exactly when the bow stands still for a split second on the top of its movements.

J. S. prepared himself for the transfer. His barrel-shaped body filled his orange survival suit completely without as much as a cubic inch of air inside. Familiar with the procedure, J. S. watched carefully the heave of the transfer vessel. After a few wave movements he stepped over on the bow of the transfer vessel. And now something unexpected happened.

Unforeseeably, another wave arrived under the transfer vessel, lifting up the bow with large force and speed. The bow went up like a catapult, sending J. S. right up in the air like an orange Michelin Man. J. S. flew a beautiful ballistic curve before he, head first, smashed into the water. While J. S. was picked up very quickly by the transfer team, a Danish voice rated the flight: "Nine point three!"

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 284 of 306

11.7 Stamps

The production and laying of submarine cables, may it be telecom or power, is a century-old art mostly unknown to the public. Still, from time to time, the achievements are brought to general attention, and why not by stamps. Submarine cables of any kind are connectivity, and this can be an enormous step forward to island nations, or countries that can be festooned with submarine cables. However, it is not really clear why countries such as Rwanda and Bhutan (each far away from the coast line) memorize submarine cables on stamps issued by their post offices (Fig. 11.2).



Fig. 11.2 The "Great Eastern" on a stamp from Bhutan, 1989. The "Great Eastern" laid the first transatlantic telegraph cable in 1858

11.8 Unusual Cable Ships

The "Great Eastern" shown in Fig. 11.2 was the largest ship in the world of those days, mobilized for this truly great cable-laying job. Not every submarine power cable project of more recent date did enjoy the participation of such an impressive vessel. Cable layers do not need the luxury of the biggest and brightest but make do with anything that can serve their purpose.



Fig. 11.3 (**a**) Purpose-built cable laying arrangement for calm waters. (**b**) Floating cable drum used as laying vessel. (Courtesy of NKT Cables A/S)

Figure 11.3a looks like a cosy installation job in calm waters, a colourful sunshade inviting to an after-hour-drink. However, the howl of the hydraulic gear would make the conversation somewhat inconvenient. Still, this cable laying spread can do its job perfectly well.

The Danish cable manufacturer NKT has successfully used floating cable drums for cable installation. Figure 11.3b illustrates that cable laying vessels can indeed come in many shapes. The floating drum was used for the installation of the Oresund cables between Denmark and Sweden in the 1950s [5]. Obviously, this technique was appropriate for short cable lengths and installation under vacation-like bathing weather, though the Oresund cables were installed in winds up to 10–12 m/s.

Cable installers would probably love to be enrolled on a job using a blimp (airship, Zeppelin) for their task. It is an amazing imagination sitting aloft over hostile swamplands with gaping crocs and poisonous frogs, paying out cable in a pleasant pace and enjoying an inspiring sunset drink. This is what the inventors of the patent application shown in Fig. 11.4 must have dreamt of [6].

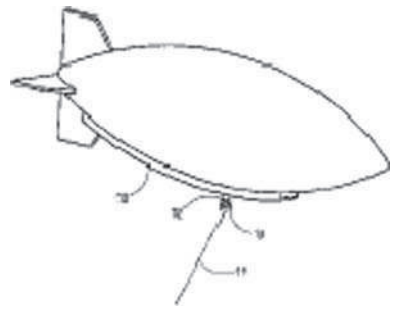


Fig. 11.4 Cable laying airship illustrated in a patent application

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 286 of 306

11.9 Master Teredo

Not unlike a science fiction creature, the teredo worm is a very nasty submarine animal eating almost everything in its way. It has a rasp-edged shell, which it uses like a buzz saw to cut through wood – or through submarine cables. Cable companies learned the hard way, early on, that it likes to eat gutta-percha, an early plant-sap-based cable insulation.

The following text is taken from a book on submarine cable laying and repair published 1898:

> "*For protection against the teredo the Telegraph Construction and Maintenance Company serve the core with brass tape, a layer of white canvas tape . . . This was introduced by Mr H. Clifford, the engineer of this Company, and has proved the most efficient protection . . .*
>
> *For this purpose also, Bright and Clark's compound, containing mineral pitch, tar, and finally powdered silica is used in alternate layers with jute yarn outside the sheathing wires (sheathing means armouring in this text) by most manufacturing companies. From the success of this compound it would seem that the sensation felt by Master Teredo as his boring-fang touches the sharp glass-like grains is one which he does not care to experience again. The compound, in fact, was devised to render this part of his organisation useless for further exploits of the kind, at any rate on submarine cables."* [3].

Few, if any, cable engineers of today have the opportunity to give name to a particular cable constituent or production process. Still, some respected colleagues have lent their names to production methods. The Hjalmarsson degree of compactness of paper insulation is based on a sophisticated "kick-the-tires" with a cedar-wood pen. Paper insulation can be firm and compact (desirable) or weak and swampy (undesirable). The pitch of the sound when a wooden pencil is knocked onto the cable insulation indicates the quality to the experienced cable engineer. Old fellow Hjalmarsson taught us young guys this lecture.

11.10 Krauts at War Searching for a Cable Break

> "*My father worked in the cable industry in the 1950s and 1960s. He tells an interesting story from the start of the second world war (WW II).*
>
> *Immediately after Britain declared war in 1939, a cable ship was sent out into the North Sea to dredge up the German cables, which ran from Hamburg through the North Sea and out into the Atlantic. They found the cables using a hook, exactly as described in this story, and cut through them.*
>
> *Of course it would be easy for the Germans to go out with their cable ship, dredge up the two ends, and join them back together again – if they knew where to look for the break. And it's not hard to find out how far along the cable the cut is, as a pulse will be reflected from the break. This had been well understood for a hundred years.*
>
> *Knowing this, the British engineers made some sort of contraption full of capacitors and coils that they could fix on to the end of the severed cable before dropping it back into the sea. This would add some extra delay to the reflection, causing the Germans to miscalculate where the break was, and send their cable ship to the wrong place."*

Cited from Internet [7], also referred to in [8].

11.11 Even More Damages

When the first transatlantic telegraph cable showed poor performance due to weak signal transmission, two gentlemen argued about the right cure. One of them was William Thomson, later named Lord Kelvin. The other was Dr. Edward Orange Wildman Whitehouse, a medical doctor, who clearly worked in the wrong field. He suggested, and tried, to cure the cable with 2000 V shocks from his patented induction coils, such ruining the cable insulation for good.

