Newfoundland and Labrador Hydro
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P.O. Box 12400. St. John's. NL
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t. 709.737.1400 I f. 709.737.1800
nlhydro.com

August 18, 2023

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Cheryl Blundon
Director of Corporate Services and Board Secretary

Re: 2024 Capital Budget Application – Revision 1

Please find enclosed Revision 1 of Newfoundland and Labrador Hydro's ("Hydro") 2024 Capital Budget Application ("Revised Application").

Hydro has removed the Purchase Spare Generator Step-Up Transformer (2024) project from its 2024 Capital Budget Application, as the requirement for a spare transformer has been accelerated since the original filing date.[1] Hydro intends to file a capital expenditure application for this project in the third quarter of 2023, supplemental to the approved "2023 Capital Budget Application." [2]

As a result of this removal, through the Revised Application, Hydro is seeking approval of $96.6 million in capital expenditures for 2024. Hydro notes that the total planned capital spend for 2024 is $135.6 million; as indicated in the original filing, this includes expenditures for 2024 previously approved through applications supplemental to the "2023 Capital Budget Application" and expenditures related to applications that Hydro anticipates filing subsequent to this Revised Application, once full analysis has been complete. It also includes $3.5 million in specifically assigned customer contributions. Further details regarding the total planned capital spend are provided in Section 6 of Schedule 1 to the Revised Application. Hydro is also seeking approval of its 2022 average rate base in the amount of $2,334,120,000, as detailed in Schedule 5 of the Revised Application.

For convenience, Hydro has included a Revision History with the Revised Application indicating the locations and reasons for the revisions, which have also been shaded grey, for ease of reference.

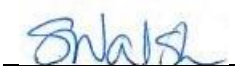
The Revised Application will be posted on Hydro's website at www.nlhydro.com in the coming days.

Should you have any questions, please contact the undersigned.

[1] "2024 Capital Budget Application," Newfoundland and Labrador Hydro, July 12, 2023 was approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 2(2023), Board of Commissioners of Public Utilities, January 26, 2023.
[2] "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO



Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/sk.kd

Encl.

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
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Dennis M. Browne, KC, Browne Fitzgerald Morgan & Avis
Stephen F. Fitzgerald, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis

Newfoundland Power Inc.
Dominic J. Foley
Lindsay S.A. Hollett
Regulatory Email

2024 Capital Budget Application

Original Submission: July 12, 2023

Revision 1: August 17, 2023

An application to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Revision History

Revision No.	Revision Date	Location	Reason
1	17-Aug-2023	Legal Application, sec. 2, p. 1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Legal Application, sec. 12(a), p. 4,	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 1, p. 2/1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 1, p. 2, Figure 1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 1, p. 2, f.n. 2	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project from the 2024 Capital Budget Application and the intention to file as a supplemental application to the 2023 Capital Budget Application.
1	17-Aug-2023	Sch. 1, sec. 1, p. 2/8	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 1, p. 3, Table 1	Updated to add $ Millions and to reflect updates to the planned 2024 capital expenditures and cost estimates including the planned inclusion of the Purchase Spare Generator Step-Up Transformer (2024–2026) project as a supplemental application and amendments to planned spend of the same for 2024.
1	17-Aug-2023	Sch. 1, sec. 1, p. 3, f.n. 7	Addition of Footnote 7 to explain the addition of the Purchase Spare Generator Step-Up Transformer in Table 1.
1	17-Aug-2023	Sch. 1, sec. 1, p. 4/1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 2.0, p. 8, Chart 1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project and the correction to the presentation of information within the chart.
1	17-Aug-2023	Sch. 1, sec. 5.1.1, p. 21, Table 9	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project and to correct the description of the total line.

Revision No.	Revision Date	Location	Reason
1	17-Aug-2023	Sch. 1, sec. 6.0, p. 24/2	Updated to reflect the removal of Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 6.0, p. 24/3	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec 6.0, p. 24, Chart 14	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 6.0, p. 26, Chart 15	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 6.5, p. 31/6	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 6.5, p. 31, Chart 18	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project and addition of Footnote 46.
1	17-Aug-2023	Sch. 1, sec. 6.9, p. 33/5	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec. 6.9, p. 34/1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, sec 8.0, p. 36/4	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, app. A, pp. A-1–A-2	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, app. A, pp A-4–A-6	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, app. A, pp. A-8–A-10	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, app. B, p. B-1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, app. B, p. B-6	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 1, app. C, p C-1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.

Revision No.	Revision Date	Location	Reason
1	17-Aug-2023	Sch. 1, app. G, p. G-2	Update to Risk Mitigated value for Remove Safety Hazards (2024), Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station, and removal of Purchase Spare Generator Step-Up Transformer (2024–2026) project
1	17-Aug-2023	Sch. 1, app. G, p. G-3	Update to Risk Mitigated per Million value for Remove Safety Hazards (2024), Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station, and removal of Purchase Spare Generator Step-Up Transformer (2024–2026) project
1	17-Aug-2023	Sch. 2, sec. 2.0, p. 1/20	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, sec. 2.0, p. 1/21	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, sec. 2.0, p. 2, Chart 1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, sec. 3.0, p. 4, Chart 2	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, sec. 3.2, p. 8, Chart 5	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, sec. 3.2, p. 8, Chart 6	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, sec. 3.4, p. 11, Chart 9	Correction to the presentation of information within the chart.
1	17-Aug-2023	Sch. 2, sec 4.0, p. 13/14	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, sec. 2.0, p. 13/15	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, app. A, p. A-1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, app. A, pp. A-8–A-9	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.

Revision No.	Revision Date	Location	Reason
1	17-Aug-2023	Sch. 2, app. A, pp. A-15–A-17	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 2, app. B, p. B-1	Updated to reflect the removal of the Purchase Spare Generator Step-Up Transformer (2024–2026) project.
1	17-Aug-2023	Sch. 6, proj. 1	Removal of Purchase Spare Generator Step-Up Transformer (2024–2026) project

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Application

IN THE MATTER OF the *Public Utilities Act*, RSNL 1990, c P-47 ("*Act*"); and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of: (i) its capital budget for 2024, pursuant to Section 41(1) of the *Act*, (ii) its proposed capital purchases and construction projects for 2024 in excess of $750,000, pursuant to Section 41(3)(a) of the *Act,* and (iii) for an Order, pursuant to Section 78 of the *Act,* fixing and determining its average rate base for 2022.

To: The Board of Commissioners of Public Utilities ("Board")

THE APPLICATION OF HYDRO STATES THAT:

A. Background

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2007*,[1] is a public utility within the meaning of the *Act,* and is subject to the provisions of the *Electrical Power Control Act, 1994*.[2]

B. Application

2. The 2024 Capital Budget Application proposes $96.6 million in 2024 expenditures, comprised of the expenditures related to single-year programs and projects proposed for completion in 2024, 2024 expenditures for multi-year proposals commencing in 2024, as well as those expenditures in 2024 related to multi-year programs and projects approved in previous capital budget applications.[3] This amount does not include planned expenditures for which contributions from customers have already been approved.[4] No new leases with costs in excess of $750,000 over the expected life of the lease are proposed for 2024.

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[1] *Hydro Corporation Act*, 2007, SNL 2007, c H-17.
[2] *Electrical Power Control Act*, *1994*, SNL 1994, c E-5.1.
[3] Sch. 1, app. B.
[4] $1.2 million in fully-contributed terminal station asset renewal expenditures specifically assigned to the Iron Ore Company of Canada; and $0.4 million in fully contributed terminal station asset renewal expenditures specifically assigned to Braya Renewable Fuels LP. Hydro will also incur approximately $50,000 in 2024 to install fire protection at the Voisey's Bay Nickel Terminal Station as proposed in Hydro's Install Fire Protection in 230 kV Stations, made as part of this application; this will be specifically assigned to Vale.

3. The 2024 Capital Budget Application request for approval does not include the 2024 expenditures related to supplemental applications approved by or currently before the Board, or those anticipated to be filed with the Board in 2024 as supplemental applications once a full analysis of the proposed project is complete.

4. Schedules 1 to 6 to this application are the 2024 Capital Budget Overview, Five-Year Capital Plan (2024–2028), Holyrood Thermal Generating Station Overview – Future Operation and Capital Expenditure Requirements, 2023 Capital Expenditures Overview, 2022 Average Rate Base and Capital Programs and Projects.

5. The 2024 Capital Budget Overview, enclosed as Schedule 1 to this Application, provides:

   a) An overview of Hydro's capital investment strategy and the capital budget proposed for 2024;

   b) A summary of the revenue requirement impact of Hydro's proposed 2024 Capital Budget Application;

   c) Hydro's 2024 Capital Budget financial schedules with projects listed by asset class, investment classification, materiality, and program and project (Schedule 1, Appendix A), by single- and multi-year programs and projects (Schedule 1, Appendix B), and by materiality: for programs and projects over $5 million (Schedule 1, Appendix C), for programs and projects $1 million to $5 million (Schedule 1, Appendix D), and for programs and projects under $1 million (Schedule 1, Appendix E)[5];

   d) The Terminal Station Asset Management Overview (Schedule 1, Appendix F); and

   e) Hydro's Risk Evaluation Matrix (Schedule 1, Appendix G).

6. Schedule 2: Five-Year Capital Plan (2024–2028) provides an overview of Hydro's investment strategy and associated planned capital work for the period 2024–2028, as well as a summary of Hydro's actual and projected capital expenditures for the period 2019–2028 (Schedule 2, Appendix B).

[5] A listing of Hydro's planned 2024 projects and programs under $750,000 is contained within Schedule 6 to this application.

7. Schedule 3: Holyrood Thermal Generating Station Overview – Future Operation and Capital Expenditure Requirements provides an overview of future operating and capital requirements for the Holyrood Thermal Generating Station, as well as the ten-year forecast of the system equipment maintenance projects for the Holyrood Thermal Generating Station (Schedule 3, Appendices B and C).

8. Schedule 4: 2023 Capital Expenditures Overview summarizes 2023 capital expenditures year-to-date May 31, 2023 and provides explanations for reportable variances between the approved budget and the forecasted total budget.

9. Schedule 5: 2022 Average Rate Base sets out Hydro's proposed 2022 rate base of $2,334,120,000. The proposed rate base is inclusive of the impacts resulting from expenditures associated with work completed under the Allowance for Unforeseen Items to address the Holyrood Thermal Generating Station Unit 2 transformer replacement. The Board, in Order No. P.U. 34(2021),[6] noted that it was satisfied that consideration of whether the expenditures associated with the Unit 2 transformer replacement at the Holyrood Thermal Generating Station should be added to rate base should be addressed as part of Hydro's application for approval of its 2021 rate base. The Holyrood Thermal Generating Station Unit 2 transformer replacement went into service in 2022 and, as a result, was excluded from Hydro's 2021 rate base. Hydro filed its final report in relation to the Unit 2 transformer replacement on February 8, 2022.[7]

10. Schedule 6: Capital Programs and Projects contains evidentiary information to support the proposed 2024 construction projects and capital purchases exceeding $750,000, segmented by programs and projects. Within each of those categories, the programs and projects are segmented by materiality i.e., Over $5 Million, $1 Million to $5 Million, and $750,000 to $1 Million. Also contained in Schedule 6 is a listing of the 2024 proposed programs and projects under $750,000. Capital purchases are included within the programs and projects.

[6] *Public Utilities Act*, RSNL 1900, c P-47, Board Order No. P.U. 34(2021), Board of Commissioners of Public Utilities, December 17, 2021.

[7] "Holyrood Thermal Generation Station Transformer T2 Failure – Final Report," Newfoundland and Labrador Hydro, February 8, 2022.

C. Reason for Approval

11. The proposed capital expenditures for 2024 as set out in the 2024 Capital Budget Application are necessary to allow Hydro to continue to provide to its customers service and facilities that are reasonably safe, adequate and just and reasonable, as required by Section 37 of the *Act*.

D. Newfoundland and Labrador Hydro's Request

12. Hydro requests that the Board make an Order as follows:

    a) Approving Hydro's 2024 capital budget of $96,583,200 as set out in Appendix A of Schedule 1, pursuant to Section 41(1) of the *Act*;

    b) Approving Hydro's 2024 capital purchases and construction projects in excess of $750,000 as set out in the appendices to Schedule 1, pursuant to Section 41(3) of the *Act*; and

    c) Fixing and determining Hydro's average rate base for 2022 in the amount of $2,334,120,000 as set out in Schedule 5, pursuant to Section 78 of the *Act*.

E. Communications

13. Communications with respect to this application should be forwarded to Shirley A. Walsh, Senior Legal Counsel, Regulatory for Hydro.

DATED at St. John's in the Province of Newfoundland and Labrador this 17th day of August 2023.

NEWFOUNDLAND AND LABRADOR HYDRO



Shirley A. Walsh
Counsel for the Applicant
Newfoundland and Labrador Hydro,
500 Columbus Drive, P.O. Box 12400
St. John's, NL A1B 4K7
Telephone: (709) 685-4973

Affidavit





IN THE MATTER OF the *Public Utilities Act*, RSNL 1990, c P-47 ("*Act*"); and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of: (i) its capital budget for 2024, pursuant to Section 41(1) of the *Act*, (ii) its proposed capital purchases and construction projects for 2024 in excess of $50,000, pursuant to Section 41(3)(a) of the *Act*, and (iii) for an Order, pursuant to Section 78 of the *Act*, fixing and determining its average rate base for 2022.

AFFIDAVIT

I, Robert Collett, of St. John's in the province of Newfoundland and Labrador, make oath and say as follows:

1. I am Vice President, Engineering and NL System Operator for Newfoundland and Labrador Hydro, the applicant named in the attached Application.
2. I have read and understand the foregoing Application.
3. To the best of my knowledge, information, and belief, all of the matters, facts, and things set out in this Application are true.

SWORN at St. John's in the province of Newfoundland and Labrador this 17th day of August 2023, before me:

Commissioner for Oaths, Newfoundland and Labrador

Robert Collett

SAMANTHA KEATS
A Commissioner for Oaths in and for the Province of Newfoundland and Labrador.
My commission expires on December 31, 2027

Sch 1: 2024 Capital Budget Overview

Schedule 1

2024 Capital Budget Overview



2024 Capital Budget Application

2024 Capital Budget Overview



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Appendix A: 2024 Capital Budget by Asset Class, Investment Classification, Materiality, and Programs and Projects

Appendix B: 2024 Capital Budget by Single- and Multi-Year Programs and Projects

Appendix C: 2024 Capital Budget by Materiality – Programs and Projects over $5 Million

Appendix D: 2024 Capital Budget by Materiality – Programs and Projects $1 Million to $5 Million

Appendix E: 2024 Capital Budget by Materiality – Programs and Projects under $1 Million

Appendix F: Terminal Station Asset Management Overview

Appendix G: Risk Evaluation Matrix

1.0 Introduction

Newfoundland and Labrador Hydro's ("Hydro") capital investment philosophy is founded on its obligation to invest responsibly in the electrical system to the benefit of its customers. Hydro is committed to investing in capital in a manner that meets its legislated mandate to provide reliable service at the lowest possible cost, and to provide service and facilities that are reasonably safe and adequate, and just and reasonable, in an environmentally responsible manner.[1]

A key area of strategic focus for Hydro is balancing the management of its aging infrastructure with its mandate. The majority of Hydro's installed assets, including the hydroelectric installation at Bay d'Espoir, the Holyrood Thermal Generating Station ("Holyrood TGS"), the Stephenville Gas Turbine, the Hardwoods Gas Turbine, and much of Hydro's transmission and distribution systems, are more than 40–50 years old. As a result, Hydro's capital investment strategy aims largely to sustain current system-level reliability by undertaking renewal-driven capital investment.

When supported by least cost and risk evaluation, Hydro's capital investment strategy also proposes targeted service-enhancement investments to address specific issues impacting system-level or localized reliability.

In its aim to balance the provision of reliable service with cost management, Hydro focuses on sound utility asset management practices, condition-based investments (versus age-based investments) where appropriate, and operational and system requirements. Hydro also seeks to engage with stakeholders and customers to inform its capital investment considerations.

Hydro has applied these practices, particularly in recent years, to work toward reduced investment to the minimum capital level prudent to not compromise customer reliability, safety, or the environment. Hydro also continues to refine its budgeting and integrated planning processes to support the efficient execution of its capital plans.

[1] In accordance with the *Hydro Corporation Act, 2007, SNL 2007, c H-17;* the *Electrical Power Control Act, 1994*; SNL 1990, c E-5.1 and the *Public Utilities Act,* RSNL 1990, c P-47.

Hydro's 2024 Capital Budget Application ("CBA") requests approval for $96.6 million of capital investment of which more than half consists of newly proposed projects or programs, with the remainder related to previously proposed projects or programs, as seen in Figure 1.

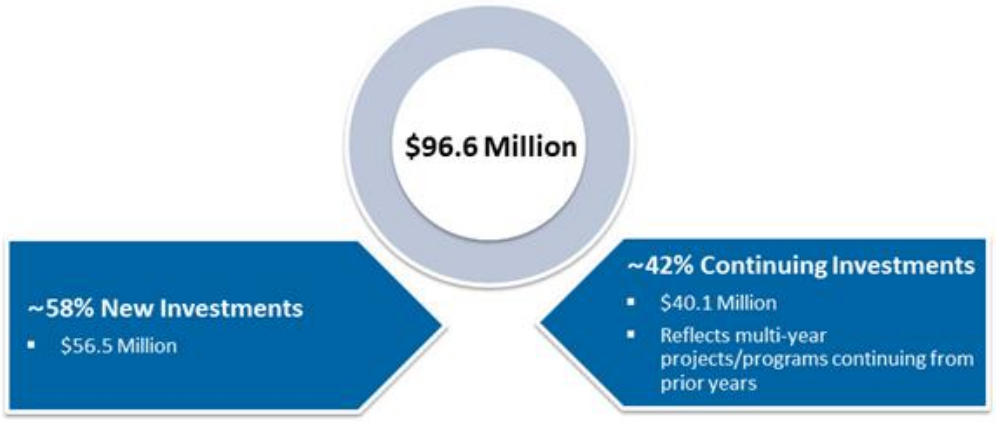


Figure 1: Hydro's 2024 Capital Budget Summary

Recognizing other investment requirements for 2024,[2] Hydro continues to take deliberate actions to achieve a lower level of requested investment in its 2024 CBA, as compared to prior years; further detail on Hydro's efforts to manage its capital spend is included in Section 5.2 of this report.

As outlined in the Five-Year Capital Plan (2024–2028), the total planned 2024 capital spend is $135.6 million, including $3.5 million in specifically assigned customer contributions.[3] The remaining capital spend not outlined in this application is associated with supplemental capital expenditures that have been approved, are currently before the Board of Commissioners of Public Utilities ("Board"), or those which Hydro intends to file in future supplemental applications. A summary of Hydro's planned 2024 Capital Expenditures is provided in Table 1.

[2] Other expenditures planned for 2024 include "Section Replacement and Weld Refurbishment for Bay d'Espoir Hydroelectric Generating Facility Penstock 1" which was approved in *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 6(2023), Board of Commissioners of Public Utilities, April 12, 2023; "Purchase and Replace Last Stage Blades – Holyrood Units 1 and 2" which was approved in *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 12(2023), Board of Commissioners of Public Utilities, May 5, 2023; the following supplemental applications currently before the Board: "Construction and Installation of Ultra-Fast Electric Vehicle Charging Stations", and "Long-Term Supply for Southern Labrador – Revision 1"; and the intended supplemental capital application—originally submitted as part of the 2024 CBA—Purchase Spare Generator Step-Up Transformer project.

[3] Hydro's Five-Year Capital Plan (2023–2027) submitted with its 2023 CBA included $111.2 million in planned expenditures for 2024; the increase reflected herein is due primarily to the advancement of planned expenditures associated with the "Section Replacement and Weld Refurbishment for Bay d'Espoir Hydroelectric Generating Facility Penstock 1" and "Long-Term Supply for Southern Labrador – Revision 1" supplemental projects.

Table 1: Planned 2024 Capital Expenditures

Item	2024 Cost Estimate ($ Millions)
2024 CBA	96.6
Replace Section and Weld Replacement Bay d'Espoir Penstock 1	13.2[4]
Purchase and Replace Last State Blades – Holyrood Units 1 and 2	2.8[5]
Long-Term Supply for Southern Labrador – Revision 1	17.8[6]
Purchase Spare Generator Step-Up Transformer	3.4[7]
Construction and Installation of Ultra-Fast Electric Vehicle Charging Stations (Fully Contributed)	1.8[8]
Total Planned Capital Spend	**135.6**
Customer Contributions	(3.5)[9]
Total for Recovery through Customer Rates	**132.1**

This 2024 Capital Budget Overview ("Overview") report generally discusses the Capital Plan proposed for 2024, which is primarily driven by the following:

- Renewal required to support the reliable operation of aging assets;
- Extension of the service life of the Holyrood TGS;[10]
- Accommodation of system growth in Labrador West; and
- Legislative compliance (i.e., safety and environmental).

[4] As approved by the Board in Order No. P.U. 6(2023).
[5] As approved by the Board in Order No. P.U. 12(2023).
[6] "Long-Term Supply for Southern Labrador – Revision 1," Newfoundland and Labrador Hydro, rev. May 31, 2023 (originally filed July 16, 2021).
[7] The Purchase Spare Generator Step-Up Transformer (2024–2026) was originally filed as part of the original submission of Hydro's 2024 Capital Budget Application on July 12, 2023. Hydro intends to file a supplemental capital application for this project with the Board in the third quarter of 2023.
[8] "Construction and Installation of Ultra-Fast Electric Vehicle Charging Stations," Newfoundland and Labrador Hydro, June 27, 2023. As stated in the application, the Government of Newfoundland and Labrador ("Government") will fund the majority of the capital cost; Hydro will contribute the remaining funds necessary beyond what is funded by Government. The capital funds Hydro expends on this project are not proposed for inclusion in its regulated rate base for recovery from customers at this time.
[9] Includes $1.7 million of known specifically assigned customer contributions; does not include contributions associated with service extensions that are determined during execution of the project in accordance with the CIAC policy. A breakdown of specifically assigned customer contributions is provided in Section 6.7 of this report.
[10] As per "Reliability and Resource Adequacy Study Review – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, the Holyrood TGS shall remain available for a "Bridging Period" until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the Labrador-Island Link ("LIL") is proven, and generation reserves are met."

Appendices A through F of this report present Hydro's 2024 Capital Budget of $96.6 million by asset class, investment classification, single- and multi-year expenditures, and program or project materiality.

1.1 Provisional Capital Budget Guidelines

The Board issued provisional CBA Guidelines ("Guidelines") that outline the evidentiary requirements to be applied, beginning with the 2023 CBA.[11] In June 2023, the Board directed that the 2024 CBAs should be filed adhering to the current Guidelines.[12] Table 2 outlines where Hydro has included the required information within the 2024 CBA as part of Hydro's compliance with each section of the Guidelines.

Table 2: Guideline Requirements

Guidelines Section	Content	2024 CBA Location
Application Summary	Activity Drivers per Investment Classification	Sch. 1, sec. 6.0
	Determination of Expenditure	Sch. 1, sec. 5.0
Reliability Information	Historical SAIDI & SAIFI statistics: 10 years	Sch. 1, sec. 4.0
	Forecast SAIDI & SAIFI statistics: 5 years	Sch. 1, sec. 4.0
	Benchmarking against other Utilities	Sch. 1, sec. 4.0
	Worst Performing Feeders	Sch. 1, sec. 4.0
Rate Impact Summary	Historical Rates	Sch. 1, sec. 6.9
	Project Budget Impact	Sch. 1, sec. 6.9
Capital Expenditures Summary	Historical Capital: 10 years	Sch. 1, sec. 2.0
	Current Capital Budget	Sch. 1, sec. 2.0
	Forecast Capital Budget: 5 years	Sch. 1, sec. 2.0
Five-Year Capital Plan	Capital Plan 2024-2028	Sch. 2
Organization	2024 Capital Budget:	
	By Asset Class, Investment Classification, Materiality, and Programs and Projects	Sch. 1, app. A
	By Single- and Multi-Year Programs and Projects	Sch. 1, app. B
	By Materiality – Programs and Projects over $5 Million	Sch. 1, app. C
	By Materiality – Programs and Projects $1 Million to $5 Million	Sch. 1, app. D
	By Materiality – Programs and Projects under $1 Million	Sch. 1, app. E
Required Information	Projects and Programs under $750,000	Sch. 6
	Project and Program Proposals over $750,000	Sch. 6
Prioritization	By Risk Mitigated per $1 Million	Sch. 1, app. G
	By Risk Mitigated	Sch. 1, app. G

[11] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, December 20, 2021.
[12] "Provisional Capital Budget Application Guidelines – 2024 Capital Budget Applications," Board of Commissioners of Public Utilities, June 12, 2023.

1.1.1 Compliance with and Interpretation of Guidelines

Hydro has continued to strive to comply with the evidentiary requirements set out in the Guidelines and has strived to meet the spirit and intent of the Guidelines where full adherence is not yet possible.[13] In most instances, Hydro has fully adhered to the Guidelines; however, there are areas where Hydro was unable to provide all of the data requested by the Board, which are discussed herein. Hydro also offers insight into its interpretation and application of the Guidelines within its 2024 CBA.

Hydro acknowledges that the process is ongoing regarding revisions to the Guidelines based on recent feedback from the utilities and regulatory stakeholders, and welcomes further discussion on this matter before the finalization of the Guidelines in future.

Organization – Programs vs. Projects

Consistent with its approach in the 2023 CBA, Hydro has again classified the project or program by the primary driver of investment and continues to define programs as only those expenditures that are expected to continue indefinitely.[14] In cases where multi-year expenditures are required to place the asset into service, programs have instead been proposed as multi-year expenditures. Expenditures that span multiple years but will ultimately no longer be required following the completion of an ongoing initiative (e.g., Hydro's previous program to install fire protection in 230 kV stations) have been redefined as projects.[15]

Required Information – Asset Data

Hydro has endeavored to provide the evidentiary requirements prescribed in the Guidelines to the best of its ability based on the data available; however, for some programs or projects, asset data to meet all requirements, such as the quantification of asset condition and asset remaining life, or historical

[13] The Board's correspondence, dated December 20, 2021, noted that full implementation of the Guidelines would be challenging in the 2022. The Board acknowledged that strict adherence to all aspects of the Guidelines may not be possible, but requested that the parties make best efforts to respect the spirit and intent of the Guidelines. As Hydro has previously stated, full compliance will take years to achieve.
[14] Prior to the 2023 CBA, Hydro generally defined programs as those expenditures that span multiple years and address specific requirements for investment, with similar justification and scope year-over-year. Hydro redefined programs in its 2023 CBA to comply with the definition of programs provided in the Guidelines.
[15] Hydro continues to classify some expenditures associated with the Holyrood TGS as programs, despite the planned retirement of the Holyrood TGS by 2030. Hydro believes that the evidentiary requirements for programs are better suited to allow fulsome review of these expenditures.

trending to the level of detail as outlined in the Guidelines, may not be available. Hydro anticipates that asset data will improve with the continuous improvement of Hydro's asset management systems.

Hydro continues to improve its asset management systems, with an early emphasis on the implementation of processes to improve and expand on asset and maintenance data. As process improvements are implemented, Hydro anticipates that its asset data will improve and will allow Hydro to address the remaining gaps in its evidentiary data supporting its capital programs. Hydro notes that its efforts to improve its asset management systems will continue over the next several years, consistent with the timeframes Hydro has observed for other Canadian utilities that have or are in the process of improving their asset management systems. While Hydro is committed to continuous improvement in this area, and recognizes the value of improved asset management systems and data will aid in enabling a fulsome review of Hydro's capital investments by its stakeholders, Hydro believes that evidence provided in support of this application fully supports proposed investments.

Prioritization

Hydro recognizes the Board's request that projects be prioritized on the basis of risk mitigated per dollar spent, as well as by reliability improvement per dollar spent. As previously communicated, Hydro believes that prioritization by risk mitigated per dollar spent may not be an effective comprehensive risk indicator for prioritization of projects. Nonetheless, Hydro has provided this metric herein in compliance with the Guidelines currently in effect. As Hydro continues to develop its asset management systems, Hydro will assess opportunities to collect and analyze data to facilitate prioritization of projects and programs by reliability improvement.

Hydro has also proposed to the Board the addition of 'Economics' to the categories in which projects and programs are evaluated for risk mitigation. Hydro believes this will enable a fulsome evaluation of service enhancement-driven expenditures that may be motivated by cost savings for ratepayers.[16]

2.0 Capital Expenditures Summary

Hydro determined its proposed 2024 capital expenditures in accordance with its capital investment strategy, as shown in Figure 2. Hydro considers many factors in the selection of the projects and

[16] "Capital Budget Application Guidelines Review – Request for Comments/Input Regarding Draft Changes – Hydro's Comments," Newfoundland and Labrador Hydro, May 5, 2023.

program for inclusion in its budget, including operational risks, ability to execute, total investment, and cumulative risk associated with balancing aging assets while providing least-cost, reliable service in an environmentally responsible manner. The focus of the 2024 CBA is to maintain the expected level of reliability while ensuring prudent and reasonable expenditures reflective of our capital plan considerations.



Figure 2: Hydro's Capital Investment Strategy

Hydro's actual expenditures trend downward over the period 2013–2022. This decrease was driven primarily by comparatively large historical capital investment, along with Hydro's continued focus on cost management, to minimize impacts to ratepayers while delivering safe and reliable service. Hydro notes that its planned expenditures are relatively higher for the period 2024–2028, primarily as a result of Hydro's ongoing refurbishment of the Bay d'Espoir Hydroelectric Generating Facility penstocks, and Hydro's proposed project for long-term supply for southern Labrador. Further discussion of Hydro's planned capital expenditures for the period 2024–2028 is provided in Schedule 2 of this application. Chart 1 demonstrates the trend in capital expenditures from 2013–2028.[17]

[17] 2023 Planned Capital Expenditures includes carryover from 2022.

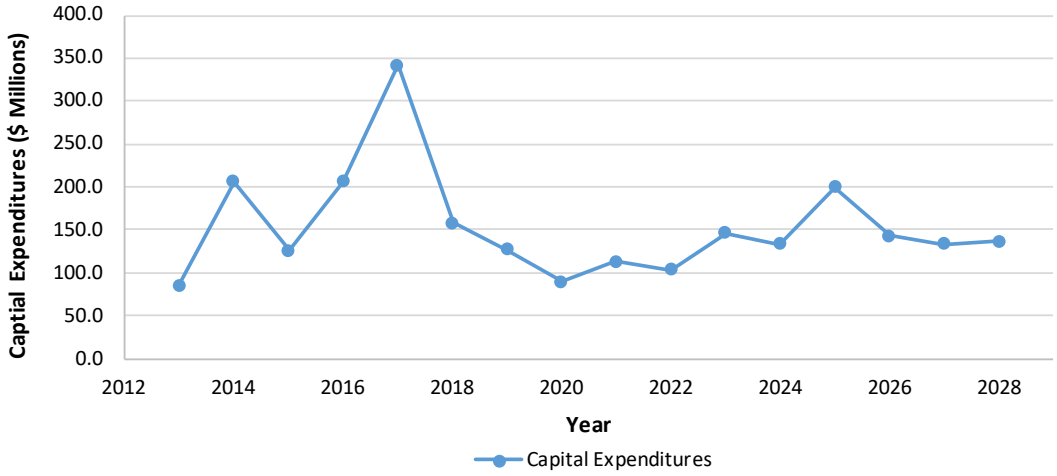


Chart 1: Historical, Budget, and Forecast Capital Budget Expenditures

Hydro's planned sustaining capital expenditures are relatively consistent over the period 2024–2028; Hydro's planned expenditures peak in 2025, primarily as a result of Hydro's planned expenditures associated with the refurbishment of the Bay d'Espoir Hydroelectric Generating Facility penstocks; and Hydro's long-term supply plan for southern Labrador.

3.0 2023 Capital Plan Execution

Hydro continues to experience increased equipment lead times and inflated costs associated with supply chain disruptions and inflationary pressures; however, the overall schedule impact is anticipated to be manageable. Hydro is closely monitoring the execution of its 2023 Capital Plan and will continue to prioritize projects to maximize reliability going into the 2023–2024 winter operating season. Consistent with prior years, capital expenditures approved in Hydro's 2023 CBA but not completed in 2023 will be carried over into 2024. Such projects will be reflected in Hydro's 2023 Capital Expenditures and Carryover Report.[18]

Schedule 4 of the 2024 CBA contains the 2023 Capital Expenditures Overview Report as of May 31, 2023, which details forecast expenditures and variances.

[18] Scheduled for filing with the Board on March 1, 2024.

4.0 Reliability

Hydro is classified as a Region 2 (Urban/Rural) utility by Electricity Canada ("EC").[19] For benchmarking against similar utilities, Hydro has provided EC Region 2 SAIDI[20] and SAIFI[21] averages excluding major events.[22] Additionally, as external causes have generally not impacted Hydro's reliability performance, Hydro does not currently track reliability impacts from external causes.

4.1 Utility Reliability

Reliability of service is integral to the mandate of Hydro, with the majority of expenditures being partially related to maintaining or improving reliability. As such, the End Consumer Performance Index was developed to measure the reliability of service to all end consumers of electricity in the province that are supplied by Hydro, other than Hydro's Industrial customers. The measure is a combination of Hydro's Service Continuity data and Newfoundland Power Inc.'s ("Newfoundland Power") Service Continuity data for outages related to loss of supply due to events on Hydro's transmission system. Therefore, the SAIDI and SAIFI data provided for End Consumer are measures of the duration and frequency of service interruptions experienced as a result of Hydro system events. Hydro does not track End Consumer metrics for the Island and Labrador separately.[23]

Service Continuity measures the reliability of service to consumers supplied directly by Hydro-owned distribution. Whereas EC Region 2 consists of utilities with a mix of rural and urban customers, Hydro's distribution customers are widely dispersed geographically, being primarily located in rural and/or remote areas; for this reason, Hydro's reliability metrics for Service Continuity are comparatively higher than the EC Region 2 average. This is consistent with Hydro's efforts to balance reliability and cost. Hydro notes that its historical reliability trends have been relatively flat over the period studied. This is reflective of Hydro's overall capital investment strategy, as renewal-driven capital investment makes up 57% of Hydro's proposed 2024 capital budget.

[19] Canadian Electrical Association was renamed Electricity Canada as of March 1, 2022. As a member utility of EC, Hydro is bound by a confidentiality agreement and is not permitted to provide reliability statistics for individual EC member utilities.
[20] System Average Interruption Duration Index ("SAIDI") is a reliability key performance indicator for distribution service, measuring service continuity in terms of the average cumulative duration of outages per customer served during the year.
[21] System Average Interruption Frequency Index ("SAIFI") is a reliability key performance indicator for distribution service, measuring the average cumulative number of sustained interruptions per customer per year.
[22] EC Region 2 averages are not available prior to 2015, and averages inclusive of major events are not available.
[23] As Hydro is the only utility serving Labrador, Hydro's Service Continuity metrics are equivalent to its End Consumer metrics in this region.

Hydro establishes End Consumer and Service Continuity SAIDI and SAIFI targets each year through the development of a five-year average.

4.1.1 Hydro System

Chart 2 and Chart 3 provide Hydro's End Consumer and Service Continuity SAIFI without major events compared to the EC Region 2 average and with major events included.

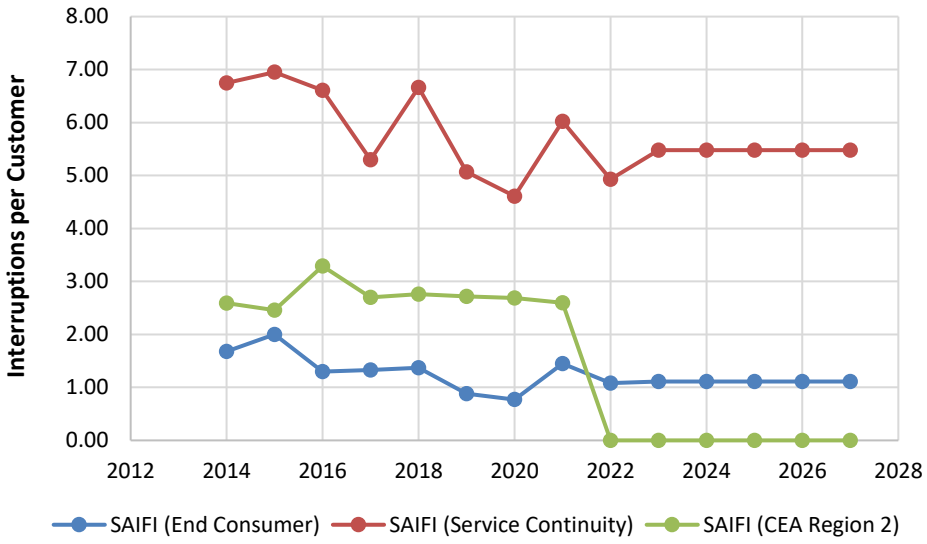


Chart 2: SAIFI Excluding Major Events

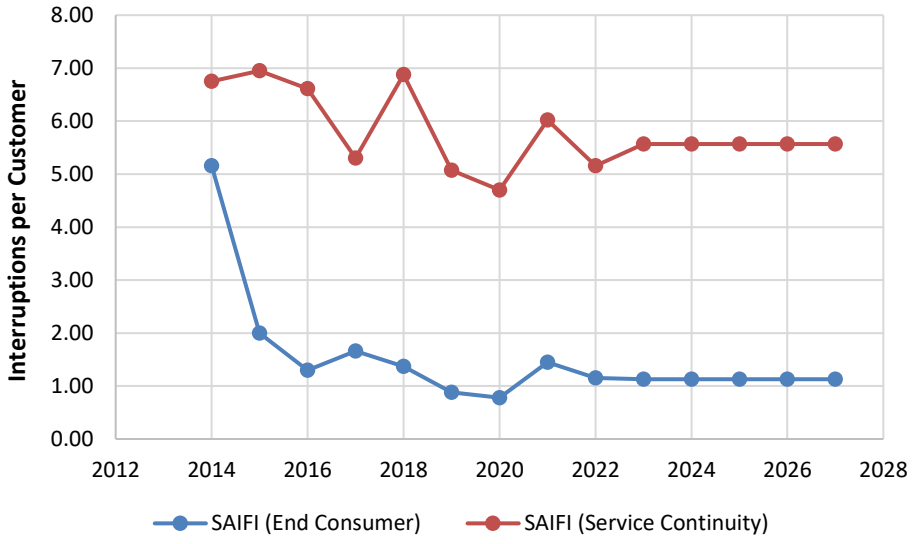


Chart 3: SAIFI Including Major Events

Chart 4 and Chart 5 provide Hydro's End Consumer and Service Continuity SAIDI without major events compared to the EC Region 2 average, and with major events included.

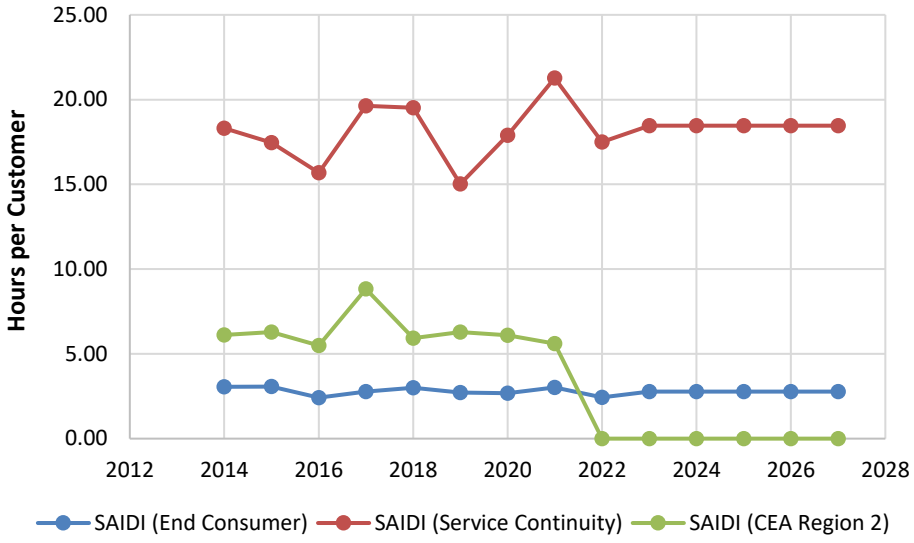


Chart 4: SAIDI Excluding Major Events

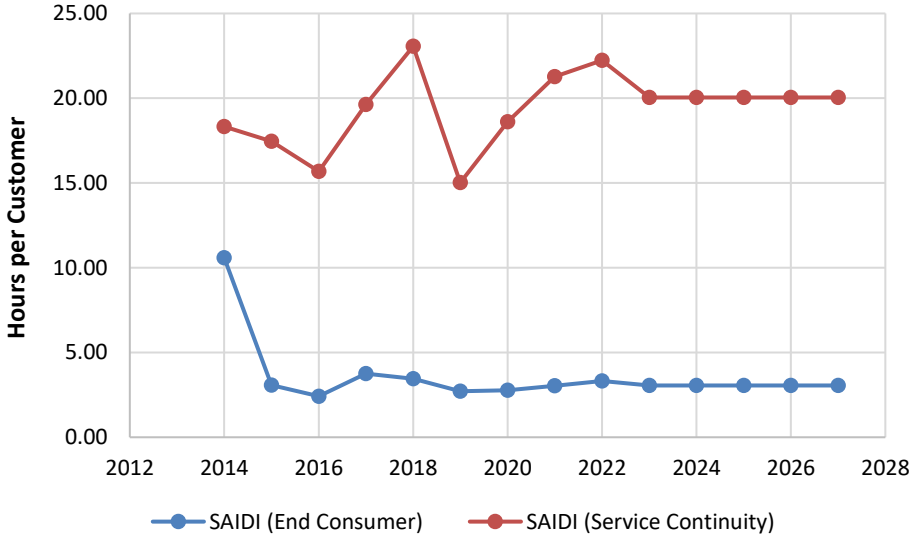


Chart 5: SAIDI Including Major Events

4.1.2 Island

Chart 6 and Chart 7 provide Hydro's Service Continuity SAIFI without major events compared to the EC Region 2 average, and with major events included, for the Island portion of the province.[24]

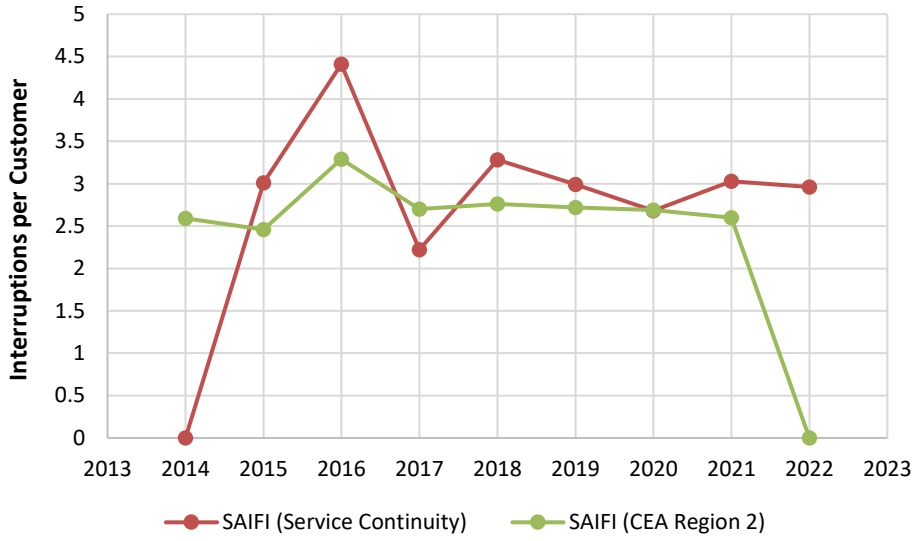


Chart 6: SAIFI Excluding Major Events – Island

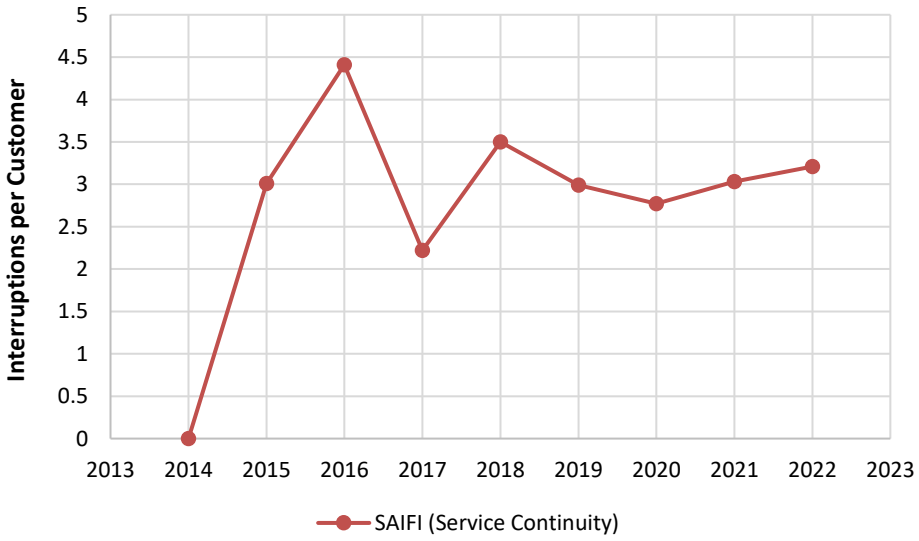


Chart 7: SAIFI Including Major Events – Island

[24] Due to an ongoing database error, reliability metrics for the Island and Labrador are not available prior to 2015 at this time.

Chart 8 and Chart 9 provide Hydro's End Consumer and Service Continuity SAIDI without major events compared to the EC Region 2 average, and with major events included, for the Island portion of the province.

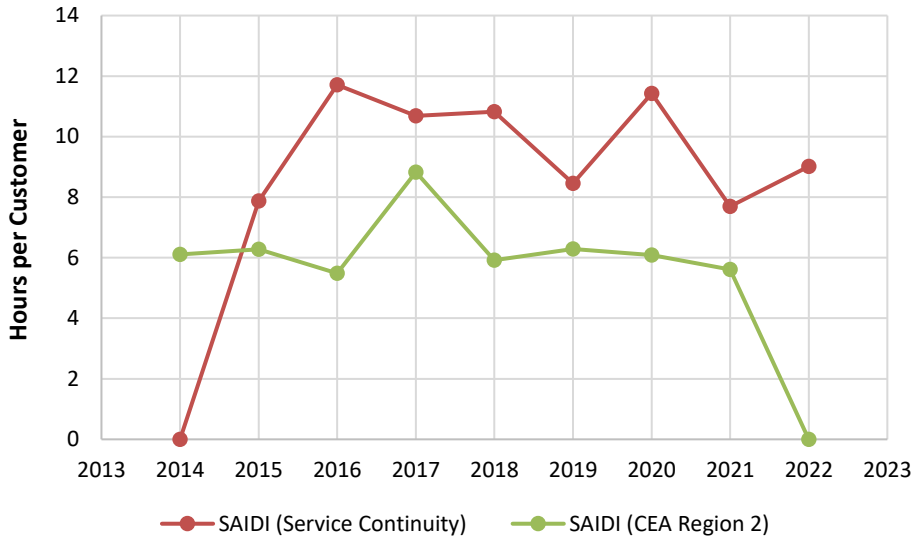


Chart 8: SAIDI Excluding Major Events – Island

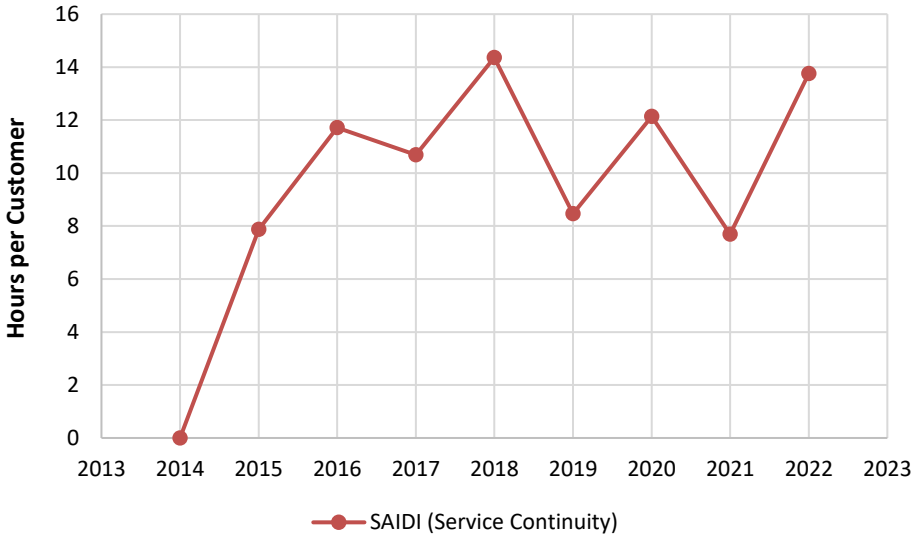


Chart 9: SAIDI Including Major Events – Island

4.1.3 Labrador

Chart 10 and Chart 11 provide Hydro's Service Continuity SAIFI without major events compared to the EC Region 2 average, and with major events included, for Labrador.[25]

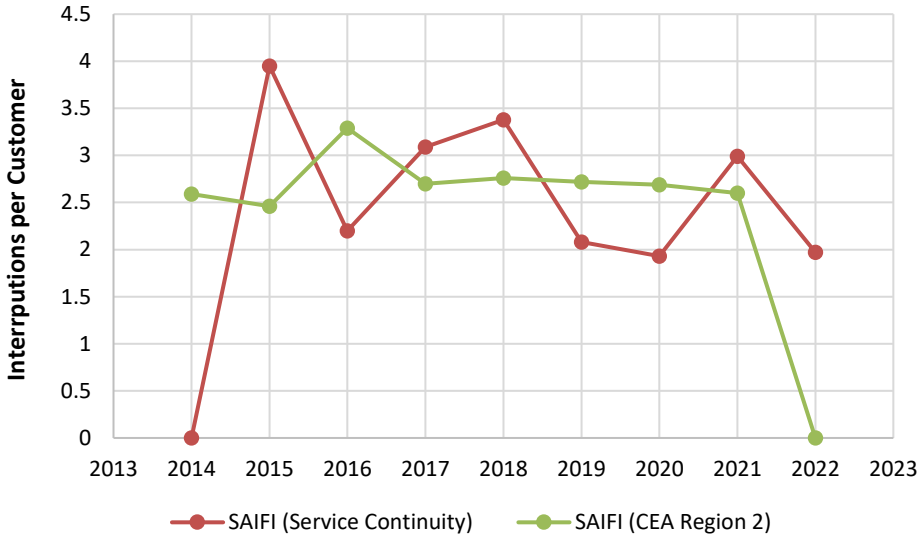


Chart 10: SAIFI Excluding Major Events – Labrador

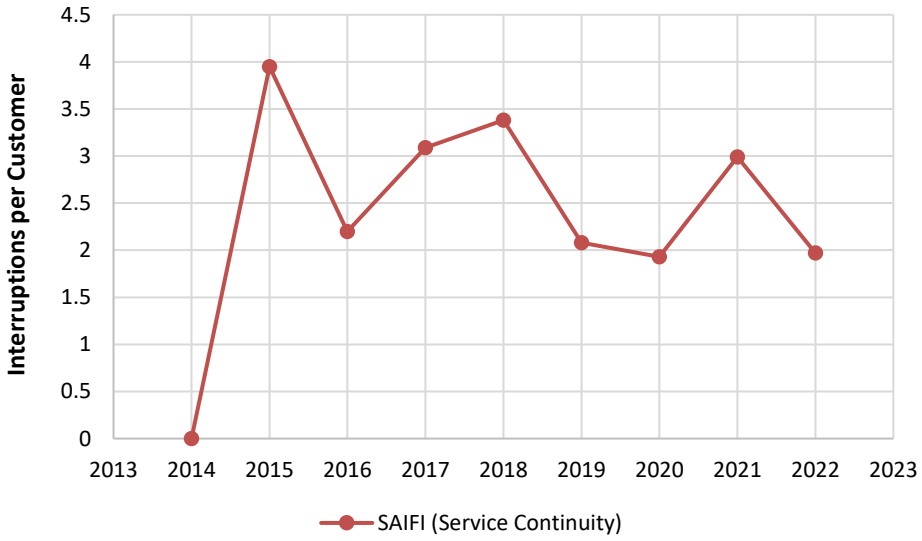


Chart 11: SAIFI Including Major Events – Labrador

[25] Due to an ongoing database error, reliability metrics for the Island and Labrador are not available prior to 2015 at this time.

Chart 12 and Chart 13 provide Hydro's End Consumer and Service Continuity SAIDI without major events compared to the EC Region 2 average, and with major events included, for Labrador.

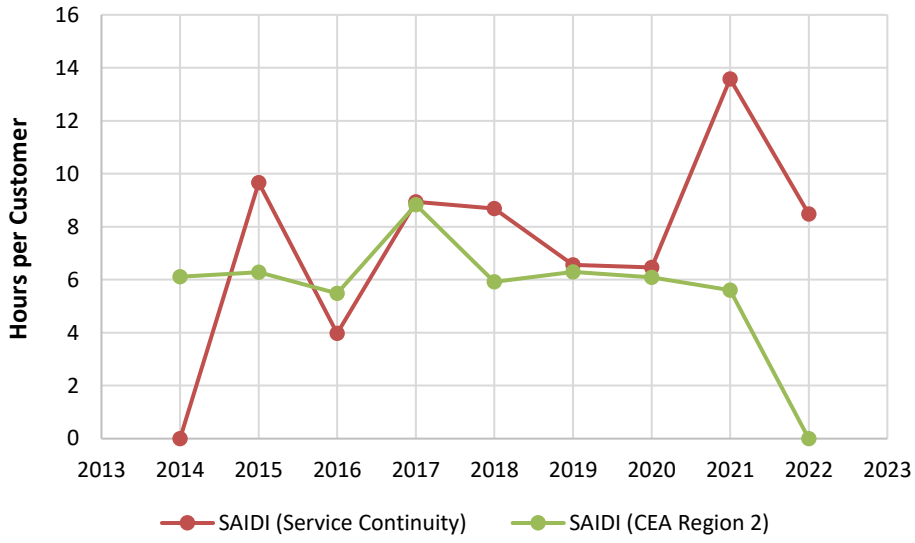


Chart 12: SAIDI Excluding Major Events – Labrador

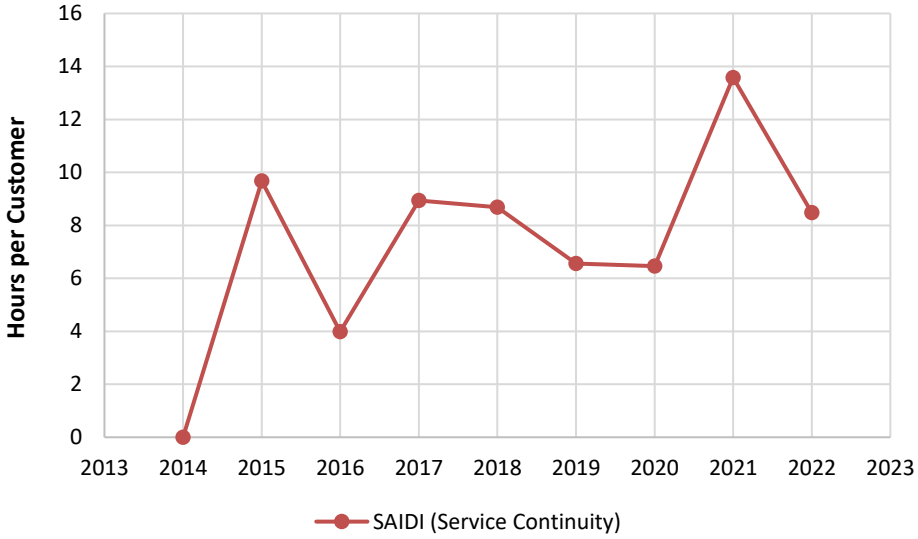


Chart 13: SAIDI Including Major Events – Labrador

4.2 Worst Performing Feeders

Hydro tracks its worst-performing feeders by SAIDI, SAIFI, and CHI[26] independently. Table 3, Table 4, and Table 5 present data related to Hydro's worst-performing feeders for each of these metrics, respectively, along with Hydro's average feeder SAIDI, SAIFI, and CHI, exclusive of contributions upstream from distribution feeders. When considering service enhancement projects to address worst-performing feeders, Hydro prioritizes feeders based on five-year average reliability indices. These metrics are used independently of each other and are intended to identify trending reliability issues. Hydro then uses condition assessment information to validate the issues identified through the indices to finalize the scope of work required to effectively upgrade the system. Finally, the criticality of the system is reviewed with respect to the number of dependent systems that rely on the reliability of the infrastructure in question.

In the 2024 CBA, Hydro is proposing a project to improve the reliability performance of L'Anse-au-Loup Line 2 ("LAL-L2"), based on the feeder's SAIDI performance, condition, and criticality. Hydro notes that there are other feeders shown on the SAIDI, SAIFI, and CHI lists that are higher or close in priority to the ranking for LAL-L2. These feeders have been excluded from the selection process for 2024 capital work as they either have capital projects planned, issues which are being corrected under other programs, such as vegetation management, or, field inspections did not indicate a root cause and additional investigation is ongoing. Please refer to the program proposal for more detailed information.

In its 2024 CBA, Hydro has also introduced a condition-based Renew Distribution Feeders program, which aims to proactively address feeders that have been evaluated as having a significant portion of deteriorated components before reliability is significantly impacted.

[26] Customer Hours Interrupted ("CHI"). Hydro's Average CHI represents the average number of Customer Hours of Interruption per feeder. It is calculated by dividing the number of total customer outage hours by the number of distribution feeders.

Table 3: Worst Performing Feeders Sorted by SAIDI (Five-Year Average)

Rank	Feeder	SAIDI
1	Jackson's Arm, Line 2	17.97
2	Farewell Head, Line 1	16.77
3	Barachoix, Line 1	16.68
4	Bottom Waters, Line 1	14.65
5	Black Tickle, Line 1	12.77
6	Barachoix, Line 4	11.54
7	Fleur de Lys, Line 1	11.44
8	L'Anse-au-Loup, Line 2	10.46
9	English Harbour, Line 1	10.38
10	Happy Valley, Line 7	10.16
	Hydro Average	13.28

Table 4: Worst Performing Feeders Sorted by SAIFI (Five-Year Average)

Rank	Feeder	SAIFI
1	Bottom Waters, Line 1	4.44
2	Barachoix, Line 4	3.81
3	Barachoix, Line 1	3.81
4	English Harbour, Line 1	3.76
5	Happy Valley, Line 15	3.62
6	L'Anse-au-Loup, Line 2	3.62
7	Happy Valley, Line 7	3.5
8	Cartwright, Line 1	3.47
9	Jackson's Arm, Line 2	3.41
10	Roddickton, Line 4	2.8
	Hydro Average	3.62

Table 5: Worst Performing Feeders Sorted by CHI (Five-Year Average)

Rank	Feeder	CHI
1	Happy Valley, Line 7	9,432
2	Barachoix, Line 4	9,374
3	Barachoix, Line 1	9,232
4	English Harbour, Line 1	8,341
5	L'Anse-au-Loup, Line 2	6,429
6	Jackson's Arm, Line 2	5,272
7	Bear Cove, Line 6	4,870
8	St. Anthony, Line 1	4,792
9	Bottom Waters, Line 1	4,422
10	Hawke's Bay, Line 3	4,396
	Hydro Average	6,656

5.0 2024 Plan Considerations

5.1 Program and Project Evaluation

5.1.1 Proposal Deferral, Cancellation, Additions, and Advancement

Prior to proposing capital programs and projects for inclusion in the CBA, Hydro considers whether the investment can be deferred in light of the condition of the asset and its criticality to the system. Where deferral of a program or project is determined to be low risk, that option is selected in an effort to balance the cost impact to customers with level of reliability required.

A number of the capital projects proposed are required to address safety concerns or to comply with regulatory and legislative requirements; therefore, deferral is not appropriate. For example, federal legislation requires polychlorinated biphenyls ("PCB") within Hydro's assets to be removed by 2025.[27] To defer such projects to future years would place Hydro behind schedule and at risk of not meeting legislative requirements. Additionally, deferral is not appropriate for projects that are required due to system growth, as it would compromise Hydro's ability to meet its peak load requirements and ensure reliable service.

As part of its assessment of alternatives, and as required by the Guidelines, Hydro considered deferral for each program or project contained in the 2024 CBA. The specific proposals detail the reason(s) for deferral not being the preferred option.

A list of deferred proposals that were originally planned to commence in 2024 is provided in Table 6.[28] The reasons for deferral of these proposals vary, and may include additional analysis required to assess alternatives, consideration of resource and outage availability, and assessment of risk associated with deferral.

[27] The *Canadian Environmental Protection Act, 1999,* PCB Regulations (SOR/2008-273) prohibits the release of PCBs in the environment.
[28] Hydro currently tracks proposal deferrals, but does not track the deferral of individual scope elements within programs or projects.

Table 6: Planned 2024 Capital Proposals Deferred

Planned Expenditure	2024 Deferred Cost ($000)
Rewedge Stator (2025–2026) – Hinds Lake	1,500.0
Rehabilitate Access Roads (2024–2025) – Hinds Lake	1,150.0
Upgrade Water Treatment Plant and Waste Water Treatment Plant (2024) – Holyrood	1,000.0
Replace Electrical Distribution System (2024–2026) – Holyrood	1,000.0
Refurbish Draft Tube Deck – Phase 3 (2025) – Bay d'Espoir	855.0
Stage I & II Cooling Water Pumphouse Condition Assessment (2024) – Holyrood	670.0
Overhaul Unit 2 (2024) – Bay d'Espoir	600.0
Install Plant Heating (2024–2025) – Holyrood	519.0
Replace Controllers (2025–2028) – Granite Canal	500.0
Replace Telecontrol Building and Upgrade Equipment – DHR	408.7
Upgrade Line Depots (2024–2026) – Bay d'Espoir	320.4
Install New Oil Systems Unit 3 (2024–2025) – Holyrood	255.0
Install Fire Barriers between T10 and T12, T10 and T11 (2024–2025) – Bay d'Espoir	220.4
Overhaul Fuel Oil Storage Tank #3	200.0
Upgrade Black Start Diesel Cables (2024) – Holyrood	150.0
Resurface Parking Lots and Roads (2024) – Bishop's Falls	150.0
Upgrade Terminal Station for Mobile Substation (2024-2025) – Bear Cove	147.7
Install Breaker Failure Protection (2024–2025) – Holyrood TS	135.0
Upgrade Property (2024) – St. Anthony	120.0
Replace SC1/SC2 Overhead Crane (2024–2025) – Wabush Terminal Station	120.0
Install Dynamic Air Gap and Vibration Monitoring System (2024–2025) – Upper Salmon	103.0
Eastern to Central Interconnect Microwave Radios	100.0
Inspect and Upgrade Light Oil System – Holyrood (2024–2025)	100.0
Upgrade Terminal Station for Mobile Substation – RWC	60.0
Replace Powerhouse Septic System (2025–2026) – Upper Salmon	50.0
Install Secondary Station Service Supply (2024–2025) – Holyrood Gas Turbine	50.0
Install Energy Efficient High Bay and Exterior Lighting (2024–2025) – Holyrood	15.9
Total Deferred 2024 Capital Proposals	**10,500.1**

Occasionally, Hydro cancels projects that had previously been identified in Hydro's capital plans. Reasons for cancellation vary but may include projects that are no longer required due to changes in system operations, scopes merged with other capital projects, or projects for which non-capital alternatives have been identified. A list of projects and programs originally planned for 2024 that have been cancelled is proved in Table 7.

Table 7: Cancelled 2024 Proposals

Cancelled Proposal	2024 Cancelled Cost ($000)
Additions for Load Growth – Isolated Generation Stations (2024)	650.0
Upgrade Public Safety Around Dams and Waterways (2024)	480.0
Replace Station Cooling Water Piping, Valves, and Controls (2024) – Upper Salmon	395.0
Upgrade Ambient Monitoring Stations – Holyrood	300.0
Replace Back Hoe Unit 9813 (2024) – Holyrood	242.0
Upgrade Transformer Paralleling (2024–2025) – Holyrood T5 and T10	100.0
Install Recloser Remote Control (2024–2025)	25.0
Total Cancelled 2024 Expenditures	**2,192.0**

Hydro occasionally includes projects or programs in its capital budget that had previously been identified in a future year. Reasons for advancement may include urgency due to faster-than-anticipated condition deterioration, or optimization of outage schedules and resources. A list of proposals advanced from future years in Hydro's 2024 CBA is provided in Table 8 and includes the advancement of work scope from 2025 into 2024 as a result of the optimization of outage schedules.

Table 8: Advanced 2024 Proposals

Advanced Proposal	2024 Advanced Cost ($000)
Inspect Fuel Tanks (2024) -–Hardwoods Gas Turbines	692.9
Overhaul Hydraulic Units	323.8
Total Advanced 2024 Expenditures	**1,016.7**

Hydro aims to capture its planned expenditures in its five-year capital plan submitted annually with its CBA; however, projects or programs not previously identified may be included as a result of changing system conditions, and newly identified requirements driven by system growth or assessment of existing assets. The majority of capital additions in 2024, listed in Table 9, are a result of the extension of the operation of the Holyrood TGS and the Hardwoods Gas turbine as per the 2022 update to the Reliability and Resource Adequacy Study.[29] These assets shall remain available for a "Bridging Period"[30] until 2030,

[29] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[30] Hydro considers the Bridging Period to be from 2023 to 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.

Table 9: 2024 Additions

Added Proposal	2024 Additional Cost ($000)
Overhaul Unit 1 Turbine Valves and Generator (2024) – Holyrood	5,181.4
Boiler Condition Assessment and Miscellaneous Upgrades (2024) – Holyrood	3,957.8
Refurbish Fuel Oil Storage Tank 4 (2024) – Holyrood	1,920.0
Renew Distribution Feeders (2024–2025)	1,287.3
[]	-
Overhaul Pumps (2024) – Holyrood	661.0
Overhaul Marine Terminal Loading Arms (2024) – Holyrood	511.0
Upgrade Unit 1 Control System (2024-2025) – Holyrood	468.3
Replace CCTV Cameras (2024)	317.6
Upgrade UPS 1 & 2 (2024-2025) – Holyrood	263.0
General Property Rehabilitation (2024) – Hydro Place	234.0
Upgrade DCS Hardware - Units 1 and 2 (2024–2025) – Holyrood	195.2
Upgrade HVAC Supervisory Controllers (2024) - Hydro Place	149.6
Upgrade Distribution (2024-2025) - Bay d'Espoir Terminal Station 2	93.2
Upgrade Station Lighting (2024-2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon Terminal Stations	91.6
Telecommunications In-Service Failure (2024)	91.4
Install Anemometer (2024) - Cat Arm	68.6
Upgrade Instrumentation (2024-2025) - Hardwoods Gas Turbine	60.9
Total [] 2024 Capital Additions	**15,551.9**

5.1.2 Capital Proposals

Maintaining Hydro's systems in reliable operating condition requires planned maintenance, rehabilitation of existing assets, and replacement of assets that have reached the end of their useful lives. Replacement of assets may also occur to reduce life cycle costs, improve operational characteristics, increase capacity for load growth, address violations of reliability criteria, improve productivity, and/or increase efficiency.

In determining whether a capital proposal is appropriate, Hydro gives consideration to:

- Safety, environmental, or reliability risk and degree of expected mitigation;

- System performance and reliability metrics;
- Hydro's long-term asset management strategy;
- Regulatory and legislative compliance;
- Load growth and system planning criteria;
- Hydro's experience with the assets, including the condition and performance of the assets;
- Ongoing operating and maintenance costs;
- Opportunities for cost efficiencies; and
- Changes to operating conditions.

For those proposals that relate to replacement of assets, Hydro bases such decisions on three broad categories of replacement criteria, as follows:

1) Time and Condition Based: hours of operation and condition, for example, diesel generators (100,000 hours of operation for 1,800 rpm units) and vehicles (combination of years and kilometres for some classes);

2) Condition Based: in-situ condition of the assets, for example, decay in transmission line wood poles; and

3) Technical Assessment Based: an evaluation of reliability, performance, condition, costs, and other factors, such as the inspection of fuel tanks and subsequent upgrade where required.

5.2 Reassessment of Planned Capital Expenditures

Beginning in 2021 with its filing of the 2022 CBA,[31] Hydro began undertaking a thorough review of its previously approved multi-year projects to identify opportunities for budget refinement for ongoing projects or programs. Hydro has continued this exercise in preparing its 2024 CBA. As a result, multi-year programs or projects with expenditures in 2024 were reduced by $8.1 million, with $6.2 million being moved or added to future years. Schedule 4, Section 2.0 of the CBA contains a list of the programs and projects and revised budgets.

[31] "2022 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 17, 2021 (originally filed August 2, 2021).

5.3 Estimate Accuracy

Estimates for Hydro's capital projects and programs are developed primarily by Hydro's engineering staff, with support from engineering consultants as required. In developing estimates for capital expenditures, Hydro completes front-end engineering design to define project scope and identify project constraints, and utilizes historical project expenditures and experience, and vendor and contractor quotes, to develop project costing.

Capital budget estimates and actual expenditures may differ for a number of reasons, including but not limited to:

- Differences in quoted and actual tendered material and contract pricing;
- Changes in market conditions (e.g. inflationary pressure, supply chain disruptions); and
- Refinement of project scope.

In accordance with estimating best practices, Hydro includes contingency[32] within its project budgets based on the level of confidence in individual component costs, resulting in project contingencies generally ranging from 10% to 15%.[33]

To determine the accuracy range of Hydro's capital estimates, Hydro completed statistical analysis of project variances based on available data for projects proposed and completed since 2013.[34] Hydro's analysis has determined that its average variance is -4%,[35] with a standard deviation of approximately +/-38%. Therefore, Hydro's expected estimate accuracy range is approximately +30%/-40%.

[32] The Association for Advancement of Cost Engineering ("AACE") defines contingency as "An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience."
[33] Prior to the 2019 CBA, Hydro generally included 20% contingency in its capital budget estimates.
[34] Variance is equal to project/program budget minus project/program actual expenditure.
[35] Expenditure with a negative variance greater than 75% are excluded from analysis, as these generally reflect cancelled scopes and are not an indication of estimate accuracy.

6.0 2024 Capital Budget

The 2024 capital budget contains 118 projects and programs,[36] as outlined in Appendix A. The total planned 2024 capital expenditure, for which Hydro is seeking approval in its 2024 CBA, is $96.6 million.[37] A breakdown and analysis on key drivers are provided in the charts herein.

Chart 14 shows the 2024 Capital Budget Summary by major area. Consistent with the 2023 CBA, the majority of 2024 expenditures are in the area of transmission and rural operations ("TRO"). This is primarily a reflection of projects to accommodate load growth and reliable operation in Labrador West, the continuation of Hydro's project to replace the metering system, and the continuation of Hydro's asset renewal projects and programs.

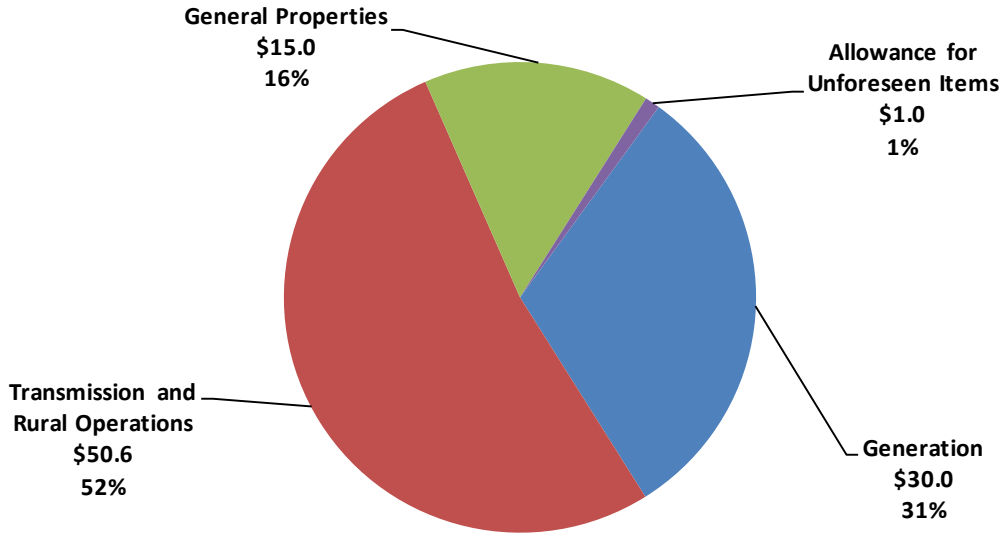


Chart 14: 2024 Capital Budget Summary by Major Asset Category ($ Millions)[38]

The discussion of proposed capital expenditures herein is primarily organized by investment classification, with discussion of the asset categories and specific projects or programs driving investment within each investment classification.

[36] Including projects less than $750,000.
[37] The 2024 CBA also includes front-end engineering and design expenditures, which are necessary to support the development of proposals, on a number of projects. Hydro will not capitalize such costs related to a project if the project does not receive Board approval.
[38] Numbers may not add due to rounding.

Chart 15 shows the 2024 Capital Budget Summary by investment classification. The majority of Hydro's expenditures relate to asset renewal, consistent with Hydro's capital investment strategy and reflective of both the age of Hydro's assets as well as the mix of asset type, and General Plant investment is driven primarily by the continuation of Hydro's projects to purchase material handler aerial devices and for renewal of light- and heavy-duty vehicles.

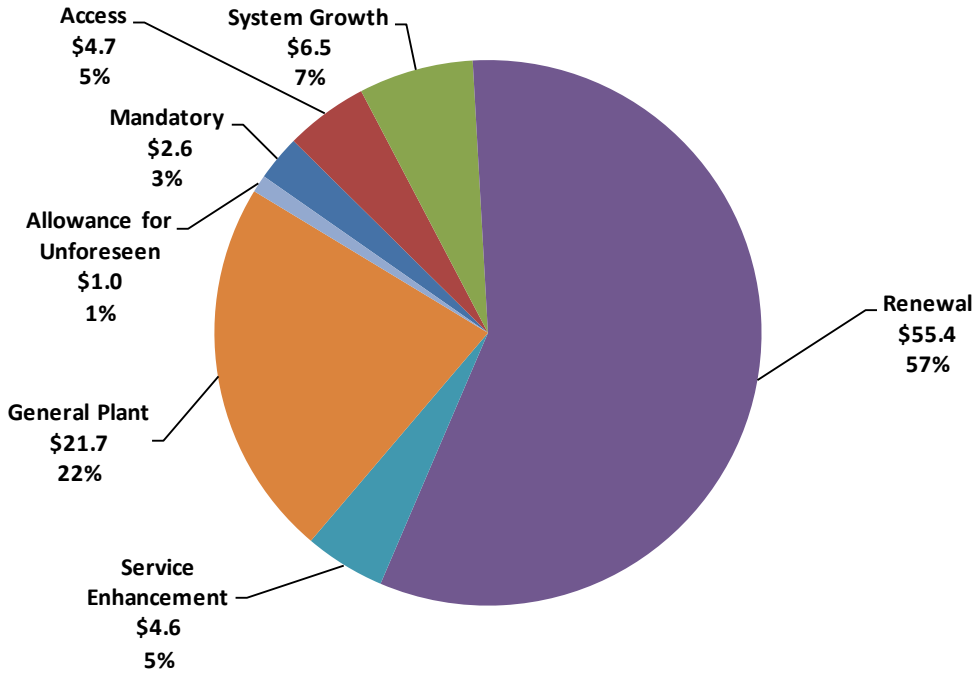


Chart 15: 2024 Capital Budget Summary by Investment Classification ($ Millions)

6.1 Renewal

Programs and projects classified as "Renewal" are those that are required to replace and/or refurbish system assets to maintain the ability to provide customers with their current electricity services. As Hydro's assets age, its capital investment strategy aims largely to sustain current system-level reliability by renewal-driven capital investment; therefore, expenditures in this area make up the majority of our capital budget projections, consistent with previous years. Hydro's proposed renewal expenditures account for over half of Hydro's total proposed 2024 capital investment, totalling $55.4 million. Hydro's proposed 2024 renewal investment by asset category is provided in Chart 16.

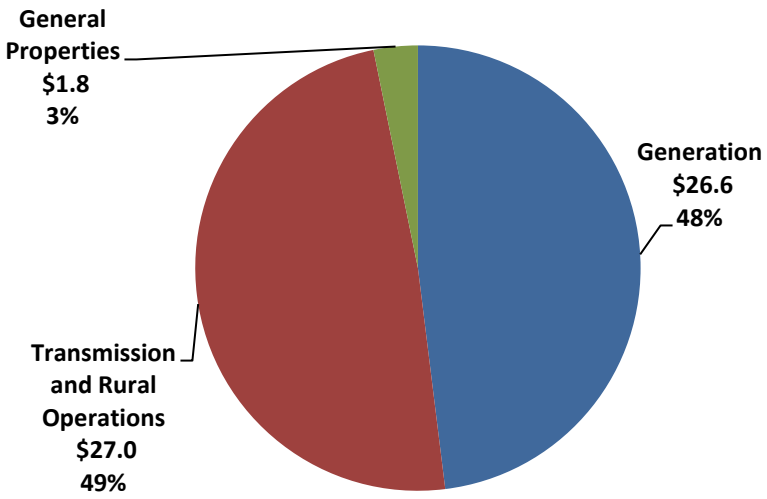


Chart 16: 2024 Proposed Renewal Investment by Asset Category ($ Millions)

6.1.1 Generation

Generation expenditures comprise of the replacement, repair and renewal of Hydro's hydraulic, thermal, and gas turbine generating assets. Hydro's proposed generation-related renewal expenditures account for nearly half of its total proposed 2024 renewal expenditures, totalling $26.6 million. Generation renewal investment for 2024 is comprised of investments in Hydro's hydraulic plant, thermal plant, and gas turbine assets.

Hydro's regulated capital program is responsible for sustaining capital investment in Hydro's six hydroelectric generating facilities, totalling approximately 960 MW of installed capacity. As such, considerable resources must be allocated to ensure safe, reliable output at these plants. Hydraulic plant renewal accounts for $10.5 million of Hydro's overall proposed capital expenditures for 2024 and represents about 40% of Hydro's generation-related renewal budget. Key drivers of hydraulic generation renewal investment include the continuation of projects to refurbish the Ebbegunbaeg Control Structure, refurbishment of the Salmon River Spillway, and the Hydraulic In-Service Failures Program.

Thermal plant renewal associated with sustaining capital investment at the Holyrood TGS accounts for $14.7 million in 2024, representing just over half of Hydro's planned spending in generation programming and projects. As Hydro expects continued operation of all three units at the Holyrood TGS during the Bridging Period until its capacity can be adequately replaced to ensure reliable operation for customers, capital expenditures for this facility to operate as a generator continue to be required. The

investment prescribed in this application reflects that which is necessary and prudent to meet this commitment. Key renewal expenditures for thermal plant assets include overhaul of the Unit 1 turbine and valves, and continuation of the "Boiler Condition Assessment and Miscellaneous Upgrades" and "Thermal In-Service Failure" programs. Further discussion of Hydro's thermal plant investments for 2024 is provided in the Holyrood Thermal Generating Station Overview, provided as Schedule 3 of the CBA.

The remainder of Hydro's generation assets consist of four gas turbines. Gas turbine renewal accounts for $1.3 million in 2024, and includes the continuation of a previously approved project to replace an oil-mist separator on the Happy Valley Gas Turbine, as well as inspection of fuel tanks and continuation of the gas turbine in-service failures program.

6.1.2 Transmission and Rural Operations

Hydro maintains over 4,400 km of transmission lines and 69 terminal stations for the Island and Labrador Interconnected Systems, as well as distribution and isolated generation assets that service almost 40,000 customers in Newfoundland and Labrador. As such, much like generation activities, TRO requires considerable capital expenditures to maintain. Approximately half of Hydro's total proposed 2024 renewal expenditures are allocated to this category.

Hydro's TRO renewal expenditures planned for 2024 are driven primarily by the continuation of programs for renewal of terminal station assets, including the continuation of the Circuit Breakers Renewal Program.[39] For the 2024 CBA onward, Hydro has dissolved the Terminal Station Renewal Program.[40] To ensure Hydro is meeting the evidentiary requirements set out in the Guidelines, Hydro is proposing individual programs for the renewal of specific assets previously covered under the Terminal Station Renewal Program, including protection and control relays and devices, disconnect switches, power transformers, instrument transformers, data alarm annunciators, batteries and chargers, and station lighting.

[39] Hydro's planned investments in its Circuit Breaker Renewal Program for 2024 includes replacement of two 25 kV Breakers; while assets of this voltage class are typically considered distribution assets, Hydro has included them in this program for regulatory and execution efficiency.
[40] The Terminal Station Asset Overview was historically appended to this program, and is now appended to this overview as Appendix F.

Hydro's 2024 TRO expenditures also include the continuation of programs for renewal of distribution assets, as well as programs to renew isolated generation assets, including diesel genset replacements and overhauls, and fuel tank replacement.

Hydro is also proposing the continuation of its programs to address in-service failures of transmission, distribution, diesel, and terminal station assets.

6.1.3 General Properties

Hydro's proposed General Properties renewal expenditures account for 3% of its total proposed 2024 renewal expenditures. General Properties renewal investment is related to telecontrol assets, including the replacement of deteriorated and obsolete power line carrier infrastructure, replacement of battery banks and chargers, and replacement of remote terminal units.

6.2 General Plant

Programs and projects classified as "General Plant" are those related to Hydro's assets that are not part of its generation, transmission, and distribution system. These largely include systems such as water and sewer, fire protection, general maintenance and renovations, property assets such as buildings and roads, and human resource or employee service needs. Hydro's proposed general plant expenditures of $21.7 million account for nearly a quarter of Hydro's proposed 2024 capital program, an increase from the 2023 CBA where this investment class accounted for approximately 11% of total expenditures. Key drivers of investment are detailed below, with a breakdown of Hydro's proposed 2024 general plant investment by asset category provided in Chart 17.

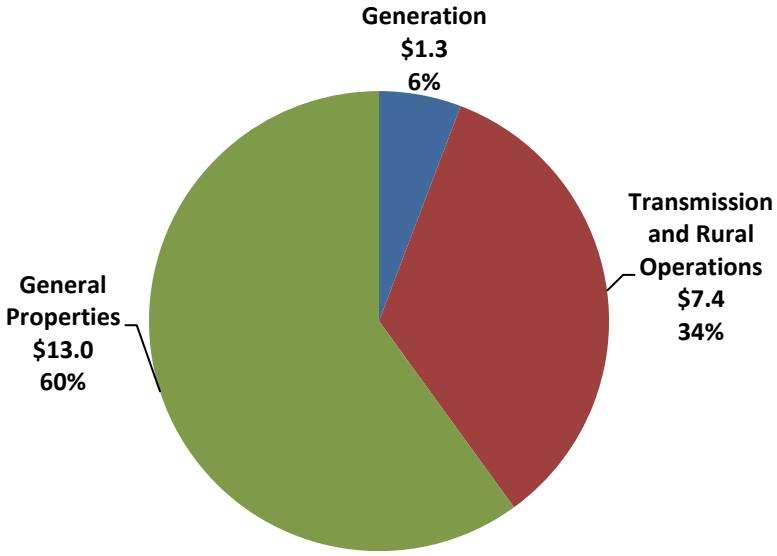


Chart 17: 2024 Proposed General Plant Investment by Asset Category ($ Millions)

6.2.1 Transmission and Rural Operations and Generation

Key drivers of general plant-related investments within TRO, as well as Generation, are new and previously approved projects predominantly relating to the refurbishment of buildings and critical safety systems supporting these operational areas.

Generation-related general plant investment includes the refurbishment of the powerhouse and outbuildings at the Holyrood TGS, the continuation of a previously approved project for water system condition assessment and updates at Bay d'Espoir, and newly proposed projects to replace the roof on the Bay d'Espoir Powerhouse 1 and to improve the slope safety factor on the Hinds Lake canal dyke.

TRO-related general plant investment includes the continuation of projects such as those previously approved at Hydro's Bishop's Falls complex to replace the diesel shop building, HVAC[41] system, domestic and fire water systems, and installation of fire protection at the Deer Lake Terminal Station.

6.2.2 General Properties

Key drivers of general properties-related investment include Hydro's administration, information systems, telecontrol, and transportation assets.

[41] Heating, ventilation, and air-conditioning ("HVAC").

Approximately half of the planned spend in this area is for the continuation of its light- and heavy-duty vehicle program, which ensures said vehicles are safe and fully operational. Hydro has completed a field verification of the light-duty vehicle fleet and has reviewed survey data from other Canadian utilities, and has determined that its replacement criteria and the size of its fleet remain appropriate at this time.

The remainder of Hydro's proposed 2024 general properties investment includes Information System and Telecontrol expenditures. Information System expenditures include the continuation of programs to upgrade software, cybersecurity, and hardware infrastructure, including personal computers and mobile devices. Updates to these systems and assets are crucial to protect against external threats, as well as ensuring access to the necessary tools and software to support the management operation of the electrical system. Notable investments in Telecontrol include the replacement of Hydro's VHF[42] mobile radio system, microwave radios, CCTV[43] Cameras, and SONET[44] multiplexors. These investments help employees communicate, improving output and safety, as well as ensuring the protection of Hydro staff and property.

6.3 System Growth

Programs and projects classified as "system growth" are those required to modify Hydro's system to meet forecast changes in customer electricity resource requirements. All of Hydro's proposed system growth-driven capital expenditures are associated with the continuation of projects to address load growth in Labrador West. Hydro's proposed system growth capital expenditures account for about 7% of Hydro's total proposed 2024 capital investment, totalling $6.5 million in 2024.

6.4 Access

Projects and programs classified as "access" are those required to meet Hydro's obligation to provide customers with access to electricity services. The proposed access capital expenditures for 2024 are associated with Hydro's Provide Service Extensions program, under which Hydro executes routine service extensions to new customers who require interconnection to the local distribution system, or

[42] Very high frequency ("VHF").
[43] Closed-circuit television ("CCTV").
[44] Synchronous Optical Network ("SONET").

customer requests to relocate services. Hydro's proposed access capital expenditures account for 5% of Hydro's total proposed 2024 capital investment, totalling $4.7 million in 2024.[45]

6.5 Service Enhancement

Programs and projects classified as "service enhancement" are those which modify Hydro's system to meet system operations requirements in a more efficient and/or effective manner, including those which improve safety or environmental compliance. This year $4.6 million, or about 5% of planned capital expenditures, are related to service enhancement. Primary drivers of service enhancement investment in 2024 include the continuation of Hydro's previously approved project to replace Hydro's metering system, as well as the continuation of Hydro's program to upgrade its worst-performing distribution feeders. Hydro's proposed 2024 service enhancements investment by asset category is provided in Chart 18.

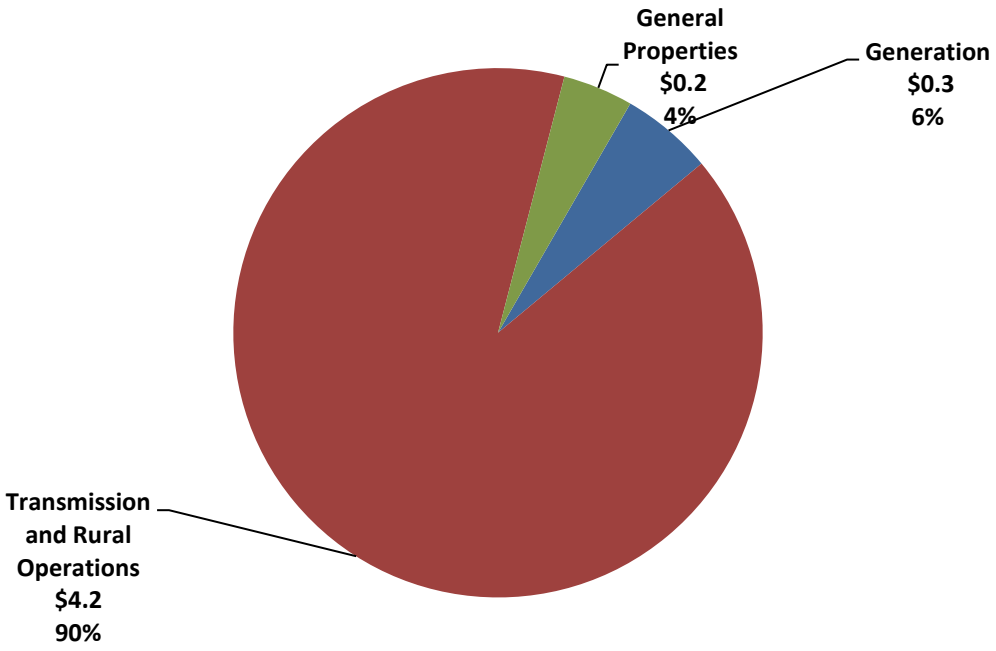


Chart 18: 2024 Proposed Service Enhancement Investment by Asset Category ($ Millions)[46]

[45] Hydro's ongoing project to replace Hydro's residential and general service metering system is driven primarily by the opportunity for cost savings associated with drive-by metering; this project is therefore classified as service enhancement, and is discussed in Section 6.5.

[46] Numbers do not match total due to rounding.

6.6 Mandatory

Mandatory projects are those prescribed by a governing body, such as legislative requirements or orders issued by the Board. While these projects are critical, the projected amount required to complete mandatory projects for the upcoming year is minimal, amounting to approximately 3% of our proposed capital investment. In this CBA, Hydro has proposed three mandatory projects: Refurbish Fuel Oil Storage Tank – Holyrood, which is required to comply with fuel storage tank regulations, and the continuation of Hydro's 2023 and 2024 terminal station lighting projects, which are required to address components suspected to contain PCBs. Hydro is required under Canadian environmental regulations to remove and dispose of all equipment containing greater than 50 ppm[47] of PCBs by December 31, 2025.

6.7 Specifically Assigned Assets for Industrial Customers

A portion of Hydro's asset base is specifically assigned to Industrial customers on the Island and in Labrador. These customers have complex, highly specified needs making Hydro a key component to their success.

Hydro's 2024 CBA includes the continuation of projects with assets specifically assigned to the Iron Ore Company of Canada ("IOC"), including the replacement of circuit breakers B3L5A and B3L5B in the Wabush Terminal Station and the replacement of Wabush Line 5 protective relays. The total estimated specifically assigned costs for IOC in 2024 is $1.2 million.

Hydro's 2024 CBA also includes the continuation of a project with assets specifically assigned to Braya Renewable Fuels for replacement of the Come By Chance Transformers T1 and T2 neutral bushings and a new project to replace protective relays for these transformers. The total estimated specifically assigned costs for Braya Renewable Fuels in 2024 is $0.4 million.

Also included in Hydro's 2024 CBA is a project to install fire protection at the Voisey's Bay Nickel Terminal Station, specifically assigned to Vale. The total estimated specifically assigned costs for Vale in 2024 is approximately $50,000.

Specifically assigned asset renewals within Hydro's Five-Year Capital Plan (2024–2028) are detailed in Table 10.

[47] Parts per million ("ppm").

Table 10: Specifically Assigned Capital Work

Customer	Specifically Assigned Work	Program or Project	2024 Specifically Assigned Cost ($000)
IOC	WABTS B3L5A Replacement	Circuit Breakers Renewal Program (2023–2024)	563.4
IOC	WABTS B4L5B Replacement	Circuit Breakers Renewal Program (2023–2024)	563.4
IOC	WABTS L5 Protection Replay Replacement	Terminal Station Renewal Program (2023–2024)	83.4
Braya	CBC T1 X0 Bushing Replacement	Terminal Station Renewal Program (2023–2024)	195.8
Braya	CBC T2 X0 Bushing Replacement	Terminal Station Renewal Program (2023–2024)	195.8
Braya	CBC T1 Protection Relay Replacement	Replace Protective Relays – Various (2024–2025)	20.5
Braya	CBC T1 Protection Relay Replacement	Replace Protective Relays – Various (2024–2025)	20.5
Vale	VBNTS Install Fire Protection	Install Fire Protection in 230 kV Stations (2024–2025) – Voisey's Bay	53.8
Tacora	WABTS B4L34 Replacement	Circuit Breakers Renewal Program (2025–2026)	-
Tacora	WABTS B4L34-1 (formerly 34B15) Replacement	Terminal Station Renewal Program (2025–2026)	-
Teck	BUCTS B2L64 Overhaul	Circuit Breakers Renewal Program (2025–2026)	-
IOC	WABTS B4L6 Replacement	Circuit Breakers Renewal Program (2026–2027)	-
Tacora	WABTS B4L35 Replacement	Circuit Breakers Renewal Program (2026–2027)	-

6.8 Leasing Costs

There are no capital leasing costs contained in the 2024 CBA.

6.9 Rate Impact Summary

On a *pro forma* basis, Hydro's 2024 and 2025 total regulated revenue requirement is estimated to increase by approximately $2.8 million and $10.6 million[48] respectively, as a result of the capital programs and projects proposed for 2024. Such a revenue requirement increase would represent an

[48] These amounts do not reflect any reduction that may occur as a result of asset retirements.

increase of 0.4% and 1.6% in 2024 and 2025 respectively, relative to Hydro's 2019 Test Year. This assumes the Holyrood TGS Accelerated Depreciation Deferral Account is extended until at least December 31, 2024, resulting in the deferral of $1.1 million depreciation; whereas, it is assumed 2025 is a test year that includes $3.5 million accelerated depreciation on Holyrood assets.[49]

The total forecast revenue requirement impact from the 2024 capital budget for rural areas is approximately $0.5 million in 2025. Based upon the 2019 Test Year Cost of Service Revenue to Cost ratios, is it estimated that rural customers will contribute $0.2 million towards this increase, with the remainder allocated to the rural deficit and included in Hydro's wholesale rates charged to Newfoundland Power.

This *pro-forma* estimate is comprised of return on rate base and depreciation. It does not reflect potential reductions in operating and maintenance charges (e.g., changes related to technology such as the conversion to LED[50] streetlights where Hydro expects savings to be realized).

Hydro's projected rate impacts as a result of programs and projects proposed in the 2024 CBA by system are detailed in Table 11.

Table 11: Projected Wholesale Rate Impact by System (%)

System	2024	2025
Island Interconnected System	0.4	1.5
Labrador Interconnected – Rural	0.7	2.8
Labrador Industrial – Regulated	4.3	15.8
Labrador Industrial – Total Billings	0.4	1.4

Hydro's ten-year historical Island Interconnected Wholesale Electricity Rate and Labrador Interconnected Electricity Rate for the years 2013–2022 are presented in Chart 19.

[49] As a result of the extension of the Holyrood TGS through the Bridging Period, Hydro intends to make an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account in 2023.
[50] Light-emitting diode ("LED").

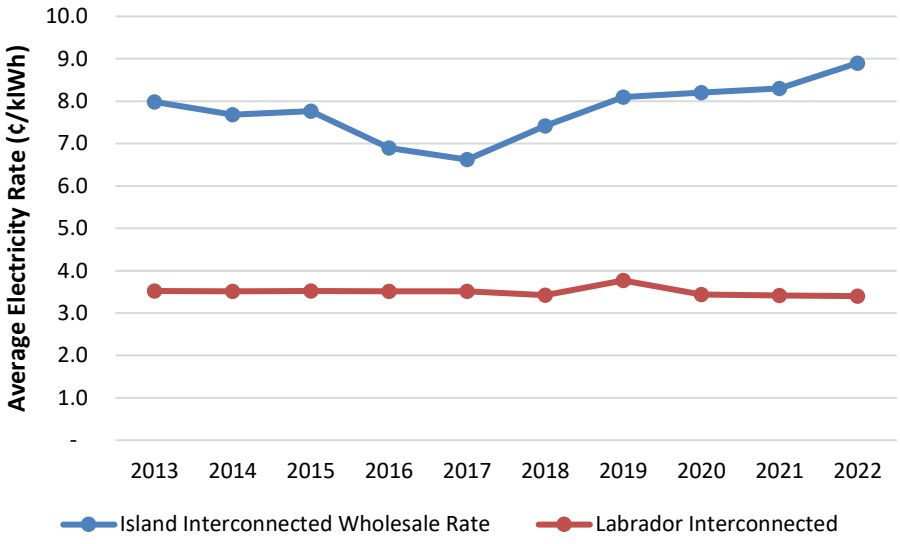


Chart 19: Ten-Year Historical Electricity Rates (¢/kWh)

7.0 Risk Evaluation and Ranking

7.1 Prioritization and Ranking

Hydro's prioritization process includes two primary steps—an initial review of proposed programs and projects to critically evaluate scope and need, followed by a prioritization of programs and projects through Hydro's matrix model.[51] With the issuance of the Guidelines, the Board has provided guidance for evaluating risk and mitigation, as well as prioritization.[52] The matrix model scores programs and projects on the basis of reliability, safety, or environmental risk, based on a judgement of probability of a given risk materializing. Hydro's Capital Risk Assessment Matrix is provided in Appendix G.

Hydro assessed risks pre- and post-implementation of the capital investments proposed in the 2024 CBA, and has calculated the risk mitigation as the difference between pre- and post-implementation risk. For projects with undefined scope, such as in-service failure projects, Hydro assumes an average level of likelihood and impact based on the historical execution experience of these programs. Hydro has also calculated the risk mitigated per $1 million of expenditure for each program or project. Table 1 of Appendix G provides the prioritization of programs and projects proposed in the 2024 CBA by risk

[51] Hydro has retired its legacy prioritization matrix, and has adapted a corporate risk assessment matrix for use in evaluating capital projects which is aligned with the ISO 31000 Risk Management Standard, in accordance with the Guidelines.
[52] Hydro is unable to provide a prioritization of projects and programs by reliability improvement per dollar spent as the relationship between individual assets and system reliability is often not a direct relationship, and is also often complex.

mitigated per $1 Million. Hydro has also included a prioritization of programs and projects proposed on the basis of risk mitigated, provided in Table 2 of Appendix G.

8.0 Conclusion

Hydro is requesting approval for $96.6 million of capital investment in its 2024 CBA. Hydro recognizes other capital investment proposals before the Board and continues to take deliberate actions to reduce requested capital investment as compared to prior years.

Hydro's capital investment strategy aims largely to sustain current system-level reliability by undertaking renewal-driven capital investment. As a result, the largest portion of Hydro's capital spend proposed within this application is related to renewal of assets. When supported by least-cost and risk evaluation, Hydro's capital investment strategy proposes targeted, service-enhancement investments to address specific issues impacting system-level or localized reliability.

The proposals presented within this application align with Hydro's mandate to provide safe, reliable and least-cost service in an environmentally responsible manner and support Hydro's focus to maintain the level of reliability expected while ensuring prudent and reasonable expenditures. Hydro believes that all of the expenditures proposed in its 2024 CBA are prudent and necessary for the safe and reliable operation of the electrical system.

Appendix A

2024 Capital Budget by Asset Class, Investment Classification, Materiality, and Programs and Projects



Newfoundland and Labrador Hydro
2024 Capital Budget Application
2024 Capital Budget Overview By Major Asset Category
($000)

	2023 and Prior Years	2024	Future Years	Total
Generation	11,462.8	30,026.9	17,512.5	**59,002.2**
Transmission and Rural Operations	34,162.7	50,558.5	32,056.9	**116,778.1**
General Properties	2,575.6	14,997.8	6,088.8	**23,662.2**
Allowance for Unforeseen Items	-	1,000.0	-	**1,000.0**
Total Capital Budget	**48,201.1**	**96,583.2**	**55,658.2**	**200,442.5**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Summary by Minor Asset Category
($000)

	2023 and Prior Years	2024	Future Years	Total
Generation				
Gas Turbines	138.5	1,504.4	385.9	**2,028.8**
Hydraulic Plant	11,324.3	11,304.8	15,518.0	**38,147.1**
Thermal Plant	-	16,822.6	1,608.6	**18,431.2**
Tools and Equipment	-	395.1	-	**395.1**
Total Generation	**11,462.8**	**30,026.9**	**17,512.5**	**59,002.2**
General Properties				
Transportation	2,470.3	6,383.3	4,630.5	**13,484.1**
Administration	-	631.9	-	**631.9**
Information Systems	-	2,519.3	-	**2,519.3**
Telecontrol	105.3	5,463.3	1,458.3	**7,026.9**
Total General Properties	**2,575.6**	**14,997.8**	**6,088.8**	**23,662.2**
Transmission and Rural Operations				
Transmission	-	3,923.7	-	**3,923.7**
Distribution	73.4	12,434.8	3,804.0	**16,312.2**
Properties	565.1	4,269.2	889.9	**5,724.2**
Metering	4,881.2	1,767.9	449.7	**7,098.8**
Tools and Equipment	2,546.5	1,776.8	1,448.6	**5,771.9**
Terminal Stations	20,191.5	22,865.3	17,531.1	**60,587.9**
Generation	5,905.0	3,520.8	7,933.6	**17,359.4**
Total Transmission and Rural Operations	**34,162.7**	**50,558.5**	**32,056.9**	**116,778.1**
Allowance for Unforeseen Items				
Allowance for Unforeseen Items	-	1,000.0	-	**1,000.0**
Total Allowance for Unforeseen Items	**-**	**1,000.0**	**-**	**1,000.0**
Total Capital Budget	**48,201.1**	**96,583.2**	**55,658.2**	**200,442.5**

Newfoundland and Labrador Hydro
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Detailed Breakdown By Minor Asset Category
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	2023 and Prior Years	2024	Future Years	Total
Generation				
Gas Turbines				
Gas Turbine In-Service Failures (2024)	-	358.0	-	**358.0**
Replace Oil Mist Separator (2023-2024) - Happy Valley Gas Turbine	138.5	262.1	-	**400.6**
Construct Maintenance Platform (2024-2025) - Holyrood Gas Turbine	-	130.5	228.7	**359.2**
Inspect Fuel Tanks (2024) - Hardwoods Gas Turbines	-	692.9	-	**692.9**
Upgrade Instrumentation (2024-2025) - Hardwoods Gas Turbine	-	60.9	157.2	**218.1**
Total Gas Turbines	**138.5**	**1,504.4**	**385.9**	**2,028.8**
Hydraulic Plant				
Refurbish Ebbegunbaeg Control Structure	9,945.2	2,781.6	4,952.2	**17,679.0**
Replace Diesel Genset 1 (2023-2024) - Ebbegunbaeg	298.0	728.3	-	**1,026.3**
Water System Condition Assessment and Upgrades (2023) - Bay d'Espoir	161.0	504.9	-	**665.9**
Refurbish Superstructure (2023-2024) - Salmon River Spillway	328.3	2,500.0	-	**2,828.3**
Replace Powerhouse Station Service Panel (2023-2024) - Upper Salmon	591.8	976.7	-	**1,568.5**
Replace Annunciator - Phase 2 (2024-2025) - Bay d'Espoir	-	294.1	187.5	**481.6**
Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir	-	57.8	231.2	**289.0**
Penstock Level II Condition Assessment (2024) - Upper Salmon	-	382.8	-	**382.8**
Hydraulic In-Service Failures (2024)	-	1,500.0	-	**1,500.0**
Overhaul Hydraulic Units (2024)	-	323.8	-	**323.8**
Replace Annunciator Panels (2024-2025) - Cat Arm	-	160.2	191.2	**351.4**
Replace Powerhouse 1 Roof (2024-2025) - Bay d'Espoir	-	140.2	1,819.2	**1,959.4**
Flatten Downstream Slope (2024-2025) - Hinds Lake	-	276.1	2,953.4	**3,229.5**
Replace Timber Crib and Insulation (2024) - Burnt Dam Spillway	-	161.8	-	**161.8**
Refurbish Surge Tank 1 (2024-2025) - Bay d'Espoir	-	175.8	2,111.4	**2,287.2**
Install Anemometer (2024) - Cat Arm	-	68.6	-	**68.6**
Refurbish Intake 1 (2024-2025) - Bay d'Espoir	-	272.1	3,071.9	**3,344.0**
Total Hydraulic Plant	**11,324.3**	**11,304.8**	**15,518.0**	**38,147.1**
Thermal Plant				
Thermal In-Service Failures (2024)	-	3,508.7	-	**3,508.7**
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood	-	3,957.8	-	**3,957.8**
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood	-	5,181.4	-	**5,181.4**
Overhaul Pumps (2024) - Holyrood	-	661.0	-	**661.0**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood	-	156.2	1,039.4	**1,195.6**
Overhaul Marine Terminal Loading Arms (2024) - Holyrood	-	511.0	-	**511.0**
Refurbish Fuel Oil Storage Tank 4 (2024) - Holyrood	-	1,920.0	-	**1,920.0**
Upgrade UPS 1 & 2 (2024-2025) - Holyrood	-	263.0	107.6	**370.6**
Upgrade Unit 1 Control System (2024-2025) - Holyrood	-	468.3	184.3	**652.6**
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood	-	195.2	277.3	**472.5**
Total Thermal Plant	**-**	**16,822.6**	**1,608.6**	**18,431.2**
Tools and Equipment				
Purchase Tools and Equipment Less than $50,000 (2024) - Gas Turbine	-	18.6	-	**18.6**
Purchase Tools and Equipment Less than $50,000 (2024) - Hydraulic Plants	-	209.4	-	**209.4**
Purchase Tools and Equipment Less than $50,000 (2024) - Thermal Plants	-	167.1	-	**167.1**
Total Tools and Equipment	**-**	**395.1**	**-**	**395.1**
Total Generation	**11,462.8**	**30,026.9**	**17,512.5**	**59,002.2**
General Properties				
Transportation				
Replace Light- and Heavy-Duty Vehicles (2022-2024)	1,162.2	2,319.6	-	**3,481.8**
Replace Light- and Heavy-Duty Vehicles (2023-2025)	1,308.1	2,584.6	473.3	**4,366.0**
Replace Light- and Heavy-Duty Vehicles (2024-2026)	-	1,479.1	4,157.2	**5,636.3**
Total Transportation	**2,470.3**	**6,383.3**	**4,630.5**	**13,484.1**
Administration				
Purchase Office Equipment Less Than $50,000 (2024)	-	50.0	-	**50.0**
Remove Safety Hazards (2024)	-	198.3	-	**198.3**
General Property Rehabilitation (2024) - Hydro Place	-	234.0	-	**234.0**
Upgrade HVAC Supervisory Controllers (2024) - Hydro Place	-	149.6	-	**149.6**
Total Administration	**-**	**631.9**	**-**	**631.9**
Information Systems				
Upgrade Energy Management System (2024)	-	366.4	-	**366.4**
Perform Software Upgrades and Minor Enhancements (2024)	-	864.2	-	**864.2**
Purchase Personal Computers (2024)	-	555.9	-	**555.9**
Replace Peripheral Infrastructure (2024)	-	276.8	-	**276.8**
Upgrade Core OT Infrastructure (2024)	-	174.7	-	**174.7**
Update Cyber Security Infrastructure (2024)	-	281.3	-	**281.3**
Total Information Systems	**-**	**2,519.3**	**-**	**2,519.3**

Newfoundland and Labrador Hydro
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($000)

	2023 and Prior Years	2024	Future Years	Total
Telecontrol				
Replace Network Communications Equipment (2024)	-	180.7	-	**180.7**
Replace Power Line Carrier (2024-2025) - TL247	-	87.2	667.4	**754.6**
Replace Power Line Carrier (2023–2024) - TL223 and TL224	105.3	852.4	-	**957.7**
Purchase Tools and Equipment Less than $50,000 (2024) - Telecontrol	-	45.6	-	**45.6**
Replace 48 V Battery Banks and Chargers (2024)	-	422.2	-	**422.2**
Replace SONET Multiplexors (2024)	-	430.4	-	**430.4**
Replace MDR8000 Microwave Radios (2024-2025)	-	953.5	500.3	**1,453.8**
Purchase Mobile Devices (2024)	-	155.6	-	**155.6**
Upgrade Remote Terminal Units (2024)	-	165.9	-	**165.9**
Telecommunications In-Service Failure (2024)	-	91.4	-	**91.4**
Minor Telecommunications Enhancements (2024)	-	96.9	-	**96.9**
Replace CCTV Cameras (2024)	-	317.6	-	**317.6**
Upgrade SCADA Network (2024)	-	402.3	-	**402.3**
Replace VHF Radio System (2024-2025)	-	1,261.6	290.6	**1,552.2**
Total Telecontrol	**105.3**	**5,463.3**	**1,458.3**	**7,026.9**
Total General Properties	**2,575.6**	**14,997.8**	**6,088.8**	**23,662.2**
Transmission and Rural Operations				
Transmission				
Transmission In-Service Failures (2024)	-	158.5	-	**158.5**
Wood Pole Line Management (2024)	-	3,765.2	-	**3,765.2**
Total Transmission	**-**	**3,923.7**	**-**	**3,923.7**
Distribution				
Upgrade of Worst-Performing Distribution Feeders (2023-2024)	73.4	1,372.6	-	**1,446.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)	-	4,345.4	-	**4,345.4**
Provide Service Extensions (2024)	-	4,272.0	-	**4,272.0**
Upgrade Worst-Performing Distribution Feeders (2024-2025)	-	1,064.3	2,227.4	**3,291.7**
Renew Distribution Feeders (2024-2025)	-	1,287.3	1,245.1	**2,532.4**
Upgrade Distribution (2024-2025) - Bay d'Espoir Terminal Station 2	-	93.2	331.5	**424.7**
Total Distribution	**73.4**	**12,434.8**	**3,804.0**	**16,312.2**
Properties				
Replace HVAC System (2023-2024) - Bishop's Falls	43.4	128.8	-	**172.2**
Upgrade Water and Fire Suppression Systems (2023-2024) - Bishop's Falls	353.7	2,886.3	-	**3,240.0**
Replace Diesel Shop Building (2023-2025) - Bishop's Falls	168.0	1,254.1	889.9	**2,312.0**
Total Properties	**565.1**	**4,269.2**	**889.9**	**5,724.2**
Metering				
Purchase Meters and Metering Equipment (2024)	-	470.7	-	**470.7**
Replace Metering System	4,881.2	994.6	-	**5,875.8**
Automate Bulk Metering (2024-2026)	-	302.6	449.7	**752.3**
Total Metering	**4,881.2**	**1,767.9**	**449.7**	**7,098.8**
Tools and Equipment				
Purchase 85' Material Handler Aerial Device on Track Unit	1,286.1	67.8	-	**1,353.9**
Purchase 46' Material Handler Aerial Device on Track Unit	719.2	38.8	-	**758.0**
Purchase Tools and Equipment Less than $50,000 (2024) - Central Region	-	188.2	-	**188.2**
Purchase Tools and Equipment Less than $50,000 (2024) - Northern Region	-	97.0	-	**97.0**
Purchase Tools and Equipment Less than $50,000 (2024) - Labrador Region	-	120.1	-	**120.1**
Replace Grader Unit V9829 (2024) - Bay d'Espoir	-	836.7	-	**836.7**
Replace Mobile Equipment (2023-2024)	541.2	187.3	-	**728.5**
Replace Mobile Equipment (2024-2025)	-	216.9	599.7	**816.6**
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024-2026) - Happy Valley Goose Bay	-	24.0	848.9	**872.9**
Total Tools and Equipment	**2,546.5**	**1,776.8**	**1,448.6**	**5,771.9**
Terminal Stations				
Wabush Terminal Station Upgrades	8,870.1	3,808.0	-	**12,678.1**
Additions for Load - Wabush Substation Upgrades	7,439.7	2,739.9	514.5	**10,694.1**
Terminal Station In-Service Failures (2024)	-	1,300.0	-	**1,300.0**
Terminal Station Renewal Program (2023-2024)	1,733.7	5,584.5	-	**7,318.2**
Circuit Breakers Renewal Program (2023-2024)	216.9	3,595.1	-	**3,812.0**
Install Breaker Failure Protection (2023-2024) - Sunnyside	73.5	216.2	-	**289.7**
Install Fire Protection in 230 kV Stations (2023-2024) - Deer Lake	79.2	535.3	-	**614.5**
Replace Terminal Station Lighting (2023-2024)	323.3	594.1	-	**917.4**
Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) - Wabush Terminal Station	577.2	516.1	-	**1,093.3**
Replace Data Alarm System Annunciators (2023) - Buchans	61.2	104.8	-	**166.0**
Replace Circuit Breaker Reclosing Controllers (2023-2024) - Hardwoods	81.6	149.6	-	**231.2**
Additions for Load Growth - Upgrade Transformer Capacity (2023-2024) - Jean Lake Terminal Station	580.0	-	5,436.1	**6,016.1**
Install Oil Spill Containment Transformer T1S (2023-2024) - Cat Arm	155.1	426.5	-	**581.6**
Refurbish Control Building (2024-2025) - Grandy Brook and Doyles	-	109.4	444.7	**554.1**
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	-	53.8	599.0	**652.8**
Replace Instrument Transformers (2024–2025)	-	154.9	714.8	**869.7**
Replace Protective Relays (2024–2025)	-	1,388.4	2,050.7	**3,439.1**
Replace Disconnects (2024–2025)	-	127.4	1,358.1	**1,485.5**
Upgrade Power Transformers (2024-2025)	-	864.6	2,711.3	**3,575.9**
Replace Terminal Station Battery Banks and Chargers (2024–2025)	-	71.8	120.9	**192.7**
Renew Circuit Breakers (2024–2025)	-	183.9	2,779.3	**2,963.2**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station	-	137.0	156.9	**293.9**
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247	-	112.4	215.8	**328.2**
Upgrade Station Lighting (2024-2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon Terminal Stations	-	91.6	429.0	**520.6**
[]	-	-	-	**-**
Total Terminal Stations	**20,191.5**	**22,865.3**	**17,531.1**	**60,587.9**

Newfoundland and Labrador Hydro
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Detailed Breakdown By Minor Asset Category
($000)

	2023 and Prior Years	2024	Future Years	Total
Generation				
Diesel Genset Replacement Unit 2012 - L'Anse-Au-Loup	2,853.1	210.2	-	**3,063.3**
Diesel Genset Replacement Program (2023-2025)	819.1	174.0	2,133.1	**3,126.2**
Replace Building Exterior (2023-2024) - Postville	124.6	558.7	-	**683.3**
Replace Intermediate Fuel Storage Tanks (2023-2024) - Nain	127.4	593.7	-	**721.1**
Overhaul Diesel Units (2024)	-	829.2	-	**829.2**
Diesel In-Service Failures (2024)	-	488.3	-	**488.3**
Diesel Genset Replacement Unit 2039 - St. Lewis	1,980.8	-	-	**1,980.8**
Purchase Accommodations Trailer (2024-2025) - Makkovik and Cartwright	-	130.9	1,420.2	**1,551.1**
Replace Diesel Gensets (2024-2026)	-	535.8	4,380.3	**4,916.1**
Total Generation	**5,905.0**	**3,520.8**	**7,933.6**	**17,359.4**
Total Transmission and Rural Operations	**34,162.7**	**50,558.5**	**32,056.9**	**116,778.1**
Allowance for Unforeseen Items				
Allowance for Unforeseen Items (2024)	-	1,000.0	-	**1,000.0**
Total Allowance for Unforeseen Items	**-**	**1,000.0**	**-**	**1,000.0**
Total Capital Budget	**48,201.1**	**96,583.2**	**55,658.2**	**200,442.5**

Newfoundland and Labrador Hydro
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2024 Capital Budget Overview - By Investment Classification
($000)

	2023 and Prior Years	2024	Future Years	Total
Renewal	19,931.6	55,354.9	32,902.0	**108,188.5**
Service Enhancement	5,109.7	4,618.9	3,063.0	**12,791.6**
General Plant	5,946.7	21,713.1	13,313.6	**40,973.4**
System Growth	16,889.8	6,547.9	5,950.6	**29,388.3**
Access	-	4,742.7	-	**4,742.7**
Mandatory	323.3	2,605.7	429.0	**3,358.0**
Allowance for Unforeseen	-	1,000.0	-	**1,000.0**
Total Capital Budget	**48,201.1**	**96,583.2**	**55,658.2**	**200,442.5**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
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($000)

	2023 and Prior Years	2024	Future Years	Total
Access				
Purchase Meters and Metering Equipment (2024)	-	470.7	-	**470.7**
Provide Service Extensions (2024)	-	4,272.0	-	**4,272.0**
Access Total	-	**4,742.7**	-	**4,742.7**
Allowance for Unforeseen				
Allowance for Unforeseen Items (2024)	-	1,000.0	-	**1,000.0**
Allowance for Unforeseen Total	-	**1,000.0**	-	**1,000.0**
General Plant				
Purchase 85' Material Handler Aerial Device on Track Unit	1,286.1	67.8	-	**1,353.9**
Purchase Office Equipment Less Than $50,000 (2024)	-	50.0	-	**50.0**
Purchase Tools and Equipment Less than $50,000 (2024) - Gas Turbine	-	18.6	-	**18.6**
Purchase Tools and Equipment Less than $50,000 (2024) - Hydraulic Plants	-	209.4	-	**209.4**
Purchase Tools and Equipment Less than $50,000 (2024) - Thermal Plants	-	167.1	-	**167.1**
Replace Network Communications Equipment (2024)	-	180.7	-	**180.7**
Purchase 46' Material Handler Aerial Device on Track Unit	719.2	38.8	-	**758.0**
Replace Light- and Heavy-Duty Vehicles (2022-2024)	1,162.2	2,319.6	-	**3,481.8**
Purchase Tools and Equipment Less than $50,000 (2024) - Central Region	-	188.2	-	**188.2**
Purchase Tools and Equipment Less than $50,000 (2024) - Northern Region	-	97.0	-	**97.0**
Purchase Tools and Equipment Less than $50,000 (2024) - Labrador Region	-	120.1	-	**120.1**
Install Fire Protection in 230 kV Stations (2023-2024) - Deer Lake	79.2	535.3	-	**614.5**
Replace Light- and Heavy-Duty Vehicles (2023-2025)	1,308.1	2,584.6	473.3	**4,366.0**
Water System Condition Assessment and Upgrades (2023) - Bay d'Espoir	161.0	504.9	-	**665.9**
Replace Building Exterior (2023-2024) - Postville	124.6	558.7	-	**683.3**
Replace HVAC System (2023-2024) - Bishop's Falls	43.4	128.8	-	**172.2**
Upgrade Water and Fire Suppression Systems (2023-2024) - Bishop's Falls	353.7	2,886.3	-	**3,240.0**
Replace Diesel Shop Building (2023-2025) - Bishop's Falls	168.0	1,254.1	889.9	**2,312.0**
Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir	-	57.8	231.2	**289.0**
Refurbish Control Building (2024-2025) - Grandy Brook and Doyles	-	109.4	444.7	**554.1**
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	-	53.8	599.0	**652.8**
Replace Grader Unit V9829 (2024) - Bay d'Espoir	-	836.7	-	**836.7**
Upgrade Energy Management System (2024)	-	366.4	-	**366.4**
Perform Software Upgrades and Minor Enhancements (2024)	-	864.2	-	**864.2**
Purchase Personal Computers (2024)	-	555.9	-	**555.9**
Replace Peripheral Infrastructure (2024)	-	276.8	-	**276.8**
Upgrade Core OT Infrastructure (2024)	-	174.7	-	**174.7**
Purchase Tools and Equipment Less than $50,000 (2024) - Telecontrol	-	45.6	-	**45.6**
Replace SONET Multiplexors (2024)	-	430.4	-	**430.4**
Replace MDR8000 Microwave Radios (2024-2025)	-	953.5	500.3	**1,453.8**
Replace Mobile Equipment (2023-2024)	541.2	187.3	-	**728.5**
Replace Powerhouse 1 Roof (2024-2025) - Bay d'Espoir	-	140.2	1,819.2	**1,959.4**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood	-	156.2	1,039.4	**1,195.6**
Purchase Accommodations Trailer (2024-2025) - Makkovik and Cartwright	-	130.9	1,420.2	**1,551.1**
Update Cyber Security Infrastructure (2024)	-	281.3	-	**281.3**
Minor Telecommunications Enhancements (2024)	-	96.9	-	**96.9**
Replace CCTV Cameras (2024)	-	317.6	-	**317.6**
Replace Light- and Heavy-Duty Vehicles (2024-2026)	-	1,479.1	4,157.2	**5,636.3**
General Property Rehabilitation (2024) - Hydro Place	-	234.0	-	**234.0**
Upgrade HVAC Supervisory Controllers (2024) - Hydro Place	-	149.6	-	**149.6**
Replace Mobile Equipment (2024-2025)	-	216.9	599.7	**816.6**
Upgrade SCADA Network (2024)	-	402.3	-	**402.3**
Replace VHF Radio System (2024-2025)	-	1,261.6	290.6	**1,552.2**
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024-2026) - Happy Valley Goose Bay	-	24.0	848.9	**872.9**
General Plant Total	**5,946.7**	**21,713.1**	**13,313.6**	**40,973.4**
Mandatory				
Replace Terminal Station Lighting (2023-2024)	323.3	594.1	-	**917.4**
Refurbish Fuel Oil Storage Tank 4 (2024) - Holyrood	-	1,920.0	-	**1,920.0**
Upgrade Station Lighting (2024-2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon Terminal Stations	-	91.6	429.0	**520.6**
Mandatory Total	**323.3**	**2,605.7**	**429.0**	**3,358.0**

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	2023 and Prior Years	2024	Future Years	Total
Renewal				
Thermal In-Service Failures (2024)	-	3,508.7	-	**3,508.7**
Refurbish Ebbegunbaeg Control Structure	9,945.2	2,781.6	4,952.2	**17,679.0**
Terminal Station In-Service Failures (2024)	-	1,300.0	-	**1,300.0**
Gas Turbine In-Service Failures (2024)	-	358.0	-	**358.0**
Diesel Genset Replacement Unit 2012 - L'Anse-Au-Loup	2,853.1	210.2	-	**3,063.3**
Transmission In-Service Failures (2024)	-	158.5	-	**158.5**
Terminal Station Renewal Program (2023-2024)	1,733.7	5,584.5	-	**7,318.2**
Circuit Breakers Renewal Program (2023-2024)	216.9	3,595.1	-	**3,812.0**
Install Breaker Failure Protection (2023-2024) - Sunnyside	73.5	216.2	-	**289.7**
Diesel Genset Replacement Program (2023-2025)	819.1	174.0	2,133.1	**3,126.2**
Replace Power Line Carrier (2024-2025) - TL247	-	87.2	667.4	**754.6**
Replace Diesel Genset 1 (2023-2024) - Ebbegunbaeg	298.0	728.3	-	**1,026.3**
Refurbish Superstructure (2023-2024) - Salmon River Spillway	328.3	2,500.0	-	**2,828.3**
Replace Powerhouse Station Service Panel (2023-2024) - Upper Salmon	591.8	976.7	-	**1,568.5**
Replace Oil Mist Separator (2023-2024) - Happy Valley Gas Turbine	138.5	262.1	-	**400.6**
Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) - Wabush Terminal Station	577.2	516.1	-	**1,093.3**
Replace Data Alarm System Annunciators (2023) - Buchans	61.2	104.8	-	**166.0**
Replace Circuit Breaker Reclosing Controllers (2023-2024) - Hardwoods	81.6	149.6	-	**231.2**
Replace Intermediate Fuel Storage Tanks (2023-2024) - Nain	127.4	593.7	-	**721.1**
Replace Power Line Carrier (2023–2024) - TL223 and TL224	105.3	852.4	-	**957.7**
Replace Annunciator - Phase 2 (2024-2025) - Bay d'Espoir	-	294.1	187.5	**481.6**
Penstock Level II Condition Assessment (2024) - Upper Salmon	-	382.8	-	**382.8**
Hydraulic In-Service Failures (2024)	-	1,500.0	-	**1,500.0**
Replace Instrument Transformers (2024–2025)	-	154.9	714.8	**869.7**
Replace Protective Relays (2024–2025)	-	1,388.4	2,050.7	**3,439.1**
Replace Disconnects (2024–2025)	-	127.4	1,358.1	**1,485.5**
Upgrade Power Transformers (2024-2025)	-	864.6	2,711.3	**3,575.9**
Replace Terminal Station Battery Banks and Chargers (2024–2025)	-	71.8	120.9	**192.7**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)	-	4,345.4	-	**4,345.4**
Overhaul Diesel Units (2024)	-	829.2	-	**829.2**
Diesel In-Service Failures (2024)	-	488.3	-	**488.3**
Replace 48 V Battery Banks and Chargers (2024)	-	422.2	-	**422.2**
Purchase Mobile Devices (2024)	-	155.6	-	**155.6**
Upgrade Remote Terminal Units (2024)	-	165.9	-	**165.9**
Diesel Genset Replacement Unit 2039 - St. Lewis	1,980.8	-	-	**1,980.8**
Overhaul Hydraulic Units (2024)	-	323.8	-	**323.8**
Replace Annunciator Panels (2024-2025) - Cat Arm	-	160.2	191.2	**351.4**
Flatten Downstream Slope (2024-2025) - Hinds Lake	-	276.1	2,953.4	**3,229.5**
Replace Timber Crib and Insulation (2024) - Burnt Dam Spillway	-	161.8	-	**161.8**
Refurbish Surge Tank 1 (2024-2025) - Bay d'Espoir	-	175.8	2,111.4	**2,287.2**
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood	-	3,957.8	-	**3,957.8**
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood	-	5,181.4	-	**5,181.4**
Overhaul Pumps (2024) - Holyrood	-	661.0	-	**661.0**
Overhaul Marine Terminal Loading Arms (2024) - Holyrood	-	511.0	-	**511.0**
Upgrade UPS 1 & 2 (2024-2025) - Holyrood	-	263.0	107.6	**370.6**
Upgrade Unit 1 Control System (2024-2025) - Holyrood	-	468.3	184.3	**652.6**
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood	-	195.2	277.3	**472.5**
Inspect Fuel Tanks (2024) - Hardwoods Gas Turbines	-	692.9	-	**692.9**
Renew Circuit Breakers (2024–2025)	-	183.9	2,779.3	**2,963.2**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station	-	137.0	156.9	**293.9**
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247	-	112.4	215.8	**328.2**
Wood Pole Line Management (2024)	-	3,765.2	-	**3,765.2**
Renew Distribution Feeders (2024-2025)	-	1,287.3	1,245.1	**2,532.4**
Upgrade Distribution (2024-2025) - Bay d'Espoir Terminal Station 2	-	93.2	331.5	**424.7**
Telecommunications In-Service Failure (2024)	-	91.4	-	**91.4**
Refurbish Intake 1 (2024-2025) - Bay d'Espoir	-	272.1	3,071.9	**3,344.0**
Replace Diesel Gensets (2024-2026)	-	535.8	4,380.3	**4,916.1**
Renewal Total	**19,931.6**	**55,354.9**	**32,902.0**	**108,188.5**
Service Enhancement				
Replace Metering System	4,881.2	994.6	-	**5,875.8**
Upgrade of Worst-Performing Distribution Feeders (2023-2024)	73.4	1,372.6	-	**1,446.0**
Upgrade Instrumentation (2024-2025) - Hardwoods Gas Turbine	-	60.9	157.2	**218.1**
Upgrade Worst-Performing Distribution Feeders (2024-2025)	-	1,064.3	2,227.4	**3,291.7**
[]	-	-	-	**-**
Service Enhancement Total	**5,109.7**	**4,618.9**	**3,063.0**	**12,791.6**
System Growth				
Wabush Terminal Station Upgrades	8,870.1	3,808.0	-	**12,678.1**
Additions for Load - Wabush Substation Upgrades	7,439.7	2,739.9	514.5	**10,694.1**
Additions for Load Growth - Upgrade Transformer Capacity (2023-2024) - Jean Lake Terminal Station	580.0	-	5,436.1	**6,016.1**
System Growth Total	**16,889.8**	**6,547.9**	**5,950.6**	**29,388.3**
Total Capital Budget	**48,201.1**	**96,583.2**	**55,658.2**	**200,442.5**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Summary by Materiality
($000)

	2023 and Prior Years	2024	Future Years	Total
$1 Million to $5 Million				
Access	-	4,272.0	-	**4,272.0**
Allowance for Unforeseen	-	1,000.0	-	**1,000.0**
General Plant	4,278.1	11,754.8	6,432.9	**22,465.8**
Mandatory	-	1,920.0	-	**1,920.0**
Renewal	7,665.2	32,188.9	24,794.6	**64,648.7**
Service Enhancement	73.4	2,436.9	2,227.4	**4,737.7**
$1 Million to $5 Million Total	**12,016.7**	**53,572.6**	**33,454.9**	**99,044.2**
Over $5 Million				
General Plant	-	1,479.1	4,157.2	**5,636.3**
Renewal	11,678.9	13,547.5	4,952.2	**30,178.6**
Service Enhancement	4,881.2	994.6	-	**5,875.8**
System Growth	16,889.8	6,547.9	5,950.6	**29,388.3**
Over $5 Million Total	**33,449.9**	**22,569.1**	**15,060.0**	**71,079.0**
$750,000 to $1 Million				
General Plant	719.2	1,980.6	1,448.6	**4,148.4**
Mandatory	323.3	594.1	-	**917.4**
Renewal	105.3	1,923.7	1,382.2	**3,411.2**
Service Enhancement	-	302.6	449.7	**752.3**
$750,000 to $1 Million Total	1,147.8	4,801.0	3,280.5	**9,229.3**
Under $750,000				
Access	-	470.7	-	**470.7**
General Plant	949.4	6,498.6	1,274.9	**8,722.9**
Mandatory	-	91.6	429.0	**520.6**
Renewal	482.2	7,694.8	1,773.0	**9,950.0**
Service Enhancement	155.1	884.8	385.9	**1,425.8**
Under $750,000 Total	1,586.7	15,640.5	3,862.8	**21,090.0**
Total Capital Budget	**48,201.1**	**96,583.2**	**55,658.2**	**200,442.5**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Summary by Program or Project
($000)

	2023 and Prior Years	2024	Future Years	Total
Program				
Access	-	4,742.7	-	**4,742.7**
Allowance for Unforeseen	-	1,000.0	-	**1,000.0**
General Plant	1,849.3	8,160.8	5,230.2	**15,240.3**
Renewal	3,346.9	42,079.0	17,493.6	**62,919.5**
Service Enhancement	73.4	2,635.2	2,227.4	**4,936.0**
Total	**5,269.6**	**58,617.7**	**24,951.2**	**88,838.5**
Project				
General Plant	929.9	11,126.1	8,083.4	**20,139.4**
Mandatory	323.3	2,605.7	429.0	**3,358.0**
Renewal	1,805.6	10,284.1	10,456.2	**22,545.9**
Service Enhancement	155.1	989.1	835.6	**1,979.8**
System Growth	580.0	-	5,436.1	**6,016.1**
Total	**3,793.9**	**25,005.0**	**25,240.3**	**54,039.2**
General Plant	3,167.5	2,426.2	-	**5,593.7**
Renewal	14,779.1	2,991.8	4,952.2	**22,723.1**
Service Enhancement	4,881.2	994.6	-	**5,875.8**
System Growth	16,309.8	6,547.9	514.5	**23,372.2**
Total	**39,137.6**	**12,960.5**	**5,466.7**	**57,564.8**
Total Capital Budget	**48,201.1**	**96,583.2**	**55,658.2**	**200,442.5**

Appendix B

2024 Capital Budget by Single- and Multi-Year Programs and Projects



Newfoundland and Labrador Hydro
2024 Capital Budget Application
Multi-Year Projects Separated
($000)

	2024
SINGLE-YEAR	**43,194.9**
Renewal	28,960.9
Service Enhancement	266.9
General Plant	6,304.4
Access	4,742.7
System Growth	-
Mandatory	1,920.0
Allowance for Unforeseen	1,000.0
	43,194.9
MULTI-YEAR (2024 Expenditures)	
Multi-Year Projects Commencing in 2021	9,329.5
Multi-Year Projects Commencing in 2022	3,631.0
Multi-Year Projects Commencing in 2023	27,286.7
Multi-Year Projects Commencing in 2024	13,141.1
	53,388.3
Total Capital Budget	**96,583.2**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Single-Year Projects
($000)

Access	
Purchase Meters and Metering Equipment (2024)	470.7
Provide Service Extensions (2024)	4,272.0
Access Total	**4,742.7**
Allowance for Unforeseen	
Allowance for Unforeseen Items (2024)	1,000.0
Allowance for Unforeseen Total	**1,000.0**
General Plant	
Purchase Office Equipment Less Than $50,000 (2024)	50.0
Purchase Tools and Equipment Less than $50,000 (2024) - Gas Turbine	18.6
Purchase Tools and Equipment Less than $50,000 (2024) - Hydraulic Plants	209.4
Purchase Tools and Equipment Less than $50,000 (2024) - Thermal Plants	167.1
Replace Network Communications Equipment (2024)	180.7
Purchase Tools and Equipment Less than $50,000 (2024) - Central Region	188.2
Purchase Tools and Equipment Less than $50,000 (2024) - Northern Region	97.0
Purchase Tools and Equipment Less than $50,000 (2024) - Labrador Region	120.1
Replace Grader Unit V9829 (2024) - Bay d'Espoir	836.7
Upgrade Energy Management System (2024)	366.4
Perform Software Upgrades and Minor Enhancements (2024)	864.2
Purchase Personal Computers (2024)	555.9
Replace Peripheral Infrastructure (2024)	276.8
Upgrade Core OT Infrastructure (2024)	174.7
Purchase Tools and Equipment Less than $50,000 (2024) - Telecontrol	45.6
Replace SONET Multiplexors (2024)	430.4
Update Cyber Security Infrastructure (2024)	281.3
Minor Telecommunications Enhancements (2024)	96.9
Replace CCTV Cameras (2024)	317.6
General Property Rehabilitation (2024) - Hydro Place	234.0
Upgrade HVAC Supervisory Controllers (2024) - Hydro Place	149.6
Replace Mobile Equipment (2024-2025)	816.6
Upgrade SCADA Network (2024)	402.3
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024-2026) - Happy Valley Goose Bay	872.9
General Plant Total	**7,753.0**
Mandatory	
Refurbish Fuel Oil Storage Tank 4 (2024) - Holyrood	1,920.0
Mandatory Total	**1,920.0**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Single-Year Projects
($000)

Renewal	
Thermal In-Service Failures (2024)	3,508.7
Terminal Station In-Service Failures (2024)	1,300.0
Gas Turbine In-Service Failures (2024)	358.0
Transmission In-Service Failures (2024)	158.5
Penstock Level II Condition Assessment (2024) - Upper Salmon	382.8
Hydraulic In-Service Failures (2024)	1,500.0
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)	4,345.4
Overhaul Diesel Units (2024)	829.2
Diesel In-Service Failures (2024)	488.3
Replace 48 V Battery Banks and Chargers (2024)	422.2
Purchase Mobile Devices (2024)	155.6
Upgrade Remote Terminal Units (2024)	165.9
Overhaul Hydraulic Units (2024)	323.8
Replace Timber Crib and Insulation (2024) - Burnt Dam Spillway	161.8
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood	3,957.8
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood	5,181.4
Overhaul Pumps (2024) - Holyrood	661.0
Overhaul Marine Terminal Loading Arms (2024) - Holyrood	511.0
Inspect Fuel Tanks (2024) - Hardwoods Gas Turbines	692.9
Wood Pole Line Management (2024)	3,765.2
Telecommunications In-Service Failure (2024)	91.4
Renewal Total	**28,960.9**
Service Enhancement	
Remove Safety Hazards (2024)	198.3
Install Anemometer (2024) - Cat Arm	68.6
Service Enhancement Total	**266.9**
Total Capital Budget	**44,643.5**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Multi-Year Projects
($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Sum of Total With Prior Year
Multi-Year Projects Commencing in 2021							
Renewal							
Refurbish Ebbegunbaeg Control Structure	9,945.2	2,781.6	4,952.2				**17,679.0**
Renewal Total	**9,945.2**	**2,781.6**	**4,952.2**				**17,679.0**
System Growth							
Wabush Terminal Station Upgrades	8,870.1	3,808.0					**12,678.1**
Additions for Load - Wabush Substation Upgrades	7,439.7	2,739.9	514.5				**10,694.1**
System Growth Total	**16,309.8**	**6,547.9**	**514.5**				**23,372.2**
Total Multi-Year Projects Commencing in 2021	**26,255.0**	**9,329.5**	**5,466.7**				**41,051.2**
Multi-Year Projects Commencing in 2022							
General Plant							
Purchase 85' Material Handler Aerial Device on Track Unit	1,286.1	67.8					**1,353.9**
Purchase 46' Material Handler Aerial Device on Track Unit	719.2	38.8					**758.0**
Replace Light- and Heavy-Duty Vehicles (2022-2024)	1,162.2	2,319.6					**3,481.8**
General Plant Total	**3,167.5**	**2,426.2**					**5,593.7**
Renewal							
Diesel Genset Replacement Unit 2012 - L'Anse-Au-Loup	2,853.1	210.2					**3,063.3**
Diesel Genset Replacement Unit 2039 - St. Lewis	1,980.8						**1,980.8**
Renewal Total	**4,833.9**	**210.2**					**5,044.1**
Service Enhancement							
Replace Metering System	4,881.2	994.6					**5,875.8**
Service Enhancement Total	**4,881.2**	**994.6**					**5,875.8**
Total Multi-Year Projects Commencing in 2022	**12,882.6**	**3,631.0**					**16,513.6**
Multi-Year Projects Commencing in 2023							
General Plant							
Install Fire Protection in 230 kV Stations (2023-2024) - Deer Lake	79.2	535.3					**614.5**
Replace Light- and Heavy-Duty Vehicles (2023-2025)	1,308.1	2,584.6	473.3				**4,366.0**
Water System Condition Assessment and Upgrades (2023) - Bay d'Espoir	161.0	504.9					**665.9**
Replace Building Exterior (2023-2024) - Postville	124.6	558.7					**683.3**
Replace HVAC System (2023-2024) - Bishop's Falls	43.4	128.8					**172.2**
Upgrade Water and Fire Suppression Systems (2023-2024) - Bishop's Falls	353.7	2,886.3					**3,240.0**
Replace Diesel Shop Building (2023-2025) - Bishop's Falls	168.0	1,254.1	889.9				**2,312.0**
Replace Mobile Equipment (2023-2024)	541.2	187.3					**728.5**
General Plant Total	**2,779.2**	**8,640.0**	**1,363.2**				**12,782.4**
Mandatory							
Replace Terminal Station Lighting (2023-2024)	323.3	594.1					**917.4**
Mandatory Total	**323.3**	**594.1**					**917.4**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Multi-Year Projects
($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Sum of Total With Prior Year
Renewal							
Terminal Station Renewal Program (2023-2024)	1,733.7	5,584.5					**7,318.2**
Circuit Breakers Renewal Program (2023-2024)	216.9	3,595.1					**3,812.0**
Install Breaker Failure Protection (2023-2024) - Sunnyside	73.5	216.2					**289.7**
Diesel Genset Replacement Program (2023-2025)	819.1	174.0	1,883.1	250.0			**3,126.2**
Replace Diesel Genset 1 (2023-2024) - Ebbegunbaeg	298.0	728.3					**1,026.3**
Refurbish Superstructure (2023-2024) - Salmon River Spillway	328.3	2,500.0					**2,828.3**
Replace Powerhouse Station Service Panel (2023-2024) - Upper Salmon	591.8	976.7					**1,568.5**
Replace Oil Mist Separator (2023-2024) - Happy Valley Gas Turbine	138.5	262.1					**400.6**
Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) - Wabush Terminal Station	577.2	516.1					**1,093.3**
Replace Data Alarm System Annunciators (2023) - Buchans	61.2	104.8					**166.0**
Replace Circuit Breaker Reclosing Controllers (2023-2024) - Hardwoods	81.6	149.6					**231.2**
Replace Intermediate Fuel Storage Tanks (2023-2024) - Nain	127.4	593.7					**721.1**
Replace Power Line Carrier (2023–2024) - TL223 and TL224	105.3	852.4					**957.7**
Renewal Total	**5,152.5**	**16,253.5**	**1,883.1**	**250.0**			**23,539.1**
Service Enhancement							
Upgrade of Worst-Performing Distribution Feeders (2023-2024)	73.4	1,372.6					**1,446.0**
Install Oil Spill Containment Transformer T1S (2023-2024) - Cat Arm	155.1	426.5					**581.6**
Service Enhancement Total	**228.5**	**1,799.1**					**2,027.6**
System Growth							
Additions for Load Growth - Upgrade Transformer Capacity (2023-2024) - Jean Lake Terminal Station	580.0	-	5,436.1				**6,016.1**
System Growth Total	580.0	-	5,436.1				**6,016.1**
Total Multi-Year Projects Commencing in 2023	**9,063.5**	**27,286.7**	**8,682.4**	**250.0**			**45,282.6**
Multi-Year Projects Commencing in 2024							
General Plant							
Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir		57.8	231.2				**289.0**
Refurbish Control Building (2024-2025) - Grandy Brook and Doyles		109.4	444.7				**554.1**
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay		53.8	599.0				**652.8**
Replace MDR8000 Microwave Radios (2024-2025)		953.5	500.3				**1,453.8**
Replace Powerhouse 1 Roof (2024-2025) - Bay d'Espoir		140.2	1,819.2				**1,959.4**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood		156.2	1,039.4				**1,195.6**
Purchase Accommodations Trailer (2024-2025) - Makkovik and Cartwright		130.9	1,420.2				**1,551.1**
Replace Light- and Heavy-Duty Vehicles (2024-2026)		1,479.1	4,148.8	8.4			**5,636.3**
Replace VHF Radio System (2024-2025)		1,261.6	290.6				**1,552.2**
General Plant Total		**4,342.5**	**10,493.4**	**8.4**			**14,844.3**
Mandatory							
Upgrade Station Lighting (2024-2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon Terminal Stations		91.6	429.0				**520.6**
Mandatory Total		**91.6**	**429.0**				**520.6**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Multi-Year Projects
($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Sum of Total With Prior Year
Renewal							
Replace Power Line Carrier (2024-2025) - TL247		87.2	667.4				**754.6**
Replace Annunciator - Phase 2 (2024-2025) - Bay d'Espoir		294.1	187.5				**481.6**
Replace Instrument Transformers (2024–2025)		154.9	714.8				**869.7**
Replace Protective Relays (2024–2025)		1,388.4	2,050.7				**3,439.1**
Replace Disconnects (2024–2025)		127.4	1,358.1				**1,485.5**
Upgrade Power Transformers (2024-2025)		864.6	2,711.3				**3,575.9**
Replace Terminal Station Battery Banks and Chargers (2024–2025)		71.8	120.9				**192.7**
Replace Annunciator Panels (2024-2025) - Cat Arm		160.2	191.2				**351.4**
Flatten Downstream Slope (2024-2025) - Hinds Lake		276.1	2,953.4				**3,229.5**
Refurbish Surge Tank 1 (2024-2025) - Bay d'Espoir		175.8	2,111.4				**2,287.2**
Upgrade UPS 1 & 2 (2024-2025) - Holyrood		263.0	107.6				**370.6**
Upgrade Unit 1 Control System (2024-2025) - Holyrood		468.3	184.3				**652.6**
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood		195.2	277.3				**472.5**
Renew Circuit Breakers (2024–2025)		183.9	2,779.3				**2,963.2**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station		137.0	156.9				**293.9**
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247		112.4	215.8				**328.2**
Renew Distribution Feeders (2024-2025)		1,287.3	1,245.1				**2,532.4**
Upgrade Distribution (2024-2025) - Bay d'Espoir Terminal Station 2		93.2	331.5				**424.7**
Refurbish Intake 1 (2024-2025) - Bay d'Espoir		272.1	3,071.9				**3,344.0**
Replace Diesel Gensets (2024-2026)		535.8	478.0	3,902.3			**4,916.1**
Renewal Total		**7,148.7**	**21,914.4**	**3,902.3**			**32,965.4**
Service Enhancement							
Construct Maintenance Platform (2024-2025) - Holyrood Gas Turbine		130.5	228.7				**359.2**
Automate Bulk Metering (2024-2026)		302.6	214.4	235.3			**752.3**
Upgrade Instrumentation (2024-2025) - Hardwoods Gas Turbine		60.9	157.2				**218.1**
Upgrade Worst-Performing Distribution Feeders (2024-2025)		1,064.3	2,227.4				**3,291.7**
[]		-	-				-
Service Enhancement Total		**1,558.3**	**2,827.7**	**235.3**			**4,621.3**
Total Multi-Year Projects Commencing in 2024		**13,141.1**	**35,664.5**	**4,146.0**			**52,951.6**
Total Capital Projects	**48,201.1**	**53,388.3**	**49,813.6**	**4,396.0**			**155,799.0**

Appendix C

2024 Capital Budget by Materiality – Programs and Projects over $5 Million



Newfoundland and Labrador Hydro
2024 Capital Budget Application
Programs and Projects Over $5 Million
($000)

	2023 and Prior Years	2024	Future Years	Total
General Plant				
Replace Light- and Heavy-Duty Vehicles (2024-2026)		1,479.1	4,157.2	**5,636.3**
General Plant Total		1,479.1	4,157.2	**5,636.3**
Renewal				
Refurbish Ebbegunbaeg Control Structure	9,945.2	2,781.6	4,952.2	**17,679.0**
Terminal Station Renewal Program (2023-2024)	1,733.7	5,584.5	-	**7,318.2**
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood		5,181.4	-	**5,181.4**
Renewal Total	**11,678.9**	**13,547.5**	**4,952.2**	**30,178.6**
Service Enhancement				
Replace Metering System	4,881.2	994.6	-	**5,875.8**
[]	-	-	-	-
Service Enhancement Total	**4,881.2**	**994.6**	**-**	**5,875.8**
System Growth				
Wabush Terminal Station Upgrades	8,870.1	3,808.0	-	**12,678.1**
Additions for Load - Wabush Substation Upgrades	7,439.7	2,739.9	514.5	**10,694.1**
Additions for Load Growth - Upgrade Transformer Capacity (2023-2024) - Jean Lake Terminal Station	580.0	-	5,436.1	**6,016.1**
System Growth Total	**16,889.8**	**6,547.9**	**5,950.6**	**29,388.3**
Total Capital Projects	**33,449.9**	**22,569.1**	**15,060.0**	**71,079.0**

Appendix D

2024 Capital Budget by Materiality – Programs and Projects $1 Million to $5 Million



Newfoundland and Labrador Hydro
2024 Capital Budget Application
Programs and Projects Over $1 Million but Less Than $5 Million
($000)

	2023 and Prior Years	2024	Future Years	Total
Access				
Provide Service Extensions (2024)		4,272.0	-	**4,272.0**
Access Total		**4,272.0**	**-**	**4,272.0**
Allowance for Unforeseen				
Allowance for Unforeseen Items (2024)		1,000.0	-	**1,000.0**
Allowance for Unforeseen Total		**1,000.0**	**-**	**1,000.0**
General Plant				
Purchase 85' Material Handler Aerial Device on Track Unit	1,286.1	67.8	-	**1,353.9**
Replace Light- and Heavy-Duty Vehicles (2022-2024)	1,162.2	2,319.6	-	**3,481.8**
Replace Light- and Heavy-Duty Vehicles (2023-2025)	1,308.1	2,584.6	473.3	**4,366.0**
Upgrade Water and Fire Suppression Systems (2023-2024) - Bishop's Falls	353.7	2,886.3	-	**3,240.0**
Replace Diesel Shop Building (2023-2025) - Bishop's Falls	168.0	1,254.1	889.9	**2,312.0**
Replace MDR8000 Microwave Radios (2024-2025)		953.5	500.3	**1,453.8**
Replace Powerhouse 1 Roof (2024-2025) - Bay d'Espoir		140.2	1,819.2	**1,959.4**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood		156.2	1,039.4	**1,195.6**
Purchase Accommodations Trailer (2024-2025) - Makkovik and Cartwright		130.9	1,420.2	**1,551.1**
Replace VHF Radio System (2024-2025)		1,261.6	290.6	**1,552.2**
General Plant Total	**4,278.1**	**11,754.8**	**6,432.9**	**22,465.8**
Mandatory				
Refurbish Fuel Oil Storage Tank 4 (2024) - Holyrood		1,920.0	-	**1,920.0**
Mandatory Total		**1,920.0**	**-**	**1,920.0**
Renewal				
Thermal In-Service Failures (2024)		3,508.7	-	**3,508.7**
Terminal Station In-Service Failures (2024)		1,300.0	-	**1,300.0**
Diesel Genset Replacement Unit 2012 - L'Anse-Au-Loup	2,853.1	210.2	-	**3,063.3**
Circuit Breakers Renewal Program (2023-2024)	216.9	3,595.1	-	**3,812.0**
Diesel Genset Replacement Program (2023-2025)	819.1	174.0	2,133.1	**3,126.2**
Replace Diesel Genset 1 (2023-2024) - Ebbegunbaeg	298.0	728.3	-	**1,026.3**
Refurbish Superstructure (2023-2024) - Salmon River Spillway	328.3	2,500.0	-	**2,828.3**
Replace Powerhouse Station Service Panel (2023-2024) - Upper Salmon	591.8	976.7	-	**1,568.5**
Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) - Wabush Terminal Station	577.2	516.1	-	**1,093.3**
Hydraulic In-Service Failures (2024)		1,500.0	-	**1,500.0**
Replace Protective Relays (2024–2025)		1,388.4	2,050.7	**3,439.1**
Replace Disconnects (2024–2025)		127.4	1,358.1	**1,485.5**
Upgrade Power Transformers (2024-2025)		864.6	2,711.3	**3,575.9**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)		4,345.4	-	**4,345.4**
Diesel Genset Replacement Unit 2039 - St. Lewis	1,980.8		-	**1,980.8**
Flatten Downstream Slope (2024-2025) - Hinds Lake		276.1	2,953.4	**3,229.5**
Refurbish Surge Tank 1 (2024-2025) - Bay d'Espoir		175.8	2,111.4	**2,287.2**
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood		3,957.8	-	**3,957.8**
Renew Circuit Breakers (2024–2025)		183.9	2,779.3	**2,963.2**
Wood Pole Line Management (2024)		3,765.2	-	**3,765.2**
Renew Distribution Feeders (2024-2025)		1,287.3	1,245.1	**2,532.4**
Refurbish Intake 1 (2024-2025) - Bay d'Espoir		272.1	3,071.9	**3,344.0**
Replace Diesel Gensets (2024-2026)		535.8	4,380.3	**4,916.1**
Renewal Total	**7,665.2**	**32,188.9**	**24,794.6**	**64,648.7**
Service Enhancement				
Upgrade of Worst-Performing Distribution Feeders (2023-2024)	73.4	1,372.6	-	**1,446.0**
Upgrade Worst-Performing Distribution Feeders (2024-2025)		1,064.3	2,227.4	**3,291.7**
Service Enhancement Total	**73.4**	**2,436.9**	**2,227.4**	**4,737.7**
Total Capital Projects	**12,016.7**	**53,572.6**	**33,454.9**	**99,044.2**

Appendix E

2024 Capital Budget by Materiality – Programs and Projects Under $1 Million



Newfoundland and Labrador Hydro
2024 Capital Budget Application
Programs and Projects Less Than $1 Million
($000)

	2023 and Prior Years	2024	Future Years	Total
General Plant				
Purchase 46' Material Handler Aerial Device on Track Unit	719.2	38.8	-	758.0
Replace Grader Unit V9829 (2024) - Bay d'Espoir		836.7	-	836.7
Perform Software Upgrades and Minor Enhancements (2024)		864.2	-	864.2
Replace Mobile Equipment (2024-2025)		216.9	599.7	816.6
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024-2026) - Happy Valley Goose Bay		24.0	848.9	872.9
General Plant Total	**719.2**	**1,980.6**	**1,448.6**	**4,148.4**
Mandatory				
Replace Terminal Station Lighting (2023-2024)	323.3	594.1	-	917.4
Mandatory Total	**323.3**	**594.1**	**-**	**917.4**
Renewal				
Replace Power Line Carrier (2024-2025) - TL247		87.2	667.4	754.6
Replace Power Line Carrier (2023–2024) - TL223 and TL224	105.3	852.4	-	957.7
Replace Instrument Transformers (2024–2025)		154.9	714.8	869.7
Overhaul Diesel Units (2024)		829.2	-	829.2
Renewal Total	**105.3**	**1,923.7**	**1,382.2**	**3,411.2**
Service Enhancement				
Automate Bulk Metering (2024-2026)		302.6	449.7	752.3
Service Enhancement Total		**302.6**	**449.7**	**752.3**
Total Capital Projects	**1,147.8**	**4,801.0**	**3,280.5**	**9,229.3**

Appendix F

Terminal Station Asset Management Overview





Terminal Station Asset Management Overview
Version 7

July 2022

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Executive Summary

This Terminal Station Asset Management Overview describes Newfoundland and Labrador Hydro's ("Hydro") Asset Management System and also describes Hydro's asset management programs for planned capital work (i.e., replacements and upgrades) on terminal station infrastructure.

The following asset classes are terminal station infrastructure:

- Instrument transformers;
- Disconnect switches;
- Surge arresters;
- Insulators;
- Grounding;
- Power transformers;
- Circuit breakers;
- Station services;
- Battery banks and chargers;
- Circuit breaker bypass switches;
- Lighting;
- Synchronous condensers;
- Equipment foundations;
- Fire protection;
- Control buildings; and
- Protection and control.

Each asset class of infrastructure has a section complete with eligibility criteria (i.e., the requirements that a piece of equipment must meet to be eligible for the planned capital work). Each section consists of an introduction and a description. Each introduction describes the high-level function and/or construction of the equipment in that asset class.

Each description details the associated capital program, including each asset class' eligibility criteria, which are typically a combination of some of the following factors: age, usage, condition, and reliability improvements.

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1.0 Introduction

Hydro has 69 terminal stations that contain electrical equipment such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment required to protect, control, and operate Hydro's electrical grid.

Hydro's Asset Management System governs the life cycle of its terminal station assets. The Asset Management System monitors, maintains, refurbishes, replaces, and disposes of assets with the objective of providing safe, reliable electrical power in an environmentally responsible manner at least cost. Within this system, assets are grouped, such as breakers, transformers, grounding systems, buildings, and sites. This allows the asset managers to establish consistent practices for equipment specification, placement, maintenance, refurbishment, replacement, and disposal. These practices mean that the monitoring, assessments, and action justifications for capital refurbishment and replacement for asset-sustaining projects are consistent. Hydro established programs that enact these practices for groups or sub-groupings of assets, for example, high-voltage switch replacements.

[]

[] This document provides information as to the assets involved, an overview of each asset program, and how this document will be updated in the event of changes to Hydro's asset management philosophies.

Hydro will provide an updated Asset Management Overview as it implements changes to its asset management philosophies appropriate for inclusion in the Asset Management Overview.

1.1 Changes in Version 7

Version 7 of this document, is included as part of Hydro's 2023 Capital Budget Application ("CBA"). All material updates in this version are shaded in grey, and are summarized below:

- Executive Summary: Replaced in its entirety;
- Section 1.0: Paragraph 3 was removed in its entirety; text was also removed from Paragraph 4;
- Section 3.0 and all sub-sections: Removed in their entirety;
- Section 4.1.1, Program Description and Justification: Updates to text throughout;
- Section 4.1.1, Manufacturer and Model: Sub-section removed in its entirety;

- Section 4.1.1, Age: Updates to text;
- Section 4.1.6, Transformer Oil Deterioration: Updates to text;
- Section 4.1.7: Removal of text in Paragraph 3;
- Section 4.2.3: Paragraph 3 was replaced in its entirety; and
- Section 4.3.1, Equipment Alarm Upgrades: Addition of Paragraph 4.

Minor changes to syntax have been made to improve readability. These minor changes have not been shaded.

2.0 Background

2.1 Hydro's Terminal Stations

Terminal stations play a critical role in the transmission and distribution of electricity. Terminal stations contain electrical equipment, such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment required to protect, control, and operate the Hydro's electrical grid. Stations act as transition points within the transmission system and interface points with the lower-voltage distribution and generation systems. Hydro has 69 terminal stations throughout Newfoundland and Labrador.

2.2 Terminal Station Infrastructure

Stations contain the following infrastructure, which is described throughout this report:

- Transformers;
- Circuit breakers;
- Instrument transformers;
- Disconnect, bypass, and ground switches;
- Surge arresters;
- Grounding;
- Buswork;
- Steel structures and foundations;

- Insulators
- Control buildings;
- Protection and control relays;
- Yards, fences, and access roads;
- Battery banks;
- Terminal station lighting; and
- Synchronous condensers.

Many of Hydro's terminal stations were constructed in the 1960s. Annual capital commitment is needed to sustain terminal station assets to ensure that Hydro can continue to provide customers with reliable electrical service.

3.0 []

4.0 Asset Management Programs

4.1 Electrical Equipment

4.1.1 High-Voltage Instrument Transformer Replacements

Introduction

The protection, control, and metering devices, such as protective relaying, power quality monitors, and kWh meters used in generation and transmission systems are not manufactured to handle the currents and voltages inherent to those systems. Measurement of the electricity's currents and voltages are provided to these devices through a current transformer ("CT") and a potential transformer ("PT"), respectively. CTs and PTs, as shown in Figure 1, are collectively known as instrument transformers ("IT"). Hydro has approximately 900 individual high-voltage ITs within the Island and Labrador Interconnected Systems.

A high-voltage IT consists of insulated electrical primary and secondary winding, tank, and bushing components. The insulation system involves the use of insulating oil or dry type insulation and a high-voltage porcelain bushing, which allows the safe connection of the winding to high-voltage conductors. The winding is enclosed in a steel tank.



Figure 1: 69 kV CT (Left) and PT (Right)

Program Description and Justification

Hydro manages planned budgeted Instrument Transformer replacements in four categories:

1) Condition;

2) Polychlorinated biphenyl ("PCB") compliance replacements;

3) []

4) Age; and

5) System concern

Condition

Deterioration or damage to the various IT components can result in the failure of the unit to provide accurate measurements to metering, protection, and control devices, which may affect the safe and reliable operation of the generation and transmission systems. Failure could also result in an oil spill. In some situations, pieces of the IT may be forcibly projected resulting in safety risks to personnel in the area or damage to other infrastructure.

Damage to an IT normally results from vandalism, impacts from catastrophically failed equipment, or accidental contact with mobile equipment. Upon such incidents, Hydro assesses the electrical and physical integrity of the IT to determine if replacement is required.

Hydro monitors ITs for physical and electrical deterioration by conducting regular visual inspections of the units as part of its station inspection program plus regularly scheduled station infrared inspections and electrical insulation testing.

Physical deterioration involves conditions such as oil leaks, rusting, or small chips and cracks in the insulation. Figure 2 shows an example of rusting on a PT tank.



Figure 2: Rusting PT

Electrical deterioration is identified by conducting power factor testing at intervals, which is used to establish the rate and level of insulation degradation. Hydro uses Doble Engineering Company to assist with the assessment of the test results, as required.

On an ongoing basis, Hydro's asset management personnel review the unit deterioration information and determine when corrective maintenance or unit replacement is required. Hydro conducts minor IT corrective maintenance, such as painting and small bushing chip treatment. External services to economically undertake major corrective maintenance or unit refurbishments do not exist, so units requiring major corrective maintenance or refurbishments are replaced.

PCB Compliance Replacements

Environment Canada's PCB Regulations require that by 2025 all ITs will not have a PCB concentration greater than 50 mg/kg. ITs are sealed oil-filled units, where the oil, which acts as an electrical insulator,

has been known to contain PCBs for equipment prior to 1985. Due to the age of the units and the risk of introducing contamination such as air into the unit, which could impact the electrical integrity of ITs, Hydro does not sample ITs. Therefore, establishing the actual PCB concentration in an IT is not possible. Hydro, in consultation with manufacturers, has established that units manufactured before 1985 are suspected to contain PCBs in concentration levels greater than or equal to 50 mg/kg. Thus Hydro has a program to replace all suspect oil-filled ITs before 2025.

[]

Age

Hydro targets replacement at 40 years of age to reduce the risk of in-service failures and minimize service interruptions. Original equipment manufacturers ("OEM") recommend that the life of an IT is approximately 30 to 40 years. In the last five years (i.e., 2017–2021), 56% of failed ITs were at least 30 years old at the time of their failure.

System Concern

System concern refers to a transient response of a specific make and model of IT to a specific system transient condition that can contribute to over-stressing (and possibly damage) equipment connected nearby. For example, following four 230 kV circuit breaker failures at Bay d'Espoir Terminal Station 1 from 2018–2019, a transient study identified three ITs with a system concern that likely contributed to overstressing these circuit breakers and thereby contributed to their failure.

Exclusions from IT Replacement Program

Modern-day circuit breaker technology includes CTs embedded in the circuit breaker bushings. Therefore, where possible, external CTs will be displaced by bushing CTs as circuit breakers are replaced, and such CTs are not included in this program.

4.1.2 High-Voltage Switch Replacements

Introduction

High-voltage switches are used to isolate equipment either for maintenance activities or for system operation and control (disconnect switches). Switches are also used to bypass equipment to prevent customer outages while work is being performed on the equipment. Disconnect switches are an important part of the Work Protection Code as they provide a visible air gap (i.e., visible isolation) for utility workers. Work protection is defined as "a guarantee that an ISOLATED, or ISOLATED and DE-

ENERGIZED, condition has been established for worker protection and will continue to exist, except for authorized tests." Proper operation of disconnect switches is essential for a safe work environment and reliable operation.

The basic components of a disconnect switch are the blade assembly, insulators, switch base, and operating mechanism. The blade assembly is the current-carrying component in the switch and the operating mechanism moves it to open and close the switch. The insulators are made of porcelain and insulate the switch base and operating mechanism from the current-carrying parts. The switch base supports insulators and mounts to a metal frame support structure. The operating mechanism is operated manually by using a handle at ground level to open and close the blade, or by a motor-operated device, in which case the switch is known as a motor-operated disconnect. A disconnect and its associated components are shown in Figure 3.

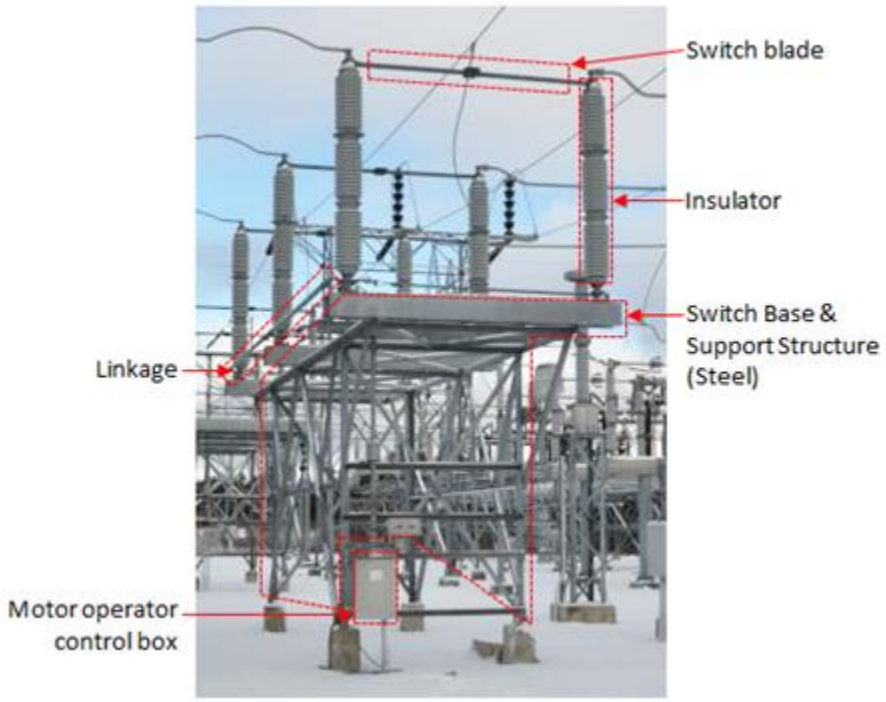


Figure 3: Various Components of a High-Voltage Disconnect Switch

Program Description and Justification

Hydro monitors the condition of its switches by conducting regular visual inspections of the units as part of its station inspection program and its infrared inspection program and by reviewing reports from the

JDEdwards EnterpriseOne work order system or staff who operate the switch, outlining problems such as inoperable mechanical linkages, misalignment of switchblades, broken insulators, and seizing of moving parts. Asset management personnel determine the timing of corrective maintenance or switch replacement. If the required parts are available then repairs are undertaken as part of ongoing maintenance. Switches that have operating deficiencies and have reached a service life of 50 years or greater are designated for replacement. Switches that have no replacement parts available due to obsolescence, are damaged beyond repair or cannot be economically repaired, and do not require immediate replacement are designated for replacement under this program.

Figure 4 shows an example of a badly damaged disconnect switch.



Figure 4: Broken Insulator on 69 kV Disconnect Switch

4.1.3 Surge Arrester Replacement

Surge arresters (also known as lightning arresters) are used on critical terminal station equipment to protect that equipment from voltage due to lightning, extreme system operating voltages, and switching transients, collectively called “overvoltages.” In these situations, voltage at the equipment can rise to levels that could damage the equipment’s insulation. The surge arresters act to maintain the voltages within acceptable levels. Without surge arresters, equipment insulation could be damaged and faults could result during overvoltages. Hydro typically has surge arresters installed on the high- and low-voltage sides of power transformers rated 46 kV and above.

Figure 5 shows the arresters on a 230 kV power transformer.



Figure 5: Western Avalon Terminal Station Transformer T3 230 kV Surge Arresters

Surge arresters can fail because of the cumulative effects of prolonged or multiple overvoltages. When a surge arrester fails, it is not repairable and must be replaced immediately; otherwise, the major equipment may be exposed to damaging overvoltages. The older arrester designs have a higher incidence of failure than the newer designs.

Hydro's surge arrester asset management program replaces surge arresters based upon the following criteria:

- Removal of gapped type arresters with zinc oxide design due to enhanced performance;
- Replacement of units due to a condition identified through visual inspections for chips or cracks or electrical testing such as power factor testing;
- If failures occur on a given transformer, all arresters on both the high and low side are considered for replacement either immediately or in a planned fashion; and

- If transformers are being planned for maintenance or other capital work, consideration is given to changing aged arresters on a common outage. Hydro targets replacement at 40 years of age, to reduce the risk of in-service failures and minimize service interruptions.

4.1.4 Insulator Replacement

Insulators provide electrical insulation between energized equipment and ground. When an insulator fails and a fault occurs, a safety hazard, and/or customer outages may occur.

Insulators consist of insulating material, such as glass, porcelain, and metal-end fittings to attach the insulator to the structure and the conductor. The metallic hardware is mated with the porcelain or glass insulator using cement. There are different styles of insulators. An example of a station post insulator is shown in Figure 6.

Terminal stations contain post type, cap and pin-top, multi-cone, and suspension type insulators.

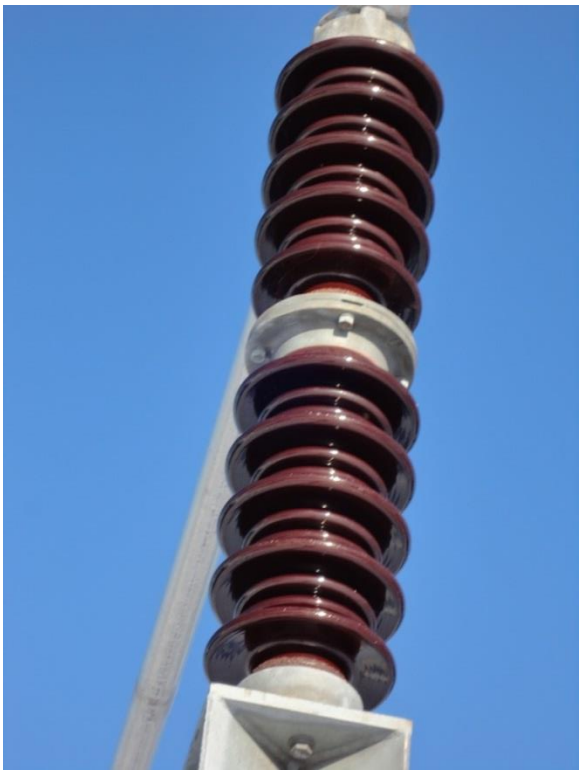


Figure 6: Multi-Cone Type Insulator Prone to Failure due to Cement Growth

For insulators using porcelain, cement is used in mating the porcelain and metal hardware. Some older insulators have been damaged by a phenomenon known as cement growth. This is a common problem in the utility industry. In such situations, water is absorbed into the concrete during freeze/thaw cycles, causing swelling of the cement placing stress upon the porcelain. Over time, the increasing pressure caused by cement growth will crack or break the porcelain resulting in insulator failure. In such situations, porcelain may fall presenting a safety hazard to crews or damaging equipment below. Faults resulting in outages to customers also often occur, when insulator failure leads to flash over. Some time ago, insulator manufacturers identified and researched cement growth problems and have improved their cement quality to eliminate this problem.

Hydro carries out detailed insulator surveys by geographical area. Hydro identifies any insulator types that are known to be prone to failure due to cement growth and replaces these insulators under this program.

4.1.5 Grounding Refurbishment and Upgrades

The grounding system in a terminal station or distribution substation consists of copper wire used in the ground grid under the station, gradient control mats for high-voltage switches, and bonding wiring connecting the structure and equipment metal components to the ground grid, as shown in Figure 7. In the event of a ground fault, electrical potential differences will exist in the grounding system. If the grounding system is inadequate or deteriorated these differences may be hazardous to personnel. These potential differences are known as step and touch potentials. Effective station grounding reduces these potentials to eliminate the hazard.



Figure 7: Typical Grounding Connection on Terminal Station Fence

To determine whether grounding upgrades are required, Hydro performs a step and touch potential analysis of the terminal station or distribution substation. A step and touch potential analysis involves the gathering and analyzing of field data to determine if ground grid modifications are required to eliminate step and touch potential hazards. This engineering is conducted in accordance with IEEE[1] Standard 80-2000.[2] Grounding systems with hazardous step and/or touch potentials are upgraded, by adding additional equipment bonding, gradient control mats, or copper wire to the station grounding grid. In the case where the terminal station grounding infrastructure has deteriorated with age or is damaged due to accidental contact or vandalism, the grounding system is refurbished by repairing damage or replacing missing infrastructure. Upgrades and refurbishments are made in accordance with Hydro's Terminal Station Grounding Standard.

4.1.6 Power Transformer Upgrades and Refurbishment

Introduction

Power transformers are a critical component of the power system. Transformers allow the cost-effective production, transmission, and distribution of electricity by converting the electricity to an appropriate voltage for each segment of the electrical system and allow for economic construction and operation of the electrical system.

Hydro has 118 power transformers and 3 oil-filled shunt reactors 46 kV and above, as well as several station service transformers at voltages lower than 46 kV.

The basic components of a power transformer are:

- Transformer steel tank containing the metal core and paper insulated windings; oil, which is part of the insulating system; and a gasket system, which keeps the oil from getting into the environment;
- Bushings mounted to the top of the transformer tank, which connects the windings to the external electrical conductors;
- Radiators and cooling fans, which remove heat for the transformer's internal components;

[1] Institute of Electrical and Electronics Engineers ("IEEE").
[2] *Guide for Safety in AC Substation Grounding*, IEEE Standard 80, 2000.

- On-load tap changer, which is a device attached internally or externally through which transformer voltages are maintained at acceptable levels; and
- Protective devices to ensure the safe operation of the transformer, such as gas detector relays, oil level and temperature relays, and gauges.

Figure 8 shows a picture of a 75 MVA, 230/66 kV power transformer at the Hardwoods Terminal Station.



Figure 8: Power Transformer

Program Description and Justification

Transformers are expensive components of the electrical system. Hydro, like many North American utilities, is working to maximize and extend the life of its transformers by regularly assessing their condition, executing regularly scheduled maintenance and testing and undertaking refurbishment or corrective actions, as required. Transformers regularly undergo visual inspection as part of Hydro's

terminal station inspection and scheduled preventive maintenance and testing, to identify concerns regarding the following transformer conditions:

- Insulating oil and paper deterioration;
- Oil moisture content;
- Oil leaks;
- Tank, radiators, and other components rusting/corrosion;
- Tap changer component wear or damage;
- Damaged/deteriorated and PCB-contaminated bushings;
- Failure of the protective devices; and
- Cooling fan failures.

Details on the assessment procedures and corrective action for each of these concerns are provided below.

Transformer Oil Deterioration

The insulating oil in a transformer and its tap changer diverter switch is a critical component of the insulation system. The normal operation of a transformer will cause its oil to deteriorate. Deterioration results from several causes, such as heating, internal arcing of electrical components, or ingress of water moisture into the transformer. Deterioration of the oil will affect its function in the insulation system and may damage the paper component of the insulation system. Unacceptable levels of deterioration can affect the reliable operation of the transformer. To ensure that the oil in a transformer is of acceptable quality, Hydro has an oil-monitoring program, in which an oil sample is obtained annually from each transformer and analyzed by a professional laboratory. The test results are assessed to determine the level of deterioration. If an unacceptable level of deterioration is identified, required corrective action is identified by asset management personnel. This action entails either the refurbishment of the oil to improve its quality or the replacement of the oil. The oil that is PCB contaminated (i.e., > 2 ppm PCB), whose refurbishment requires oil reclamation, will be replaced.

Moisture Content

Oil samples are also analyzed to determine their moisture content. Moisture in a power transformer may be residual moisture or may result from the ingress of atmospheric moisture. Oil and insulating paper with a high moisture content have a reduced dielectric strength; therefore, their performance as an electrical insulator is diminished. To address transformers with high moisture content, Hydro will either install an online molecular sieve dry-out system (which circulates and dries the transformer oil without requiring an equipment outage) or perform a hot oil dry-out (which circulates and dries the transformer oil and requires an equipment outage).

Oil Leaks and Corrosion

Transformer oil leaks are an environmental hazard and as oil is part of the insulation system, unchecked leaks can affect the safe and reliable operation of a transformer. Leaks can be caused by several factors, including failed gaskets or severely corroded radiators, tank piping, and other steel components. Transformers are visually inspected for leaks as part of the regularly scheduled terminal station inspection program and assessed by asset management personnel to determine the level of corrective action. Minor action, such as small repairs, patching, and minor painting, is undertaken as part of the maintenance. Work requiring major refurbishments and replacements such as radiator or bushing replacements, gasket replacements, and tank rusting refurbishment is undertaken under this program.

On-Load Tap Changer

On-load tap changer diverter switches, which are externally mounted on the tank, adjust the voltage by changing the electrical connection point of the transformer winding. This involves moving parts, which are subject to wear and damage. Additionally, in older non-vacuum-designed diverter switches, arcing occurs during the movement, leading to the deterioration of the insulating oil. This wear and deterioration can lead to the failure of the tap changer. Oil testing techniques have been developed by professional laboratories that provide assessments of the condition of the parts and oil. Oil samples are obtained annually from each on-load tap changer to perform a tap changer activity signature analysis by the laboratory. This analysis provides a condition assessment of the tap changer oil and components. Hydro typically implements the laboratory's sampling interval recommendations. This ranges from continued or increased annual sampling, planned refurbishment, or immediate removal from service, inspection, and repair. The latter two activities are covered by this project. Another component covered by this project is to correct leaking seals between tap changer diverter switches and the transformer

main tank. Currently, Hydro has several transformers that show low levels of combustible gases, such as acetylene, due to gasses migrating from the tap changer diverter switch compartment to the main tank.

Bushings

In addition to the aforementioned leaking bushings, Hydro must also address suspected bushings to have PCB levels not compliant with the latest PCB Regulations, as well as bushings with degraded electrical properties.

The latest PCB Regulations state that all equipment remaining in service beyond 2025 must have a PCB concentration of less than 50 mg/kg. Hydro has approximately 450 sealed bushings that were manufactured prior to 1985 that are suspected to contain PCBs greater than 50 mg/kg. Some sealed bushings have sampling ports to allow sampling; however, Hydro does not sample, due to a small quantity of oil in bushings and the risk of contamination during sampling. Bushings that are known or suspected of having unacceptable PCB levels are replaced.

Hydro performs power factor testing on bushings every six years as part of the transformer preventive maintenance. When power factor results indicate unacceptable electrical degradation, bushings are scheduled for replacement.

Protective Devices and Cooling Fans

Protective devices and cooling fans are tested during visual inspections and preventive maintenance and are replaced when they fail to operate as designed or their condition warrants replacement. In addition, cooling fans are added where additional cooling is required due to increased loads.

Online Oil Analysis

In addition to oil quality, dissolved gas analysis (“DGA”) is performed on oil. DGA analyzes the levels of dissolved gases in oil, which provides insight into the condition of the transformer insulation. The presence of gases can indicate if the transformer has been subjected to fault conditions or overheating, or if there is internal arcing or partial discharge occurring in the windings. The annual oil sample test can only provide an analysis of transformer conditions at the time when the sample is taken. In 2015, as part of this program, Hydro began installing online dissolved gas monitoring on generator step-up (“GSU”) transformers, to allow real-time, continuous monitoring of dissolved gases in oil. This continuously monitors the transformer and provides early fault detection. Continuous data is also a useful tool for personnel to use to trend gases to help schedule repairs or replacements prior to in-service failures,

improving the overall reliability of the Island Interconnected System. Continuous monitoring enables Hydro to reduce unplanned outages and lessen the probability of equipment in-service failure.

This program was extended to non-GSU transformers in 2017, with online DGA being installed on critical power transformers on the Island Interconnected System. The factors used to determine the criticality score were submitted to the Board of Commissioners of Public Utilities in the June 2, 2014 "Transformers Report."[3] Hydro has identified 49 transformers for the installation of online DGA devices between 2019 and 2024.

4.1.7 Circuit Breaker Refurbishment and Replacements

The circuit breaker is a critical component of the power system. Located in a terminal station, each circuit breaker performs switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of circuit breakers through their fast response and complete interruption of current flow is essential for the protection and stability of the power system. The failure of a breaker to operate as designed may affect the reliability and safety of the electrical system, resulting in the failure of other equipment and the occurrence of an outage affecting more end users. Hydro has over 230 terminal station circuit breakers in service with a voltage rating of 46 kV or greater.

Currently, Hydro maintains three different types of high-voltage circuit breakers, as shown in Figure 9:

1) Air-blast circuit breakers ("ABCB") use high-pressure air to interrupt currents and will be at least 38 years old at replacement. In the 2016 CBA project Upgrade Circuit Breakers – Various Sites, approval was obtained to replace ABCBs on an accelerated schedule by the end of 2020.[4] This work is covered under a separate project and is not part of the work outlined in the Asset Management Overview. Hydro has since modified this program and is targeting completion in 2023.

2) Oil circuit breakers ("OCB") use oil to interrupt currents and will be at least 36 years old at replacement. In the 2016 CBA project Upgrade Circuit Breakers – Various Sites, approval was obtained for the replacement of ten OCBs up to 2020 that were not compliant with Environment

[3] "Report to the Board of Commissioners of Public Utilities Regarding Work to be Performed on Transformers," Newfoundland and Labrador Hydro, June 2, 2014.
[4] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol II, tab 8 was approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

Canada's PCB Regulations. Hydro has since modified this program and is targeting completion of that scope in 2022. The remaining non-compliant breakers will be replaced before 2025. From 2017, any replacements not previously approved in the 2016 CBA will be included in the work conducted under this section of the Asset Management Overview.

3) Sulphur hexafluoride ("SF_6") circuit breakers use SF_6 gas to interrupt current. The installation of these breakers started in 1979 and continues for all new installations.



Figure 9: Circuit Breakers: ABCB (Left), Oil (Middle), and SF_6 (Right)

As presented in the 2016 CBA project Upgrade Circuit Breakers – Various Sites, SF_6 circuit breakers rated at 138 kV and above are required to be refurbished after 20 years of service. In 2018, Hydro added 66 kV-rated breakers to also be refurbished after 20 years. Replacement of SF_6 circuit breakers rated at 66 kV and above will be planned after 40 years of service. However as SF_6 circuit breakers come due, a further condition assessment will be completed to determine if life extension can be achieved through refurbishment. Some SF_6 circuit breakers may require replacement before the 40-year service life period based on their condition and operational history.[]

4.1.8 Station Service Refurbishment and Upgrades

The power required to operate the various terminal stations and distribution substations,—collectively referred to as "station" equipment and infrastructure— is provided by the Station Service System. The station service system provides ac and dc power to operate the equipment in a station.

The ac station service is generally supplied by one or more transformers in the station. Due to their criticality, 230 kV terminal stations have a redundant station service feed, feed either through a redundant transformer tertiary, supplied from Newfoundland Power Inc.'s ("Newfoundland Power") electrical system where available, or by a diesel generator.

Common ac station service loads are:

- Transformer cooling fans;
- Anti-condensation heaters;
- Station lighting;
- Control building HVAC;
- Control building lighting;
- Air compressors; and
- Battery chargers.

The dc station service is supplied by a battery bank that is charged from the ac station service. The dc station service provides power to critical devices in the station and is designed to allow operation of the station in the event of an ac station service failure. Hydro's dc station service system is a 125 V system in the majority of the stations with some lower voltage stations and telecommunications equipment having 48 V systems. Common dc station service loads are:

- Circuit breaker trip and close circuits and charging motors;
- Protection relays;
- Emergency lighting;
- Disconnect switch motor operators for local/remote operation; and
- Telecommunications equipment.

As terminal station equipment is replaced, added, or upgraded, the ac and dc station service loads may increase. Upon the installation of new equipment in the terminal station, Hydro carries out a station service study to determine the loading on the station service system. In the event that the new station service loads exceed the design load of the system, upgrades such as cable, circuit breaker panel, splitter, and transfer switch replacements or additions are required. Replacement of station service transformers is not included in this program, as they are addressed separately in the CBA, under the replace power transformers project, if required.

4.1.9 Battery Banks and Chargers

Introduction

Battery banks and their chargers supply dc power to critical station infrastructure, such as circuit breakers, protection and control relays, disconnect switch motor operators, and telecontrol equipment. Battery banks are designed to provide a minimum of eight hours of auxiliary power to critical infrastructure in the event of a loss of ac station service supply. The majority of Hydro's battery banks consist of lead-acid flooded-cell type batteries, whose capacity deteriorates over time.

Program Description and Justification

Hydro currently completes discharge testing on criticality A and B battery banks after 10 years and then every 5 years for flooded cell and every 2 years for valve regulated. If the battery bank's capacity has fallen to 80% or less of its rated capacity, Hydro will plan replacements. In addition, due to the critical nature of battery banks, flooded cell batteries are replaced after 20 years while valve-regulated lead-acid batteries are replaced after 10 years. An example of a 120 Vdc battery bank is shown in Figure 10.



Figure 10: 125 Vdc Terminal Station Battery Bank

4.1.10 Install Breaker Bypass Switches

High-voltage circuit breakers, with their associated protection and control equipment, are used to control the flow of electrical current to ensure safe and reliable operation of the electrical system. When a breaker is removed from service for maintenance, troubleshooting, refurbishment, or replacement, an alternate electrical path must be implemented to avoid customer outages. On radial systems,[5] this alternate path is accomplished using a bypass switch. When closed, the bypass switch allows electricity

[5] A radial system is an electrical network that has only one electrical path between the source and the load.

to flow around the breaker allowing the breaker to be safely de-energized, while maintaining service continuity, as shown in Figure 11.

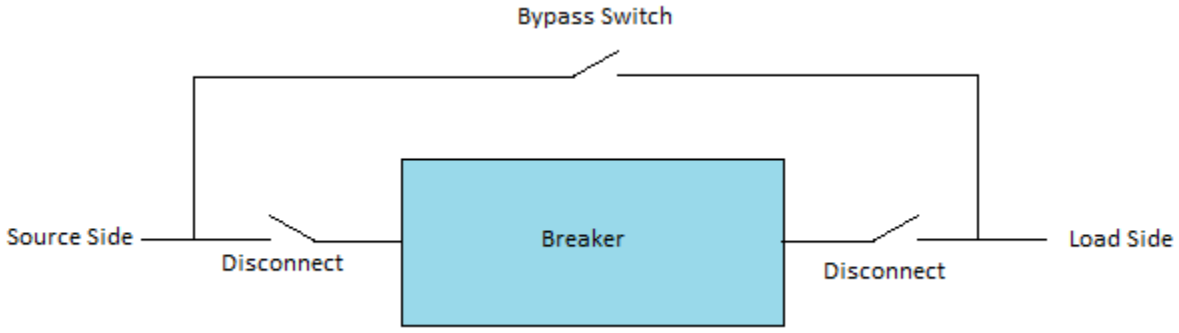


Figure 11: Example of Bypass Switch Installation

Listed in Table 1 are five radial systems, servicing multiple customers, where breakers are installed without bypass switches. To ensure service continuity during breaker downtime, Hydro is considering the installation of breaker bypass as noted in Table 1.