> *Dr. Wildman Whitehouse and his 5-foot-long induction coils were the first hazard to destroy a submarine cable but hardly the last. It sometimes seems as though every force of nature, every flaw in the human character, and every biological organism on the planet is engaged in a competition to see which can sever the most cables. The Museum of Submarine Telegraphy in Porthcurno, England, has a display of wrecked cables bracketed to a slab of wood. Each is labeled with its cause of failure, some of which sound dramatic, some cryptic, some both: trawler maul, intermittent disconnection, strained core, teredo worms, crab's nest, fish bite, even "spliced by Italians."* [9]

11.12 Loops

When a large cable ship installed a large HVDC cable some years ago, the DP system was not really the latest and could hold only a limited number of pre-programmed way points. During the night, the officer on duty fell asleep for a short moment while the vessel automatically traveled along the cable corridor. All of a sudden, the last of the pre-programmed way points was reached and the vessel stopped. Unfortunately, pay-out of the cable continued and an unknown amount of cable was fed over the aft wheel until the vessel started move again. The cable laying operation was finished.

A later inspection however revealed a "beautiful" loop where the cable had been paid out without ship movement. Post-lay trenching was not possible at the location and the cable loop had to be protected by expensive shiploads of rocks.

11.13 Cable Ship Reefs

There are some submarine cable project managers who allegedly uttered a sigh combined with the strong wish to blow up the cable-laying vessel (CLV) involved with their project. For them, it may be a little comfort to know that CLV can be really useful as habitats for corals and fish once they have settled on the sea floor.

On July 25th, 2003, the Government of Caribbean St. Eustatius created its latest reef. The "Charles L. Brown", a 320 ft cable-layer acquired from AT&T, was sunk in 95 fsw and now lays on its side on a clear sandy bottom. The ship was originally constructed in 1954 in Italy and was acquired by Statia's government in 2002. The vessel was prepared for sinking (cleaning of oils and fuel, removal of hazardous waste, opening of safety passages for divers) in an operation managed by

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 288 of 306

a committee of the three island dive operations, the Statia Marine Park and the Statia Tourism office. Today, a few short months after the sinking, divers can explore the wreck and observe as various marine organisms begin to make their home there [10].

The Navy cable ship USS Aeolus is one of the oldest artificial reefs. After a career as warship and cable vessel, she was sunk at her final resting place 22 miles south of Beaufort Inlet off Morehead City, North Carolina, in 1988. She sank on one side, but 1996 hurricane “Fran” turned the wreck through 90°, then righted here and broke here in three [11].



11.14 Poetry

In spite of their unimpressive appearance, submarine cables have been recognized in other literature than engineering books. The author of the Jungle Book, Rudyard Kipling, wrote a poem on submarine telegraph cables, transferring human messages through the unimaginably silent depth of the ocean. The poem goes as follows:

The Deep-Sea Cables

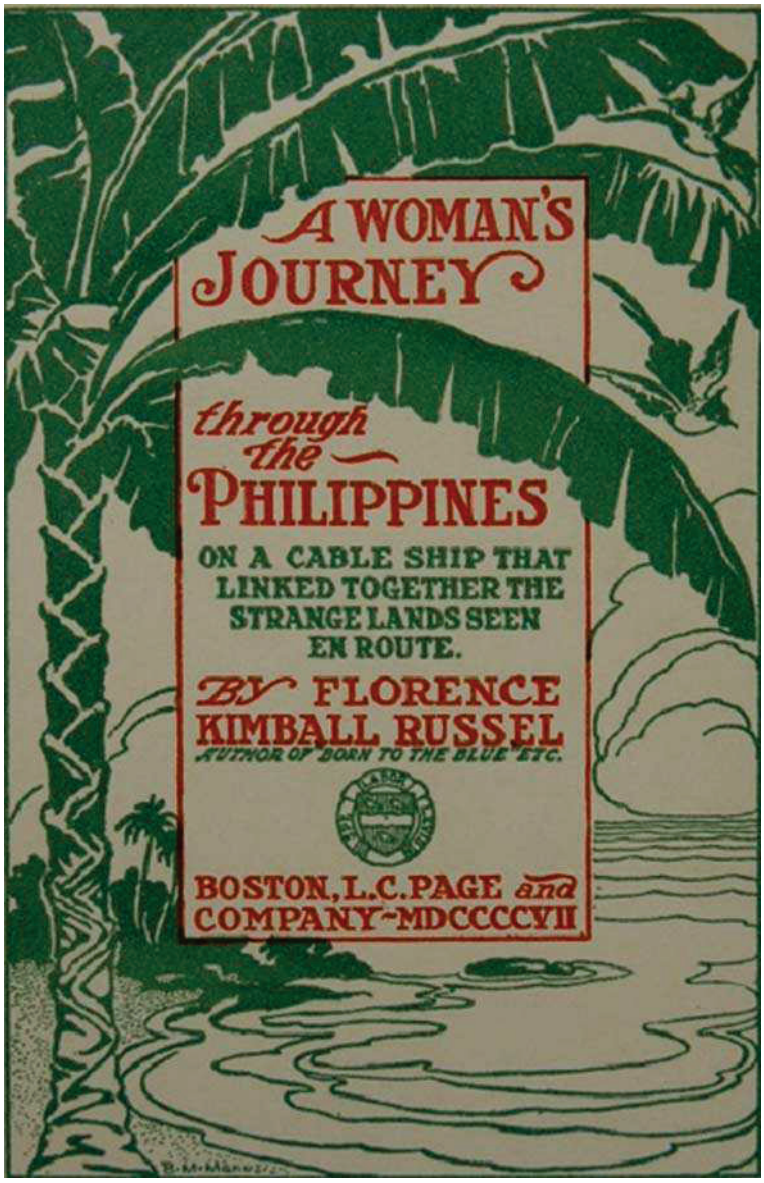
The wrecks dissolve above us; their dust drops down from afar –
Down to the dark, to the utter dark, where the blind white sea-snakes are.
There is no sound, no echo of sound, in the deserts of the deep,
Or the great gray level plains of ooze where the shell-burred cables creep.

Here in the womb of the world – here on the tie-ribs of earth
Words, and the words of men, flicker and flutter and beat –
Warning, sorrow and gain, salutation and mirth –
For a Power troubles the Still that has neither voice nor feet.