Table 1: Circuit Breakers without Bypass Switches

Breaker Location	Customers Affected
Bottom Waters L60T1	2,253 Bottom Waters area customers
Buchans B2T1	665 Buchans area Newfoundland Power customers and Duck Pond Mine
Howley B1T2	773 Hampden and Jackson's Arm area customers and 665 Newfoundland Power Howley area customers
Peter's Barren B1L41	1,900 Great Northern Peninsula customers north of Daniel's Harbor
South Brook L22T1	2,340 South Brook area customers

Hydro placed a hold on this program in 2018 and is looking closer at doing this work only when other major terminal station work is planned or if there is a low-cost solution. For example, Doyles B1L15 had a low-cost bypass installed in the first quarter of 2020 through an in-service failure project to facilitate the topping up of an ongoing leak in Breaker B1L15.

4.1.11 Replace Station Lighting

Terminal station lighting is essential to provide adequate illumination for a safe working environment, as well as for deterring theft and vandalism in terminal stations. Hydro utilizes a variety of lighting

technologies and configurations, depending on the application and vintage of the lighting system. Over time, exposure to the elements can cause physical deterioration, such as corrosion (as shown in Figure 12 and Figure 13), leading to moisture ingress that impacts the function of the lighting system. Additionally, some legacy lighting technologies have become obsolete.

Under this program, Hydro will replace deteriorated lighting systems as they become unable to provide adequate illumination of the terminal station and have become obsolete or beyond repair. Hydro will replace legacy lighting systems with modern, efficient lighting technologies whenever possible.



Figure 12: Corroded Ballast Requiring Replacement



Figure 13: Light Fixture Showing Perforations due to Corrosion, Enabling Moisture Ingress

4.1.12 Synchronous Condensers

Hydro maintains two synchronous condensers located at the Wabush Terminal Station. Each condenser undergoes major and minor inspections on a three-year rotating cycle, with minor inspections performed on both Year One and Year Two of the cycle, and a major inspection performed on Year Three. Each involves a standard list of checks, tests and general maintenance as well as any additional items that have been identified for follow-up based on the results of previous inspections.

The minor inspections involve function testing, vibrations checks, lube oil system maintenance and oil sampling, disassembly and inspection of the top half of bearings, clearance checks, electrical tests, visual inspections, as well as cleaning and general maintenance including replacement of various gaskets, filters, and hardware.

The major inspections expand on the same activities performed under the minor inspections by also rotor and stator inspection, disassembly, and inspection of the bottom half of the bearings and replacement of the thrust bearings.

4.2 Civil Works and Buildings

4.2.1 Equipment Foundations

Reinforced concrete foundations support high-voltage equipment and structures in Hydro's terminal stations. The majority of these structures formed part of the original station construction and support critical terminal station equipment and buswork.

The service life of galvanized steel structures varies depending on the operating environment but can exceed 100 years, outliving the foundations on which they are built. A number of the foundations in Hydro terminal stations have deteriorated significantly due to repeated exposure to damaging freeze/thaw cycles, weathering, and age, leading to concerns over their integrity. Examples of degraded structure foundations are shown in Figure 14 and Figure 15.



Figure 14: Structure B1T1 Bottom Brook Terminal Station



Figure 15: Structure L01L37-1 Western Avalon Terminal Station

To ensure foundations perform as per the original design intent, severely deteriorated concrete foundations must be refurbished or replaced. Failure to complete repairs could result in a catastrophic failure, causing outages or personal injury. Hydro has carried out engineering inspections of all 230 kV stations and identified foundations requiring repairs. Additionally, Hydro performs visual inspections of foundations every 120 days during regular terminal station inspections. Foundations identified for repair are addressed under this program.

4.2.2 Fire Protection

Hydro's terminal station control buildings contain combustible materials. As these facilities are unattended, a fire could spread, causing severe damage to protection and control wiring and equipment, which would cause extended and widespread outages. To restore of a terminal station severely damaged by fire to normal operation could take months.

Hydro is installing fire suppression systems in its 230 kV terminal stations to protect the control cabinets and cables and any other critical equipment from being destroyed by a fire, without damaging sensitive electronic equipment and wiring.

In the 2015 and 2016 CBAs Install Fire Protection projects, Hydro received approval to install fire protection in the Holyrood and Bay d'Espoir Terminal Stations.[6,7] Due to their criticality, Hydro intends to continue its program to install fire suppression systems in all 230 kV terminal stations.

4.2.3 Control Buildings

Terminal station control buildings contain critical station infrastructure such as protection, control, and monitoring equipment; telecontrol equipment; station service equipment; and compressed air systems. Many control buildings also contain offices, breakrooms, and washroom facilities, for use by Hydro crews when working in the station. As the equipment in control buildings is critical to the function of the terminal station, it is imperative that Hydro ensures the structural integrity, weather tightness, and security of its control buildings. While addressing these issues, Hydro also ensures that building auxiliaries such as electrical, plumbing, and HVAC systems function properly to ensure reliable and safe operation and use of the terminal station and the control building.

Typical refurbishment activities for control building involve replacement of the roof membrane (Figure 16), siding, and doors (Figure 17), and may also include replacement of electrical equipment (such as distribution panels, transfer switches, or low-voltage disconnects), plumbing (such as water service entries and internal plumbing), and HVAC (such as intake and exhaust fans, louvers, heaters, and air conditioning equipment).

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Based on building conditions, Hydro proposes refurbishment or replacement projects for the standalone control building, as required.

[6] "2015 Capital Budget Application," Newfoundland and Labrador Hydro, August 1, 2014, approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 50(2014), Board of Commissioners of Public Utilities, December 2, 2014.
[7] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

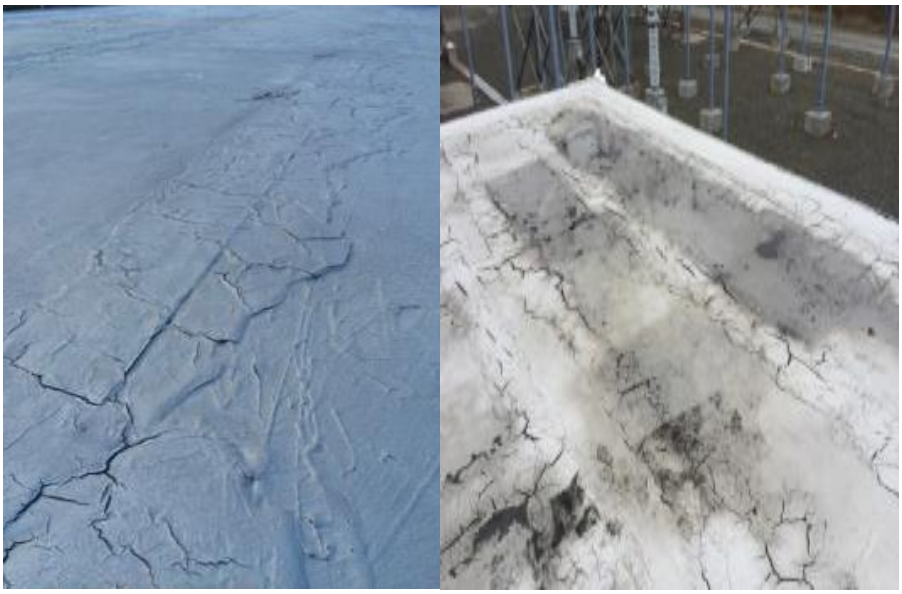


Figure 16: Terminal Station Control Buildings (Come by Chance and Sunnyside) Showing Cracking and Deterioration of the Roof Membrane System



Figure 17: Building Exterior Cladding and Exterior Doorways Displaying Severe Rusting and Deterioration

4.3 Protection, Control, and Monitoring

4.3.1 Protection and Control Upgrades and Refurbishment

Introduction

The terminal station protection and control system automatically monitors, analyzes, and causes action by other equipment, such as breakers, to ensure the safe, reliable operation of the electrical system, or to initiate action when a command is issued by system operators. The protection and control system also provides indications of system conditions and alarms, and allows the recording of system conditions for analysis. Hydro carries out capital work on various protection and control equipment, including:

- Protective relays;
- Breaker failure protection;
- Circuit breaker reclosing controllers;
- Tap changer controls;
- Data alarm systems;
- Digital fault recorders; and
- Cables and panels.

Program Description and Justification

Electromechanical and Solid State Protective Relay Replacement

Protective relays monitor and analyze the operation conditions of the electrical system. When a relay identifies unacceptable operating conditions, such as a fault, it will initiate an action to isolate the source of the condition by commanding high-voltage equipment, such as breakers, to operate. Protective relays play a crucial role in maintaining system stability and preventing hazardous conditions from damaging electrical equipment or harming personnel.

Older, obsolete relays existing on Hydro's system are the electromechanical and older solid-state types, and lack features such as data storage and event recording capability. Modern digital multifunction relays are used to replace these older style relays, as they have increased setting flexibility, fault disturbance monitoring, communications capability and metering functionality, and offer greater dependability and security, enhancing system reliability. Digital and electromechanical relays are showing in Figure 18.

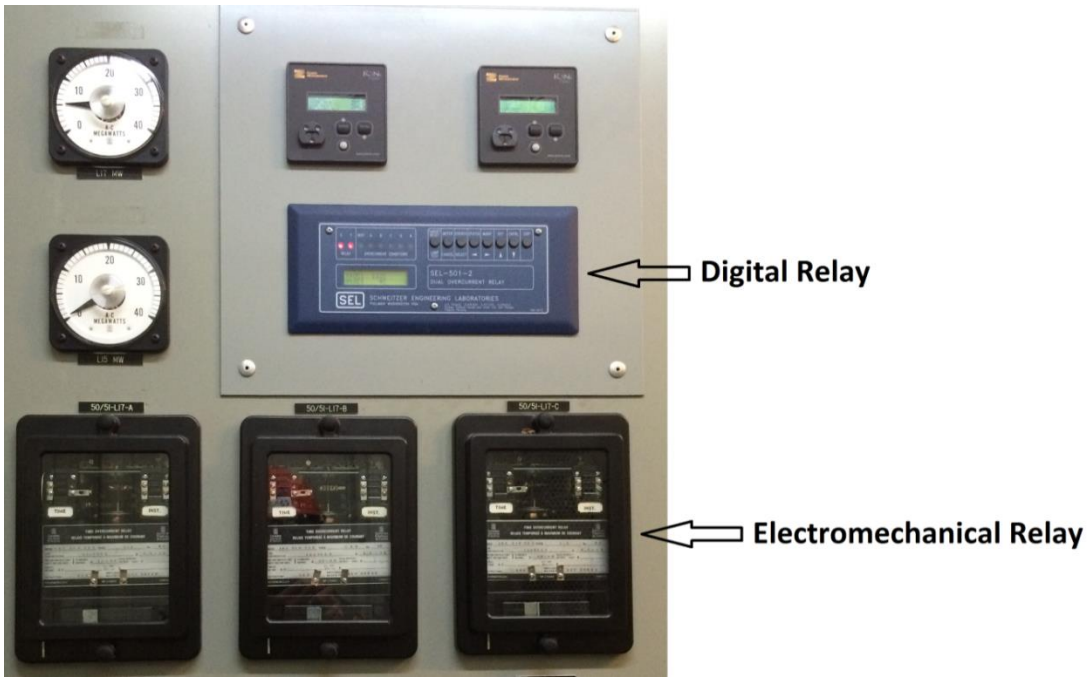


Figure 18: Digital and Electromechanical Relays

In a 2014 report, Hydro stated it " . . . plans to review its existing transformer, bus, and line protections in an effort to develop plans for future implementation of modern digital relays with data storage and fault-recording capabilities."[8] To fulfill this commitment, Hydro completed the following:

- A review of all transformer, bus, and line protection on 230 kV, 138 kV, and 69 kV systems, including data storage and fault recording capabilities; and
- A plan to replace all existing electromechanical transformer, bus, timer, and line protection relays with modern digital relays. The 230 kV relays are the priority for the first phase of the plan, with 138 kV and 69 kV to follow.

As part of its annual Terminal Station Renewal Program,[9] Hydro will continue to execute the replacement of 230 kV electromechanical and obsolete solid-state generator, transformer, line, and bus relays with modern digital multifunction relays, which began in 2016 under the Replace Protective Relays – Various Sites project.[10] Additionally, in line with Hydro's response to CA-NLH-037, filed as part

[8] "Report to the Board of Commissioners of Public Utilities Related to Alarms, Event Recording Devices, and Digital Relays," Newfoundland and Labrador Hydro, August 1, 2014, s 3.1.
[9] Formerly known as the "Terminal Station Refurbishment and Modernization" project.
[10] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol III, tab 19.

of the 2016 CBA, Hydro installed redundant multifunction transformer protection relays in 2016 for transformers rated above 10 MVA. Under this program, Hydro will continue to install these upgrades.

Furthermore, continuing in 2023 as part of the annual Terminal Station Renewal Program, Hydro plans to replace protection relays in the Wabush Terminal Station on 46 kV feeders. Each replacement is currently planned to coincide with the replacement of the circuit breaker associated with that protection.

Breaker Failure Protection

Protective relaying is designed to trip a breaker during fault conditions to remove the fault from the electrical system to minimize equipment outages and maintain system stability and safe, reliable operation. When a breaker does not properly isolate a fault, other breakers will be commanded to trip to isolate the fault. This will result in larger outages but will ensure isolation of the original fault in a time to minimize damage to equipment and minimize impact to the system. The failure of a breaker to isolate a fault when commanded is called a breaker failure.

Prior to 2014, breaker failure protection was implemented only in Hydro's 230 kV terminal stations. In 2014, Hydro completed a review of breaker failure protection in 66 kV and 138 kV terminal stations. Hydro also developed a protection and control standard, Application of Breaker Failure Relaying, calling for breaker failure protection on transmission breakers rated at 66 kV and above. From this review, Hydro identified 20 terminal stations requiring breaker failure protection.

As part of Hydro's 2016 CBA, Hydro proposed and received Board approval for the installation of breaker failure protection in three terminal stations.[11] As part of the annual Terminal Station Renewal Program, Hydro will continue its plan to execute the installation of breaker failure protection in the remaining terminal stations. As well, Hydro has identified concerns with the reliability of legacy breaker failure in 230 kV stations and will be replacing as necessary under this program.

[11] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

Tap Changer Paralleling Control Replacement

Tap changer paralleling controls are designed to:

- Ensure the load bus voltage is regulated as prescribed by the setting;
- Minimize the current that circulates between the transformers, as would be due to the tap changers operating on inappropriate tap positions;
- Ensure the controller operates correctly in multiple transformer applications regardless of system configuration changes or station breaker operations and resultant station configuration changes.

Current tap changer controls are of similar vintage as the power transformers dating back to the late 1960s and require replacement. Recent feedback from the tap changer paralleling control supplier indicated older equipment has capacitors that will dry out over time resulting in control issues. Additionally, it was recommended the same controller model be applied to all transformers to optimize tap changing control. The control issues as described by the supplier have been seen by Hydro staff at numerous sites.

Hydro started replacing tap changer paralleling controls in 2019 beginning at the Western Avalon Terminal Station.

Equipment Alarm Upgrades

Alarms inform the Energy Control Centre ("ECC") and operating personnel that equipment and relaying requires attention and are communicated to the ECC, and/or displayed locally on the station annunciator, as shown in Figure 19.



Figure 19: Annunciator Commonly Found in Hydro Terminal Stations

Hydro's review of alarms, event recording devices, and digital relays found that by providing more detailed alarm schemes, the ECC and local operators are able to troubleshoot system events more accurately and quickly.

Hydro's internal study identified required increases to alarm detail to the ECC for five 230 kV terminal stations. Stony Brook, Holyrood, Sunnyside, Oxen Pond, and Massey Drive Terminal Stations were assessed. Hydro proposed and received approval to implement the proposed upgrades at the Stony Brook Terminal Station as part of the 2016 CBA project Upgrade Data Alarm Systems – Stony Brook.[12] Hydro will continue its plan to install improved data alarm management as part of the Terminal Station Renewal Program, with the remaining stations being addressed in future CBAs.

Deterioration of an annunciator can result in the failure of individual alarms or the whole unit and these failures may negatively affect the safe and reliable operation of the generation and transmission systems. For this reason, Hydro also replaces deteriorated obsolete annunciators.

[12] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol. I, s D, pp. D-374 to D-394, approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

Digital Fault Recorders

Digital fault recorders ("DFR") record analog electrical data, such as voltage, frequency, and current, as well as digital relay contact positions, at a high resolution to allow Hydro to determine the cause and location of an electrical fault. This data allows Hydro to restore service in a timely manner, and address system configurations and settings to mitigate the impact of future faults and improve the protection of critical electrical infrastructure. Hydro has DFRs deployed in several stations and has a program to install DFRs in areas where Hydro does not have sufficient DFR coverage to allow the analysis of faults.

Protection and Control Cable and Panel Modifications

This program will cover protection and control panels and wiring that may require alteration, replacement, or addition to existing wiring due to deterioration from environmental conditions, accidental damage or the modification/addition of protection and control equipment.

Appendix G

Risk Evaluation Matrix



Impact	Safety	Environment	System Reliability					
						General Plant and Business Continuity		
			Generation	Transmission and Terminals	Distribution	Buildings and Land	Tools and Equipment	Electronic Devices, Software, Telecontrol and Cyber Security (Including IT/OT/IS)
Very High (5)	- Fatality or injury causing permanent disability	- Regulatory non-compliance resulting in shut down of all operations for extended period - Major impact of extended duration requiring full scale response - Damage will be evident for more than 10 years - Observed effect observed beyond 10 km radius from Hydro property	- Loss of generation totalling 100 MW or greater - Loss of multiple prime power diesel generating units - Incident occurs between December - February in NL or October - April in Labrador - Total loss of control of generating units by the ECC - Total loss of hydraulic control structure	- Non-redundant equipment serving industrial customer or Newfoundland Power Urban Area - Non-redundant equipment interconnecting generation to IS or LIS - Non-redundant 230kV or supporting equipment	- Impact to an entire region (e.g., Avalon Peninsula Newfoundland Power customers) - Restoration time >36 hours, or rotating outages for greater than 36 hours	- Building unsafe to enter - Damage to equipment inside building leading to a business or service interruption of key infrastructure / critical assets (including IT/OT/IS) at multiple critical sites concurrently, or suspension of all operations for any amount of time - Inability to access assets due to condition of land	- Inability to utilize tools or equipment, leading to a business or service interruption of key infrastructure / critical assets (including IT/OT/IS) at multiple critical sites concurrently	- Service interruption of multiple critical services (infrastructure and applications) concurrently, or suspension of all operations for any amount of time - Complete loss of electrical system stability - Cyber security threat event with multiple severe adverse effects on multiple organizational operations, assets, individuals, customers, or other organizations - Interruption to multiple non critical services (infrastructure or applications) concurrently, or suspension of non critical operations for more than 50% of users
High (4)	- Safety event involving a lost time injury	- Regulatory non-compliance with stop work orders issued - Extended clean-up effort required - Damage will be evident for next 5-10 years - Observed effect within 10 km radius from Hydro property	- Loss of generation totaling 75 MW or greater - Loss of prime power diesel generating unit - Incident occurs between April - November in NL or May - September in Labrador - Partial loss of control of hydraulic control structure - Loss of control of termnial station or non-staffed generating station by ECC	- Redundant equipment serving industrial customers or Newfoundland Power Urban Area - Redundant equipment interconnecting generation to IS or LIS - Redundant 230kV or supporting equipment	- Impact to remote island community or other Newfoundland Power urban area (St. John's metro, Grand Falls, Gander, Corner Brook, >5000 customers) - Restoration time of 24-36 hours, or rotating outages between 24-36 hours	- Damage to equipment inside building leading to a business or service interruption of key infrastructure / critical assets (including IT/OT/IS) at a single critical location with an outage length between 24-36 hours, or rotating outages between 24-36 hours - Inability to access assets by ground due to condition of land	- Inability to utilize tools or equipment, leading to a business or service interruption of key infrastructure/critical assets (including IT/OT/IS) at a critical site	- Service interruption of a single critical service (infrastructure or application) resulting in lost of control/visibility of assets by the ECC, impacts the electricity system, or a critical function of the business cannot be performed - High impact to electrical system stability - Cyber security threat event with a severe adverse effect on organizational operations, assets, individuals, customers, or other organizations - Interruption to a critical service (infrastructure or application) where non critical functions cannot be performed, and 150-300 users
Moderate (3)	- Injury leading to a medical treatment incident	- Regulatory non-compliance Identified by government inspector resulting in administrative penalty - Reportable with some cleanup measures - Temporary damage - Observed effect on/directly adjacent to Hydro property (within 500m radius)	- Loss of generation totaling 50 to 75MW - Incident occurs between November - March in NL or September - April in Labrador	- Redundant 138kV or supporting equipment - Non-redundant 66/69kV class or supporting equipment	- Impact 1000-5000 customers - Restoration time of 12-24 hours	- Damage to equipment inside building leading to a business or service interruption of infrastructure/assets (including IT/OT/IS) at multiple non-critical locations or at a single critical location causing a disruption in performance levels between 12-24 hours, without suspending operations - Access to assets by ground leads to greater than 12-24 hour delay in arrival	- Inability to utilize tools or equipment, leading to a business or service interruption of infrastructure/assets (including IT/OT/IS) at a non-critical site for 72-96 hours	- Service interruption of a single critical service (Infrastructure or application) resulting in an indirect impact to the ECC, the electricity system, or a critical business function is compromised - Medium impact to electrical system stability - Cyber security event where the organization is able to safely perform primary functions at a reduced capacity - Interruption to non critical service (infrastructure or application) where non critical functions cannot be performed, and 50 – 150 users are impacted
Low (2)	- Injury requiring first aid treatment	- Regulatory non-compliance addressed by internal improvement initiatives - Reportable with limited clean-up measures - Non-permanent damage - Observed effect on Hydro property only	-Loss of generation totaling 25 to 50MW - Incident occurs between May - October in NL or June - August in Labrador	- Redundant 138kV or supporting equipment - Non-redundant 66/69kV class or supporting equipment	- Impact to 100-1000 customers - Restoration time <8 hours	- Damage to equipment inside building leading to a business or service interruption of non-critical infrastructure/assets or of critical infrastructure / assets which is restorable in 4-12 hours without disruption to performance levels - Access to assets by ground leads to 4-12 hour delay in arrival	- Inability to utilize tools or equipment, leading to a business or service interruption of infrastructure/assets (including IT/OT/IS) at a non-critical site for 48-72 hours	- Service interruption to a single critical service (infrastructure or application) with no impact to the ECC, or the electricity system, but a critical business function is compromised - Low impact to electrical system stability - Cyber security event where the organization is able to safely perform primary functions - Interruption to non critical service (Infrastructure or application) with non critical function compromised for less than 50 users
Very Low (1)	- Injury not requiring first aid, no absence from work	- No regulatory compliance concern - Not reportable with no cleanup measures - No observed effect on Nalcor property or adjacent properties	- Loss of generation up to 25MW - Incident occurs between June - September in NL or July - August in Labrador	- Redundant 66/69kV class or supporting equipment	- Impact to <100 customers - Restoration time <4 hours	- Damage to equipment inside building leading to a business or service interruption which is not noticed outside of operational area monitoring the impacted system - Access to assets by ground leads to 1-4 hour delay in arrival	- Inability to utilize tools or equipment, leading to a business or service interruption of infrastructure/assets (including IT/OT/IS) at a non-critical site for 24-48 hours	- Service interruption to a single critical service (infrastructure or application) with no impact to the ECC, the electricity system or any critical business functions - No impact to electrical system stability - Cyber security event where there are no impacts to the electricity system or any business functions - Interruption to Non critical service (infrastructure or application) with little to no impact to users.

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Risk Mitigated

	Risk Mitigated
General Plant	
Purchase Accommodations Trailer (2024-2025) - Makkovik and Cartwright	17
Replace MDR8000 Microwave Radios (2024-2025)	15
Minor Telecommunications Enhancements (2024)	12
Replace VHF Radio System (2024-2025)	12
Replace SONET Multiplexors (2024)	10
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood	10
Update Cyber Security Infrastructure (2024)	10
Upgrade SCADA Network (2024)	10
Replace Grader Unit V9829 (2024) - Bay d'Espoir	9
Perform Software Upgrades and Minor Enhancements (2024)	9
Purchase 50' Material Handler Aerial Device on Track Unit (2024-2026) - Happy Valley Goose Bay	9
Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir	9
Replace Powerhouse 1 Roof (2024-2025) - Bay d'Espoir	9
Replace Light- and Heavy-Duty Vehicles (2024-2026)	9
Replace Mobile Equipment (2024-2025)	9
Upgrade Core OT Infrastructure (2024)	8
Upgrade Energy Management System (2024)	8
Replace CCTV Cameras (2024)	6
Replace Peripheral Infrastructure (2024)	6
Refurbish Control Building (2024-2025) - Grandy Brook and Doyles	6
Purchase Personal Computers (2024)	6
General Property Rehabilitation (2024) - Hydro Place	6
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	5
Upgrade HVAC Supervisory Controllers (2024) - Hydro Place	4
Replace Network Communications Equipment (2024)	3
Renewal	
Overhaul Unit 1 (2024) - Granite Canal	15
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood	15
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood	15
Replace Power Line Carrier (2024-2025) - TL247	12
Transmission In-Service Failures (2024)	12
Terminal Station In-Service Failures (2024)	12
Hydraulic In-Service Failures (2024)	12
Gas Turbine In-Service Failures (2024)	12
Overhaul Pumps (2024) - Holyrood	12
Telecommunications In-Service Failure (2024)	12
Diesel In-Service Failures (2024)	12
Thermal In-Service Failures (2024)	12
Upgrade Power Transformers (2024-2025)	12
Upgrade Distribution (2024-2025) - Bay d'Espoir Terminal Station 2	12
Wood Pole Line Management (2024)	12
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)	12
Replace 48 V Battery Banks and Chargers (2024)	12
Upgrade Unit 1 Control System (2024-2025) - Holyrood	10
Flatten Downstream Slope (2024-2025) - Hinds Lake	10
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood	10
Refurbish Intake 1 (2024-2025) - Bay d'Espoir	10
Replace Disconnects (2024–2025)	10
Renew Circuit Breakers (2024–2025)	10
Upgrade UPS 1 & 2 (2024-2025) - Holyrood	10
Overhaul Marine Terminal Loading Arms (2024) - Holyrood	10
Replace Instrument Transformers (2024–2025)	9
Penstock Level II Condition Assessment (2024) - Upper Salmon	9
Replace Annunciator - Phase 2 (2024-2025) - Bay d'Espoir	9
Replace Annunciator Panels (2024-2025) - Cat Arm	9
Replace Protective Relays (2024–2025)	8
Overhaul Diesel Units (2024)	8
Upgrade Remote Terminal Units (2024)	8
Inspect Fuel Tanks (2024) - Hardwoods Gas Turbines	8
Replace Diesel Gensets (2024-2026)	8
Replace Timber Crib and Insulation (2024) - Burnt Dam Spillway	6
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247	6
Renew Distribution Feeders (2024-2025)	6
Purchase Mobile Devices (2024)	6
Replace Terminal Station Battery Banks and Chargers (2024–2025)	5
Refurbish Surge Tank 1 (2024-2025) - Bay d'Espoir	5
Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station	4
Service Enhancement	
Construct Maintenance Platform (2024-2025) - Holyrood Gas Turbine	16
Remove Safety Hazards (2024)	12
[]	[]
Install Anemometer (2024) - Cat Arm	9
Upgrade Instrumentation (2024-2025) - Hardwoods Gas Turbine	8
Automate Bulk Metering (2024-2026)	8
Upgrade Worst-Performing Distribution Feeders (2024-2025)	4

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Risk Mitigated per $1 Million

	Risk Mitgated Per $1 Million
General Plant	
Minor Telecommunications Enhancements (2024)	123.8
Upgrade Core OT Infrastructure (2024)	45.8
Update Cyber Security Infrastructure (2024)	35.5
Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir	31.1
Upgrade HVAC Supervisory Controllers (2024) - Hydro Place	26.7
General Property Rehabilitation (2024) - Hydro Place	25.6
Upgrade SCADA Network (2024)	24.9
Replace SONET Multiplexors (2024)	23.2
Upgrade Energy Management System (2024)	21.8
Replace Peripheral Infrastructure (2024)	21.7
Replace CCTV Cameras (2024)	18.9
Replace Network Communications Equipment (2024)	16.6
Replace Mobile Equipment (2024-2025)	11.0
Purchase Accommodations Trailer (2024-2025) - Makkovik and Cartwright	11.0
Refurbish Control Building (2024-2025) - Grandy Brook and Doyles	10.8
Purchase Personal Computers (2024)	10.8
Replace Grader Unit V9829 (2024) - Bay d'Espoir	10.8
Perform Software Upgrades and Minor Enhancements (2024)	10.4
Replace MDR8000 Microwave Radios (2024-2025)	10.3
Purchase 50' Material Handler Aerial Device on Track Unit (2024-2026) - Happy Valley Goose Bay	10.3
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood	8.4
Replace VHF Radio System (2024-2025)	7.7
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	7.7
Replace Powerhouse 1 Roof (2024-2025) - Bay d'Espoir	4.6
Replace Light- and Heavy-Duty Vehicles (2024-2026)	1.6
Renewal	
Telecommunications In-Service Failure (2024)	131.3
Transmission In-Service Failures (2024)	75.7
Upgrade Remote Terminal Units (2024)	48.2
Overhaul Unit 1 (2024) - Granite Canal	46.3
Purchase Mobile Devices (2024)	38.6
Replace Timber Crib and Insulation (2024) - Burnt Dam Spillway	37.1
Gas Turbine In-Service Failures (2024)	33.5
Replace 48 V Battery Banks and Chargers (2024)	28.4
Upgrade Distribution (2024-2025) - Bay d'Espoir Terminal Station 2	28.3
Upgrade UPS 1 & 2 (2024-2025) - Holyrood	27.0
Replace Terminal Station Battery Banks and Chargers (2024–2025)	25.9
Replace Annunciator Panels (2024-2025) - Cat Arm	25.6
Diesel In-Service Failures (2024)	24.6
Penstock Level II Condition Assessment (2024) - Upper Salmon	23.5
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood	21.2
Overhaul Marine Terminal Loading Arms (2024) - Holyrood	19.6
Replace Annunciator - Phase 2 (2024-2025) - Bay d'Espoir	18.7
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247	18.3
Overhaul Pumps (2024) - Holyrood	18.2
Replace Power Line Carrier (2024-2025) - TL247	15.9
Upgrade Unit 1 Control System (2024-2025) - Holyrood	15.3
Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station	13.7
Inspect Fuel Tanks (2024) - Hardwoods Gas Turbines	11.5
Replace Instrument Transformers (2024–2025)	10.3
Overhaul Diesel Units (2024)	9.6
Terminal Station In-Service Failures (2024)	9.2
Hydraulic In-Service Failures (2024)	8.0
Replace Disconnects (2024–2025)	6.7
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood	3.8
Thermal In-Service Failures (2024)	3.4
Renew Circuit Breakers (2024–2025)	3.4
Upgrade Power Transformers (2024-2025)	3.4
Wood Pole Line Management (2024)	3.2
Flatten Downstream Slope (2024-2025) - Hinds Lake	3.1
Refurbish Intake 1 (2024-2025) - Bay d'Espoir	3.0
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood	2.9
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)	2.8
Renew Distribution Feeders (2024-2025)	2.4
Replace Protective Relays (2024–2025)	2.3
Refurbish Surge Tank 1 (2024-2025) - Bay d'Espoir	2.2
Replace Diesel Gensets (2024-2026)	1.6
Service Enhancement	
Install Anemometer (2024) - Cat Arm	131.2
Remove Safety Hazards (2024)	60.5
Construct Maintenance Platform (2024-2025) - Holyrood Gas Turbine	44.5
Upgrade Instrumentation (2024-2025) - Hardwoods Gas Turbine	36.7
Automate Bulk Metering (2024-2026)	10.6
[]	[]
Upgrade Worst-Performing Distribution Feeders (2024-2025)	1.2

Sch 2: Five-Year
Capital Plan

Schedule 2

Five-Year Capital Plan (2024–2028)



2024 Capital Budget Application

Five-Year Capital Plan (2024–2028)



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Appendix A: Five-Year Capital Plan (2024–2028)

Appendix B: Capital Expenditures (2019–2028)

1.0 Introduction

In Order No. P.U. 30(2007), the Board of Commissioners of Public Utilities ("Board") directed Newfoundland and Labrador Hydro ("Hydro") to file a five-year capital expenditure plan, commencing with the 2009 Capital Budget Application ("CBA"). The Board indicated the plan should focus on strategic spending priorities over the five-year period, identify changing circumstances contributing to these shifts, and set out alternative approaches under consideration.[1]

Hydro's five-year capital plan was developed consistent with its investment philosophy to invest responsibly in the electrical system to the benefit of its customers. The five-year capital plan includes details on the costs and timing of forecast asset replacements and refurbishments. The five-year plan is revised considering evolving asset management practices, asset condition information, operational and system requirements, as well as operating environment factors.[2] Recognizing major investment requirements in the five-year capital plan, Hydro continues to take deliberate actions to achieve a lower level of capital investment where appropriate. As such, Hydro's 2024–2028 capital plan reflects the capital investments necessary to maintain infrastructure and provide safe, reliable, least-cost electricity for customers, while aiming to balance cost, reliability, and environmental impacts.

In this report, Hydro has provided a discussion of the major drivers of expenditure in each of the investment classifications, including a discussion of shifts in spending priorities and the circumstances for such shifts, where applicable.

2.0 Five-Year Plan Overview

Hydro's five-year plan reflects an investment of approximately $750 million in plant and equipment over the 2024–2028 period; $743 million is related to expenditures to be recovered through customer rates, while $7 million is related to investment with up-front contributions (e.g., specifically assigned assets). The average total annual capital expenditure is approximately $149 million. Chart 1 outlines the total planned capital spend per year from 2024–2028.

[1] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 30(2007), Board of Commissioners of Public Utilities, November 22, 2007, p. 5/37–42.
[2] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, December 20, 2021.

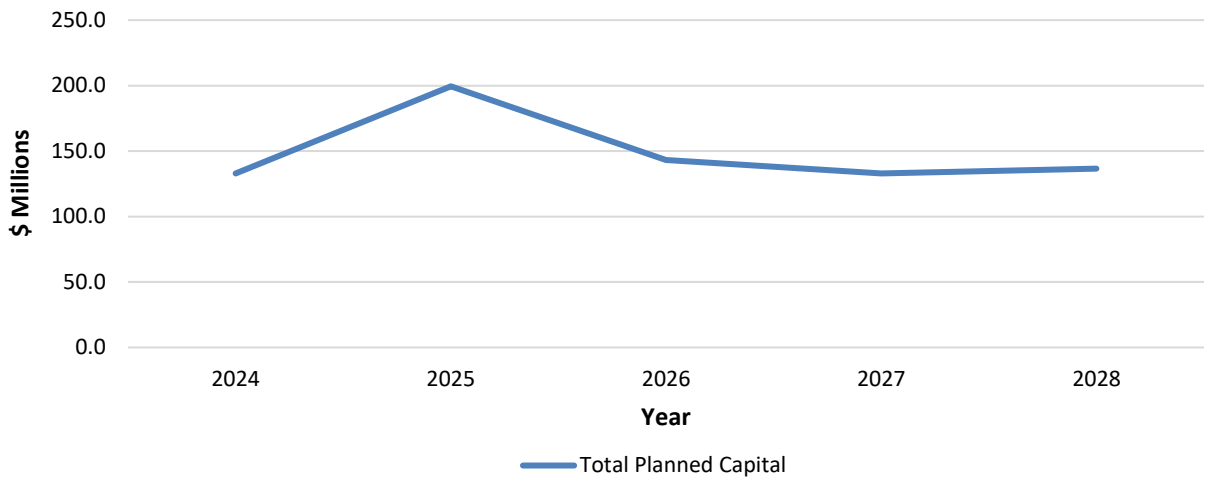


Chart 1: Total Planned Capital Expenditures (2024–2028)

Consistent with the 2024 CBA, the projects identified for the 2024–2028 period are primarily required for renewal-driven capital, which is largely driven by the age of Hydro's assets. The majority of Hydro's installed assets, including many terminal stations and transmission lines, the hydroelectric installation at Bay d'Espoir, the Holyrood Thermal Generating Station ("Holyrood TGS"), the Stephenville Gas Turbine, the Hardwoods Gas Turbine, and much of Hydro's transmission and distribution systems, are more than 40–50 years old.

Capital investments include major projects to refurbish the penstocks supplying Units 1–6 at the Bay d'Espoir Hydroelectric Generating Facility, and new projects to renew Hydro's steel-tower transmission lines. The 2024–2028 capital plan also reflects system growth expenditures related to capital upgrades required to accommodate growth in Labrador West, service enhancement expenditures including the interconnection of the communities of southern Labrador, and renewal of assets specifically assigned to Industrial customers ($5 million).[3]

Hydro's five-year capital plan includes projects for the renewal of assets at the Holyrood TGS totalling $99 million.[4] This level of expenditure reflects the continued operation of the Holyrood TGS as a generating facility until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the Labrador-Island Link ("LIL") is proven, and generation reserves are met. In

[3] Excluding federal government contributions for ultra-fast Direct Current Fast Chargers.
[4] Includes an allocation of $18 million for in-service failures.

2021, Hydro engaged Hatch Ltd. to complete an assessment of the condition of the Holyrood TGS assets, and a study of the long-term viability of the Holyrood TGS as a generating facility.[5] Hydro's planned thermal generation capital expenditures reflect the findings of this study.

Hydro notes that in its 2022 update to the Reliability and Resource Adequacy Study and the associated technical conference in May 2023, Hydro noted the requirement for additional generation on the Island to provide reliable backup in the event of an extended outage to the LIL, and to accommodate load growth associated with changing market conditions and increased electrification driven by net-zero targets established by the Government of Canada. Hydro has committed to filing a Biennial Resource Adequacy Plan, with the next update planned for the spring of 2024.[6] Hydro is advancing a significant number of fronts to inform next steps on additional generation, and anticipates that the outcomes of its resource adequacy plan will support application(s) for additional generation in the second half of 2024. Due to the uncertainly surrounding the timing, cost, and scope of associated projects, any associated expenditures are not included in the 2024–2028 five-year plan. Hydro's five-year capital plan will be updated as more details become available. Hydro is cognizant of the significant investment that would be required to implement additional generation, and therefore will seek opportunities to reduce or defer other capital expenditures in its five-year plan where appropriate and when associated risks can be acceptably mitigated.

3.0 Investment Drivers

In accordance with the provisional CBA guidelines,[7] and continuing its approach presented in the 2023 CBA, Hydro has provided a discussion of significant expenditures within each investment classification. This approach allows Hydro to refocus its analysis and discussion of planned expenditures to highlight major drivers of investment across its assets. Hydro recognizes that segmentation by asset category also provides valuable insight into its strategy and the drivers of planned investment in its assets, particularly in the context of asset renewal; therefore, where appropriate, Hydro has provided a discussion of significant planned expenditures by asset category within appropriate investment classifications.

[5] "*Reliability and Resource Adequacy Study Review* – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 31, 2022, att. 2.
[6] "*Reliability and Resource Adequacy Study Review* – Current Schedule for Future Updates," Newfoundland and Labrador Hydro, June 19, 2023.
[7] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, December 20, 2021.

Hydro's five-year planned expenditures for the period 2024–2028, segmented by investment classification, are presented in Chart 2.

The drivers of investment and any shifts in spending priorities are provided herein, segmented by investment classification.

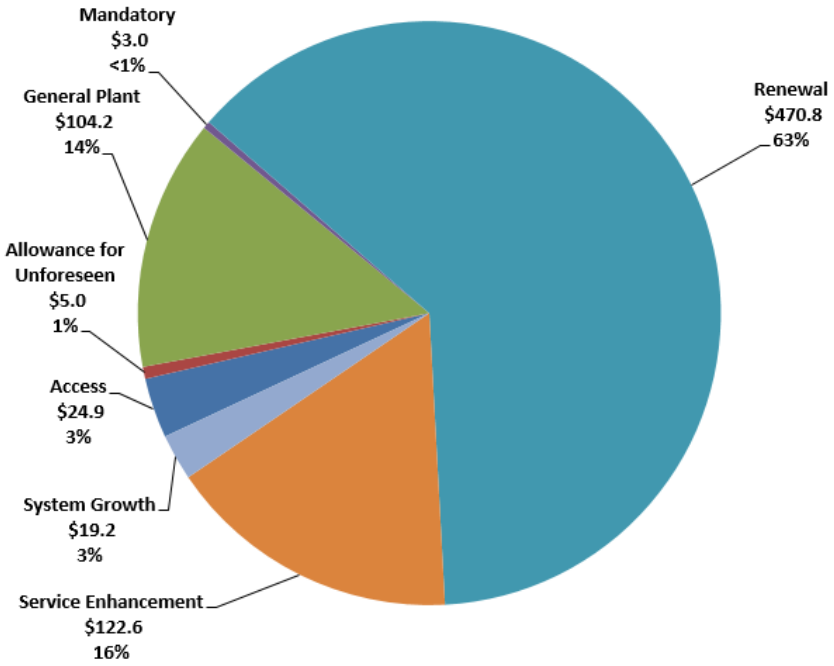


Chart 2: Five-Year Planned Capital Expenditures by Investment Classification (2024–2028) ($ Millions)

3.1 Renewal

Projects and programs classified as "renewal" are those that are required to replace and/or refurbish system assets to maintain the ability to provide customers with their current electricity services. Renewal expenditures are critical to ensuring Hydro's ability to sustain its assets and to continue to safely and reliably provide the level of service required to its customers.

Asset renewal comprises approximately $471 million, or 63%, of Hydro's planned capital expenditures for the next five years. Hydro's planned renewal expenditures are expected to rise in 2025 and then remain relatively consistent for the remainder of the period. The increase between 2024 and 2025 is primarily due to planned expenditures associated with the refurbishment of the Bay d'Espoir penstocks, detailed below. Hydro's planned renewal expenditures for the period 2024–2028 are provided in Chart 3.

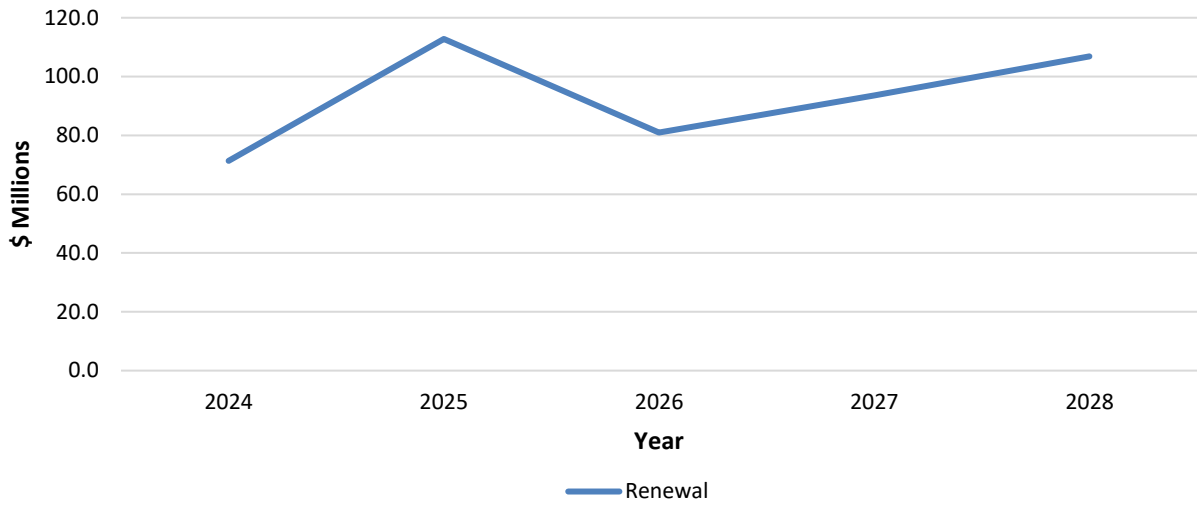


Chart 3: Planned Renewal Capital Expenditures (2024–2028)

Hydro's total planned renewal expenditures for the period 2024–2028 organized by major asset category is provided in Chart 4.

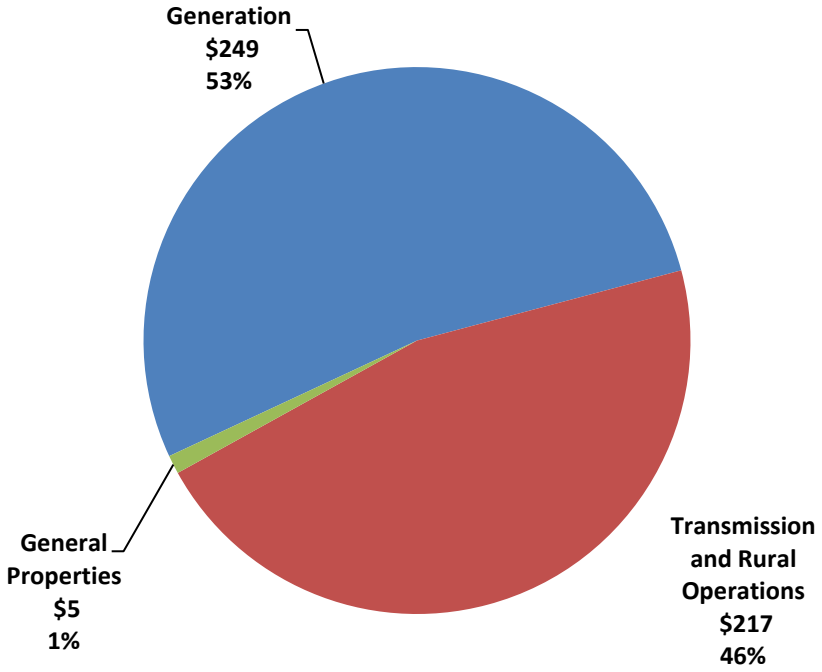


Chart 4: Five-Year Planned Renewal Expenditures by Category (2024–2028) ($ Millions)

Transmission and Rural Operations ("TRO") renewal-driven investment is forecast to be $217 million over the next five years. TRO renewal investment is largely driven by Hydro's asset renewal programs,

such as its terminal station renewal, circuit breaker renewal, wood pole line management, and diesel unit replacement and overhaul programs, which are required for the reliable operation of aging assets.

The primary drivers of planned TRO renewal investment in Hydro's five-year capital plan are as follows:

- Renewal of terminal station assets, which is comprised of the continuation of multiple programs to renew aging or deteriorated terminal station assets;
- Renewal of steel-tower transmission Lines – Required to address deficiencies identified by inspection of Hydro's steel-tower transmission lines, with nine transmission lines planned for renewal over the next five years;
- Renewal of distribution feeders through Hydro's Worst-Performing Feeder and Renew Distribution Feeders programs; and
- Wood Pole Line Management Program, required for renewal of Hydro's wood pole transmission lines.

Generation renewal-driven investment is forecast to total $249 million over the next five years. The requirement to invest sustaining capital in generation facilities increased several years ago, as parts of Hydro's generating facilities approached or surpassed their normal expected service lives. Primary drivers for these projects are the end of service lives for equipment and deterioration causing reductions in reliability or performance. Hydro's five-year capital plan also includes approximately $91 million in projects required for the renewal of Holyrood TGS assets. Further discussion of Hydro's planned expenditures for the Holyrood TGS is provided in the Holyrood Thermal Generating Station Overview – Future Operation and Capital Expenditure Requirements, which is provided as Schedule 3.

The primary drivers of planned generation renewal investment in Hydro's five-year plan are as follows:

- Penstock Life Extension—Hydro received approval for Phase 1 of this initiative, which involves the refurbishment of Penstock 1 at the Bay d'Espoir Hydroelectric Facility in 2023, planned for completion in 2025. Phase 2, which will see the refurbishment of Penstock 2, is planned to commence in 2026. An update on the execution of Phase 1 of this initiative is provided in Hydro's 2023 Capital Expenditure Overview, provided as Schedule 4.
- Renewal of Hydraulic Generating Assets – Required to renew aging or deteriorating assets associated with Hydro's Hydraulic Generating Assets, including dams and hydraulic structures,

unit, turbine, and generator overhauls, and replacement of aging or deteriorating ancillary equipment.

- Renewal of Thermal Generating Assets – Required to sustain reliable operation of the Holyrood TGS until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.
- Renewal of Gas Turbine Assets – In particular, major inspection of the Holyrood Gas Turbine required on the basis of turbine operating hours.

Renewal-driven investments also include the In-Service Failures Programs in all years, which is an allotment of funds to be used in the event that immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or determination of faster than anticipated equipment deterioration.[8]

3.2 Service Enhancement

Projects and programs classified as "service enhancement" are those that modify Hydro's system to meet system operations requirements in a more efficient and/or effective manner, including those that improve safety or environmental compliance. Hydro undertakes service enhancement investments to address known issues that impact Hydro's ability to reliably and safely serve its customers efficiently and effectively.

Service enhancement accounts for $123 million, or 16%, of Hydro's planned capital expenditures for the next five years. Hydro's planned service enhancement expenditures peak in 2025, and trend downwards for the remainder of the period; this is primarily due to expenditures associated with Hydro's long-term plan for supply for southern Labrador, which are also expected to peak in 2025. Hydro's planned service enhancement expenditures segmented by asset category for the period 2024–2028 are provided in Chart 5.

[8] Work will not be completed under this program if it is more appropriate for it to be executed as allowance for unforeseen or through a capital budget supplemental project.

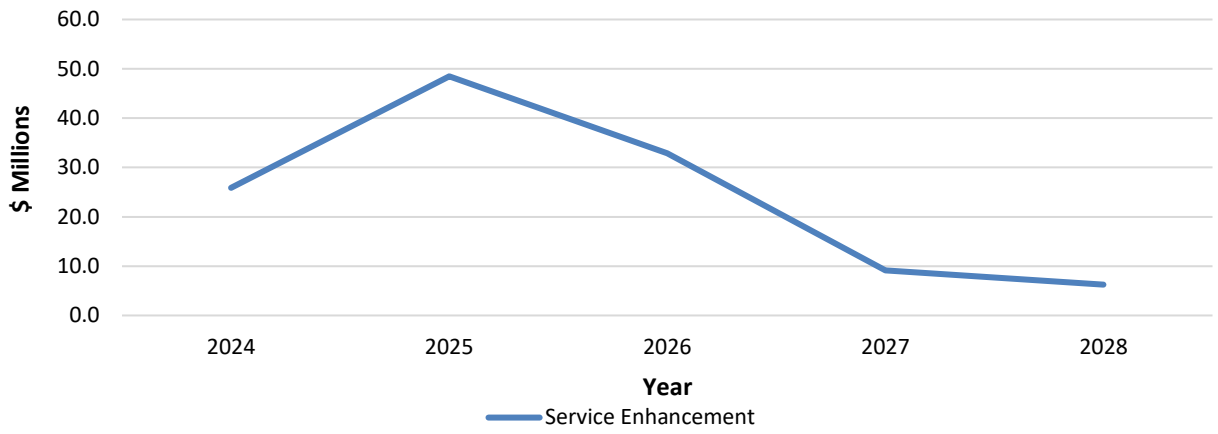


Chart 5: Planned Service Enhancement Capital Expenditures (2024–2028) ($ Millions)

Hydro's total planned service enhancement expenditures for the period 2024–2028 organized by major asset category is provided in Chart 6.

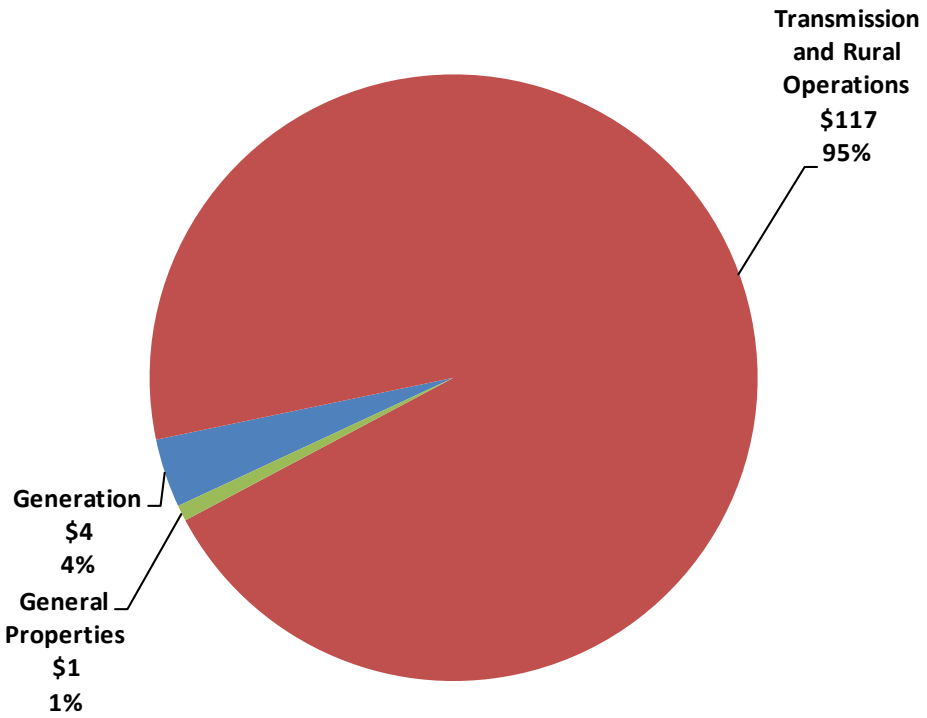


Chart 6: Five-Year Planned Service Enhancement Expenditures by Category (2024–2028) ($ Millions)

The primary drivers of planned service enhancement investment in Hydro's five-year capital plan are as follows:

- Long-term supply for southern Labrador, which is required to establish efficient and effective long-term supply for the communities of southern Labrador following the destruction of the Charlottetown Diesel Generating Station due to a fire in 2019;[9]
- Hydro's program to Upgrade of Worst-Performing Distribution Feeders, which is required to address deficiencies on distribution feeders that perform significantly worse than Hydro's average;
- Modifications to terminal stations to improve oil and fire containment and to accommodate the interconnection of mobile substations when required; and
- Replacement of Hydro's Metering System and the automation of Hydro's bulk metering, which are required to replace Hydro's metering systems to enhance safety, efficiency, and accuracy by enabling automated meter reading ("AMR").

3.3 General Plant

Projects and programs classified as "general plant" are those related to Hydro's assets that are not part of its generation, transmission, and distribution system. Investment in general plant is required to renew assets that support Hydro's operations, such as transportation, properties, information systems, and telecommunications infrastructure.

General plant is the third largest investment driver in Hydro's five-year capital plan, totaling $104 million, or 14% of Hydro's planned capital expenditures for the next five years. Hydro's planned general plant expenditures remain relatively steady over the period, with a slight downward trend associated with higher than average vehicle expenditures 2024 and 2025 resulting from a backlog of vehicle deliveries due to global supply chain challenges. Hydro's planned general plant expenditures for the period 2024–2028 are provided in Chart 7.

[9] "Long-Term Supply for Southern Labrador – Revision 1," Newfoundland and Labrador Hydro, rev. May 31, 2023 (originally filed July 16, 2021). Regulatory review of Hydro's application is ongoing.

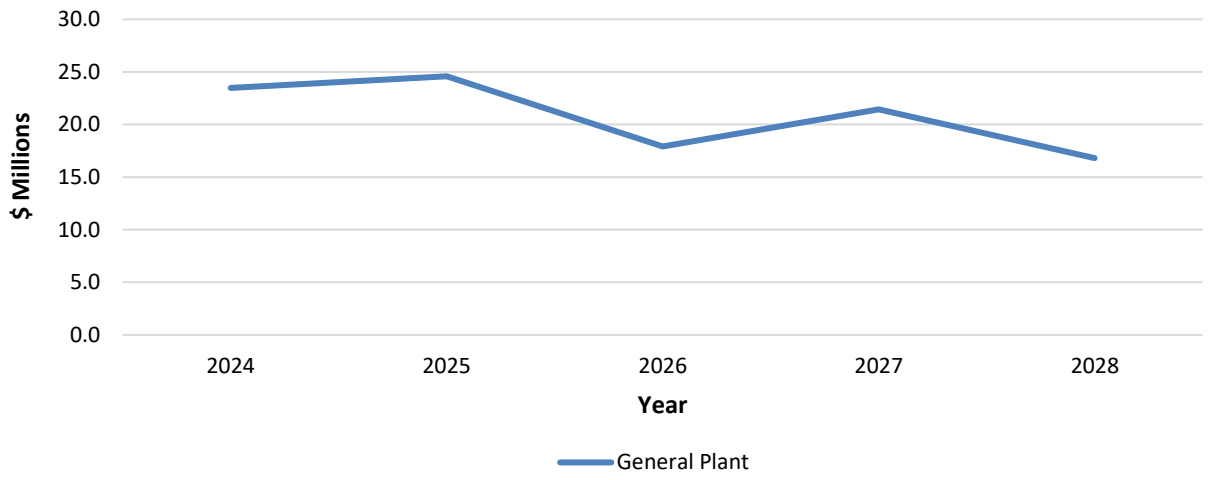


Chart 7: Planned General Plant Capital Expenditures (2024-2028)

Hydro's total planned general plant expenditures for the period 2024–2028 organized by major asset category is provided in Chart 8.

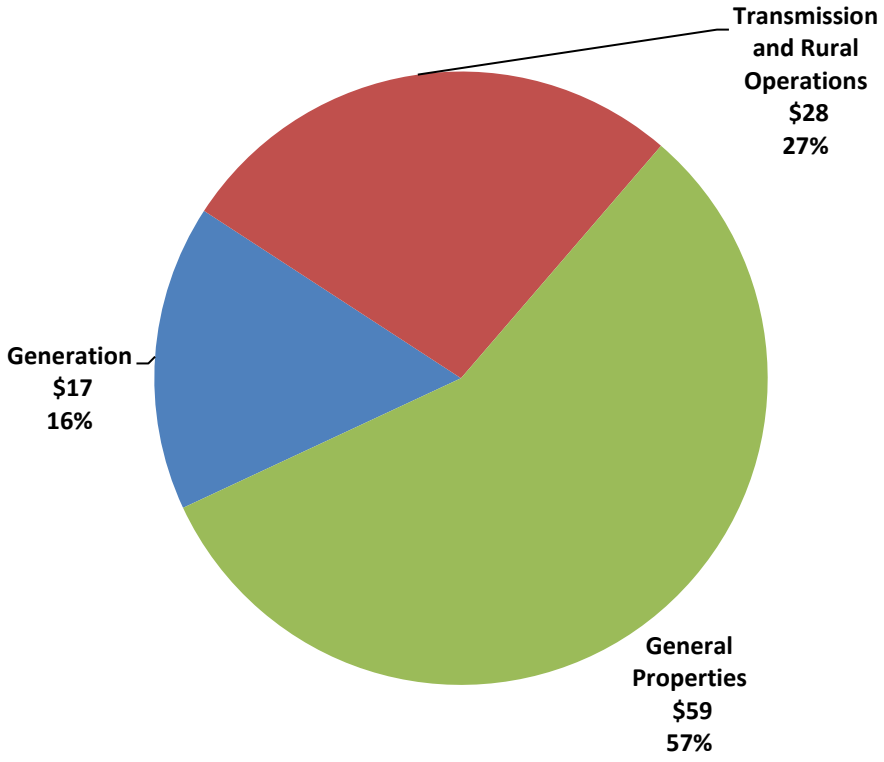


Chart 8: Five-Year Planned General Plant Expenditures by Category (2024–2028) ($ Millions)

The primary drivers of general plant investment in Hydro's five-year capital plan are as follows:

- The Replace Light- and Heavy-Duty Vehicles program, which is required to renew Hydro's fleet of light- and heavy-duty vehicles that are required to support the operation and maintenance of its assets;
- Projects and programs to renew information systems infrastructure, such as software, cyber security, and operations technology infrastructure, personal computers, and mobile devices;
- Projects and programs to renew telecontrol infrastructure, including VHF and microwave radio systems, fiber optic infrastructure, mobile devices, security, and other communications infrastructure; and
- Sustaining capital investment required for Hydro's properties, including water and sewer, administrative buildings, terminal station control buildings, diesel plants, powerhouses, line depots, and roads.

3.4 Access

Projects and programs classified as "access" are those required to meet Hydro's obligation to provide customers with access to electricity services. Access-related expenditures account for $25 million, or 3%, of Hydro's planned capital expenditures for the next five years. Hydro's planned access expenditures for the period 2024–2028 are provided in Chart 9.

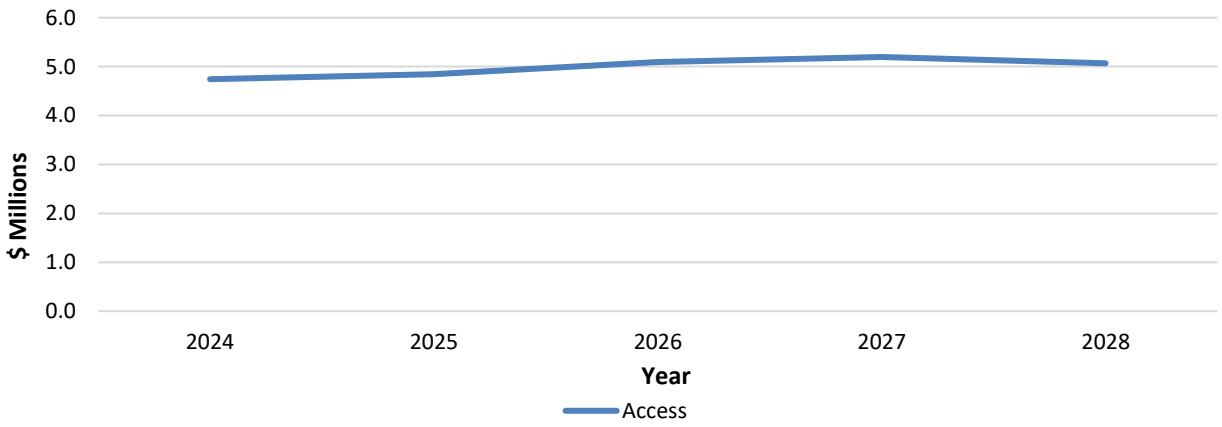


Chart 9: Planned Access Capital Expenditures (2024–2028)

Hydro's planned access-driven expenditures remain consistent for the period 2024–2028. Hydro's five-year plan includes the following access-driven investments:

- Continuation of the Provide Service Extensions program, which is required to provide service extensions to accommodate customers' requests for service; and
- Hydro's program to purchase meters and metering equipment[10] to ensure Hydro has sufficient inventory to connect new services or replace deteriorated meters.

3.5 System Growth

Projects and programs classified as "system growth" are those that are required to modify Hydro's system to meet forecast changes in customers' electricity resource requirements. System growth accounts for $19 million, or 3%, of Hydro's planned capital expenditures for the next five years. Hydro's planned access expenditures for the period 2024–2028 are provided in Chart 10.

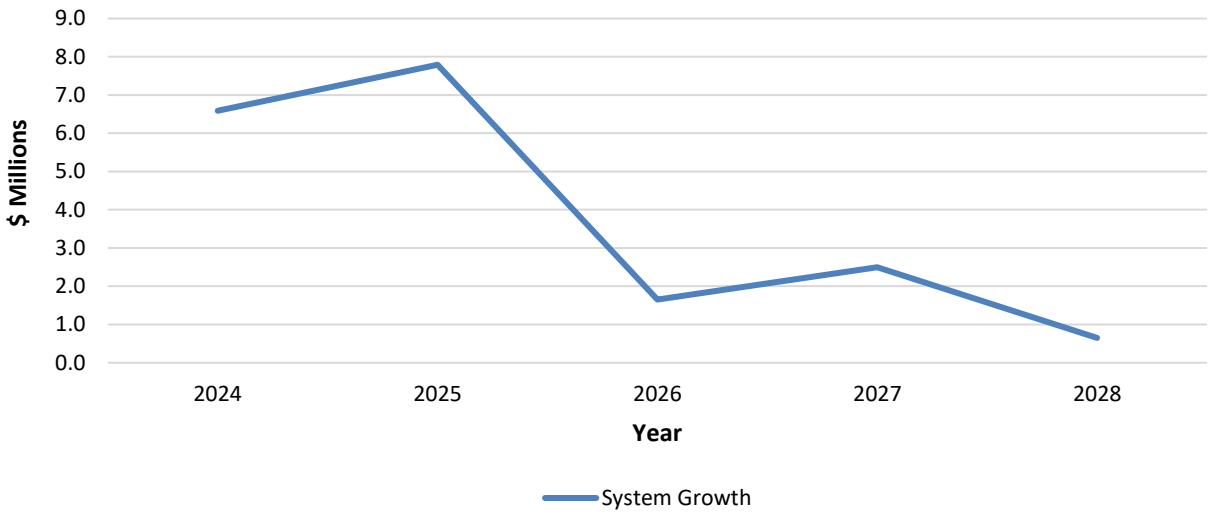


Chart 10: Planned System Growth Capital Expenditures (2024–2028)

[10] Meters not related to the AMR or bulk metering projects.

Hydro's planned system growth expenditures trend downward over the period 2024–2028, primarily as a result of the conclusion of projects to accommodate load growth in Labrador West. Hydro's planned system growth investments in the five-year plan consist of:

- Continuation of Hydro's Additions For Load Growth programs for distribution systems and isolated generating stations, which are required to accommodate load growth in Hydro's service areas; and

- The continuation of previously approved projects to accommodate load growth in western Labrador.

As previously noted, Hydro's current five-year plan does not include expenditures associated with the requirement for additional generation on the Island Interconnected System. As any such expenditures would be classified as system growth-driven, Hydro anticipates that expenditures in this category will significantly increase following their inclusion.

4.0 Conclusion

Hydro's five-year plan reflects an investment of approximately $750 million in plant and equipment over the 2024–2028 period; $743 million is related to expenditures to be recovered through customer rates, while $7 million is related to investment assets with up-front contributions.

Capital expenditures in the five-year plan are primarily driven by investments in asset renewal and general plant and include investments to support service enhancement, access, and system growth.

Hydro's five-year capital plan is consistent with its investment philosophy to invest responsibly in the electrical system to the benefit of its customers. Hydro has planned and identified projects to balance capital expenditures with customer reliability, safety, and/or the environment. The five-year capital plan reflects Hydro's continued focus on cost management to minimize impacts to ratepayers while delivering safe and reliable service.

Appendix A

Five-Year Capital Plan (2024–2028)



Newfoundland and Labrador Hydro
2024 Capital Budget Application
Five-Year Capital Plan - By Investment Class
($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Access		4,742.7	4,844.5	5,092.5	5,196.5	5,065.5	**24,941.7**
Allowance for Unforeseen		1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	**5,000.0**
General Plant	6,009.2	23,479.1	24,584.0	17,381.4	19,467.4	19,302.9	**110,224.0**
Mandatory	323.3	2,605.7	429.0				**3,358.0**
Renewal	23,652.3	71,339.7	112,755.0	83,174.6	95,291.9	108,260.4	**494,473.9**
Service Enhancement	7,667.6	25,851.3	48,474.2	32,905.8	9,154.0	6,250.2	**130,303.1**
System Growth	16,889.8	6,585.8	7,791.9	1,650.0	2,500.0	650.0	**36,067.5**
Total Capital Plan	**54,542.2**	**135,604.3**	**199,878.6**	**141,204.3**	**132,609.8**	**140,529.0**	**804,368.2**

Newfoundland and Labrador Hydro
2024 Capital Budget Application
Five-Year Capital Plan - By Investment Classification
($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Access							
Provide Service Extensions (2024)		4,272.0					**4,272.0**
Purchase Meters and Metering Equipment (2024)		470.7					**470.7**
Provide Service Extensions (2025)			4,369.0				**4,369.0**
Purchase Meters and Metering Equipment (2025)			475.5				**475.5**
Provide Service Extensions (2026)				4,467.0			**4,467.0**
Purchase Meters and Metering Equipment (2026)				625.5			**625.5**
Provide Service Extensions (2027)					4,567.0		**4,567.0**
Purchase Meters and Metering Equipment (2027)					629.5		**629.5**
Provide Service Extensions (2028)						4,670.0	**4,670.0**
Purchase Meters and Metering Equipment (2028)						395.5	**395.5**
Access Total		**4,742.7**	**4,844.5**	**5,092.5**	**5,196.5**	**5,065.5**	**24,941.7**
Allowance for Unforeseen							
Allowance for Unforeseen Items (2024)		1,000.0					**1,000.0**
Allowance for Unforeseen Items (2025)			1,000.0				**1,000.0**
Allowance for Unforeseen Items (2026)				1,000.0			**1,000.0**
Allowance for Unforeseen Items (2027)					1,000.0		**1,000.0**
Allowance for Unforeseen Items (2028)						1,000.0	**1,000.0**
Allowance for Unforeseen Total		**1,000.0**	**1,000.0**	**1,000.0**	**1,000.0**	**1,000.0**	**5,000.0**
General Plant							
Replace Light- and Heavy-Duty Vehicles (2022-2024)	1,162.2	2,319.6					**3,481.8**
Purchase 85' Material Handler Aerial Device on Track Unit	1,286.1	67.8					**1,353.9**
Purchase 46' Material Handler Aerial Device on Track Unit	719.2	38.8					**758.0**
Replace Light- and Heavy-Duty Vehicles (2023-2025)	1,308.1	2,584.6	473.3				**4,366.0**
Replace Diesel Shop Building (2023-2025) - Bishop's Falls	168.0	1,254.1	889.9				**2,312.0**
Ultra-Fast Direct-Current EV Chargers - Purchase and Installation	62.5	1,766.0	231.3				**2,059.8**
Upgrade Water and Fire Suppression Systems (2023-2024) - Bishop's Falls	353.7	2,886.3					**3,240.0**
Replace Mobile Equipment (2023-2024)	541.2	187.3					**728.5**
Replace Building Exterior (2023-2024) - Postville	124.6	558.7					**683.3**
Water System Condition Assessment and Upgrades (2023) - Bay d'Espoir	161.0	504.9					**665.9**
Install Fire Protection in 230 kV Stations (2023-2024) - Deer Lake	79.2	535.3					**614.5**
Replace HVAC System (2023-2024) - Bishop's Falls	43.4	128.8					**172.2**
Replace Light- and Heavy-Duty Vehicles (2024-2026)		1,479.1	4,148.8	8.4			**5,636.3**
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024-2026) - Happy Valley Goose Bay		24.0	841.8	7.1			**872.9**
Replace Powerhouse 1 Roof (2024-2025) - Bay d'Espoir		140.2	1,819.2				**1,959.4**
Replace VHF Radio System (2024-2025)		1,261.6	290.6				**1,552.2**
Purchase Accommodations Trailer (2024-2025) - Makkovik and Cartwright		130.9	1,420.2				**1,551.1**
Replace MDR8000 Microwave Radios (2024-2025)		953.5	500.3				**1,453.8**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood		156.2	1,039.4				**1,195.6**
Replace Mobile Equipment (2024-2025)		216.9	599.7				**816.6**
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay		53.8	599.0				**652.8**
Refurbish Control Building (2024-2025) - Grandy Brook and Doyles		109.4	444.7				**554.1**
Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir		57.8	231.2				**289.0**
Perform Software Upgrades and Minor Enhancements (2024)		864.2					**864.2**
Replace Grader Unit V9829 (2024) - Bay d'Espoir		836.7					**836.7**
Purchase Personal Computers (2024)		555.9					**555.9**
Replace SONET Multiplexors (2024)		430.4					**430.4**
Upgrade SCADA Network (2024)		402.3					**402.3**
Upgrade Energy Management System (2024)		366.4					**366.4**
Replace CCTV Cameras (2024)		317.6					**317.6**
Update Cyber Security Infrastructure (2024)		281.3					**281.3**
Replace Peripheral Infrastructure (2024)		276.8					**276.8**
General Property Rehabilitation (2024) - Hydro Place		234.0					**234.0**
Purchase Tools and Equipment Less than $50,000 (2024) - Hydraulic Plants		209.4					**209.4**
Purchase Tools and Equipment Less than $50,000 (2024) - Central Region		188.2					**188.2**
Replace Network Communications Equipment (2024)		180.7					**180.7**
Upgrade Core OT Infrastructure (2024)		174.7					**174.7**
Purchase Tools and Equipment Less than $50,000 (2024) - Thermal Plants		167.1					**167.1**
Upgrade HVAC Supervisory Controllers (2024) - Hydro Place		149.6					**149.6**
Purchase Tools and Equipment Less than $50,000 (2024) - Labrador Region		120.1					**120.1**
Purchase Tools and Equipment Less than $50,000 (2024) - Northern Region		97.0					**97.0**
Minor Telecommunications Enhancements (2024)		96.9					**96.9**
Purchase Office Equipment Less Than $50,000 (2024)		50.0					**50.0**
Purchase Tools and Equipment Less than $50,000 (2024) - Telecontrol		45.6					**45.6**

Newfoundland and Labrador Hydro
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($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Purchase Tools and Equipment Less than $50,000 (2024) - Gas Turbine		18.6					**18.6**
Upgrade Line Depots (2025-2027) - Bay d'Espoir			320.4	1,514.7	1,400.6		**3,235.7**
Replace East Coast to Central Interconnect Microwave Radios (2025-2027)			100.0	400.0	150.0		**650.0**
Replace Light- and Heavy-Duty Vehicles (2025-2026)			2,000.0	2,000.0			**4,000.0**
Replace Off Road Heavy-Duty Equipment (2025-2026)			500.0	500.0			**1,000.0**
Construct Storage Building (2025-2026) - Springdale			135.0	730.0			**865.0**
Barrier Free Improvements - Washrooms (2025-2026)			428.0	346.5			**774.5**
Install Fire Protection in 230 kV Stations (2025-2026) - Come By Chance			68.0	616.0			**684.0**
Replace SC1/SC2 Overhead Crane (2025-2026) - Wabush Terminal Station			120.0	340.0			**460.0**
Refurbish Control Building (2025-2026)			125.1	310.4			**435.5**
Refurbish Meteorological Sites (2025)			100.0	100.0			**200.0**
Refurbish Office Energy Efficiency and HVAC Systems (2025-2026) - Deer Lake			75.0	100.0			**175.0**
Rehabilitate Access Roads (2025-2026) - Hinds Lake			1,150.0				**1,150.0**
Perform Software Upgrades and Minor Enhancements (2025)			705.0				**705.0**
Purchase Personal Computers (2025)			635.8				**635.8**
Replace Mobile Equipment (2025)			600.0				**600.0**
Upgrade Core OT Infrastructure (2025)			375.0				**375.0**
Upgrade Property (2025) - Bishop's Falls, Whitbourne, St. Anthony			370.0				**370.0**
Install CCTV Systems (2025)			321.3				**321.3**
Replace Diesel/Office/SF6 Roofs (2025) - Cat Arm			275.0				**275.0**
Stabilize Powerhouse Slope - Phase 2 (2025) - Cat Arm			242.3				**242.3**
Update Cyber Security Infrastructure (2025)			225.0				**225.0**
Replace Network Communications Equipment (2025)			215.5				**215.5**
Upgrade Station Access Road (2025) - Buchans, Western Avalon, Sunnyside, Deer Lake			200.0				**200.0**
Replace Peripheral Infrastructure (2025)			190.4				**190.4**
Purchase Tools and Equipment Less than $50,000 (2025) - Central Region			180.0				**180.0**
Upgrade Remote Terminal Units (2025)			168.0				**168.0**
Resurface Parking Lots and Roads (2024) - Bishop's Falls			150.0				**150.0**
Purchase Mobile Devices (2025)			132.0				**132.0**
Upgrade Outside Property (2025) - Deer Lake			129.0				**129.0**
Purchase Tools and Equipment Less than $50,000 (2025) - Northern Region			120.0				**120.0**
Site Physical Security Program (2025)			108.0				**108.0**
Purchase Tools and Equipment Less than $50,000 (2025) - Labrador Region			100.0				**100.0**
Minor Telecommunications Enhancements (2025)			98.8				**98.8**
Telecommunications In-Service Failure (2025)			93.0				**93.0**
Replace Uninterruptible Power Supply Batteries (2025) - Hydro Place			75.0				**75.0**
Purchase Furniture & Equipment Less Than $50,000 (2025)			67.3				**67.3**
Purchase Tools and Equipment Less than $50,000 (2025) - Thermal Plants			50.0				**50.0**
Purchase Tools and Equipment Less than $50,000 (2025)			49.7				**49.7**
Security Improvements Less Than $50,000 (2025)			37.0				**37.0**
Purchase Tools and Equipment Less than $50,000 (2025) - Gas Turbines			20.0				**20.0**
Window Refurbishment/Replacement Program (2026-2028)				1,041.5	1,057.5	1,074.0	**3,173.0**
Replace Light- and Heavy-Duty Vehicles (2026-2027)				2,000.0	2,000.0		**4,000.0**
Install Plant Heating (2028-2029) - Holyrood					519.0	2,500.0	**3,019.0**
Upgrade Synchronous Condenser Building (2026-2027) - Holyrood				200.0	1,000.0		**1,200.0**
Replace Off Road Heavy-Duty Equipment (2026-2027)				500.0	500.0		**1,000.0**
Resurface Access Road and Intake (2026-2027) Paradise River				100.0	861.1		**961.1**
Replace Site Domestic Water System (2026-2027) - Bay d'Espoir				50.0	750.0		**800.0**
Install Fire Protection in 230 kV Stations (2026-2027) - Bottom Brook				68.0	616.0		**684.0**
Refurbish Control Building (2026–2027)				124.9	310.0		**434.9**
Replace Powerhouse Septic System (2026-2027) - Hinds Lake				50.0	227.3		**277.3**
Replace Burnt Dam Septic System (2026-2027) - Bay d'Espoir				50.0	125.0		**175.0**
Replace Back-up Generators at Microwave Repeater Sites (2026-2027)				100.0	50.0		**150.0**
Purchase Personal Computers (2026)				941.5			**941.5**
Perform Software Upgrades and Minor Enhancements (2026)				625.0			**625.0**
Replace Mobile Equipment (2026)				600.0			**600.0**
Replace/Upgrade Fire Suppression System (2026)				508.0			**508.0**
Upgrade Core OT Infrastructure (2026)				375.0			**375.0**
Upgrade Energy Management System (2026) - Hydro Place				355.0			**355.0**
Update Cyber Security Infrastructure (2026)				322.0			**322.0**
Upgrade Property (2026) - Port Saunders, Stephenville, and Happy Valley				300.0			**300.0**
Replace Network Communications Equipment (2026)				222.0			**222.0**
Purchase Mobile Devices (2026)				202.6			**202.6**
Install CCTV Systems (2026)				200.0			**200.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Central Region				180.0			**180.0**
Upgrade Remote Terminal Units (2026)				173.0			**173.0**

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Five-Year Capital Plan - By Investment Classification
($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Replace Peripheral Infrastructure (2026)				172.4			**172.4**
Replace Sewage System (2026) - Bishop's Falls				150.0			**150.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Northern Region				120.0			**120.0**
Site Physical Security Program (2026)				112.0			**112.0**
Minor Telecommunications Enhancements (2026)				101.7			**101.7**
Purchase Tools and Equipment Less than $50,000 (2026) - Labrador Region				100.0			**100.0**
Telecommunications In-Service Failure (2026)				96.0			**96.0**
Replace Walkway to Toe of Dam (2026) - Paradise River				80.0			**80.0**
Purchase Office Equipment Less Than $50,000 (2026)				68.0			**68.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Thermal Plants				50.0			**50.0**
Purchase Tools and Equipment Less than $50,000 (2026)				49.7			**49.7**
Purchase Tools and Equipment Less than $50,000 (2026) - Gas Turbines				20.0			**20.0**
Replace Light- and Heavy-Duty Vehicles (2027-2028)					2,000.0	2,000.0	**4,000.0**
Resurface On-Site Roads (2027-2028) - Bay d'Espoir					100.0	1,400.0	**1,500.0**
Replace Off Road Heavy-Duty Equipment (2027-2028)					500.0	500.0	**1,000.0**
Replace Power Line Carrier (2027-2028) - TL212					93.6	681.4	**775.0**
Replace Powerhouse Roofs (2027-2028) - Hinds Lake					50.0	500.0	**550.0**
Refurbish Control Building (2027-2028)					85.5	219.2	**304.7**
Purchase Personal Computers (2027)					986.6		**986.6**
Replace Roof (2027) - Cartwright					700.0		**700.0**
Perform Software Upgrades and Minor Enhancements (2027)					625.0		**625.0**
Replace Mobile Equipment (2027)					600.0		**600.0**
Upgrade Outside Property (2027) - St. Anthony, Bishop's Falls, Stephenville, and Whitbourne					428.0		**428.0**
Upgrade Core OT Infrastructure (2027)					375.0		**375.0**
Fire System Upgrades (2027)					350.0		**350.0**
Update Cyber Security Infrastructure (2027)					350.0		**350.0**
Replace Peripheral Infrastructure (2027)					269.1		**269.1**
Upgrade Drainage to Stop Frost Heaving (2027) - Stoney Brook, Springdale, Holyrood, Jackson's Arm, and Buchans					250.0		**250.0**
Replace Network Communications Equipment (2027)					229.0		**229.0**
Install CCTV Systems (2027)					212.2		**212.2**
Fire Panel and Device Upgrade (2027)					197.0		**197.0**
Purchase Mobile Devices (2027)					183.4		**183.4**
Purchase Tools and Equipment Less than $50,000 (2027) - Central Region					180.0		**180.0**
Upgrade Remote Terminal Units (2027)					179.0		**179.0**
Replace Cisco Call Manager Appliances					130.0		**130.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Northern Region					120.0		**120.0**
Site Physical Security Program (2027)					116.0		**116.0**
Minor Telecommunications Enhancements (2027)					104.8		**104.8**
Purchase Tools and Equipment Less than $50,000 (2027) - Labrador Region					100.0		**100.0**
Upgrade Software Applications (2027)					100.0		**100.0**
Telecommunications In-Service Failure (2027)					99.0		**99.0**
Purchase Furniture & Equipment Less Than $50,000 (2027)					68.0		**68.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Thermal Plants					50.0		**50.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Telecontrol					49.7		**49.7**
Purchase Tools and Equipment Less than $50,000 (2027) - Gas Turbine					20.0		**20.0**
Replace Light- and Heavy-Duty Vehicles (2028-2029)						2,000.0	**2,000.0**
Upgrade Property (2028)						1,150.0	**1,150.0**
Replace Generators and Associated Switchgear						1,000.0	**1,000.0**
Replace Powerhouse 2 Roof (2028) - Bay d'Espoir						960.0	**960.0**
Perform Software Upgrades and Minor Enhancements (2028)						725.0	**725.0**
Replace Mobile Equipment (2028)						600.0	**600.0**
Replace Off Road Heavy-Duty Equipment (2028-2029)						500.0	**500.0**
Refurbish Rip Rap Material on SD-1 (2028) - North Salmon Dam						450.0	**450.0**
Upgrade Core OT Infrastructure (2028)						425.0	**425.0**
Upgrade Energy Management System (2028)						380.0	**380.0**
Update Cyber Security Infrastructure (2028)						375.0	**375.0**
Purchase Personal Computers (2028)						325.8	**325.8**
Replace Network Communications Equipment (2028)						236.0	**236.0**
Replace Multi-Stack Chiller Level 1 Mechanical Room						200.0	**200.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Central Region						180.0	**180.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Northern Region						120.0	**120.0**
Minor Telecommunications Enhancement (2028)						107.9	**107.9**
Replace Peripheral Infrastructure (2028)						105.9	**105.9**
Refurbish Blue Grass Access Road - Spillway to Dam (2028-2029) - Hinds Lake						100.0	**100.0**
Replace Fuel Tank, Lines, Pumps and Associated Hardware						100.0	**100.0**

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Rehabilitate Access Roads - Powerhouse, Intake, and North Salmon Spillway (2028-2029) - Upper Salmon						100.0	**100.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Labrador Region						100.0	**100.0**
Purchase Furniture & Equipment Less Than $50,000 (2028)						68.0	**68.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Thermal Plants						50.0	**50.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Telecontrol						49.7	**49.7**
Purchase Tools and Equipment Less than $50,000 (2028) - Gas Turbine						20.0	**20.0**
General Plant Total	**6,009.2**	**23,479.1**	**24,584.0**	**17,381.4**	**19,467.4**	**19,302.9**	**110,224.0**
Mandatory							
Replace Terminal Station Lighting (2023-2024)	323.3	594.1					**917.4**
Upgrade Station Lighting (2024-2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon Terminal Stations		91.6	429.0				**520.6**
Refurbish Fuel Oil Storage Tank 4 (2024) - Holyrood		1,920.0					**1,920.0**
Mandatory Total	**323.3**	**2,605.7**	**429.0**				**3,358.0**
Renewal							
Refurbish Ebbegunbaeg Control Structure	9,945.2	2,781.6	4,952.2				**17,679.0**
Diesel Genset Replacement Unit 2012 - L'Anse-Au-Loup	2,853.1	210.2					**3,063.3**
Diesel Genset Replacement Program (2023-2025)	819.1	174.0	1,883.1	250.0			**3,126.2**
Penstock Life Extension - Phase 1 (2023-2025)	2,105.0	13,172.6	35,329.1				**50,606.7**
Terminal Station Renewal Program (2023-2024)	1,733.7	5,584.5					**7,318.2**
Purchase and Replace Last Stage Blades - Holyrood Units 1 and 2	3,596.5	2,812.2					**6,408.7**
Circuit Breakers Renewal Program (2023-2024)	216.9	3,595.1					**3,812.0**
Refurbish Superstructure (2023-2024) - Salmon River Spillway	328.3	2,500.0					**2,828.3**
Replace Powerhouse Station Service Panel (2023-2024) - Upper Salmon	591.8	976.7					**1,568.5**
Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) - Wabush Terminal Station	577.2	516.1					**1,093.3**
Replace Diesel Genset 1 (2023-2024) - Ebbegunbaeg	298.0	728.3					**1,026.3**
Replace Power Line Carrier (2023–2024) - TL223 and TL224	105.3	852.4					**957.7**
Replace Intermediate Fuel Storage Tanks (2023-2024) - Nain	127.4	593.7					**721.1**
Replace Oil Mist Separator (2023-2024) - Happy Valley Gas Turbine	138.5	262.1					**400.6**
Install Breaker Failure Protection (2023-2024) - Sunnyside	73.5	216.2					**289.7**
Replace Circuit Breaker Reclosing Controllers (2023-2024) - Hardwoods	81.6	149.6					**231.2**
Replace Data Alarm System Annunciators (2023) - Buchans	61.2	104.8					**166.0**
Replace Diesel Gensets (2024-2026)		535.8	478.0	3,902.3			**4,916.1**
Upgrade Power Transformers (2024-2025)		864.6	2,711.3				**3,575.9**
Replace Protective Relays (2024–2025)		1,388.4	2,050.7				**3,439.1**
Refurbish Intake 1 (2024-2025) - Bay d'Espoir		272.1	3,071.9				**3,344.0**
Flatten Downstream Slope (2024-2025) - Hinds Lake		276.1	2,953.4				**3,229.5**
Renew Circuit Breakers (2024–2025)		183.9	2,779.3				**2,963.2**
Renew Distribution Feeders (2024-2025)		1,287.3	1,245.1				**2,532.4**
Refurbish Surge Tank 1 (2024-2025) - Bay d'Espoir		175.8	2,111.4				**2,287.2**
Replace Disconnects (2024–2025)		127.4	1,358.1				**1,485.5**
Replace Instrument Transformers (2024–2025)		154.9	714.8				**869.7**
Replace Power Line Carrier (2024-2025) - TL247		87.2	667.4				**754.6**
Upgrade Unit 1 Control System (2024-2025) - Holyrood		468.3	184.3				**652.6**
Replace Annunciator - Phase 2 (2024-2025) - Bay d'Espoir		294.1	187.5				**481.6**
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood		195.2	277.3				**472.5**
Upgrade Distribution (2024-2025) - Bay d'Espoir Terminal Station 2		93.2	331.5				**424.7**
Upgrade UPS 1 & 2 (2024-2025) - Holyrood		263.0	107.6				**370.6**
Replace Annunciator Panels (2024-2025) - Cat Arm		160.2	191.2				**351.4**
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247		112.4	215.8				**328.2**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station		137.0	156.9				**293.9**
Replace Terminal Station Battery Banks and Chargers (2024–2025)		71.8	120.9				**192.7**
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood		5,181.4					**5,181.4**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)		4,345.4					**4,345.4**
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood		3,957.8					**3,957.8**
Wood Pole Line Management (2024)		3,765.2					**3,765.2**
Thermal In-Service Failures (2024)		3,508.7					**3,508.7**
Hydraulic In-Service Failures (2024)		1,500.0					**1,500.0**
Terminal Station In-Service Failures (2024)		1,300.0					**1,300.0**
Overhaul Diesel Units (2024)		829.2					**829.2**
Inspect Fuel Tanks (2024) - Hardwoods Gas Turbines		692.9					**692.9**
Overhaul Pumps (2024) - Holyrood		661.0					**661.0**
Overhaul Marine Terminal Loading Arms (2024) - Holyrood		511.0					**511.0**
Diesel In-Service Failures (2024)		488.3					**488.3**
Replace 48 V Battery Banks and Chargers (2024)		422.2					**422.2**
Penstock Level II Condition Assessment (2024) - Upper Salmon		382.8					**382.8**
Gas Turbine In-Service Failures (2024)		358.0					**358.0**
Overhaul Hydraulic Units (2024)		323.8					**323.8**

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Upgrade Remote Terminal Units (2024)		165.9					**165.9**
Replace Timber Crib and Insulation (2024) - Burnt Dam Spillway		161.8					**161.8**
Transmission In-Service Failures (2024)		158.5					**158.5**
Purchase Mobile Devices (2024)		155.6					**155.6**
Telecommunications In-Service Failure (2024)		91.4					**91.4**
Replace Controllers (2025-2028) - Granite Canal			500.0	500.0	500.0	500.0	**2,000.0**
Replace Protective Relays (2025-2026)			1,250.0	2,250.0			**3,500.0**
Upgrade Power Transformers (2025–2026)			114.0	2,599.0			**2,713.0**
Renew Distribution Feeders (2025-2026)			1,287.3	1,245.1			**2,532.4**
Refurbish Intake 2 (2025-2026) - Bay d'Espoir			500.0	2,000.0			**2,500.0**
Rewedge Stator (2025-2026) - Hinds Lake			1,500.0	750.0			**2,250.0**
Renew Circuit Breakers (2025-2026)			531.8	1,709.6			**2,241.4**
Replace Telecontrol Building and Upgrade Equipment (2025-2026) - Daniel's Harbour			408.7	1,505.2			**1,913.9**
Replace Diesel Gensets (2025-2026)			200.0	1,400.0			**1,600.0**
Refurbish Stage I & II Cooling Water Pumphouses (2025-2026) - Holyrood			670.0	700.0			**1,370.0**
Replace Disconnects (2025-2026)			439.2	815.7			**1,254.9**
Marine Terminal Upgrades (2025) - Holyrood			200.0	800.0			**1,000.0**
Upgrade Cooling (2025-2026) - Hardwoods Gas Turbine			200.0	800.0			**1,000.0**
Replace T1 Burgeo Substation (2025-2026)			200.0	600.0			**800.0**
Replace Circuit Breaker Reclosing Controller (2025-2026) - Sunnyside			54.0	710.0			**764.0**
Replace Rectifier Transformer (2025-2026) - Hinds Lake			510.0	250.0			**760.0**
Replace Switchgear Synchronous Condensers 1 and 2 (2025-2026) - Wabush Terminal Station			50.0	700.0			**750.0**
Refurbish Needle Valve Assembly Unit 2 and Purchase Spare Needle (2025-2026) - Cat Arm			100.0	600.0			**700.0**
Replace Instrument Transformers (2025-2026)			420.0	280.0			**700.0**
Refurbish Unit Control Panels Unit 2 (2025-2026) - Cat Arm			100.0	570.0			**670.0**
Inspect Fuel Tanks (2025-2026) - Happy Valley Gas Turbine			100.0	500.0			**600.0**
Refurbish Spherical Valves Units 1 and 2 (2025) - Cat Arm			200.0	350.0			**550.0**
Install Breaker Failure Protection (2025–2026) - Holyrood TS			135.0	315.0			**450.0**
Replace Unit Annunciator (2025-2026) - Hinds Lake			150.0	240.0			**390.0**
Replace Terminal Station Battery Banks and Chargers (2025-2026)			210.0	140.0			**350.0**
Replace Annunciator Panel (2025-2026) Upper Salmon			150.0	200.0			**350.0**
Replace Switchgear (2025-2026) - Grand Falls Terminal Station			50.0	300.0			**350.0**
Upgrade Data Alarm Systems (2025-2026) - Hardwoods			120.0	180.0			**300.0**
Replace Station Service Transformer 1 (2025-2026) - Bay d'Espoir			200.0	100.0			**300.0**
Synchronous Condenser 2 Major Inspection (2025-2026) - Wabush Terminal Station			40.0	240.0			**280.0**
Replace Cooling Water Pumps (2025-2026) - Cat Arm			50.0	200.0			**250.0**
Replace Powerhouse Septic System (2025-2026) - Upper Salmon			50.0	200.0			**250.0**
Replace Emergency Diesel Generator (2025-2026) - Cat Arm			50.0	170.0			**220.0**
Turbine and Valve Overhaul - Unit 3 (2025) - Holyrood			11,444.7				**11,444.7**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2025)			4,454.0				**4,454.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood			3,750.0				**3,750.0**
Thermal In-Service Failures (2025)			3,450.0				**3,450.0**
Wood Pole Line Management (2025)			2,446.0				**2,446.0**
Hydraulic In-Service Failures (2025)			1,569.0				**1,569.0**
Overhaul Diesel Units (2025)			1,500.0				**1,500.0**
Terminal Station In-Service Failures (2025)			1,387.1				**1,387.1**
Unit 1 and Unit 2 Major Refurbishment (2025) - Bay d'Espoir			1,000.0				**1,000.0**
Inspect Fuel Storage Tanks (2025) - MacCallum			1,000.0				**1,000.0**
Refurbish Draft Tube Deck - Phase 3 (2025) - Bay d'Espoir			855.0				**855.0**
Unit 1 & 2 Spherical Valve Overhaul (2025) - Bay d'Espoir			750.0				**750.0**
Inspect Fuel Tanks (2025) - Hardwoods Gas Turbine			682.0				**682.0**
Overhaul Hydraulic Units (2025)			600.0				**600.0**
Diesel In-Service Failures (2025)			489.5				**489.5**
Replace 48 V Battery Banks and Chargers (2025)			428.3				**428.3**
Intake 4 Level II Condition Assessment (2025) - Bay d'Espoir			400.0				**400.0**
Gas Turbine In-Service Failures (2025)			376.0				**376.0**
Major Pump Overhaul (2025) - Holyrood			350.0				**350.0**
Replace Flow Measuring Devices Units 1 to 7 (2025) - Bay d'Espoir			349.6				**349.6**
Penstock Level II Condition Assessment (2025) - Granite Canal			200.0				**200.0**
Transmission In-Service Failures (2025)			162.0				**162.0**
Purchase Tools and Equipment Less than $50,000 (2025) - Hydraulic Plants			100.0				**100.0**
Level II Condition Assessment Powerhouse Roof (2025) - Hinds Lake			100.0				**100.0**
Telecommunications Tower Condition Management (2025)			93.0				**93.0**
Steel-Tower Transmission Line Renewal (2026-2032)				5,000.0	24,595.0	36,233.0	**65,828.0**
Penstock Life Extension - Phase 2 (2026-2028)				1,900.0	8,200.0	10,000.0	**20,100.0**
Major Inspection Gas Turbine (2026-2027) - Holyrood Gas Turbine				7,500.0	7,500.0		**15,000.0**

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Upgrade Synchronous Condenser Building (2026-2027) - Holyrood				200.0	4,600.0		**4,800.0**
Renew Distribution Feeders (2026-2027)				1,287.3	1,245.1		**2,532.4**
Replace Protective Relays (2026-2027)				850.0	1,350.0		**2,200.0**
Replace T2 St. Anthony Diesel Plant Terminal Station (2026-2027)				500.0	1,500.0		**2,000.0**
Upgrade Power Transformers (2026–2027)				89.0	1,837.0		**1,926.0**
Renew Circuit Breakers (2026-2027)				406.0	794.0		**1,200.0**
Replace Disconnects (2026-2027)				348.3	646.8		**995.1**
Upgrade Cranes and Hoists (2026-2027) - Holyrood				200.0	300.0		**500.0**
Replace Instrument Transformers (2026-2027)				290.0	200.0		**490.0**
Install Breaker Failure Protection (2026-2027) - Hardwoods				135.0	315.0		**450.0**
Refurbish Spherical Valves Unit 5 (2026-2027) - Bay d'Espoir				100.0	275.0		**375.0**
Replace Terminal Station Battery Banks and Chargers (2026-2027)				190.0	130.0		**320.0**
Replace Burnt Dam Diesel Fuel Tanks 2 and 3 (2026-2027) - Bay d'Espoir				50.0	250.0		**300.0**
Synchronous Condenser 1 Major Inspection (2026-2027) - Wabush Terminal Station				40.0	240.0		**280.0**
Upgrade Data Alarm System (2026–2027) - Springdale and Indian River Terminal Stations				50.0	80.0		**130.0**
Replace Circuit Breaker Reclosing Controllers (2026-2027) - Holyrood				54.0	71.0		**125.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2026)				4,565.0			**4,565.0**
Wood Pole Line Management (2026)				4,386.0			**4,386.0**
Overhaul Unit 2 Turbine Valves				3,873.0			**3,873.0**
Thermal In-Service Failures (2026)				3,528.0			**3,528.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2026)				3,500.0			**3,500.0**
Overhaul Unit 2 Generator				1,839.0			**1,839.0**
Hydraulic In-Service Failures (2026)				1,604.0			**1,604.0**
Overhaul Diesel Units (2026)				1,500.0			**1,500.0**
Terminal Station In-Service Failures (2026)				1,480.0			**1,480.0**
Overhaul Hydraulic Units (2026)				1,425.0			**1,425.0**
Major Pump Overhaul (Unit 1 WBFP, Unit 1 ECWP, Unit 1 SCEP, Unit 2 SCEP, Unit 3 WBFP)				1,400.0			**1,400.0**
Upgrade Water Treatment Plant and Waste Water Treatment Plant - Holyrood				1,000.0			**1,000.0**
Refurbish Rip Rap Material on Pudops Dam MD-2 (2026) - Bay d'Espoir				800.0			**800.0**
Replace Parts of Unit 3: 129 Vdc Battery Chargers, Batteries, Panels, and Breakers (2026) - Holyrood				750.0			**750.0**
Inspect Fuel Storage Tanks (2026) - Rigolet				650.0			**650.0**
Refurbish Air Intake (2026) - Happy Valley Gas Turbine				600.0			**600.0**
Diesel In-Service Failures (2026)				490.0			**490.0**
Replace 48 V Battery Banks and Chargers (2026)				441.1			**441.1**
North Salmon Spillway Level II Condition Assessment (2026) - Upper Salmon				400.0			**400.0**
Gas Turbine In-Service Failures (2026)				395.0			**395.0**
Inspect Stacks (2026) - Holyrood				250.0			**250.0**
Penstock Level II Condition Assessment- Steel Liner (2026) - Cat Arm				200.0			**200.0**
Penstock Level II Condition Assessment (2026) - Hind's Lake				200.0			**200.0**
Transmission In-Service Failures (2026)				166.0			**166.0**
Level II Condition Assessment Powerhouse 2 Roof (2026) - Bay d'Espoir				100.0			**100.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Hydraulic Plants				100.0			**100.0**
Telecommunications Tower Condition Management (2026)				96.0			**96.0**
Replace Batteries				75.0			**75.0**
Replace Air Dryer				50.0			**50.0**
Replace DC Fuel Pumps				50.0			**50.0**
Replace Transformer T3 (2027-2028) - Wabush Terminal Station					1,254.0	4,959.0	**6,213.0**
Unit 7 Major Refurbishment Turbine & Generator (2027-2029) - Bay d'Espoir					500.0	5,000.0	**5,500.0**
Replace Transformer T3 (2027-2028) - Bay d'Espoir					900.0	1,900.0	**2,800.0**
Renew Distribution Feeders (2027-2028)					1,287.3	1,245.1	**2,532.4**
Replace Protective Relays (2027-2028)					900.0	1,400.0	**2,300.0**
Inspect and Upgrade Light Oil System - Holyrood					200.0	800.0	**1,000.0**
Replace Disconnects (2027-2028)					311.5	578.5	**890.0**
Upgrade Power Transformers (2027–2028)					71.0	816.0	**887.0**
Refurbish Spherical Valves Units 2 and 4 (2027-2028) - Bay d'Espoir					200.0	550.0	**750.0**
Replace Instrument Transformers (2027-2028)					360.0	240.0	**600.0**
Install Breaker Failure Protection (2027-2028) - Western Avalon					135.0	315.0	**450.0**
Replace Glycol Cooler Coil (2027-2028) - Happy Valley Gas Turbine					50.0	250.0	**300.0**
Replace Fuel Pumps (2027) - Hardwoods					100.0	100.0	**200.0**
Upgrade Data Alarm Systems (2027-2028) - Grand Falls Frequency Converter					60.0	90.0	**150.0**
Replace Terminal Station Battery Banks and Chargers (2027-2028)					90.0	60.0	**150.0**
Replace Circuit Breaker Reclosing Controllers (2027-2028) - Roddickton					54.0	71.0	**125.0**
Wood Pole Line Management (2027)					4,767.0		**4,767.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2027)					4,167.0		**4,167.0**
Overhaul Unit 1 Turbine Valves - Holyrood					4,066.7		**4,066.7**
Thermal In-Service Failures (2027)					3,607.0		**3,607.0**

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Boiler Condition Assessment and Miscellaneous Upgrades (2027)					3,500.0		**3,500.0**
Overhaul Unit 3 Generator and Upgrade Online Monitoring (2027) - Holyrood					1,930.9		**1,930.9**
Hydraulic In-Service Failures (2027)					1,640.0		**1,640.0**
Terminal Station In-Service Failures (2027)					1,579.2		**1,579.2**
Overhaul Diesel Units (2027)					1,500.0		**1,500.0**
Upgrade Unit 3 Synchronous Condenser Cooling Water Systems H2, Generator Lube Oil, and Seal Oil (2027) - Holyrood					1,500.0		**1,500.0**
Major Pump Overhaul (Unit 1 NCEP, Unit 1 EBFP, Unit 3 SCEP, Unit 3 EBFP)					1,200.0		**1,200.0**
Upgrade Wastewater Basin and Underground Drainage (2027) - Holyrood					1,000.0		**1,000.0**
Overhaul Hydraulic Units (2027)					550.0		**550.0**
Overhaul Marine Terminal Loading Arms					550.0		**550.0**
Diesel In-Service Failures (2027)					495.0		**495.0**
Replace 48 V Battery Banks and Chargers (2027)					454.4		**454.4**
Gas Turbine In-Service Failures (2027)					414.0		**414.0**
West Salmon Spillway Level II Condition Assessment (2027) - Upper Salmon					400.0		**400.0**
Inspect Fuel Storage Tanks (2027) - Hawke's Bay					300.0		**300.0**
Penstock Level II Condition Assessment (2027) - Paradise River					200.0		**200.0**
Transmission In-Service Failures (2027)					170.0		**170.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Hydraulic Plants					100.0		**100.0**
Telecommunications Tower Condition Management (2027)					99.0		**99.0**
Major Inspection (2028) - Holyrood Gas Turbine						7,500.0	**7,500.0**
Distribution System In-Service Failures, Miscellaneous Upgrades and Street Lights (2028)						4,284.0	**4,284.0**
Overhaul Unit 3 Turbine Valves						4,270.0	**4,270.0**
Thermal In-Service Failures (2028)						3,686.0	**3,686.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2028)						3,500.0	**3,500.0**
Wood Pole Line Management (2028)						2,474.0	**2,474.0**
Overhaul Diesel Units (2028)						2,250.0	**2,250.0**
Renew Circuit Breakers (2028-2029)						2,100.0	**2,100.0**
Terminal Station In-service Failures (2028)						1,685.0	**1,685.0**
Hydraulic In Service Failures (2028)						1,677.0	**1,677.0**
Renew Distribution Feeders (2028-2029)						1,287.3	**1,287.3**
Replace Diesel Gensets (2028)						1,000.0	**1,000.0**
Replace Station Service (2028) - Hind's Lake						900.0	**900.0**
Replace Protective Relays (2028-2029)						800.0	**800.0**
Overhaul Hydraulic Units (2028)						600.0	**600.0**
Diesel In-Service Failures (2028)						500.0	**500.0**
Major Refurbishment Turbine & Generator (2028-2029) - Upper Salmon						500.0	**500.0**
Replace 48 V Battery Banks and Chargers (2028)						468.0	**468.0**
Major Pump Overhaul (Unit 2 NCEP, Unit 2 ECWP)						450.0	**450.0**
Gas Turbine In-Service Failures (2028)						435.0	**435.0**
Replace Disconnects (2028-2029)						370.0	**370.0**
Replace Equipment Foundations (2028-2029)						280.0	**280.0**
Upgrade Drainage to Stop Frost Heaving (2028) - Stoney Brook, Springdale, Holyrood, Jackson's Arm, Buchan's Terminal Stations						250.0	**250.0**
Replace Instrument Transformers (2028-2029)						250.0	**250.0**
Install CCTV Cameras (2028)						218.5	**218.5**
Upgrade Remote Terminal Units (2028)						184.0	**184.0**
Transmission In-Service Failures (2028)						174.0	**174.0**
Replace Terminal Station Battery Banks and Chargers (2028-2029)						150.0	**150.0**
Purchase Mobile Devices (2028)						144.0	**144.0**
Condition Assessment of doors siding and roofing						120.0	**120.0**
Telecommunications In-Service Failure (2028)						102.0	**102.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Hydraulic Plants						100.0	**100.0**
Upgrade Data Alarm Systems (2028-2029)						100.0	**100.0**
Refurbish Spherical Valves Unit 3 (2028-2029) - Bay d'Espoir						100.0	**100.0**
Refurbish CD4 Rip Rap (2028) - Cat Arm						100.0	**100.0**
Upgrade Power Transformers (2028-2029)						90.0	**90.0**
Upgrade Reclosing Circuit Breakers (2028-2029) - Berry Hill						54.0	**54.0**
Renewal Total	**23,652.3**	**71,339.7**	**112,755.0**	**83,174.6**	**95,291.9**	**108,260.4**	**494,473.9**
Service Enhancement							
Replace Metering System	4,881.2	994.6					**5,875.8**
Long-Term Supply for Southern Labrador - Phase 1	1,835.0	17,812.0	40,116.3	23,327.6	3,304.3		**86,395.2**
Upgrade of Worst-Performing Distribution Feeders (2023-2024)	73.4	1,372.6					**1,446.0**
Install Oil Spill Containment Transformer T1S (2023-2024) - Cat Arm	155.1	426.5					**581.6**
[]	-	-	-				**-**
Purchase Spare Generator Step-Up Transformer	722.9	3,420.4	3,643.0				**7,786.3**
Automate Bulk Metering (2024-2026)		302.6	214.4	235.3			**752.3**
Upgrade Worst-Performing Distribution Feeders (2024-2025)		1,064.3	2,227.4				**3,291.7**

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	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Construct Maintenance Platform (2024-2025) - Holyrood Gas Turbine		130.5	228.7				**359.2**
Upgrade Instrumentation (2024-2025) - Hardwoods Gas Turbine		60.9	157.2				**218.1**
Remove Safety Hazards (2024)		198.3					**198.3**
Install Anemometer (2024) - Cat Arm		68.6					**68.6**
Upgrade Worst-Performing Distribution Feeders (2025-2026)			480.3	2,720.0			**3,200.3**
Install Fire Barriers between T10 and T12, T10 and T11 (2025-2026) 2			220.4	1,108.6			**1,329.0**
Upgrade Terminal Station for Mobile Substation (2025-2026)2			147.7	1,105.0			**1,252.7**
Construct Fire Separation Walls between Transformers (2025-2026) 2			54.8	773.9			**828.7**
TL220 Install Mid Span Poles (2025-2026)			150.0	600.0			**750.0**
Install Dynamic Air Gap Monitoring System (2025-2026) - Hinds Lake			100.0	403.0			**503.0**
Upgrade Terminal Station for Mobile Substation (2025-2026) 2			60.0	400.0			**460.0**
Distribution Equipment SCADA Additions (2025-2026)			30.0	270.0			**300.0**
Install Secondary Station Service Supply (2025-2026) - Holyrood Gas Turbine			50.0	250.0			**300.0**
Install Asset Health Monitoring System (2025-2026) - Cat Arm			150.0	150.0			**300.0**
Install Remote Fuel Monitoring on Gasoline Fuel Tank (2025-2026) - Granite Canal			150.0	100.0			**250.0**
Install New Station Service Feed (2025-2026) - Berry Hill			50.0	150.0			**200.0**
Upgrade Transformer Paralleling (2025-2026) - Stoney Brook			36.0	54.0			**90.0**
Remove Safety Hazards (2025)			208.0				**208.0**
Upgrade Worst-Performing Distribution Feeders (2026-2027)				480.3	2,720.0		**3,200.3**
Install Fire Barriers between Substation and T1, T2, and T3 (2026-2027) 2				39.1	731.5		**770.6**
TL220 Relocate Section of Line (2026-2027)				150.0	600.0		**750.0**
Upgrade Excitation System (2026-2027) - Paradise River				250.0	250.0		**500.0**
Upgrade Terminal Station for Mobile Substation (2026–2027) - St. Anthony Diesel				60.0	400.0		**460.0**
Distribution Equipment SCADA Additions (2026-2027)				30.0	270.0		**300.0**
Upgrade Transformer Paralleling (2026-2027) - Sunnyside				36.0	54.0		**90.0**
Remove Safety Hazards (2026)				213.0			**213.0**
Upgrade Worst-Performing Distribution Feeders (2027-2028)					480.3	2,720.0	**3,200.2**
Upgrade Terminal Station for Mobile Substation (2027-2028) - Glenburnie					60.0	400.0	**460.0**
Distribution Equipment SCADA Additions (2027-2028)					30.0	270.0	**300.0**
Upgrade Transformer Paralleling (2027-2028) - Bottom Brook					36.0	54.0	**90.0**
Remove Safety Hazards (2027)					218.0		**218.0**
Upgrade Rotor (2028-2029) - Holyrood Gas Turbine						2,000.0	**2,000.0**
Upgrade Worst-Performing Distribution Feeders (2028-2029)						480.3	**480.3**
Remove Safety Hazards (2028)						200.0	**200.0**
Upgrade Terminal Station for Mobile Substation (2028-2029) - Roddickton						60.0	**60.0**
Upgrade Transformer Paralleling (2028-2029) - Bay d'Espoir Terminal Station 2						36.0	**36.0**
Distribution Equipment SCADA Additions (2028-2029)						30.0	**30.0**
Service Enhancement Total	**7,667.6**	**25,851.3**	**48,474.2**	**32,905.8**	**9,154.0**	**6,250.2**	**130,303.1**
System Growth							
Additions for Load - Wabush Substation Upgrades	7,439.7	2,739.9	514.5				**10,694.1**
Wabush Terminal Station Upgrades	8,870.1	3,808.0					**12,678.1**
Additions for Load Growth - Upgrade Transformer Capacity (2023-2024) - Jean Lake Terminal Station	580.0	-	5,436.1				**6,016.1**
Additions for Load Growth - Distribution System - Labrador City Duley Lake, Walsh River, and Landfill Sites (2024-2025)		37.9	191.3				**229.2**
Additions for Load (2025) - Distribution System			1,000.0				**1,000.0**
Additions for Load Growth - Isolated Generation Stations (2025)			650.0				**650.0**
Additions for Load (2026) - Distribution System				1,000.0			**1,000.0**
Additions for Load Growth - Isolated Generation Stations (2026)				650.0			**650.0**
Additions for Load Growth - Isolated Generation Stations (2027)					1,500.0		**1,500.0**
Additions for Load (2027) - Distribution System					1,000.0		**1,000.0**
Additions for Load Growth - Isolated Generation Stations (2028)						650.0	**650.0**
System Growth Total	**16,889.8**	**6,585.8**	**7,791.9**	**1,650.0**	**2,500.0**	**650.0**	**36,067.5**
Total Capital Plan	**54,542.2**	**135,604.3**	**199,878.6**	**141,204.3**	**132,609.8**	**140,529.0**	**804,368.2**

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Five-Year Capital Plan - By Asset Category
($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Generation							
Gas Turbines							
Replace Oil Mist Separator (2023-2024) - Happy Valley Gas Turbine	138.5	262.1					**400.6**
Construct Maintenance Platform (2024-2025) - Holyrood Gas Turbine		130.5	228.7				**359.2**
Upgrade Instrumentation (2024-2025) - Hardwoods Gas Turbine		60.9	157.2				**218.1**
Inspect Fuel Tanks (2024) - Hardwoods Gas Turbines		692.9					**692.9**
Gas Turbine In-Service Failures (2024)		358.0					**358.0**
Upgrade Cooling (2025-2026) - Hardwoods Gas Turbine			200.0	800.0			**1,000.0**
Inspect Fuel Tanks (2025-2026) - Happy Valley Gas Turbine			100.0	500.0			**600.0**
Install Secondary Station Service Supply (2025-2026) - Holyrood Gas Turbine			50.0	250.0			**300.0**
Inspect Fuel Tanks (2025) - Hardwoods Gas Turbine			682.0				**682.0**
Gas Turbine In-Service Failures (2025)			376.0				**376.0**
Major Inspection Gas Turbine (2026-2027) - Holyrood Gas Turbine				7,500.0	7,500.0		**15,000.0**
Refurbish Air Intake (2026) - Happy Valley Gas Turbine				600.0			**600.0**
Gas Turbine In-Service Failures (2026)				395.0			**395.0**
Replace Batteries				75.0			**75.0**
Replace Air Dryer				50.0			**50.0**
Replace DC Fuel Pumps				50.0			**50.0**
Replace Glycol Cooler Coil (2027-2028) - Happy Valley Gas Turbine					50.0	250.0	**300.0**
Replace Fuel Pumps (2027) - Hardwoods					100.0	100.0	**200.0**
Gas Turbine In-Service Failures (2027)					414.0		**414.0**
Major Inspection (2028) - Holyrood Gas Turbine						7,500.0	**7,500.0**
Upgrade Rotor (2028-2029) - Holyrood Gas Turbine						2,000.0	**2,000.0**
Gas Turbine In-Service Failures (2028)						435.0	**435.0**
Total	**138.5**	**1,504.4**	**1,793.9**	**10,220.0**	**8,064.0**	**10,285.0**	**32,005.8**
Hydraulic Plant							
Refurbish Ebbegunbaeg Control Structure	9,945.2	2,781.6	4,952.2				**17,679.0**
Penstock Life Extension - Phase 1 (2023-2025)	2,105.0	13,172.6	35,329.1				**50,606.7**
Refurbish Superstructure (2023-2024) - Salmon River Spillway	328.3	2,500.0					**2,828.3**
Replace Powerhouse Station Service Panel (2023-2024) - Upper Salmon	591.8	976.7					**1,568.5**
Replace Diesel Genset 1 (2023-2024) - Ebbegunbaeg	298.0	728.3					**1,026.3**
Water System Condition Assessment and Upgrades (2023) - Bay d'Espoir	161.0	504.9					**665.9**
Refurbish Intake 1 (2024-2025) - Bay d'Espoir		272.1	3,071.9				**3,344.0**
Flatten Downstream Slope (2024-2025) - Hinds Lake		276.1	2,953.4				**3,229.5**
Refurbish Surge Tank 1 (2024-2025) - Bay d'Espoir		175.8	2,111.4				**2,287.2**
Replace Powerhouse 1 Roof (2024-2025) - Bay d'Espoir		140.2	1,819.2				**1,959.4**
Replace Annunciator - Phase 2 (2024-2025) - Bay d'Espoir		294.1	187.5				**481.6**
Replace Annunciator Panels (2024-2025) - Cat Arm		160.2	191.2				**351.4**
Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir		57.8	231.2				**289.0**
Hydraulic In-Service Failures (2024)		1,500.0					**1,500.0**
Penstock Level II Condition Assessment (2024) - Upper Salmon		382.8					**382.8**
Overhaul Hydraulic Units (2024)		323.8					**323.8**
Replace Timber Crib and Insulation (2024) - Burnt Dam Spillway		161.8					**161.8**
Install Anemometer (2024) - Cat Arm		68.6					**68.6**
Replace Controllers (2025-2028) - Granite Canal			500.0	500.0	500.0	500.0	**2,000.0**
Refurbish Intake 2 (2025-2026) - Bay d'Espoir			500.0	2,000.0			**2,500.0**
Rewedge Stator (2025-2026) - Hinds Lake			1,500.0	750.0			**2,250.0**
Replace Rectifier Transformer (2025-2026) - Hinds Lake			510.0	250.0			**760.0**
Refurbish Needle Valve Assembly Unit 2 and Purchase Spare Needle (2025-2026) - Cat Arm			100.0	600.0			**700.0**
Refurbish Unit Control Panels Unit 2 (2025-2026) - Cat Arm			100.0	570.0			**670.0**
Refurbish Spherical Valves Units 1 and 2 (2025) - Cat Arm			200.0	350.0			**550.0**
Install Dynamic Air Gap Monitoring System (2025-2026) - Hinds Lake			100.0	403.0			**503.0**
Replace Unit Annunciator (2025-2026) - Hinds Lake			150.0	240.0			**390.0**
Replace Annunciator Panel (2025-2026) Upper Salmon			150.0	200.0			**350.0**
Install Asset Health Monitoring System (2025-2026) - Cat Arm			150.0	150.0			**300.0**
Replace Station Service Transformer 1 (2025-2026) - Bay d'Espoir			200.0	100.0			**300.0**
Replace Cooling Water Pumps (2025-2026) - Cat Arm			50.0	200.0			**250.0**
Replace Powerhouse Septic System (2025-2026) - Upper Salmon			50.0	200.0			**250.0**
Install Remote Fuel Monitoring on Gasoline Fuel Tank (2025-2026) - Granite Canal			150.0	100.0			**250.0**
Replace Emergency Diesel Generator (2025-2026) - Cat Arm			50.0	170.0			**220.0**
Hydraulic In-Service Failures (2025)			1,569.0				**1,569.0**
Rehabilitate Access Roads (2025-2026) - Hinds Lake			1,150.0				**1,150.0**
Unit 1 and Unit 2 Major Refurbishment (2025) - Bay d'Espoir			1,000.0				**1,000.0**
Refurbish Draft Tube Deck - Phase 3 (2025) - Bay d'Espoir			855.0				**855.0**
Unit 1 & 2 Spherical Valve Overhaul (2025) - Bay d'Espoir			750.0				**750.0**
Overhaul Hydraulic Units (2025)			600.0				**600.0**
Intake 4 Level II Condition Assessment (2025) - Bay d'Espoir			400.0				**400.0**
Replace Flow Measuring Devices Units 1 to 7 (2025) - Bay d'Espoir			349.6				**349.6**
Replace Diesel/Office/SF6 Roofs (2025) - Cat Arm			275.0				**275.0**
Stabilize Powerhouse Slope - Phase 2 (2025) - Cat Arm			242.3				**242.3**
Penstock Level II Condition Assessment (2025) - Granite Canal			200.0				**200.0**
Level II Condition Assessment Powerhouse Roof (2025) - Hinds Lake			100.0				**100.0**
Penstock Life Extension - Phase 2 (2026-2028)				1,900.0	8,200.0	10,000.0	**20,100.0**
Resurface Access Road and Intake (2026-2027) Paradise River				100.0	861.1		**961.1**
Replace Site Domestic Water System (2026-2027) - Bay d'Espoir				50.0	750.0		**800.0**
Upgrade Excitation System (2026-2027) - Paradise River				250.0	250.0		**500.0**
Refurbish Spherical Valves Unit 5 (2026-2027) - Bay d'Espoir				100.0	275.0		**375.0**
Replace Burnt Dam Diesel Fuel Tanks 2 and 3 (2026-2027) - Bay d'Espoir				50.0	250.0		**300.0**
Replace Powerhouse Septic System (2026-2027) - Hinds Lake				50.0	227.3		**277.3**
Replace Burnt Dam Septic System (2026-2027) - Bay d'Espoir				50.0	125.0		**175.0**
Hydraulic In-Service Failures (2026)				1,604.0			**1,604.0**
Overhaul Hydraulic Units (2026)				1,425.0			**1,425.0**
Refurbish Rip Rap Material on Pudops Dam MD-2 (2026) - Bay d'Espoir				800.0			**800.0**
North Salmon Spillway Level II Condition Assessment (2026) - Upper Salmon				400.0			**400.0**
Penstock Level II Condition Assessment (2026) - Hind's Lake				200.0			**200.0**

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	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Penstock Level II Condition Assessment- Steel Liner (2026) - Cat Arm				200.0			**200.0**
Level II Condition Assessment Powerhouse 2 Roof (2026) - Bay d'Espoir				100.0			**100.0**
Replace Walkway to Toe of Dam (2026) - Paradise River				80.0			**80.0**
Unit 7 Major Refurbishment Turbine & Generator (2027-2029) - Bay d'Espoir					500.0	5,000.0	**5,500.0**
Resurface On-Site Roads (2027-2028) - Bay d'Espoir					100.0	1,400.0	**1,500.0**
Refurbish Spherical Valves Units 2 and 4 (2027-2028) - Bay d'Espoir					200.0	550.0	**750.0**
Replace Powerhouse Roofs (2027-2028) - Hinds Lake					50.0	500.0	**550.0**
Hydraulic In-Service Failures (2027)					1,640.0		**1,640.0**
Overhaul Hydraulic Units (2027)					550.0		**550.0**
West Salmon Spillway Level II Condition Assessment (2027) - Upper Salmon					400.0		**400.0**
Penstock Level II Condition Assessment (2027) - Paradise River					200.0		**200.0**
Hydraulic In Service Failures (2028)						1,677.0	**1,677.0**
Replace Powerhouse 2 Roof (2028) - Bay d'Espoir						960.0	**960.0**
Replace Station Service (2028) - Hind's Lake						900.0	**900.0**
Overhaul Hydraulic Units (2028)						600.0	**600.0**
Major Refurbishment Turbine & Generator (2028-2029) - Upper Salmon						500.0	**500.0**
Refurbish Rip Rap Material on SD-1 (2028) - North Salmon Dam						450.0	**450.0**
Refurbish CD4 Rip Rap (2028) - Cat Arm						100.0	**100.0**
Refurbish Spherical Valves Unit 3 (2028-2029) - Bay d'Espoir						100.0	**100.0**
Rehabilitate Access Roads - Powerhouse, Intake, and North Salmon Spillway (2028-2029) - Upper Salmon						100.0	**100.0**
Refurbish Blue Grass Access Road - Spillway to Dam (2028-2029) - Hinds Lake						100.0	**100.0**
Total	**13,429.3**	**24,477.4**	**62,798.0**	**14,142.0**	**15,078.4**	**23,437.0**	**153,362.1**
Thermal Plant							
Upgrade Synchronous Condenser Building (2026-2027) - Holyrood				400.0	5,600.0		**6,000.0**
Purchase and Replace Last Stage Blades - Holyrood Units 1 and 2	3,596.5	2,812.2					**6,408.7**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood		156.2	1,039.4				**1,195.6**
Upgrade Unit 1 Control System (2024-2025) - Holyrood		468.3	184.3				**652.6**
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood		195.2	277.3				**472.5**
Upgrade UPS 1 & 2 (2024-2025) - Holyrood		263.0	107.6				**370.6**
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood		5,181.4					**5,181.4**
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood		3,957.8					**3,957.8**
Thermal In-Service Failures (2024)		3,508.7					**3,508.7**
Refurbish Fuel Oil Storage Tank 4 (2024) - Holyrood		1,920.0					**1,920.0**
Overhaul Pumps (2024) - Holyrood		661.0					**661.0**
Overhaul Marine Terminal Loading Arms (2024) - Holyrood		511.0					**511.0**
Refurbish Stage I & II Cooling Water Pumphouses (2025-2026) - Holyrood			670.0	700.0			**1,370.0**
Marine Terminal Upgrades (2025) - Holyrood			200.0	800.0			**1,000.0**
Turbine and Valve Overhaul - Unit 3 (2025) - Holyrood			11,444.7				**11,444.7**
Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood			3,750.0				**3,750.0**
Thermal In-Service Failures (2025)			3,450.0				**3,450.0**
Major Pump Overhaul (2025) - Holyrood			350.0				**350.0**
Install Plant Heating (2028-2029) - Holyrood					519.0	2,500.0	**3,019.0**
Upgrade Cranes and Hoists (2026-2027) - Holyrood				200.0	300.0		**500.0**
Overhaul Unit 2 Turbine Valves				3,873.0			**3,873.0**
Thermal In-Service Failures (2026)				3,528.0			**3,528.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2026)				3,500.0			**3,500.0**
Overhaul Unit 2 Generator				1,839.0			**1,839.0**
Major Pump Overhaul (Unit 1 WBFP, Unit 1 ECWP, Unit 1 SCEP, Unit 2 SCEP, Unit 3 WBFP)				1,400.0			**1,400.0**
Upgrade Water Treatment Plant and Waste Water Treatment Plant - Holyrood				1,000.0			**1,000.0**
Replace Parts of Unit 3: 129 Vdc Battery Chargers, Batteries, Panels, and Breakers (2026) - Holyrood				750.0			**750.0**
Inspect Stacks (2026) - Holyrood				250.0			**250.0**
Inspect and Upgrade Light Oil System - Holyrood					200.0	800.0	**1,000.0**
Overhaul Unit 1 Turbine Valves - Holyrood					4,066.7		**4,066.7**
Thermal In-Service Failures (2027)					3,607.0		**3,607.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2027)					3,500.0		**3,500.0**
Overhaul Unit 3 Generator and Upgrade Online Monitoring (2027) - Holyrood					1,930.9		**1,930.9**
Upgrade Unit 3 Synchronous Condenser Cooling Water Systems H2, Generator Lube Oil, and Seal Oil (2027) - Holyrood					1,500.0		**1,500.0**
Major Pump Overhaul (Unit 1 NCEP, Unit 1 EBFP, Unit 3 SCEP, Unit 3 EBFP)					1,200.0		**1,200.0**
Upgrade Wastewater Basin and Underground Drainage (2027) - Holyrood					1,000.0		**1,000.0**
Overhaul Marine Terminal Loading Arms					550.0		**550.0**
Fire System Upgrades (2027)					350.0		**350.0**
Overhaul Unit 3 Turbine Valves						4,270.0	**4,270.0**
Thermal In-Service Failures (2028)						3,686.0	**3,686.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2028)						3,500.0	**3,500.0**
Major Pump Overhaul (Unit 2 NCEP, Unit 2 ECWP)						450.0	**450.0**
Condition Assessment of doors siding and roofing						120.0	**120.0**
Total	**3,596.5**	**19,634.8**	**21,473.3**	**18,240.0**	**24,323.6**	**15,326.0**	**102,594.2**
Tools and Equipment							
Purchase Tools and Equipment Less than $50,000 (2024) - Hydraulic Plants		209.4					**209.4**
Purchase Tools and Equipment Less than $50,000 (2024) - Thermal Plants		167.1					**167.1**
Purchase Tools and Equipment Less than $50,000 (2024) - Gas Turbine		18.6					**18.6**
Purchase Tools and Equipment Less than $50,000 (2025) - Hydraulic Plants			100.0				**100.0**
Purchase Tools and Equipment Less than $50,000 (2025) - Thermal Plants			50.0				**50.0**
Purchase Tools and Equipment Less than $50,000 (2025) - Gas Turbines			20.0				**20.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Hydraulic Plants				100.0			**100.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Thermal Plants				50.0			**50.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Gas Turbines				20.0			**20.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Hydraulic Plants					100.0		**100.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Thermal Plants					50.0		**50.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Gas Turbine					20.0		**20.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Hydraulic Plants						100.0	**100.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Thermal Plants						50.0	**50.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Gas Turbine						20.0	**20.0**
Total		**395.1**	**170.0**	**170.0**	**170.0**	**170.0**	**1,075.1**

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	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Total Generation	**17,164.3**	**46,011.7**	**86,235.2**	**42,772.0**	**47,636.0**	**49,218.0**	**289,037.2**
General Properties							
Transportation							
Replace Light- and Heavy-Duty Vehicles (2022-2024)	1,162.2	2,319.6					**3,481.8**
Replace Light- and Heavy-Duty Vehicles (2023-2025)	1,308.1	2,584.6	473.3				**4,366.0**
Ultra-Fast Direct-Current EV Chargers - Purchase and Installation	62.5	1,766.0	231.3				**2,059.8**
Replace Light- and Heavy-Duty Vehicles (2024-2026)		1,479.1	4,148.8	8.4			**5,636.3**
Replace Light- and Heavy-Duty Vehicles (2025-2026)			2,000.0	2,000.0			**4,000.0**
Replace Mobile Equipment (2025)			600.0				**600.0**
Replace Light- and Heavy-Duty Vehicles (2026-2027)				2,000.0	2,000.0		**4,000.0**
Replace Mobile Equipment (2026)				600.0			**600.0**
Replace Light- and Heavy-Duty Vehicles (2027-2028)					2,000.0	2,000.0	**4,000.0**
Replace Mobile Equipment (2027)					600.0		**600.0**
Replace Light- and Heavy-Duty Vehicles (2028-2029)						2,000.0	**2,000.0**
Replace Mobile Equipment (2028)						600.0	**600.0**
Total	**2,532.8**	**8,149.3**	**7,453.4**	**4,608.4**	**4,600.0**	**4,600.0**	**31,943.9**
Administration							
General Property Rehabilitation (2024) - Hydro Place		234.0					**234.0**
Remove Safety Hazards (2024)		198.3					**198.3**
Upgrade HVAC Supervisory Controllers (2024) - Hydro Place		149.6					**149.6**
Purchase Office Equipment Less Than $50,000 (2024)		50.0					**50.0**
Barrier Free Improvements - Washrooms (2025-2026)			428.0	346.5			**774.5**
Remove Safety Hazards (2025)			208.0				**208.0**
Purchase Furniture & Equipment Less Than $50,000 (2025)			67.3				**67.3**
Security Improvements Less Than $50,000 (2025)			37.0				**37.0**
Window Refurbishment/Replacement Program (2026-2028)				1,041.5	1,057.5	1,074.0	**3,173.0**
Replace/Upgrade Fire Suppression System (2026)				508.0			**508.0**
Remove Safety Hazards (2026)				213.0			**213.0**
Purchase Office Equipment Less Than $50,000 (2026)				68.0			**68.0**
Remove Safety Hazards (2027)					218.0		**218.0**
Fire Panel and Device Upgrade (2027)					197.0		**197.0**
Purchase Furniture & Equipment Less Than $50,000 (2027)					68.0		**68.0**
Replace Generators and Associated Switchgear						1,000.0	**1,000.0**
Remove Safety Hazards (2028)						200.0	**200.0**
Replace Multi-Stack Chiller Level 1 Mechanical Room						200.0	**200.0**
Replace Fuel Tank, Lines, Pumps and Associated Hardware						100.0	**100.0**
Purchase Furniture & Equipment Less Than $50,000 (2028)						68.0	**68.0**
Total		**631.9**	**740.3**	**2,177.0**	**1,540.5**	**2,642.0**	**7,731.7**

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	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Information Systems							
Perform Software Upgrades and Minor Enhancements (2024)		864.2					**864.2**
Purchase Personal Computers (2024)		555.9					**555.9**
Upgrade Energy Management System (2024)		366.4					**366.4**
Update Cyber Security Infrastructure (2024)		281.3					**281.3**
Replace Peripheral Infrastructure (2024)		276.8					**276.8**
Upgrade Core OT Infrastructure (2024)		174.7					**174.7**
Perform Software Upgrades and Minor Enhancements (2025)			705.0				**705.0**
Purchase Personal Computers (2025)			635.8				**635.8**
Upgrade Core OT Infrastructure (2025)			375.0				**375.0**
Update Cyber Security Infrastructure (2025)			225.0				**225.0**
Replace Peripheral Infrastructure (2025)			190.4				**190.4**
Purchase Personal Computers (2026)				941.5			**941.5**
Perform Software Upgrades and Minor Enhancements (2026)				625.0			**625.0**
Upgrade Core OT Infrastructure (2026)				375.0			**375.0**
Upgrade Energy Management System (2026) - Hydro Place				355.0			**355.0**
Update Cyber Security Infrastructure (2026)				322.0			**322.0**
Replace Peripheral Infrastructure (2026)				172.4			**172.4**
Purchase Personal Computers (2027)					986.6		**986.6**
Perform Software Upgrades and Minor Enhancements (2027)					625.0		**625.0**
Upgrade Core OT Infrastructure (2027)					375.0		**375.0**
Update Cyber Security Infrastructure (2027)					350.0		**350.0**
Replace Peripheral Infrastructure (2027)					269.1		**269.1**
Upgrade Software Applications (2027)					100.0		**100.0**
Perform Software Upgrades and Minor Enhancements (2028)						725.0	**725.0**
Upgrade Core OT Infrastructure (2028)						425.0	**425.0**
Upgrade Energy Management System (2028)						380.0	**380.0**
Update Cyber Security Infrastructure (2028)						375.0	**375.0**
Purchase Personal Computers (2028)						325.8	**325.8**
Replace Peripheral Infrastructure (2028)						105.9	**105.9**
Total		**2,519.3**	**2,131.2**	**2,790.9**	**2,705.7**	**2,336.7**	**12,483.8**
Telecontrol							
Replace Power Line Carrier (2023–2024) - TL223 and TL224	105.3	852.4					**957.7**
Replace VHF Radio System (2024-2025)		1,261.6	290.6				**1,552.2**
Replace MDR8000 Microwave Radios (2024-2025)		953.5	500.3				**1,453.8**
Replace Power Line Carrier (2024-2025) - TL247		87.2	667.4				**754.6**
Replace SONET Multiplexors (2024)		430.4					**430.4**
Replace 48 V Battery Banks and Chargers (2024)		422.2					**422.2**
Upgrade SCADA Network (2024)		402.3					**402.3**
Replace CCTV Cameras (2024)		317.6					**317.6**
Replace Network Communications Equipment (2024)		180.7					**180.7**
Upgrade Remote Terminal Units (2024)		165.9					**165.9**
Purchase Mobile Devices (2024)		155.6					**155.6**
Minor Telecommunications Enhancements (2024)		96.9					**96.9**
Telecommunications In-Service Failure (2024)		91.4					**91.4**
Purchase Tools and Equipment Less than $50,000 (2024) - Telecontrol		45.6					**45.6**
Replace East Coast to Central Interconnect Microwave Radios (2025-2027)			100.0	400.0	150.0		**650.0**
Refurbish Meteorological Sites (2025)			100.0	100.0			**200.0**
Refurbish Office Energy Efficiency and HVAC Systems (2025-2026) - Deer Lake			75.0	100.0			**175.0**
Replace 48 V Battery Banks and Chargers (2025)			428.3				**428.3**
Install CCTV Systems (2025)			321.3				**321.3**
Replace Network Communications Equipment (2025)			215.5				**215.5**
Upgrade Remote Terminal Units (2025)			168.0				**168.0**
Purchase Mobile Devices (2025)			132.0				**132.0**
Site Physical Security Program (2025)			108.0				**108.0**
Minor Telecommunications Enhancements (2025)			98.8				**98.8**
Telecommunications Tower Condition Management (2025)			93.0				**93.0**
Telecommunications In-Service Failure (2025)			93.0				**93.0**
Replace Uninterruptible Power Supply Batteries (2025) - Hydro Place			75.0				**75.0**
Purchase Tools and Equipment Less than $50,000 (2025)			49.7				**49.7**
Replace Back-up Generators at Microwave Repeater Sites (2026-2027)				100.0	50.0		**150.0**
Replace 48 V Battery Banks and Chargers (2026)				441.1			**441.1**
Replace Network Communications Equipment (2026)				222.0			**222.0**
Purchase Mobile Devices (2026)				202.6			**202.6**
Install CCTV Systems (2026)				200.0			**200.0**
Upgrade Remote Terminal Units (2026)				173.0			**173.0**
Site Physical Security Program (2026)				112.0			**112.0**
Minor Telecommunications Enhancements (2026)				101.7			**101.7**
Telecommunications In-Service Failure (2026)				96.0			**96.0**
Telecommunications Tower Condition Management (2026)				96.0			**96.0**
Purchase Tools and Equipment Less than $50,000 (2026)				49.7			**49.7**
Replace Power Line Carrier (2027-2028) - TL212					93.6	681.4	**775.0**
Replace 48 V Battery Banks and Chargers (2027)					454.4		**454.4**
Replace Network Communications Equipment (2027)					229.0		**229.0**
Install CCTV Systems (2027)					212.2		**212.2**
Purchase Mobile Devices (2027)					183.4		**183.4**

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Upgrade Remote Terminal Units (2027)					179.0		**179.0**
Replace Cisco Call Manager Appliances					130.0		**130.0**
Site Physical Security Program (2027)					116.0		**116.0**
Minor Telecommunications Enhancements (2027)					104.8		**104.8**
Telecommunications Tower Condition Management (2027)					99.0		**99.0**
Upgrade Remote Terminal Units (2028)						184.0	**184.0**
Purchase Mobile Devices (2028)						144.0	**144.0**
Minor Telecommunications Enhancement (2028)						107.9	**107.9**
Telecommunications In-Service Failure (2028)						102.0	**102.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Telecontrol						49.7	**49.7**
Total	**105.3**	**5,463.3**	**3,515.9**	**2,394.1**	**2,150.1**	**2,191.5**	**15,820.2**
Total General Properties	**2,638.1**	**16,763.8**	**13,840.8**	**11,970.4**	**10,996.3**	**11,770.2**	**67,979.6**
Transmission and Rural Operations							
Transmission							
Wood Pole Line Management (2024)		3,765.2					**3,765.2**
Transmission In-Service Failures (2024)		158.5					**158.5**
TL220 Install Mid Span Poles (2025-2026)			150.0	600.0			**750.0**
Wood Pole Line Management (2025)			2,446.0				**2,446.0**
Transmission In-Service Failures (2025)			162.0				**162.0**
Steel-Tower Transmission Line Renewal (2026-2032)				5,000.0	24,595.0	36,233.0	**65,828.0**
TL220 Relocate Section of Line (2026-2027)				150.0	600.0		**750.0**
Wood Pole Line Management (2026)				4,386.0			**4,386.0**
Transmission In-Service Failures (2026)				166.0			**166.0**
Wood Pole Line Management (2027)					4,767.0		**4,767.0**
Transmission In-Service Failures (2027)					170.0		**170.0**
Wood Pole Line Management (2028)						2,474.0	**2,474.0**
Transmission In-Service Failures (2028)						174.0	**174.0**
Total		**3,923.7**	**2,758.0**	**10,302.0**	**30,132.0**	**38,881.0**	**85,996.7**
Distribution							
Upgrade of Worst-Performing Distribution Feeders (2023-2024)	73.4	1,372.6					**1,446.0**
Upgrade Worst-Performing Distribution Feeders (2024-2025)		1,064.3	2,227.4				**3,291.7**
Renew Distribution Feeders (2024-2025)		1,287.3	1,245.1				**2,532.4**
Upgrade Distribution (2024-2025) - Bay d'Espoir Terminal Station 2		93.2	331.5				**424.7**
Additions for Load Growth - Distribution System - Labrador City Duley Lake, Walsh River, and Landfill Sites (2024-2025)		37.9	191.3				**229.2**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)		4,345.4					**4,345.4**
Provide Service Extensions (2024)		4,272.0					**4,272.0**
Upgrade Worst-Performing Distribution Feeders (2025-2026)			480.3	2,720.0			**3,200.3**
Renew Distribution Feeders (2025-2026)			1,287.3	1,245.1			**2,532.4**
Replace T1 Burgeo Substation (2025-2026)			200.0	600.0			**800.0**
Distribution Equipment SCADA Additions (2025-2026)			30.0	270.0			**300.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2025)			4,454.0				**4,454.0**
Provide Service Extensions (2025)			4,369.0				**4,369.0**
Additions for Load (2025) - Distribution System			1,000.0				**1,000.0**
Upgrade Worst-Performing Distribution Feeders (2026-2027)				480.3	2,720.0		**3,200.3**
Renew Distribution Feeders (2026-2027)				1,287.3	1,245.1		**2,532.4**
Replace T2 St. Anthony Diesel Plant Terminal Station (2026-2027)				500.0	1,500.0		**2,000.0**
Distribution Equipment SCADA Additions (2026-2027)				30.0	270.0		**300.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2026)				4,565.0			**4,565.0**
Provide Service Extensions (2026)				4,467.0			**4,467.0**
Additions for Load (2026) - Distribution System				1,000.0			**1,000.0**
Upgrade Worst-Performing Distribution Feeders (2027-2028)					480.3	2,720.0	**3,200.2**
Renew Distribution Feeders (2027-2028)					1,287.3	1,245.1	**2,532.4**
Distribution Equipment SCADA Additions (2027-2028)					30.0	270.0	**300.0**
Provide Service Extensions (2027)					4,567.0		**4,567.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2027)					4,167.0		**4,167.0**
Additions for Load (2027) - Distribution System					1,000.0		**1,000.0**
Provide Service Extensions (2028)						4,670.0	**4,670.0**
Distribution System In-Service Failures, Miscellaneous Upgrades and Street Lights (2028)						4,284.0	**4,284.0**
Renew Distribution Feeders (2028-2029)						1,287.3	**1,287.3**
Upgrade Worst-Performing Distribution Feeders (2028-2029)						480.3	**480.3**
Distribution Equipment SCADA Additions (2028-2029)						30.0	**30.0**
Total	**73.4**	**12,472.7**	**15,815.9**	**17,164.7**	**17,266.6**	**14,986.6**	**77,779.9**
Properties							
Replace Diesel Shop Building (2023-2025) - Bishop's Falls	168.0	1,254.1	889.9				**2,312.0**
Upgrade Water and Fire Suppression Systems (2023-2024) - Bishop's Falls	353.7	2,886.3					**3,240.0**
Replace HVAC System (2023-2024) - Bishop's Falls	43.4	128.8					**172.2**
Upgrade Line Depots (2025-2027) - Bay d'Espoir			320.4	1,514.7	1,400.6		**3,235.7**
Construct Storage Building (2025-2026) - Springdale			135.0	730.0			**865.0**
Upgrade Property (2025) - Bishop's Falls, Whitbourne, St. Anthony			370.0				**370.0**
Resurface Parking Lots and Roads (2024) - Bishop's Falls			150.0				**150.0**
Upgrade Outside Property (2025) - Deer Lake			129.0				**129.0**
Upgrade Property (2026) - Port Saunders, Stephenville, and Happy Valley				300.0			**300.0**
Replace Sewage System (2026) - Bishop's Falls				150.0			**150.0**
Upgrade Outside Property (2027) - St. Anthony, Bishop's Falls, Stephenville, and Whitbourne					428.0		**428.0**
Upgrade Property (2028)						1,150.0	**1,150.0**
Total	**565.1**	**4,269.2**	**1,994.3**	**2,694.7**	**1,828.6**	**1,150.0**	**12,501.9**

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	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Metering							
Replace Metering System	4,881.2	994.6					**5,875.8**
Automate Bulk Metering (2024-2026)		302.6	214.4	235.3			**752.3**
Purchase Meters and Metering Equipment (2024)		470.7					**470.7**
Purchase Meters and Metering Equipment (2025)			475.5				**475.5**
Purchase Meters and Metering Equipment (2026)				625.5			**625.5**
Purchase Meters and Metering Equipment (2027)					629.5		**629.5**
Purchase Meters and Metering Equipment (2028)						395.5	**395.5**
Total	**4,881.2**	**1,767.9**	**689.9**	**860.8**	**629.5**	**395.5**	**9,224.8**
Tools and Equipment							
Purchase 85' Material Handler Aerial Device on Track Unit	1,286.1	67.8					**1,353.9**
Purchase 46' Material Handler Aerial Device on Track Unit	719.2	38.8					**758.0**
Replace Mobile Equipment (2023-2024)	541.2	187.3					**728.5**
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024-2026) - Happy Valley Goose Bay		24.0	841.8	7.1			**872.9**
Replace Mobile Equipment (2024-2025)		216.9	599.7				**816.6**
Replace Grader Unit V9829 (2024) - Bay d'Espoir		836.7					**836.7**
Purchase Tools and Equipment Less than $50,000 (2024) - Central Region		188.2					**188.2**
Purchase Tools and Equipment Less than $50,000 (2024) - Labrador Region		120.1					**120.1**
Purchase Tools and Equipment Less than $50,000 (2024) - Northern Region		97.0					**97.0**
Replace Off Road Heavy-Duty Equipment (2025-2026)			500.0	500.0			**1,000.0**
Purchase Tools and Equipment Less than $50,000 (2025) - Central Region			180.0				**180.0**
Purchase Tools and Equipment Less than $50,000 (2025) - Northern Region			120.0				**120.0**
Purchase Tools and Equipment Less than $50,000 (2025) - Labrador Region			100.0				**100.0**
Replace Off Road Heavy-Duty Equipment (2026-2027)				500.0	500.0		**1,000.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Central Region				180.0			**180.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Northern Region				120.0			**120.0**
Purchase Tools and Equipment Less than $50,000 (2026) - Labrador Region				100.0			**100.0**
Replace Off Road Heavy-Duty Equipment (2027-2028)					500.0	500.0	**1,000.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Central Region					180.0		**180.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Northern Region					120.0		**120.0**
Purchase Tools and Equipment Less than $50,000 (2027) - Labrador Region					100.0		**100.0**
Replace Off Road Heavy-Duty Equipment (2028-2029)						500.0	**500.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Central Region						180.0	**180.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Northern Region						120.0	**120.0**
Purchase Tools and Equipment Less than $50,000 (2028) - Labrador Region						100.0	**100.0**
Total	**2,546.5**	**1,776.8**	**2,341.5**	**1,407.1**	**1,400.0**	**1,400.0**	**10,871.9**
Terminal Stations							
Additions for Load - Wabush Substation Upgrades	7,439.7	2,739.9	514.5				**10,694.1**
Wabush Terminal Station Upgrades	8,870.1	3,808.0					**12,678.1**
Additions for Load Growth - Upgrade Transformer Capacity (2023-2024) - Jean Lake Terminal Station	580.0	-	5,436.1				**6,016.1**
Terminal Station Renewal Program (2023-2024)	1,733.7	5,584.5					**7,318.2**
Circuit Breakers Renewal Program (2023-2024)	216.9	3,595.1					**3,812.0**
Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) - Wabush Terminal Station	577.2	516.1					**1,093.3**
Replace Terminal Station Lighting (2023-2024)	323.3	594.1					**917.4**
Install Fire Protection in 230 kV Stations (2023-2024) - Deer Lake	79.2	535.3					**614.5**
Install Oil Spill Containment Transformer T1S (2023-2024) - Cat Arm	155.1	426.5					**581.6**
Install Breaker Failure Protection (2023-2024) - Sunnyside	73.5	216.2					**289.7**
Replace Circuit Breaker Reclosing Controllers (2023-2024) - Hardwoods	81.6	149.6					**231.2**
Replace Data Alarm System Annunciators (2023) - Buchans	61.2	104.8					**166.0**
Purchase Spare Generator Step-Up Transformer	722.9	3,420.4	3,643.0				**7,786.3**
[]	-	-	-				-
Upgrade Power Transformers (2024-2025)		864.6	2,711.3				**3,575.9**
Replace Protective Relays (2024–2025)		1,388.4	2,050.7				**3,439.1**
Renew Circuit Breakers (2024–2025)		183.9	2,779.3				**2,963.2**
Replace Disconnects (2024–2025)		127.4	1,358.1				**1,485.5**
Replace Instrument Transformers (2024–2025)		154.9	714.8				**869.7**

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($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay		53.8	599.0				**652.8**
Refurbish Control Building (2024-2025) - Grandy Brook and Doyles		109.4	444.7				**554.1**
Upgrade Station Lighting (2024-2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon Terminal Stations		91.6	429.0				**520.6**
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247		112.4	215.8				**328.2**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station		137.0	156.9				**293.9**
Replace Terminal Station Battery Banks and Chargers (2024–2025)		71.8	120.9				**192.7**
Terminal Station In-Service Failures (2024)		1,300.0					**1,300.0**
Replace Protective Relays (2025-2026)			1,250.0	2,250.0			**3,500.0**
Upgrade Power Transformers (2025–2026)			114.0	2,599.0			**2,713.0**
Renew Circuit Breakers (2025-2026)			531.8	1,709.6			**2,241.4**
Replace Telecontrol Building and Upgrade Equipment (2025-2026) - Daniel's Harbour			408.7	1,505.2			**1,913.9**
Install Fire Barriers between T10 and T12, T10 and T11 (2025-2026) 2			220.4	1,108.6			**1,329.0**
Replace Disconnects (2025-2026)			439.2	815.7			**1,254.9**
Upgrade Terminal Station for Mobile Substation (2025-2026)2			147.7	1,105.0			**1,252.7**
Construct Fire Separation Walls between Transformers (2025-2026) 2			54.8	773.9			**828.7**
Replace Circuit Breaker Reclosing Controller (2025-2026) - Sunnyside			54.0	710.0			**764.0**
Replace Switchgear Synchronous Condensers 1 and 2 (2025-2026) - Wabush Terminal Station			50.0	700.0			**750.0**
Replace Instrument Transformers (2025-2026)			420.0	280.0			**700.0**
Install Fire Protection in 230 kV Stations (2025-2026) - Come By Chance			68.0	616.0			**684.0**
Upgrade Terminal Station for Mobile Substation (2025-2026) 2			60.0	400.0			**460.0**
Replace SC1/SC2 Overhead Crane (2025-2026) - Wabush Terminal Station			120.0	340.0			**460.0**
Install Breaker Failure Protection (2025–2026) - Holyrood TS			135.0	315.0			**450.0**
Refurbish Control Building (2025-2026)			125.1	310.4			**435.5**
Replace Terminal Station Battery Banks and Chargers (2025-2026)			210.0	140.0			**350.0**
Replace Switchgear (2025-2026) - Grand Falls Terminal Station			50.0	300.0			**350.0**
Upgrade Data Alarm Systems (2025-2026) - Hardwoods			120.0	180.0			**300.0**
Synchronous Condenser 2 Major Inspection (2025-2026) - Wabush Terminal Station			40.0	240.0			**280.0**
Install New Station Service Feed (2025-2026) - Berry Hill			50.0	150.0			**200.0**
Upgrade Transformer Paralleling (2025-2026) - Stoney Brook			36.0	54.0			**90.0**
Terminal Station In-Service Failures (2025)			1,387.1				**1,387.1**
Upgrade Station Access Road (2025) - Buchans, Western Avalon, Sunnyside, Deer Lake			200.0				**200.0**
Replace Protective Relays (2026-2027)				850.0	1,350.0		**2,200.0**
Upgrade Power Transformers (2026–2027)				89.0	1,837.0		**1,926.0**
Renew Circuit Breakers (2026-2027)				406.0	794.0		**1,200.0**
Replace Disconnects (2026-2027)				348.3	646.8		**995.1**
Install Fire Barriers between Substation and T1, T2, and T3 (2026-2027)				39.1	731.5		**770.6**
Install Fire Protection in 230 kV Stations (2026-2027) - Bottom Brook				68.0	616.0		**684.0**
Replace Instrument Transformers (2026-2027)				290.0	200.0		**490.0**
Upgrade Terminal Station for Mobile Substation (2026–2027) - St. Anthony Diesel				60.0	400.0		**460.0**
Install Breaker Failure Protection (2026-2027) - Hardwoods				135.0	315.0		**450.0**
Refurbish Control Building (2026–2027)				124.9	310.0		**434.9**
Replace Terminal Station Battery Banks and Chargers (2026-2027)				190.0	130.0		**320.0**
Synchronous Condenser 1 Major Inspection (2026-2027) - Wabush Terminal Station				40.0	240.0		**280.0**
Upgrade Data Alarm System (2026–2027) - Springdale and Indian River Terminal Stations				50.0	80.0		**130.0**
Replace Circuit Breaker Reclosing Controllers (2026-2027) - Holyrood				54.0	71.0		**125.0**
Upgrade Transformer Paralleling (2026-2027) - Sunnyside				36.0	54.0		**90.0**
Terminal Station In-Service Failures (2026)				1,480.0			**1,480.0**
Replace Transformer T3 (2027-2028) - Wabush Terminal Station					1,254.0	4,959.0	**6,213.0**
Replace Transformer T3 (2027-2028) - Bay d'Espoir					900.0	1,900.0	**2,800.0**
Replace Protective Relays (2027-2028)					900.0	1,400.0	**2,300.0**
Replace Disconnects (2027-2028)					311.5	578.5	**890.0**
Upgrade Power Transformers (2027–2028)					71.0	816.0	**887.0**
Replace Instrument Transformers (2027-2028)					360.0	240.0	**600.0**
Upgrade Terminal Station for Mobile Substation (2027-2028) - Glenburnie					60.0	400.0	**460.0**
Install Breaker Failure Protection (2027-2028) - Western Avalon					135.0	315.0	**450.0**
Refurbish Control Building (2027-2028) 2					85.5	219.2	**304.7**
Replace Terminal Station Battery Banks and Chargers (2027-2028)					90.0	60.0	**150.0**
Upgrade Data Alarm Systems (2027-2028) - Grand Falls Frequency Converter					60.0	90.0	**150.0**
Replace Circuit Breaker Reclosing Controllers (2027-2028) - Roddickton					54.0	71.0	**125.0**
Upgrade Transformer Paralleling (2027-2028) - Bottom Brook					36.0	54.0	**90.0**
Terminal Station In-Service Failures (2027)					1,579.2		**1,579.2**
Upgrade Drainage to Stop Frost Heaving (2027) - Stoney Brook, Springdale, Holyrood, Jackson's Arm, and Buchans					250.0		**250.0**
Renew Circuit Breakers (2028-2029)						2,100.0	**2,100.0**
Terminal Station In-service Failures (2028)						1,685.0	**1,685.0**
Replace Protective Relays (2028-2029)						800.0	**800.0**
Replace Disconnects (2028-2029)						370.0	**370.0**
Replace Equipment Foundations (2028-2029)						280.0	**280.0**
Upgrade Drainage to Stop Frost Heaving (2028) - Stoney Brook, Springdale, Holyrood, Jackson's Arm, Buchan's Terminal Stations						250.0	**250.0**
Replace Instrument Transformers (2028-2029)						250.0	**250.0**
Replace Terminal Station Battery Banks and Chargers (2028-2029)2						150.0	**150.0**
Upgrade Data Alarm Systems (2028-2029)2						100.0	**100.0**
Upgrade Power Transformers (2028-2029)						90.0	**90.0**
Upgrade Terminal Station for Mobile Substation (2028-2029) - Roddickton						60.0	**60.0**
Upgrade Reclosing Circuit Breakers (2028-2029) - Berry Hill						54.0	**54.0**
Upgrade Transformer Paralleling (2028-2029) - Bay d'Espoir Terminal Station 2						36.0	**36.0**
Total	**20,914.4**	**26,285.7**	**27,465.9**	**20,862.7**	**13,921.5**	**17,327.7**	**126,777.9**

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2024 Capital Budget Application
Five-Year Capital Plan - By Asset Category
($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	Total
Generation							
Diesel Genset Replacement Unit 2012 - L'Anse-Au-Loup	2,853.1	210.2					**3,063.3**
Long-Term Supply for Southern Labrador - Phase 1	1,835.0	17,812.0	40,116.3	23,327.6	3,304.3		**86,395.2**
Diesel Genset Replacement Program (2023-2025)	819.1	174.0	1,883.1	250.0			**3,126.2**
Replace Intermediate Fuel Storage Tanks (2023-2024) - Nain	127.4	593.7					**721.1**
Replace Building Exterior (2023-2024) - Postville	124.6	558.7					**683.3**
Replace Diesel Gensets (2024-2026)		535.8	478.0	3,902.3			**4,916.1**
Purchase Accommodations Trailer (2024-2025) - Makkovik and Cartwright		130.9	1,420.2				**1,551.1**
Overhaul Diesel Units (2024)		829.2					**829.2**
Diesel In-Service Failures (2024)		488.3					**488.3**
Replace Diesel Gensets (2025-2026)			200.0	1,400.0			**1,600.0**
Overhaul Diesel Units (2025)			1,500.0				**1,500.0**
Inspect Fuel Storage Tanks (2025) - MacCallum			1,000.0				**1,000.0**
Additions for Load Growth - Isolated Generation Stations (2025)			650.0				**650.0**
Diesel In-Service Failures (2025)			489.5				**489.5**
Overhaul Diesel Units (2026)				1,500.0			**1,500.0**
Inspect Fuel Storage Tanks (2026) - Rigolet				650.0			**650.0**
Additions for Load Growth - Isolated Generation Stations (2026)				650.0			**650.0**
Diesel In-Service Failures (2026)				490.0			**490.0**
Overhaul Diesel Units (2027)					1,500.0		**1,500.0**
Additions for Load Growth - Isolated Generation Stations (2027)					1,500.0		**1,500.0**
Replace Roof (2027) - Cartwright					700.0		**700.0**
Diesel In-Service Failures (2027)					495.0		**495.0**
Inspect Fuel Storage Tanks (2027) - Hawke's Bay					300.0		**300.0**
Overhaul Diesel Units (2028)						2,250.0	**2,250.0**
Replace Diesel Gensets (2028)						1,000.0	**1,000.0**
Additions for Load Growth - Isolated Generation Stations (2028)						650.0	**650.0**
Diesel In-Service Failures (2028)						500.0	**500.0**
Total	**5,759.2**	**21,332.8**	**47,737.1**	**32,169.9**	**7,799.3**	**4,400.0**	**119,198.3**
Total Transmission and Rural Operations	**34,739.8**	**71,828.8**	**98,802.6**	**85,461.9**	**72,977.5**	**78,540.8**	**442,351.4**
Allowance for Unforeseen							
Allowance for Unforeseen Items (2024)		1,000.0					**1,000.0**
Allowance for Unforeseen Items (2025)			1,000.0				**1,000.0**
Allowance for Unforeseen Items (2026)				1,000.0			**1,000.0**
Allowance for Unforeseen Items (2027)					1,000.0		**1,000.0**
Allowance for Unforeseen Items (2028)						1,000.0	**1,000.0**
Total		**1,000.0**	**1,000.0**	**1,000.0**	**1,000.0**	**1,000.0**	**5,000.0**
Total Allowance for Unforeseen Items		**1,000.0**	**1,000.0**	**1,000.0**	**1,000.0**	**1,000.0**	**5,000.0**
Total Capital Plan	**54,542.2**	**135,604.3**	**199,878.6**	**141,204.3**	**132,609.8**	**140,529.0**	**804,368.2**

Appendix B

Capital Expenditures (2019–2028)



Newfoundland and Labrador Hydro
2024 Capital Budget Application
Capital Expenditures 2019–2028
($000)

	Actuals				Budget					
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Mandatory	-	-	-	-	155.1	2,605.7	429.0	-	-	-
Renewal	100,612.0	72,476.2	96,225.3	58,147.7	83,328.2	71,339.7	112,755.0	83,174.6	95,291.9	108,260.4
Service Enhancement	10,488.8	2,344.0	1,268.2	7,214.0	13,027.3	25,851.3	48,474.2	32,905.8	9,154.0	6,250.2
System Growth	3,299.5	1,517.8	2,607.3	11,496.3	13,101.0	6,585.8	7,791.9	1,650.0	2,500.0	650.0
General Plant	9,051.5	9,374.0	8,221.7	7,414.6	16,005.9	23,479.1	24,584.0	17,381.4	19,467.4	19,302.9
Access	3,744.0	3,962.5	5,169.6	16,308.9	13,533.0	4,742.7	4,844.5	5,092.5	5,196.5	5,065.5
Allowance for Unforeseen	-	-	-	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Total Capital Expenditures	**127,195.8**	**89,674.5**	**113,492.1**	**101,581.5**	**140,150.5**	**135,604.3**	**199,878.6**	**141,204.3**	**132,609.8**	**140,529.0**

Sch 3: Holyrood TGS
Overview

Schedule 3

Holyrood Thermal Generating Station Overview – Future Operation and Capital Expenditure Requirements



2024 Capital Budget Application

Holyrood Thermal Generating Station Overview – Future Operation and Capital Expenditure Requirements



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Appendix B: Planned Capital Expenditures

Appendix C: Ten-Year System Equipment Maintenance Expenditures

1.0 Background

In Order No P.U. 5(2012),[1] the Board of Commissioners of Public Utilities ("Board") directed Newfoundland and Labrador Hydro ("Hydro") to file, in conjunction with its 2013 Capital Budget Application ("CBA"), an overview in relation to the proposed capital expenditures for the Holyrood Thermal Generating Station ("Holyrood TGS"). The Board required the overview to include the following:[2]

- An updated outlook regarding anticipated changes in the role of the Holyrood TGS on the system;
- An updated schedule of anticipated changes in the Holyrood TGS operations that may reasonably be expected to have an impact on capital expenditure requirements;
- A summary description of all proposed Holyrood TGS capital projects, including an explanation of how such projects relate to one another and whether such projects may be impacted by decisions yet to be taken regarding the Holyrood TGS's role on the system;
- A summary guide to all internal and external reports filed in support of the capital expenditure proposals, summarizing alternatives considered, and recommendations made; and
- An explanation of the necessity of all proposed capital expenditures in the context of the anticipated changes in the Holyrood TGS operations.

In subsequent Board Orders in relation to Hydro's annual CBAs, the Board required Hydro to update and file the Holyrood TGS Overview Report with future CBAs. In Order No. P.U. 2(2023),[3] the Board requested that Hydro file a more comprehensive report with its 2024 CBA, outlining the planned operation of the facility until the latter of March 31, 2030 or the anticipated conclusion of generation operations at the facility, and including full discussion and analysis of reasonable alternative approaches and reasonable capital costs over the full period. This report outlines Hydro's operational outlook, maintenance strategy, and capital plan for the period 2024–2030.

[1] "*Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 5(2012)," Board of Commissioners of Public Utilities, February 10, 2012.
[2] Ibid., p. 14.
[3] "*Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 2(2023)," Board of Commissioners of Public Utilities, January 26, 2023.

2.0 Introduction

The Holyrood TGS is currently a critical part of the Island Interconnected System. With three oil-fired generating units providing an installed capacity of 490 MW, the Holyrood TGS represents approximately one third of Hydro's Island Interconnected System generating capacity and approximately one quarter of the total Island Interconnected System capacity, when included with all other customer-owned generation. Units 1 and 2 were commissioned in 1970 and 1971, respectively, and Unit 3 in 1979. Units 1 and 2 were originally designed to produce 150 MW each and were upgraded to 170 MW in 1988 and 1989, respectively. Unit 3 retains its original configuration and is rated at 150 MW. In 1986, Unit 3 was retrofitted with synchronous condensing capability to provide voltage support on the eastern area of the Island Interconnected System during periods when power generation from this unit is not required.



Figure 1: Holyrood Thermal Generating Station

The three major components of the thermal generating process are the boiler, turbine, and generator, with supporting systems such as fuel oil storage and delivery, controls, and cooling and feedwater supply systems. Through combustion of No. 6 heavy fuel oil, the power boiler provides high-energy steam to the turbine. The turbine is directly coupled to the generator and provides the rotating energy necessary for the generator to produce rated output power on the Island Interconnected System. The

generator itself is pressurized and cooled by hydrogen gas to provide maximum efficiency both in heat transfer and reduced windage losses.[4]

3.0 Current Operational Outlook and Schedule

During the early operational stages of the Labrador-Island Link ("LIL"), the three Holyrood units will be base loaded to ensure the availability of capacity for the power system. This will remain the case as Hydro continues to monitor LIL performance and reliability. If the LIL is found to perform reliably for an extended period and system conditions permit, Hydro would have the opportunity to strategically remove the Holyrood TGS units from service to place them in standby. As there are reliability concerns associated with the operation of the units at the Holyrood TGS in standby capacity, there are significant fuel costs associated with the continued base-loaded operation of the three units. Hydro is committed to investigating operational strategies to optimize the dispatch of the units to manage start-up challenges while minimizing cost.

Therefore, Hydro recommends that all three Holyrood TGS units are to remain available for operation until they are no longer required for the provision of reliable service to customers. Hydro will continually assess the current context and consider opportunities to reduce capital expenditures, considering the needs of the system and LIL reliability assumptions on an annual basis for capital planning purposes. While Hydro requires the continued availability of the Holyrood TGS, it is recognized that there is a need to accelerate the integration of new generation to reduce the dependency and costs of relying on the Holyrood TGS.

The results of the Holyrood TGS condition assessment[5] provide an indication of the capital asset renewal and maintenance investments that will be required for the continued operation of the Holyrood TGS in the near term. On the basis of the information provided, Hydro can expect the reasonable operation of the facility through the planned end-of-generation on March 31, 2030, with required human, capital and maintenance investments.

[4] Windage losses refer to the losses sustained by a machine due to the resistance offered by air to the rotation of the shaft. Windage losses occur in electric rotating machines such as motors and generators.
[5] "*Reliability and Resource Adequacy Study Review* – Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 31, 2022, att. 2.

4.0 Maintenance Strategy through to Decommissioning

Scheduled overhauls of plant equipment are continuing to support the safe operation and continued availability of assets for generation. Significant changes to Hydro's maintenance strategy between now and the planned retirement date are not anticipated at this time; however, should additional capital costs be identified, diligent consideration will be given to the expenditures prior to application to the Board. Changes in equipment refurbishment intervals may be considered depending on annual operating hours; extension beyond more typical timeframes may be achieved in some instances, allowing Hydro to reduce cost while maintaining safety and reliability.

During post-steam operations, assets with operational synchronous condenser requirements will continue to be optimally maintained. An overview of Hydro's maintenance philosophy for the Holyrood TGS assets is provided in Appendix A to this report.

5.0 Holyrood 2024 Capital Plan Summary

Planned 2024 capital expenditures for the Holyrood TGS include both generation-related and non-generation-related (i.e., synchronous condenser mode) investments. The 2024 capital project proposals, as outlined in Table 1, Table 2, and Table 3, were identified considering safety, environment, asset condition, equipment obsolescence, forecast production requirements, and Hydro's commitment to have the Holyrood TGS fully available to March 31, 2030. The projects outlined herein reflect the necessary refurbishment and replacement projects to support the reliability of the Holyrood TGS and provision of service to customers. In the event of unforeseen failure or unexpected as-found condition, adjustments or additions may be required beyond the current plan.

The extension of steam generation from March 2024 through the Bridging Period to March 2030 potentially has prompted a reassessment of the capital work required to ensure continued reliable operation of the Holyrood generation assets. This reassessment has resulted in the deferral of a number of projects to align with the new operational plan. The No. 2 Pump House, Upgrade of Water Treatment Plant and Waste Water Treatment Plant, Install Plant Heating, and the Installation of New Generator Oil Systems on Unit 3 projects were deferred from the 2024 plan to align with end-of-steam operation. Additionally, a number of projects were removed from the capital plan due to further detailed assessment of required investments to support reliable operation.

Table 1 provides a summary description of the proposed 2024 capital programs and projects for the Holyrood TGS.

Table 1: Holyrood TGS Programs and Projects Proposed in the 2024 CBA

	Program/Project (Totals)	Scope Summary	Proposal Location
Generation Related	Overhaul Unit 1 Turbine Valves and Generator ($5.1 million)	This program is required to complete the scheduled six-year overhaul of the Unit 1 generator and three-year overhaul of the Unit 1 turbine valves. Concurrently with this project, the work to replace the last stage blades (2023 Supplemental Project) will be completed. The last generator overhaul was completed in 2018 and the last valve overhaul was completed in 2021. Deferral would present an unacceptable level of risk to reliability and safety. Regular overhauls are required to ensure continued safe and reliable operation. The generator overhaul will include removal of the generator rotor for detailed condition assessment, electrical testing, and refurbishment of the stator and rotor. Included will be detailed inspection of bearings and other mechanical components including clearances, dimensional checks, and alignment. The valve overhaul will include disassembly, detailed measurement, and inspection, replacement of components, reassembly and commissioning of the major valves, including the stop valves, combined reheat valves, control valves, blowdown valve, and non-return valves. Overhaul of the valves is required for safe control and operation of the steam turbine.	Schedule 6, Program 2
Generation Related	Boiler Condition Assessment and Miscellaneous Upgrades ($4.0 million)	This program is required to complete identified level II condition assessments and detailed inspections of high-pressure boiler components and high-energy piping components. The boilers and associated high-energy piping are exposed to multiple aggressive degradation mechanisms and require regular inspection to monitor deterioration rates and plan interventions. This work is essential to ensure safe and reliable operation of the boilers. The 2024 scope includes work that was identified through prior assessments. Replacements and refurbishments identified through completion of the boiler work, such as the replacement of expansion joints that are deemed capital in nature will be included in the scope.	Schedule 6, Program 6

	Program/Project (Totals)	Scope Summary	Proposal Location
Synchronous Condenser Related	Thermal In-Service Failures (2024)[6] ($3.5 million)	The purpose of this program is to allow completion of capital work due to failure of equipment or the recognition of an incipient failure that cannot wait for the next capital submission cycle. Previously, capital work of this nature required a supplemental submission for approval. This program also includes the purchase of critical capital spares to reduce downtime and increase availability should a failure of a key component occur.	Schedule 6, Program 9
Generation Related	Refurbish Fuel Oil Storage Tank 4 ($1.9 million)	This project proposes to complete a refurbishment of fuel oil storage Tank 4. With retirement of Tank 2 in 2023, and expiration of Tank 4 in 2024, this project will be required to maintain three-tank operation, which is necessary to ensure reliable operation of the Holyrood thermal units. Based on historical and operational data, the consultant expects that patching of the floor rather than replacement of the floor will be acceptable.	Schedule 6, Project 6
Synchronous Condenser Related	Refurbish Outbuilding and Powerhouse Building Envelopes ($0.2 million in 2024; $1.2 million total)	This two-year project is to correct deficiencies found during a 2022 building condition assessment of Holyrood facilities. Work will include roof replacement on four outbuildings where the roof has been deemed to have 1-2 years life expectancy remaining, partial siding replacement on two buildings where siding is at risk of harming people or production as it continues to deteriorate, and replacement of doors and door components as required to ensure these emergency exits remain viable.	Schedule 6, Project 10
Generation Related	Overhaul Pumps ($0.7 million)	This program is required to complete an overhaul of the Unit 1 vacuum pump south, Unit 2 vacuum pump north, and Unit 2 boiler feed pump east. Regular overhauls of major pumps are required to ensure continued reliable operation.	Schedule 6, Proposals Under $750,000
Generation Related	Upgrade Unit 1 Turbine Control System ($0.5 million in 2024; $0.7 million total)	This two-year project is required to replace the turbine control system (governor) on Unit 1. The controls system on Unit 2 is being replaced in 2023 under a previously approved project. The control system controls the turbine valves and adjusts the steam intake into the turbine, maintaining desired generation at the required rotational speed of 3600 rpm. Upgrade will replace control cards that have been obsolete since 2014 with currently supported system controls. Continuing to use the	Schedule 6, Proposals Under $750,000

[6] Depending on the failure type, a portion of the expenditures in this project could be attributed to generation-related expenditures.

	Program/Project (Totals)	Scope Summary	Proposal Location
		current system maintains an increased risk of a unit shut down due to an in-service failure, with a long duration due to unavailability of trained service technicians and parts. Unit 3 does not have this type of control system.	
Generation Related	Overhaul Marine Terminal Loading Arms ($0.5 million)	This project is required to overhaul the marine terminal loading arms that provide the link connection between a delivery tanker and the shore piping that leads to the fuel oil storage tank farm. This work is a continuation of a three year overhaul schedule that has proven to be effective. The loading arms were last overhauled in 2021. Overhaul is required to ensure that the arms will operate as required to accept a tanker delivery, and will not leak heavy fuel oil into the ocean during off-loading activities. Tanker deliveries are required several times per year depending on fuel consumption rates.	Schedule 6, Proposals Under $750,000
Generation Related	Upgrade DCS Hardware – Units 1 and 2 ($0.2 million in 2024; $0.5 million total)	This two-year project proposes to replace obsolete components of the DCS (Distributed Control System), which monitors and controls the operation of much of the plant equipment including boilers, fans, turbines, breakers, and transformers. A previously approved project, scheduled to be complete in 2023, will complete this upgrade on components required for post steam operation of Unit 3 as a synchronous condenser. This proposed project will replace obsolete components required to support generation operation of all three units. Without upgrade the equipment is at elevated risk of in-service failure causing unit outages with long durations, and is more vulnerable to cyber-attack.	Schedule 6, Proposals Under $750,000
Generation Related	Upgrade UPS 1 & 2 ($0.3 million in 2024; $0.4 million total)	This two-year project is required to replace UPS 1 and UPS 2. UPS 3 and 4 were replaced in 2022. UPS 1 and 2 have been in service on a continual basis for approximately 25 years. They provide uninterrupted power to critical systems on Unit 1 and Unit 2 respectively during black outs and other system disruptions. They have been at “end of life” status since 2010, with limited parts and no technical support available from the OEM. Replacement is needed for continued reliable operation of HTGS.	Schedule 6, Proposals Under $750,000

Hydro is managing several deteriorating pieces of infrastructure, notably fuel oil storage tanks, with the intention of reaching end-of-generation life with minimal refurbishment costs. To continue to minimize the investment in assets that are not planned for long-term operation, Hydro has been working with a consultant and the regulator to extend the operating life of the fuel oil storage tanks as is summarized in Table 2.

Table 2: Fuel Oil Storage Tank Status

Tank	Status
Fuel Oil Storage Tank 1	Removed from service in 2021 in preparation for retirement but now being restored in 2023 as it is in better condition than Tank 2.
Fuel Oil Storage Tank 2	Expires 2023. Will be removed from service and retired in 2023.
Fuel Oil Storage Tank 3	Expiry in 2025, however, discussions are underway with the regulator to extend. Moved to 2026 in capital plan pending decision on extension, which is expected later in 2023.
Fuel Oil Storage Tank 4	Expiry in 2024. Project submitted in 2024 CBA to refurbish.
Day Tank	Expires 2023. Project underway to refurbish in 2023.

Based on current operating assumptions, Hydro has determined that the increased risks related to operating with three tanks are acceptable until the planned transition to synchronous generator operation in 2030 or before.

There were no additional internal or external reports, outside of those contained in this CBA, filed in support of the capital expenditure proposals.

Table 3 outlines programs and projects proposed in the 2024 CBA included by major system or subsystem and necessity to generation or synchronous condenser operation.

Table 3: 2024 Program/Project Necessity in the Context of Generation or Synchronous Condenser Operation

Major System or Subsystem	Program/Project	Generation	Synchronous Condenser Operation
Fuel Storage and Delivery	Refurbish Fuel Oil Storage Tank 4 Overhaul Marine Terminal Loading Arms	Required	N/A
Feedwater and Condensate	Overhaul Pumps	Required	N/A
Boiler	Boiler Condition Assessment and Miscellaneous Upgrades	Required	N/A
Turbine Generator	Overhaul Unit 1 Turbine Valves and Generator Upgrade Unit 1 Control System	Required	N/A
Cooling Water Systems	None Required	N/A	N/A
Buildings and Grounds	Refurbish Powerhouse and Outbuildings	Required	Required
Common Systems	Upgrade UPS 1 &2 Upgrade DCS Hardware – Units 1 and 2	Required	N/A
	Thermal In-Service Failures[7]	Required	Required

6.0 Holyrood TGS 2024–2030 Capital Expenditures Outlook

Capital investment will be necessary throughout the period of 2024–2030 to ensure continued reliability of supply and maintenance of the level of service required in generation and synchronous condenser operations. Various types of investments and expenditures for the Holyrood TGS are anticipated, including refurbishment, upgrade or replacement of failed or obsolete equipment, and general plant infrastructure work. In 2021, Hatch Ltd. ("Hatch") completed its Life Extension Condition Assessment Study, including a capital plan to support standby operation of the Holyrood TGS to 2030. Hydro's capital plan for 2024–2030 largely reflects the capital plan provided by Hatch, with modifications to reflect the operating scenario outlook outlined in Section 3.0. Hydro's planned capital expenditures for the Holyrood TGS for the period 2024–2030, segmented by generation-related and synchronous condenser-related expenditures, are provided in Figure 2.

[7] Major system or subsystem is dependent on the type of failure.

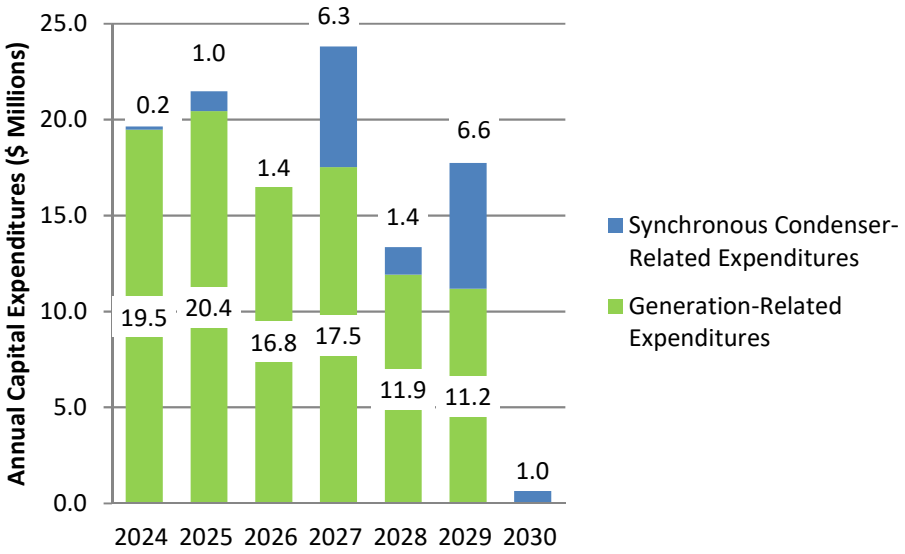


Figure 2: Holyrood TGS Capital Expenditures 2024–2030[8,9]

Planned expenditures for the 2024–2030 capital plan period total $118.9 million, of which, $101 million is related to generation, and $18 million is related to synchronous condenser operation. Approximately $93 million is associated with the continuation of existing capital programs and routine expenditures, including regularly scheduled overhauls of critical generation equipment including boilers, turbine valves and turbines, generators and major pumps. Continuation of these programs is essential in maintaining safe and reliable operation of the thermal units. In addition to asset renewal, the five-year capital plan includes the design and implementation of a plant heating solution for the Holyrood TGS, required following the end-of-steam generation at the Holyrood TGS. Hydro is assessing options for plant heating following the decommissioning of steam-generating components; therefore, the timing and scope of this project is subject to change.

A detailed list of planned capital expenditures are provided in Appendix B.

A number of assumptions have been made in the creation of the capital plan for the Holyrood TGS. This includes projected scenarios of timelines for transition of generation capability from the Holyrood TGS to new generation assets, the expected retirement sequence and retirement dates of the thermal

[8] Numbers may not add due to rounding.
[9] Included in the 2024 to 2029 generation-related expenditures category is approximately $3.5 million for thermal in-service failures. Depending on the failure type, a portion of the $3.5 million could be attributed to synchronous condenser-related expenditures. In 2030 the entire thermal in-service failure expenditure of $700 thousand is considered to be synchronous condenser-related.

generating units at the Holyrood TGS, and other key operational assumptions. These assumptions and the associated capital plan reflect prudent investment required to ensure safe, cost-effective, and reliable operation of the thermal units, until their planned retirement dates.

Assumptions and Constraints:

1) When steam generation is complete at Holyrood TGS, the site will continue to operate Unit 3 as a synchronous condenser. The Holyrood Gas Turbine and the black start diesels will also continue to operate. On-site assets, including buildings, which are required to support these functions will continue to be maintained as appropriate beyond the end-of-steam date until no longer required.

2) The plant annual operation schedule is assumed to remain consistent with recent operation, with critical winter operation from December 1 to March 31 ("operating months") annually, and time available for capital upgrades and maintenance outside of this operating period.

3) It is assumed that units will be mostly online during the operating months and as such there will not be a requirement to exercise idle units by starting them and running them up to full load on a regular basis. Hence this operational plan does not require a change in capital and maintenance requirements which would be necessitated by increasing the number of stops and starts performed on the units annually.

Years 2023–2030:

There will be one Holyrood TGS unit online in mid-October through November; two Holyrood TGS units online from December to February; and one unit online in March.

1) Since units are assumed to be mostly online during the operating months, it is assumed there will be no reduction in maintenance philosophy including preventative maintenance programs, which will not materially change other than continuous improvements through annual reviews completed by Hydro.

2) Staffing levels at Holyrood TGS will remain consistent with current operation.

3) Units will not be required to startup faster than the current rate of 24 hours from cold for the first unit, and 30 hours for second unit. No capital investment will be made to facilitate faster start times or improve standby operation.

4) An alternate source of building heat is not required until 2030 as at least one unit will be online through winter months until 2030.

5) Current reliability targets; DAUFOP – 20% (as noted in the Reliability and Resource Adequacy Study ("RRA")) will continue to be maintained. Capital investment will focus on maintaining, but not improving these levels. Specific investments to improve start-up performance will not be made.

6) The order of unit decommissioning, when appropriate, will be Unit 3 (generating components only), Unit 1, and Unit 2.

7) Three fuel oil storage tanks are required for safe, cost effective, and reliable operation. The potential to operate Holyrood TGS with two tanks has been studied and is not considered feasible due to fuel capacity and delivery constraints, and logistical and operational challenges associated with two-tank operation.[10]

8) The Unit 3 turbine steam chest crack is being managed with support from the turbine service provider, General Electric ("GE"). GE has completed an engineering study. Remediation of this crack is planned during the 2025 planned major overhaul.

9) The Last Stage Blades ("LSB") on Unit 1 and Unit 2 turbines require replacement in 2023 and 2024 as recommended by the original equipment manufacturer and independent consultant. One set of LSBs is being installed on Unit 2 in 2023. A second set will be installed on Unit 1 in 2024.

10) Decommissioning costs are not included in the capital plan and are assumed to be funded by an Asset Retirement Obligation ("ARO") budget. The ARO study was last done in 2016 and is being updated in 2023 to provide updated estimates. This study is outside the scope of the capital plan.

[10] For further details on the risk posed to Holyrood TGS by two-tank operation, please refer to "Application for Approval of Various Supplemental Capital Projects at the Holyrood Thermal Generation," Newfoundland and Labrador Hydro, June 6, 2022, sch. 2, sec. 3.2.

11) The proposed capital projects from the Life Extension Condition Assessment ("LECA") study will be considered in detail relative to the transition scenarios and assumptions. Changing assumptions will be evaluated and may result in deviations from the capital plan contained within the LECA study. Project governance processes will be followed for all proposed projects.

12) Transmission and Rural Operations ("TRO") assets are not included in the Holyrood TGS capital plan. It is assumed that the TRO assets in the switchyard and those adjacent to the powerhouse (unit transformers, station service transformers, and associated components) will be maintained and upgraded as required by TRO to ensure safe and reliable operation of the Holyrood TGS.

Non-critical assets will be monitored and may be allowed to deteriorate where such action does not increase risk to safe and reliable production. Data will be collected from inspections, online monitoring, and formal condition assessments and used to determine the optimal work plan for the assets in light of the changing role of the Holyrood TGS.

6.1 Depreciation Impacts of Holyrood TGS Life Extension

The extension of the Holyrood TGS through the Bridging Period, potentially to March 31, 2030, in combination with additional capital required to ensure the asset is fully available for generation during that timeframe, has created depreciation cost volatility. Depreciation is required to be calculated on an accelerated basis (i.e., monthly depreciation = capital investment divided by remaining months of service life). As per Order No. P.U. 33(2021),[11] the Board approved the deferral of the expenditure variances in excess of $2.5 million above the test year to mitigate material increases in Holyrood assets due to the projected end of generation date.[12]

7.0 Holyrood TGS 2024–2033 Operating Expenses

In Order No. P.U. 14(2004),[13] the Board directed Hydro to file a ten-year plan of maintenance expenditures for the Holyrood TGS with its annual CBA until otherwise directed by the Board. The

[11] "*Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 33(2021)," Board of Commissioners of Public Utilities, December 8, 2021.
[12] As a result of the extension of the Holyrood TGS through the Bridging Period, Hydro intends to make an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account in 2023.
[13] "*Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 14(2004)," Board of Commissioners of Public Utilities, May 4, 2004.

identified and expected system equipment maintenance ("SEM") expenditures for the years 2024–2033, inclusive, are provided in Appendix C to this report.

Due to the harsh operating environment, evolving production requirements, timing of replacement generation assets, the shift to synchronous condensing operation, and the age of units may trigger revision of the maintenance plan to address unforeseen events. The plan currently reflects Hydro's commitment to have the Holyrood TGS fully available for generation through the Bridging Period potentially until March 31, 2030 and is based on the assumptions presented in Section 6.0; changes in operational outlook may result in changes in maintenance expenses. Although expenses for major overhauls are included in capital, some variability in the annual SEM budget will remain as a result of the complexity of numerous components and integrated systems that form a fossil fuel-fired thermal electric generating system.