They have wakened the timeless Things; they have killed their father Time;
Joining hands in the gloom, a league from the last of the sun.
Hush! Men talk to-day o’er the waste of the ultimate slime,
And a new Word runs between: whispering, “Let us be one!”

11.14.1 The Journey of Mrs. Florence Kimball Russel

The figure shows the front cover of a book by Florence Kimball Russel, published in 1907. Mrs. Russel tells us about a long journey on a cable ship through the Philippine archipelago. Mission: installation of telegraph cables between the islands.



NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 290 of 306

Mrs Russel writes:

> *"Whether we are picking it up, or paying it out; whether it is lying inert, coil upon coil, in the tanks like some great gorged anaconda, or gliding along the propelling machinery into some other tank, or off into the sea at our bow or stern; whether the dynamometer shows its tension to be great or small; whether we are grappling for it, or underrunning it; whether it is a shore end to be landed, or a deep-sea splice to be made, the cable is sure to develop most alarming symptoms, and some learned doctor must constantly sit in the testing-room, his finger on the cable's pulse, taking its temperature from time to time as if it were a fractious child with a bad attack of measles, the eruption in this case being faults or breaks or leakages or kinks. . ."* [12].

No doubt, a book worth reading for a cable engineer. It not only pictures the worries of a cable installer, particularly at sea, but also reveals a great insight in the contemporary conditions in the archipelago.

Let me conclude this book with the words of Mrs Russel:

> **Life on a cable-ship would be a lotus-eating dream were it not for the cable.**

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Chapter 12
Useful Tables

Contents

12.1 Dielectric Properties of Cable Insulation Material 281
12.2 Lead Alloys 282
12.3 Non-metric Conductor Size: kcmil 283
12.4 Non-metric Wire Diameter 283
12.5 The Galvanic Series of Metals and Alloys in Seawater 285
12.6 Classification of Submarine Soil in Different Countries 286
12.7 Non-metric Units 287
12.8 Tidal Terms 288
References 288

12.1 Dielectric Properties of Cable Insulation Material

	Dielectric loss factor tan δ	Dielectric constant ε_r
Source: Anders [2] in Chap. 3 IEC 60287		
XLPE $\leq$ 18/30 kV	0.004	2.5
XLPE > 18/30 kV	0.001	2.5
EPR	0.005–0.020	3
Oil/paper >87 kV	0.0033	3.6
Mass-impregnated	0.01	4
Source: Allister [8], p. 100 in Chap. 3		
XLPE	0.008	2.5
EPR	0.04	3
Oil/paper >87 kV	0.004	3.3
Mass-impregnated	0.01	4
Source: Bartnikas [9], p. 99 in Chap. 3		
XLPE 20°C	0.002	2.3
EPR	0.0013–0.0023	2.7–2.8

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NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 292 of 306

(*continued*)

	Dielectric loss factor tan δ	Dielectric constant ε_r
Source: Deschamps [1]		
LDPE	8.10^{-4}	2.3
HDPE	8.10^{-4}	2.3
Oil/paper	30.10^{-4}	

Note: Tan δ is depending on temperature.

12.2 Lead Alloys

Alloy designation acc. to		Alloy elements and percentage (by weight). Min and max values						
EN50307	Convention	As	Bi	Cd	Cu	Sb	Sn	Te
PK008S	PbSb-0.5					0.45 0.55		
PK012S	½C			0.06 0.09			0.17 0.23	
PK021S	E					0.15 0.25	0.35 0.45	
PK022S	EL					0.06 0.10	0.35 0.45	
PK023S	½E					0.08 0.12	0.17 0.23	
PK031S	F3	0.15 0.18	0.08 0.12				0.10 0.13	
PK041S	Cu-Te				0.030 0.045			0.035 0.045
PK042S	½Cu-Te				0.014 0.020			0.014 0.020
PK043S	¼Cu-Te				0.006 0.009			0.006 0.009
PK049S	PbTeCu				0.03 0.045			0.03 0.045
PK071S / PK079S	Pb-Te							0.035 0.045

Note: Lead alloys and their constituents suitable for submarine cables. The table shows the designation according to EN 50307, and the conventional names for the nearest related alloy.

12.3 Non-metric Conductor Size: kcmil

The unit is based on the concept of a circular Mil. A Mil is 1/1000's of an inch (= 0.0254 mm), and a circular Mil is the area of a circle with a diameter of 1 Mil. Now, 1 cmil = 0.0005064 mm^2 and 1 kcmil is 1000 cmil = 0.5064 mm^2. Sometimes the acronym MCM is used for kcmil.

kcmils	mm^2	kcmils	Mm^2
300	152.01	800	405.37
350	177.35	900	456.04
400	202.68	1000	506.71
450	228.02	1250	633.38
500	253.35	1500	760.06
600	304.03	1750	886.74
700	354.70	2000	1013.42
750	380.03		

12.4 Non-metric Wire Diameter

In Anglo-Saxon markets the wire size is sometimes specified in non-metric units. Various "wire gauge" scales are deducted from the wire making process where the wire is drawn through consecutive dies each reducing the wire diameter. A higher wire gauge number indicates more wire drawing steps and a smaller wire. Some gauge scales are described here but there are more scales around.

AWG (American Wire Gauge)

Used in the United States since at least the 1880s for wires in all metals except iron and steel. Number 0000 wire is 0.4600 inch in diameter. The diameter of each succeeding size is 0.890525 times the diameter of the previous size.

BWG (Birmingham Wire Gage)

The steps are irregular. Departmental sanction by the United States government ended in 1914 but the scale is used widely even so.

SWG (Imperial Wire Gage, or British Standard Gage)

Legalized Standard Wire Gauge, Imperial Standard Wire Gauge, or in other countries, simply British Standard. Fixed by order of council August 23, 1883. It was constructed by improving the Birmingham wire gage. Made legal standard March 1, 1884.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 294 of 306