The SEM expenditures presented in Appendix C are based on the SEM budget planning information for 2024 and 2025. Future years, beyond 2025, are adjusted to reflect the Holyrood TGS's role using the best available information, including up-to-date maintenance tactics and known restoration and inspection work, to establish a ten-year forecast of the maintenance projects for the Holyrood TGS.[14] Actual operation will vary based on the operating requirements of the Holyrood TGS, the results of inspections, and assessments of changing equipment conditions.

8.0 Alternative Approaches

As per the 2022 update to the RRA,[15] the Holyrood TGS shall remain available for a "Bridging Period"[16] until 2030, or until such time that the units are not required for the provision of reliable service to customers.

In the RRA technical conference held on May 1–2, 2023, additional generating assets are required to be brought online (i) to ensure reliable system operation in the event of an extended outage on the LIL, and

[14] In the ten-year maintenance plan (Appendix B), a single escalation factor of 2.0% per year has been used for 2026–2033 based on an average rate from Hydro's current corporate assumptions.
[15] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[16] Hydro considers the Bridging Period to be from 2023 to 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

(ii) to accommodate anticipated load growth with associated federal government targets to reach a net zero by 2050, and a net-zero electricity grid by 2035.

As a follow up to the technical conference, Hydro outlined its planned schedule for future updates to the RRA proceeding.[17] Therein, Hydro communicated its intention to transition to the biennial development of the Resource Adequacy Plan, consisting of updates to Hydro's planning criteria and a long-term resource plan. The development of this plan includes the assessment of various generation alternatives, including renewable generation such as hydraulic units, as well as thermal generation including additional gas turbines. Following the completion of this plan, Hydro anticipates filing an application for additional generation in 2024. While these assessments are still ongoing, Hydro anticipates that the approval, engineering, procurement, construction, and commissioning of new generation sources will take seven to ten years. While Hydro is committed to transitioning from Holyrood as a generating facility as soon as reasonably possible, as a result of these timeframes, there are no reasonable alternatives that would allow Hydro to transition from generation at Holyrood sooner than has been communicated to date. Should any alternatives be identified or the timing of replacement generation changed, this section will be updated accordingly.

[17] "*Reliability and Resource Adequacy Study Review* – Current Schedule for Future Updates," Newfoundland and Labrador Hydro, June 19, 2023.

Appendix A

Holyrood Thermal Generating Station Asset Maintenance Philosophy



Maintenance Philosophy

Maintenance efforts aim to prevent functional failure and extend the operational life of assets, helping to minimize total asset life cycle cost. The type and amount of maintenance applied is dependent on the criticality of the asset and the impact of failure on service delivery. Hydro seeks to balance the cost of maintenance against the cost of failure and its impact on safe, reliable service when applying maintenance strategies and tactics. There are four main types or categories of maintenance undertaken at the Holyrood TGS: preventive maintenance, corrective maintenance, boiler overhauls, and operating projects.

Preventive Maintenance

Hydro continues to use up-to-date maintenance techniques and practices to maintain plant efficiency, availability, and reliability. These include preventive, predictive, and condition-based maintenance techniques, which are usually referred to by the overall term of "preventive maintenance." The basic principle underlying this approach to maintenance is timely intervention to prevent imminent or catastrophic failure that may cause a substantial safety exposure, an extended unavailability of the unit or system, or an increase in cost.

Preventive maintenance comprises routine inspections, minor checks, and component replacement at specific time intervals to prevent failures that are known, or reasonably expected, to occur within a definable time or operating hour interval during the life of the equipment (e.g., generator brush wear, air and oil filter replacements). This also includes discarding equipment or components when it is less costly than repairing or refurbishing them.

Predictive maintenance involves routine testing of equipment to determine deterioration rates and initiating and carrying out repairs in a timely manner before a failure occurs (e.g., ultrasonic thickness checks on fluid lines to monitor erosion wear rates and non-destructive testing of boiler and turbine components to determine fatigue, wear or corrosion rates, and remaining life). Predictive maintenance items include such things as boiler and auxiliary equipment annual overhauls, wherein an assessment is made of components or subsystems that are only accessible during these overhauls.

There is also regular or continual monitoring of equipment operating parameters with a comparison of the results with optimum conditions to determine the most economic time to intervene and perform

remedial work that is intended to return the equipment to optimum performance levels (e.g., air heater washes, generator winding insulation condition, oil sampling and testing).

Since 2008, the Preventive Maintenance Program has been enhanced to include the extra costs associated with plant cleaning in areas where asbestos and heavy metals have been identified as potential health hazards.

Corrective Maintenance

In addition to the preventive maintenance techniques outlined, there are also corrective maintenance requirements. These include work performed to identify, isolate, and restore equipment, machines or systems to a level in which it can be operated safely and used for its intended purpose. The requirement of corrective maintenance may arise for various reasons including failure, wear and tear, and harsh environments such as humid or salt laden air. Examples of corrective maintenance include wear and tear on pumps, pipes, and valves in the main and auxiliary systems.

Boiler Overhauls

Boiler overhauls consist of the maintenance and refurbishment work required to ensure reliable boiler operation for the upcoming season. Boiler overhauls include packages of standard work, defined work, and as-found work. Standard work covers activities that are predictable and required on an annual basis due to normal operation, and wear and tear. Defined work represents planned, specific activities that do not normally occur on an annual basis and addresses issues identified from prior condition inspections and trending. As-found work covers unforeseen issues identified during an ongoing boiler overhaul. In some cases the nature of defined or as-found work meets the criteria for capitalization; in such cases it is not included in SEM.

Operating Projects

Operating projects are low-cost repairs and annual inspections that are required to return structures and equipment to their original or near original operability, to maintain structural integrity, improve efficiency, improve availability, and prevent or reduce environmental risks. Such projects include emissions monitoring and testing, and periodic basin cleaning in the Wastewater Treatment Plant.

Appendix B

Planned Capital Expenditures



Newfoundland and Labrador Hydro
2024 Capital Budget Application
Planned Capital Expenditures
($000)

	2023 and Prior Years	2024	2025	2026	2027	2028	2029	2030	Total
Generator									
Purchase and Replace Last Stage Blades - Holyrood Units 1 and 2	3,596.5	2,812.2							**6,408.7**
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood		5,181.4							**5,181.4**
Refurbish Fuel Oil Storage Tank 4 (2024) - Holyrood		1,920.0							**1,920.0**
Overhaul Pumps (2024) - Holyrood		661.0							**661.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood		3,957.8							**3,957.8**
Overhaul Marine Terminal Loading Arms (2024) - Holyrood		511.0							**511.0**
Thermal In-Service Failures (2024)		3,508.7							**3,508.7**
Upgrade Unit 1 Control System (2024-2025) - Holyrood		468.3	184.3						**652.6**
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood		195.2	277.3						**472.5**
Upgrade UPS 1 & 2 (2024-2025) - Holyrood		263.0	107.6						**370.6**
Thermal In-Service Failures (2025)			3,450.0						**3,450.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood			3,750.0						**3,750.0**
Major Pump Overhaul (2025) - Holyrood			350.0						**350.0**
Turbine and Valve Overhaul - Unit 3 (2025) - Holyrood			11,444.7						**11,444.7**
Marine Terminal Upgrades (2025) - Holyrood			200.0	800.0					**1,000.0**
Refurbish Stage I & II Cooling Water Pumphouses (2025-2026) - Holyrood			670.0	700.0					**1,370.0**
Major Pump Overhaul (Unit 1 WBFP, Unit 1 ECWP, Unit 1 SCEP, Unit 2 SCEP, Unit 3 WBFP)				1,400.0					**1,400.0**
Overhaul Unit 2 Turbine Valves				3,873.0					**3,873.0**
Overhaul Unit 2 Generator				1,839.0					**1,839.0**
Thermal In-Service Failures (2026)				3,528.0					**3,528.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2026)				3,500.0					**3,500.0**
Replace Parts of Unit 3: 129 Vdc Battery Chargers, Batteries, Panels, and Breakers (2026) - Holyrood				750.0					**750.0**
Inspect Stacks (2026) - Holyrood				250.0					**250.0**
Overhaul Fuel Oil Storage Tank 3				200.0	4,600.0				**4,800.0**
Major Pump Overhaul (Unit 1 NCEP, Unit 1 EBFP, Unit 3 SCEP, Unit 3 EBFP)					1,200.0				**1,200.0**
Overhaul Marine Terminal Loading Arms					550.0				**550.0**
Overhaul Unit 1 Turbine Valves - Holyrood					4,066.7				**4,066.7**
Boiler Condition Assessment and Miscellaneous Upgrades (2027)					3,500.0				**3,500.0**
Thermal In-Service Failures (2027)					3,607.0				**3,607.0**
Boiler Condition Assessment and Miscellaneous Upgrades (2028)						3,500.0			**3,500.0**
Major Pump Overhaul (Unit 2 NCEP, Unit 2 ECWP)						450.0			**450.0**
Thermal In-Service Failures (2028)						3,686.0			**3,686.0**
Overhaul Unit 3 Turbine Valves						4,270.0			**4,270.0**
Overhaul of Unit 2 Turbine Valves							4,484.0		**4,484.0**
Overhaul Major Pumps (Unit 2 BFPW; Unit 3 CWPW, CEPN)							700.0		**700.0**
Thermal In Service Failures							2,500.0		**2,500.0**
Boiler Condition Assessment and Misc. Upgrades (2029)							3,500.0		**3,500.0**
Total Generator	**3,596.5**	**19,478.6**	**20,433.9**	**16,840.0**	**17,523.7**	**11,906.0**	**11,184.0**		**100,962.7**
Synchronous Condenser									
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood		156.2	1,039.4						**1,195.6**
Upgrade Water Treatment Plant and Waste Water Treatment Plant - Holyrood				1,000.0					**1,000.0**
Upgrade Cranes and Hoists (2026-2027) - Holyrood				200.0	300.0				**500.0**
Upgrade Synchronous Condenser Building (2026-2027) - Holyrood				200.0	1,000.0				**1,200.0**
Overhaul Unit 3 Generator and Upgrade Online Monitoring (2027) - Holyrood					1,930.9				**1,930.9**
Fire System Upgrades (2027)					350.0				**350.0**
Upgrade Unit 3 Synchronous Condenser Cooling Water Systems H2, Generator Lube Oil, and Seal Oil (2027) - Holyrood					1,500.0				**1,500.0**
Upgrade Wastewater Basin and Underground Drainage (2027) - Holyrood					1,000.0				**1,000.0**
Inspect and Upgrade Light Oil System - Holyrood					200.0	800.0			**1,000.0**
Condition Assessment of doors siding and roofing						120.0			**120.0**
Install Plant Heating - Holyrood						519.0	2,500.0		**3,019.0**
Synchronous Condenser Unit 3 Exciter/Transformer Upgrades							4,000.0		**4,000.0**
Condition Assessment Stage 1 North Service Air Receiver							50.0		**50.0**
Thermal In Service Failures								700.0	**700.0**
Replace Batteries / Chargers								250.0	**400.0**
Total Synchronous Condenser		**156.2**	**1,039.4**	**1,400.0**	**6,280.9**	**1,439.0**	**6,550.0**	**950.0**	**17,965.5**
Grand Total	**3,596.5**	**19,634.8**	**21,473.3**	**18,240.0**	**23,804.6**	**13,345.0**	**17,734.0**	**950.0**	**118,928.2**

Appendix C

Ten-Year System Equipment Maintenance Expenditures





Ten-Year System Equipment Maintenance Expenditures[1]
($000)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Generating Units										
Materials (inc. Boiler Overhauls)	955	975	975	995	1,015	1,035	1,056	81	82	84
Lubes, Chems, Gases	-	9	9	9	10	10	10	-	-	-
Contract Labour (inc. Boiler Overhauls	3,829	4,104	4,223	4,308	4,394	4,482	4,571	189	193	197
Generating Units Total	**4,784**	**5,088**	**5,208**	**5,312**	**5,418**	**5,526**	**5,637**	**270**	**275**	**281**
Common Equipment										
Materials	541	544	544	554	566	577	588	285	291	297
Tools and Operating Supplies	21	26	26	27	27	28	28	14	15	15
Lubes, Chems, Gases	88	68	68	69	71	72	74	8	8	9
Contract Labour (Service Contracts)	1,399	1,577	1,377	1,404	1,433	1,461	1,490	476	485	495
Common Equipment Total	**2,049**	**2,215**	**2,015**	**2,055**	**2,096**	**2,138**	**2,181**	**783**	**799**	**815**
Environmental										
Materials	182	181	181	184	188	192	196	79	80	82
Tools and Operating Supplies	10	15	15	15	16	16	16	7	7	7
Lubes, Chems, Gases	332	334	334	341	347	354	362	172	176	179
Contract Labour (Service Contracts)	99	102	102	254	106	108	110	282	114	117
Environmental Total	**622**	**631**	**631**	**794**	**657**	**670**	**683**	**540**	**378**	**385**
Grand Total	**7,455**	**7,934**	**7,854**	**8,161**	**8,171**	**8,334**	**8,501**	**1,593**	**1,452**	**1,481**

[1] Numbers may not add due to rounding.

Sch 4: 2023 Capital Expenditures Overview

Schedule 4

2023 Capital Expenditures Overview



2024 Capital Budget Application

2023 Capital Expenditures Overview



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Appendix A: Capital Programs and Projects Variance Summary

1.0 Variance Explanations

Explanations are provided below for projects and programs for which overall expenditures, on a total project/program basis, have a forecasted variance of more than $100,000 and 10% from the budgeted amount as of May 31, 2023.[1] As this is a mid-year report, variances are based on focused management and re-forecasting efforts and are subject to change throughout the year as the projects and programs proceed. Actual variances at the completion of each project and program will be discussed in the 2023 Capital Expenditures and Carryover Report[2] when annual expenditures are final.

1.1 Hydraulic Generation Projects and Programs

1.1.1 Hydraulic In-Service Failures (2023)

Table 1: Program Variance – Hydraulic In-Service Failures (2023) ($000)

Budget	Expenditures and Forecast	Variance
1,500.0	2,750.0	1,250.0

This one-year program (2023) for capital expenditures to address in-service failures is expected to be completed in 2023. The program scope is to undertake refurbishment and replacement work due to the occurrence of actual failures, the identification of incipient failures, or the determination of faster-than-anticipated equipment deterioration for Hydro's hydraulic generation assets, and includes the procurement of capital spares required to support such work. The variance in overall program forecast is attributed to more scopes of work expected in 2023 than originally planned.

The forecast for this program includes the cost of known scopes of work as of May 2023, estimated at $2.8 million, and an allowance for additional work that may be identified through the remainder of 2023. A detailed list of work executed under this program will be included in Hydro's Capital Expenditures and Carryover Report for the Year Ending December 31, 2023, to be filed with the Board of Commissioners of Public Utilities ("Board") in the first quarter of 2024.

[1] Capital expenditures for 2023 are based on year-to-date May 31, 2023 actual results.
[2] As per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 2(2023), Board of Commissioners of Public Utilities, January 26, 2023, p. 2/36–37, Hydro's 2023 Capital Expenditures and Carryover Report is to be filed by March 1, 2024.

1.1.2 Hydraulic Generation Refurbishment and Modernization (2022–2023)

Table 2: Project Variance – Hydraulic Generation Refurbishment and Modernization (2022–2023) ($000)

Budget	Expenditures and Forecast	Variance
6,759.5	7,534.1	774.6

This is a two-year project (2022–2023) that commenced in 2022. The project scope includes replacement or refurbishment of failing or failed assets at several hydraulic generating facilities.

The variance in overall project forecast is primarily attributed to the additional refurbishment work required for the overhaul of Unit 6 at the Bay d'Espoir Hydroelectric Generating Station, completed in 2022. More refurbishment work was required for the turbine runner and various components of the generator rotor than anticipated at the time of budget estimate preparation.

The variance is also associated with the draft tube deck substructure condition assessment at the Bay d'Espoir Hydroelectric Generating Station. There were additional construction costs associated with a requirement to schedule the in-water inspections in stages, necessitated by unforeseen challenges in taking the Bay d'Espoir generating units offline so that inspection work could be completed safely. In addition, the work was impacted by a forest fire in Central Newfoundland that resulted in the closure of the Bay d'Espoir Highway in 2022. Construction resources responsible for the underwater portion of the inspection were unable to travel to the project site, which resulted in standby costs. Construction resources already mobilized to site were stranded in the Bay d'Espoir area until the highway reopened, which also resulted in standby costs. The generation outages necessary to complete the underwater portion of the inspection could not be rescheduled within 2022 and the remaining work has been rescheduled to 2023.

1.1.3 Refurbish Ebbegunbaeg Control Structure

Table 3: Project Variance – Refurbish Ebbegunbaeg Control Structure ($000)

Budget	Expenditures and Forecast	Variance[3]
13,619.9	17,679.1	4,059.2

This project budget has been updated as part of the 2024 Capital Budget Application ("CBA"); please refer to Section 2.1 for further discussion.

1.1.4 Hydraulic Generation Refurbishment and Modernization (2021–2022)

Table 4: Project Variance – Hydraulic Generation Refurbishment and Modernization (2021–2022) ($000)

Budget	Expenditures and Forecast	Variance
11,575.1	10,319.2	(1,255.9)

This two-year project (2021–2022) commenced in 2021 and has carried over into 2023. The project scope includes replacement or refurbishment of failing or failed assets at several hydraulic generating facilities. Most of the project work scopes were completed in 2021 and 2022 as planned. Two scopes of work representing less than one percent of the overall project budget were carried over for completion in 2023:

- The planned replacement of annunciator components for Bay d'Espoir Powerhouse 1 commenced but could not be completed in 2022 due to a diminished resource pool for the required technical construction resources due to vacancies and impacts of the COVID-19 pandemic.
- The planned replacement of annunciator components for Hinds Lake Hydroelectric Generating Station commenced but could not be completed in 2022 due to issues with compatibility requirements of equipment.

The variance in overall project forecast is primarily associated with the diesel generator replacement at Burnt Dam Spillway completed in 2022. In 2021, improvements at the Victoria Control Structure

[3] This project has been re-forecasted as per Section 2.0, and therefore has variance against the original approved budget.

resulted in the availability of a 50 kW diesel generator with a low number of operating hours on the unit. That existing unit was able to meet the project requirements at Burnt Dam Spillway and was installed at a lower cost compared to budget estimate to purchase and install a new generator.

The variance is also associated with Unit 6 stator rewind at the Bay d'Espoir Hydroelectric Generating Station completed in 2022. Contract award pricing for the rewind was less than the original budget estimate.

1.1.5 Rotor Rim Shrinking and Stator Recentering at the Upper Salmon Hydroelectric Generating Station

Table 5: Project Variance – Rotor Rim Shrinking and Stator Recentering at the Upper Salmon Hydroelectric Generating Station ($000)

Budget	Expenditures and Forecast	Variance
3,999.8	5,886.4	1,886.6

This is a two-year supplemental project (2022–2023) that commenced in 2022. The project scope is to complete a rotor rim shrinking and stator recentering of the Upper Salmon generating unit generator stator and rotor assemblies. The variance in overall project forecast is attributed to:

- Complexities in completing the engineering and planning work, compounded by performance issues with the owner's engineer that Hydro had initially contracted for this project, resulting in more effort required and greater use of external technical resources;
- Greater than originally estimated construction and materials costs to complete the planned generator refurbishment work;
- Greater than originally estimated level of inspection, refurbishment, testing and re-certification of the powerhouse crane and lifting device, required for the planned lift of the generator rotor;
- Addition of generating unit overhaul activities to the project scope that were originally scheduled for 2024, but advanced to take advantage of the unit disassembly for this project in 2023;[4] and

[4] This allows Hydro to avoid disassembling the unit twice in consecutive years, reducing overall costs.

- Increased project contingency due to the likelihood of additional required scope of work that may be identified following disassembly and inspection of the unit, including possible requirements to remove rotor poles for cleaning and completing stator repairs.

1.2 Terminal Stations Projects and Programs[5]

1.2.1 Circuit Breakers Renewal Program (2023–2024)

Table 6: Project Variance - Circuit Breakers Renewal Program (2023–2024) ($000)

Budget	Expenditures and Forecast	Variance[6]
5,277.9	3,812.0	(1,465.9)

This program budget has been updated as part of the 2024 CBA; please refer to Section 2.4 for further discussion.

1.2.2 Upgrade Circuit Breakers (2022–2023) – Various

Table 7: Project Variance – Upgrade Circuit Breakers (2022–2023) – Various ($000)

Budget	Expenditures and Forecast	Variance
9,483.7	6,398.0	(3,085.7)

This is a two-year project (2022–2023) that commenced in 2022. The project scope includes several circuit breaker replacements and refurbishments at a number of terminal stations. The variance in overall project forecast is attributed to work being completed for less than the budget estimate, primarily as a result of the use of internal construction forces rather than contractors for most of the work.

[5] Hydro anticipates a variance on the 2023 Terminal Station In-Service Failures as a result of the inclusion of returning the current BDE T5 to service as a spare GS, at an estimated cost of $2 million. This inclusion was not reflected in the May 31, 2023 data that is the basis for this report.
[6] This project has been re-forecasted as per Section 2.0, and therefore has variance against the original approved budget.

1.2.3 Upgrade Circuit Breakers (2021–2022) – Various

Table 8: Project Variance – Upgrade Circuit Breakers (2021–2022) – Various ($000)

Budget	Expenditures and Forecast	Variance
10,532.7	8,202.0	(2,330.7)

This is a three-year project (2021–2022) that commenced in 2021.[7] The project scope includes several circuit breaker replacements and refurbishments at a number of terminal stations.

The variance in overall project expenditures is attributed to work being completed for less than the budget estimate, primarily as a result of the use of internal construction forces rather than contractors for most of the work.

1.2.4 Terminal Station Refurbishment and Modernization (2021–2022)

Table 9: Project Variance - Terminal Station Refurbishment and Modernization (2021–2022) ($000)

Budget	Expenditures and Forecast	Variance
13,128.9	11,657.1	(1,471.8)

This two-year project (2021–2022) has carried over into 2023. The project includes a number of consolidated program-type projects across several sites. All projects were closed in 2022 except for the project to install a fire protection system at Massey Drive Terminal Station, which has carried over into 2023.

The variance in overall project forecast is primarily associated with the capital programs for power transformers and grounding systems, and is attributed to completion of work for less than the original budget estimates for several scopes of work.

[7] This project was originally proposed as a two-year project (2021–2022) as part of the 2021 CBA. The project schedule was then updated and approved as a three-year project (2021–2023) as part of the 2022 CBA.

This variance was partially offset by increased costs associated with the capital programs for protection, control and monitoring systems; disconnect switches; and instrument transformers. This offset is primarily attributed to:

- Completion of data alarm management work at the Oxen Pond Terminal Station at costs higher than the original budget estimates; and
- Addition of disconnect switch replacement scope at the Churchill Falls Terminal Station and instrument transformer replacement scope at several terminal stations to this project, transferred from previous projects.

1.2.5 Upgrades for Future Retirement of Stephenville Gas Turbine

Table 10: Project Variance - Upgrades for Future Retirement of Stephenville Gas Turbine ($000)

Budget	Expenditures and Forecast	Variance
6,874.8	7,661.3	786.5

This is a two-year project (2021–2022) that commenced in 2021 and is now planned to carry over into 2024. The project scope includes a number of upgrades to the Bottom Brook and Stephenville Terminal Stations to minimize the risk of customer outages due to a transformer or transmission line failure, following the planned decommissioning of the Stephenville Gas Turbine.[8] The remaining construction activities at Bottom Brook are expected to be completed in 2023. The remaining construction activities at Stephenville must be completed in parallel with gas turbine disconnection and removal activities. The variance in overall project forecast is a result of higher-than-estimated contract pricing for the civil and electrical construction work.

[8] In light of anticipated load growth and the recent positive performance of the Stephenville Gas Turbine, Hydro will consider the continued operation of the Stephenville Gas Turbine beyond 2024, if deemed necessary, in its analysis for the 2024 Reliability and Resource Adequacy update.

1.2.6 Additions for Load – Wabush Substation Upgrades

Table 11: Project Variance – Additions for Load – Wabush Substation Upgrades ($000)

Budget	Expenditures and Forecast	Variance[9]
9,333.8	10,694.2	1,360.4

This project budget has been updated as part of the 2024 CBA; please refer to Section 2.2 for further discussion.

1.2.7 Replace Transformer T7 – Holyrood Terminal Station

Table 12: Project Variance – Replace Transformer T7 – Holyrood Terminal Station ($000)

Budget	Expenditures and Forecast	Variance
2,678.1	4,450.8	1,772.7

This one-year project (2020) has carried over into 2023. The project scope is to replace the Holyrood Transformer T7 with a transformer to be removed from the Churchill Falls Switchyard and complete associated civil, protection and control upgrades. Removal of the old Holyrood T7 and its foundation, and installation of a new concrete pad and oil containment system, were completed in 2020. The transport of the Churchill Falls transformer to Holyrood and the remaining construction activity at Holyrood is expected to be completed in 2023.

As a result of Hydro's decision to maintain Transmission Line L1301 as a backup for the Muskrat Falls – Happy Valley Interconnection for the winter of 2020–2021, Churchill Falls Transformer T31 was not available in 2020 to replace Holyrood T7 as planned by Hydro and approved by the Board. In 2020, Hydro performed an analysis of the resulting risk and confirmed that there would be low risk to customers as a result of this deferral. Hydro advised Newfoundland Power Inc. ("Newfoundland Power") of this decision. In 2021, as a consequence of the further deferral of the Muskrat Falls – Happy Valley Interconnection, the Churchill Falls Transformer T31 again was not available to replace Holyrood T7. As Hydro intended to continue to maintain L1301 as a backup supply for the 2021–2022 winter

[9] This project has been re-forecasted as per Section 2.0, and therefore has variance against the original approved budget.

season, T31 remained in Churchill Falls. In 2022, the transport of the transformer from Churchill Falls to Holyrood could not proceed due to logistical issues related to the size of the transformer and its transportation route. The proposed route by the contractor included the Marine Atlantic ferry service from North Sydney, Nova Scotia to Port Aux Basques, Newfoundland and Labrador. The contractor had based their proposal on the Hydro-supplied manufacturer's as-built drawing for the maximum height of the transformer. The transportation sub-contractor discovered at site that the transformer height exceeded that shown on the as-built drawing and the transformer could not be transported on the ferry. After investigating several other options for transporting the transformer in the fall of 2022, it was decided to delay to a more favorable time of year in 2023 and allow further investigation of more economical options.

The variance in overall project forecast is attributed to higher-than-originally estimated transformer transportation costs. As noted, Hydro is investigating more economical transport options in 2023.

1.3 Distribution Projects and Programs

1.3.1 Install Recloser Remote Control (2022–2023) – Various

Table 13: Project Variance - Install Recloser Remote Control (2022–2023) – Various ($000)

Budget	Expenditures and Forecast	Variance
323.7	223.7	(100.0)

This is a two-year project (2022–2023) that commenced in 2022. The project scope is to install one recloser remote control at the Coney Arm Terminal Station and two recloser remote controls at the Jackson's Arm Terminal Station. During detailed project planning for the Coney Arm scope of work, it was determined that the work would result in significantly lower benefits than were expected at the time of the project proposal. The installation of recloser remote control is no longer justified at Coney Arm and that scope of work was cancelled. The work at Jackson's Arm remains justified and is expected to be completed in 2023. The variance in overall project forecast is attributed to the cancelled scope of work for Coney Arm.

1.4 Rural Generation Projects and Programs

1.4.1 Additions for Load (2022) – Mary's Harbour Service Conductor

Table 14: Project Variance - Additions for Load (2022) – Mary's Harbour Service Conductor ($000)

Budget	Expenditures and Forecast	Variance
359.1	211.0	(148.1)

This is a two-year project (2022-2023) that commenced in 2022 and has been paused for review of the project justification. The project scope is to increase the capacity of the service conductor to address the load growth occurring in Mary's Harbour due to a new seafood processing plant. The construction activity originally planned for 2022 did not proceed as it was determined that the work can only be completed during a full plant outage, which could not be scheduled in 2022 due to issues coordinating a customer outage.

The variance in overall project forecast is attributed to an expected reduction in the required scope of work. However, during a subsequent constructability review, it was determined that this reduction may not be feasible and it is likely this decrease will not be realized.

In early 2023, a decision was made to pause the project and review the project justification, particularly as it relates to the long-term supply for southern Labrador project, wherein interconnection of Mary's Harbour to a regional plant would occur in 2027.[10] This interconnection was originally planned for 2030. If Mary's Harbour is interconnected to a regional plant, the service conductor will no longer be required. This pace advancement would significantly reduce the risk of existing service conductor failure because the cables will experience less periods of peak load. Delaying the project to upgrade the service conductor in Mary's Harbour to 2024 will allow Hydro to finalize its decision to either proceed or cancel this replacement.

[10] "Long-Term Supply for Southern Labrador – Revision 1," Newfoundland and Labrador Hydro, rev. May 31, 2023 (originally filed July 16, 2021).

1.4.2 Makkovik Diesel Generating Station Roof Replacement

Table 15: Project Variance – Makkovik Diesel Generating Station Roof Replacement ($000)

Budget	Expenditures and Forecast	Variance
634.0	810.5	176.5

This is a two-year supplemental project (2022–2023) that commenced in 2022. The project scope is to replace the roof on the original section of the Makkovik Diesel Generating Station. The variance in overall project forecast is attributed the contract pricing exceeding the original budget estimate, in part due to increases in steel prices.

1.4.3 Install Fire Protection in Diesel Plants (2022–2023) – Ramea

Table 16: Project Variance – Install Fire Protection in Diesel Plants (2022–2023) – Ramea ($000)

Budget	Expenditures and Forecast	Variance
1,928.8	1,578.8	(350.0)

This is a two-year project (2022–2023) that commenced in 2022. The project scope is to install an automatic hybrid nitrogen-water fire suppression system at the Ramea Diesel Generating Station. The variance in overall project forecast is attributed to reduction in the required size of the system. The size reduction was possible following a review of a new standard released in 2021. This standard allows for a minimum system discharge time of five minutes, compared to a discharge time of ten minutes that was assumed at the time of the budget estimate preparation. With this change, fewer nitrogen cylinders are required and the planned storage building to contain the cylinders is no longer required.

1.5 Transportation Projects and Programs

1.5.1 Replace Light- and Heavy-Duty Vehicles (2021–2022)

Table 17: Project Variance – Replace Light- and Heavy-Duty Vehicles (2021–2022) ($000)

Original Budget	Expenditures and Forecast	Variance
2,656.1	3,316.1	660.0

This is a two-year project (2021–2022) that has carried over into 2023. The project scope is to procure 26 light-duty vehicles and 6 heavy-duty vehicles. The variance in overall project forecast is attributed to cost escalations from vehicle manufacturers due to global supply chain impacts.

1.5.2 Replace Light- and Heavy-Duty Vehicles (2020–2021) – Various

Table 18: Project Variance – Replace Light- and Heavy-Duty Vehicles (2020–2021) – Various ($000)

Original Budget	Expenditures and Forecast	Variance
3,208.9	4,099.1	890.2

This is a two-year project (2020–2021) that has carried over into 2023. The project scope is to procure 29 light-duty vehicles and 10 heavy-duty vehicles. The variance in overall project forecast is attributed to cost escalations from vehicle manufacturers due to global supply chain impacts.

1.6 Administrative Projects and Programs

1.6.1 Replace Transfer Switches and Associated Hardware – Hydro Place

Table 19: Project Variance – Replace Transfer Switches and Associated Hardware – Hydro Place ($000)

Original Budget	Expenditures and Forecast	Variance
1,135.9	1,285.9	150.0

This is a two-year project (2021–2022) that has carried over into 2023. The project scope is to replace automatic transfer switches and associated hardware at Hydro Place. The variance in overall project forecast is attributed to procurement and construction costs which are expected to exceed the original budget estimate. An arc-flash energy review of the detailed design identified a requirement to upgrade four circuit breakers, which was not included in the original budget estimate. There also has been a

price escalation of industrial goods due to global supply chain challenges since preparation of the original budget estimate.

1.6.2 Replace Elevator Motors and Control Equipment – Hydro Place

Table 20: Project Variance – Replace Elevator Motors and Control Equipment – Hydro Place ($000)

Original Budget	Expenditures and Forecast	Variance
736.7	960.7	224.0

This is a two-year project (2020–2021) that has carried over into 2023. The project scope is to replace motors and control equipment for the two elevators at Hydro Place. The construction work was completed late in 2022 following delays by the contractor, including strike action by the unionized labour. One of the two elevators was tested, certified and released for service in 2022. The final testing and certification of the second elevator carried over and was completed in early 2023.

The variance in overall project forecast is attributed to additional elevator equipment upgrades, necessitated by updated building code requirements.

2.0 Project and Program Budget Updates

Hydro completed a review of the scope, schedule, and cost estimates for multi-year projects and programs continuing in 2024 that were approved as part of the 2023 CBA. Hydro identified previously approved projects and programs where:

- The revised forecast expenditure exceeds the original estimate by 10% or more;
- The revised forecast expenditure is lower than the original estimate; and/or
- The forecasted expenditures are expected to shift beyond 2024.

This review resulted in updated estimates for seven projects and programs. The 2024 portion of the budget for each of these projects and programs is now different than originally presented in the 2023 CBA. A summary of the original and updated cost estimates as of May 2023 for these projects and programs are provided herein.

2.1 Refurbish Ebbegunbaeg Control Structure

This four-year project (2021–2024) commenced in 2021. The project scope is to refurbish the three water control gates and associated equipment at the Ebbegunbaeg Control Structure. Hydro is forecasting an increased cost for the remaining construction activities and is extending the project schedule into 2025.

The forecast cost increase is attributed to:

- Greater complexity and effort in completing stop log slot repairs in Bay 2 (the center gate), which are deteriorated to a greater extent than Bays 1 and 3 (the two outer gates) and may require a substantial cofferdam to facilitate safe work;
- Higher-than-originally estimated contractor pricing for construction work related to the gates and embedded parts; and
- Increased cost associated with the Bay 1 and Bay 3 screw hoists, for which it was determined that replacement is required as refurbishment was not technically feasible due to obsolesce of the equipment.

There remains uncertainty regarding the construction strategy for work in Bay 2, and further engineering and planning will be undertaken in 2023. In order to complete this work in a structured, cost-efficient manner, the project will be extended into 2025.

The budget estimate in Table 21 has been revised to reflect the forecast cost increase and the schedule extension into 2025. A further budget update will be included in the 2025 CBA, if required, following refinement of the execution plan for the remaining work.

Table 21: Budget Update – Refurbish Ebbegunbaeg Control Structure ($000)[11]

	Approved					
Project Cost	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Budget Estimate in 2023 CBA	3,236.8	3,238.3	3,470.1	3,674.7	-	**13,619.9**
Revised Budget Estimate in 2024 CBA[12]	3,236.8	3,238.3	3,470.1	2,781.6	4,952.2	**17,679.1**
Actual Expenditure and Forecast	2,196.4	4,301.5	3,953.9	2,275.0	4,952.2	**17,679.1**

[11] Numbers may not add due to rounding.
[12] The revised budget estimates for 2024 and 2025 are the estimated expenditures plus the forecasted overspend of budget previously approved.

2.2 Additions for Load – Wabush Substation Upgrades

This four-year project (2021–2024) commenced in 2021. The project scope is to complete upgrades at the Jean Lake Terminal Station (formerly the Wabush Substation). Hydro is forecasting an increased cost for the remaining construction activities and is extending the project schedule into 2025.

The forecast cost increase is attributed to:

- Higher than originally estimated contractor pricing for construction of the new control building and extension of the terminal station yard; and
- The requirement to install oil containment systems for the new Transformer T1 and the spare transformer pads, which was not identified during the original project estimate.

The construction of the new control building and extension of the terminal station yard are taking longer than originally estimated and a portion of the equipment installations is now expected to be completed in 2025. The budget estimate in Table 22 has been revised to reflect the forecast cost increase and the schedule extension into 2025.

Table 22: Budget Update – Additions for Load – Wabush Substation Upgrades ($000)[13]

	Approved					
Project Cost	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Budget Estimate in 2023 CBA	1,186.7	6,253.0	-	1,894.1	-	**9,333.8**
Revised Budget Estimate in 2024 CBA[14]	1,186.7	6,253.0	-	2,739.9	514.5	**10,694.2**
Actual Expenditure and Forecast	300.6	2,299.4	4,499.3	3,080.3	514.5	**10,694.2**

2.3 Wabush Terminal Station Upgrades

This four-year project (2021–2024) commenced in 2021. The project scope is to complete upgrades at the Wabush Terminal Station. Hydro is forecasting an increased cost for the remaining construction activities attributed to higher than originally estimated contractor pricing for construction of the new capacitor bank. The budget estimate in Table 23 has been revised to reflect the forecast cost increase.

[13] Numbers may not add due to rounding.
[14] The revised budget estimates for 2024 and 2025 are the estimated expenditures less the forecasted carry over of budget previously approved.

Table 23: Budget Update – Wabush Terminal Station Upgrades ($000)[15]

Project Cost	2021	Approved 2022	2023	2024	Total
Budget Estimate in 2023 CBA	2,301.7	4,935.5	1,632.9	2,702.8	**11,572.9**
Revised Budget Estimate in 2024 CBA[16]	2,301.7	4,935.5	1,632.9	3,808.0	**12,678.1**
Actual Expenditure and Forecast	794.0	1,843.2	7,338.1	2,702.8	**12,678.1**

2.4 Circuit Breakers Renewal Program (2023-2024)

This two-year program (2023–2024) commenced in 2023. The program scope is to refurbish or replace select 69 kV class, 138 kV, and 230 kV circuit breakers. Hydro is forecasting a decreased cost for the remaining construction activities, attributed to a greater portion of the construction activities being completed by internal resources and based on recent breaker replacements and refurbishment expenditures on other projects. The budget estimate in Table 24 has been revised to reflect the forecast cost decrease.

Table 24: Budget Update – Circuit Breaker Renewal Program (2023–2024) ($000)[17]

Program Cost	Approved 2023	2024	Total
Budget Estimate in 2023 CBA	216.9	5,061.0	**5,277.9**
Revised Budget Estimate in 2024 CBA	216.9	3,595.1	**3,812.0**
Actual Expenditure and Forecast	216.9	3,595.1	**3,812.0**

2.5 Additions for Load Growth – Upgrade Transformer Capacity (2023–2024) – Jean Lake Terminal Station

This two-year project (2023–2024) commenced in 2023. The project scope is to complete modifications to the Jean Lake Terminal Station (formerly the Wabush Substation), necessary to ensure an adequate supply of power to the Town of Wabush in the event of a failure to the largest Transformer, T1. The project schedule is extending into 2025 due to the long lead time for the new transformer, which can not be delivered in time for installation in 2024. The project schedule has been updated to install and

[15] Numbers may not add due to rounding.
[16] The revised budget estimate for 2024 is the estimated expenditure plus the forecasted overspend of budget previously approved.
[17] Numbers may not add due to rounding.

commission the transformer in 2025. The budget estimate in Table 25 has been revised to reflect the schedule extension into 2025.

Table 25: Budget Update – Additions for Load Growth – Upgrade Transformer Capacity (2023–2024) – Jean Lake Terminal Station ($000)[18]

Project Cost	Approved 2023	2024	2025	Total
Budget Estimate in 2023 CBA	580.0	5,436.1	-	**6,016.1**
Revised Budget Estimate in 2024 CBA[19]	580.0	-	5,436.1	**6,016.1**
Actual Expenditure and Forecast	52.1	480.7	5,483.3	**6,016.1**

2.6 Diesel Genset Replacement Unit 2039 - St. Lewis

This three-year project (2022–2024) commenced in 2022. The project scope is to replace Unit 2039 and replace or upgrade associated equipment at the St. Lewis Diesel Generating Station. Hydro is forecasting a decreased cost for the remaining construction activities attributed to the cancellation of a portion of the project scope. The plant automation scope was cancelled following a review of the community peak load history and forecast. There are no benefits to automating the plant as there are no circumstances where more than one unit would be required to operate at any given time. The budget estimate in Table 26 has been revised to reflect the cancelled scope.

Table 26: Budget Update – Diesel Genset Replacement Unit 2039 – St. Lewis ($000)[20]

Project Cost	Approved 2022	2023	2024	Total
Budget Estimate in 2023 CBA	397.0	1,583.8	134.9	**2,115.7**
Revised Budget Estimate in 2024 CBA[21,22]	397.0	1,533.8	-	**1,980.0**
Actual Expenditure and Forecast	238.7	1,692.1	34.9	**1,965.7**

[18] Numbers may not add due to rounding.
[19] The revised budget estimates for 2024 and 2025 are the estimated expenditures less the forecasted carryover of budget previously approved.
[20] Numbers may not add due to rounding.
[21] The revised budget estimate for 2024 is the estimated expenditures less the forecasted carryover of budget previously approved.
[22] As the amounts approved by the Board within 2022 and 2023 cannot be changed, the budget exceeds the forecast.

2.7 Diesel Genset Replacement Program (2023–2025)

This three-year program (2023–2025) commenced in 2023. The program scope is to:

- Replace Unit 2053 and replace or upgrade associated equipment at the Hopedale Diesel Generating Station; and
- Replace Unit 2056 and replace or upgrade associated equipment at the St. Brendan's Diesel Generating Station.

Hydro is forecasting a decreased cost for the planned construction activities at Hopedale and is extending the project schedule into 2026. The work at St. Brendan's remains on schedule for completion in 2023 with no change to the forecast cost.

The forecast cost decrease for Hopedale is attributed to a change in the least-cost alternative. Following the initial tender for the new genset, it was determined that the planned 1,067 kW, 1,200 rpm genset cost was significantly higher than originally estimated. An updated analysis of alternatives concluded that a genset between 700 and 850 kW at 1,800 rpm is now the least cost alternative by a significant margin. Hydro is re-tendering for the procurement of this smaller genset.

The program schedule is extending into 2026 as a result of the additional time required to re-evaluate alternatives and significant genset lead times. The genset cannot be delivered and installed in 2024 as originally planned, and is now expected to be delivered when seasonal ferry service to the community of Hopedale begins in late spring of 2025. Installation is scheduled to commence in the summer of 2025 and the automation scope of work is expected to be completed in 2026. The budget estimate in Table 27 has been revised to reflect the forecast cost decrease and schedule extension into 2026.

Table 27: Budget Update – Diesel Genset Replacement Program (2023–2025) ($000)[23]

Program Cost	Approved 2023	2024	2025	2026	Total
Budget Estimate in 2023 CBA	819.1	2,333.6	223.4	-	**3,376.1**
Revised Budget Estimate in 2024 CBA[24]	819.1	174.0	1,883.1	250.0	**3,126.1**
Actual Expenditure and Forecast	643.0	350.0	1,883.1	250.0	**3,126.1**

[23] Numbers may not add due to rounding.
[24] The revised budget estimates for 2024 and 2025 are the estimated expenditures less the forecasted carryover of budget previously approved.

3.0 Bay d'Espoir Penstock Execution Update

On April 12, 2023, the Board approved Hydro's supplemental capital project for section replacement and weld refurbishment of Penstock 1 at the Bay d'Espoir Hydroelectric Generating Station and ordered that "Until further direction of the Board, Hydro shall file a report annually, beginning with its 2024 Capital Budget Application addressing the Penstock 1 project as well as planned life extension work on Penstocks 2 and 3."[25] While Hydro recognizes that more substantial reporting may be required as execution progresses, Hydro has included its first update herein as limited progress reporting is available at this early stage of project execution.

Since approval, a project team has been assigned, and specifications for an Engineering, Procurement, and Construction Management ("EPCM") contract are under development. Hydro anticipates tendering of this contract by the end of July 2023. This is a critical task which includes all requirements for the detailed design, procurement support, construction contract administration, and construction management for the project. At this time, the project budget and schedule remain consistent with Hydro's approved application. Hydro anticipates it will be better positioned to update project costs and schedule once the EPCM contract has been awarded. Hydro's project expenditures to date total approximately $521,000, and its forecasted expenditures for 2023 total $1.5 million.

In May 2023, inspections were completed on Penstocks 2 and 3 at Bay d'Espoir. Inspections revealed two indications on Penstock 2, and nine indications on Penstock 3, ranging from several inches to several feet. As a result of these findings, the inspection depth was increased to the same level as that of Penstock 1, to ensure the inspection captured all indications. All indications were repaired and the penstocks were returned to service. The findings of the inspection are currently under review by Kleinschmidt, who will provide recommendations for future life extension work. Hydro anticipates that it will be recommended to continue the increased depth of inspections on Penstock 3 until such time that a long-term solution is implemented.

[25] As per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 6(2023), Board of Commissioners of Public Utilities, April 12, 2023, p. 9/7–9.

Appendix A

Capital Programs and Projects Variance Summary



Total Open Capital Project Variance[1]

Overview - All Years

($000)

Asset Type	Board-Approved Budget	Total Project Expenditures and Forecast	Variance	Variance %
Hydraulic	41,794	46,621	4,828	12%
Thermal	20,153	20,140	(13)	0%
Gas Turbines	6,627	6,627	(0)	0%
Terminal Stations	96,632	93,435	(3,197)	-3%
Transmision	2,976	2,976	0	0%
Distribution	13,984	13,884	(100)	-1%
Rural Generation	18,398	17,325	(1,073)	-6%
Properties	5,724	5,724	0	0%
Metering	6,102	6,102	0	0%
Rural Systems Tools and Equipment	4,544	4,544	0	0%
Information Systems	1,633	1,611	(22)	-1%
Telecontrol	2,304	2,304	0	0%
Transportation	14,013	15,563	1,550	11%
Administrative	2,146	2,520	374	17%
Allowance for Unforeseen	1,000	1,000	0	0%
Supplemental Projects	88,454	90,517	2,063	2%
Projects Approved for less than $50,000	124	124	0	0%

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Year[1]
($000)

	Capital Budget[2]							Actual Expenditure and Forecast								
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F	H+I-D
Summary	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	Forecast Jun-Dec 2023	2024 and Beyond	Total	Project Variance	Annual Variance
2023 Projects	-	-	-	-	55,424.7	55,424.7	89,248.8	**144,673.5**	-	-	-	12,761.7	43,208.9	88,236.9	**144,207.6**	(465.9)	546.0
2022 Projects	-	-	17,805.1	2,403.1	43,856.2	46,259.4	3,765.9	**65,427.3**	-	-	12,788.8	11,835.9	32,362.2	7,541.9	**64,528.8**	(898.5)	(2,061.3)
2021 Projects	-	34,941.6	53,248.3	30,664.9	6,628.0	37,292.8	8,271.6	**103,089.4**	-	16,517.8	37,439.1	10,630.4	26,683.0	14,707.0	**105,977.3**	2,887.9	20.5
2020 Projects	5,064.2	5,926.9	2,427.4	6,922.8	-	6,922.8	-	**13,418.5**	885.5	1,649.7	6,109.4	1,653.2	6,007.7	-	**16,305.5**	2,887.0	738.2
Grand Total	**5,064.2**	**40,868.5**	**73,480.8**	**39,990.8**	**105,908.9**	**145,899.7**	**101,286.3**	**326,608.6**	**885.5**	**18,167.5**	**56,337.3**	**36,881.3**	**108,261.8**	**110,485.9**	**331,019.2**	**4,410.6**	**(756.6)**

2023 Capital Budget Approved by Board Order No. P.U. 2(2023)	90,828.7
New Project Approved by Board Order No. P.U. 27(2021)	586.4
New Project Approved by Board Order No. P.U. 28(2021)	118.3
New Project Approved by Board Order No. P.U. 12(2022)	457.2
New Project Approved by Board Order No. P.U. 14(2022)	137.7
New Project Approved by Board Order No. P.U. 17(2022)	1,560.6
New Project Approved by Board Order No. P.U. 18(2022)	3,040.4
New Project Approved by Board Order No. P.U. 30(2022)	3,385.5
New Project Approved by Board Order No. P.U. 32(2022)	44.9
New Project Approved by Board Order No. P.U. 6(2023)	2,105.0
New Project Approved by Board Order No. P.U. 12(2023)	3,596.5
2022 New Projects under $50,000 Approved by Hydro	47.7
Total Approved Capital Budget Before Carryovers	105,908.9
Carryover Projects 2022 to 2023[3]	39,990.8
TOTAL APPROVED CAPITAL BUDGET	145,899.7
Less:	
Carryover CIAC's[3]	(3,097.5)
Supplemental CIAC's	0.0
TOTAL APPROVED CAPITAL BUDGET NET OF CIAC's	142,802.2

[1] Numbers may not add due to rounding

[2] Annual budgets previous to 2023 pertain to projects that have expenditures in 2023

[3] The 2022 carryover is $39.991 million net of Contributions in Aid of Construction ("CIAC") of $3.097 million ($39.991 - $3.097 = $36.893).

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
	A		B	C	D (B+C)	E	F (A+C+E)		G		H	I	J	K (G+H+I+J)	K-F		H+I-D	
Hydraulic Generation Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2023 Projects																			
Replace Powerhouse Station Service Panel (2023-2024) - Upper Salmon	-	-	-	-	591.8	591.8	976.7	**1,568.5**	-	-	-	72.8	519.0	976.7	**1,568.5**	-	0.00%	-	0.00%
Overhaul Turbine Gen - BDE Unit 1&3 (2023)	-	-	-	-	975.7	975.7	-	**975.7**	-	-	-	403.9	571.8	-	**975.7**	-	0.00%	-	0.00%
Replace Emergency Lift (2023) - Salmon River Spillway	-	-	-	-	49.8	49.8	-	**49.8**	-	-	-	20.5	29.3	-	**49.8**	-	0.00%	-	0.00%
Replace Diesel Genset 1 (2023-2024) - Ebbegunbaeg	-	-	-	-	298.0	298.0	728.3	**1,026.3**	-	-	-	73.6	224.4	728.3	**1,026.3**	-	0.00%	-	0.00%
Hydraulic In-Service Failures (2023)	-	-	-	-	1,500.0	1,500.0	-	**1,500.0**	-	-	-	909.0	1,841.0	-	**2,750.0**	1,250.0	83.33%	1,250.0	83.33%
Refurbish Superstructure (2023-2024) - Salmon River Spillway	-	-	-	-	328.3	328.3	2,500.0	**2,828.3**	-	-	-	37.6	290.7	2,500.0	**2,828.3**	-	0.00%	-	0.00%
Upgrade Public Safety Around Dams and Waterways (2023)	-	-	-	-	482.1	482.1	-	**482.1**	-	-	-	45.2	436.9	-	**482.1**	-	0.00%	-	0.00%
Water System Condition Assessment and Upgrades (2023) - Bay d'Espoir	-	-	-	-	161.0	161.0	504.9	**665.9**	-	-	-	24.6	136.4	504.9	**665.9**	-	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2023) - Hydraulic Plants	-	-	-	-	144.9	144.9	-	**144.9**	-	-	-	33.9	111.0	-	**144.9**	-	0.00%	-	0.00%
Unit 7 Condition Assessment (2023) - Bay d'Espoir	-	-	-	-	597.5	597.5	-	**597.5**	-	-	-	39.9	557.6	-	**597.5**	-	0.00%	-	0.00%
2022 Projects																			
Hydraulic Generation Refurbishment and Modernization - Various Sites	-	-	2,970.6	1,080.7	3,788.9	4,869.6	-	**6,759.5**	-	-	2,664.6	461.6	4,408.0	-	**7,534.1**	774.6	11.46%	-	0.00%
2021 Projects																			
Refurbish Ebbegunbaeg Control Structure	-	3,236.8	3,238.3	(22.9)	3,470.1	3,447.2	3,674.7	**13,619.9**	-	2,196.4	4,301.5	152.9	3,801.1	7,227.2	**17,679.1**	4,059.2	29.80%	506.7	14.70%
Hydraulic Generation Refurbishment and Modernization - Various Sites	-	6,569.5	5,005.6	111.5	-	111.5	-	**11,575.1**	-	3,640.2	6,567.5	103.7	7.8	-	**10,319.2**	(1,255.9)	-10.85%	-	0.00%
Total Hydraulic Generation Projects	**-**	**9,806.4**	**11,214.5**	**1,169.3**	**12,388.1**	**13,557.4**	**8,384.6**	**41,793.6**	**-**	**5,836.6**	**13,533.6**	**2,379.0**	**12,935.1**	**11,937.1**	**46,621.5**	**4,827.9**		**1,756.7**	
		9,806.4	11,214.5	1,169.3	12,388.1	13,557.43	8,384.6	**41,793.6**		5,836.6	13,533.6	2,379.0	12,935.1	11,937.1	**46,621.5**	4,827.91		1,756.70	
		-	-	-	-	-	-	-		-	-	-	-	-	-				

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
		A		B	C	D (B+C)	E	F (A+C+E)		G		H	I	J	K (G+H+I+J)	K-F		H+I-D	
Thermal Generation Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2023 Projects																			
Thermal In-Service Failures (2023)	-	-	-	-	3,300.0	3,300.0	-	**3,300.0**	-	-	-	420.4	2,879.6	-	**3,300.0**	-	0.00%	-	0.00%
Overhaul Pumps (2023) - Holyrood	-	-	-	-	742.4	742.4	-	**742.4**	-	-	-	22.5	719.9	-	**742.4**	-	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2023) - Thermal Plants	-	-	-	-	55.1	55.1	-	**55.1**	-	-	-	49.2	5.9	-	**55.1**	-	0.00%	-	0.00%
Overhaul Unit 2 Turbine and Valves (2023) - Holyrood	-	-	-	-	9,701.8	9,701.8	-	**9,701.8**	-	-	-	238.1	9,463.7	-	**9,701.8**	-	0.00%	-	0.00%
Refurbish Workshop Roof (2023) - Holyrood	-	-	-	-	243.7	243.7	-	**243.7**	-	-	-	30.8	212.9	-	**243.7**	-	0.00%	-	0.00%
Boiler Condition Assessment and Miscellaneous Upgrades (2023) - Holyrood	-	-	-	-	2,926.6	2,926.6	-	**2,926.6**	-	-	-	148.7	2,777.9	-	**2,926.6**	-	0.00%	-	0.00%
Refurbish BioGreen Sewage System (2023) - Holyrood	-	-	-	-	256.6	256.6	-	**256.6**	-	-	-	27.7	228.9	-	**256.6**	-	0.00%	-	0.00%
2022 Projects																			
Unit 3 Generator Components Condition Assessment and Miscellaneous Upgrades	-	-	153.0	(69.8)	338.8	269.0	-	**491.8**	-	-	210.0	140.3	128.8	-	**479.0**	(12.8)	-2.61%	-	0.00%
Replace Underground Fire Water Distribution System - Holyrood	-	-	128.3	13.1	1,578.0	1,591.1	-	**1,706.3**	-	-	115.2	183.8	1,407.3	-	**1,706.3**	-	0.00%	-	0.00%
2021 Projects																			
Upgrade Distributed Control System Hardware - Holyrood	-	360.4	368.2	205.2	-	205.2	-	**728.6**	-	171.6	351.7	164.8	40.4	-	**728.6**	(0.0)	0.00%	-	0.00%
Total Thermal Generation Projects	**-**	**360.4**	**649.5**	**148.6**	**19,143.0**	**19,291.6**	**-**	**20,152.9**	**-**	**171.6**	**676.8**	**1,426.3**	**17,865.3**	**-**	**20,140.1**	**(12.8)**		-	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast									
		A		B	C	D (B+C)	E	F (A+C+E)				H	I	J	K (G+H+I+J)	K-F		H+I-D	
Gas Turbine Generation Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2023 Projects																			
Purchase Tools and Equipment Less than $50,000 (2023) - Gas Turbine	-	-	-	-	18.3	18.3	-	**18.3**	-	-	-	16.7	1.6	-	18.3	-	0.00%	-	0.00%
Replace Human Machine Interface (2023) - Happy Valley Gas Turbine	-	-	-	-	138.6	138.6	-	**138.6**	-	-	-	27.8	110.8	-	138.6	-	0.00%	-	0.00%
Replace Oil Mist Separator (2023-2024) - Happy Valley Gas Turbine	-	-	-	-	138.5	138.5	262.1	**400.6**	-	-	-	17.1	121.4	262.1	400.6	-	0.00%	-	0.00%
Gas Turbine In-Service Failures (2023)	-	-	-	-	344.2	344.2	-	**344.2**	-	-	-	33.2	311.0	-	344.2	-	0.00%	-	0.00%
								-											
2022 Projects								-											
Control System Replacement - Holyrood Gas Turbine	-	-	146.0	75.2	41.0	116.2	-	**187.0**	-	-	70.8	74.5	41.6	-	187.0	-	0.00%	-	0.00%
Install Infrared Scanning Ports - Happy Valley Gas Turbine	-	-	39.6	22.4	25.6	48.0	-	**65.2**	-	-	17.2	16.5	31.5	-	65.2	-	0.00%	-	0.00%
								-											
2020 Projects								-											
Perform Combustor Inspection - Holyrood Gas Turbine	546.1	2,500.0	2,427.4	3,031.7	-	3,031.7	-	**5,473.5**	35.0	39.3	2,367.5	79.5	2,952.3	-	5,473.5	(0.0)	0.00%	-	0.00%
Total Gas Turbine Generation Projects	**546.1**	**2,500.0**	**2,613.0**	**3,129.2**	**706.2**	**3,835.4**	**262.1**	**6,627.4**	**35.0**	**39.3**	**2,455.6**	**265.3**	**3,570.2**	**262.1**	**6,627.4**	**(0.0)**		-	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
		A		B	C	D (B+C)	E	F (A+C+E)		G		H	I	J	K (G+H+I+J)	K-F		H+I-D	
Terminal Stations Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2023 Projects																			
Terminal Station In-Service Failures (2023)	-	-	-	-	1,300.0	1,300.0	-	**1,300.0**	-	-	-	129.6	1,170.4	-	**1,300.0**	-	0.00%	-	0.00%
Install Fire Protection in 230 kV Stations (2023-2024) - Deer Lake	-	-	-	-	79.2	79.2	535.3	**614.5**	-	-	-	18.1	61.1	535.3	**614.5**	-	0.00%	-	0.00%
Circuit Breakers Renewal Program (2023-2024)	-	-	-	-	216.9	216.9	5,061.0	**5,277.9**	-	-	-	34.9	182.0	3,595.1	**3,812.0**	(1,465.9)	-27.77%	-	0.00%
Install Oil Spill Containment Transformer T1S (2023-2024) - Cat Arm	-	-	-	-	155.1	155.1	426.5	**581.6**	-	-	-	14.1	141.0	426.5	**581.6**	-	0.00%	-	0.00%
Install Breaker Failure Protection (2023-2024) - Sunnyside	-	-	-	-	73.5	73.5	216.2	**289.7**	-	-	-	33.4	40.1	216.2	**289.7**	-	0.00%	-	0.00%
Replace Data Alarm System Annunciators (2023) - Buchans	-	-	-	-	61.2	61.2	104.8	**166.0**	-	-	-	21.4	39.8	104.8	**166.0**	-	0.00%	-	0.00%
Replace Circuit Breaker Reclosing Controllers (2023-2024) - Hardwoods	-	-	-	-	81.6	81.6	149.6	**231.2**	-	-	-	17.3	64.3	149.6	**231.2**	-	0.00%	-	0.00%
Replace Terminal Station Lighting (2023-2024)	-	-	-	-	323.3	323.3	594.1	**917.4**	-	-	-	43.2	280.1	594.1	**917.4**	-	0.00%	-	0.00%
Major Condition Assessment and Miscellaneous Refurbishments Synchronou	-	-	-	-	577.2	577.2	516.1	**1,093.3**	-	-	-	505.8	71.4	516.1	**1,093.3**	-	0.00%	-	0.00%
Additions for Load Growth - Upgrade Transformer Capacity (2023-2024) - Je	-	-	-	-	580.0	580.0	5,436.1	**6,016.1**	-	-	-	30.9	21.2	5,964.0	**6,016.1**	-	0.00%	(527.9)	-91.02%
Terminal Station Renewal Program - Various Sites	-	-	-	-	1,733.7	1,733.7	5,584.5	**7,318.2**	-	-	-	309.5	1,424.2	5,584.5	**7,318.2**	-	0.00%	-	0.00%
2022 Projects																			
Upgrade Circuit Breakers (2022-2023) - Various	-	-	2,121.9	(1,081.2)	7,361.8	6,280.6	-	**9,483.7**	-	-	117.4	2,250.3	4,030.3	-	**6,398.0**	(3,085.7)	-32.54%	-	0.00%
Terminal Station Refurbishment and Modernization - Various Sites	-	-	3,111.9	1,075.5	6,109.7	7,185.2	-	**9,221.6**	-	-	2,168.7	1,958.3	5,226.9	-	**9,354.0**	132.4	1.44%	-	0.00%
2021 Projects																			
Upgrade Circuit Breakers (2021-2022) - Various	-	5,418.8	4,293.6	(539.6)	820.3	280.7	-	**10,532.7**	-	2,597.7	4,818.6	446.4	339.3	-	**8,202.0**	(2,330.7)	-22.13%	505.0	179.94%
Upgrades for Future Retirement of Stephenville Gas Turbine	-	1,530.3	5,344.5	5,662.2	-	5,662.2	-	**6,874.8**	-	151.8	1,060.9	429.5	4,837.0	1,182.1	**7,661.3**	786.5	11.44%	(395.6)	-6.99%
Additions for Load - Wabush Substation Upgrades	-	1,186.7	6,253.0	6,200.1	-	6,200.1	1,894.1	**9,333.8**	-	300.6	2,299.4	1,790.6	2,708.7	3,594.9	**10,694.2**	1,360.4	14.57%	(1,700.7)	-27.43%
Wabush Terminal Station Upgrades	-	2,301.7	4,935.5	4,600.0	1,632.9	6,232.9	2,702.8	**11,572.9**	-	794.0	1,843.2	2,837.4	4,500.7	2,702.8	**12,678.1**	1,105.2	9.55%	1,105.2	17.73%
Terminal Station Refurbishment and Modernization - Various Sites	-	6,171.6	6,957.3	321.4	-	321.4	-	**13,128.9**	-	3,903.3	7,432.3	263.5	57.9	-	**11,657.1**	(1,471.8)	-11.21%	-	0.00%
2020 Projects																			
Replace Transformer T7 - Holyrood Terminal Station	2,678.1	-	-	2,244.0	-	2,244.0	-	**2,678.1**	660.6	250.2	557.9	115.3	2,866.9	-	**4,450.8**	1,772.7	66.19%	738.2	32.89%
Total Terminal Stations Projects	**2,678.1**	**16,609.1**	**33,017.7**	**18,482.4**	**21,106.4**	**39,588.8**	**23,221.1**	**96,632.5**	**660.6**	**7,997.6**	**20,298.3**	**11,249.6**	**28,063.3**	**25,166.0**	**93,435.4**	**(3,197.0)**		**(275.9)**	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget							Actual Expenditure and Forecast										
		A		B	C	D (B+C)	E	F (A+C+E)		G		H	I	J	K (G+H+I+J)	K-F		H+I-D	
Transmission Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2023 Projects																			
Wood Pole Line Management Program (2023)	-	-	-	-	2,824.4	2,824.4	-	**2,824.4**	-	-	-	498.8	2,325.6	-	**2,824.4**	-	0.00%	-	0.00%
Transmission In-Service Failures (2023)	-	-	-	-	151.7	151.7	-	**151.7**	-	-	-	147.9	3.8	-	**151.7**	-	0.00%	-	0.00%
Total Transmission Projects	**-**	**-**	**-**	**-**	**2,976.1**	**2,976.1**	**-**	**2,976.1**	**-**	**-**	**-**	**646.6**	**2,329.5**	**-**	**2,976.1**	**-**		**-**	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
	A			B	C	D (B+C)	E	F (A+C+E)	A			H	I	J	K (G+H+I+J)	K-F		H+I-D	
Distribution Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2023 Projects																			
Provide Service Extensions - Various	-	-	-	-	3,964.0	3,964.0	-	**3,964.0**	-	-	-	1,466.8	2,497.2	-	**3,964.0**	-	0.00%	-	0.00%
Distribution System In-Service Failures, Misc. Upgrd, and Street Lights - Various	-	-	-	-	3,986.0	3,986.0	-	**3,986.0**	-	-	-	2,960.1	1,025.9	-	**3,986.0**	-	0.00%	-	0.00%
Upgrade of Worst-Performing Distribution Feeders (2023-2024)	-	-	-	-	73.4	73.4	1,372.6	**1,446.0**	-	-	-	56.1	17.3	1,372.6	**1,446.0**	-	0.00%	-	0.00%
2022 Projects																			
Install Recloser Remote Control (2022-2023)	-	-	174.6	36.8	149.1	185.9	-	**323.7**	-	-	37.8	52.7	133.1	-	**223.7**	(100.0)	-30.89%	-	0.00%
Upgrade of Worst-Performing Distribution Feeders (2022-2023)	-	-	850.0	(11.8)	1,922.9	1,911.1	-	**2,772.9**	-	-	861.8	644.4	1,266.7	-	**2,772.9**	-	0.00%	-	0.00%
Labrador City L22 Voltage Conversion (2022-2023)	-	-	486.8	387.7	1,004.4	1,392.1	-	**1,491.2**	-	-	99.1	66.9	9.7	1,315.5	**1,491.2**	-	0.00%	(1,315.5)	-94.50%
Total Distribution Projects	**-**	**-**	**1,511.4**	**412.7**	**11,099.8**	**11,512.5**	**1,372.6**	**13,983.8**	**-**	**-**	**998.7**	**5,247.0**	**4,950.0**	**2,688.1**	**13,883.8**	**(100.0)**		**(1,315.5)**	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast											
		A		B	C	D (B+C)	E	F (A+C+E)		G		H	I	J	K (G+H+I+J)	K-F		H+I-D	
Rural Generation Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2023 Projects																			
Diesel Genset Replacement Program (2023-2025)	-	-	-	-	819.1	819.1	2,557.0	**3,376.1**	-	-	-	130.2	512.8	2,483.1	**3,126.1**	(250.0)	-7.40%	(176.1)	-21.50%
Diesel In-Service Failures (2023)	-	-	-	-	480.4	480.4	-	**480.4**	-	-	-	8.0	472.4	-	**480.4**	-	0.00%	-	0.00%
Overhaul Diesel Units (2023)	-	-	-	-	1,502.0	1,502.0	-	**1,502.0**	-	-	-	295.8	1,206.2	-	**1,502.0**	-	0.00%	-	0.00%
Replace Building Exterior (2023-2024) - Postville	-	-	-	-	124.6	124.6	558.7	**683.3**	-	-	-	39.8	84.8	558.7	**683.3**	-	0.00%	-	0.00%
Replace Intermediate Fuel Storage Tanks (2023-2024) - Nain	-	-	-	-	127.4	127.4	593.7	**721.1**	-	-	-	20.2	107.2	593.7	**721.1**	-	0.00%	-	0.00%
2022 Projects																			
Install Fire Protection in Diesel Plants (2022-2023) - Ramea	-	-	90.7	(336.2)	1,838.1	1,501.9	-	**1,928.8**	-	-	76.9	40.3	1,461.6	-	**1,578.8**	(350.0)	-18.15%	-	0.00%
Additions for Load (2022) - Mary's Harbour Service Conductor	-	-	307.8	36.7	51.3	88.0	-	**359.1**	-	-	123.0	28.7	(1.2)	60.5	**211.0**	(148.1)	-41.24%	(60.5)	-68.76%
Diesel Genset Replacement Unit 2039 - St. Lewis	-	-	397.0	158.3	1,583.8	1,742.1	134.9	**2,115.7**	-	-	238.7	219.8	1,472.3	34.9	**1,965.7**	(150.0)	-7.09%	(50.0)	-2.87%
Diesel Genset Replacement Unit 2012 - L'Anse-Au-Loup	-	-	339.9	169.6	2,513.2	2,682.8	210.2	**3,063.3**	-	-	170.3	61.3	121.5	2,710.2	**3,063.3**	0.0	0.00%	(2,500.0)	-93.18%
2021 Projects																			
Diesel Genset Replacements (2021-2022)	-	2,560.6	286.2	131.7	-	131.7	-	**2,846.8**	-	1,503.8	1,036.3	132.5	(0.7)	-	**2,671.8**	(175.0)	-6.15%	-	0.00%
2020 Projects																			
Replace Powerhouse Roofing System - L'Anse Au Loup and St. Anthony	125.3	1,195.8	-	130.9	-	130.9	-	**1,321.2**	121.6	105.8	963.0	18.0	112.9	-	**1,321.3**	0.2	0.01%	-	0.00%
Total Rural Generation Projects	**125.3**	**3,756.4**	**1,421.6**	**291.1**	**9,039.9**	**9,331.0**	**4,054.5**	**18,397.8**	**121.6**	**1,609.5**	**2,608.1**	**994.7**	**5,549.7**	**6,441.1**	**17,324.8**	**(1,072.9)**		**(2,786.6)**	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category [1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
		A		B	C	D (B+C)	E	F (A+C+E)		G		H	I	J	K (G+H+I+J)	K-F		H+I-D	
Properties Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2023 Projects																			
Upgrade Water and Fire Suppression Systems (2023-2024) - Bishop's Falls	-	-	-	-	353.7	353.7	2,886.3	3,240.0	-	-	-	81.2	272.5	2,886.3	3,240.0	-	0.00%	-	0.00%
Replace Diesel Shop Building (2023-2025) - Bishop's Falls	-	-	-	-	168.0	168.0	2,144.0	2,312.0	-	-	-	55.8	112.2	2,144.0	2,312.0	-	0.00%	-	0.00%
Replace HVAC System (2023-2024) - Bishop's Falls	-	-	-	-	43.4	43.4	128.8	172.2	-	-	-	14.0	29.4	128.8	172.2	-	0.00%	-	0.00%
Total Properties Projects	**-**	**-**	**-**	**-**	**565.1**	**565.1**	**5,159.1**	**5,724.2**	**-**	**-**	**-**	**151.0**	**414.1**	**5,159.1**	**5,724.2**	**-**		**-**	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
		A		B	C	D (B+C)	E	F (A+C+E)		G		H	I	J	K (G+H+I+J)	K-F		H+I-D	
Metering Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2023 Projects																			
Purchase Meters and Metering Equipment (2023)	-	-	-	-	226.6	226.6	-	**226.6**	-	-	-	6.7	219.9	-	226.6	-	0.00%	-	0.00%
2022 Projects																			
Replace Metering System	-	-	515.6	(1,748.8)	4,365.6	2,616.8	994.6	**5,875.8**	-	-	2,264.4	740.6	1,876.2	994.6	5,875.8	0.0	0.00%	-	0.00%
Total Metering Projects	**-**	**-**	**515.6**	**(1,748.8)**	**4,592.2**	**2,843.4**	**994.6**	**6,102.4**	**-**	**-**	**2,264.4**	**747.2**	**2,096.1**	**994.6**	**6,102.4**	**0.0**		**-**	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category [1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
		A		B	C	D (B+C)	E	F (A+C+E)		G		H	I	J	K (G+H+I+J)	K-F		H+I-D	
Information Systems Projects	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	Forecast Jun-Dec 2023	2024 and Beyond	Total	Project Variance	Project Variance (%)	Annual Variance	Annual Variance (%)
2023 Projects																			
Purchase Personal Computers (2023)	-	-	-	-	221.6	221.6	-	**221.6**	-	-	-	151.6	70.0	-	**221.6**	-	0.00%	-	0.00%
Replace Peripheral Infrastructure (2023)	-	-	-	-	187.4	187.4	-	**187.4**	-	-	-	3.4	184.0	-	**187.4**	-	0.00%	-	0.00%
Upgrade Core OT Infrastructure (2023)	-	-	-	-	171.7	171.7	-	**171.7**	-	-	-	125.2	46.5	-	**171.7**	-	0.00%	-	0.00%
Update Cyber Security Infrastructure (2023)	-	-	-	-	232.1	232.1	-	**232.1**	-	-	-	58.0	174.1	-	**232.1**	-	0.00%	-	0.00%
Perform Software Upgrades and Minor Enhancements (2023)	-	-	-	-	451.2	451.2	-	**451.2**	-	-	-	82.5	368.7	-	**451.2**				
2022 Projects																			
Upgrade Energy Management System (2022) - Hydro Place	-	-	292.6	43.0	-	43.0	-	**292.6**	-	-	249.6	121.0	(78.0)	-	**292.6**	0.0	0.00%	-	0.00%
Hydro Command Centre Upgrade (2022) - Hydro Place	-	-	76.4	61.9	-	61.9	-	**76.4**	-	-	14.5	36.0	4.0	-	**54.5**	(21.9)	-28.66%	(21.9)	-35.35%
Total Information Systems Projects	**-**	**-**	**369.0**	**104.9**	**1,264.0**	**1,368.9**	**-**	**1,633.0**	**-**	**-**	**264.1**	**577.6**	**769.4**	**-**	**1,611.1**	**(21.9)**		**(21.9)**	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast									
		A		B	C	D (B+C)	E	F (A+C+E)				H	I	J	K (G+H+I+J)	K-F		H+I-D
													Forecast					
				Carryover	Original	Revised	2024 and						Jun-Dec	2024 and		Project	Project	Annual
Tools and Equipment	**2020**	**2021**	**2022**	**to 2023**	**2023**	**2023**	**Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**2023**	**Beyond**	**Total**	**Variance**	**Variance (%)**	**Variance**
2023 Projects																		
Replace Mobile Equipment (2023-2024)	-	-	-	-	541.2	541.2	187.3	728.5	-	-	-	10.5	530.7	187.3	728.5	-	0.00%	-
Tools and Equipment Less than $ 50,000	-	-	-	-	1,008.9	1,008.9	-	1,008.9	-	-	-	35.6	973.3	-	1,008.9	-	0.00%	-
2022 Projects																		
Purchase 46' Material Handler Aerial Device on Track Unit	-	-	20.4	7.2	698.8	706.0	38.8	758.0	-	-	13.2	14.0	692.1	38.8	758.0	-	0.00%	-
Purchase 85' Material Handler Aerial Device on Track Unit	-	-	20.4	(2.0)	1,265.7	1,263.7	67.8	1,353.9	-	-	22.4	18.7	1,245.0	67.8	1,353.9	-	0.00%	-
Replace Light-Duty Mobile Equipment (2022) - Various	-	-	695.0	80.3	-	80.3	-	695.0	-	-	614.7	60.6	19.6	-	695.0	0.0	0.00%	-
Total Tools and Equipment	**-**	**-**	**735.8**	**85.5**	**3,514.6**	**3,600.1**	**293.9**	**4,544.3**	**-**	**-**	**650.3**	**139.5**	**3,460.6**	**293.9**	**4,544.3**	**0.0**		**-**

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
		A		B	C	D (B+C)	E	F (A+C+E)				H	I	J	K (G+H+I+J)	K-F		H+I-D	
				Carryover	Original	Revised	2024 and						Forecast Jun-Dec	2024 and		Project	Project	Annual	Annual
Telecontrol Projects	**2020**	**2021**	**2022**	**to 2023**	**2023**	**2023**	**Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**2023**	**Beyond**	**Total**	**Variance**	**Variance (%)**	**Variance**	**Variance (%)**
2023 Projects																			
Replace Remote Terminal Units (2023)	-	-	-	-	179.7	179.7	-	**179.7**	-	-	-	37.1	142.6	-	**179.7**	-	0.00%	-	0.00%
Replace Network Communications Equipment (2023)	-	-	-	-	189.0	189.0	-	**189.0**	-	-	-	122.1	66.9	-	**189.0**	-	0.00%	-	0.00%
Upgrade Site Facilities (2023)	-	-	-	-	45.2	45.2	-	**45.2**	-	-	-	15.9	29.3	-	**45.2**	-	0.00%	-	0.00%
Replace Power Line Carrier (2023–2024) - TL223 and TL224	-	-	-	-	105.3	105.3	852.4	**957.7**	-	-	-	30.0	75.3	852.4	**957.7**	-	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2023) - Telecontrol	-	-	-	-	40.4	40.4	-	**40.4**	-	-	-	29.0	11.4	-	**40.4**	-	0.00%	-	0.00%
Replace 48 V Battery Banks and Chargers (2023)	-	-	-	-	439.7	439.7	-	**439.7**	-	-	-	14.6	425.1	-	**439.7**	-	0.00%	-	0.00%
Purchase Mobile Devices (2023)	-	-	-	-	83.4	83.4	-	**83.4**	-	-	-	54.2	29.2	-	**83.4**	-	0.00%	-	0.00%
Replace Standalone PBX Phone Systems (2023)	-	-	-	-	175.5	175.5	-	**175.5**	-	-	-	23.8	151.7	-	**175.5**	-	0.00%	-	0.00%
2022 Projects																			
Replace Network Communications Equipment (2022)	-	-	193.0	119.6	-	119.6	-	**193.0**	-	-	73.4	130.5	(10.9)	-	**193.0**	0.0	0.00%	-	0.00%
Total Telecontrol Projects	**-**	**-**	**193.0**	**119.6**	**1,258.2**	**1,377.8**	**852.4**	**2,303.6**	**-**	**-**	**73.4**	**457.3**	**920.5**	**852.4**	**2,303.6**	**0.0**		**-**	

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2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
				B	C	D (B+C)	E	F (A+C+E)				H	I	J	K (G+H+I+J)	K-F		H+I-D	
Transportation	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	Forecast Jun-Dec 2023	2024 and Beyond	Total	Project Variance	Project Variance (%)	Annual Variance	Annual Variance (%)
2023 Projects																			
Replace Light- and Heavy-Duty Vehicles (2023-2025)	-	-	-	-	1,308.1	1,308.1	3,057.9	**4,366.0**	-	-	-	1,707.3	(399.2)	3,057.9	**4,366.0**	-	0.00%	-	0.00%
2022 Projects																			
Replace Light- and Heavy-Duty Vehicles (2022-2024)	-	-	569.0	443.4	593.2	1,036.6	2,319.6	**3,481.8**	-	-	125.6	304.7	732.0	2,319.6	**3,481.8**	-	0.00%	-	0.00%
2021 Projects																			
Replace Light- and Heavy-Duty Vehicles (2021-2022)	-	1,321.0	1,335.1	2,014.2	-	2,014.2	-	**2,656.1**	-	81.4	1,220.5	13.1	2,001.1	-	**3,316.1**	660.0	24.85%	-	0.00%
Level II Chargers for Electric Vehicles	-	299.8	-	72.5	-	72.5	-	**299.8**	-	194.1	33.1	72.7	(0.2)	-	**299.8**	(0.0)	0.00%	-	0.00%
2020 Projects																			
Replace Light and Heavy Duty Vehicles (2020-2021) - Various	1,625.4	1,583.5	-	1,471.7	-	1,471.7	-	**3,208.9**	4.0	658.7	1,964.7	1,415.8	55.9	-	**4,099.1**	890.2	27.74%	-	0.00%
Total Transportation	**1,625.4**	**3,204.3**	**1,904.1**	**4,001.8**	**1,901.3**	**5,903.1**	**5,377.5**	**14,012.6**	**4.0**	**934.2**	**3,343.9**	**3,513.6**	**2,389.5**	**5,377.5**	**15,562.8**	**1,550.2**		**-**	

	Capital Budget								Actual Expenditure and Forecast										
Administrative	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	Forecast Jun-Dec 2023	2024 and Beyond	Total	Project Variance	Project Variance (%)	Annual Variance	Annual Variance (%)
2023 Projects																			
Remove Safety Hazards (2023)	-	-	-	-	198.2	198.2	-	**198.2**	-	-	-	18.7	179.5	-	**198.2**	-	0.00%	-	0.00%
Purchase Office Equipment Less Than $50,000 (2023)	-	-	-	-	75.6	75.6	-	**75.6**	-	-	-	50.6	25.0	-	**75.6**	-	0.00%	-	0.00%
2021 Projects																			
Replace Transfer Switches and Associated Hardware - Hydro Place	-	197.4	938.5	1,099.0	-	1,099.0	-	**1,135.9**	-	107.7	79.2	50.8	1,048.2	-	**1,285.9**	150.0	13.21%	-	0.00%
2020 Projects																			
Replace Elevator Motors and Control Equipment - Hydro Place	89.1	647.6	-	44.4	-	44.4	-	**736.7**	64.2	595.7	256.3	24.7	19.7	-	**960.7**	224.0	30.40%	-	0.00%
Total Administrative	**89.1**	**845.0**	**938.5**	**1,143.5**	**273.8**	**1,417.3**	**-**	**2,146.4**	**64.2**	**703.4**	**335.5**	**144.8**	**1,272.5**	**-**	**2,520.4**	**374.0**			-

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

Allowance For Unforeseen	Capital Budget A 2020	A 2021	A 2022	B Carryover to 2023	C Original 2023	D (B+C) Revised 2023	E 2024 and Beyond	F (A+C+E) Total	Actual Expenditure and Forecast G 2020	G 2021	G 2022	H 2023	I Forecast Jun-Dec 2023	J 2024 and Beyond	K (G+H+I+J) Total	K-F Project Variance	Project Variance (%)	H+I-D Annual Variance	Annual Variance (%)
2023 Projects																			
Contingency Fund	-	-	-	-	1,000.0	1,000.0	-	**1,000.0**	-	-	-	-	1,000.0	-	**1,000.0**	-	0.00%	-	0.00%
Total Allowance For Unforeseen	**-**	**-**		**-**	**1,000.0**	**1,000.0**	**-**	**1,000.0**	**-**	**-**		**-**	**1,000.0**	**-**	**1,000.0**	**-**		**-**	

Supplemental Projects	Capital Budget A 2020	A 2021	A 2022	B Carryover to 2023	C Original 2023	D (B+C) Revised 2023	E 2024 and Beyond	F (A+C+E) Total	Actual Expenditure and Forecast G 2020	G 2021	G 2022	H 2023	I Forecast Jun-Dec 2023	J 2024 and Beyond	K (G+H+I+J) Total	K-F Project Variance	Project Variance (%)	H+I-D Annual Variance	Annual Variance (%)
2023 Projects																			
Penstock Refurbishment BDE	-	-	-	-	2,105.0	2,105.0	48,501.7	**50,606.7**	-	-	-	501.1	1,603.9	48,501.7	**50,606.7**	-	0.00%	-	0.00%
Purchase/Replace LT Blades Units 1 and 2	-	-	-	-	3,596.5	3,596.5	2,812.2	**6,408.7**	-	-	-	44.1	3,552.4	2,812.2	**6,408.7**	-	0.00%	-	0.00%
2022 Projects																			
Replace Diesel Plant Roof - MAK	-	-	176.8	257.6	457.2	714.8	-	**634.0**	-	-	95.7	46.9	667.9	-	**810.5**	176.5	27.83%	-	0.00%
Mary's Harbour (MSH) Engine Replacement	-	-	-	-	137.7	137.7	-	**137.7**	-	-	-	111.1	26.6	-	**137.7**	-	0.00%	-	0.00%
Lt Stage Blades Holyrood	-	-	18.3	(146.3)	1,560.6	1,414.4	-	**1,578.9**	-	-	164.5	1,412.7	1.7	-	**1,578.9**	-	0.00%	-	0.00%
USL Rotor Rim Shrinking	-	-	959.4	236.5	3,040.4	3,276.9	-	**3,999.8**	-	-	722.9	1,131.4	4,032.1	-	**5,886.4**	1,886.6	47.17%	1,886.6	57.57%
Holyrood Replace Underground Tank Farm	-	-	83.5	55.6	1,330.5	1,386.1	-	**1,414.0**	-	-	27.9	96.9	1,289.2	-	**1,414.0**	-	0.00%	-	0.00%
Holyrood Day Tank Refurbishment	-	-	89.4	49.6	707.8	757.4	-	**797.2**	-	-	39.8	112.3	645.0	-	**797.2**	-	0.00%	-	0.00%
Upgrade Turbine Control System Unit 2	-	-	235.9	85.2	490.1	575.3	-	**726.0**	-	-	150.7	121.1	454.2	-	**726.0**	-	0.00%	-	0.00%
Holyrood Tank 1 Refurbishment	-	-	1,195.0	164.4	857.1	1,021.5	-	**2,052.1**	-	-	1,030.6	304.0	717.4	-	**2,052.1**	-	0.00%	-	0.00%
Charlottetown Winterize Unit 2102	-	-	1,269.8	1,064.2	44.9	1,109.1	-	**1,314.7**	-	-	205.6	828.8	280.3	-	**1,314.7**	-	0.00%	-	0.00%
2021 Projects																			
Valentine Gold Interconnection	-	3,479.3	12,281.7	8,756.0	586.4	9,342.4	-	**16,347.3**	-	826.1	6,178.9	3,927.1	5,415.3	-	**16,347.4**	0.1	0.00%	-	0.00%
Replace Unit 2047 Ramea (2021)	-	307.7	2,010.8	2,053.4	118.3	2,171.7	-	**2,436.8**	-	49.0	216.1	245.3	1,926.4	-	**2,436.8**	-	0.00%	-	0.00%
Total Supplemental Projects Approved by PUB	**-**	**3,787.0**	**18,320.6**	**12,576.3**	**15,032.5**	**27,608.8**	**51,313.9**	**88,453.9**	**-**	**875.1**	**8,832.7**	**8,882.9**	**20,612.4**	**51,313.9**	**90,517.1**	**2,063.2**		**1,886.6**	

Projects Less than $50,000	Capital Budget A 2020	A 2021	A 2022	B Carryover to 2023	C Original 2023	D (B+C) Revised 2023	E 2024 and Beyond	F (A+C+E) Total	Actual Expenditure and Forecast G 2020	G 2021	G 2022	H 2023	I Forecast Jun-Dec 2023	J 2024 and Beyond	K (G+H+I+J) Total	K-F Project Variance	Project Variance (%)	H+I-D Annual Variance	Annual Variance (%)
2023 Projects																			
TL215 Guying Upgrades	-	-	-	-	47.7	47.7	-	**47.7**	-	-	-	13.7	34.0	-	**47.7**	-	0.00%	-	0.00%
2022 Projects																			
IOC SCADA Data Link	-	-	28.2	26.4	-	26.4	-	**28.2**	-	-	1.9	0.1	26.2	-	**28.2**	-	0.00%	-	0.00%
Replace Tracks - V7271	-	-	48.3	48.3	-	48.3	-	**48.3**	-	-	-	45.0	3.3	-	**48.3**	-	0.00%	-	0.00%
Total Projects Less than $50,000	**-**	**-**	**76.5**	**74.7**	**47.7**	**122.4**	**-**	**124.2**	**-**	**-**	**1.9**	**58.8**	**63.6**	**-**	**124.2**	**-**		**-**	

[1] Numbers may not add due to rounding.

2023 Capital Expenditures By Category[1]
($000)

	Capital Budget								Actual Expenditure and Forecast										
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F		H+I-D	
Distribution (CIACs) Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2022**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2022 Projects																			
Provide Service Extenstions - All Areas - CIAC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	N/A
Upgrade Disribution Systems - All Areas - CIAC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	N/A
Total Distribution Projects	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-		-	

	Capital Budget								Actual Expenditure and Forecast										
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F		H+I-D	
Supplemental and Carryover Contribution in Aid of Construction (CIACs) Projects	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2022**	**Forecast Jun-Dec 2023**	**2024 and Beyond**	**Total**	**Project Variance**	**Project Variance (%)**	**Annual Variance**	**Annual Variance (%)**
2022 Projects																			
IOC SCADA Data Link - CIAC	-	-	(28.2)	(28.2)	-	(28.2)	-	**(28.2)**	-	-	-	-	(28.2)	-	**(28.2)**	-	0.00%	-	0.00%
Upstream Capacity Charge pursuant to the Network Additions Policy	-	-	-	-	-	-	(290.6)	**(290.6)**	-	-	-	-	(290.6)	-	**(290.6)**	-	0.00%	(290.6)	N/A
2021 Projects																			
Valentine Gold Interconnection - CIAC	-	(3,730.0)	(12,085.0)	(3,069.3)	-	(3,069.3)	-	**(15,815.0)**	-	(3,730.0)	(9,015.7)	(2,447.0)	(622.3)	-	**(15,815.0)**	(0.0	0.00%	-	0.00%
Total Supplemental Projects Approved by PUB	**-**	**(3,730.0)**	**(12,113.2)**	**(3,097.5)**	**-**	**(3,097.5)**	**(290.6)**	**(16,133.8)**	**-**	**(3,730.0)**	**(9,015.7)**	**(2,447.0)**	**(941.1)**	**-**	**(16,133.8)**	**(0.0)**		**(290.6)**	

[1] Numbers may not add due to rounding.

Sch 5: 2022 Average Rate Base

Schedule 5

2022 Average Rate Base



2024 Capital Budget Application

2022 Rate Base





Table 1: Computation of Rate Base for the Year Ended December 31, 2022 ($000)[1,2]

	2022
Capital Assets - Return 4	2,869,697
Work in Progress[3]	22,755
	2,892,452
Deduct:	
Accumulated Depreciation - Return 6[4]	654,859
Contributions in Aid of Construction - Return 7[3]	50,987
Total Capital Assets	2,186,606
Deduct Items Excluded from Rate Base:	
Work in Progress[3]	(22,755)
Asset Retirement Obligations (net of amortization)	(2,734)
Net Capital Assets	2,161,118
Net Capital Assets, Previous Year	2,165,756
Unadjusted Average Capital Assets	2,163,437
Deduct:	
Average Net Capital Assets Excluded from Rate Base	(8,628)
Average Capital Assets	2,154,809
Cash Working Capital Allowance - Return 8	10,312
Fuel Inventory - Return 10	70,512
Supplies Inventory - Return 10	38,856
Average Deferred Charges - Return 11	59,632
Average Rate Base at Year End - Return 12	**2,334,120**

[1] The 2022 Average Rate Base is an excerpt of Return 3. For further information, please refer to "2022 Annual Return," Newfoundland and Labrador Hydro, March 31, 2023, Return 3.
[2] Numbers may not add due to rounding.
[3] Contributions of $13.7 million (2021 – $4.4 million) related to capital assets not in service have been net in work in progress. In addition, insurance proceeds of $1.0 million (2021 – $3.6 million) related to capital assets not in service have been net in work in progress.
[4] Accumulated amortization is net of the Retirement Asset Pool and Removal Provision. For further details, please refer "2022 Annual Return," Newfoundland and Labrador Hydro, March 31, 2023, Return 6.

Sch 6: Capital Programs and Projects

Schedule 6

Capital Programs and Projects



Programs

Programs



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Schedule 6: Capital Programs and Projects

Programs	**Program**
• Replace Light- and Heavy-Duty Vehicles (2024–2026)	1
• Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood	2
• Replace Diesel Gensets (2024–2026)	3
• Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)	4
• Provide Service Extensions (2024)	5
• Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood	6
• Wood Pole Line Management (2024)	7
• Upgrade Power Transformers (2024–2025)	8
• Thermal In-Service Failures (2024)	9
• Replace Protective Relays (2024–2025)	10
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• Renew Circuit Breakers (2024–2025)	12
• Renew Distribution Feeders (2024–2025)	13
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• Replace Disconnects (2024–2025)	15
• Terminal Station In-Service Failures (2024)	16
• Replace Instrument Transformers (2024–2025)	17
• Perform Software Upgrades and Minor Enhancements (2024)	18
• Overhaul Diesel Units (2024)	19
• Replace Mobile Equipment (2024–2025)	20

Program 1

Replace Light- and Heavy-Duty Vehicles (2024–2026)

July 2023

newfoundland labrador hydro

Replace Light- and Heavy-Duty Vehicles (2024–2026)

Location: Various

Investment Classification: General Plant

Asset Category: Transportation

Executive Summary

Newfoundland and Labrador Hydro (”Hydro”) operates a fleet of vehicles comprised of approximately 236 light-duty vehicles (e.g., cars, pickup trucks, vans) and approximately 70 heavy-duty vehicles (e.g., aerial devices, material handlers, line body and boom trucks). The fleet is distributed across Hydro’s operating areas throughout the province and is utilized daily to support staff engaged in the operation and maintenance of the electrical system.

This program provides for the replacement of light- and heavy-duty vehicles that meet the established replacement criteria. Deferral of these vehicles is not appropriate. Supply chain issues are creating long lead purchase times and the specific purposes for which many of these vehicles are required leaves limited options for rental or backup. As equipment purchased under this program is required for remote operations to support the reliability of the electrical system, there is no other viable alternative. This program will contribute to the safe and reliable operation of Hydro’s light- and heavy-duty vehicle fleet.

Hydro is proposing the replacement of 30 light-duty and 8 heavy-duty vehicles under the proposed scope of this program.

This program has a multi-year approach, with completion planned in 2026, due to ongoing supply chain challenges,[1] at an estimated cost of $5,636,300.

[1] Due to factory shut downs in 2020, 2021, and 2022, the estimated delivery time for heavy-duty vehicles specifically is now in the range of 18 to 30 months, depending on the supplier.