Gauge	AWG American Wire Gauge	BWG Birmingham Iron Wire	SWG Imperial Wire Gauge	AWG American Wire Gauge	BWG Birmingham Iron Wire	SWG Imperial Wire Gauge
	inch	inch	inch	mm	mm	mm
7/0	–	–	0.5000	–	–	12.700
6/0	0.5800	–	0.4640	14.732	–	11.786
5/0	0.5165	0.500	0.4320	13.119	12.700	10.973
4/0	0.4600	0.454	0.4000	11.684	11.532	10.160
3/0	0.4096	0.425	0.3720	10.404	10.795	9.449
2/0	0.3648	0.380	0.3480	9.266	9.652	8.839
0	0.3249	0.340	0.3240	8.252	8.636	8.230
1	0.2893	0.300	0.3000	7.348	7.620	7.620
2	0.2576	0.284	0.2760	6.543	7.214	7.010
3	0.2294	0.259	0.2520	5.827	6.579	6.401
4	0.2043	0.238	0.2320	5.189	6.045	5.893
5	0.1819	0.220	0.2120	4.620	5.588	5.385
6	0.1620	0.203	0.1920	4.115	5.156	4.877
7	0.1443	0.180	0.1760	3.665	4.572	4.470
8	0.1285	0.165	0.1600	3.264	4.191	4.064
9	0.1144	0.148	0.1440	2.906	3.759	3.658
10	0.1019	0.134	0.1280	2.588	3.404	3.251
11	0.0907	0.120	0.1160	2.304	3.048	2.946
12	0.0808	0.109	0.1040	2.052	2.769	2.642
13	0.0720	0.095	0.0920	1.829	2.413	2.337
14	0.0641	0.083	0.0800	1.628	2.108	2.032
15	0.0571	0.072	0.0720	1.450	1.829	1.829
16	0.0508	0.065	0.0640	1.290	1.651	1.626
17	0.0453	0.058	0.0560	1.151	1.473	1.422
18	0.0403	0.049	0.0480	1.024	1.245	1.219
19	0.0359	0.042	0.0400	0.912	1.067	1.016
20	0.0320	0.035	0.0360	0.813	0.889	0.914
21	0.0285	0.032	0.0320	0.724	0.813	0.813

Note: Wire sizes under 0.7 mm diameter are omitted.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 295 of 306

12.5 The Galvanic Series of Metals and Alloys in Seawater

Magnesium and magnesium alloys	–1.60 to –1.63
Zinc	–0.98 to –1.03
Aluminum alloys	–0.76 to –1.00
Mild steel	–0.60 to –0.71
Wrought iron	–0.60 to –0.71
Cast iron	–0.60 to –0.71
Type 410 (13% chromium) stainless steel – active	–0.46 to –0.58
Type 304 (18–8) stainless steel – active	–0.46 to –0.58
Type 316 (18–8.3% Mo) stainless steel – active	–0.43 to –0.54
Inconel (78% Ni; 13.5% Cr; 6% Fe) – active	–0.35 to –0.46
Aluminum bronze (92%Cu; 8% Al)	–0.31 to –0.42
Naval brass (60%Cu; 39%Zinc)	–0.30 to –0.40
Yellow brass (65%Cu; 35%Zn)	–0.30 to –0.40
Red brass (85%Cu; 15%Zn)	–0.30 to –0.40
Tin	–0.31 to –0.33
Copper	–0.30 to –0.57
Lead-tin solder (50%–50%)	–0.28 to –0.37
Admiralty brass (71%Cu; 28%Zn; 1%Sn)	–0.28 to –0.36
Aluminum brass (76%Cu; 22%Zn; 2%Al)	–0.28 to –0.36
Manganese bronze (58.5%Cu; 39%Zn; 1%Sn; 1%Fe; 0.3%Mn)	–0.27 to –0.34
Silicon bronze (96%Cu; 0.80%Fe; 1.50%Zn; 2%Si; 0.75%Mn; 1.60%Sn)	–0.26 to –0.29
Type 410 (13% chromium) stainless steel – passive	–0.26 to –0.35
Lead	–0.19 to –0.25
Inconel (78% Ni; 13.5% Cr; 6% Fe) – passive	–0.14 to –0.17
Nickel 200	–0.10 to –0.20
Type 304 (18–8) stainless steel – passive	–0.05 to –0.10
Monel 400 (70%Ni; 30%Cu)	–0.04 to –0.14
Type 316 (18–8, 3% Mo) stainless steel – passive	0.00 to –0.10
Titanium	–0.05 to +0.06
Platinium	+0.19 to +0.25

Note: Alloys are listed in order of the potential they exhibit in flowing seawater. Some alloys may become active and exhibit a potential near –0.5 V in low-velocity or poorly aerated water and at shielded areas.

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 296 of 306

12.6 Classification of Submarine Soil in Different Countries

US Dept. of Agric.	Germany DIN 4022	England BST 1377:1961	Sweden (Atterberg)	Denmark
Cobbles (>75)	Stein (>60)	Stone (>60)	Block (>200)	
Coarse gravel (8–75)	Grobkies (20–60)	Coarse gravel (20–60)	Sten (20–200)	Sten (>20)
Fine gravel (2–8)	Mittelkies (6–20)	Medium gravel (6–20)	Grovgrus (6–20)	Grus (2–20)
Very coarse sand (1–2)	Feinkies (2–6)	Fine gravel (2–6)	Fingrus (2–6)	
Coarse sand (0.5–1)	Grobsand (0.6–2)	Coarse sand (0.6–2)	Grovsand (0.6–2)	Grovsand (0.2–2)
Medium sand (0.25–0.5)	Mittelsand (0.2–0.6)	Medium sand (0.2–0.6)	Mellansand (0.2–0.6)	
Fine sand (0.1–0.25)	Feinsand (0.06–0.2)	Fine sand (0.06–0.2)	Grovmo (0.06–0.2)	
Very fine sand (0.05–0.1)	Grobschluff (0.02–0.06)	Coarse silt (0.02–0.6)	Finmo (0.02–0.06)	Finsand (0.02–0.2)
	Mittelschluff (0.006–0.02)	Medium silt (0.006–0.02)	Grov mjäla (0.006–0.02)	
Silt (0.002–0.05)	Feinschluff (0.002–0.006)	Fine silt (0.002–0.006)	Fin mjäla (0.002–0.006)	Silt (0.002–0.02)
Clay (<0.002)	Ton (<0.002)	Clay (<0.002)	Ler (<0.002)	Ler (<0.002)

Note: Denomination in local language. The grain size is given in mm.