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1.0 Introduction

Hydro operates a fleet of vehicles comprised of light-duty vehicles (e.g., cars, pickup trucks, vans) and heavy-duty vehicles (e.g., aerial devices, material handlers, line body and boom trucks) distributed across Hydro's operating areas throughout the province. This fleet is utilized daily to support staff engaged in the operation and maintenance of the electrical system.

2.0 Program Description and Justification

Hydro operates its fleet of light- and heavy-duty vehicles as required to maintain the safety and reliability of the electrical system. Hydro's replacement criteria for light- and heavy-duty vehicles are provided in Table 1.

Table 1: Replacement Criteria

Vehicle	Replacement Criteria
Light-Duty	7 years or 200,000 kilometres (odometer reading), depending on condition/maintenance cost and reliability
Heavy Duty Classes 4 and 6	6 to 8 years or 200,000 kilometres (odometer reading), depending on condition/maintenance cost and reliability.

3.0 Asset Overview

3.1 Asset Background

In early 2023, Hydro completed the majority of its light-duty fleet verification exercise, which included a review of Hydro's existing fleet quantities and types, survey information from similar Canadian utilities, as well as statistics on vehicle usage rates, to ensure Hydro's criteria and vehicle replacement rates are appropriate and conducive to Hydro's operations. Hydro's current fleet is composed of 236 vehicles, of which 174 are pickup trucks, 13 are specialized box vans, and the remaining 49 are comprised of SUVs,[2] cars, and minivans. On average, Hydro's vehicles accumulate 25,000 to 30,000 kilometres per year, or an average of 175,000 to 210,000 kilometres over the seven-year life of the vehicle. These averages indicate that Hydro's vehicle replacement criteria are consistent with its operational experience and that Hydro's light-duty fleet is appropriately sized for its operation.[3]

[2] Sport utility vehicle ("SUV").
[3] Vehicle data as of mid-2022. Fleet numbers may vary year-to-year depending on the specific timing of vehicle replacements and retirements.

3.2 Asset Condition

As equipment ages, it can experience increased downtime that could impact response times for outages or planned maintenance. In many cases, light- and heavy-duty vehicles are subjected to accelerated wear and tear due to operation in rough areas and premature corrosion from salt spray. Light- and heavy-duty vehicles are inspected in accordance with the preventive maintenance schedule and all maintenance and repairs are performed by third-party service providers as needed.

Assets identified for replacement would need to meet the criteria specified in Table 1. These assets are replaced based on the age of the asset or kilometres accumulated, with consideration given to vehicle condition. Should an asset that has reached one of the replacement milestones be assessed and determined to be in adequate condition to remain as part of the fleet, Hydro would explore this option.

3.3 Condition-Based Remaining Life

Hydro evaluates assets as they reach retirement criteria to determine if it is appropriate to extend the life of the vehicles. This could include reassignment to an area with less or different usage or usage in easier terrain, among other considerations.

3.4 Asset Ages

Chart 1 and Chart 2 provide light- and heavy-duty vehicle asset age of the fleet including those proposed for replacement, respectively. The replacements in the 0- to 5-year age range category are a result of the vehicles meeting the mileage and condition criteria.

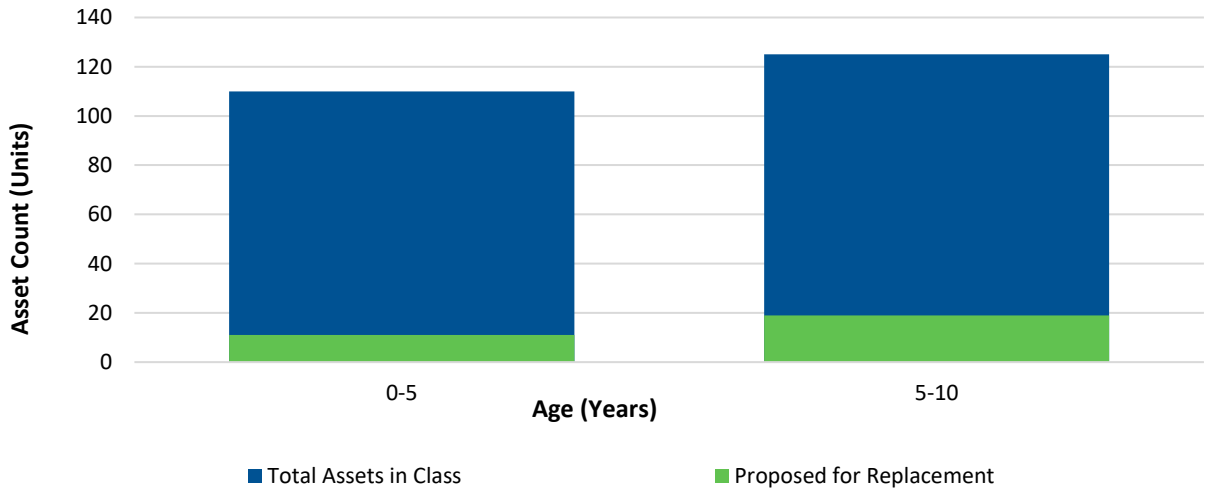


Chart 1: Light-Duty Vehicle Asset Counts by Age

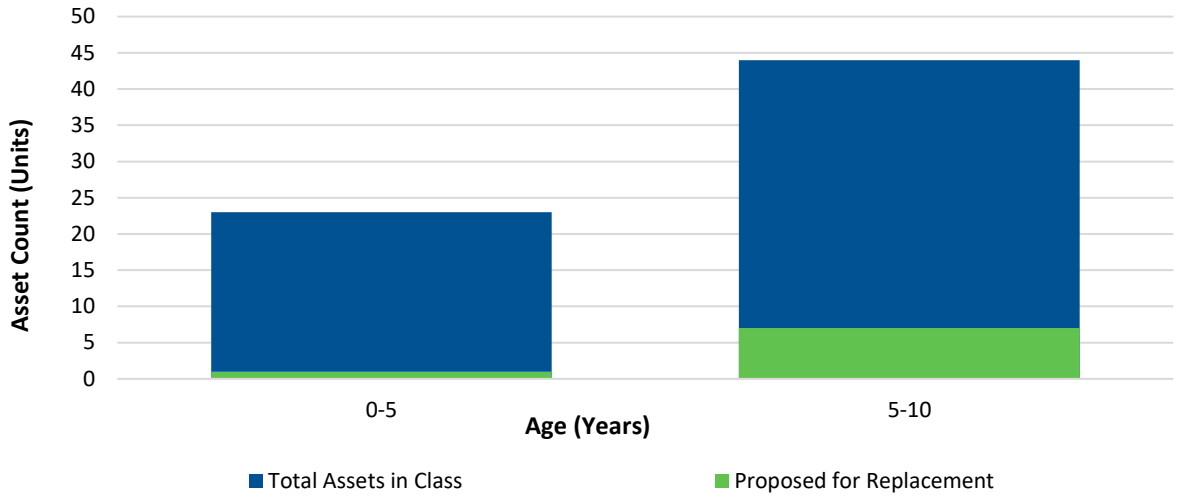


Chart 2: Heavy-Duty Asset Counts by Asset Age

4.0 Trending

4.1 Assets Installed/Replaced/Upgraded

Chart 3 provides the five-year historical, current, and five-year forecast number of light-duty vehicles replaced under this program. Assets in service in 2020 and 2021 are below average due to global supply chain challenges. The increase in 2022 and 2023 is due to the receipt of most of the 2021 purchased vehicles in 2022 and the projected receipt of vehicles in 2023 purchased in 2022. The projections below reflect current fleet size requirements and may differ from future proposals as a result of the fleet optimization review.

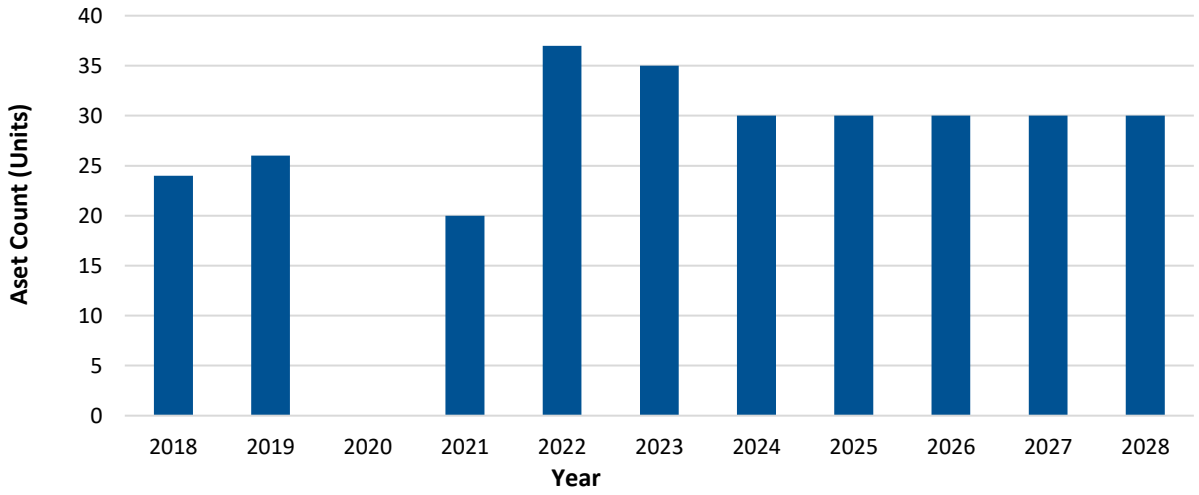


Chart 3: Historical and Forecast Assets Replaced – Light-Duty Vehicles

Chart 4 provides the five-year historical, current, and five-year forecast number of heavy-duty vehicles replaced under this program. Assets in service in 2020 and 2021 are below average due to global supply chain challenges.

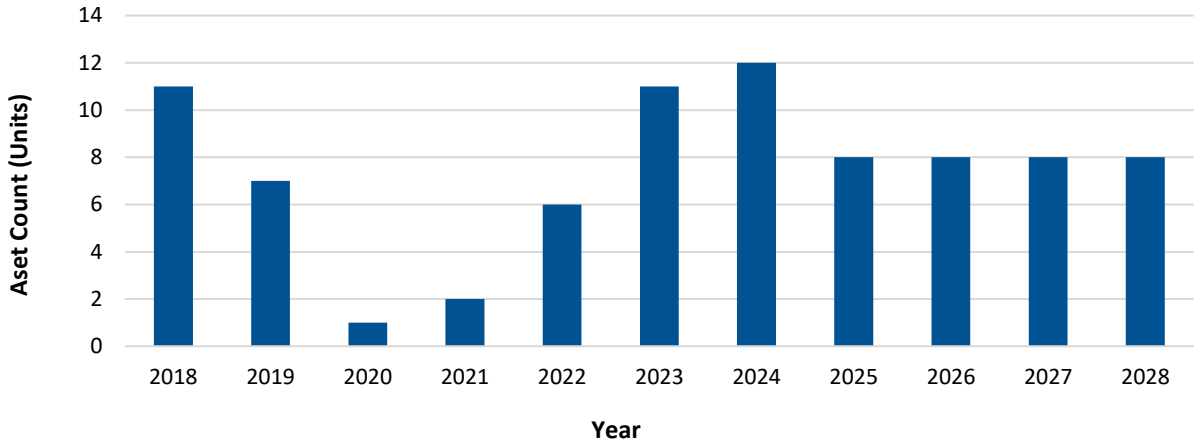


Chart 4: Historical and Forecast Assets Replaced – Heavy-Duty Vehicles

4.2 Historical and Forecast Average Unit Costs

Chart 5 indicates the average cost of vehicles for replacement and is reflective of the average cost for both light- and heavy-duty vehicles combined. While the purchases of vehicles can be broken down into categories, there are overheads and efficiencies gained from combining the scopes of work. As such, these expenditures have not been split between light- and heavy-duty vehicles. The variation seen in the 2020 cost per unit is attributed to receiving more heavy-duty vehicles than light-duty vehicles in that year; heavy-duty vehicles are historically, on average, more expensive.

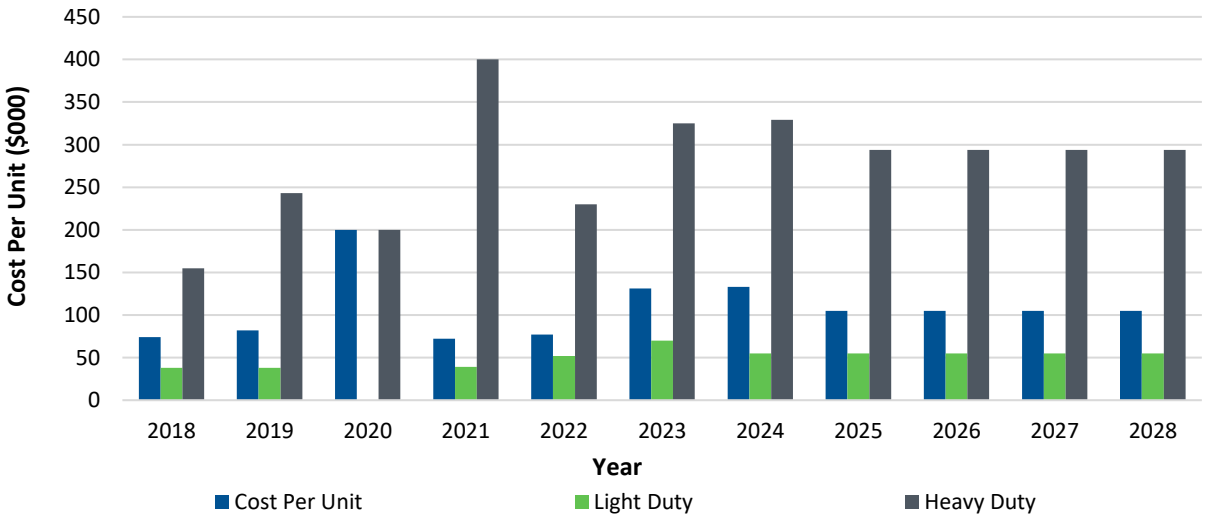


Chart 5: Average Unit Costs of Assets Installed/Replaced

5.0 Historical Reliability

Light- and heavy-duty vehicles are inspected in accordance with the preventive maintenance schedule and all maintenance and repairs are performed by third-party service providers, as needed.

6.0 Analysis

6.1 Evaluation of Alternatives

Hydro considered the following alternatives:

- Pace reduction;
- Pace advancement;
- Continue program at current pace; and
- Alternative strategies.

6.1.1 Pace Reduction

In 2020, Hydro re-evaluated its replacement criteria and reduced the pace based on consultation with other utilities and the condition of the units upon replacement. Hydro's replacement criteria are consistent with utility counterparts across Canada and, based on Hydro's current experience, further extending the timing of these replacements would present reliability risks. For this reason, pace reduction is not considered a viable option.

6.1.2 Pace Advancement

Advancing the pace of this program would result in premature retirement of existing, functional assets, requiring a level of investment that is not required for the continuation of safe, least-cost, environmentally responsible, and reliable power. For this reason, pace advancement is not considered a viable option.

6.1.3 Continue Program at Current Pace

Hydro has determined the current criteria are appropriate based on consultation with other utilities, the condition of the units upon replacement, and vehicle usage statistics. This approach allows Hydro to balance cost with the reliability of Hydro's vehicle fleet. These vehicles are required to facilitate required maintenance and timely response to system events and, as such, are required to be available and in appropriate working condition.

6.1.4 Alternative Strategies

Due to long procurement lead times as a result of supply chain constraints, Hydro has considered supplementing its fleet vehicle needs with rental vehicles. Rental vehicle vendors are experiencing the same supply chain challenges, and therefore local availability of rental vehicles is limited. Hydro does not consider this a viable alternative for this program.

6.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

6.3 Recommended Alternative

Hydro's recommended alternative is to proceed with the identified replacements based on its replacement criteria.

6.3.1 Risk of Asset Stranding

This program is necessary to maintain a safe and reliable fleet. Failure to replace this equipment will lead to increased maintenance costs, less reliable equipment, delays in scheduled and unscheduled work, and possible safety issues for operators. As such, the risk of asset stranding is low.

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2026 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 2.

Table 2: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	4	**12**
Post-Execution	3	1	**3**
		Risk Mitigated	**9**
		Risk Mitigated per $1 Million	**1.6**

7.0 Scope of Work

This program proposes the replacement of thirty light-duty mobile and eight heavy-duty vehicles in accordance with Hydro's replacement criteria. This scope includes procurement of the vehicles, and accessorizing as required based on the purpose of the vehicle.[4]

7.1 Program Budget

The estimate for the 2024–2026 program is shown in Table 3.

Table 3: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	1,201.1	3,510.5	0.0	**4,711.6**
Labour	106.2	90.7	7.5	**204.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	46.9	192.4	0.5	**239.8**
Contingency	124.9	355.2	0.4	**480.5**
Total	**1,479.1**	**4,148. 8**	**8.4**	**5,636.3**

The majority of the heavy-duty vehicles that are requisitioned in the first year will not be delivered until the end of the second year of this scope of the program. Hydro plans to replace all proposed vehicles by the end of 2026.

Chart 6 shows the five-year historical expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028. Light- and heavy-duty vehicles are replaced considering age, accumulated kilometres, and condition; as such, the makeup of types of vehicles replaced will vary from year-to-year. This will result in budget variability due to the type and quantity of equipment purchased. Increases in costs in 2024 and beyond are not reflective of changes in Hydro's strategy regarding the replacement of light- and heavy-duty vehicles but rather are reflective of increasing costs due to supply chain constraints and inflationary pressure. This program budget provides data for both the light- and heavy-duty fleet scopes of work. While purchases of the vehicles can be broken down into categories, there are overheads and efficiencies gained from combining the scopes of

[4] Where appropriate, Hydro will consider electric vehicles during the procurement process. Vehicles will be selected based on their suitability for their intended purpose, as well as life-cycle cost.

work that are reflected below; as such, these expenditures have not been split between the light- and heavy-duty vehicles.

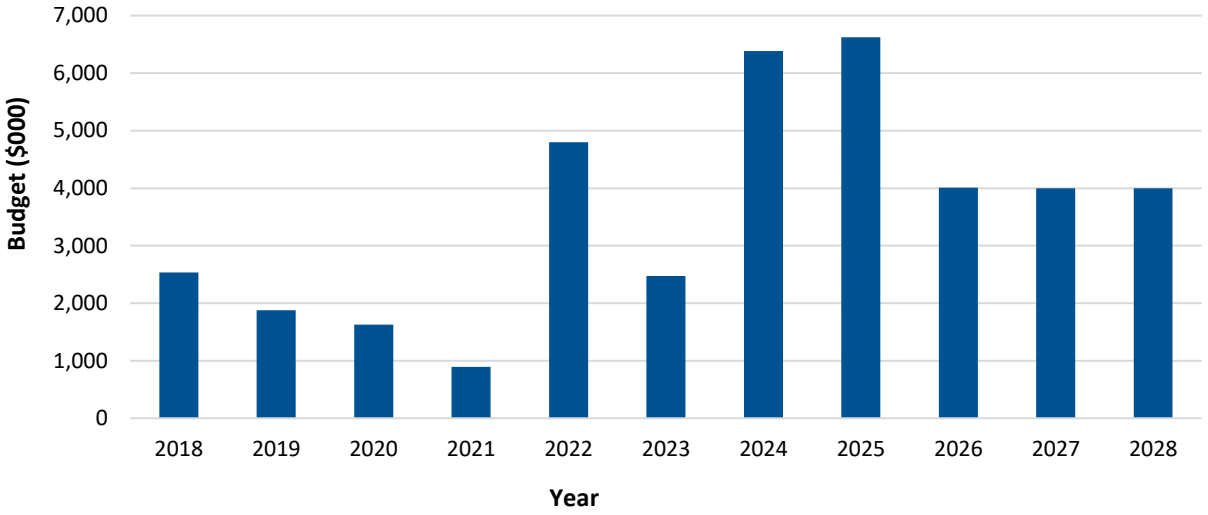


Chart 6: Historical and Forecast Program Budget

7.2 Program Schedule

The schedule for the 2024–2026 program is shown in Table 4.

Table 4: Program Schedule

Activity	Start Date	End Date
Planning: Open work orders and plan and develop detailed schedules.	January 2024	February 2024
Procurement: Tender and award contracts to purchase light- and heavy-duty vehicles.	February 2024	March 2024
Commissioning: Receive and commission light- and heavy-duty vehicles.	September 2024	November 2025
Closeout: Close work order, complete all documentation, and complete lessons learned	May 2026	June 2026

8.0 Conclusion

Hydro operates a fleet of light- and heavy-duty vehicles to enable effective maintenance of the electrical system and timely response to system events. The established replacement guidelines have been determined to be appropriate. Hydro proposes to continue with the replacement of vehicles under this program for 2024.

Overhaul Unit 1 Turbine Valves and Generator (2024)

Holyrood

July 2023

newfoundland labrador hydro

Overhaul Unit 1 Turbine Valves and Generator (2024)

Location: Holyrood

Investment Classification: Renewal

Asset Category: Thermal Plant

Executive Summary

To support the continued safe and reliable operation of the Holyrood Thermal Generating Station ("Holyrood TGS"), Newfoundland and Labrador Hydro ("Hydro") will execute a program for the overhaul of the turbines, turbine valves and generators. Under this program, Hydro is proposing to overhaul the Unit 1 turbine valves and generator in 2024.

Hydro's historical experience at the Holyrood TGS has demonstrated that an overhaul on a nine-year cycle for the turbines, a three-year cycle for the turbine valves, and a six-year cycle for the generators is appropriate, based on the observations made during previous overhauls. These overhaul cycles are also consistent with the original equipment manufacturer's ("OEM") recommendations.

The Unit 1 turbine and turbine valves overhaul was last performed in 2021. The Unit 1 generator overhaul was last performed in 2018. As such, the Unit 1 turbine valves and generator are due for an overhaul in 2024 according to the established overhaul cycles. As the turbine overhaul is not due to be performed until 2030, it is not included in this year of the program.

If an overhaul is not completed at this time, the turbine valves or generator could fail while in operation. Such failure could result in forced unit outages resulting in the loss of up to 170 MW for several weeks to several months in duration, depending on the magnitude of the failure.

As per the "Reliability and Resource Adequacy Study – 2022 Update,[1] the Holyrood TGS shall remain available for a "Bridging Period"[2] until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the Labrador-Island Link ("LIL") is proven, and generation

[1] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[2] Hydro considers the Bridging Period to be from 2023 to 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

reserves are met. At this time, capital investment related to the generation function of the Holyrood TGS, such as the overhaul of the turbine valves and generator, is necessary to support system reliability and maintain Hydro's ability to meet customer demand during peak periods.

The estimated cost for work executed under the 2024 program is $5,181,400.

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1.0 Introduction

The Unit 1 turbine and generator are critical assets required for the generation of 170 MW of power from Unit 1 at the Holyrood TGS. The turbine is equipped with valves critical to the unit's operation. These valves are exposed to several high degradation mechanisms including erosion, wear, fatigue, and cracking due to high temperature, high pressure, and high flow velocity. The Unit 1 generator consists of a stator and rotor for electricity production. The generator rotor is directly coupled to the turbine rotor. The generator is subjected to electrical and magnetic stresses while providing power for the Island grid. Proper function of the turbine valves and the generator is required for the safe and reliable operation of Unit 1.

2.0 Program Description and Justification

The Holyrood TGS provides 490 MW of generation capacity to the Island Interconnected System. To ensure these assets remain in reliable operating condition, it is prudent that regular preventive maintenance is performed. The scope of work under this program consists of inspections and associated refurbishments completed every nine years for turbines, every three years for turbine valves, and every six years for generators. The overhaul frequency is based on OEM recommendations, industry standards, and Hydro's operational experience and involves the removal and disassembly of turbine, generator, and valve components to inspect, test, clean, and refurbish or overhaul as required. The scope of work under this program in 2024 consists of the overhaul of the Unit 1 turbine valves and the Unit 1 generator. Completing these overhauls will ensure the continued reliable and safe operation of Unit 1 through a reduction in forced outages or deratings as well as confirmation of the operational accuracy of critical safety valves.

As per the "Reliability and Resource Adequacy Study – 2022 Update," the Holyrood TGS shall remain available for a "Bridging Period" until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.

3.0 Asset Overview

3.1 Asset Background

The assets covered under this program for 2024 are the Unit 1 turbine valves and generator, required for generation from Unit 1 at the Holyrood TGS.

The Unit 1 turbine, manufactured by General Electric ("GE") in 1969, is equipped with a set of 17 major steam valves; one main stop valve, six control valves, two combined reheat stop/intercept valves, seven extraction steam non-return valves, and one blowdown valve. These valves control the admission of steam energy into the turbine to control the production of electricity and provide protection to the turbine during operational upset situations, such as a unit trip, power line trip, or generator fault that could otherwise cause a catastrophic turbine overspeed condition or other damage to the turbine components. Failure of any turbine valve component has the potential to become a serious safety hazard due to the high temperature and pressure of steam flows to the turbine and the risk of turbine over-speed. Failure of turbine valves could also increase the risk of a forced outage.

The Unit 1 generator, which is coupled to the steam turbine rotor, was also manufactured by GE in 1969. The generator is comprised of two primary components, a stator and a rotating field ("rotor"). The rotor is coupled to, and driven by, the steam turbine and rotates inside the stator to produce electricity in the stator windings. The generator overhaul includes removal of the rotor, electrical testing of the windings, visual inspection, non-destructive examination ("NDE") and refurbishment of components as required, such as rotor retaining rings, bearings[3], hydrogen seals[4], end-winding supports, hydrogen coolers[5] and collector rings. These components are subjected to deterioration during operation due to different degradation mechanisms such as wear, vibration and thermal stresses. Failure of critical generator components such as bearings, hydrogen seals, winding and rotor retaining rings would require premature costly repair work and a major outage to the unit.

In line with OEM recommendations and industry-standard practice, turbine valve overhauls are performed on a three-year cycle and generator overhauls are performed on a six-year cycle. The Unit 1 turbine valves were last overhauled in 2021, while the generator was last overhauled in 2018; as such, the Unit 1 turbine valves and generator are due for overhaul in 2024.

3.2 Asset Condition

A 2021 condition assessment conducted by Hatch Ltd. determined that the Unit 1 turbine valves and generator are in good condition, indicating that these components may show signs of slightly defective

[3] The generator is supported by two journal bearings.
[4] Hydrogen seals ensure that the hydrogen does not escape between the rotor and stator components at both ends of the generator using oil.
[5] Hydrogen coolers utilize cooling water to maintain the correct hydrogen temperature within the generator.

or deteriorated components, but are overall functional.[6] As the turbine valves are exposed to degradation mechanisms such as high temperatures, high pressures, corrosive fluids, and erosive flows, regular maintenance and overhauls ensure the components continue to function as expected.

The Unit 1 generator windings are original and approaching 55 years old. Electrical testing on the windings has been performed annually for the past number of years, showing evidence of aging with no immediate concerns.

3.3 Asset Ages

This program covers the turbines, including the turbine valves, as well as the generators for Units 1, 2, and 3 at the Holyrood TGS. Units 1 and 2 turbines, turbine valves, and generators were placed in service in 1970, while the components for Unit 3 were placed in service in 1979. Chart 1 to Chart 3 provide the age for all assets covered under the program.

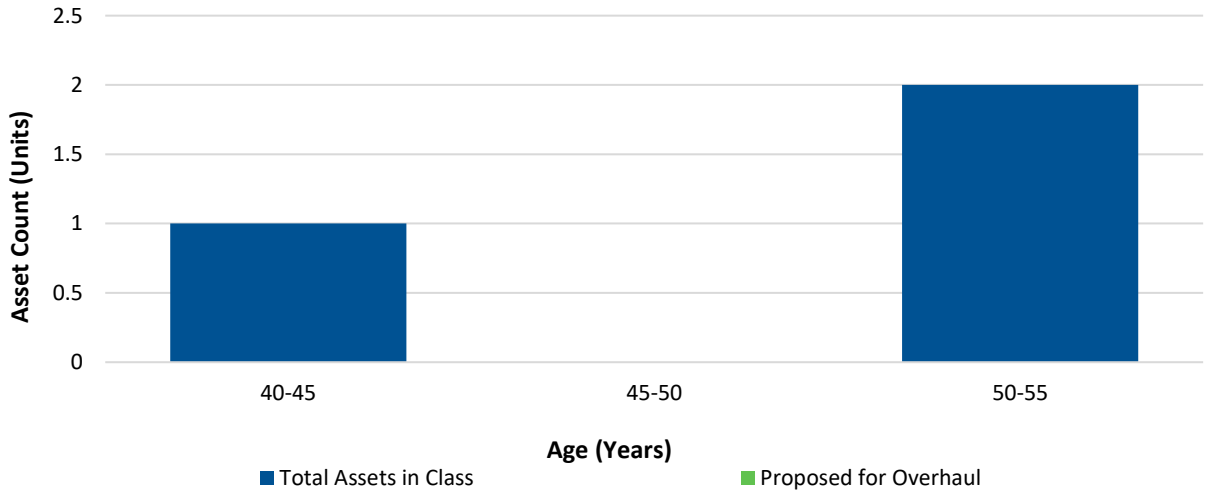


Chart 1: Asset Counts by Asset Age – Turbine

[6] "HTGS Condition Assessment and Life Extension Study," Hatch Ltd., March 31, 2022, vol. I and vol. II.

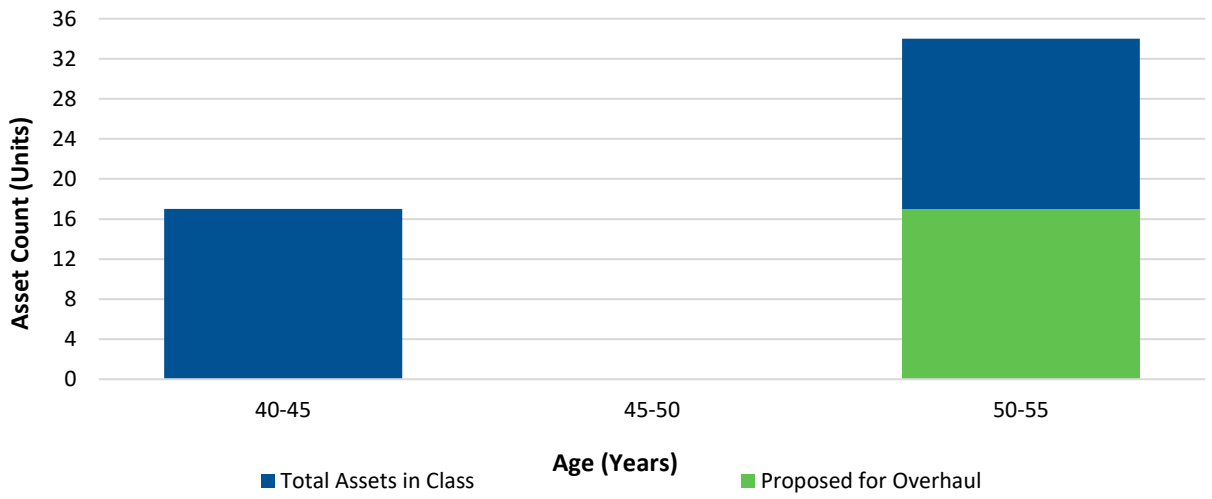


Chart 2: Asset Counts by Asset Age – Turbine Valves

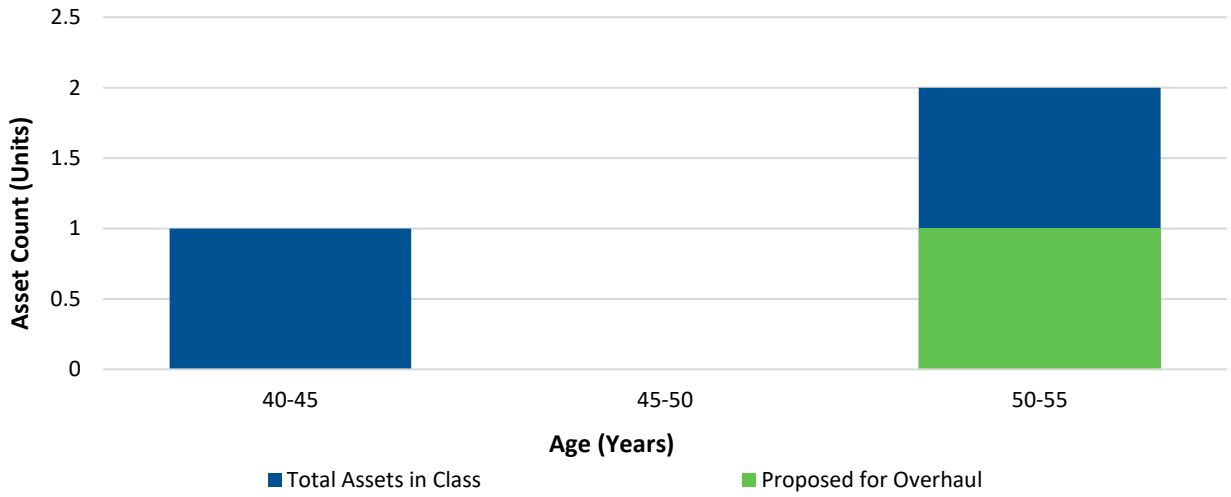


Chart 3: Asset Counts by Asset Age – Generator

4.0 Trending

Hydro completes an overhaul under this program based on the established overhaul cycle of nine years for each turbine, three years for the turbine valves (17 valves per turbine), and six years for each generator.

4.1 Assets Installed/Replaced/Upgraded

Chart 4 to Chart 6 provide the five-year historical, current, and five-year forecast number of assets overhauled per year.[7]

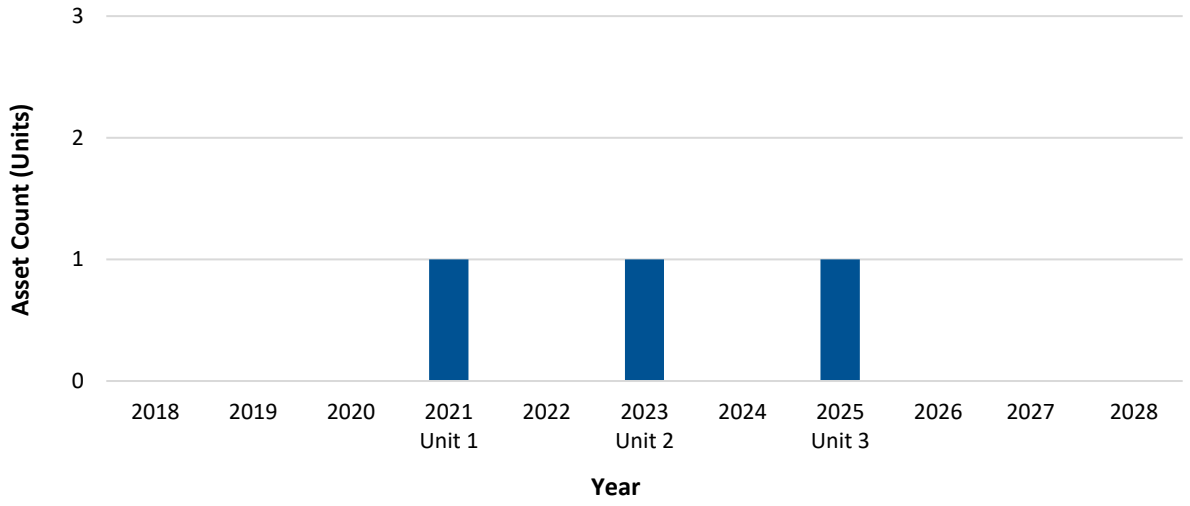


Chart 4: Historical and Forecast Assets Overhauled Count – Turbine

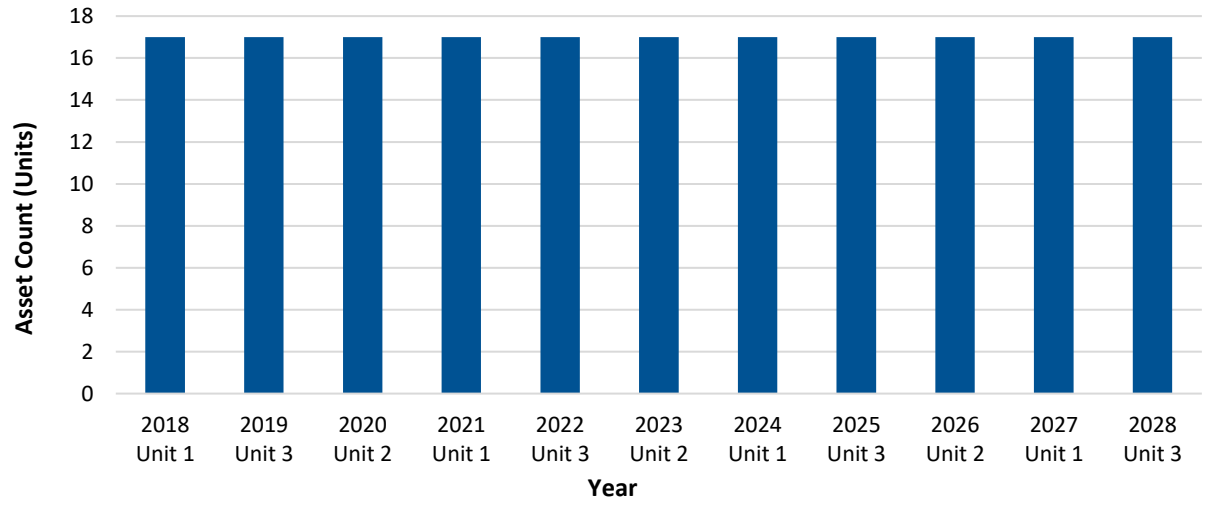


Chart 5: Historical and Forecast Assets Overhauled – Turbine Valves

[7] The forecast for this program was based on the assumption of continued operation of all generating units at the Holyrood TGS through the Bridging Period until its capacity can be adequately replaced. Hydro's capital projections assume all three generating units remain online until 2030, and are subject to change based on changes in operating regime.

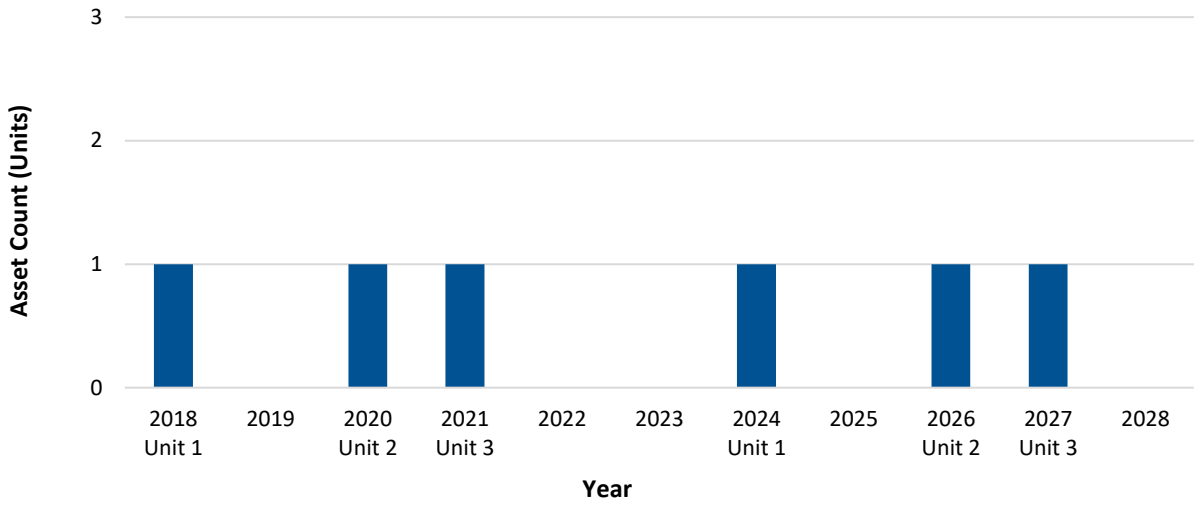


Chart 6: Historical and Forecast Assets Overhauled – Generator

4.2 Historical and Forecast Average Unit Costs

Chart 7 to Chart 9 provide the five-year historical, current, and five-year forecast average unit cost of asset overhauls in each year.

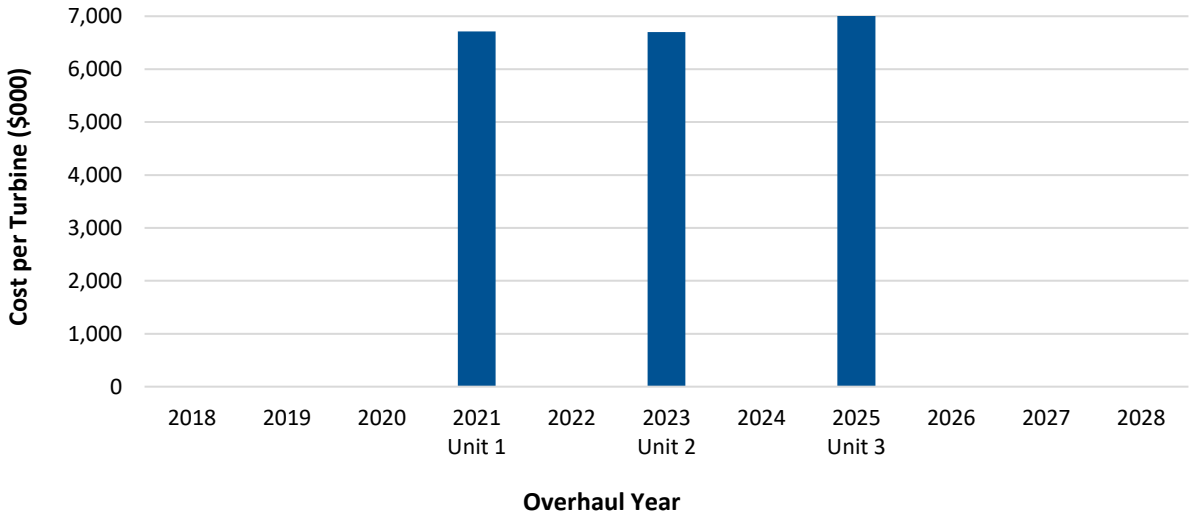


Chart 7: Average Unit Costs of Assets Overhauled – Turbine

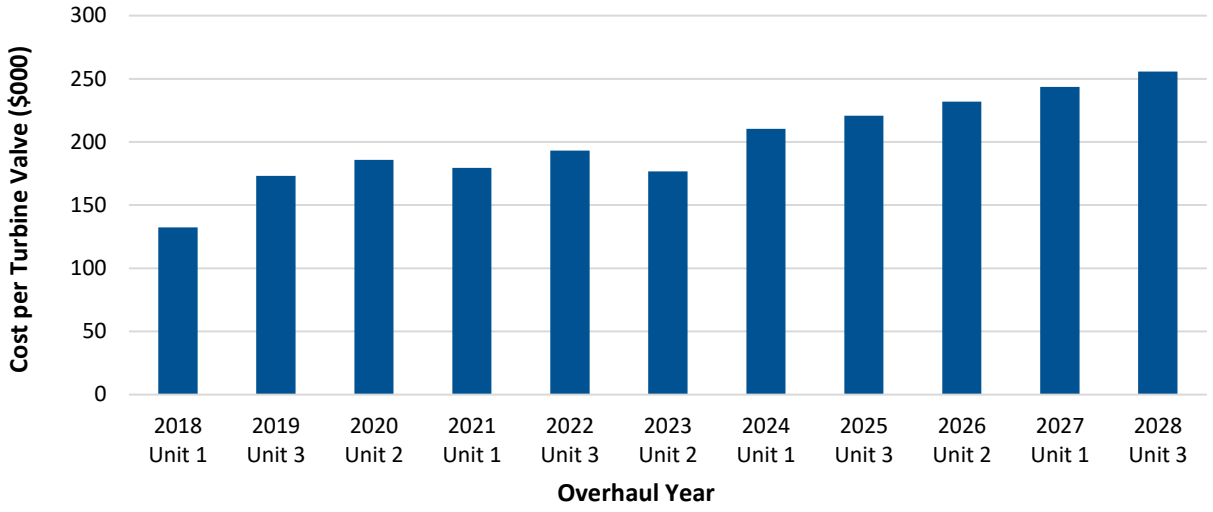


Chart 8: Average Unit Costs of Assets Overhauled – Turbine Valves

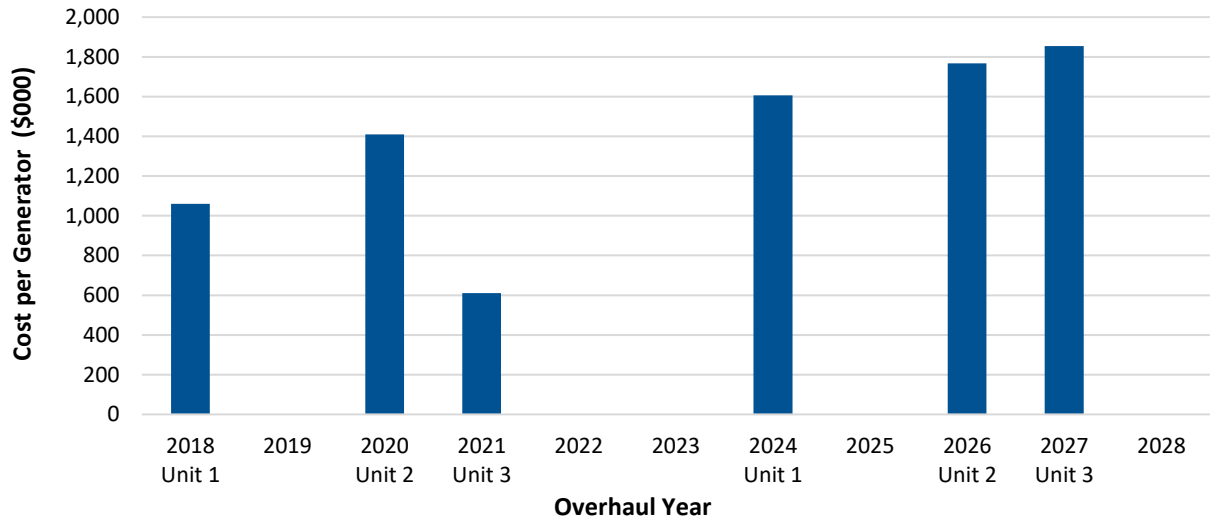


Chart 9: Average Unit Costs of Assets Overhauled – Generator

5.0 Historical Reliability

Hydro tracks performance data for its thermal generation units using the Derated Adjusted Forced Outage Rate ("DAFOR").[8] DAFOR is a metric that measures the percentage of time that a unit or group of units is unable to generate at its maximum continuous rating due to forced outages or unit deratings.

[8] Filed quarterly with the Board, most recently "Quarterly Report on Performance of Generating Units for the Twelve Months Ended March 31, 2022," Newfoundland and Labrador Hydro, April 29, 2022.

This program plays a key role in allowing Hydro to minimize the DAFOR of its thermal generation units to ensure the provision of reliable service to customers.

6.0 Analysis

6.1 Evaluation of Alternatives

Hydro evaluated the following alternatives:

- Pace reduction;
- Pace advancement;
- Condition-based refurbishment; and
- Overhaul.

6.1.1 Pace Reduction

A pace reduction of this program increases the failure risk of the Unit 1 turbine valves or generator while in operation, which could result in collateral damage and loss of 170 MW of generation for several weeks. Data obtained through preventive maintenance activities is not comprehensive enough to allow Hydro to make an accurate prediction regarding the likelihood of failure in advance of the next planned overhaul.

If the turbine valves are not overhauled, there will be an elevated risk of not functioning as designed. Oxide scale build-up can impede valve movement. Erosion and wear can increase clearances and lead to valve failures. Cracking and other damage may occur and propagate, leading to failures. Proper operation of all of the turbine valves is required to admit steam to the turbine and control the turbine to spin the generator and produce electricity. Any failure will limit production and likely result in a forced outage. Because of the complexity and magnitude of the components, significant outages would be expected if repairs were required. For example, a control valve camshaft failure on Unit 2 in 2019 resulted in a forced outage of 22 days. From a safety perspective, the stop valves, blowdown valves, and non-return valves must function properly during an operational upset condition to prevent overspeed of the turbine and generator rotor. Overspeed can happen very quickly and these valves must slam shut (or open in the case of the blowdown valve). The turbine rotor weighs approximately 60,000 pounds and rotates at 60 times per second. An overspeed failure has the potential to be catastrophic and can severely impact safe and reliable operations. Furthermore, the steam admitted to the turbine, even in

the intermediate section, is at very high temperatures and pressures. Failure of any pressure boundary valve component has the potential to become a serious safety hazard.

If the generator is not overhauled, critical components such as bearings, hydrogen seals, windings and rotor retaining rings could fail in service, requiring unplanned costly repair work and causing a major outage. For example, the generator rotor must be removed from the stator to replace damaged rotor retaining rings.

All turbine valves at the Holyrood TGS are currently on a three-year overhaul cycle and generators are on a six-year cycle. These intervals were recommended by the OEM and proven an appropriate period based on Hydro's experience. Therefore, Hydro believes a pace reduction of this program poses an unacceptable risk to the safe and reliable operations of the Holyrood TGS.

6.1.2 Pace Advancement

Hydro's historical experience with this program has not demonstrated a need to accelerate turbine valve and generator overhauls.

6.1.3 Condition-Based Refurbishment

The condition of the turbine valves and generator cannot be adequately determined through external inspection or monitoring instrumentation. To assess the condition of internal components, disassembly of the turbine valves and generator is required. As such, condition-based refurbishment of the turbine valves and generator is not a viable option.

6.1.4 Continuation of Overhaul Program

This alternative consists of planned disassembly, detailed internal inspection, refurbishment and reassembly of all major internal components of the Unit 1 turbine valves and generator. Components that have been identified as damaged in the inspections are refurbished or replaced. This alternative aligns with Hydro's experience and OEM recommendations and allows Hydro to manage risk within an acceptable level.

6.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

6.3 Recommended Alternative

Hydro recommends overhauling the Holyrood TGS Unit 1 turbine valves and generator in 2024. Overhauling the Unit 1 turbine valves and generator in accordance with Hydro's practice and the OEM recommendations will maintain these assets in good operating condition, contributing to the continued safe and reliable operation of Unit 1. Without regular overhauls, these components are at an elevated risk of malfunctioning.

6.3.1 Risk of Asset Stranding

The risk of asset stranding is less imminent as a result of the decision to extend Holyrood TGS to remain available through the Bridging Period. As Hydro expects continued operation of all three units at the Holyrood TGS through the Bridging Period until its capacity can be adequately replaced to ensure reliable operation for customers, capital expenditures for this facility to operate as a generator continue to be required. Depreciation is required to be calculated on an accelerated basis (i.e., monthly depreciation = capital investment ÷ remaining months of service life).[9]

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	5	4	**20**
Post-Execution	5	1	**5**
		Risk Mitigated	**15**
		Risk Mitigated per $1 Million	**2.9**

7.0 Scope of Work

7.1 Unit 1 Turbine Valves Overhaul

The overhaul of the Unit 1 turbine valves will consist of dismantling all the control valves, main stop valves, combined reheat stop and intercept valves, extraction non-return valves, and blowdown valves

[9] As a result of the extension of the Holyrood TGS through the Bridging Period, Hydro intends to make an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account in 2023.

for inspection and detailed measurements. The valves will be refurbished as required through the replacement of damaged parts. The valves will be reassembled and commissioned to ensure proper operation.

7.2 Unit 1 Generator Overhaul

The overhaul of the Unit 1 generator will consist of dismantling the generator end shields, hydrogen seals and bearings, removal of the rotor from the stator, electrical testing of the stator and rotor windings, inspection, replacement or refurbishment of components as required, and re-assembly of generator components. The generator will be reassembled and commissioned to ensure proper operation.

7.3 Program Budget

The estimate for the 2024 program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	171.0	0.0	0.0	171.0
Labour	473.9	0.0	0.0	473.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	3,939.4	0.0	0.0	3,939.4
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	138.6	0.0	0.0	138.6
Contingency	458.5	0.0	0.0	458.5
Total	**5,181.4**	**0.0**	**0.0**	**5,181.4**

Chart 10 to Chart 13 provide the historical expenditures since 2018, the forecast 2023 expenditures, the proposed 2024 budget, and the forecast costs through 2028.[10]

[10] A forecast for the costs of this program was based on the assumption of continued operation of all generating units at the Holyrood TGS through the Bridging Period until its capacity can be adequately replaced. Hydro's capital projections assume all three generating units remain online until 2030, and are subject to change based on changes in operating regime.

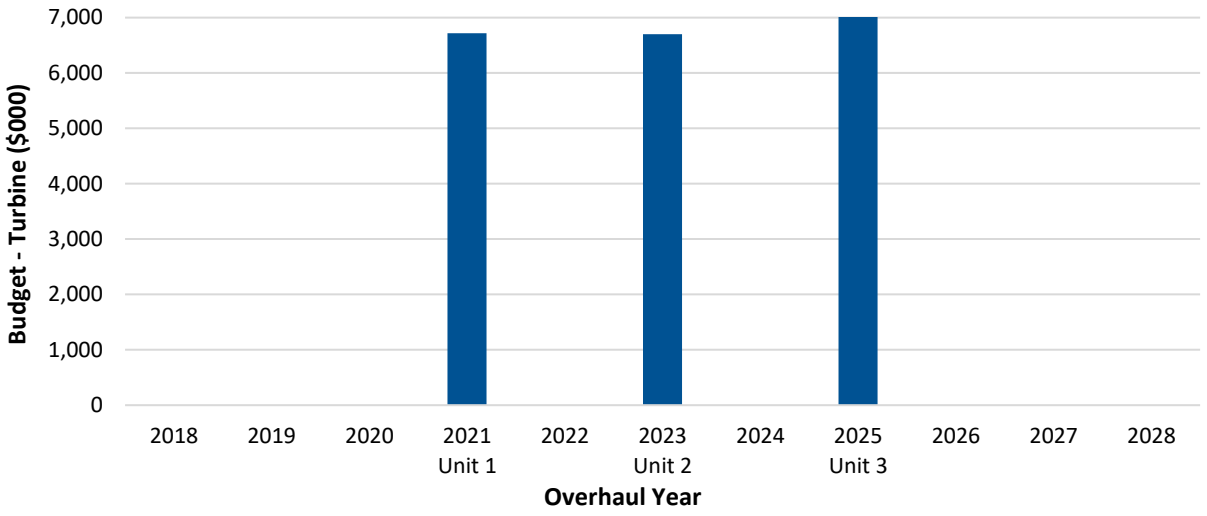


Chart 10: Historical and Forecast Program Budget – Turbine

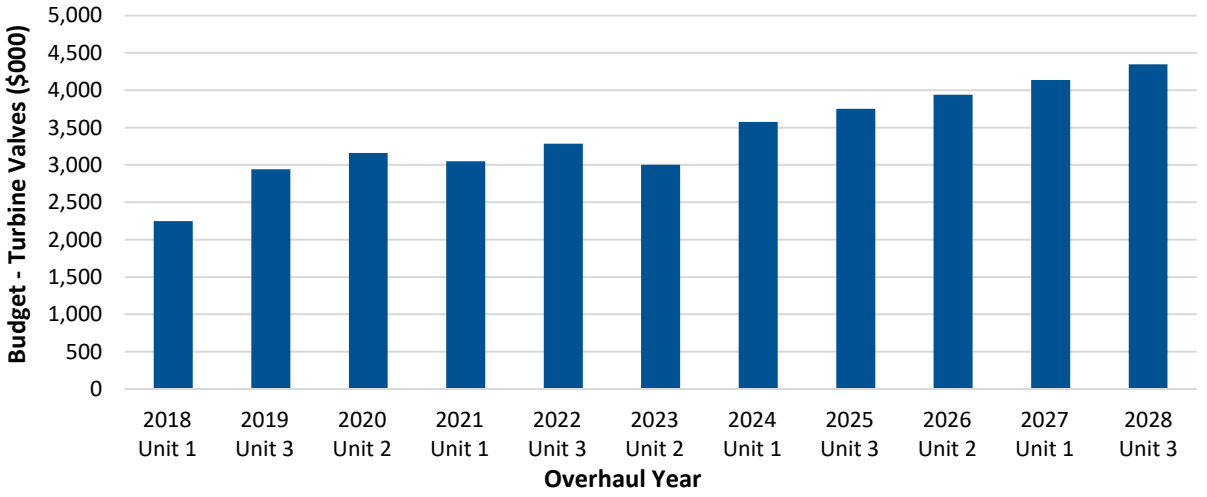


Chart 11: Historical and Forecast Program Budget – Turbine Valves

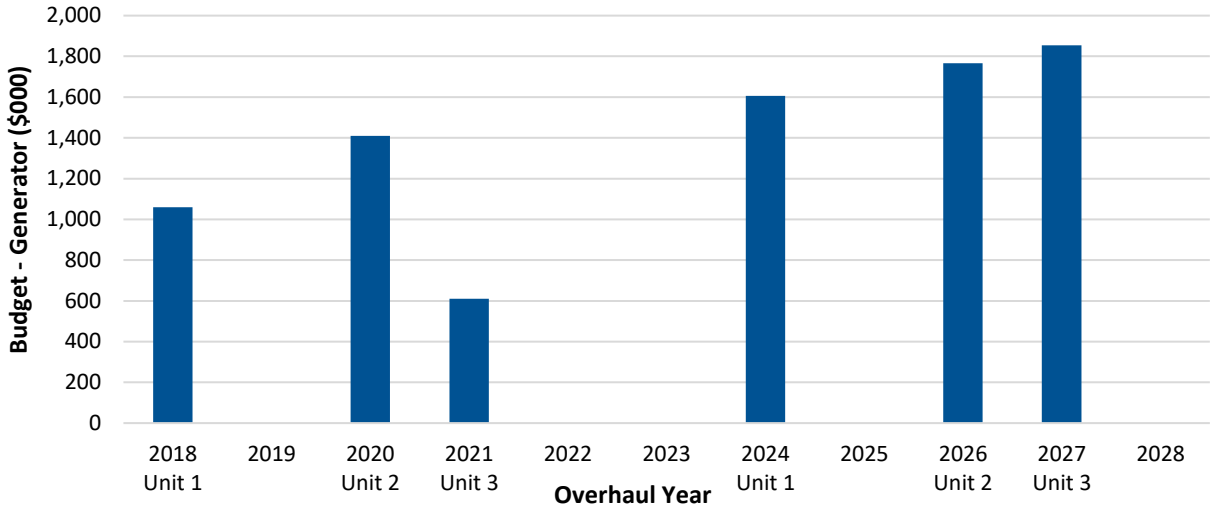


Chart 12: Historical and Forecast Program Budget – Generator

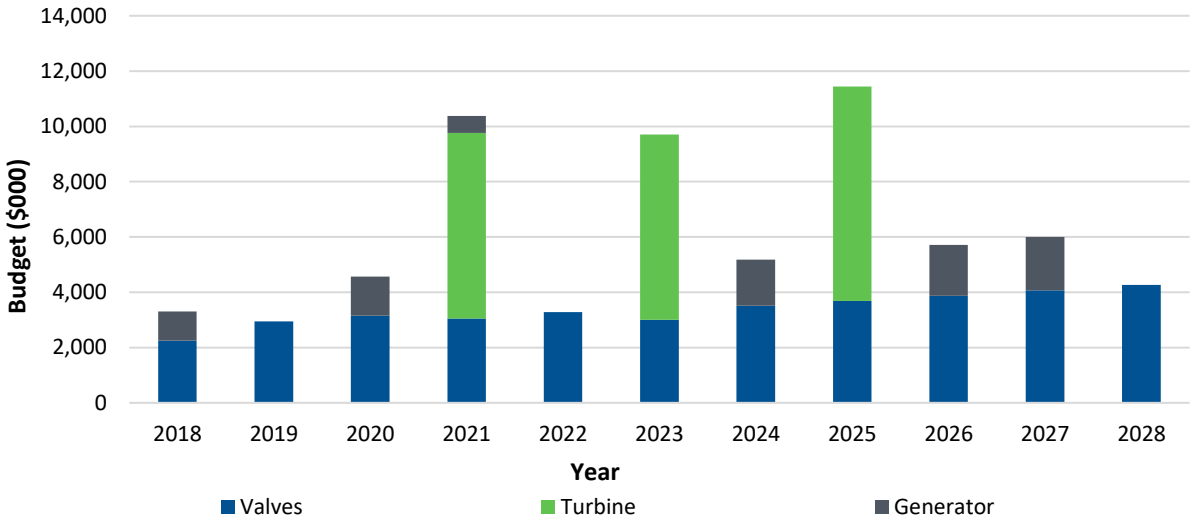


Chart 13: Historical and Forecast Program Budget – Total

7.4 Program Schedule

The schedule for the 2024 program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Prepare planning documents.	January 2024	January 2024
Design:		
Prepare technical conditions for the overhaul contract.	February 2024	February 2024
Procurement:		
Prepare overhaul contract documents and award the contract.	February 2024	March 2024
Construction:		
Review materials inventory and supply construction materials.	March 2024	November 2024
Perform Unit 1 turbine valve and generator overhauls.	June 2024	November 2024
Closeout:		
Prepare closeout documents.	November 2024	December 2024

8.0 Conclusion

The overhaul of the Holyrood TGS Unit 1 turbine valves was last performed in 2021 and the overhaul of the Unit 1 generator was last performed in 2018. To support the continued safe and reliable operation of Unit 1 at its rated output of 170 MW, Hydro recommends overhauling the Unit 1 turbine valves and generator in 2024. This planned overhaul is consistent with previous overhaul cycles that have demonstrated that such frequency is appropriate. It is also consistent with the established OEM overhaul frequency that has historically supported the safe and reliable operation of Holyrood TGS Unit 1.

Program 3

Replace Diesel Gensets (2024–2026)

July 2023



Replace Diesel Gensets (2024–2026)

Location: Nain and Makkovik

Investment Classification: Renewal

Asset Category: Generation

Executive Summary

The community of Nain is located on the north coast of Labrador, where Newfoundland and Labrador Hydro ("Hydro") provides electrical service to approximately 515 customers. Electricity is supplied by a diesel generating station that is owned and operated by Hydro. Currently, the Nain Diesel Generating Station contains four units. Unit 2085 is a 1,275 kW, 1,800 rpm diesel generating set ("genset"), which was installed in 2009. The load profile in Nain is expected to grow over the next five years.

The community of Makkovik is located on the north coast of Labrador, where Hydro provides electrical service to approximately 230 customers. Electricity is supplied by a diesel generating station that is owned and operated by Hydro. Currently, the Makkovik Diesel Generating Station contains three units. Unit 3033 is a 565 kW, 1,800 rpm diesel genset, which was installed in 1992. The load profile in Makkovik is expected to grow over the next five years.

Consistent with other utilities in Canada with prime power diesel generating stations, Hydro's Asset Management Program requires the replacement of 1,800 rpm diesel gensets when they reach 100,000 operating hours. Unit 2085 in Nain is forecast to reach this threshold in 2026. Unit 3033 in Makkovik has reached this threshold; however, a premature failure and subsequent unscheduled overhaul extended its service life beyond this milestone. Continuing to operate these units beyond the recommended number of operating hours would increase the likelihood of engine failure and reduce reliability for customers. If Unit 2085 in Nain and Unit 3033 in Makkovik were to fail, it could potentially result in rotating outages due to a lack of firm capacity. As such, deferral of these replacements is not an acceptable alternative.

Hydro's least-cost evaluation determined that replacing Unit 2085 in Nain with a 1,800 rpm, 1,600 kW unit is the least-cost option, as it addresses the need for increased firm capacity in Nain due to forecast load growth. Work in Nain is scheduled for completion in 2026, with an estimated cost of $2,894,600.

Hydro's least-cost evaluation determined that replacing Unit 3033 in Makkovik with a 1,800 rpm, 545 kW unit is the least-cost option.[1] Work in Makkovik is scheduled for completion in 2026, with an estimated cost of $2,021,500.

This program has a multi-year approach, with completion planned in 2026 at an estimated cost of $4,916,100.

[1] To ensure a competitive tendering process, Hydro may consider gensets in the range of 525 kW to 725 kW; the suitable unit with the lowest life cycle cost will be selected.

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1.0 Introduction

Many communities in coastal Labrador are not connected to Hydro's Labrador Interconnected System for power supply. Communities on the coast are provided with electricity from diesel generating stations that are owned and operated by Hydro.

The community of Nain is located on the north coast of Labrador where Hydro provides electrical service to approximately 515 customers. Currently, Nain contains four units with capacities of 1,050 kW (Unit 595), 1,275 kW (Unit 2085), 865 kW (Unit 576), and 860 kW (Unit 591).

The community of Makkovik is located on the north coast of Labrador where Hydro provides electrical service to approximately 230 customers. Currently, Makkovik contains three units with capacities of 945 kW (Unit 593), 565 kW (Unit 3033), and 565 kW (Unit 2029).

The load profile in both Nain and Makkovik is forecasted to grow over the next five years.

2.0 Program Description and Justification

This program is required to maintain the reliable operation of Hydro's diesel generating stations and maintain customer demand. Diesel generating stations are isolated and in most cases are the sole sources of power to a community. As per Hydro's Asset Management Program, 1,800 rpm diesel gensets are replaced when they reach 100,000 operating hours. Unit 2085 in Nain is projected to reach this operational milestone in 2026. Unit 3033 in Makkovik has reached this threshold; however, a premature failure and subsequent unscheduled overhaul extended its service life beyond this milestone. As such, both units are proposed for replacement under this program.

3.0 Asset Overview

3.1 Asset Background

Unit 2085 in Nain is a 1,275 kW diesel genset, which was installed in 2009. This unit has been overhauled four times, most recently in 2022. At the time of overhaul in 2022, the unit had accumulated 86,598 operating hours. As of the end of 2022, the unit had accumulated approximately 88,000 operating hours. Based on usage, it is expected that this unit will reach its recommended operating hours of 100,000 in 2026.

Unit 3033 in Makkovik is a 565 kW diesel genset, which was installed in 2009. This unit has been overhauled five times, most recently in 2020. At the time of the overhaul in 2020, the unit had accumulated 97,323 operating hours. As of the end of 2022, the unit had accumulated approximately 103,000 operating hours. Due to its recent overhaul at 97,323 hours, Unit 3033 will operate past 100,000 operating hours.

3.2 Asset Condition

Diesel gensets are overhauled based on operating hours. 1,200 rpm units are overhauled at 120,000 hours and 1,800 rpm units are overhauled at 100,000 hours.[2] There are instances where these replacement intervals are advanced or exceeded; this is evaluated on a case-by-case basis. This timing facilitates a potential further condition assessment, which will then be used to determine the scope of work in each program year.

Unit 3033 had one premature failure that required overhaul. Due to generation problems during the winter of 2020, the decision was made to overhaul this unit at approximately 97,000 hours instead of replacing the genset. As a result, normal replacement intervals were exceeded; as such, this unit will be operated for an additional 20,000 hours from its 2020 overhaul.

Chart 1 provides the asset count for all assets covered under the program.

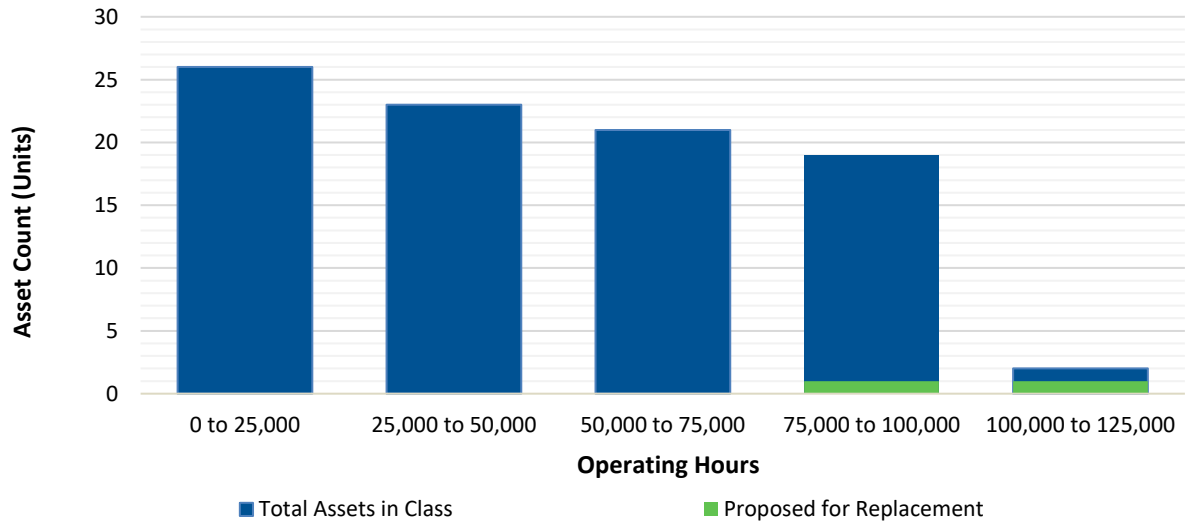


Chart 1: Asset Count Based on Operating Hours

[2] There are no 1,200 rpm units included within the scope of the 2024–2026 program.

3.3 Asset Ages

Chart 2 shows the ages of the gensets in Hydro's fleet. This includes units of varying sizes, ranging from 40 kW to 2,500 kW.

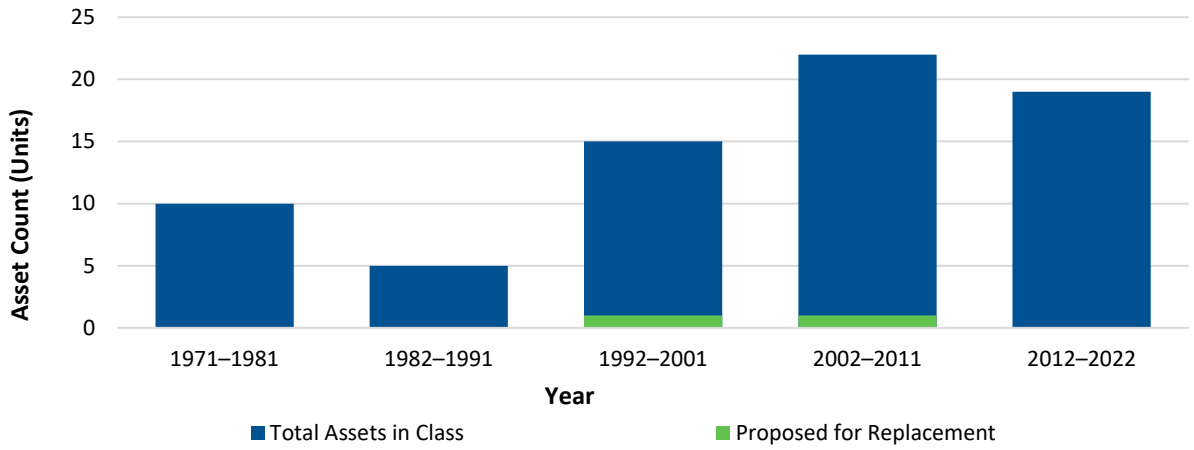


Chart 2: Asset Counts by Asset Age

4.0 Trending

Between 2018 and 2023, an average of 1.7 engines (10 over 6 years) have been replaced annually. Hydro is forecasting another 8 genset replacements over the next 5 years, starting in 2024. This number may increase or decrease based on genset usage and electricity demand in the communities they serve.

4.1 Assets Installed

Chart 3 indicates the historical and forecast number of diesel gensets replaced under this program. There are currently no anticipated installations in 2027.

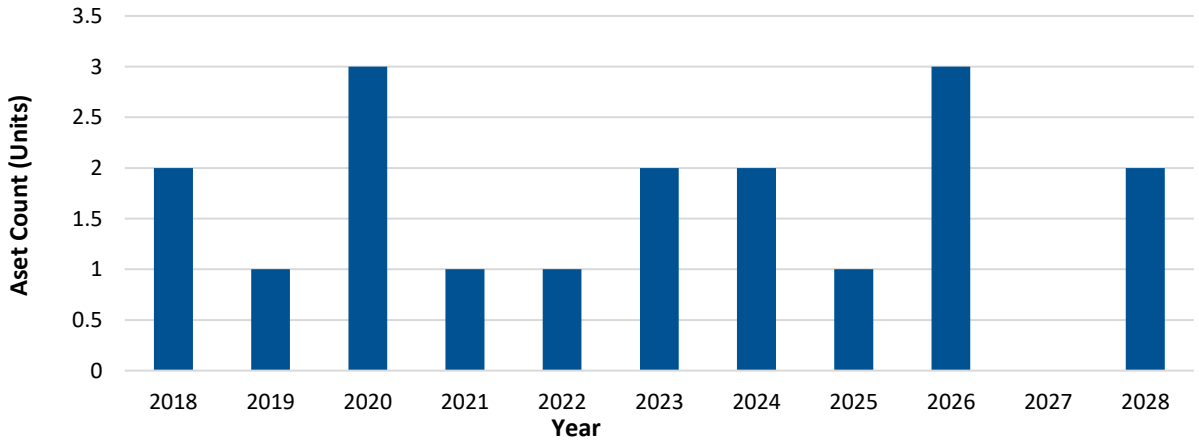


Chart 3: Historical and Forecast Assets Replaced

4.2 Historical and Forecast Average Unit Costs

Chart 4 indicates the average cost of genset replacement per year. Costs change significantly based on engine size, which can range from 40 kW to 2,500 kW and some genset installation projects require diesel generating station extensions, which significantly increases the program cost. In some cases, Hydro may be able to re-purpose decommissioned units, which would further decrease costs. There are currently no anticipated installations in 2027; however, this may change with engine operating requirements.

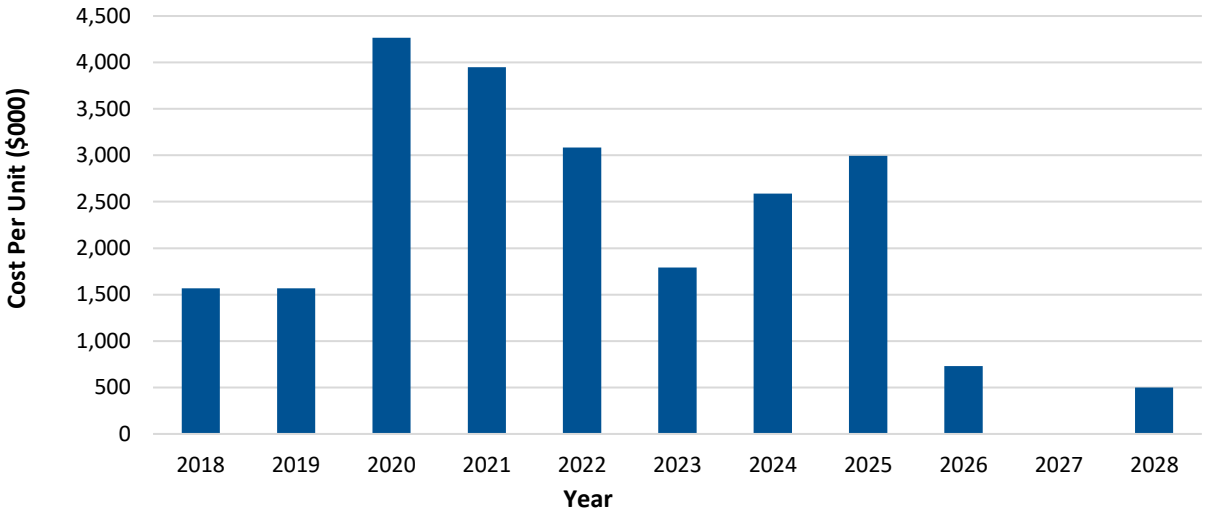


Chart 4: Historical and Forecast Average Unit Costs of Assets Replaced

5.0 Historical Reliability

Hydro tracks reliability for diesel communities similar to its other locations using SAIDI[3] and SAIFI;[4] however, it is tracked at a system level, not by individual generating units. These statistics do not distinguish between the different outage causes, such as line outages, recloser issues, blown fuses, fuel system problems, generator issues, etc. If Hydro does not perform replacements as per the original equipment manufacturer's ("OEM") recommendation proposed under this program, diesel units may experience catastrophic failure before their operating hour lifespan.

[3] System Average Interruption Duration Index ("SAIDI").
[4] System Average Interruption Frequency Index ("SAIFI").

6.0 Analysis

6.1 Evaluation of Alternatives

Hydro has evaluated the following alternatives:

- Pace reduction;
- Pace advancement; and
- Continue program at current pace.

6.1.1 Pace Reduction

Diesel generating stations are isolated and in most cases are the sole sources of power to a community. This program is required to maintain the reliable operation of the diesel generating station and maintain customer demand. Deferral of work past the recommended operating hours would increase the risk of unit failure.

6.1.2 Pace Advancement

Hydro has determined the current operating hours' approach is appropriate based on the OEM's recommendations and historical experience. Advancing the timing of these replacements would result in the premature replacement of these assets.

6.1.3 Continue Program at Current Pace

In Hydro's experience, the replacement of diesel gensets at 120,000 operating hours for 1,200 rpm units and 100,000 operating hours for 1,800 rpm units ensures the proactive replacement of diesel gensets and supports the safe and reliable operation of Hydro's diesel generating stations while maximizing the serviceable life of the asset. As this program sees the replacement of diesel gensets across Hydro's system, it represents a pooled approach to genset replacement.

6.2 Least-Cost Evaluation

6.2.1 Nain Unit 2085 Replacement

A sizing study was completed, as the load profile in Nain is expected to grow through the next five years. Table 1 shows the existing unit information.

Table 1: Existing Unit Information – Nain

Unit ID	Unit Rating (kW)	Engine Speed (rpm)	Total Hours at the End of 2022	Hours Since Last Overhaul
Unit 2085 (to be replaced)	1,275	1,800	87,843	736
Unit 595	1,050	1,200	5,265	0
Unit 576	865	1,800	67,576	8,197
Unit 591	860	1,200	44,794	0
Plant Installed Capacity	4,050	-	-	-
Plant Firm Capacity	2,775	-	-	-

Unit Sizing Alternatives

Four alternative unit sizes were considered for the replacement of Unit 2085 within this analysis. They were:

- Alternative 1: 945 kW, 1,200 rpm
- Alternative 2: 945 kW, 1,800 rpm
- Alternative 3: 1,275 kW, 1,800 rpm
- Alternative 4: 1,600 kW, 1,800 rpm

The load forecast used for this analysis is the 2023 long-term load forecast for Nain. This forecast, as well as plant firm capacity, existing capacity deficit, and capacity deficit for each alternative, is presented in Table 2. This table does not take into consideration any future unit replacements, as described herein.

Table 2: Long-Term Load Forecast – Nain (kW)

Year	Forecast Gross Peak	Existing Firm Capacity	Existing Excess Capacity	Alternatives 1 and 2 Excess Capacity[5]	Alternatives 3 and 4 Excess Capacity[6,7]
2023	2,279	2,775	496	391	496
2024	2,309	2,775	466	361	466
2025	2,337	2,775	438	333	438
2026	2,364	2,775	411	306	411
2027	2,385	2,775	390	285	390
2028	2,385	2,775	390	285	390
2029	2,421	2,775	354	249	354
2030	2,456	2,775	319	214	319
2031	2,492	2,775	283	178	283
2032	2,528	2,775	247	142	247
2033	2,565	2,775	210	105	210
2034	2,602	2,775	173	68	173
2035	2,640	2,775	135	30	135
2036	2,679	2,775	96	-9	96
2037	2,718	2,775	57	-48	57
2038	2,757	2,775	18	-87	18
2039	2,798	2,775	-23	-128	-23
2040	2,839	2,775	-64	-169	-64
2041	2,880	2,775	-105	-210	-105
2042	2,922	2,775	-147	-252	-147
2043	2,922	2,775	-147	-252	-147

If Alternatives 1 or 2 were implemented, a violation of the planning firm capacity would begin to occur in the year 2036. To prevent this, both of the small units, Units 576 and 591, would need to be replaced with larger diesel gensets within the next 20 years.

Within Alternatives 1 and 2, two different options for avoiding future planning criteria violations were considered:

- Option 1 (Alternative 1-1 and 2-1):

[5] The installed capacity of Alternative 1 and 2 would be 3,720 kW (945 kW + 1,050 kW + 865 kW + 860 kW) and the firm capacity would be 2,670 kW (945 kW + 865 kW + 860 kW).
[6] The installed capacity of Alternative 3 would be 4,050 kW (1,275 kW + 1,050 kW + 865 kW + 860 kW) and the firm capacity would be 2,775 kW (1,050 kW + 865 kW + 860 kW).
[7] The installed capacity of Alternative 4 would be 4,375 kW (1,600 kW + 1,050 kW + 865 kW + 860 kW) and the firm capacity would be 2,775 kW (1,050 kW + 865 kW + 860 kW).

- Unit 576 is assumed to be replaced with a 1,275 kW, 1,800 rpm unit when it reaches its end-of-life (estimated at 2029).
- Unit 591 is assumed to be replaced with a 945 kW, 1,200 rpm unit when it reaches its end-of-life (estimated at 2036).

- Option 2 (Alternative 1-2 and 2-2):
  - Unit 576 is assumed to be replaced with a 1,275 kW, 1,800 rpm unit when it reaches its end of life (estimated at 2029).
  - Unit 591 is assumed to be replaced with a 945 kW, 1,800 rpm unit when it reaches its end of life (estimated at 2036).

If Alternative 3 or 4 were implemented, a violation of the planning firm capacity would occur in 2039. To prevent this, only one of the small units, Units 576 and 591, would need to be replaced with a larger diesel genset within the next 20 years. In Alternative 3, it was assumed that Unit 576 would be replaced with a similarly sized unit when it reaches its estimated end-of-life in 2030 and Unit 591 would be replaced with a 1,275 kW, 1,800 rpm unit when it reaches its estimated end-of-life in 2039. In Alternative 4, it was assumed that Unit 576 would be replaced with a 1,275 kW, 1,800 rpm unit when it reaches its estimated end-of-life in 2034. In this alternative, the replacement of Unit 591 is not expected to be required within the study duration.

Simulation

A diesel plant simulator was used to estimate the overhaul and replacement frequencies and total unit operating hours over 20 years for different plant configurations. The simulation inputs included the system load forecast, existing genset information, and alternative genset information. A summary of the simulation results can be found in Table 3.

Table 3: Simulation Summary – Nain

Alternative	Total Unit Operating Hours	Unit Replacements	Overhauls
1-1: 945 kW, 1,200 rpm	293,735	3	4
1-2: 945 kW, 1,200 rpm	293,735	3	5
2-1: 945 kW, 1,800 rpm	293,735	3	6
2-2: 945 kW, 1,800 rpm	293,735	3	7
3: 1,275 kW, 1,800 rpm	280,509	3	8
4: 1,600 kW, 1,800 rpm	230,119	2	7

A least-cost evaluation was completed in 2023 to compare the alternatives to replace Unit 2085, as proposed under this program. The following were the assumptions made for this analysis:

- Unit replacement costs:
  - $2.911 million for a 945 kW, 1,200 rpm unit;
  - $2.311 million for a 945 kW, 1,800 rpm unit;
  - $2.811 million for a 1,275 kW, 1,800 rpm unit; and
  - $2.911 million for a 1,600 kW, 1,800 rpm unit.
- Unit overhaul costs:
  - $400,000 for a 945 kW, 1,200 rpm unit;
  - $375,000 for a 945 kW, 1,800 rpm unit;
  - $540,000 for a 1,275 kW, 1,800 rpm unit; and
  - $720,000 for a 1,600 kW, 1,800 rpm unit.
- The overhaul and replacement frequencies:
  - 945 kW, 1,200 rpm unit: Overhaul every 60,000 hours, replacement every 120,000 hours;
  - 945 kW, 1,800 rpm unit: Overhaul every 20,000 hours, replacement every 100,000 hours;
  - 1,275 kW, 1,800 rpm unit: Overhaul every 20,000 hours, replacement every 100,000 hours; and
  - 1,600 kW, 1,800 rpm unit: Overhaul every 20,000 hours, replacement every 100,000 hours.
- Timing of unit replacements and overhauls were based on simulation results unless a unit reaches 35 years of operation, at which time it will be assumed replaced due to obsolescence and potential lack of availability of parts.

A summary of the net present value ("NPV") analysis results[8] is presented in Table 4. The lowest cost option is Alternative 4.

Table 4: Least-Cost Evaluation Summary – Nain ($)

Alternatives	NPV	NPV Difference between Alternative and the Least-Cost Alternative
4: 1,600 kW, 1,800 rpm	5,673,543	-
3: 1,275 kW, 1,800 rpm	5,846,337	172,794
1-1: 945 kW, 1,200 rpm[9]	6,048,454	374,911
1-2: 945 kW, 1,200 rpm[10]	6,091,725	418,182
2-1: 945 kW, 1,800 rpm[11]	6,225,680	552,137
2-2: 945 kW, 1,800 rpm[12]	6,268,951	595,408

Based on this analysis, it is recommended to replace Unit 2085 in Nain with a 1,600 kW, 1,800 rpm genset.

6.2.2 Makkovik Unit 3033 Replacement

As the load profile in Makkovik is expected to grow through the next five years, a sizing study was completed. Table 5 shows the existing diesel unit information.

Table 5: Existing Unit Information – Makkovik

Unit ID	Unit Rating (kW)	Engine Speed (rpm)	Total Hours at the End of 2022	Hours Since Last Overhaul
Unit 3033 (To be replaced)	565	1,800	102,442	5,119
Unit 2029	565	1,800	89,272	3,301
Unit 593	945	1,200	15,707	0
Plant Installed Capacity	2,075	-	-	-
Plant Firm Capacity	1,130	-	-	-

[8] These results do not include the fuel consumption of the alternatives; the fuel efficiency of the genset is evaluated during the tendering process and can vary greatly depending on unit make and model.
[9] Includes the replacement of Unit 576 with a 1,275 kW, 1,800 rpm unit in 2029 and the replacement of Unit 591 with a 945 kW, 1,200 rpm unit in 2036.
[10] Includes the replacement of Unit 576 with a 1,275 kW, 1,800 rpm unit in 2029 and the replacement of Unit 591 with a 945 kW, 1,800 rpm unit in 2036.
[11] Includes the replacement of Unit 576 with a 1,275 kW, 1,800 rpm unit in 2029 and the replacement of Unit 591 with a 945 kW, 1,200 rpm unit in 2036.
[12] Includes the replacement of Unit 576 with a 1,275 kW, 1,800 rpm unit in 2029 and the replacement of Unit 591 with a 945 kW, 1,800 rpm unit in 2036.

The load forecast used for this analysis is the 2023 long-term load forecast for Makkovik and is presented in Table 6. No additional firm capacity will be needed to meet the long-term load forecast.

Table 6: Long-Term Load Forecast – Makkovik (kW)

Year	Gross Peak
2023	879
2024	890
2025	900
2026	910
2027	920
2028	922
2029	927
2030	935
2031	941
2032	946
2033	951
2034	957
2035	962
2036	967
2037	970
2038	973
2039	975
2040	978
2041	981
2042	984
2043	984

A diesel plant simulator was used to estimate the overhaul and replacement frequencies and total unit operating hours over a 20-year period for different plant configurations. The simulation inputs included the system load forecast, existing genset information, and alternative genset information. A summary of the simulation results can be found in Table 7.

Table 7: Simulation Summary – Makkovik

Alternatives	Total Unit Operating Hours	Unit Replacements	Overhaul
1: 545 kW, 1,800 rpm	157,687	2	4
2: 725 kW, 1,800 rpm	157,687	3	5
3: 945 kW, 1,800 rpm	157,687	3	4
4: 945 kW, 1,200 rpm	157,687	3	4

Four different unit configuration alternatives were considered. All sizes considered allow the system's firm capacity criteria to be maintained.

A least-cost evaluation was completed in 2023 to compare the alternatives to replace Unit 2033. The following were the assumptions made for this analysis:

- Unit replacement costs:
  - $1.851 million for a 545 kW, 1,800 rpm unit;
  - $1.951 million for a 725 kW, 1,800 rpm unit;
  - $2.241 million for a 945 kW, 1,800 rpm unit; and
  - $2.621 million for a 945 kW, 1,200 rpm unit.
- Unit overhaul costs:
  - $180,000 for a 545 kW, 1,800 rpm unit;
  - $240,000 for a 725 kW, 1,800 rpm unit;
  - $375,000 for a 945 kW, 1,800 rpm unit; and
  - $400,000 for a 945 kW, 1,200 rpm unit.
- The overhaul and replacement frequencies:
  - 545 kW, 1,800 rpm unit: Overhaul every 20,000 hours, replacement every 100,000 hours;
  - 725 kW, 1,800 rpm unit: Overhaul every 20,000 hours, replacement every 100,000 hours;
  - 945 kW, 1,800 rpm unit: Overhaul every 20,000 hours, replacement every 100,000 hours; and
  - 945 kW, 1,200 rpm unit: Overhaul every 60,000 hours, Replacement every 120,000 hours.

Timing of unit replacements and overhauls are based on simulation results unless a unit reaches 35 years of operation, at which time it will be assumed replaced due to obsolescence and the potential lack of availability of parts.

The summary of the NPV analysis results[13] is presented in Table 8. These results do not include the fuel consumption of the alternatives. The lowest cost option is Alternative 1. Based on this analysis, it is recommended to replace Unit 3033 with a 545 kW, 1,800 rpm genset.[14]

Table 8: Least-Cost Evaluation Summary – Makkovik ($)

Alternatives	NPV	NPV Difference between Alternative and the Least-Cost Alternative
1: 545 kW, 1,800 rpm	3,417,411	-
2: 725 kW, 1,800 rpm	4,039,072	621,662
3: 945 kW, 1,800 rpm	4,189,363	771,952
4: 945 kW, 1,200 rpm	4,358,355	940,945

6.3 Recommended Alternative

Hydro recommends the replacement of Unit 2085 at Nain with a new 1,600 kW, 1,800 rpm diesel genset and Unit 3033 in Makkovik with a 545 kW, 1,800 rpm unit. These new genset installations will increase reliability and enable Hydro to meet firm capacity requirements.

6.3.1 Risk of Asset Stranding

Diesel generating stations are isolated and in most cases are the sole sources of power to a community. The gensets in Nain and Makkovik are required to meet firm capacity; as such, the risk of asset stranding is low.

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2026 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 9.

[13] These results do not include the fuel consumption of the alternatives. The fuel efficiency of the genset is evaluated during the tendering process and can vary greatly depending on unit make and model.
[14] To ensure a competitive tendering process, Hydro may consider gensets in the range of 525 kW to 725 kW; the suitable unit with the lowest life cycle cost will be selected.

Table 9: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	4	4	**16**
Post-Execution	4	2	**8**
		Risk Mitigated	**8**
		Risk Mitigated per $1 Million	**1.6**

7.0 Scope of Work

The 2024–2026 program will replace Unit 2085 at the Nain Diesel Generating Station with a new 1,600 kW 1,800 rpm diesel genset. It will include the design, procurement, and installation of a new genset, exhaust stack, radiator, aftercooler, switchgear with breaker, and all other equipment necessary to facilitate the proper function of the new unit. Upgrades to some existing protection and control equipment will be required including additions to the motor control centre ("MCC") programmable logic controller ("PLC") cabinet, modifications to Main PLC and modification/testing of PLC logic.

Unit 3033 at Makkovik will be replaced with a 545 kW 1,800 rpm unit. The scope of work includes the design, procurement, and installation of a new genset, exhaust stack, radiator, aftercooler, switchgear with breaker, and all other equipment necessary to facilitate the proper function of the new unit. Upgrades to some existing protection and control equipment will be required, including additions to the MCC PLC cabinet, modifications to Main PLC and modification/testing of PLC logic.

7.1 Program Budget

The estimates for the 2024–2026 program are shown in Table 10, Table 11, and Table 12.

Table 10: Program Estimate – Combined ($000)

Program Cost	**2024**	**2025**	**Beyond**	**Total**
Material Supply	41.0	0.0	1,855.7	**1,896.7**
Labour	386.5	367.3	1,018.5	**1,772.3**
Consultant	6.0	6.0	12.0	**24.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	36.9	19.6	374.7	**431.2**
Interest and Escalation	26.5	54.2	323.5	**404.2**
Contingency	38.9	30.9	317.9	**387.7**
Total	**535.8**	**478.0**	**3,902.3**	**4,916.1**

The estimate for the work in Nain is shown in Table 11.

Table 11: Program Estimate – Nain ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	16.5	0.0	1,271.2	**1,287.7**
Labour	216.2	183.0	495.0	**894.2**
Consultant	6.0	0.0	6.0	**12.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	23.7	5.9	205.2	**234.8**
Interest and Escalation	14.9	28.0	191.2	**234.1**
Contingency	21.8	15.3	194.7	**231.8**
Total	**299.1**	**232.2**	**2,363.3**	**2,894.6**

The estimate for the work in Makkovik is shown in Table 12.

Table 12: Program Estimate – Makkovik ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	24.5	0.0	584.5	**609.0**
Labour	170.3	184.3	523.5	**878.1**
Consultant	0.0	6.0	6.0	**12.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	13.2	13.7	169.5	**196.4**
Interest and Escalation	11.6	26.2	132.3	**170.1**
Contingency	17.1	15.6	123.2	**155.9**
Total	**236.7**	**245.8**	**1,539.0**	**2,021.5**

Chart 5 provides the five-year historical program expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028. Budget variability in 2022 is due to increased load in the communities requiring the existing genset to be replaced with a larger capacity unit, as a plant extension was required under this program to accommodate the larger genset. The program budget amount also changes due to the lead time of the genset. There are no expenditures in 2027 as there are currently no anticipated iterations of this program scheduled to commence in 2027, nor installations from previous iterations scheduled.

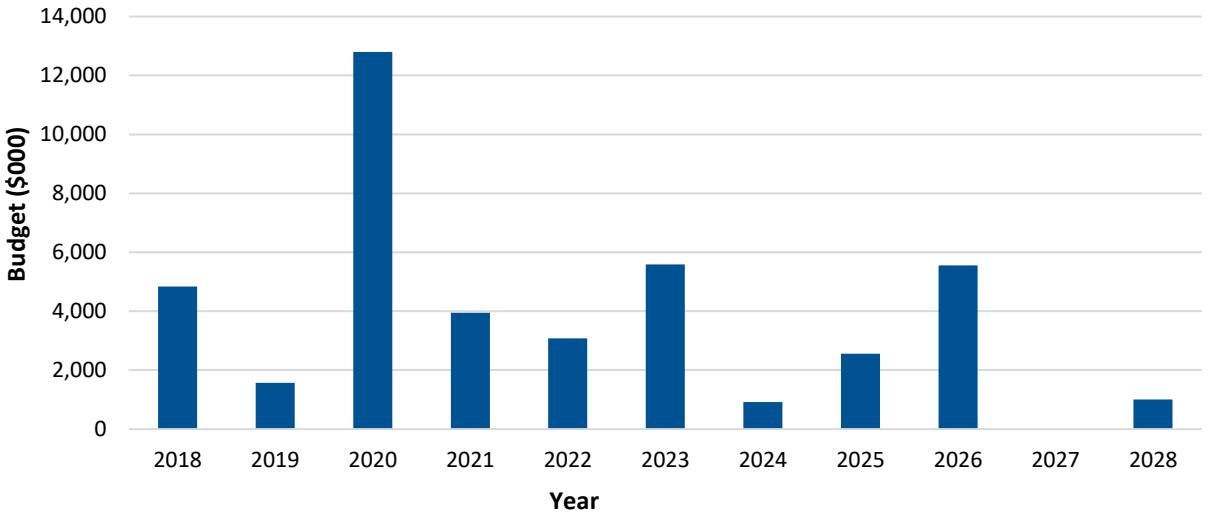


Chart 5: Historical and Forecast Program Budget

7.2 Program Schedule

The 2024–2026 program schedule for Nain is provided in Table 13.

Table 13: Program Schedule – Nain

Activity	Start Date	End Date
Planning: Open work orders and plan and develop detailed schedules.	January 2024	February 2024
Design: Design and specification development for tender and procurement.	February 2024	May 2024
Procurement: Procure required materials for the genset and protection and control upgrades.	May 2024	July 2025
Construction: Remove old genset, electrical, and protection and control equipment.	July 2026	August 2026
Commissioning – Manual Mode: Run up the new genset without automation, confirm operation, and release to operations.	August 2026	September 2026
Construction and Commissioning - Automation: PLC/HMI[15] programming, PLC I/O wiring, PLC I/O and logic testing, confirm operation, and release to operations.	September 2026	November 2026
Closeout: Close work order, complete all documentation, and complete lessons learned.	November 2026	December 2026

[15] Human-machine interface ("HMI").

The 2024–2026 program schedule for Makkovik is provided in Table 14.

Table 14: Program Schedule – Makkovik

Activity	Start Date	End Date
Planning: Open work orders and plan and develop detailed schedules.	January 2024	February 2024
Design: Design and specification development for tender and procurement.	February 2024	May 2024
Procurement: Procure required materials for the genset and protection and control upgrades.	May 2024	July 2025
Construction: Remove old genset, electrical, and protection and control equipment.	July 2026	August 2026
Commissioning – Manual Mode: Run up the new genset without automation, confirm operation, and release to operations.	August 2026	September 2026
Construction and Commissioning - Automation: PLC/HMI programming, PLC I/O wiring, PLC I/O and logic testing, confirm operation, and release to operations.	September 2026	November 2026
Closeout: Close work order, complete all documentation, and complete lessons learned.	November 2026	December 2026

8.0 Conclusion

Hydro's Asset Management Program requires the replacement of 1,800 rpm diesel gensets when they reach 100,000 operating hours. Unit 2085 at the Nain Diesel Generating Station is forecast to reach this threshold in 2026. Unit 3033 at the Makkovik Diesel Generating Station has already exceeded its threshold. Continuing to operate these units beyond recommended operating hours would increase the likelihood of engine failure and reduce reliability for customers. Under this program, Hydro is proposing to replace the units to maintain the reliable operation of the Nain and Makkovik Diesel Generating Stations.

Program 4

Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)

July 2023

newfoundland labrador hydro

Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)

Location: Various

Investment Classification: Renewal

Asset Category: Distribution

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has an Asset Management Program that governs the life cycle of its distribution assets. This program monitors, maintains, refurbishes, replaces, and disposes of assets to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner. The program also includes expenditures related to the replacement of existing street lights with light-emitting diode ("LED") street lights, as Hydro works to complete the retirement of high-pressure sodium ("HPS") and mercury vapour ("MV") street lighting in its system.

Generally, Hydro identifies and plans the refurbishment and replacement work that will be required for its distribution assets in time for inclusion within the capital budget applications ("CBA"). However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or the determination of faster-than-anticipated equipment deterioration.

Hydro directly supplies electricity to over 39,000 customers across the province. Hydro proposes the continuation of this program to maintain system reliability and least-cost service for customers.

The estimated cost for work executed under this program in 2024 is $4,345,400, which is based on the average expenditures over the past three years, from 2020 to 2022.

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1.0 Introduction

Hydro conducts asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize disruption of service and to avoid unsafe working conditions due to equipment failure. An objective of Hydro's Asset Management Program is to identify refurbishment and replacement activities that require approval by the Board of Commissioners of Public Utilities ("Board") in time to be included in Hydro's annual CBA. This identification is done through the preventive maintenance program using various condition-based assessments and testing procedures.

Hydro has had success in projecting the deterioration rate of equipment for submission of refurbishment or replacement work into CBAs. However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or the determination of faster-than-anticipated equipment deterioration. These situations can be caused by events such as vandalism, storm damage, lightning, accidental damage, abnormal system operations, existing installation deficiencies, etc. Hydro uses historical data and engineering judgment to predict the magnitude of in-service failure expenditures.

The Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights program permits Hydro to perform refurbishment and upgrades of equipment as required, ensuring the continued delivery of reliable electrical service to its customers.

2.0 Program Description and Justification

Under the Distribution System In-Service Failures and Miscellaneous Upgrades portion of this program, Hydro is proposing to undertake the immediate capital refurbishment and replacement work required to maintain the safe and reliable operation of its distribution systems. Due to the nature of distribution equipment and infrastructure, unanticipated failures and deterioration will occur.

The program also includes expenditures related to the replacement of existing street lights with LED street lights, as Hydro works to complete the retirement of HPS and MV street lighting in its system. The capital investment to modernize street lights is justified based on the long-term cost savings and reliability benefits to customers, as shown in Chart 1. Hydro's street light modernization effort is consistent with Newfoundland Power Inc.'s plan to transition to LED street lights, resulting in reduced street and area lighting rates for customers.

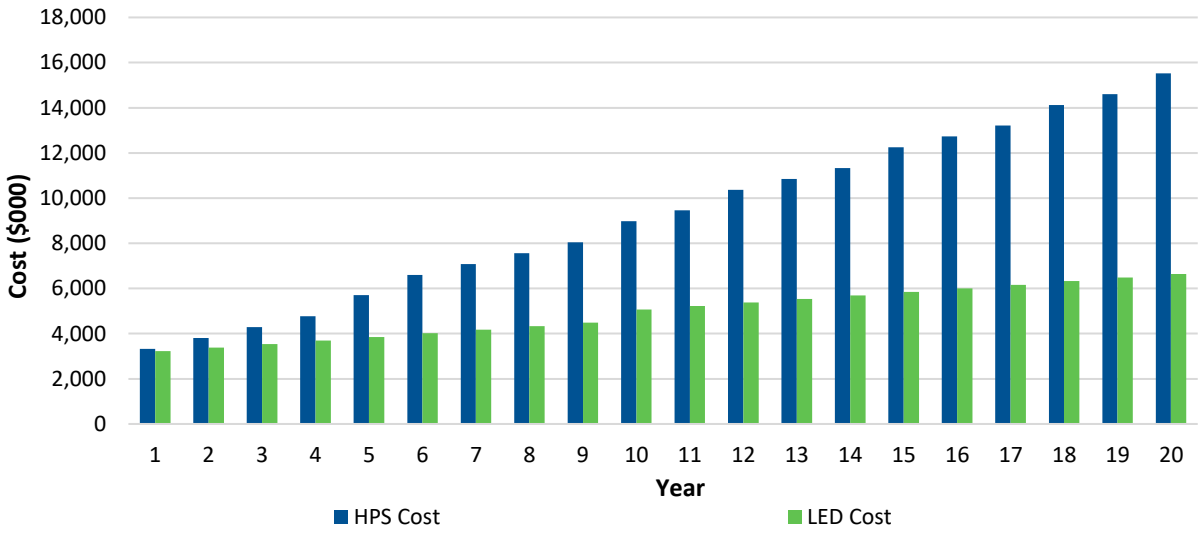


Chart 1: Cumulative Estimated 20-Year Cost Savings of LED vs HPS Street Lighting

Deferral of work that is justified under this program could result in a detrimental impact to customer power supply or unacceptable risk to worker or public safety. Required work will be evaluated to determine the appropriate form of execution as an in-service failure, an allowance for unforeseen item, or a supplemental project, depending on the relevant circumstances.

3.0 Asset Overview

3.1 Asset Background

The majority of Hydro's distribution system assets were installed in the 1960s and 1970s and have been deteriorating at varying rates over the last 50 to 60 years. Like many electrical systems, the reliability of the entire distribution network is a function of its least reliable component. The assets requiring immediate, unplanned replacement or refurbishment work in a given year cannot be identified in advance. Broad categories of distribution assets that are included under the Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights program are:

- Substation transformers;
- Voltage regulators;
- Reclosers;
- Capacitors;
- Sectionalizers;

- Switches;
- Poles;
- Crossarms/insulators/conductors/hardware;
- Pole top distribution transformers; and
- Street lights

3.1 Asset Condition

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure.

3.2 Condition-Based Remaining Life

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure; therefore, these assets have reached the end of their serviceable life.

3.3 Asset Ages

The age of assets potentially covered under this program varies. Unplanned replacement or refurbishment activities due to failure may be necessary at any time during the asset life cycle.

4.0 Trending

Data from 2022 indicates that Hydro replaced 221 distribution assets during that year. The average over the past five years has been 268 assets replaced per year, excluding the street light modernization effort.

4.1 Assets Installed/Replaced/Upgraded

Chart 2 indicates the total number of assets installed under the program during the five-year period from 2018 to 2022. The types of assets replaced vary from year-to-year. As of May 2023, Hydro has replaced more than 4,500 street lights with LED technology and anticipates the completion of the street light modernization effort in 2026 as planned.

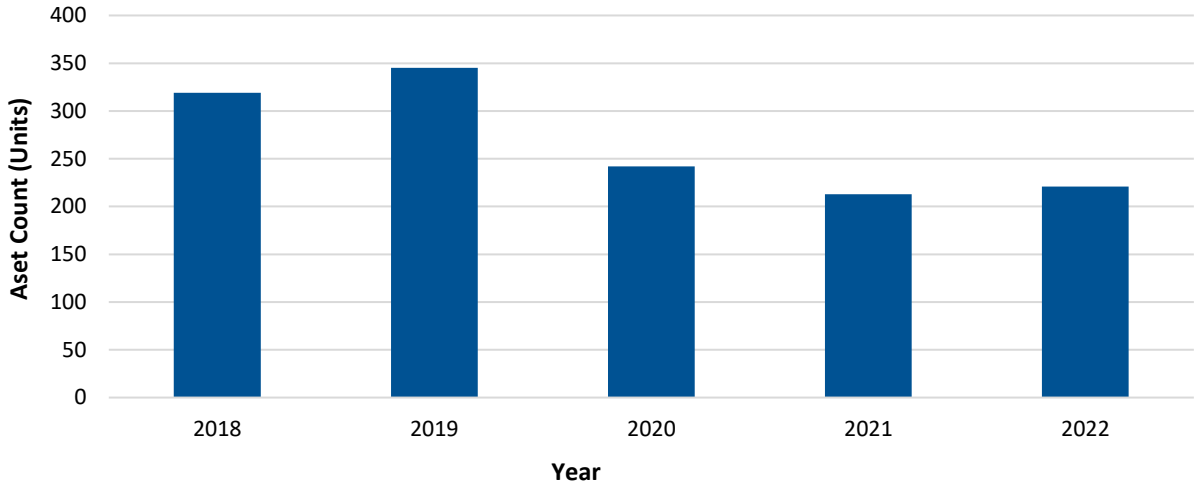


Chart 2: Historical and Forecast Assets Installed/Replaced/Upgraded

4.2 Historical and Forecast Average Unit Costs

Due to the nature of this program and the range of assets covered, average unit cost information is not applicable. An increase in program cost is forecast based on the anticipated escalation of both material and labour costs, as seen in Chart 3 in Section 7.1.

5.0 Historical Reliability

This program plays a key role in allowing Hydro to ensure the provision of reliable service to customers. Hydro tracks reliability data for its distribution systems and feeders using several metrics, including SAIDI,[1] SAIFI,[2] CHI,[3] CHIKM,[4] and CIKM.[5] A summary of Hydro's distribution reliability performance is provided in Schedule 1.

[1] System Average Interruption Duration Index ("SAIDI") indicates the System Average Interruption Duration Index for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.
[2] System Average Interruption Frequency Index ("SAIFI") is the System Average Interruption Frequency Index per year, which indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.
[3] Customer-Hours of Interruption ("CHI") is the sum of the products of the outage duration multiplied by the number of customers affected during the outage for each event within a one-year period.
[4] Customer-Hours of Interruption per Kilometer "(CHIKM") is calculated by dividing the number of customer outage hours by the kilometers of feeder.
[5] Customers Interrupted per Kilometer ("CIKM") is calculated by dividing the sum of the number of customers that have experienced an outage within a one-year period by the kilometers of feeder.

6.0 Analysis

6.1 Evaluation of Alternatives

Depending on the nature of each failure or incipient failure, Hydro reviews viable technical alternatives to determine the most appropriate solution to address the unplanned event while balancing safety and operational risks.

The alternative of executing required unplanned work under the Allowance for Unforeseen Items Account is considered on a case-by-case basis, subject to the requirements set out by the Board for the use of the account.

6.1.1 Risk of Asset Stranding

The assets installed under this program can generally be redeployed should the service requirements change in a given location. For this reason, the risk of asset stranding is low.

6.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	5	**15**
Post-Execution	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**2.8**

7.0 Scope of Work

The Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights program covers the annual expenditures required to upgrade Hydro's distribution systems in response to in-service failures of equipment, address localized service deficiencies, and accommodate small-scale infrastructure replacements. The scope of this program also includes the ongoing conversion of Hydro's existing street lights to efficient LED technology.[6]

[6] The street light modernization effort is expected to conclude in 2026.

7.1 Program Budget

The estimate for the 2024 program is shown in Table 2. The estimate is based on the average expenditures from 2020 to 2022.

Table 2: Program Estimate ($000)[7]

Program Cost	2024	2025	Beyond	Total
Material Supply	1,925.2	0.0	0.0	**1,925.2**
Labour	1,597.6	0.0	0.0	**1,597.6**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	271.4	0.0	0.0	**271.4**
Other Direct Costs	337.1	0.0	0.0	**337.1**
Interest and Escalation	214.1	0.0	0.0	**214.1**
Contingency	0.0	0.0	0.0	**0.0**
Total	**4,345.4**	**0.0**	**0.0**	**4,345.4**

Chart 3 shows the five-year historical expenditures, the forecast 2023 expenditures, the proposed 2024 budget, and the forecast costs through 2028. The reduced forecast for years 2027 and 2028 reflects the anticipated completion of the street light modernization program in 2026. As Hydro cannot predict the quantity and nature of failures to be addressed within this program for future years, Hydro has forecast future expenditures for this program based on the 2023 program budget with cost escalation applied.

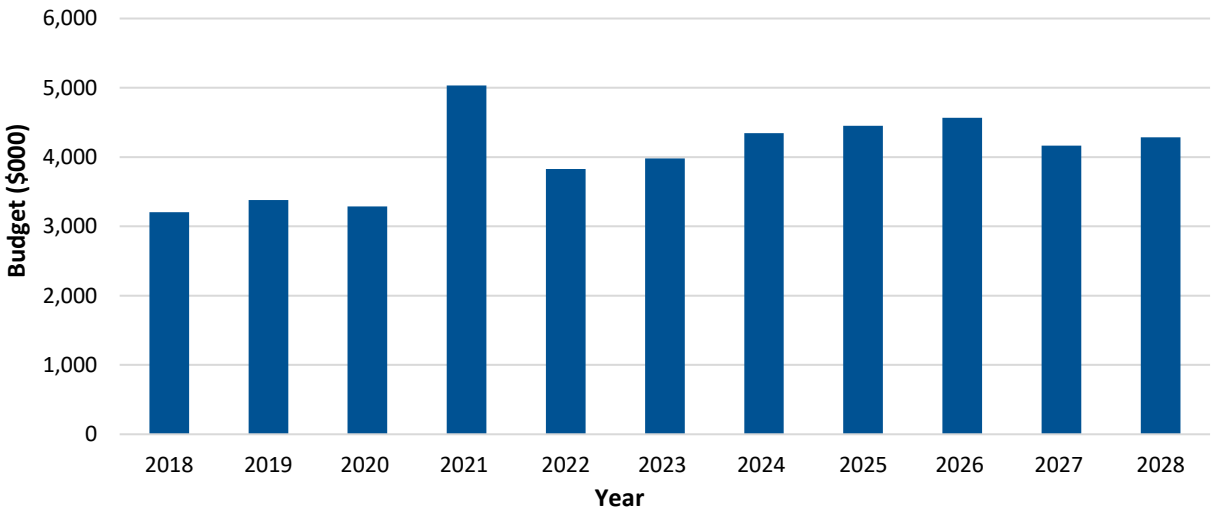


Chart 3: Historical and Forecast Program Budget

[7] Includes an estimated $90,000 to be recovered through contributions in aid of construction.

7.2 Program Schedule

Work schedules are established subsequent to an unplanned failure or incipient failure event. Street light installations are performed on an ongoing basis.

8.0 Conclusion

The Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights program allows Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable electrical distribution to customers. The street light modernization effort will result in cost savings for Hydro and its customers.

Program 5

Provide Service Extensions (2024)

July 2023

newfoundland labrador hydro

Provide Service Extensions (2024)

Location: Transmission and Rural Operations – Various Locations

Investment Classification: Access

Asset Category: Distribution

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") provides service hookups on an as-required basis using customer-driven service requests. This program provides an annual allotment for new service connections and street lights based on past expenditures and forecasted activity within the central, northern, and Labrador regions.

Service requests can include residential, cabin, and new business developments. Each customer requires interconnection with the local distribution service system. Service requests are received by Hydro's Customer Service Department and plans are developed by the local regions to provide the service extensions required to meet the requests within this program.

This program will also include the relocation of distribution infrastructure at the request of customers or third parties. Service requests and relocation requests are governed by Hydro's policy respecting Contributions in Aid of Construction ("CIAC").

Hydro's Customer Service Department receives more than 500 new service requests ("NSR") per year; this program trend is expected to continue in the coming years.

The cost estimate for work executed under this program in 2024 is $4,272,000.

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1.0 Introduction

Hydro provides direct service to approximately 39,000 customers within its service areas. Hydro provides service connections on an as-required basis using customer-driven service requests. This program provides an annual allotment for new service connections and street lights based on past expenditures and forecasted activity within the regions.

2.0 Program Description and Justification

Hydro receives service requests for both residential and general service, driven by local growth and activity within Hydro's three service regions—central, northern, and Labrador. Service requests can include residential, cabin, and new business developments. Each customer requires interconnection to the local distribution service system. Hydro's Customer Service Department receives service requests and plans are developed by the local regions to provide the service extensions required to meet the requests. In addition to NSRs, Hydro occasionally receives requests from customers or third parties to relocate distribution infrastructure. Such relocations, when they arise, are addressed within this program. In some cases, CIACs funded by the requestor are required and are applied under Hydro's CIAC Policy.

While Hydro will plan the work under this program as efficiently as possible, Hydro is obligated to provide the requested services and deferral is not an option.

3.0 Asset Overview

3.1 Asset Background

Typically, Hydro accommodates NSRs to customers as required and receives more than 500 NSRs per year. However, the NSRs for the Labrador Interconnected System are governed by Hydro's approved load restriction for Labrador East and Labrador West, which limits the load growth for new services based on current transmission capacity.[1]

[1] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 34(2019), Board of Commissioners of Public Utilities, October 29, 2019.

4.0 Trending

4.1 Assets Installed/Replaced/Upgraded

Chart 1 shows the five-year historical, current, and five-year forecast number of NSRs received each year. The total number of NSRs for each year is comprised of those completed, on hold, and cancelled.

The historical data for 2018 to 2022 shows that the number of NSRs received continues to trend above 500. This program trend is expected to continue in the coming years.

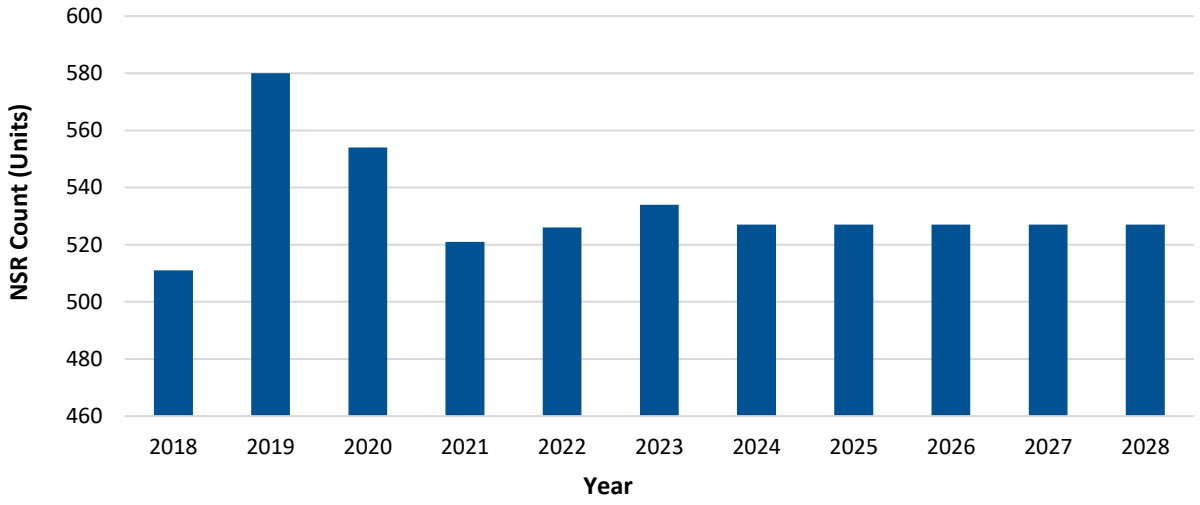


Chart 1: Historical and Forecast NSRs Received

4.2 Historical and Forecast Average Costs

Historical and forecast program costs are provided in Chart 2. As this is a customer-driven program that includes a range of scopes and costs, actual historical costs per year tend to fluctuate. Forecast costs are based on a three-year historical average. Costs per service request vary greatly depending on the nature of the request and the magnitude of infrastructure modifications required to accommodate the request. Hydro does not currently have sufficient data to calculate historical costs per service request.

5.0 Analysis

5.1 Recommended Alternative

Hydro is obligated to provide service extensions upon request. During the technical review of individual requests, viable alternatives will be considered where appropriate.

As this program is customer-driven, Hydro does not have the ability to reduce the pace of service extensions implemented within this program.

5.2 Risk of Asset Stranding

Although generally not applicable to this program, Hydro would consider the risk of asset stranding in the context of individual requests. Temporary requests for service are governed by Hydro's Schedule of Rates, Rules and Regulations and the CIAC Policy.

6.0 Scope of Work

Work executed under this program involves the installation of new service connections and streetlights on an as-required basis throughout Hydro's service areas. On average, Hydro receives over 500 requests for new service connections per year with varying scopes of work.

6.1 Program Budget

The estimate for the 2024 program is shown in Table 1.

Table 1: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	1,578.1	0.0	0.0	**1,578.1**
Labour	1,928.6	0.0	0.0	**1,928.6**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	219.6	0.0	0.0	**219.6**
Other Direct Costs	331.4	0.0	0.0	**331.4**
Interest and Escalation	214.3	0.0	0.0	**214.3**
Contingency	0.0	0.0	0.0	**0.0**
Total	**4,272.0**	**0.0**	**0.0**	**4,272.0**

Chart 2 shows the five-year historical expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028.

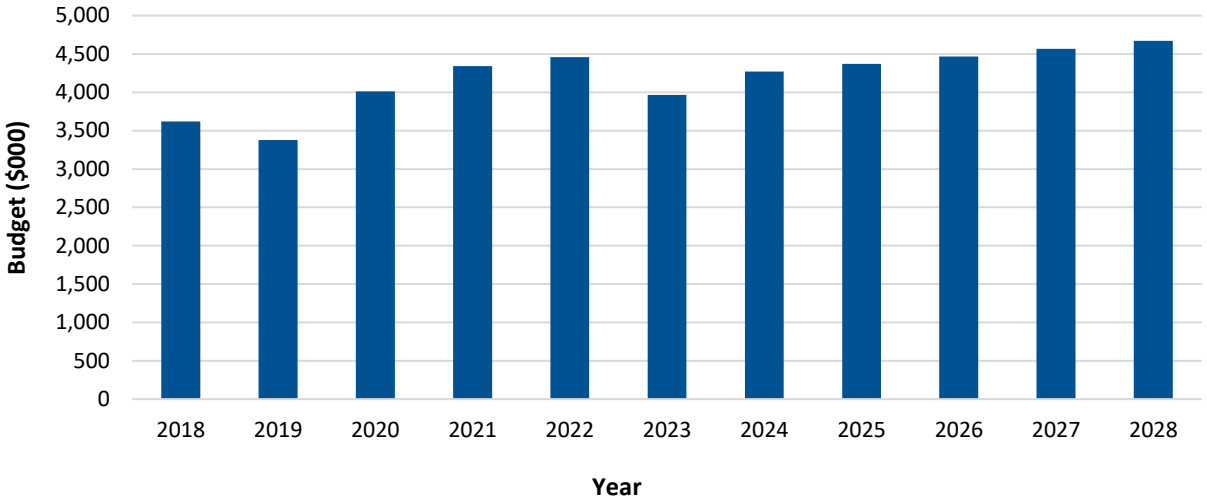


Chart 2: Historical and Forecast Program Budget

6.2 Program Schedule

NSRs are customer-driven and are ongoing throughout the year.

7.0 Conclusion

Hydro provides service connections on an as-required basis using customer-driven service requests in its service areas. This program provides an annual allotment, adjusted from year to year, based on the average expenditure over the past three years for Hydro's connection of new residential and general service requests and distribution infrastructure relocation.

Boiler Condition Assessment and Miscellaneous Upgrades (2024)

Holyrood

July 2023

newfoundland labrador hydro

Boiler Condition Assessment and Miscellaneous Upgrades (2024)

Location: Holyrood

Investment Classification: Renewal

Asset Category: Thermal Plant

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") is proposing to continue with the Boiler Condition Assessment and Miscellaneous Upgrades Program in 2024. This will support the continued safe and reliable operation of the Holyrood Thermal Generating Station ("Holyrood TGS").

This program has been completed on an annual basis since 2017 and has been integral in supporting the safe and reliable operation of steam supply systems at the Holyrood TGS. As per the "Reliability and Resource Adequacy Study – 2022 Update,"[1] the Holyrood TGS shall remain available for a "Bridging Period"[2] until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the Labrador Island Link ("LIL") is proven, and generation reserves are met. Therefore, Hydro believes it is prudent to continue this program in 2024.

Boilers and associated high-energy piping are exposed to multiple aggressive degradation mechanisms. As a result, regular inspections and assessments are required to monitor degradation rates and to plan interventions. Failure of any steam system while in service could result in serious safety incidents, and generation outages with a duration of weeks or months, depending on the magnitude of the failure. The continuation of the Boiler Condition Assessment and Miscellaneous Upgrades Program into 2024 is required to support Hydro's safety and reliability standards, including Hydro's ability to meet customer demand during peak periods. The scope of this program includes a Level 2 Condition Assessment on the internal components of the boilers and associated external high-energy piping. The program also includes the completion of miscellaneous upgrades identified in the 2023 investigation and required interventions identified during the 2024 assessment that are necessary to support safe and reliable

[1] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[2] Hydro considers the Bridging Period to be from 2023 to 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

operation through the 2024–2025 winter operating season. The majority of the work will be performed during outages planned in 2024 for each generating unit.

The estimated cost for work executed under the 2024 program is $3,957,800.

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1.0 Introduction

In 2017, Hydro commenced a Boiler Condition Assessment and Miscellaneous Upgrades Program for the Holyrood TGS. The scope of this program includes a Level 2 Condition Assessment related to internal components of the main steam generators (boilers) and associated external high-energy piping, as well as the proposal and execution of various upgrades and replacements to support the reliable operation of the steam generation equipment. This proposal entails the extension of the program for 2024.

The boilers and associated steam supply systems are the focus of the Boiler Condition Assessment and Miscellaneous Upgrades Program. A specialized boiler service contractor has been retained under a maintenance service agreement to perform all remedial work on the boiler, including the Boiler Condition Assessment and Miscellaneous Upgrades program.

Annual boiler condition assessments maintain reliability by discovering damaged or deteriorated components that are at risk of failure. Examples of damages or deterioration discovered in past boiler condition assessments include the following:

- Cracking of various components that are subject to thermal cycling;
- Critical damage to material or failure of structural components;
- Critical damage to refractory materials;
- Duct erosion; and
- Thinning of the boiler tube walls due to corrosion and erosion.

Deterioration of boiler components identified during Level 2 Condition Assessments are typically corrected during the next available outage period unless they are determined to be critical, in which case they are addressed immediately as part of this program if such critical items are determined to be capital in nature.

2.0 Program Description and Justification

The primary work for 2024 is to perform a Level 2 Condition Assessment on the internal components of the boilers and associated external high-energy piping to determine what refurbishments or replacements are required before the 2024–2025 winter operating season. The program for 2024 also includes miscellaneous upgrades identified in the 2023 and 2024 condition assessments scheduled for

completion in 2024, such as the replacement of boiler expansion joints and boiler refractory to support safe and reliable operation through the 2024–2025 winter operating season. Additionally, for upgrades identified and executed in 2024 that are material in dollar value and meet capitalization criteria, Hydro proposes to implement and communicate these items to the Board of Commissioners of Public Utilities in its 2024 Capital Expenditures and Carryover Report.

The detailed scope of the boiler condition assessment follows the inspection and test plan that was prepared for the Holyrood TGS by the original equipment manufacturer for Unit 1 and Unit 2 boilers, Alstom SA, and the engineering consulting firm, AMEC NSS Limited. The inspection and test plan covers all boiler pressure parts and high-energy piping. Inspection and test scope, assessment methods, and intervals were developed based on recommendations of Alstom SA and AMEC NSS Limited. Hydro will contract a specialized boiler service company to complete boiler and high-energy piping assessments and upgrades. Hydro personnel will assist the contracted company when required, oversee the work protection application, and provide overall management and liaison for the upgrades.

3.0 Asset Overview

3.1 Asset Background

The Holyrood TGS is equipped with three thermal generating units (Units 1, 2, and 3), all of which can be used for power production. Unit 3 is also capable of functioning as a synchronous condenser to assist with system voltage regulation. Each unit is supplied with steam by one of three dedicated boilers fired with Bunker C fuel.

3.2 Asset Condition

The existing main steam generators (boilers) and associated high-energy piping (main steam piping, hot reheat piping, cold reheat piping, and high-pressure feed water piping) are exposed to degradation mechanisms such as high temperatures, high pressure, corrosive boiler gas, and erosive flows. In its 2021 condition assessment,[3] Hatch Ltd. (“Hatch”) found the Unit 1 and 2 boilers to be in good condition and the Unit 3 boiler was determined to be in adequate condition. The main issues Hydro has encountered with the boilers relate to the boiler tube failures referenced in Section 5.0.

[3] “HTGS Condition Assessment and Life Extension Study,” Hatch Ltd., March 31, 2022, vol. I.

3.3 Condition-Based Remaining Life

A condition assessment of the boilers and associated high-energy piping by Hatch determined that these systems are in adequate condition and are expected to remain serviceable until at least 2030.[4] While these systems are generally in adequate condition, this program is required annually to address components or sections of the boilers and associated high-energy piping systems at risk of failure in the near term.

3.4 Asset Ages

The boilers for Units 1 and 2 were designed by the Combustion Engineering Company[5] and began operating in 1969 and 1970, respectively. The Unit 3 boiler was designed by the Babcock & Wilcox Company; it began operating in 1979.

4.0 Trending

4.1 Assets Installed/Replaced/Upgraded

Hydro implemented the Boiler Condition Assessment and Miscellaneous Upgrades Program in 2017. Since that time, Hydro completes these assessments annually under the program. The nature and quantity of miscellaneous upgrades completed under the program are determined by the condition assessment and vary year to year.

4.2 Historical and Forecast Average Unit Costs

This program involves condition assessments and miscellaneous upgrades of a range of assets associated with the unit boilers and associated high-energy piping, many of which are not itemized; therefore, per-unit costs are not applicable. Historical, current, and forecast program costs are provided in Section 7.1.

5.0 Historical Reliability

The boiler tubes are exposed to multiple degradation mechanisms, such as corrosion, thermal fatigue, creep, stress corrosion cracking, and erosion. Previous Level 2 Condition Assessments indicated that boiler tubes were at risk of failure due to degradation. Replacements or repairs by applying pad welds were completed. Level 2 Condition Assessments aim to reduce in-service failures of boiler systems, with

[4] "HTGS Condition Assessment and Life Extension Study," Hatch Ltd., March 31, 2022, vol. I and vol. II.
[5] Currently General Electric ("GE").

a focus on boiler tubes and pressure pining, as they present a safety and reliability risk if they fail while in service; however, there are situations where unforeseen in-service failures occur. Several in-service boiler tube failures have occurred in the last five years, which resulted in the following forced outages:

- On December 12, 2020, a boiler superheater tube failure occurred in Unit 2, which resulted in a forced outage of Unit 2 for five days;
- On January 18, 2021, a leak in a boiler water wall tube in Unit 3 occurred, which resulted in a forced outage of Unit 3 for eight days;
- From September 11 to November 19, 2021, Unit 3 was on a forced outage. While Hydro was in the process of returning Unit 3 to service following a planned maintenance outage, a rupture on Boiler Tube 5 occurred on the east water wall of the Unit 3 boiler. A section of the tube (approximately 13.5 inches tall by 3 inches wide) was ejected during the rupture, which resulted in the release of steam into the powerhouse. This failure presented a safety risk and resulted in a forced extension of the planned outage of Unit 3;
- On February 6, 2023, a leak in a boiler water wall tube in Unit 3 occurred, which resulted in a forced outage of Unit 3 for twelve days; and
- On February 21, 2023, an air heater expansion joint failure occurred in Unit 3, which resulted in a forced outage of Unit 3 for two days.

6.0 Analysis

6.1 Evaluation of Alternatives

Hydro evaluated the following alternatives:

- Pace reduction;
- Pace advancement; and
- Continue program at current pace.

Hydro has not identified any viable alternative strategies for the continued safe and reliable operation of the boilers for Units 1, 2, and 3 and associated high-energy piping through the Bridging Period until the capacity of Holyrood TGS can be adequately replaced

6.1.1 Pace Reduction

This program is required annually. Pace reduction for deteriorated components that are approaching critical time to failure would preclude Hydro from assessing the unit boilers and high-energy steam piping and intervening to prevent in-service failure of the assets, which would present a risk to safe and reliable operations of the Holyrood TGS. Hydro's experience with this program has demonstrated that assessment and miscellaneous upgrades are required on an annual basis.

6.1.2 Pace Advancement

Hydro's historical experience with this program has not demonstrated a need to accelerate these assessments and associated upgrades. Additional inspections would require extensive unit outages during the winter operating season, which cannot be accommodated.

6.1.3 Continue Program at Current Pace

Under this alternative, the condition of internal components of the boilers and associated external high-energy piping are assessed annually through inspections. Hydro has found this approach to be effective in supporting the safe and reliable operation of the Holyrood TGS boilers.

6.2 Least-Cost Evaluation

As there are no viable alternatives to this program conducive to the safe and reliable operation of the Holyrood TGS, a least-cost evaluation was not performed. In a case where the condition assessment shows that a deteriorated component is reaching a critical time to failure before the next condition assessment, and may impact the safe and reliable operation of the boiler systems, least-cost evaluations would be considered on a case-by-case basis to evaluate and determine the most viable alternative to address the issue.

6.3 Recommended Alternative

Hydro recommends the continuation of the Boiler Condition Assessment and Miscellaneous Upgrades Program in 2024.

Regular inspections and condition assessments are required to monitor the deterioration rates of systems and perform remedial work on an annual basis to reduce the risk of failures during operation. This approach allows Hydro to complete repairs in a planned, measured manner while continuing to

operate the Holyrood TGS boilers safely and reliably. Hydro's experience with this approach has proven effective.

6.3.1 Risk of Asset Stranding

The risk of asset stranding is less imminent as a result of the decision to extend Holyrood TGS to remain available through the Bridging Period. As Hydro expects continued operation of all three units at the Holyrood TGS through the Bridging Period until its capacity can be adequately replaced to ensure reliable operation for customers, capital expenditures for this facility to operate as a generator continue to be required. Depreciation is required to be calculated on an accelerated basis (i.e., monthly depreciation = capital investment ÷ remaining months of service life).[6]

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	5	4	**20**
Post-Execution	5	1	**5**
		Risk Mitigated	**15**
		Risk Mitigated per $1 Million	**3.8**

7.0 Scope of Work

The scope of work includes the following:

- Level 2 Condition Assessment on the internal components of the boilers and associated external high-energy piping; and
- Completion of miscellaneous upgrades identified in the 2023 investigation and required interventions identified during the 2024 assessment that are necessary to support safe and reliable operation through the 2024–2025 winter operating season.

[6] As a result of the extension of the Holyrood TGS through the Bridging Period, Hydro intends to make an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account in 2023.

7.1 Program Budget

The estimate for the 2024 program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	230.0	0.0	0.0	**230.0**
Labour	397.6	0.0	0.0	**397.6**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	2,880.0	0.0	0.0	**2,880.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	99.4	0.0	0.0	**99.4**
Contingency	350.8	0.0	0.0	**350.8**
Total	**3,957.8**	**0.0**	**0.0**	**3,957.8**

Chart 1 shows the five-year historical expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028.[7]

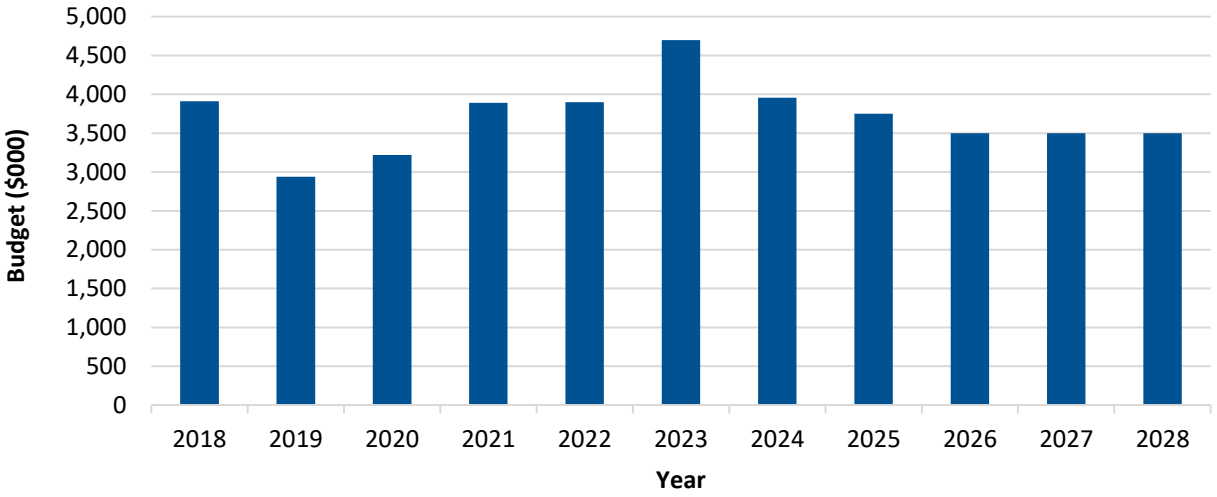


Chart 1: Historical and Forecast Program Budget

[7] A forecast for the costs of this program was based on the assumption of continued operation of all generating units at the Holyrood TGS through the Bridging Period until its capacity can be adequately replaced. Hydro's capital projections assume all three generating units remain online until 2030 and are subject to change based on changes in operating regime.

7.2 Program Schedule

The schedule for the 2024 program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Complete planning documentation.	January 2024	January 2024
Procurement:		
Order long lead parts.	February 2024	March 2024
Construction:		
Perform condition assessment[8] and upgrade work.	April 2024	October 2024
Closeout:		
Prepare closeout documentation.	November 2024	December 2024

8.0 Conclusion

To support the continued safe and reliable operation of the Holyrood TGS through the 2024–2025 winter operating season, Hydro recommends continuing the Boiler Condition Assessment and Miscellaneous Upgrades Program in 2024, as, historically, it has been effective and supports the optimal timing of refurbishment and replacement. This measured, planned approach is prudent and supports the safe and reliable operation of the boilers and high-energy piping.

[8] The condition assessment and upgrade work will take place during the outage period for each of the three boilers.

Program 7

Wood Pole Line Management (2024)

July 2023

newfoundland labrador hydro



Wood Pole Line Management (2024)

Location: Various

Investment Classification: Renewal

Asset Category: Transmission

Executive Summary

The Wood Pole Line Management ("WPLM") program is a condition-based asset renewal program that uses reliability-centred maintenance principles and strategies.[1] Under the program, data from transmission line inspections is analyzed on an annual basis and recommendations are made, as required, for refurbishment or replacement of line components, including poles, structures, hardware, and conductors. Recommended work is completed in subsequent years. Inspection data and refurbishment or replacement of assets are recorded in a centralized database that is used for future analysis and tracking.

The purpose of the WPLM program is to detect and treat deteriorating wood poles and line components before the integrity of a structure is jeopardized. If the deterioration of the structure or components is not detected early, the reduced integrity of the structure could affect the reliability of the line. It could also lead to increased failure costs and, potentially, customer interruptions. Safety issues and hazards for Newfoundland and Labrador Hydro ("Hydro") personnel and the public could also result from wood poles that have weakened structural integrity.

The estimated cost for work executed under this program in 2024 is $3,765,200.

[1] Reliability-centered maintenance is a maintenance strategy that is implemented to optimize the maintenance program of a company or facility.

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Appendix A: IOWA Curve – Hydro's Wood Pole Line Network

1.0 Introduction

Many of Hydro's transmission lines are of wood pole construction. As wood poles age, their preservative retention levels decrease and the poles become increasingly vulnerable to deterioration by different agents, including fungi and insects. Wood poles must be regularly inspected and treated to proactively identify and assess deterioration.

The WPLM program is an annual program that promotes the early detection of deteriorated poles and other line components. Early detection is required to avoid potential safety hazards and identify poles and other components that are at early stages of decay to ensure that corrective measures can be taken to extend the expected useful life of the poles. This program is a least-cost strategy for WPLM, as investments made in regular inspection and early detection of issues extend the useful life of the poles, support the deferral of line reconstruction, and prevent forced outages.

2.0 Program Description and Justification

2.1 Program Background

Hydro first initiated the WPLM program as a pilot study in 2003 and subsequently determined that the program should continue as a long-term asset management and life extension program. The WPLM program was presented to the Board of Commissioners of Public Utilities ("Board") as part of Hydro's "2005 Capital Budget Application."[2]

Prior to 2003, Hydro's pole inspection and maintenance practices followed the traditional utility approach of sounding inspections only. In 1998, Hydro began to collect core samples from select poles to test for preservative retention levels and pole decay. The results of early tests raised concerns regarding the general preservative retention levels in the poles. This testing confirmed that there were poles in Hydro's system that had a preservative level below that which is necessary to maintain the required design criteria. During this period, Hydro replaced certain poles because the preservative level had decreased to the point that decay had advanced and the pole was no longer structurally sound. These inspections and the analysis of the data confirmed that a more rigorous WPLM program was required.

[2] "2005 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 28, 2004 (originally filed August 10, 2004), sec. G, app. 2.

Figure 1 illustrates typical wood pole inspection techniques conducted in the WPLM program. Figure 2 provides examples of wood pole line inspection results.



Figure 1: WPLM Inspection Techniques.
Clockwise from Bottom Left: (1) Field Data Collector, (2) Installing Boron Treatment, (3) Climbing Inspection, (4) Destructive Testing at Memorial University of Newfoundland



Figure 2: Examples of Wood Pole Inspection Results

Historically, Hydro used 40 years as the anticipated useful or economic life for its wooden lines. As of 2023, Hydro has 32 wood pole transmission lines that have surpassed this anticipated useful life. Of these lines, 22 are over the age of 45 years, with the oldest wood pole line having been installed

58 years ago in 1965. Hydro's experience with the WPLM program has therefore demonstrated that the expected useful life of its transmission lines can be extended by more than 15 years through early inspection and refurbishment. For details, please refer to "Interim Report – Review of the Current WPLM Program,"[3] "Progress Report #2 (2012–2017) Review of the Current Wood Pole Line Management (WPLM) Program,"[4] and "Wood Pole Line Management Program Progress Report (2018-2022)."[5]

2.2 Program Description

The WPLM program is a condition-based asset renewal program that uses the basic principles and strategies of reliability-centred maintenance. Under the WPLM Program, full climbing inspections are performed on wooden transmission structures, poles are re-treated internally with preservatives, and components are assigned a rating. Inspections that result in findings on the lower end of the rating scale are subject to further assessment and increased inspection frequency as necessary. If these inspection results identify concerns over the adequacy of a pole, further engineering analysis is performed to estimate the in-service pole strength and to determine if the structure is still able to withstand its design loads. Recommendations are then made for refurbishment or replacement of deteriorated line components including poles, bracing, hardware, conductors, etc. Recommended work is generally completed in subsequent years; however, in cases where components are deemed unable to last another year, Hydro replaces or refurbishes in the current year. Such replacements are managed within the existing budget.

The purpose of the WPLM program is to detect and treat deteriorating wood poles and line components before the integrity of the structures is jeopardized. If the deterioration of the structures or components is not detected early, the reduced integrity of the structure could affect the reliability of the line and present safety issues and hazards for Hydro personnel and the public.

The WPLM program inspection schedule generally reflects plans to complete older lines first and works toward newer lines. The specific lines and the number of poles included in the program are reviewed on

[3] "2013 Capital Budget Application," Newfoundland and Labrador Hydro, rev. August 31, 2012 (originally filed August 8, 2012), vol. II, tab 17, app. B.
[4] "2019 Capital Budget Application," Newfoundland and Labrador Hydro, rev. October 9, 2018 (originally filed July 31, 2018), vol. I, 2019–2023 Capital Plan, app. C.
[5] "Wood Pole Line Management Program Progress Report (2018–2022)," Newfoundland and Labrador Hydro, April 21, 2023.

an annual basis and may be modified based on age, priority (i.e., radial or redundant), and condition. Lines are incorporated into the program at the age of 20 years.

Hydro committed to providing the Board with annual updates on the WPLM program, including progress summaries of the work completed to date and a forecast of future program objectives. This update is provided herein.

2.2.1 2022 WPLM Program Review

One of the objectives of the 2022 WPLM program was to inspect, test, and treat 2,356 poles and associated line components. Table 1 summarizes the 2022 inspections.

Table 1: 2022 Inspections Completed

Regions	Line Name	Year	Voltage Level (kV)	Planned Number of Poles to Inspect	Actual Number of Poles Inspected	Percent Complete
Eastern	TL201	1966	230	321	617	192%
Central	TL210	1969	138	547	547	100%
	TL220	1970	69	8	8	100%
	TL234	1981	230	163	163	100%
	TL260	1990	138	163	163	100%
Western	TL233	1973	230	321	321	100%
Northern	TL221	1970	69	350	350	100%
	TL239	1982	138	0	224	100%
	TL256	1996	138	224	0	0%
	TL259	1990	138	259	259	100%
Totals				**2,356**	**2,661**	**113%**

Two changes were made to the 2022 inspection plan reported in Hydro's "2023 Capital Budget Application."[6] The first change was an increase in the number of poles to be inspected on TL201, from 321 to 617. This was done to include a complete data set for this line in Hydro's "Wood Pole Line Management Program Progress Report (2018–2022)." The second change was the substitution of 224 pole inspections on TL239 in lieu of inspections planned for TL256. This change was made after a broken crossarm was discovered on TL239 in May 2022.

[6] "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022, vol. II, sch. 6, prog. 15.

Another objective of the 2022 WPLM program was the refurbishment of defective components identified in previous inspections. A summary of the work completed in 2022 is provided in Table 2.

Table 2: Summary of 2022 Refurbishment

	Region					
Component	**Eastern**	**Central**	**Western**	**Northern**	**Labrador**	**Total**
Poles	-	6	3	2	2	**13**
Crossarms	2	-	-	2	-	**4**
Cross Bracing	-	-	-	-	-	**-**
Knee Bracing	-	-	-	-	-	**-**
Foundations	-	-	-	-	-	**-**

2.2.2 2023 WPLM Program Update

The inspection and treatment work scheduled for 2023 is summarized in Table 3. This work is scheduled for execution between May and October of 2023.

Table 3: 2023 Inspection Plan

Regions	**Line Name**	**Year**	**Voltage Level (kV)**	**Planned Number of Poles to Inspect**
Central	TL222	1967	138	693
	TL234	1981	230	100
Western	TL245	1969	138	281
Northern	TL221	1970	69	244
	TL226	1970	69	414
	TL256	1996	138	224
Labrador	L1303	1976	138	277
Total				**2,233**

A list of the refurbishment work scheduled for completion in 2023 is provided in Table 4. Hydro has accounted for these refurbishment activities in the approved 2023 WPLM program.

Table 4: 2023 Refurbishment Plan

	Region				
Component	**Eastern**	**Central**	**Western**	**Northern**	**Total**
Poles	5	12	12	-	**29**
Crossarms	11	15	9	-	**35**
Cross bracing	16	8	2	-	**26**
Knee bracing	3	16	2	-	**21**
Foundations	1	-	1	-	**2**
Miscellaneous (Insulators, hardware, etc.)	51	46	11	16	**124**

2.3 Program Justification

The program is a strategic asset management and life extension program for Hydro's wood pole transmission lines. Since its inception, Hydro has demonstrated that it is a least-cost strategy for WPLM, as investments made in the regular inspection and early detection of issues extend the useful life of the poles, support the deferral of line reconstruction, and prevent forced outages. In 2004, the Board determined that this approach was justified and prudent, stating:

> This approach is a more strategic method of managing wood poles and conductors and associated equipment and (the Board) is persuaded that the new WPLM Program, based on RCM principles, will lead to an extension of the life of the assets, as well as a more reliable method of determining the residual life of each asset. One of the obvious benefits of RCM will be to defer the replacement of these assets thereby resulting in a direct benefit to the ratepayers.[7]

Two complete inspection cycles have now been performed under the program; the results of which demonstrate that the cost of the WPLM program is well justified by cost-avoidance savings through reduced in-service failures and reduced unplanned repair costs, as well as reliability improvements and life extension of existing pole plant assets. In addition, the program has been effective in preventing the premature retirement of viable components, which still have continued life expectancy.

3.0 Asset Overview

3.1 Asset Background

Hydro maintains approximately 2,300 kilometres of wood pole transmission lines operating at voltages of 69 kV, 138 kV, and 230 kV. These lines consist of over 23,000 poles of varying ages from new to

[7] *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 53(2004), Board of Commissioners of Public Utilities, December 23, 2004, p. 23/13-18.

58 years old. As of 2023, approximately 98% of Hydro's transmission pole assets are more than 20 years old; approximately 64% are more than 40 years old.

3.2 Asset Condition

All poles inspected under the program are rated based on a full climbing inspection and condition assessment. Explanations for the rating system are found in Table 5.

Table 5: WPLM Rating System

Condition	Rating	Post-Inspection and Treatment Action
Severe/Hazardous to Climb	5	Refurbishment is required as soon as practicable.
Poor	4	Engineering analysis and subsequent refurbishment if deemed necessary.
Moderate	3	Monitor.
No issues	2	None.
New (<10 Years)	1	Climbing inspection and treatment are not required.

Chart 1 presents Hydro's wood transmission pole assets by condition rating as of April 2023.

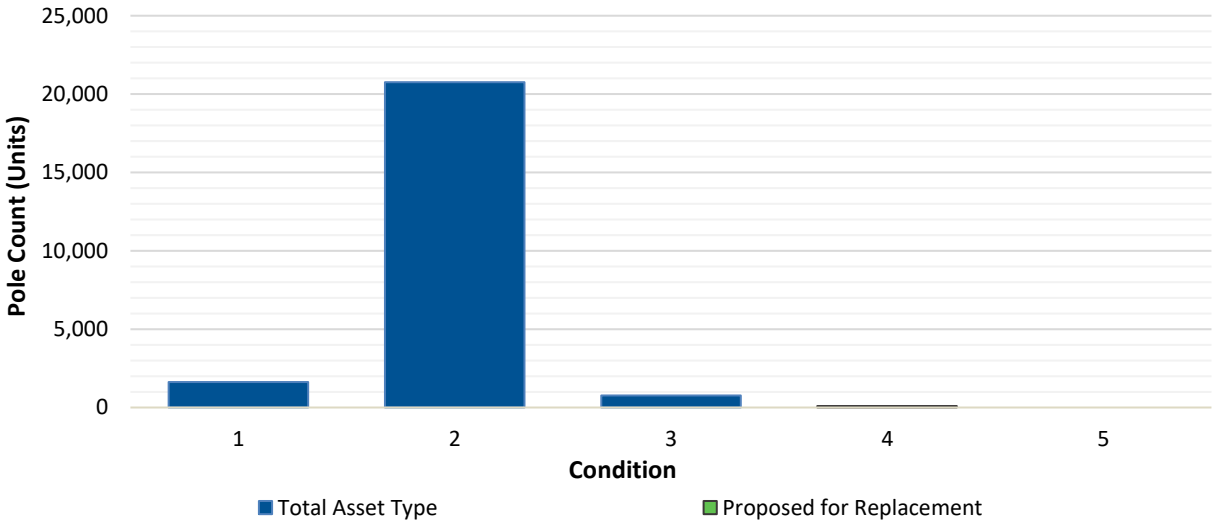


Chart 1: Asset Condition

3.3 Condition-Based Remaining Life

Chart 2 presents Hydro's wood transmission pole assets by expected remaining life as of April 2023.

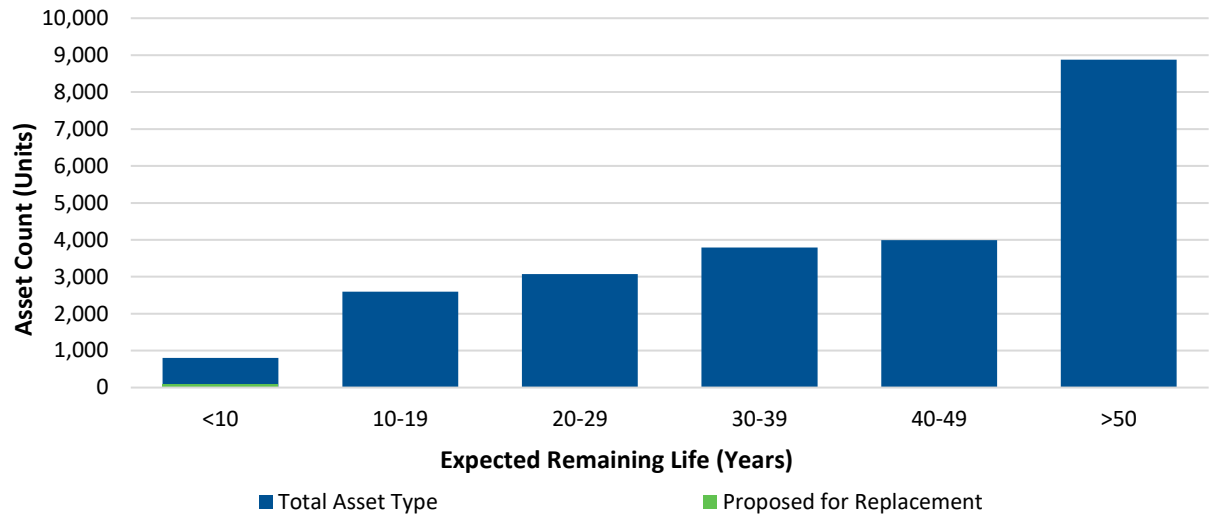


Chart 2: Condition-Based Expected Remaining Life

3.4 Asset Ages

Chart 3 presents Hydro's wood transmission pole assets by age as of April 2023.

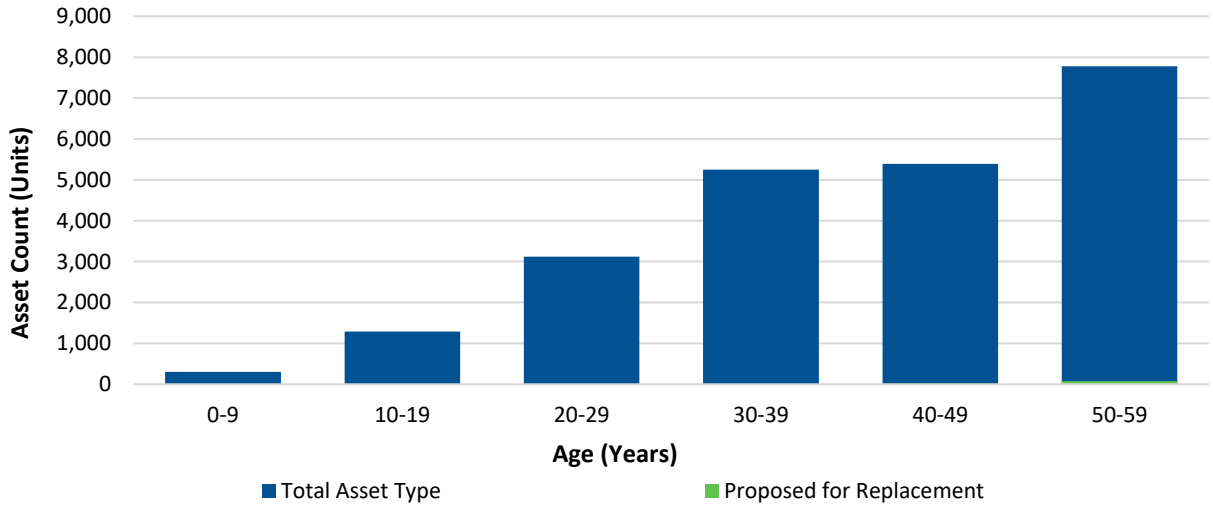


Chart 3: Asset Counts by Asset Age

4.0 Trending

4.1 Assets Installed/Replaced/Upgraded

Chart 4 provides the five-year historical, current, and five-year forecast number of poles replaced per year.

Hydro is forecasting a sizeable increase in pole replacements for the years 2026 and 2027. Forecasted numbers are determined through Iowa curves. Iowa curves display functional failures or retirements of asset classes. They were developed in a study at the University of Iowa. Each curve represents a probability distribution and has a series of attributes. The curves support realistic forecasting of the remaining life of groups of assets. The latest Iowa curve for poles in Hydro's Island Interconnected System can be found in Appendix A. Costs for this increase have been accounted for in the projected program budget as presented in Section 0.

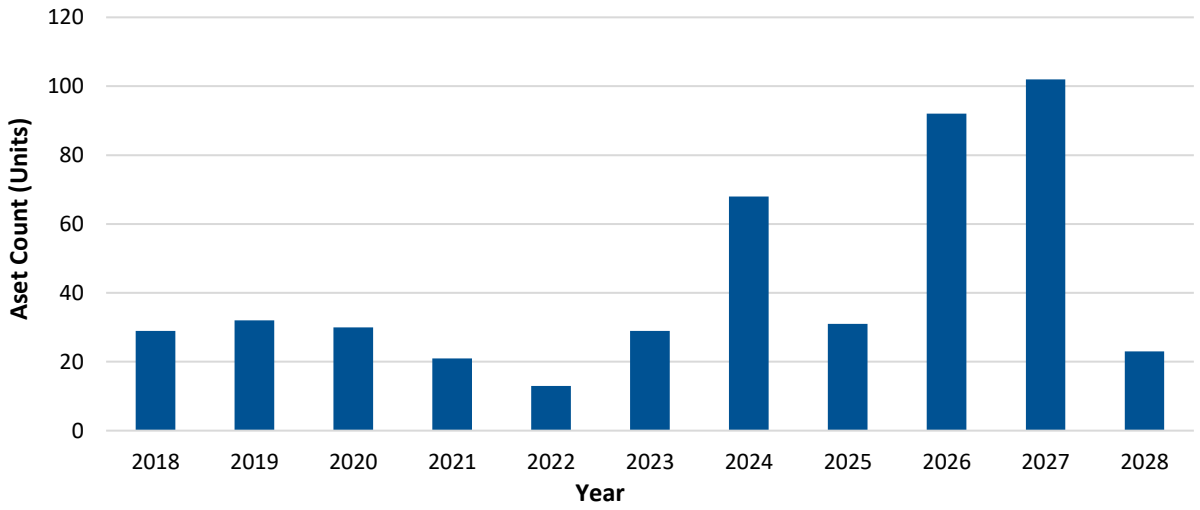


Chart 4: Historical and Forecast Assets Installed/Replaced/Upgraded

4.2 Historical and Forecast Average Unit Costs

As discussed, in addition to pole replacements, the WPLM program includes the inspection and refurbishment of all components of Hydro's wooden transmission lines such as crossarms, cross bracing, knee bracing, hardware, etc. The work completed varies based on the actual condition of the asset. In most cases, the work completed on any one structure is not related to the work on the next structure (e.g., one structure may require a pole replacement and the next structure may need a crossarm or an

insulator replacement). The same is true for a breakdown by individual transmission line, where the cost will be affected by the configuration, voltage, age, and geographical location of the line.

5.0 Historical Reliability

Chart 5 and Chart 6 show the average annual forced outage hours due to structural failures on wooden transmission lines before and after the implementation of the WPLM program. Chart 5 presents data for the entirety of the Island Interconnected System while Chart 6 presents data for the Avalon Peninsula specifically. The outage data demonstrates that there has been a material improvement on the Avalon Peninsula since Hydro launched the WPLM program in 2003.

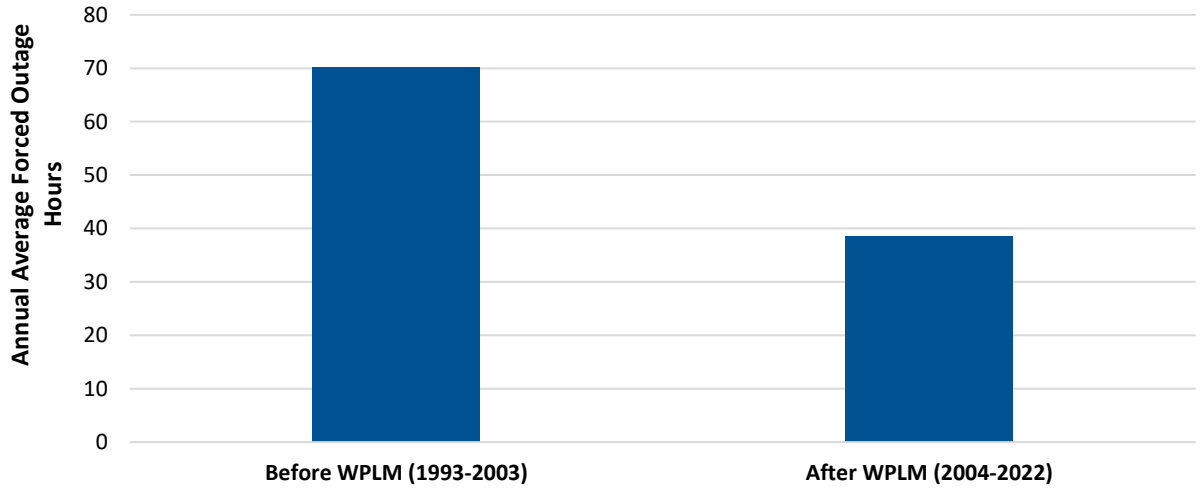


Chart 5: Outage Data for Hydro's Wooden Transmission System (1993–2022)

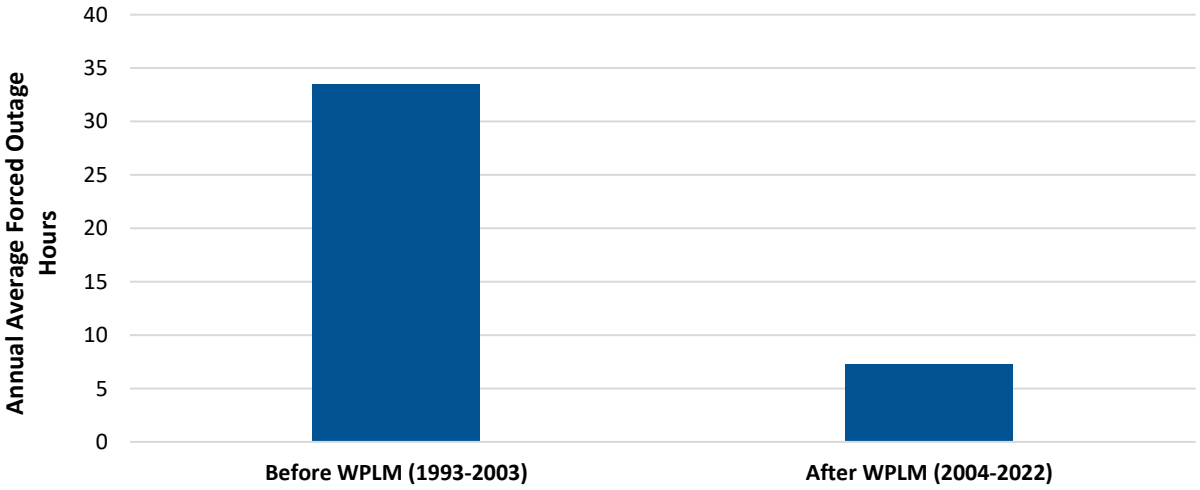


Chart 6: Outage Data for Hydro's Wooden Transmission System on the Avalon Peninsula (1993–2022)

Chart 7 and Chart 8 show the historical total outage frequencies and durations for Hydro's wooden transmission lines from 2018 to 2022. The increase in total outage duration for 2022 (as seen in Chart 8) can be attributed mainly to failures that occurred on TL203 and TL219 during an ice storm in early February 2022.[8]

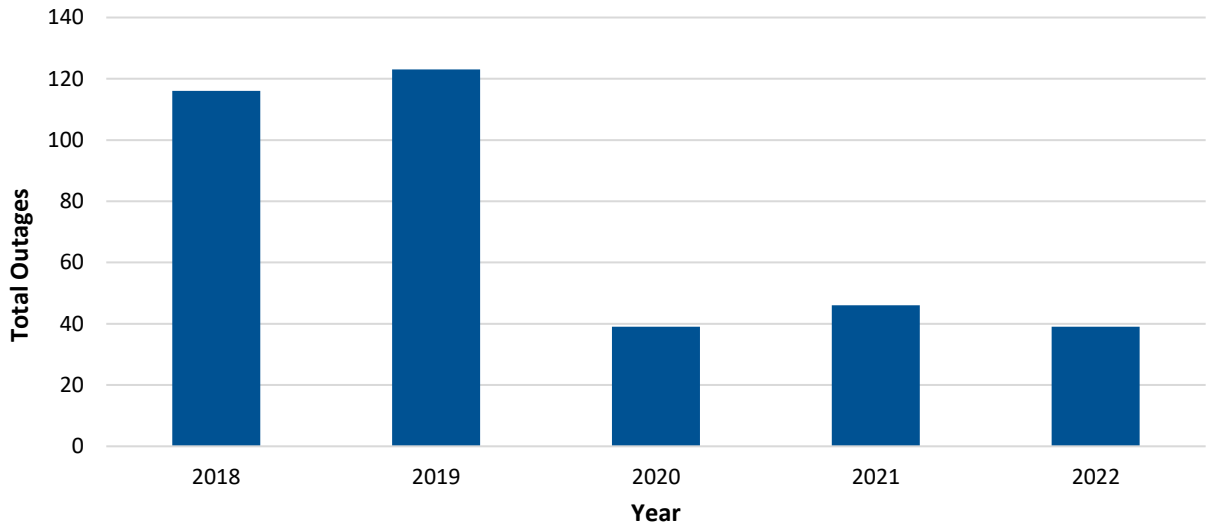


Chart 7: Historical Line Outage Frequency for Wooden Transmission Lines (All Causes)

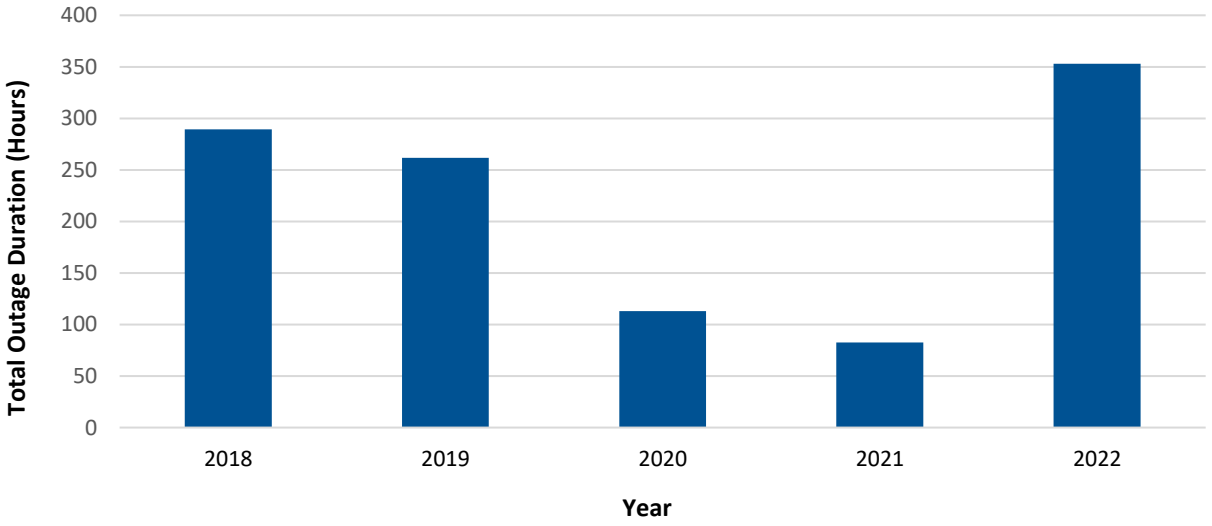


Chart 8: Historical Line Outage Duration for Wooden Transmission Lines (All Causes)

[8] As reported to the Board in "Power Outage and Incident Advisory Report 2022-H-010-a," Hydro experienced an unplanned outage to its customers served by the English Harbour West Distribution System on February 5, 2022.

6.0 Analysis

6.1 Evaluation of Alternatives

Hydro considered the following alternatives:

- Pace reduction; and
- Continue program at current pace.

6.1.1 Pace Reduction

The program employs a balanced, ten-year inspection cycle that includes inspection, treatment, and replacement, as required, following reliability-centred maintenance principles. Deferral of the program would be detrimental to program execution, effectiveness, and resource balancing. In 2018, as part of its second WPLM program progress report, Hydro investigated the optimum inspection/maintenance interval for the program. Results showed that Hydro's inspection interval is in line with industry best practices.

6.1.2 Continue Program at Current Pace

The WPLM program is a proactive, condition-based asset management program that follows reliability-centred maintenance principles. Transmission line assets must be managed in such a manner to balance reliability and costs. Condition-based programs are more progressive than age-based programs in which assets are replaced once they have surpassed their expected useful life with no or little consideration of their condition.

6.2 Least-Cost Evaluation

This program is a least-cost strategy for WPLM, as investments made in regular inspection, treatment and early detection of issues extend the useful life of the lines, support the deferral of line reconstruction, and prevent forced outages. Hydro's analysis of this program substantiates the program as a least-cost strategy. It demonstrates that the cost of the WPLM program and the average inspection interval of 10 years is well justified by cost-avoidance savings through reduced in-service failures and reduced unplanned repair costs, as well as life extension of existing pole plant assets by between 10 to 20 years. The overall pole replacement rate per year is well below the published industry data. The development of a rigorous methodology to assess and analyze the pole inspection data allows Hydro to continue to proactively identify the right level of expenditure, on the right poles, at the right time.

6.3 Recommended Alternative

Hydro proposes the continuation of its WPLM program at the current inspection intervals as this approach is demonstrated to be the least-cost strategy for the renewal of wood pole transmission lines.

6.3.1 Risk of Asset Stranding

All of the transmission lines currently included in the program are planned to remain in service, therefore, Hydro does not foresee any risk of asset stranding as it relates to the WPLM program.

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 6.

Table 6: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	4	4	**16**
Post-Execution	4	1	**4**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**3.2**

7.0 Scope of Work

The inspection and treatment work scheduled for 2024 is summarized in Table 7. This work is scheduled for execution between May 2024 and October 2024.

Table 7: 2024 Inspection Plan

Region	Line No.	Year Built	Age of Line	Target Number of Poles to Inspect
Eastern	TL203	1965	59	424
Central	TL224	1968	56	602
	TL263	2002	22	152
Western	TL250	1987	37	300
Northern	TL227	1970	54	726
	TL262	2002	22	48
Total				**2,252**

The scheduled refurbishment for 2024 is summarized in Table 8.

Table 8: 2024 Refurbishment Plan

	Region				
Component	**Eastern**	**Central**	**Western**	**Northern**	**Total**
Poles	37	22	1	8	**68**
Crossarms	41	5	11	2	**59**
Cross bracing	48	19	3	1	**71**
Knee bracing	21	3	1	-	**25**
Foundations	1	-	-	-	**1**
Miscellaneous (Insulators, hardware, etc.)	87	35	5	14	**141**

7.1 Program Budget

The estimate for the 2024 program is shown in Table 9.

Table 9: 2024 Project Estimate

Project Cost	**2024**	**2025**	**Beyond**	**Total**
Material Supply	326.7	0.0	0.0	**326.7**
Labour	2,142.2	0.0	0.0	**2,142.2**
Consultant	16.7	0.0	0.0	**16.7**
Contract Work	356.0	0.0	0.0	**356.0**
Other Direct Costs	719.4	0.0	0.0	**719.4**
Interest and Escalation	204.2	0.0	0.0	**204.2**
Contingency	0.0	0.0	0.0	**0.0**
Total	**3,765.2**	**0.0**	**0.0**	**3,765.2**

Chart 9 shows the historical expenditures since the program was initiated, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast budget through 2028.

The 2022 program expenditures were approximately 24% greater than the initial budget of $1,603,500. This variance was primarily attributed to an additional 300 pole inspections completed on Transmission Line TL 201, as discussed in Section 2.2.1 of this report. In addition, higher than anticipated costs were incurred on several lines for the replacement of wood pole line components.

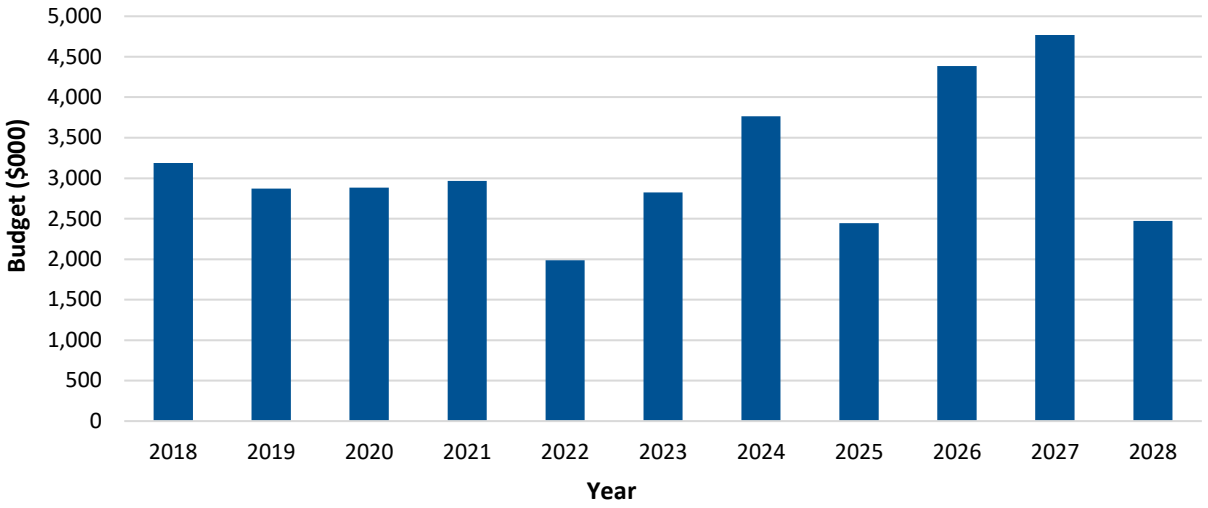


Chart 9: Historical and Forecast Program Budget

7.2 Program Schedule

The 2024 program schedule involves many transmission lines and is dependent on the annual workload and availability of outages. Work scheduled for 2024 will commence as early in the year as system conditions allow. The detailed annual work schedule for 2024 will be determined during the spring of 2024.

Table 10 provides a high-level program activity schedule reflecting the planned cycle of the program. This takes into account the one-year gap between inspections and resultant refurbishment work.

Table 10: Program Schedule

Activity	Start Date	End Date
Line Inspection and Treatment	May 2024	September 2024
Inspection Data Analysis	June 2024	October 2024
Material Procurement	February 2025	November 2025
Refurbishment Work Field Planning	May 2025	September 2025
Refurbishment	April 2026	October 2026

8.0 Conclusion

The WPLM program is an important part of Hydro's ongoing asset renewal. Proactive refurbishment of Hydro's wood pole transmission lines is required to support Hydro's legislated mandate to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner. Therefore, Hydro proposes to continue the WPLM program in 2024.

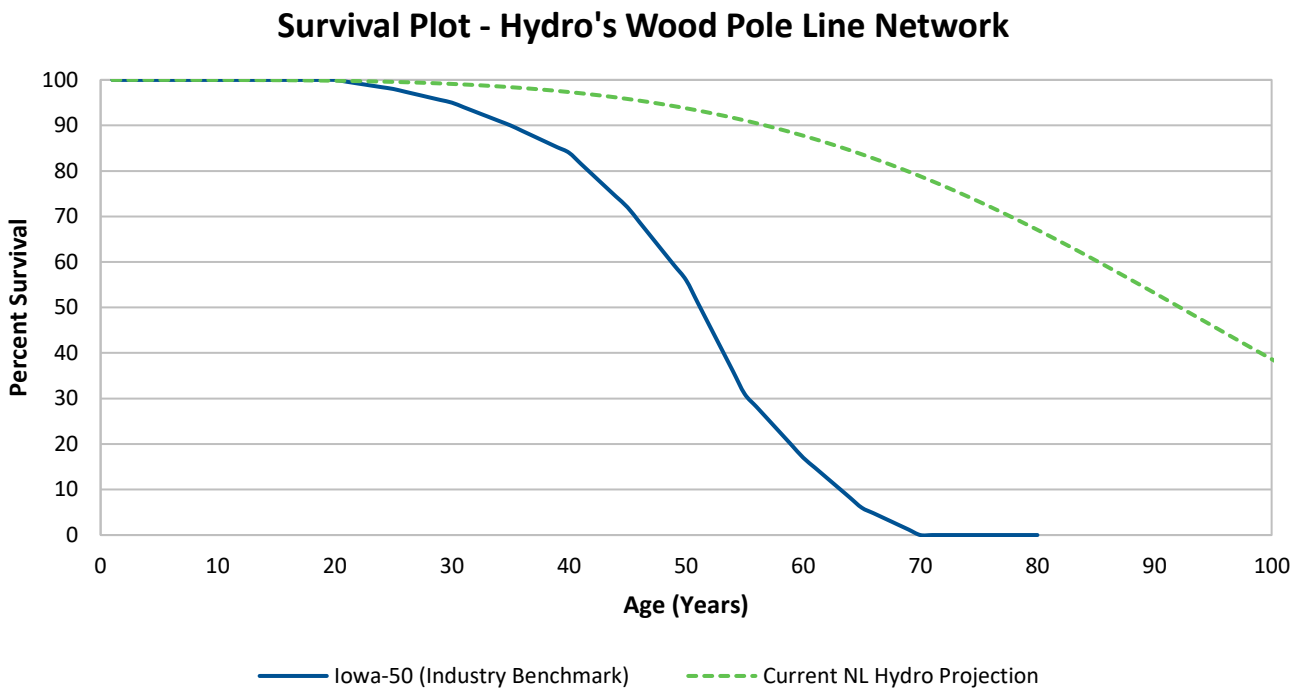
Appendix A

Iowa Curve

Island Interconnected System






Survival Plot - Hydro's Wood Pole Line Network
Percent Survival
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80
90
100
Age (Years)
Iowa-50 (Industry Benchmark)
Current NL Hydro Projection

Program 8

Upgrade Power Transformers (2024–2025)

July 2023

newfoundland labrador hydro

Upgrade Power Transformers (2024–2025)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") replaces or refurbishes failing or failed terminal station assets, including power transformers, to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

Hydro's philosophy for the assessment of equipment and the selection and justification of projects is outlined in the Terminal Station Asset Management Overview ("Asset Management Overview"), included as an Appendix to Schedule 1.[1]

Under this program, Hydro proposes the refurbishment of 18 power transformers, which are located within terminal stations across Hydro's system. Of the power transformers identified, 9 are being refurbished to ensure compliance with federal environmental *PCB Regulations*, as these units are suspected to contain bushings contaminated with polychlorinated biphenyls ("PCB"), which must be removed by 2025.[2] The other transformers have been identified for refurbishment based on condition, a legal requirement, or to provide improved condition monitoring to mitigate the risk of transformer failure.

For the assets recommended for refurbishment within this program, the following alternatives were considered:

- Pace reduction;
- Pace advancement; and
- Continue program at current pace.

[1] Hydro proposed the activities within this program under the Terminal Station Renewal (2023–2024) program, filed as part of the "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022.
[2] The *Canadian Environmental Protection Act, 1999,* SC 1999, c 33 includes *PCB Regulations* (SOR/2008-273), which provide end-of-use dates for various concentrations of PCBs.

This program has a multi-year approach, with completion planned in 2025 at an estimated cost of $3,575,900.

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Appendix A: Upgrade Power Transformers Program: 2024–2028 Plan

1.0 Introduction

Power transformers are used to transform or convert the voltage of an electrical circuit. By modifying voltage levels, the electrical system can be operated in an economically sound manner. Power transformers consist of several components including bushings, tap changers, and transformer oil, which affect the lifespan and operation of the transformer.

2.0 Program Description and Justification

Hydro completes regular condition assessments, scheduled maintenance, and testing to identify concerns with insulating oil and paper deterioration, oil moisture content, oil leaks, component rusting, tap changer component wear or damage, damaged or deteriorated bushings that are suspected to be PCB-contaminated, failure of the protective devices, and cooling fan failures.

Under the scope of the 2024–2025 program, 18 transformers will be refurbished.[3] The following transformer upgrades and/or refurbishments are planned for 2024–2025:

- Replacement of bushings;
- Replacement of radiators;
- Replacement or refurbishment of oil;
- Overhaul of tap changers;
- Leak refurbishments;
- Installation of online oil dehydrator; and
- Installation of online dissolved gas analysis (“DGA”) monitors.

A detailed list of the activities planned for completion in 2025 is provided in Table A-2 within Appendix A.

[3] Some transformers are due for major refurbishment, which includes two or more of the upgrades/refurbishments listed.

3.0 Asset Overview

3.1 Asset Background

The power transformers in the Upgrade Power Transformers (2024–2025) program are operational. The performance of these assets allows these units to remain in service; however, reliability could be compromised if not replaced in a timely manner once the replacement criterion is reached.

The justification for each transformer is either condition-based, required for compliance with regulations, or to provide improved condition monitoring as outlined in the Asset Management Overview.

3.2 Asset Condition

Hydro plans to complete work in the following job activities for power transformers under this capital program and is providing asset condition information for each:

- Power transformer solid insulation moisture removal;
- Power transformer on-load tap changer ("OLTC") refurbishment; and
- Power transformer bushing replacement.

The charts (Chart 1 and Chart 2) included in this proposal for the various power transformer components have ranges from Category A to Category D.[4]

3.2.1 Asset Condition – Power Transformer Solid Insulation Moisture

The power transformer solid insulation moisture asset condition categories represent severity, as defined by Hydro, based on the estimated solid insulation moisture as a percentage of the weight of the solid insulation. Each category is defined as follows:

- Category A: Less than 1.5%;
- Category B: Between 1.5% and 2.4%;
- Category C: Between 2.5% and 3.5%; and
- Category D: Greater than 3.5%.

[4] A Category A assessment indicates that the component is in normal operating condition. A Category D assessment indicates that the component requires either replacement or refurbishment or the component is being monitored to determine what actions are appropriate. Category B and Category C assessments are scaled between Categories A and D.

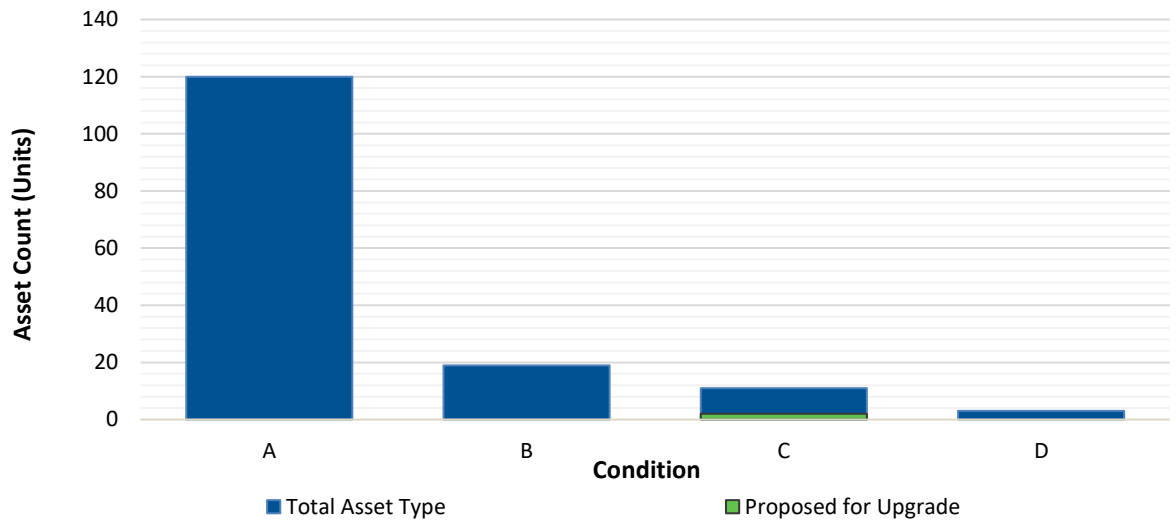


Chart 1: Asset Condition – Power Transformers Solid Insulation Moisture

There are three power transformers with paper moisture, categorized as Category D, that are not proposed for upgrade in this program. Of these three, one had recent oil processing completed, one has an online moisture reduction unit currently installed, and one has a moisture reduction job in the scope of an in-progress capital project.

3.2.2 Asset Condition – Power Transformer OLTC

The power transformer OLTC asset condition categories represent severity based on the condition of the OLTC inferred from Tap Changer Activity Signature Analysis ("TASA") Condition and Stenestam[5] Condition. Each category is defined as follows[6]:

- Category 1: Asset Condition = A
- Category 2: Asset Condition = B
- Category 3: Asset Condition = C
- Category 4: Asset Condition = D

[5] This categorization has been updated from previous reports to put greater weighting on the Stenestam ratio. The Stenestam ratio is calculated from measured levels of methane (CH_4), ethylene (C_2H_4), ethane (C_2H_6), and acetylene (C_2H_2) in the latest DGA results for a given OLTC, Stenestam ratio = (CH_4) + (C_2H_4) + (C_2H_6) ÷ (C_2H_2). An alphabetical Stenestam condition value is then mapped from these ratios as follows: A = < 0.5, B = > 0.5 to < 5, C = > 5.

[6] A Category 1 assessment indicates that both the TASA Condition and Stenestam Condition equal A. A Category 2 assessment indicates either TASA Condition or Stenestam Condition equal B without either having a worse letter grade. A Category 3 assessment indicates either TASA Condition or Stenestam Condition equal C without either having a worse letter grade. A Category 4 Assessment indicates that the TASA Condition equals D.

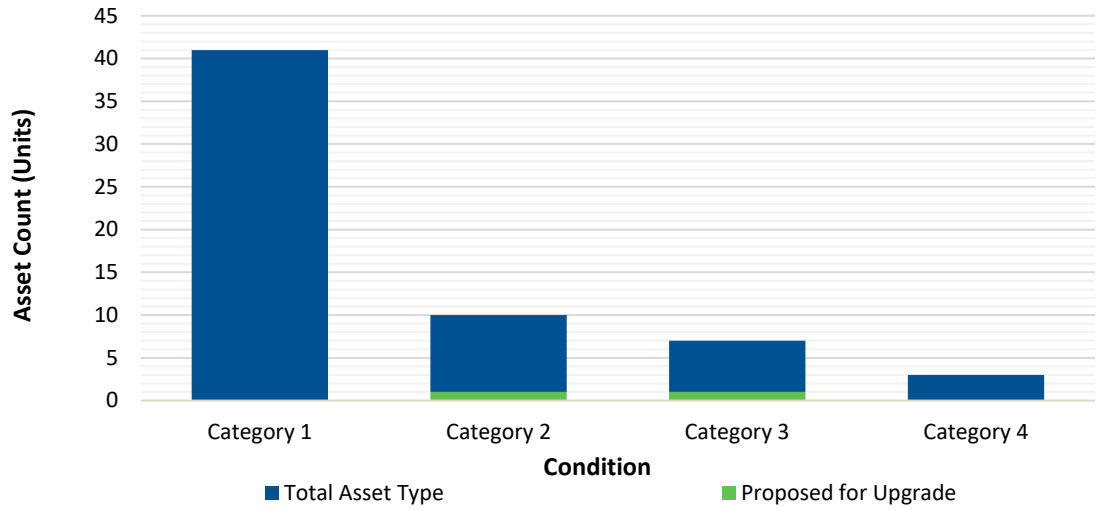


Chart 2: Asset Condition – Power Transformer OLTC

The three power transformers with a Category 4 rating are included in the Terminal Station Refurbishment and Modernization (2022–2023) program[7] or Terminal Station Renewal Program (2023–2024).[8]

3.2.3 Asset Condition – Power Transformer Bushings

Nine power transformers are to have their bushings replaced in this program, all of which are due to suspected PCB contamination.

At present, Hydro does not maintain a complete dataset of the categories of transformer bushing conditions; therefore, this data is not available.