Wentworth Scale

Grain size		Phi units	Sediment types
4–64	mm	–6 to –2	Pebble
2–4	mm	–2 to –1	Granule
1–2	mm	–1 to –0	Very coarse sand
0.5–1	mm	0–1	Coarse sand
250–500	μm	1–2	Medium sand
125–250	μm	2–3	Fine sand
63–125	μm	3–4	Very fine sand
<63	μm	>4	Silt

12.7 Non-metric Units

1 inch	= 25.4 mm
1 foot (U.S. and British)	= 12 inches = 0.3048 m
1 fathom	= 6 ft = 1.8288 m
1 cable	= 219.4560 m
1 nautical mile	= 1852 m
1 lbs	= 0.45359 kg
1 short ton	= 2000 lbs = 0.907185 MT
1 long ton	= 1.016047 MT
1 MT	= 1000 kg
1 cubic inch	= 16.387 cm^3
1 cubic foot	= 0.028317 m^3
1 register ton	= 100 cubic foot = 2.8317 m^3
1 hectopascal	= 1 mb
1 mm of mercury	= 1.3332 mb
1 pound per square inch (psi)	= 0.06895 bar
1 kn	= 1.852 km/h = 0.51444 m/s
1 m/s	= 3.6 km/h = 1.94384 kn

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 298 of 306

12.8 Tidal Terms

English	English abbreviation	German	German abbreviation
Tides		Gezeiten	
Height of tide		Gezeitenhub	
Tidal streams		Gezeitenstrom	
Highest astronomical tide	HAT	Höchstmöglicher Gezeiten-wasserstand	
High water	HW	Hochwasser	HW
High water heights	HW Hts.	Hochwasserhöhe	HWH
High water time	HW Time	Hochwasserzeit	HWZ
		Höhe der Gezeit	H
Chart datum	CD	Kartennull, Kartendatum (Seekarten)	KN
Mean tide level	ML	Mittelwasser, Mittlerer Wasserstand	MW
Mean high water	MHW	Mittleres Hochwasser	MHW
Mean low water	MLW	Mittleres Niedrigwasser	MNW
Mean high water neaps	MHWN	Mittleres Nip-phochwasser	MNpHW
Mean low water neaps	MLWN	Mittleres Nipp-niedrigwasser	MNpNW
Mean high water springs	MHWS	Mittleres Springhochwasser	MSpHW
Mean low water springs	MLWS	Mittleres Spring-niedrigwasser	MSpNW
Lowest astronomical tide	LAT	Niedrigstmöglicher Gezeiten-wasserstand	
Low water	LW	Niedrigwasser	NW
Low water heights	LW Hts.	Niedrigwasserhöhe	NWH
Low water time	LW Time	Niedrigwasserzeit	NWZ
High water neaps	HWN	Nipphochwasser	NpHW
Low water neaps	NWN	Nippniedrigwasser	NpNW
Neap tides	Np	Nipptide	Np
Ordnance datum	OD	Normalnull	NN
Spring tides	Sp	Springgezeiten	Sp
High water springs	HWS	Springhochwasser	SpHW
Low water springs	LWS	Springniedrigwasser	SpNW
Slack water		Stauwasser	
Admiralty tide tables	ATT		

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Index

A
Abrasion resistance, 136
Acceleration
  vertical, 192
Acetophenone, 252
Added-mass coefficient, 89
AEIC, 144
AEIC CS9–06, 96
A-frame, 163
Ageing, 20, 148
  electric, 21
  multi-stress, 21
  thermal, 21
AIS, 205
Aluminium laminate, 32, 40
Aluminium sheath, 32
Ambient soil temperature, undisturbed, 58
Ambient temperature, 45, 141
Ammunition-dumping grounds, 195
Ammunition dumps, 257
Ampacities, 14, 40, 59
  a.c, 63
Anchor handling, 202
Anchors, 34
Annual variations, 158
ANSI, 137
Antioxidants, 125
Aramid fibres, 37
Armoring, 36, 131, 136
  counter-helical, 35, 37
  flat wire, 36
  losses, 42
  machine, 132
  non-magnetic, 36
  open, 36
  unidirectional, 36, 134
  wire overlength, 85
Arrhenius model, 21
Artificial reefs, 258
Assembly time, 112
Autonomous Underwater Vehicles (AUV), 157
Availability, 212, 237, 245
Avoidance limit, 262
Axis distance, 57

B
Baltic Cable, 3, 88, 178, 180
Baltic Sea, 37
Barge, 163, 174
Base resin, 19
Bass Link, 3
Beach joint, 178
Bedding layer, 14
Behavioural changes, 257
Bellmouth, 131, 181
Bending, 137
Bending radius, 177, 208
Bending stiffness, 34
Bend restrictor, 120
Bend stiffener, 120
Benthos, 256, 259
Bifurcation joint, 114
Bitumen, 38, 133, 135
Black-out, 241
Bonding
  cross-, 61
  single-side, 61
Bottom tension, 79, 175, 208
Boulders, 183
Breakdown strength, 93
Breakdown voltage, 92
Breakwaters, 195
BritNed, 3
Burial depth, 56, 57, 71, 260
Burial equipment, 198
Butt gap, 127

T. Worzyk, *Submarine Power Cables*, Power Systems,
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NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 300 of 306

C
Cable bends, 112, 120
Cable break, 225
Cable burying, 156
Cable corridor, 155
Cable Dependent Voltage Control, 239
Cable-laying vessel (CLV), 162
Cable loop, 235
Cable plough, 35, 199
Cable protection, 195, 213
Cable securing device, 193
Cable surface temperature, 67
Cable tension, 235
Cable termination, 142, 143
Cable utilization, 78
Capacitive current, 40
Capstan wheel, 175
Carbon-black, 107
Cargo vessel, 173, 174
Casing, 112
Cast iron half-pipes, 61
Catenary line, 79, 206, 222
Cauer-type RC ladder network, 64
Charge injection, 99
Chart
  electronic, 153
  paper, 153
Chart datum, 154
Chinese fingers, 233
Chirp-profiler, 156
Cigré, 138, 241
Cigré study, 106
Cigré study on submarine power cable damages, 213
Circulating screen/sheath currents, 61
Coastline, 195
Coaxial geometry, 63
CO_2 emission, 5
Coiling, 34, 39
Coiling diameter, 134, 166
Coiling direction, 135
Coiling pad, 134, 135
Compass deviation, 265
Compressed round wires, 11
Concrete slabs, 204
Conductivity
  specific, 97
Conductor, 7
  corrosion resistance, 10
  current, 37
  filling factor, 11
  hollow, 14
  joint, 108, 111
  large segment, 61
  Milliken, 13
  profiled wire, 12
  resistance, 15, 125, 144
  screen, 125, 20, 27, 99
  segmental, 14
  size, 105, 124
  solid, 10
  stranded, 11
  superconducting, 16
  temperature, 26, 43, 144
    steady-state, 68
Contaminations, 157
Continuous armoring, 106
Cook Strait, 28, 105
Cooling, 128
Copper wire screen, 32, 40
Coral reefs, 257
Corporate ethics, 152
Corrosion, 32, 37, 116, 118, 130, 137, 239
  cathodic protection, 38
  electric, 38
Corrosion protection, 37
Corrugated cable sheaths, 32
Corrugated copper sheath, 32
Costs
  Capex, 75, 78
  generation for losses, 77
  initial, 75
  operational, 75
  Opex, 75
  repair, 79, 93
Cross Sound Cable, 22
Current density, 59
Current flow lines, 12
Current velocity, 88
Cutter-suction dredger, 203
Cutting wheel, 203

D
Departure angle, 192, 208
Design voltage, 96
Desk Top Study, 153, 195
Dielectric constant, 60
Dielectric strength, 19, 20, 91
  intrinsic, 91
Diffusion rates, 32
Dike crossing, 158
Distributed lateral force, 87
Distributed Temperature Measurement System, 238

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 301 of 306

Drum
drum twister, 130
pay-off, 130
take-up, 130
DTS, 45
Dynamic cable rating, 239
Dynamic force, 79
Dynamic positioning system, 168

E
Eel, 264
Elasmobranch, 262
Electra, 138
Electric breakdown, 91
Electric design, 94
Electric field, 261
Electromagnetic impact, 261
Emergency cut, 193
Emergency cutter, 170
Ems River, 6
EN 50307, 31, 129
End cap, 126
Energy price, 76
Environment, 28
corrosive, 37
Environmental Impact Assessment (EIA), 249
Epoxy resin spacers, 113
EPR, 23
dielectric constant, 60, 281–282
loss factor, 60, 281–282
Estlink, 10, 22
Ethylene propylene rubber, 23
Export cable, 4
Extruded d.c. cables, 100
Extruded plastic profiles, 63
Extrusion, 124
Extrusion length, 126

F
Factory joint, 126, 146
Failure rate, 242, 246
Failures
internal, 242
joint, 242
Failure statistics, 242, 245
Fathom, 154
Fatigue, 31, 32, 137, 237
Fault
characteristics, 225
high-ohmic, 225, 228
location, 24
low-ohmic, 225
recorder, 231
Ferrule, 106
Fetch, 186
Fibre defects, 230
Field dependency coefficient, 98
Field-grading element, 117
Filler profiles, 41
Filler ropes, 41
Fish bite, 212
Fishing
bottom set fixed, 214
dredge, 214
dynamite, 213
industry, 215
techniques, 213
Fishing gear, 34, 212
Fixed cable tank, 176
Flexible joint, 139
Floating device, 179, 180, 181
Flow velocity, 89
Fluid-filled cable, 113, 125
Force
dynamic, 34
tensile, 38
tensional, 34
torsional, 34
Forced outage, 244
Fox Island cable, 88, 245
Free span, 73, 88, 156, 239
length of, 89
Freezing, 142
Friction
between the cable layers, 87
coefficient, 39, 177, 179

G
Gaseous by-products, 252
Gas-filled submarine cables, 28
Gas-insulated lines, 30
Geomagnetic field, 264
Gooseneck, 175
Gotland, 2
Grain size, 70
Green investment, 251
Green power, 1, 3
Ground wire, 182
Guilo Verne, 162

H
Hansson-Robertson lead extruder, 129
HAZOP (Hazard and Operability), 224
Heading, 189
Heat losses, 258
Helicopter landing pad, 171
HelIgoland, 2
Horizontal Directional Drilling, 6, 178

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 302 of 306

H.P Lading, 164
Human exposure, 262
Humidity, 126, 128, 133
Humidity diffusion, 30, 31
HVDC cables, 27
Hydrographical offices, 153
Hydrophobicity, 241
Hydrostatic pressure, 137

I
IEC 60228, 12, 16
IEC 60287, 52
IEC 60853, 69
IEEE, 137
Impregnation, 27
Impregnation vessel, 127
Impulse generator, 230
Impulse propagation velocity, 225
Impulse shape, 143
Impulse travel time, 225
Installation
  tensional forces during, 34
Installation of submarine cables, 255
Insulation materials, 17
Insulation paper, 24
Insulation screen, 19
Insurance, 244
International Cable Protection Committee, 205
International Commission on Non-Ionizing Radiation Protection (ICNIRP), 262
Interstices, 39
Ionisation factor, 144
Islands
  distant, 2
  near-shore, 1

J
Jersey and Guernsey, 2
Joint, 20, 182
  beach, 221
  final, 184, 222
  flexible, 234
  hairpin, 185
  post-lay, 184
  repair, 232
  transition, 272
Jointer teams, 223
Jointing house, 223, 235
Jointing methods, 110
Jointing shack, 108, 109, 163, 182
J-tube, 158, 181

K
2 K criterion, 73
Kinks, 135
2 K limit, 260
Kontek, 25, 43, 58
Kontiskan, 198
Kraft paper, 24

L
Landing point, 114
Laplace equation, 94
Laplace operator, 94
Lay direction, 132
Laying barge, 202
Laying parameters, 59
Laying speed, 175
Laying wheel, 79, 139
Laying wheel movement, 191
Lay length, 15, 34
Lead alloy, 129, 253
Lead extruder, 129
Lead press, 129
Lead profiles, 90
Lead sheath, 30, 41, 112
  individual, 41
Leaking lead sheath, 222
Length
  continuous, 125
  drum, 130
  extrusion, 126
  factory, 133
  production, 123
Life Cycle Assessment (LCA), 250
Lifetime, 21, 70, 77
  electric, 79
  expected, 77
  technical, 77
Linear alkylbenzene, 266
Linear cable engine, 132, 134, 175
LME copper price, 77
Load capacity, 165
Long Island, 2, 39
Long Island Power Authority, 205
Loop, 175
Losses
  conductor, 59
  dielectric, 60
  eddy-current, 61
  magnetic, 61
  ohmic, 52
  screen, 61
  sheath/screen/armoring losses, 76
  loss factor, 281–282
Loss of position, 193
Lowest Astronomical Tide, 154

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 303 of 306

Low-frequency engine noise, 256
LPOF, low-pressure oil-filled cables, 13, 24

M
Magnetic compass, 264
Magnetic field, 42, 261
Magnetic flux density, 262
Magnetic losses, 37, 43
Mainland grid, 1
Maintenance, 237
  scheduled, 244
  unscheduled, 244
Mangrove forests, 257
Marginal sea, 186
Marine authorities, 238
Marine fauna, 256
Marine growth, 89
Marine mammals, 257
Marine reptiles, 258
Marine survey, 70
Mass-impregnated
  dielectric constant, 60, 281–282
  loss factor, 60, 281–282
Mass-impregnated cable, 27, 124, 128
Mean-time-to-failure (MTTF), 93
Messina Strait, 6
Metallic screen/sheath, 55
Metallic sheath, 30
Model cables, 136
Molecular weight, 17
Möllerhöj-cable, 25
Montsinger rule, 21
Moyle Interconnector, 44
Multi-beam echo-sounder, 154

N
Natural frequency, 88, 90
Noise impact, 257
NorNed, 58, 178
North Sea salinity, 37

O
Obstacles, 151
Offshore platform, 6, 181
Offshore windfarms, 30, 37, 43
Offshore wind parks (OWP), 1
Offshore wind turbines, 167
Oil
  high-viscosity, 27
  low-viscosity, 13, 23
Oil&gas production, 1
Oil channel, 24, 25, 42
Oil expansion vessel, 118
Oil-filled cables, 266
Oil-free, 116
Oil/paper
  dielectric constant, 60, 281–282
  loss factor, 60, 281–282
Oil pressure
  loss of, 240
  monitoring, 240
Open trench, 178
Optical cables, 41
Optical fibre, 133
Optical Time Domain Reflectometry, 45
Organic contents, 157
Organic materials, 70
Overload
  temporary, 66
Overload for short periods, 67
Overvoltage, 21, 95, 237
  power frequency, 95
OWP, 238

P
Paper insulation, 126
Paper insulation, mass impregnated, 54
Paper insulation, oil-filled cables, 54
Paper tension, 127
Payload, 162
PE, 254, 267
Penetration depth, 71
PE sheath, 31
Petrojelly, 16
Pipeline crossing, 198
Pipeline heating cables, 7
Planetary movement, 132
Plastic over-sheath, 253
Plastic sheath, 31
Platform
  floating, 6
  production, 5
Ploughshare, 199
Poisson equation, 99
Polyethylene, 17
  cross-linked, 18
Polymeric sheath, 30, 38
Polypropylene yarn
  thermal resistivity, 54
Post-lay burial (PLB), 201
Post-lay cable protection, 238
Power frequency, 59
PPLP, 26
Pre-Lay Grapnel Run (PLGR), 255
Pre-moulded joint, 110
Present value, 75
Present value method, 75

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 304 of 306

Pressure drop, 24
Pressure feeding unit, 24
Pressure reinforcement, 133
Profiled conductor wires, 53
Propulsion system, 168
Protection
  after installation, 205
  degree of, 203
Protection pipes, 61
Proximity effect, 12, 59
Proximity effect factor y_p, 59
Pull-in, 178
PVC, 33, 254

Q
Quadrant, 185, 234

R
Radar plot, 253
Radial pressure, 111
Raw material production, 251
Redundancy, 43, 241
Reliability, 241
Remote-Operated Vehicles (ROV), 157
Repair
  vessel, 231, 233
Repair costs, 213
Repair deck, 222
Repair job, 166
Reproduction period, 256
Reproductive behaviour, 259
Resistivity
  of the screen materials, 20
  specific, 15
  temperature coefficient of, 15
Resonance circuit, 145, 147
Response Amplitude Operator, 189
Risk assessment, 244
Rock armor, 35, 86, 197
Rock dumping, 204
Roller tracks, 140
Route selection, 196
ROV, 161, 175, 194, 223, 235

S
SACOI, 31, 204
Safety standards, 118
St. Lawrence River, 6
Salt, 115, 116
Salt layer deposits, 241
Salt water, 37
SAPEI, 3
SCADA, 240
SCFF, self-contained fluid-filled cables, 13, 24
SCOF, self-contained oil-filled cables, 24
Screen current, 37, 62
Screw connectors, 106, 110
Seafloor
  warming of the, 73
Seafloor topography, 45
Sea-keeping characteristics, 80
Search coil, 229
Seasickness, 192
Seastate, 81
Seastate forecast, 188
Sediment, 238
Sediment plume, 256
Self-amalgamating tapes, 107
Serving, 133
SF_6, 30
Shallow coastal waters, 212
Sheath
  aluminium laminate, 129
  copper, 130
  lead, 126
  metallic, 40
  oversheath, 129
Shipwreck, 153
Shore winch, 180
Short-circuit current, 32
Side-wall pressure, 87, 140
Significant wave height, 80
Skagerrak, 162
Skagerrak HVDC cable, 244
Skin effect, 12, 14, 59
Skin effect factor y_s, 59
S-lay, 12, 135
Slope angle, 155
Soak test, 147
Soil
  rocky, 200
  sea bottom, 56
  soft, 200
Soil samples, 70
Solar radiation, 135
Solid insulation, 266
Space charges, 99
Spacing, 57, 59
Spare cable, 222, 223, 232
Spatial resolution, 227
Specific electric resistivity, 54
  thermal coefficient of, 54
Specific heat, 64
Specific thermal resistivity, 54, 57
Spectrum of overtones, 52
Speed of light, 230
Spinning reserve, 3

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 305 of 306

Splash zone, 115, 178
Step function, 64
Stepping, 124
Stiffness
  bending, 87
Stop joint, 113
Store Belt, 3
Stray currents, 196
Stress
  applied, 93
  breaking, 85
  distribution, 94
    d.c, 99
  mechanical, 83
  operating, 20
Stress enhancement, 19
Strouhal number, 88
Submersible pump, 201
Subsea observatories, 7
Supply vessel, 166
Surface temperature, 69
Survey, 162
Swell, 188
Swelling powder, tapes and yarns, 16, 125
Swepol, 3
Synthetic cable fluid, 24
Synthetic cable oil, 266
SZ-lay, 130

T
Tape winder, 133
Temperature
  cable surface, 67
Temperature dependency coefficient, 98
Temperature limit, 51
Temperature profile, 239
Temperature rise has reached 63% of its final value, 65
Temporary overload, 66, 68
Tensile forces, 38
Tensile strength, 36
Tensional force, 79
Tensional stability, 34
Tensional strength, 79, 140
Teredo, 133
Test
  coiling, 139
  electric, 137
  internal pressure, 140
  material, 137
  non-electric, 142, 148
  polarity reversal, 142
  sea trial, 140
  tensile bending, 139
  type, 137
Test voltage, 141
Test voltage factor, 141, 148
Thermal capacitance, 64, 69
Thermal expansion, 24
Thermal hazards, 238
Thermal model, 52, 64
Thermal reserve, 67
Thermal resistance T_4, 54, 57, 64
Thermal resistivity, 157
Thermoplastic polyethylene, 253
Three-core cables (3C), 40
Tidal current, 214
Tidal flats, 70
Tides, 152
Time constant
  cable, 65
  classical, 65
  soil, 66
  thermal, 65
Time domain reflectometry, 146
Top tension, 80, 208
Torsion balance, 34
Touchdown point, 79, 182, 206
Towfish, 156
Transient conditions, 64
Transmission losses, 251
Transport of the cable, 255
Trawl door, 213
Trawling, 213
  beam, 214
  gear, 214
  Otter, 213
Trenching depth, 202
Trenching gear, 256
Trenching methods, 199
Trench profile, 178
Trifurcation joints, 114
Triple-extrusion, 20
Turntable, 134, 135, 165

U
UCTE, 3
Umbilicals, 6
Undisturbed, 71
Undisturbed seafloor, 260

V
Vancouver Island, 2, 28
Vertical acceleration, 82, 83
Vessel Monitoring System (VMS), 205
Vessel motion, 80
Vessels of opportunity, 153

NSPML 2026 Holdback Mechanism IG IR-25 Attachment 2 Page 306 of 306

Vessel traffic, 238
Vibration, 238
Viscosity, 128
Void, 28, 100
Voltage duration, 96
Voltage peaks, 96
Vortex-induced vibrations, 89
Vortex shedding, 90
Vortex shedding frequency, 88, 90

W
Wadden Sea, 259
Waste incineration, 256
Water barrier, 129
Water-blocking compound, 15, 53
Water-blocking sheath, 30
Water current, 88, 179
Water depth, 208
Water ingress, 233
Water jetting, 200
Water protection, 111
Water temperature
  annual variation, 71
Water tightness
  longitudinal, 16
Water-treeing, 19
Wave
  direction, 188
  patterns, 195
  refraction and interference of, 188
  shape, 143
  significant height, 188
  spectra, 187
Weather conditions, 225
Weather window, 109, 202, 225
Weibull distribution, 19, 91
Weibull plot, 92
Welding, 125, 130
Welding methods, 106
Wheel
  radius, 87
Windfarm export cable, 245
Wind speed, 186
Wind turbine generators (WTG), 4
Wind waves, 186
Wire
  copper, brass, bronze, 131
  flat armoring, 132
  galvanized steel, 131
  profiled, 124
  welding, 125
World Geodetic System, 84, 153
Wrinkles, 127

X
XLPE, 18, 54, 253
  dielectric constant, 281–282
  carbon-black filled, 20
  semi-conductive, 20
X-rays, 106

Y
Yarn layer, 39

Z
Zero alternative, 251
Zinc
  sacrificial wires, 38
Zinc coating, 38
Z-lay, 12

Request IR-26:

Reference: N-01, Application, Attachment 1, Concentric Evidence, page 33/36 (pdf page 70)

Preamble: Concentric recommends that outage months should be "*excluded from the calculation of the 12-month reliability thresholds*".

(a) Please provide the specific mathematical adjustment method Concentric recommends the Board apply (e.g., denominator adjustment by outage days; reprofiling of contract amount; alternative performance window, etc.).

(b) Please provide worked calculations for each month for which Concentric supports relief (July 2023, September 2023, March 2024, April 2024), showing:

(i) **Contract amount (MWh);**

(ii) **Delivered Base NS Block excluding Make-Up (MWh);**

(iii) **Unadjusted percentage;**

(iv) **Adjustment inputs (days/hours excluded; curtailment limits; derates)**

(v) **Adjusted percentage; and**

(vi) **Resulting "12 consecutive months" determination.**

(c) Please provide Concentric's step-by-step determination showing that, after applying Concentric's proposed relief methodology, each of the 12 consecutive months meets the ≥90% requirement (excluding Make-Up Energy), identifying any month that still would not meet the

threshold.

(d) Please confirm whether Concentric's approach effectively treats some months as "ignored" for the consecutive-months test; if so, explain how "consecutive" is preserved.

Response IR-26:

a) Concentric did not provide a specific mathematical adjustment formula in its filed evidence. Concentric's filed position is that the Board should grant relief for specified months affected by planned outages consistent with Good Utility Practice, and that, subject to that relief, the 12-month performance threshold was met for May 2023 through April 2024. The evidence states that, after "adjusting for the impact" of the identified outage events, deliveries in the remaining days of the affected months were in the range of 97 percent to 99 percent of contracted volumes, but it does not set out a formal calculation methodology beyond that.

b) Concentric did not develop any worked month by month calculations for its filed evidence showing excluded days or hours, a revised denominator, a reprofiling of contract amounts, or a computed adjusted percentage for each relief month.

c) Concentric's filed determination is as follows:

The relevant 12-month period is May 2023 through April 2024.

i) Eight of those months met the 90 percent threshold on an unadjusted basis: May, June, August, October, November, December, January, and February. The unadjusted percentages shown in Appendix A for those months are 99 percent, 93 percent, 99 percent, 100 percent, 100 percent, 97 percent, 100 percent, and 98 percent, respectively.

ii) The remaining four months are the relief months: July 2023, September 2023, March 2024, and April 2024.

iii) For those four months, Concentric's evidence states that, once the impact of the qualifying outage events is removed, each month satisfies the Board's 90 percent threshold:

- July 2023: exceeds 97 percent absent the 5-day planned outage.
- September 2023: exceeds 99 percent absent the planned outages.
- March 2024: exceeds 90 percent absent either the planned outage or the ice event, and exceeds 99 percent absent both.
- April 2024: approximately 98 percent absent the icing event and the April 30 planned outage.

iv) On that basis, Concentric concludes that each of the 12 months in May 2023 through April 2024 meets the ≥90 percent requirement once relief is granted, and the filing does not identify any month that would remain below 90 percent after applying the requested relief.

d) Concentric's filed approach does not expressly say that the affected months are "ignored". Rather, the filed evidence keeps the same 12-month period, May 2023 through April 2024, and says that, subject to relief for identified outage events, the threshold was met for that period.