3.3 Asset Ages

Chart 3 shows the age of the power transformers at the time of filing; however, this does not represent the age of any non-original components of the power transformers. None of the scope within the Upgrade Power Transformers (2024–2025) program is justified based on age.

[7] "2022 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 17, 2021 (originally filed August 2, 2021), vol. II, tab 10, sec. 2.1.3.
[8] "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022, vol. II, prog. 3, sec. 2.3.

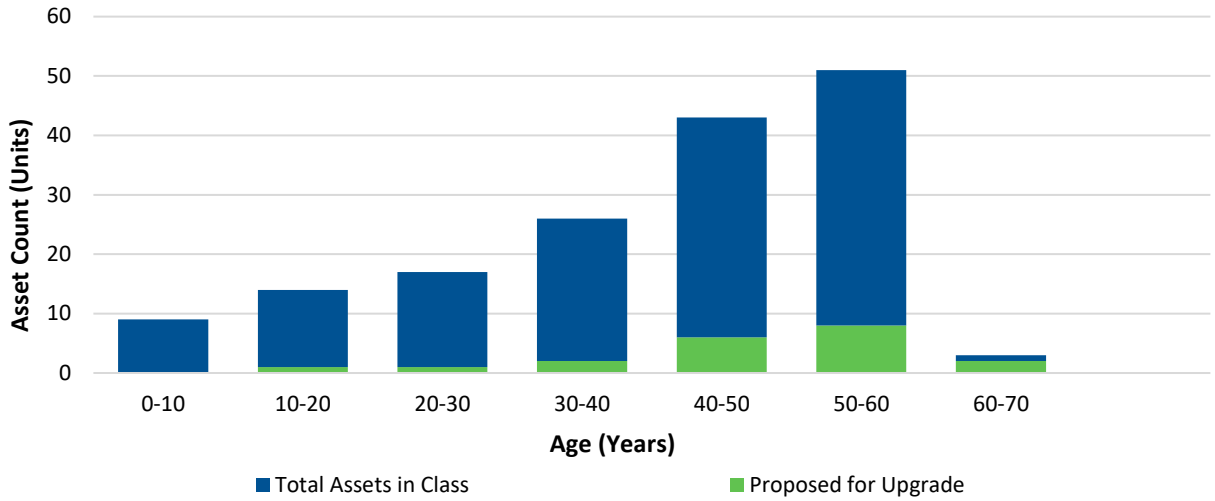


Chart 3: Asset Counts by Asset Age

4.0 Trending

4.1 Assets Installed/Replaced/Upgraded

The quantity of assets to be replaced or refurbished or that are forecast to be replaced or refurbished under this program each year is presented in Chart 4.

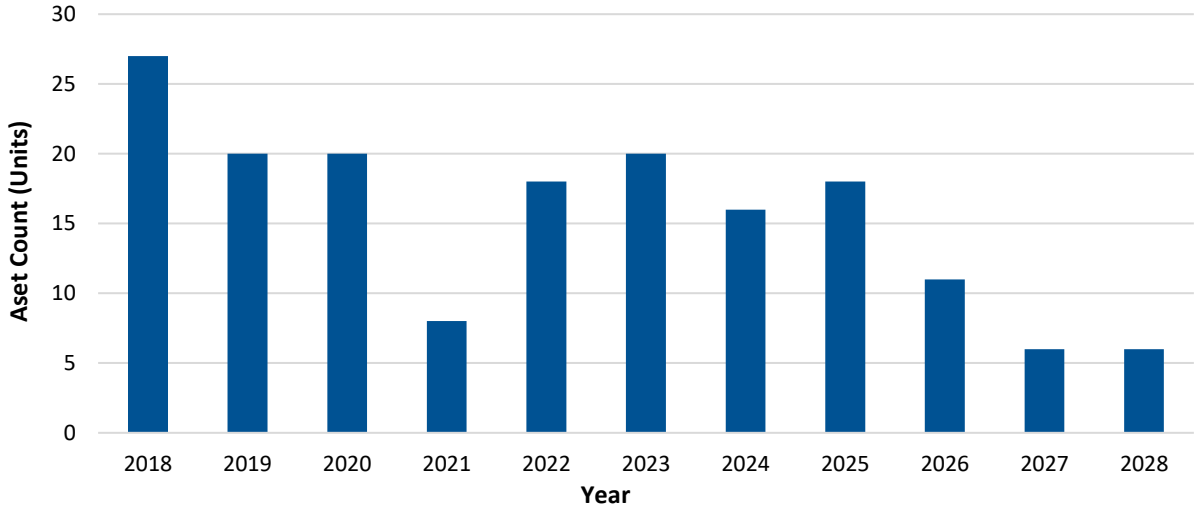


Chart 4: Historical and Forecast Assets Replaced

There is a reduction in the forecast number of refurbishments beyond 2025, as all of the suspected PCB-contaminated units will have been removed.

4.2 Historical and Forecast Average Unit Costs

Unit costs per asset refurbished or replaced are presented in Chart 5. As this program addresses a variety of assets, unit costs vary significantly from year to year.

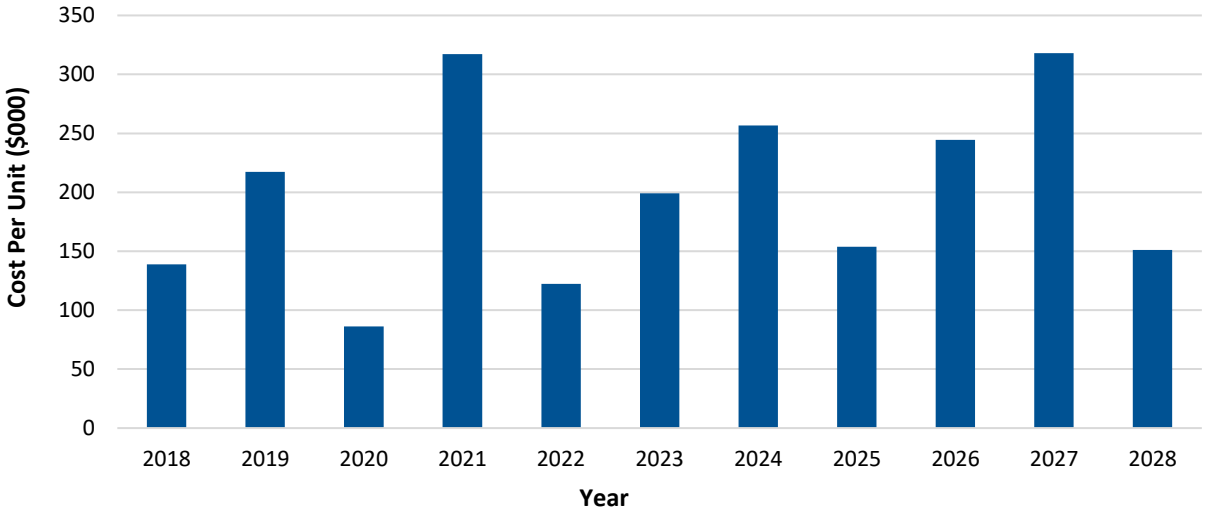


Chart 5: Historical and Forecast Average Unit Costs

Forecast expenditures for 2026 onwards increase in relation to the planned scopes of work, as activities[9] planned for those years are typically higher in cost.

5.0 Historical Reliability

A listing of sustained forced outages for the last five years is shown in Table 1.

Table 1: Power Transformer Outages and Durations from 2018 to 2022 (minutes)

Start Date	Transformer	Outage Duration
6-Aug-2022	Grandy Brook T1	241
3-Jul-2022	Bay d'Espoir T5	36,482
28-Apr-2022	Sunnyside T1	5
28-Apr-2022	Sunnyside T4	5
22-Apr-2022	Deer Lake T2	337
21-Mar-2022	Holyrood T10	1475
21-Mar-2022	Holyrood T5	1376

[9] Planned activities include leak refurbishment, oil processing, and OLTC refurbishment, which are typically higher in cost due to the high cost per asset and contractor involvement.

6.0 Analysis

6.1 Evaluation of Alternatives

The following alternatives were considered:

- Pace reduction;
- Pace advancement; and
- Continue program at current pace.

6.1.1 Pace Reduction

Tap Changer Overhauls/Refurbishment

The scope of work includes tap changer refurbishments for two transformers. The tap changers for these units are in deteriorated condition. The continued operation of these units in their present condition increases the risk of failure. Deferral of this work is not a viable alternative.

Bushing Replacements

The scope of work includes bushing replacements for nine transformers. The bushings identified for replacement are suspected to contain PCBs. Deferral of this program is not a viable alternative, as these bushings must be removed by December 31, 2025 to ensure compliance with federal environmental *PCB Regulations*.

Installation of Online DGA Monitors

The scope of work includes the installation of online DGA monitors for five transformers.

The installation of online DGA monitors can allow early indication if a transformer is subjected to fault conditions, overheating, or if there is internal arcing or partial discharge occurring in the windings. These installations permit Hydro to continuously monitor these transformers and provide early fault detection. Continuous data is also a useful tool for personnel to trend gases to help schedule repairs or replacements prior to in-service failures, which improves the overall reliability of the interconnected system. The identified installations are part of Hydro's program to install online DGA monitors on power transformers throughout the system. Deferral of this work reduces Hydro's ability to monitor power transformers and increases the risk of these units experiencing a serious fault. Deferral of this work is not a viable alternative.

Installation of Online Oil Dehydrator

The scope of work includes the installation of an online oil dehydrator on one transformer.

Oil samples from this transformer indicate the presence of excessive moisture content. Moisture in a power transformer may be residual moisture or may result from the ingress of atmospheric moisture. Oil and insulating paper with high moisture content have reduced dielectric strength; as such, its performance as an electrical insulator is diminished. To address this issue, Hydro is recommending the installation of an online oil dehydrator, which circulates and dries the transformer oil without requiring an equipment outage. Deferral of this work increases the risk of this transformer experiencing a serious fault. Deferral of this work is not a viable alternative.

6.1.2 Pace Advancement

Pace advancement is not a viable option due to resource and outage availability concerns.

6.1.3 Continue Program at Current Pace

The tap changer overhauls, bushing replacements, online DGA monitor installations, and online oil dehydrator installation as identified in a planned, strategic manner as outlined in this proposal are prudent. This approach enables Hydro to complete the identified power transformer upgrades in a manner that supports its mandate to provide safe, reliable, least-cost electricity in an environmentally responsible manner.

6.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

6.3 Recommended Alternative

Hydro recommends proceeding with the proposed work as identified herein. Deferral of this work increases the risk of transformer failure and would place Hydro in violation of federal environmental *PCB Regulations*.

6.3.1 Risk of Asset Stranding

For all assets included within this program, there is no undue risk that these capital additions will be stranded before their useful life has been reached, as there are no plans to retire any existing terminal stations.

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 2.

Table 2: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	5	**15**
Post-Execution	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**3.4**

7.0 Scope of Work

Hydro's five-year plan for the Upgrade Power Transformers program is provided in Appendix A. Based on current condition and asset data, Hydro plans to refurbish 18 power transformers under this program, with completion scheduled by the end of 2025. Based on asset condition and outage and resource availability at the time of execution, Hydro may advance or defer the replacement of specific assets to ensure efficient and effective implementation of this program.

7.1 Program Budget

The estimate for the 2024–2025 program is shown in Table 3.

Table 3: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	481.0	337.5	0.0	**818.5**
Labour	255.4	599.1	0.0	**854.5**
Consultant	0.0	107.5	0.0	**107.5**
Contract Work	0.0	1,089.0	0.0	**1,089.0**
Other Direct Costs	18.7	190.5	0.0	**209.2**
Interest and Escalation	34.0	155.3	0.0	**189.3**
Contingency	75.5	232.4	0.0	**307.9**
Total	**864.6**	**2,711.3**	**0.0**	**3,575.9**

Chart 6 provides the five-year historical program expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028.

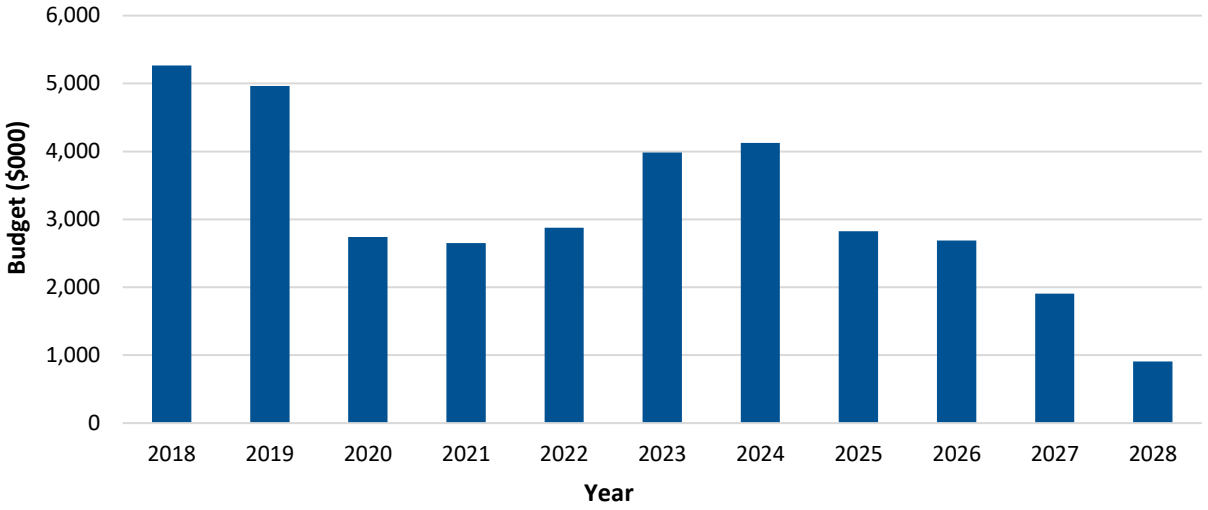


Chart 6: Historical and Forecast Program Budget

7.2 Program Schedule

The schedule for the 2024–2025 program is shown in Table 4.

Table 4: Program Schedule

Activity	Start Date	End Date
Planning:		
Initial planning and scheduling.	January 2024	May 2024
Design:		
Conduct site visits and complete detailed design.	May 2024	November 2025
Procurement:		
Ordering and delivery of equipment.	March 2024	September 2025
Construction:		
Install new equipment.	January 2025	November 2025
Commissioning:		
Commissioning.	January 2025	November 2025
Closeout:		
Complete closeout documentation.	October 2025	December 2025

8.0 Conclusion

The scope of work identified within this program is required to refurbish 18 power transformers to allow Hydro to continue to provide safe, reliable, least-cost electricity in an environmentally responsible manner. Of the power transformers identified, 9 are being refurbished to ensure compliance with federal environmental *PCB Regulations*, as these units are suspected to contain bushings contaminated with PCBs, which must be removed by December 31, 2025. The remaining transformers have been

identified for refurbishment based on condition, a legal requirement, or to provide improved condition monitoring to mitigate the risk of transformer failure.

Appendix A

Upgrade Power Transformers Program

2024–2028 Plan





Assets planned for upgrade from 2024 to 2028 under the Upgrade Power Transformers program are provided in Table A-1 to Table A-5.

Table A-1: Assets Planned for Upgrade in 2024[1,2]

Name	Voltage (kV)	Activity
Bay d'Espoir T12	230	Replace bushings (LV).
Bear Cove T1	138	Install online composite gas monitor.
Bottom Brook T3	230	Major refurbishment: Replace bushings (HV, LV, X0[3]) and install online composite gas monitor.
Cat Arm T2	230	Replace bushing (N[4]).
Come By Chance T1	230	Replace bushing (N).
Come By Chance T2	230	Replace bushing (N).
Doyles T1	138	Replace bushings (LV) and install online composite gas monitor.
Hardwoods GT1	69	Replace bushing (N).
Holyrood SST1-2	69	Replace bushings (HV, LV, N).
Oxen Pond T1	230	Refurbish tap changer.
Plum Point T1	69	Install online composite gas monitor.
Wabush Terminal Station T12	46	Install online oil dehydrator.
Wabush Terminal Station T7	230	Major refurbishment: Replace HV bushings (two only) and install online composite gas monitor.
Wabush Terminal Station T8	230	Major refurbishment - Replace bushings (HV, X2, X3) and install online composite gas monitor.
Wiltondale T1	69	Replace bushings (HV, LV, N).

[1] The Assets Planned for Upgrade in 2024, as listed in Table A-1, are planned for completion in 2024 and were approved as part of the Terminal Station Renewal Program (2023–2024) included in the "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022, vol. II, prog. 3, which was approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 2(2023), Board of Commissioners of Public Utilities, January 26, 2023.

[2] HV refers to all high-voltage bushings and LV refers to all low-voltage bushings. If H is followed by a digit (e.g., H1), it represents an individual high-voltage bushing. If L or X are followed by a digit (e.g., L2, X3), it represents an individual low-voltage bushing.

[3] Neutral located on low-voltage winding ("XO").

[4] Neutral ("N").

Table A-2: Assets Planned for Upgrade in 2025[5]

Name	Voltage (kV)	Activity
Bay d'Espoir T3	230	Replace bushings (HV).
Bottom Brook T2	138	Install online composite gas monitor.
Bottom Waters T1	138	Install online composite gas monitor.
Coney Arm T1	69	Replace bushings (HV, LV, N).
Cow Head T1	69	Major refurbishment: Replace radiators, re-gasket, replace valves, and paint.
Grand Falls Frequency Convertor T2	230	Replace bushings (H1, H3).
Grandy Brook T1	138	Major refurbishment: Install online composite gas monitor and painting.
Holyrood T1	230	Replace bushings (HV, LV, N).
Holyrood T2	230	Replace bushings (HV, N).
Muskrat Falls T1	138	Install online composite gas monitor.
Peter's Barren SST	69	Major refurbishment: Replace bushings (HV, LV, N) and leak refurbishment.
Peter's Barren T1	138	Major refurbishment: Refurbish tap changer and install online composite gas monitor.
Quartzite T2	69	Refurbish tap changer.
South Brook T1	138	Oil refurbishment.
Wabush Terminal Station SS1	69	Major refurbishment: Replace oil and hot oil rinse.
Wabush Terminal Station T1	230	Major refurbishment: Replace bushings (LV, N), oil refurbishment, and install online oil dehydrator.
Wabush Terminal Station T2	230	Replace bushings (HV, N).
Wabush Terminal Station T6	230	Major refurbishment: Replace bushing (N), replace radiators, and oil refurbishment.

[5] HV refers to all high-voltage bushings and LV refers to all low-voltage bushings. If H is followed by a digit (e.g., H1), it represents an individual high-voltage bushing. If L or X are followed by a digit (e.g., L2, X3), it represents an individual low-voltage bushing.

Table A-3: Assets Planned for Upgrade in 2026

Name	Voltage (kV)	Activity
Bottom Brook T1	230	Major refurbishment: Leak refurbishment and OLTC leak refurbishment.
Bay D'Espoir T12	230	Refurbish tap changer.
Berry Hill T1	138	Major refurbishment: Moisture reduction and install online composite gas monitor.
Deer Lake T1	69	Oil refurbishment.
Happy Valley T1	138	Refurbish tap changer.
Happy Valley T2	138	Major refurbishment: Moisture reduction and oil refurbishment.
Oxen Pond T2	230	Moisture reduction.
St. Anthony Airport T1	69	Major refurbishment: OLTC refurbishment and install online composite gas monitor.
Stony Brook T1	230	Major refurbishment: OLTC replacement and OLTC leak refurbishment.
Western Avalon T1	230	Major refurbishment: Moisture reduction and oil refurbishment.
Western Avalon T2	230	Oil refurbishment.

Table A-4: Assets Planned for Upgrade in 2027

Name	Voltage (kV)	Activity
Daniel's Harbour T1	69	Moisture reduction.
Holyrood T9	13.8	Oil refurbishment.
Stony Brook T2	230	Major refurbishment: OLTC replacement, OLTC leak refurbishment, and oil reclamation.
Vanier 2 T2	69	Refurbish tap changer.
Wabush Terminal Station T2	230	Major refurbishment: Leak refurbishment and install online composite gas monitor.
Wabush Terminal Station T3	230	Major refurbishment: Leak refurbishment and install online composite gas monitor.

Table A-5: Assets Planned for Upgrade in 2028

Name	Voltage (kV)	Activity
Buchans T1S	230	Oil refurbishment.
Grand Falls Frequency Convertor T1	230	Major refurbishment: Oil refurbishment and leak refurbishment.
Holyrood T10	230	Major refurbishment: Leak refurbishment and painting.
Massey Drive T1	230	Refurbish tap changer.
Wabush Terminal Station T1	230	Install online composite gas monitor.
Wabush Terminal Station T4	230	Install online composite gas monitor.

Program 9

Thermal In-Service Failures (2024)

July 2023



Thermal In-Service Failures (2024)

Location: Holyrood

Investment Classification: Renewal

Asset Category: Thermal Plant

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has an Asset Management Program that governs the life cycle of its thermal generation assets. This program monitors, maintains, refurbishes, replaces, and disposes of assets to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

Generally, Hydro identifies and plans the refurbishment and replacement work that will be required for its thermal generation assets in time for inclusion within the annual capital budget applications ("CBA"). However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or the determination of faster-than-anticipated equipment deterioration.

Hydro is proposing that, within the Thermal In-Service Failures program, it will undertake the immediate capital refurbishment and replacement work required for its thermal generation assets to maintain safe and reliable operation and to ensure the availability of capital spares required to support such work.

As per the "Reliability and Resource Adequacy Study – 2022 Update," ("RRA Study – 2022 Update")[1] the Holyrood Thermal Generating Station ("Holyrood TGS") shall remain available for a "Bridging Period"[2] until 2030 or until such time that sufficient alternative generation is commissioned, adequate performance of the Labrador-Island Link is proven, and generation reserves are met. Hydro expects continued operation of all three units at the Holyrood TGS through the Bridging Period to ensure reliable operation for customers until its capacity can be adequately replaced. Therefore, Hydro believes this program is prudent and necessary to ensure the reliable and safe operation of the Holyrood TGS.

[1] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[2] Hydro considers the Bridging Period to be from 2023 to 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

The estimated cost for work executed under this program in 2024 is $3,508,700, which is based on the average expenditure over the past three years from 2020 to 2022.

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1.0 Introduction

Hydro conducts asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize the disruption of service and to avoid unsafe working conditions due to equipment failure. An objective of Hydro's Asset Management Program is to identify refurbishment and replacement activities that require approval by the Board of Commissioners of Public Utilities ("Board") in time to be included in Hydro's annual CBA. This is achieved through the preventive maintenance program using various condition-based assessments and testing procedures.

Hydro has had success in projecting the deterioration rate of equipment for submission of refurbishment or replacement work into CBAs. However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or the identification of faster-than-anticipated equipment deterioration. These situations can be caused by events such as vandalism, storm damage, lightning, accidental damage, abnormal system operations, cavitation, corrosion, wear of mechanical components, sudden equipment failure, or existing installation deficiencies, etc. Hydro uses historical data and engineering judgment to predict the magnitude of in-service failure expenditures.

2.0 Program Description and Justification

Due to the operating conditions that thermal generating equipment and systems are subject to, such as high pressure and temperature, unanticipated failures and deterioration occur. Under the Thermal In-Service Failures program, Hydro is proposing to undertake the immediate capital refurbishment and replacement work required for the Holyrood TGS, as needed, to maintain safe and reliable operations and to ensure the availability of capital spares required to support such work. At this time, Hydro does not have any planned capital spare acquisitions under this program; however, throughout 2024, Hydro may purchase capital spares identified by asset management personnel as requiring immediate procurement to offset deficiencies in its capital spares.

Deferral of work that is justified under this program could result in a detrimental impact to customer power supply or unacceptable risk to worker or public safety.

Depending on the relevant circumstances, required work will be evaluated to determine the appropriate form of execution as an in-service failure, an allowance for unforeseen item, or a supplemental project.

3.0 Asset Overview

3.1 Asset Background

The assets requiring immediate, unplanned replacement or refurbishment work in a given year cannot be identified in advance.

For further information on the work executed under the Thermal In-Service Failures (2022) program, please refer to Hydro's "Capital Expenditures and Carryover Report for the Year Ended December 31, 2022."[3]

3.2 Asset Condition

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure.

3.3 Condition-Based Remaining Life

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure; therefore, these assets have reached the end of their serviceable life.

3.4 Asset Ages

The age of assets potentially covered under this program varies. Unplanned replacement or refurbishment activities due to failure or incipient failure may be necessary at any time during the asset life cycle.

4.0 Trending

Hydro implemented the Thermal In-Service Failures program in 2018. Since that time, on average, Hydro has initiated 27 unplanned projects per year under this program.

[3] "Capital Expenditures and Carryover Report for the Year Ended December 31, 2022," Newfoundland and Labrador Hydro, March 30, 2023, sec. 11.0, Table 8, pp.57–61. <http://pub.nl.ca/indexreports/expenditure/From%20NLH%20-%202022%20Capital%20Expenditures%20and%20Carryover%20Report%20-%202023-03-31.PDF>

4.1 Assets Installed/Replaced/Upgraded

The number of unplanned In-Service Failures projects initiated under this program over the past five years is provided in Chart 1. Details of each project, and the associated assets and costs, are filed with the Board within Hydro's annual Capital Expenditures and Carryover Report.

Hydro anticipates that unplanned failures will continue to occur given the age and number of thermal assets covered under this program. Hydro continues to plan the budget for this program based on historical information.

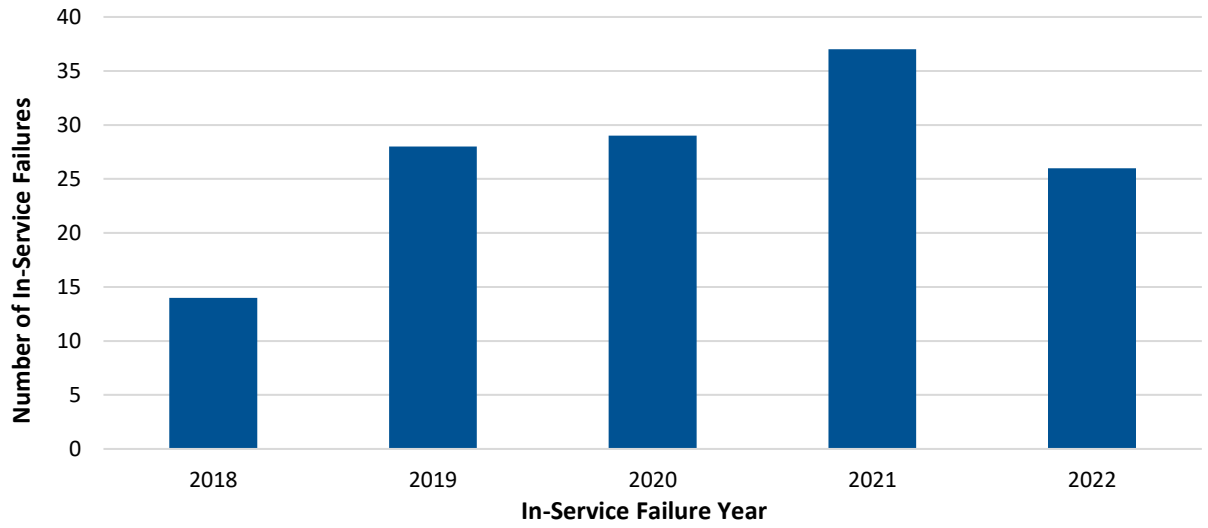


Chart 1: In-Service Failure Frequency

4.2 Historical and Forecast Average Unit Costs

Historical and forecast program costs are provided in Chart 2 in Section 7.1. Due to the nature of this program and the range of assets covered, average unit cost information is not applicable. An increase in program cost is forecast based on the anticipated escalation of both material and labour costs.

The level of expenditure ($5.8 million) in 2021 for this program was higher than in other years. Prior to the RRA Study – 2022 Update, Hydro's commitment to have the Holyrood TGS fully available for generation was extended several times in one-year increments, increasing the challenge to balance cost and reliability for an aging plant nearing the end of its service requirement as a generating facility. With

a more certain future, many of the 2021 Thermal In-Service Failure projects would likely have been completed under planned capital work, such as the Overhaul of Marine Terminal Loading Arm project.[4]

5.0 Historical Reliability

Hydro tracks performance data for its thermal generation units using the Derated Adjusted Forced Outage Rate ("DAFOR").[5,6] This program plays a key role in allowing Hydro to minimize the DAFOR of its thermal generation units to ensure the provision of reliable service to customers. In its May Near-Term Reliability Update, Hydro's modelling indicated that Derated Adjusted Utilization Forced Outage Probability ("DAUFOP") in excess of 20%, coupled with LIL forced outage rates in excess of 5% would result in a violation of Hydro's generation planning criteria. This program ensures Hydro can address failing components quickly to minimize forced outages that could impact the system.

6.0 Analysis

6.1 Evaluation of Alternatives

Depending on the nature of each failure or incipient failure, Hydro reviews viable technical alternatives to determine the most appropriate solution to address the unplanned event while balancing urgent safety and operational risks.

Due to the urgent nature of work executed under this program, seeking approval through a supplemental capital expenditures application or deferring the work for inclusion in the next CBA are not viable alternatives. The alternative of executing required unplanned work under the Allowance for Unforeseen Items Account is also considered on a case-by-case basis, subject to the requirements set out by the Board for use of the account.

6.2 Risk of Asset Stranding

The risk of asset stranding is less imminent as a result of the decision to extend Holyrood TGS to remain available through the Bridging Period. As Hydro expects continued operation of all three units at the

[4] The Overhaul of Marine Terminal Loading Arm project is a single-year project, with estimated completion in 2024. As the estimated cost for this project is under $750,000, it has been included in the listing of Proposals Under $750,000.
[5] DAFOR is a metric that measures the percentage of time that a unit or group of units is unable to generate at its maximum continuous rating due to forced outages or unit deratings.
[6] Filed quarterly with the Board, most recently the "Quarterly Report on Performance of Generating Units for the Twelve Months Ended March 31, 2023," Newfoundland and Labrador Hydro, April 28, 2023.

Holyrood TGS through the Bridging Period until its capacity can be adequately replaced to ensure reliable operation for customers, capital expenditures for this facility to operate as a generator continue to be required. Depreciation is required to be calculated on an accelerated basis (i.e., monthly depreciation = capital investment ÷ remaining months of service life).[7]

6.3 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	5	**15**
Post-Execution	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**3.4**

7.0 Scope of Work

Work executed under this program in 2024 will be reported to the Board in Hydro's 2024 Capital Expenditures and Carryover Report.[8]

7.1 Program Budget

The estimate for the 2024 program is shown in Table 2. The estimate is based on the average expenditures from 2020 to 2022. The details of each project covered under this program, including the associated assets and costs, as well as the total program expenditures for each year are filed with the Board within Hydro's annual Capital Expenditures and Carryover Report.

[7] As a result of the extension of the Holyrood TGS through the Bridging Period, Hydro intends to make an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account in 2023.
[8] Hydro's 2024 Capital Expenditures and Carryover Report is to be filed on or before April 1, 2025.

Table 2: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	500.0	0.0	0.0	**500.0**
Labour	841.5	0.0	0.0	**841.5**
Consultant	80.0	0.0	0.0	**80.0**
Contract Work	2,000.0	0.0	0.0	**2,000.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	87.2	0.0	0.0	**87.2**
Contingency	0.0	0.0	0.0	**0.0**
Total	**3,508.7**	**0.0**	**0.0**	**3,508.7**

The Thermal In-Service Failures program started in 2018. Chart 2 shows the historical expenditures since the program was initiated, the forecast 2023 expenditures, the proposed 2024 budget, and the forecast costs through 2028.[9] As Hydro cannot predict the quantity and the nature of failures to be addressed within this program for future years, Hydro has forecast future expenditures for this program based on the 2023 program budget with cost escalation applied.

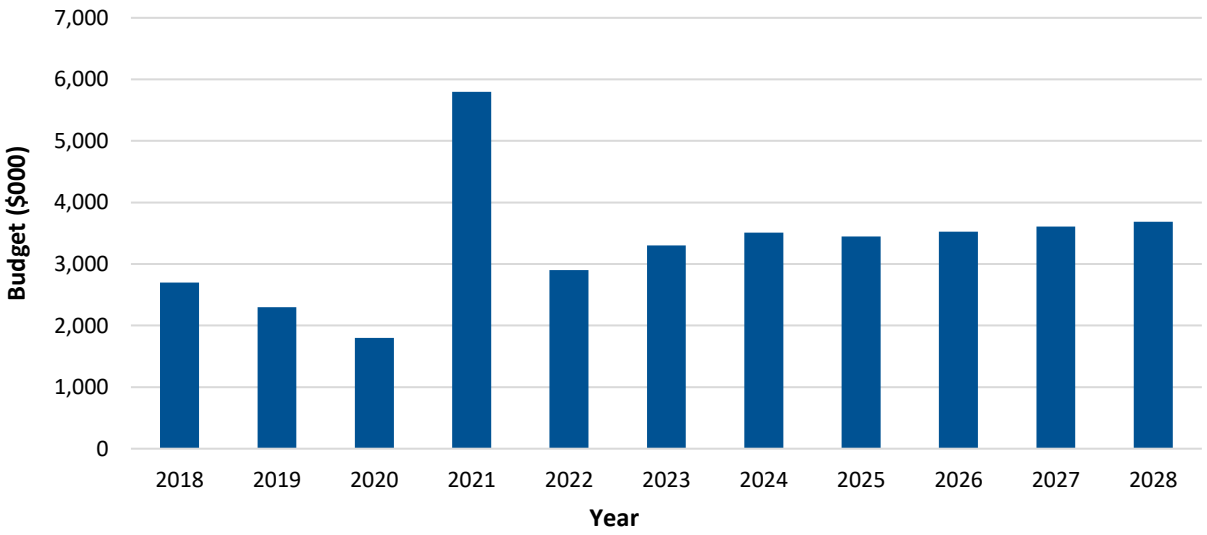


Chart 2: Historical and Forecast Program Estimates

[9] A forecast for the costs of the thermal in-service failures was based on the assumption of continued operation of all generating units at the Holyrood TGS through the Bridging Period until its capacity can be adequately replaced. Hydro's capital projections assume all three generating units remain online until 2030. These projections are subject to change based on changes in operating regime.

7.2 Program Schedule

Work schedules are established subsequent to an unplanned failure, or incipient failure event. There are currently no planned capital spare acquisitions under this program for 2024.

8.0 Conclusion

The Thermal In-Service Failures program allows Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable operations, in an environmentally responsible manner. This program also allows Hydro to continue to proactively manage the pool of capital spare equipment to support thermal operations.

Replace Protective Relays (2024–2025)

July 2023



Replace Protective Relays (2024–2025)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") replaces obsolete protective relays that have reached the end of their service life with modern, microprocessor-based relays. Aging relays, or relays that are not compliant with Hydro's current standards, can fail or inadequately protect the electrical system during faults or abnormal system conditions, preventing timely isolation of the faults or hazards, thus compromising power system reliability, stability, and overall equipment health.

Hydro's philosophy for the assessment of equipment and the selection and justification of programs and projects is outlined in the Terminal Station Asset Management Overview ("Asset Management Overview"), included as an Appendix to Schedule 1.[1]

Under this program, Hydro proposes the replacement of 16 different protection systems located within terminal stations and generating stations. For the systems recommended for replacement, the following alternatives were considered:

- Pace reduction;
- Pace advancement; and
- Continue program at current pace.

Hydro recommends proceeding with the identified upgrades to ensure that aging and non-standard protective relays are replaced in a planned manner. An in-service failure of a protection relay would reduce the reliability of the asset being protected and may involve an extended outage on the protection until the replacement equipment can be procured, engineered, and installed. In certain

[1] Hydro proposed the activities within this program under the Terminal Station Renewal (2023–2024) program, filed as part of the "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022.

cases, the asset would need to be taken out of service entirely until the replacement equipment is installed.

This program has a multi-year approach, with completion planned in 2025 at an estimated cost of $3,439,100.

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Appendix A: Replace Protective Relays Program: 2024–2028 Plan

1.0 Introduction

Protective relaying is a vital part of an electrical system during trouble, faults, and abnormal disturbances. Protective relays are found in all of Hydro's terminal stations and generating stations. Protective relays function to protect major electrical equipment including, but not limited to, transmission and distribution lines, transformers, busses, circuit breakers, and generators. Properly applied and functioning protective relaying initiates the disconnection or clearing of faults to protect equipment while the operation and service of the rest of the system continue. Protective relaying should not take action under normal operating conditions.

Existing protective relays in Hydro's system are either electromechanical, solid state (digital), or microprocessor-based. They are to be replaced based on the criteria in the Asset Management Overview.

2.0 Program Description and Justification

The replacement of protective relays is driven by condition and/or obsolescence. Hydro replaces electromechanical and solid-state relays with modern digital relays, improving reliability and, in some cases, providing additional functionality. Hydro's approach to protection, control, and modernization asset management is detailed in the Asset Management Overview.

This program was initiated in 2016, with a plan to replace all existing electromechanical transformers, buses, and line protection relays with modern digital relays. The 230 kV relays are the priority for the first phase of the plan, with 138 kV and 69 kV to follow. Installation of redundant transformer protection relays was also included in the program, in line with Hydro's Transformer Protection Standard. Generator protection relays were added to the program in recognition of the vital role they play in system reliability.

This program is required to ensure the reliable operation of protective relaying. Aging or non-standard protective relays can fail or inadequately protect the system during faults or abnormal system conditions. This would prevent timely isolation of the fault(s) or hazards, thus compromising power system reliability, stability, and overall equipment health. Hydro proposes to replace 16 different protection systems located at terminal stations and generating stations across the system.

3.0 Asset Overview

3.1 Asset Background

The Asset Management Overview outlines Hydro's asset management programs as they relate to terminal station equipment. Hydro completes routine maintenance on a six-year cycle for protective relays and identifies any deficiencies for follow-up. The assets designated for upgrade herein have been selected by Hydro's Asset Management staff to align with Hydro's commitment to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

The protective relays in the Replace Protective Relays (2024–2025) program are operational. The justification for each project within this program is obsolescence or lack of required functionality. Protective relays continuously monitor for abnormal conditions on the electrical system.

3.2 Asset Condition

Existing protective relays are either electromechanical, solid state (digital), or microprocessor-based. The oldest of these are electromechanical; wear and heating issues may cause them to fail or misoperate. Digital or static relays have little to no moving parts; however, they do experience failure associated with aging internal components (e.g., power supplies, capacitors, LCD[2] displays), most of which are unrepairable or obsolete.

A deficient relay may have two failure modes—it may not operate when needed to protect electrical equipment (which may result in widespread outages and/or equipment damage) and it may operate inadvertently (causing unplanned outages).

Each relay in Hydro's fleet is tested on a six-year preventive maintenance cycle. This program intends to replace aging and obsolete relays prior to finding them deficient during the six-year preventive maintenance test or upon failure.

3.3 Asset Ages

The age of assets covered under this program varies. Unplanned replacement or refurbishment activities due to failure may be necessary at any time during the asset life cycle.

[2] Liquid crystal display ("LCD").

The information in Chart 1 represents Hydro's protective relay fleet. All protective relays in the scope of the Replace Protective Relays (2024–2025) program are either obsolete or lack functionality. The relays planned for replacement that are 50 to 60 years old are all obsolete electromechanical relays. The relays planned for replacement that are less than 40 years old are all solid-state relays that have been deemed obsolete by the original equipment manufacturer and relays for 230 kV lines that are obsolete and not compliant with Hydro's current standards. Upgrades to existing relays are also planned for generator protections that are 10 to 20 years old to make them compliant with Hydro's current standards.

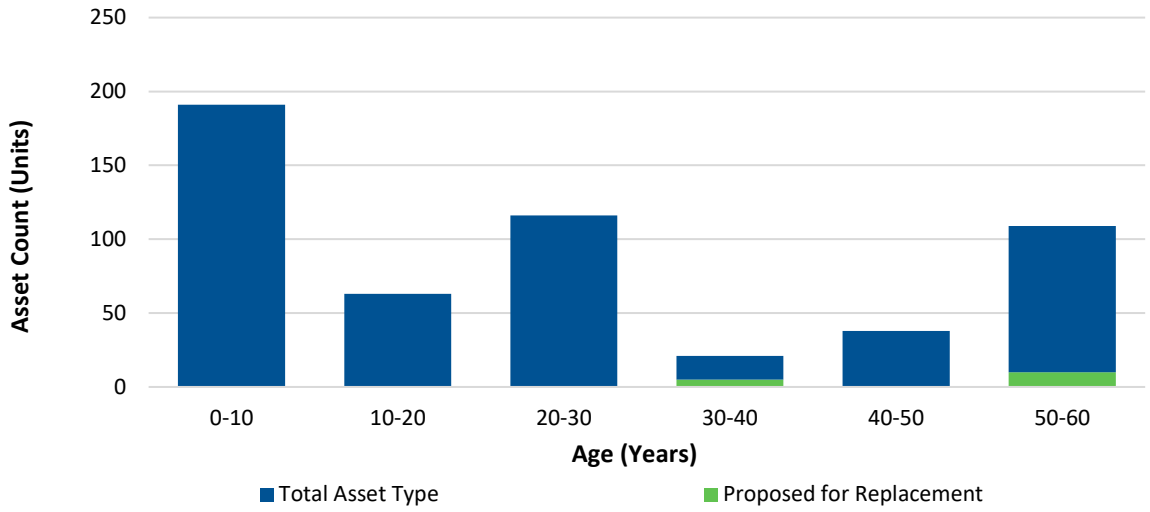


Chart 1: Asset Counts by Asset Age[3]

4.0 Trending

Hydro's Asset Management staff maintains a list of in-service protective relays categorized by voltage class, equipment (i.e., type of protection—transmission line, feeder, transformer, bus, etc.), protection system (i.e., distance, overcurrent, differential, primary, secondary, backup, etc.), main relay model number (i.e., auxiliary relays are not tracked), and age. This is the basis for planning program replacements/upgrades.

4.1 Assets Installed/Replaced/Upgraded

Chart 2 provides the five-year historical, current, and five-year forecast number of installations, replacements, or upgrades of protective relays per year. The number of installations in 2019 was higher

[3] Chart 1 represents relays for which the age is known or estimated. There is an ongoing multi-year effort to identify their year of manufacture to support these estimates.

than typical due to the number of installations that carried over from 2018. The program was then paused in 2020 to complete installations through 2020 and 2021 that had carried over from previous years. This resulted in fewer installations in 2021. The number of installations in 2023 was deliberately planned to be lower due to execution constraints; however, a reduction in installations is not sustainable, and therefore this number is expected to be higher through 2028.

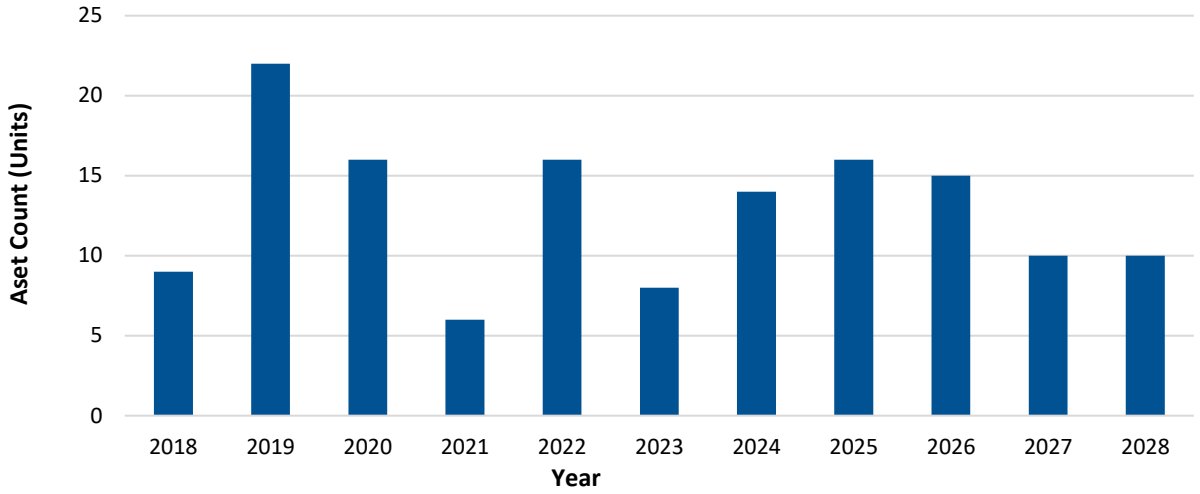


Chart 2: Historical and Forecast Assets Installed/Replaced/Upgraded

4.2 Historical and Forecast Average Unit Costs

Chart 3 shows the five-year historical, current, and five-year forecast average unit cost of installations, replacements, or upgrades of protective relays in each year. The average cost for 2021 is high compared to other years because two out of six protection replacements in 2021 were for transmission lines.[4] The average cost for other years, where more protections were completed overall, is more reflective of a typical mix of protection types.

[4] Transmission lines typically have higher costs than other types of protection (i.e., transformers, buses, feeders) due to their complexity and the associated increased engineering and construction efforts required.

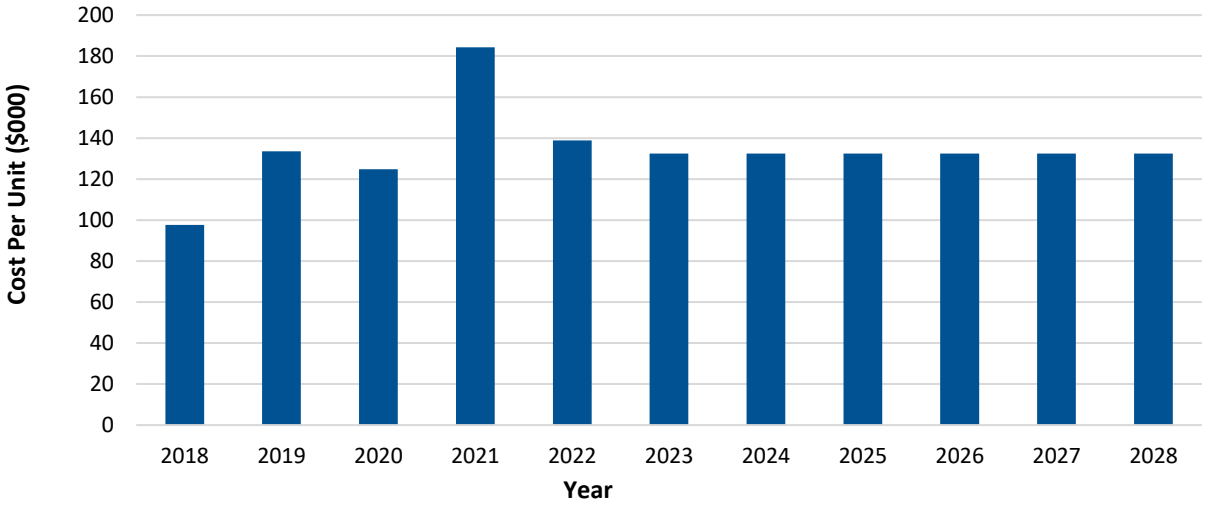


Chart 3: Average Unit Costs of Assets Installed/Replaced/Upgraded

5.0 Historical Reliability

Hydro does not record protective relay outage statistics; therefore, Hydro is unable to provide this data at this time.

6.0 Analysis

6.1 Evaluation of Alternatives

The following alternatives were considered:

- Pace reduction;
- Pace advancement; and
- Continue program at current pace.

6.1.1 Pace Reduction

The protective relays that are proposed for replacement have been identified as obsolete or not compliant with Hydro's current standards. Hydro has developed the replacement program, which was initiated in 2016, considering system criticality and ability to execute along with resource and outage constraints. In 2019, it was discovered that the pace was causing problems due to resource and outage concerns. To reduce the pace, Hydro did not submit a Replace Protective Relays program in 2020 and updated its long-term plan to appropriately align the scope within each year. Hydro feels its current plan is a balance between resource and outage constraints while ensuring the reliable operation of

protective relays. Deferral of this work any further will increase the risk of relay misoperation and is not a viable alternative.

6.1.2 Pace Advancement

Pace advancement is not a viable option due to resource and outage availability concerns.

6.1.3 Continue Program at Current Pace

The protective relay replacements as identified in a planned, strategic manner as outlined in this proposal are prudent. This approach enables Hydro to complete these upgrades to support its mandate to provide safe, least-cost, reliable service in an environmentally responsible manner.

6.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

6.3 Recommended Alternative

Hydro recommends proceeding with the proposed protective relay replacements.

6.3.1 Risk of Asset Stranding

For the majority of the assets included within this program, there is no undue risk that these capital additions will be stranded before their useful life has been reached, as there are no plans to retire any existing terminal stations.

This program does include upgrades to generator protective relays at the Holyrood Thermal Generating Station ("Holyrood TGS"). These upgrades were deferred in the past due to asset stranding risks associated with the anticipated retirement dates of Units 1 and 2 in 2024; however, the risk of asset stranding is less imminent as a result of the decision to extend Holyrood TGS to remain available through the Bridging Period.[5] As Hydro expects continued operation of all three units at the Holyrood TGS during the Bridging Period, capital expenditures for this facility to operate as a generator continue to be required, and these replacements can no longer be deferred. In consideration of the

[5] As per the "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, Hydro considers the Bridging Period to be from 2023 to 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

limited life remaining for Units 1 and 2, Hydro is proposing to upgrade the existing generator protection system rather than replace the generator protection relays.

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	4	3	**12**
Post-Execution	4	1	**4**
		Risk Mitigated	**8**
		Risk Mitigated per $1 Million	**2.3**

7.0 Scope of Work

Hydro's five-year plan for the Replace Protective Relays program is provided in Appendix A.[6] Based on current conditions and asset data, Hydro plans to replace 16 different protection systems located within terminal stations and generating stations under this program, with completion scheduled by the end of 2025. Based on asset condition and outage and resource availability at the time of execution, Hydro may advance or defer the replacement of specific assets to ensure efficient and effective implementation of this program.

Hydro will also refurbish or replace protection and control panels, wiring, cables, auxiliary relays, or trenches as required due to deterioration from environmental conditions, accidental damage, or the modification/addition of protection and control equipment required for the relay replacements.

[6] Replacement of line or transformer protection may involve replacement of multiple protective relays.

7.1 Program Budget

The estimate for the 2024–2025 program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	304.7	465.5	0.0	**770.2**
Labour	929.4	1,306.0	0.0	**2,235.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	28.4	45.7	0.0	**74.1**
Interest and Escalation	62.7	142.6	0.0	**205.3**
Contingency	63.2	90.9	0.0	**154.1**
Total	**1,388.4**	**2,050.7**	**0.0**	**3,439.1**

Chart 4 shows the five-year historical expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028. The actual expenditures and budget for the protective relay program vary, due to the variation in the number of relays installed and the average cost from year-to-year.

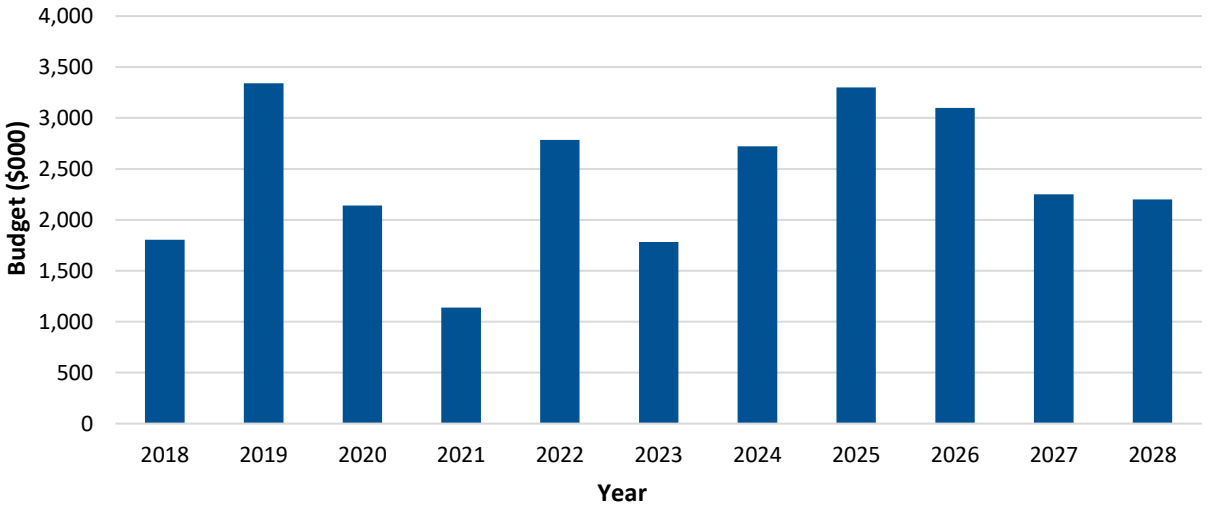


Chart 4: Historical and Forecast Program Budget

7.2 Program Schedule

The schedule for the 2024–2025 program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Initial planning and scheduling.	January 2024	March 2024
Design:		
Prepare drawings and settings.	February 2024	September 2025
Procurement:		
Order relays and long lead items.	February 2024	April 2025
Construction/Commissioning:		
Holyrood TGS protection upgrades.	April 2024	August 2024
Other protection upgrades.	April 2025	November 2025
Closeout:		
Completion of closeout documentation.	November 2025	December 2025

8.0 Conclusion

The work identified within this program is required to replace aging, non-standard, or obsolete equipment to allow Hydro to continue to provide safe, reliable, least-cost electricity in an environmentally responsible manner. The replacements are based upon assessments of the in-service equipment, as per the strategies detailed in Hydro's Asset Management Overview. Hydro recommends completing these upgrades and replacements to ensure that protective relays will operate when required to protect electrical equipment during abnormal operating conditions.

Appendix A

Replace Protective Relays Program

2024–2028 Plan



Assets planned for replacement from 2024 to 2028 under the Replace Protective Replays program are provided in Table A-1 to Table A-5.

Table A-1: Assets Planned for Replacement in 2024

Name	Voltage of Protected Equipment (kV)
Buchans Transmission Line TL205	230
Come By Chance Transmission Line TL237	230
Granite Canal Transformer T1	230
Granite Canal Unit G1	13.8
Hardwoods Transformer T2	230
Hawke's Bay Transmission Line TL221	69
Howley Transmission Line TL251	69
Stony Brook Transmission Line TL205	230
Sunnyside Transformer T4	230
Sunnyside Transmission Line TL212	138
Wabush Terminal Station Feeder IOC 5	46
Western Avalon Transmission Line TL237	230

Table A-2: Assets Planned for Replacement in 2025

Name	Voltage of Protected Equipment (kV)
Buchans Transmission Line TL228	230
Buchans Transmission Line TL232	230
Churchill Falls Bus B25B26	230
Come By Chance Transformer T1	230
Come By Chance Transformer T2	230
Grand Falls Frequency Converter Transformer T1	230
Grand Falls Frequency Converter Transformer T2	230
Holyrood Unit U1 and Transformer T1	230
Holyrood Unit U2 and Transformer T2	230
Indian River Transmission Line TL224	138
Massey Drive Transmission Line TL228	230
Massey Drive Transformer T1	230
Massey Drive Transformer T2	230
Massey Drive Transformer T3	230
Stony Brook Transmission Line TL232	230
Western Avalon Transformer T5	230

Table A-3: Assets Planned for Replacement in 2026

Name	Voltage of Protected Equipment (kV)
Berry Hill Transmission Line TL227	69
Buchans Transmission Line TL232	230
Cat Arm Transformer T2	230
Deer Lake Transformer T2	230
Hardwoods Transformer T1	230
Massey Drive Transformer T2	230
Oxen Pond Transformer T2	230
Sunnyside Transmission Line 100L	138
Sunnyside Bus B1	230
Sunnyside Transmission Line TL219	138
Stony Brook Bus B1B2	230
Stony Brook Transmission Line TL235	230
Wabush Terminal Station Transformer T7	230
Western Avalon Bus B1	230
Western Avalon Transformer T3	230

Table A-4: Assets Planned for Replacement in 2027

Name	Voltage of Protected Equipment (kV)
Cat Arm Unit G1	13.8
Deer Lake Bus B2	69
Deer Lake Bus B3	230
Hardwoods Transformer T4	230
Stony Brook Bus B3	138
Stony Brook Transmission Line TL210	138
Sunnyside Transmission Line 100L	138
Sunnyside Transmission Line 109L	138
Wabush Terminal Station Transmission Line L6	46
Wabush Terminal Station Transformer T8	230

Table A-5: Assets Planned for Replacement in 2028[1]

Name	Voltage of Protected Equipment (kV)
Cat Arm Unit G2	13.8
Come By Chance Bus B1	230
Come By Chance Bus B2	230
Massey Drive Transmission Line TL248	230
Unidentified Job 1	Unknown
Unidentified Job 2	Unknown
Unidentified Job 3	Unknown
Unidentified Job 4	Unknown
Unidentified Job 5	Unknown
Unidentified Job 6	Unknown

[1] Hydro anticipates that approximately six additional jobs will be identified for inclusion in the Replace Protective Relays (2028) program, as there are at least six not-yet-planned jobs that meet the criteria for inclusion.

Upgrade Worst-Performing Distribution Feeders (2024–2025)

July 2023

newfoundland labrador hydro

Upgrade Worst-Performing Distribution Feeders (2024–2025)

Location: L'Anse-au-Loup, Line 2

Investment Classification: Service Enhancement

Asset Category: Distribution

Executive Summary

This program includes the refurbishment of a distribution feeder located in the L'Anse-au-Loup Distribution System, which has been prioritized through the examination of reliability performance data and confirmed as requiring upgrades to the existing infrastructure based on recent condition assessments. The 2024–2025 scope of this program is required to improve the reliability of the L'Anse-au-Loup Line 2 ("LAL-L2") feeder.

The LAL-L2 feeder was selected for an upgrade at this time due to its five-year average performance in three key reliability indices—SAIDI,[1] SAIFI,[2] and CHI.[3] Additionally, an assessment of its condition indicates that it requires upgrades at this time.

Newfoundland and Labrador Hydro ("Hydro") considered several options, including deferral of this program for a year, installation of a new feeder, and upgrading the existing equipment. Deferral of this program would create a growing backlog of deficiencies that would present an increased risk to distribution system reliability, which could potentially impact customer service and negatively impact future costs. Installing a new feeder would necessitate a level of investment that is not required for the continuation of the reliable provision of electricity. Hydro determined that upgrading the existing feeder is the best alternative to balance cost and reliability.

[1] System Average Interruption Duration Index ("SAIDI"). SAIDI indicates the System Average Interruption Duration Index for customers served per year, or the average length of time a customer is without power in the respective distribution system per year. This index is calculated excluding loss of supply outages, planned outages, customer requests, and major events.
[2] System Average Interruption Frequency Index ("SAIFI"). SAIFI is the System Average Interruption Frequency Index per year, which indicates the average of sustained interruptions per customer served per year, or the average number of power outages a customer has experienced in the respective distribution system per year. This index is calculated excluding loss of supply outages, planned outages, and customer requests.
[3] Customer-Hours of Interruption ("CHI") is the sum of the products of the outage duration multiplied by the number of customers affected during the outage for each event within a one-year period. This index is calculated excluding loss of supply outages, planned outages, customer requests, and major events.

Hydro proposes to upgrade LAL-L2 by replacing all non-standard or deteriorated insulators, conductors, poles, structures, and associated hardware. Hydro will also install mid-span poles, in-line and storm guy wires, airflow spoilers, fused switches, fault circuit indicators, and a three-phase recloser.

This program has a multi-year approach, with completion planned in 2025 at an estimated cost of $3,291,700.

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List of Appendices

Appendix A: Worst-Performing Feeder List and Summary of Data Analysis

1.0 Introduction

Hydro owns and operates distribution systems in the rural communities it serves. Each distribution system typically consists of a substation coupled with wood pole distribution feeder(s) that supply power from the substation to service drops throughout a community. Historically, Hydro used a condition-based assessment approach to identify components of its distribution systems that needed to be refurbished to ensure reliable operation, which is now included under Hydro's Renew Distribution Feeders program. Since 2019, Hydro has also been prioritizing the refurbishment of distribution feeders that have poor reliability performance. The Upgrade Worst-Performing Distribution Feeders (2024–2025) program includes the refurbishment of a distribution feeder located in the L'Anse-au-Loup System, which has been prioritized through the examination of reliability performance data and confirmed as requiring upgrades to the existing infrastructure based on recent condition assessments.

2.0 Program Description and Justification

Work proposed under Hydro's Upgrade Worst-Performing Distribution Feeders program is prioritized based on five-year average reliability indices: SAIDI, SAIFI, CHI, CHIKM,[4] and CIKM[5]. These metrics are used independently of each other and are intended to identify trending reliability issues. Hydro then uses condition assessment information to validate the issues identified through these indices to finalize the scope of work required to upgrade the system effectively.

SAIDI and SAIFI represent the reliability performance of a distribution feeder based on the impact outages have on that feeder's customers. One of the drawbacks of selecting feeders based on the SAIDI or SAIFI method alone is that it considers the feeder-level indices and does not consider the impact the feeder has on overall distribution system reliability indices. SAIFI can be improved by reducing the number of interruptions and SAIDI can be improved by reducing the duration of these interruptions, and both of these reflect reliability improvements. Hydro examines the distribution feeders based on CHI value as well. CHI measures feeder reliability based on the impact the feeder has on overall reliability indices. CHI value tends to be higher for the feeders serving a large number of customers. Feeders with

[4] Customer Hours of Interruption per Kilometre ("CHIKM") is calculated by dividing the number of customer-outage-hours by the kilometres of feeder. This index is calculated excluding loss of supply outages, planned outages, customer requests, and major events.

[5] Customers Interrupted per Kilometre ("CIKM") is calculated by dividing the number of customers that have experienced an outage by the kilometres of feeder. This index is calculated excluding loss of supply outages, planned outages, and customer requests.

an elevated CHI value are further analyzed to identify the asset condition, performance, and associated customer impact. While Hydro does not prioritize one reliability metric over another, in instances where feeders have similar performance based on SAIDI and SAIFI, Hydro will consider CHI to target reliability improvements that will provide the largest benefit to the greatest number of customers.

In 2022, Hydro added two additional indices to its reliability analysis for this program—CHIKM and CIKM. CHIKM and CIKM represent the reliability performance of a distribution feeder based on the circuit length. These indices tend to identify problematic feeders with shorter lengths. Due to the length of the LAL-L2 feeder, the CHIKM and CIKM indices are not relevant and have been removed from this report to simplify the analysis.

Hydro's worst-performing feeder lists by reliability metric and a summary of data analysis are provided in Appendix A. Table A-1 to Table A-3 show feeder ranking by reliability metric and Table A-4 shows the analysis summary.

The top 20 worst-performing feeders on each list are analyzed to identify the root cause of the poor performance. This includes a review of current inspection data, overall system design, work completed on past capital projects, other line dependants, and a site visit to both confirm data collected and collect additional asset information. Once the assessment is completed, Hydro selects the capital work that will improve the reliability of the distribution feeder, which is justified by inspection data and feeder assessment. For example, if an issue causing poor performance was due to an isolated incident or was recently addressed by other capital work, Hydro would not undertake any capital work and the feeder is identified for continued monitoring.

Hydro's most recent analysis of worst-performing distribution feeders has identified LAL-L2 as requiring upgrades. LAL-L2 is included as one of Hydro's worst-performing feeders from the perspective of all three reliability metrics—SAIDI, SAIFI and CHI, as shown in Appendix A. These results have been validated based on a recent field assessment of the feeder's condition.

Hydro notes that there are other feeders shown on the SAIDI, SAIFI, and CHI lists in Appendix A that are higher or close in priority to the ranking for LAL-L2; however, these have been excluded from the selection process for capital work for the following reasons:

- Capital work has already been completed or is in progress. As the indices are based on five-year performance data, these feeders will continue to be monitored for performance. Examples of these include Farewell Head Line 1, Barachoix Line 1 and Line 4, Bottom Waters Line 1, and Fleur-de-Lys Line 1.
- The majority of outages are the result of encroaching vegetation issues and not any specific line components. This is typically dealt with through Hydro's ongoing vegetation management program. Examples of these include Jackson's Arm Line 2 and Happy Valley Line 7.
- The majority of outages are the result of failures on larger equipment such as metering tanks, reclosers, power transformers, voltage regulators, etc. These items are being assessed independently and will continue to be monitored.
- The majority of outages are the result of isolated issues and/or prolonged power outages due to remote access. These feeders will continue to be monitored for performance. Examples of these include Black Tickle Line 1 and Happy Valley Line 15.
- The inspections do not yield adequate data to investigate the true source of the reliability issue. This requires additional monitoring to ensure that reliability improvement efforts are being directed at the source of the issues. Additional field investigation is required before a capital project can be proposed to improve reliability. An example of this includes English Harbour West L1.

3.0 Asset Overview

3.1 Asset Background

LAL-L2 is a three-phase, 25 kV distribution feeder that originates from the L'Anse-au-Loup Substation. It is connected to Hydro-Québec through L'Anse-au-Loup Line 1. System energy is supplied through Hydro's diesel generating station in L'Anse-au-Loup and imported energy from Hydro-Québec. This feeder services approximately 616 customers, including a fish plant. The location of LAL-L2 is shown in Figure 1 and Figure 2.

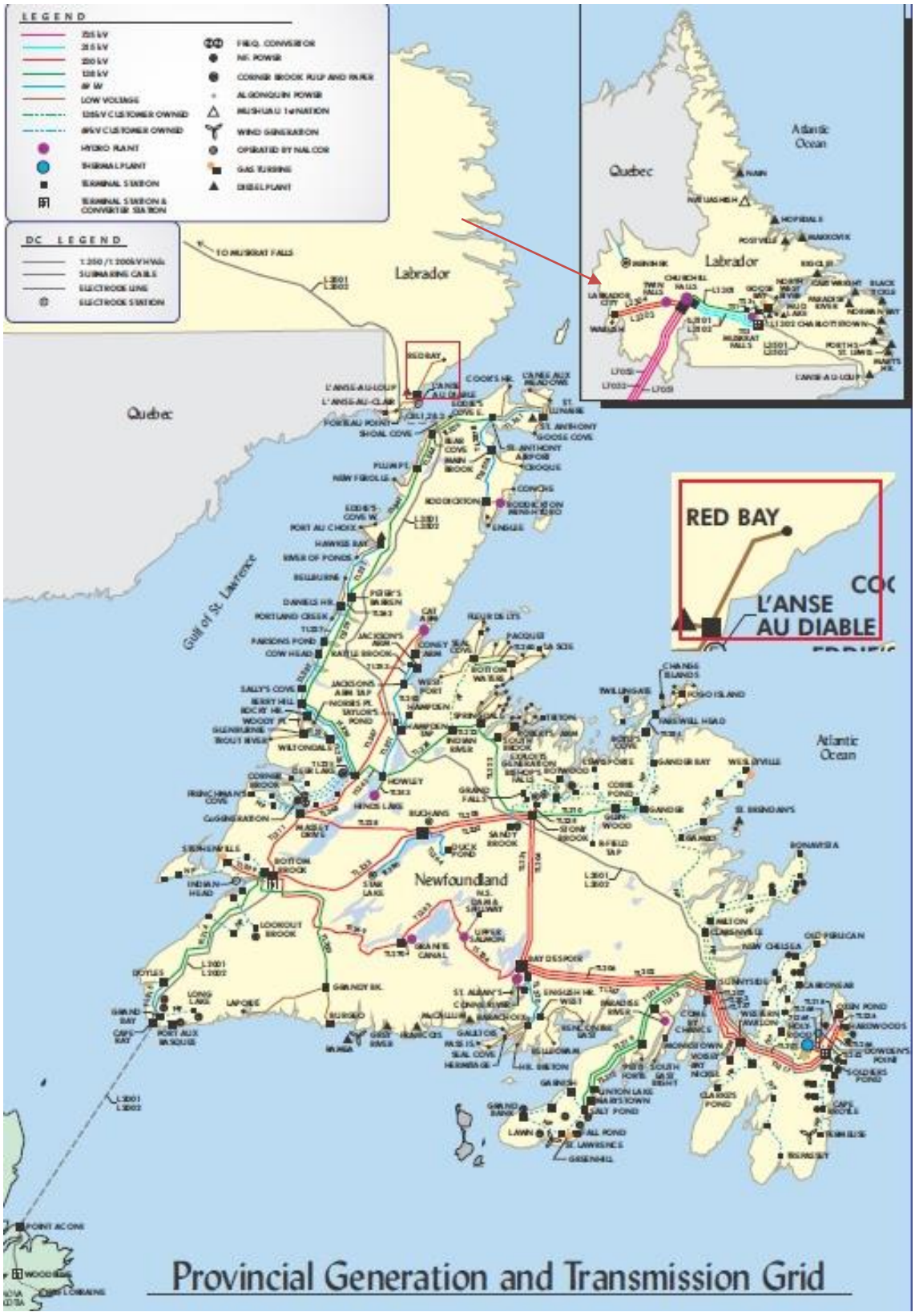


Figure 1: Location of LAL-L2

LAL-L2 runs from the L'Anse-au-Loup Substation for approximately 12 kilometres along the Trans-Labrador Highway, Route 510, as a three-phase overhead feeder supplying customers in the communities of L'Anse-au-Loup, L'Anse-au-Diable, Capstan Island, and West St. Modeste. The line continues approximately 5 kilometres along Route 510 as a two-phase feeder, supplying customers in the community of Pinware. The line then extends approximately 35 kilometres along Route 510 as a single-phase circuit, supplying power to the community of Red Bay.



Figure 2: Layout of LAL-L2

3.2 Asset Condition

Insulators on several sections of LAL-L2 have insufficient creepage distance for operation in high levels of salt contamination area.

When salt and ice build up on insulators it creates a contamination layer, resulting in leakage current from the conductor to the insulator base. Over time, this condition results in a flashover event and equipment failures. Therefore, the replacement of those problematic insulators with higher creepage distance units is necessary. Figure 3 shows deteriorated insulators on LAL-L2 that exhibit signs of flashover.



Figure 3: Damaged Insulators, LAL-L2

A field survey has identified several deteriorated poles on this feeder that require replacement. In the past, broken pole incidents on this feeder have caused prolonged power outages. Due to the location and deteriorating condition of the structures, this feeder is becoming more prone to damage when exposed to heavy winds, ice, and snow loading. It has also been identified that this feeder has several long-span structures, which are required to be addressed by installing mid-span poles to eliminate the risk of line component failure. In addition, sections of the feeder are located at high elevations and experience performance issues due to severe ice loading. Therefore, the installation of inline and storm guy wires in those highly elevated areas is required to reduce structural damage risk. Figure 4 shows a picture of a LAL-L2 pole, damaged by a severe icing event in 2022.



Figure 4: Damaged Pole in Red Bay, 2022

On the two-phase circuit servicing the community of Pinware, the feeder experiences phase-to-phase conductor clearance issues, resulting in recloser trip events. As a result, this section of LAL-L2 must be restructured and/or replaced with higher poles to mitigate clearance problems. Figure 5 shows a structure in Pinware with a clearance issue and the proposed mitigation plan.



Figure 5: Structure with clearance issue, Pinware

LAL-L2 also experiences conductor galloping in open areas, particularly the two-phase section, which can result in power outages. Hydro proposes to install airflow spoilers on the conductor span in problematic areas of LAL-L2 to reduce galloping.

The primary line of this feeder has sections of #2 ACSR,[6] which is non-standard and prone to failure. ACSR is not recommended for saltwater environments because of the potential for excessive corrosion caused by oxidization between the steel core and the aluminum outer strands. The sections of non-standard conductors, a length of approximately 30 kilometres, require replacement.

As a result of the deteriorated or substandard components on LAL-L2, the feeder's reliability performance is below Hydro's average reliability performance for distribution feeders, as detailed in Section 5.0.

[6] Aluminum-conductor steel reinforced ("ACSR").

LAL-L2 feeder has several taps without any fuse protection. Installation of fused disconnect switches will help to isolate any local faults on these taps and reduce the number of affected customers.

LAL-L2 is a lengthy radial feeder with an approximately 52-kilometre-long circuit. The beginning of this feeder near the L'Anse-au-Loup substation is protected by a three-phase recloser with the next single-phase recloser approximately 12 kilometres away. The majority of the customer load is located amid these reclosers. When a fault occurs between the two reclosers, the operation of the L'Anse-au-Loup substation recloser results in an outage to all the customers supplied by LAL-L2; therefore, another three-phase recloser should be installed. In the event of a fault downstream of the new recloser, this will reduce both the number of affected customers and the outage duration time. The proposed location of the recloser is provided in Figure 6. In addition to the recloser, fault circuit indicators should be installed on this long radial circuit to minimize outage durations. This will improve power restoration time by allowing crews to locate faults and isolate faulted sections faster.

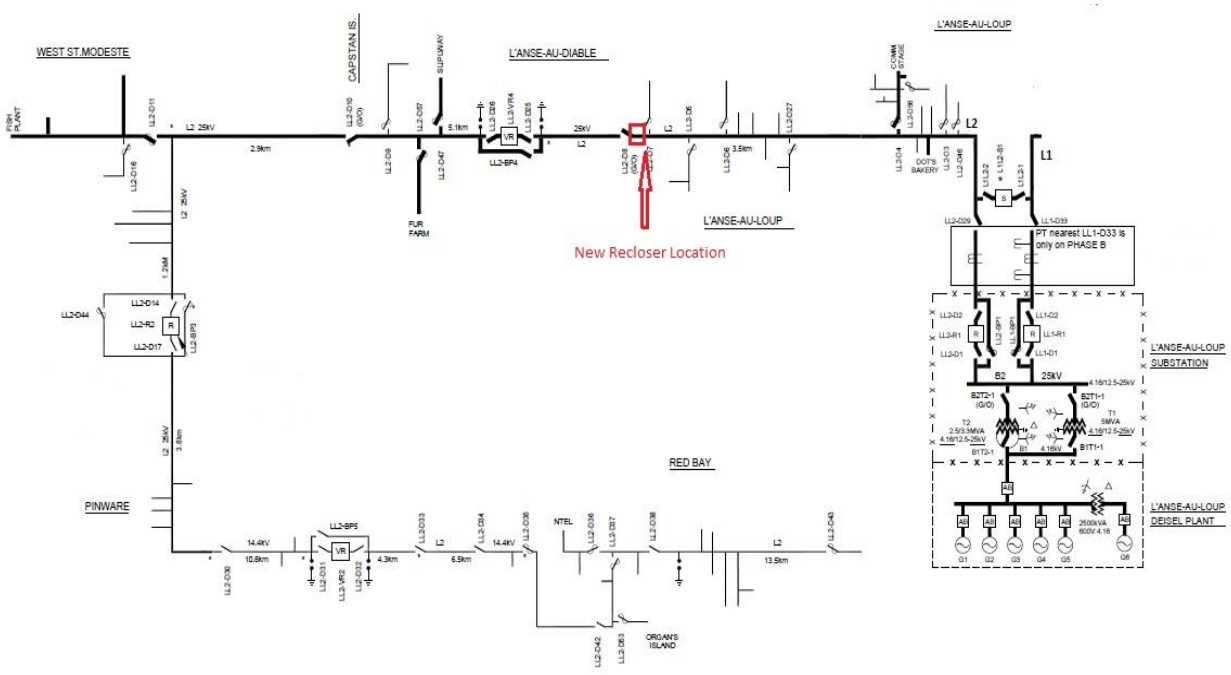


Figure 6: New Recloser Location

3.3 Asset Ages

The feeders covered under this program have numerous types of assets. The age of assets varies as the feeders are continuously updated through planned and unplanned replacement or refurbishment activities. The LAL-L2 feeder has some assets dating back to the 1960s.

3.4 Condition-Based Remaining Life

The assets to be replaced under this program have failed, are nearing the point of failure, or are obsolete; as such, they have reached the end of their remaining useful life. The remaining line components not addressed under this program are considered to be in adequate to good condition and have expected remaining useful lives ranging from 6 years (until the next preventive maintenance cycle) to 20 years or more.

4.0 Trending

The scope of work executed within the Upgrade Worst-Performing Feeders Program varies significantly each year based on the specific issues identified on the feeders to be addressed. Hydro has not tracked the number of individual assets installed or upgraded within this program; therefore, trending is not currently available for this program.

5.0 Historical Reliability

Table 1 provides the reliability data for LAL-L2 as well as a comparison to Hydro's average, which indicates that this feeder has performed poorly relative to the Hydro average SAIDI, SAIFI, and CHI.

Table 1: Five-Year Average Reliability Data for LAL-L2 (2018–2022)

Location	SAIDI	SAIFI	CHI
LAL-L2	10.46	3.62	6,429
Hydro Average	4.41	1.79	1,286[7]

A feeder assessment completed in 2023 identified that the reliability experienced by the customers serviced by this feeder during the 2018–2022 period was impacted by equipment failures, such as insulator failures, broken poles, and broken conductor incidents. Salt contaminations and line slaps from wind also contributed to poor reliability.

6.0 Analysis

Hydro considered the following alternatives:

- Pace reduction;

[7] Hydro Average CHI represents the average number of Customer Hours of Interruption per feeder. It is calculated by dividing the number of total customer-outage-hours by the number of distribution feeders.

- Continue program at current; and
- Contruct new feeder.

6.1 Evaluation of Alternatives

6.1.1 Pace Reduction

If the pace of this program were to be reduced, upgrade work would be deferred to a future year. This would create a growing backlog of deficiencies that would negatively impact future costs and present an increased risk to distribution system reliability, potentially resulting in increased costs associated with unplanned work or outage response. Therefore, pace reduction is not a viable option.

6.1.2 Continue Program at Current Pace

Continuation of this program at the current pace ensures that feeders identified as having poor reliability performance, and are found to be candidates for capital intervention, are addressed in a timely manner, thus avoiding excessive customer outages and associated costs related to unplanned work or outage response.

6.1.3 Construct New Feeder

Hydro has considered constructing a new feeder; however, LAL-L2 is approximately 52 kilometres long and approximately 54% of the poles are less than 43 years old.[8] Other existing feeder components are still in operable condition, such as conductors, insulators, and crossarms. The complete replacement of the existing feeder requires a level of investment that is not required for the continuation of reliable service and is not considered a viable option.

6.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

6.3 Recommended Alternative

Hydro proposes the continuation of this program at the current pace, with the upgrade of LAL-L2 beginning in 2024.

[8] Hydro uses 43 years as the anticipated useful or economic life for its distribution wood poles.

6.3.1 Risk of Asset Stranding

Hydro does not anticipate a change in service requirements in this area; therefore, the risk of asset stranding is low.

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 2.

Table 2: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	2	4	**8**
Post-Execution	2	2	**4**
		Risk Mitigated	**4**
		Risk Mitigated per $1 Million	**1.2**

7.0 Scope of Work

An overview of the work to be completed under this program beginning in 2024 is as follows:

- Install approximately 98 poles to address deteriorated poles, long spans, and clearance issues;
- Replace all non-standard or deteriorated conductors, approximately 30 kilometres;
- Install center phase on crossarm of approximately 64 two-phase structures;
- Replace all deteriorated insulators;
- Install inline and storm guy wires;
- Install a three-phase recloser; and
- Install airflow spoilers, fused disconnect switches, and fault circuit indicators.

7.1 Program Budget

The estimate for the 2024–2025 program is shown in Table 3.

Table 3: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	195.6	670.9	0.0	**866.5**
Labour	203.3	1050.4	0.0	**1,253.7**
Consultant	0.0	50.0	0.0	**50.0**
Contract Work	472.9	2.5	0.0	**475.4**
Other Direct Costs	29.2	7.2	0.0	**36.4**
Interest and Escalation	73.2	268.3	0.0	**341.5**
Contingency	90.1	178.1	0.0	**268.2**
Total	**1,064.3**	**2,227.4**	**0.0**	**3,291.7**

Chart 1 shows the historical expenditures since the program was initiated, the forecast 2023 expenditures, the proposed 2024 budget, and the forecast costs through 2028. Hydro began the program in 2019, with construction activities commencing in 2020. The 2020 budget included construction activity on three feeders.

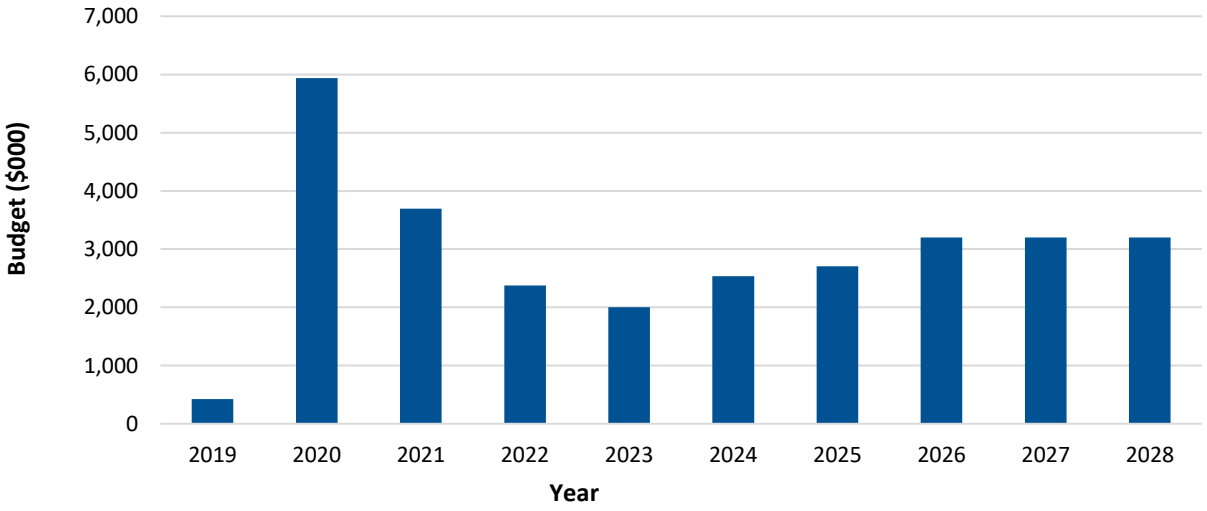


Chart 1: Historical and Forecast Program Budget

7.2 Program Schedule

The anticipated schedule for the 2024–2025 program is shown in Table 4.

Table 4: Program Schedule

Activity	Start Date	End Date
Planning:		
Resource planning.	January 2024	January 2025
Design:		
Conduct site visits and detailed design.	January 2024	May 2025
Procurement:		
Order materials.	April 2024	May 2025
Construction:		
Construction.	July 2024	September 2025
Commissioning:		
Commissioning of refurbished work.	July 2024	September 2025
Closeout:		
Complete closeout documentation.	September 2025	November 2025

8.0 Conclusion

Hydro regularly executes larger feeder refurbishment and replacement work under this program to maintain or improve distribution system reliability performance. These larger upgrades are selected based on reliability performance analysis and condition assessments. This 2024–2025 program is required to improve the reliability of the LAL-L2 feeder.

Appendix A

Worst-Performing Feeder List and Summary of Data Analysis





Table A-1: Worst-Performing Feeders Sorted by SAIDI

Rank	Feeder	SAIDI
1	Jackson's Arm, Line 2	17.97
2	Farewell Head, Line 1	16.77
3	Barachoix, Line 1	16.68
4	Bottom Waters, Line 1	14.65
5	Black Tickle, Line 1	12.77
6	Barachoix, Line 4	11.54
7	Fleur-de-Lys, Line 1	11.44
8	L'Anse-Au-Loup, Line 2	10.46
9	English Harbour, Line 1	10.38
10	Happy Valley, Line 7	10.16
11	Bottom Waters, Line 3	8.37
12	Main Brook, Line 2	8.29
13	Cartwright, Line 1	8.03
14	Monkstown, Line 2	7.61
15	St. Anthony, Line 1	7.35
16	L'Anse-Au-Loup, Line 1	7.24
17	Kings Point, Line 1	7.08
18	Roddickton, Line 4	7.07
19	Bear Cove, Line 6	7.06
20	Farewell Head, Line 4	6.44

Table A-2: Worst-Performing Feeders Sorted by SAIFI

Rank	Feeder	SAIFI
1	Bottom Waters, Line 1	4.44
2	Barachoix, Line 4	3.81
3	Barachoix, Line 1	3.81
4	English Harbour, Line 1	3.76
5	Happy Valley, Line 15	3.62
6	L'Anse-Au-Loup, Line 2	3.62
7	Happy Valley, Line 7	3.50
8	Cartwright, Line 1	3.47
9	Jackson's Arm, Line 2	3.41
10	Roddickton, Line 4	2.80
11	Farewell Head, Line 6	2.80
12	Happy Valley, Line 6	2.68
13	Farewell Head, Line 4	2.63
14	Fleur-de-Lys, Line 1	2.63
15	Bear Cove, Line 6	2.61
16	Makkovik, Line 1	2.61
17	Farewell Head, Line 5	2.57
18	Black Tickle, Line 1	2.50
19	Farewell Head, Line 1	2.50
20	Nain, Line 1	2.43

Table A-3: Worst-Performing Feeders Sorted by CHI

Rank	Feeder	CHI
1	Happy Valley, Line 7	9,432
2	Barachoix, Line 4	9,374
3	Barachoix, Line 1	9,232
4	English Harbour, Line 1	8,341
5	L'Anse-Au-Loup, Line 2	6,429
6	Jackson's Arm, Line 2	5,272
7	Bear Cove, Line 6	4,870
8	St. Anthony, Line 1	4,792
9	Bottom Waters, Line 1	4,422
10	Hawke's Bay, Line 3	4,396
11	South Brook, Line 1	4,057
12	Kings Point, Line 1	4,010
13	Bay D'Espoir, Line 1	3,735
14	Farewell Head, Line 1	3,677
15	Farewell Head, Line 5	3,205
16	Roddickton, Line 1	3,196
17	L'Anse-Au-Loup, Line 1	3,039
18	Farewell Head, Line 6	2,908
19	Happy Valley, Line 16	2,682
20	Rocky Harbour, Line 1	2,665

Table A-4: Summary of Data Analysis[9]

Feeder	Summary
Barachoix, Line 1	This feeder experienced a significant outage in 2022 associated with a major ice storm. In 2020–2021, tree contacts impacted reliability. Overall reliability statistics on this feeder have been impacted by several broken primary conductors as well as hardware and equipment failure incidents. This feeder was upgraded as part of the 2019–2020 distribution system upgrades project and no capital work is required at this time.
Barachoix, Line 4	This feeder experienced a significant outage in 2022 associated with a major ice storm. Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents and other defective line hardware incidents. This feeder was upgraded as part of the 2019–2020 distribution system upgrades project and no capital work is required at this time.
Bay D'Espoir, Line 1	The majority of large outages on this feeder were related to birds building nests on top of distribution structures. Tree contacts in the past caused frequent outages but improved in 2022. No capital work is required at this time but this feeder will continue to be monitored.
Bear Cove, Line 6	The largest outages were caused by conductor failures and hardware failures. The upgrade project was completed in 2021 and no capital work is required at this time.
Black Tickle, Line 1	The customers of this feeder experienced power outage due to weather-related events or defective line hardware; however, the reliability of this feeder was mainly impacted by the remoteness of the site. The power outage was often extended due to remote access.
Bottom Waters, Line 1	Reliability statistics were impacted by tree contacts, broken insulators, and damaged conductor incidents. Work is being carried out on this feeder under the Upgrade of Worst Performing Distribution Feeders Program (2022–2023).
Bottom Waters, Line 3	Overall reliability statistics on this feeder have been impacted by several weather events, tree-related incidents, broken line component issues, and a faulty voltage regulator incident. Line upgrading work was completed on this feeder under the 2019–2020 Distribution System Upgrades project. Tree trimming was completed in 2018 and there was no tree contact incident in 2021-2022. The regulator bank was completely replaced in 2021. No work is required at this time.
Cartwright, Line 1	Poor reliability was driven by numerous power outages with no apparent cause and isolated events. Lightning incidents also impacted the feeder performance. Surge arrester installation on the entire system is being carried out in 2023. No capital work is required at this time but this feeder will continue to be monitored.

[9] Based on 2018–2022 data.

Feeder	Summary
English Harbour, Line 1	Poor reliability statistics were driven by several weather events, tree-related incidents, broken poles, and conductor failures. Recently, recloser/sectionalizer coordination work has been completed. No capital work is required at this time but this feeder will continue to be monitored.
Farewell Head, Line 1	This feeder reliability has been impacted by equipment failures, such as corroded switches, insulator failures, and broken conductor incidents in the 2018–2022 period. This feeder has many other problematic issues. Work is being carried out on this feeder under the Upgrade of Worst Performing Distribution Feeders Program (2023–2024).
Farewell Head, Line 4	Multiple incidents of broken primary conductors contributed to poor reliability statistics. This feeder was upgraded as part of the Upgrade of Worst Performing Distribution Feeders Program (2021–2022).
Farewell Head, Line 5	Poor reliability was driven by numerous line component issues. This feeder was upgraded as part of the under the Upgrade of Worst Performing Distribution Feeders Program (2021–2022).
Farewell Head, Line 6	Defective protection device events, broken insulator incidents and line slap impacted the reliability. Protection device repair is scheduled for the summer of 2023. No capital work is required at this time but this feeder will continue to be monitored.
Fleur-de-Lys, Line 1	Tree contacts and broken insulator incidents were the leading causes of outages in the 2018–2022 period. A recent joint-use request eliminated long spans. The 2021 upgrade project was completed by replacing deteriorated poles, crossarms, and feeder rerouting. No work is required at this time but this feeder will continue to be monitored.
Happy Valley, Line 15	Broken conductors and line slap were the largest outage causes. Human error during the Happy Valley Terminal Station project and the overloading of the line when tied together were significant. No capital work is required at this time but this feeder will continue to be monitored.
Happy Valley, Line 16	Human error and equipment overloading were significant issues from 2018 to 2022. No capital work is required at this time but this feeder will continue to be monitored.
Happy Valley, Line 6	Tree contacts were the only significant contributors to outages on this line. Tree cutting has been completed in 2022.
Happy Valley, Line 7	Poor reliability statistics were mainly driven by tree-related incidents. Tree trimming was completed recently. Other leading causes of outages were feeder overloading, metering tank failure and a broken crossarm. The metering tank was removed and the upgrading work for L7 loading has been completed in 2022.

Feeder	Summary
Hawke's Bay, Line 3	A broken pole incident in 2018 and a primary conductor failure incident in 2022 impacted the reliability statistics. No work is required at this time.
Jackson's Arm, Line 2	Poor reliability statistics were driven by mainly tree-related events. Tree trimming and ground cutting were completed in 2022 with additional work planned for 2023. No work is required at this time.
Kings Point, Line 1	Poor reliability statistics were principally driven by multiple tree-related incidents. Tree trimming and ground cutting were completed in 2022 with additional work planned for 2023. No work is required at this time.
L'Anse-Au-Loup, Line 1	Major outages to this feeder were caused by line component failures due to salt tracking. No capital work is required at this time but this feeder will continue to be monitored.
L'Anse-Au-Loup, Line 2	Overall reliability statistics on this feeder have been impacted by several insulator failures, broken conductors and broken pole incidents in the 2018–2022 period. Salt contamination and line slap from wind also contributed to the poor reliability. This feeder has many other problematic issues. A feeder assessment of this feeder has been completed recently and an upgrade of this feeder is recommended. Details are provided herein.
Main Brook, Line 2	Overall reliability statistics on this feeder have been impacted by several equipment and line component issues. However, this feeder performed well in 2021–2022. No work is proposed at this time.
Makkovik, Line 1	Poor reliability was driven by numerous power outages with no apparent cause and isolated events. No capital work is required at this time but this feeder will continue to be monitored.
Monkstown, Line 2	An isolated event of a broken primary conductor due to adverse weather significantly impacted the reliability. No work is required at this time.
Nain, Line 1	Poor reliability was driven by numerous power outages with no apparent cause and isolated events. No capital work is required at this time but this feeder will continue to be monitored.
Rocky Harbour, Line 1	A substation hardware failure incident in 2022 and a broken crossarm incident in 2018 impacted the reliability significantly. No capital work is required at this time.
Roddickton, Line 1	Poor reliability was driven by tree contacts, a failed voltage regulator, and broken primary conductor issues. The regulator has been replaced. No capital work is required at this time but this feeder will continue to be monitored.
Roddickton, Line 4	Poor reliability was driven by broken insulator issues. Work has been completed on this feeder to replace the insulators.

Feeder	Summary
South Brook, Line 1	Overall reliability statistics on this feeder have been impacted by trees falling across the line during wind/snowstorms. Recloser cold load pickup issues and burned recloser bypass switches were also significant causes. Switches were replaced in 2021 and recloser was upgraded in 2022. Tree trimming was completed previously. No capital work is required at this time.
St. Anthony, Line 1	Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents and a damaged insulator incident. No capital work is required at this time but this feeder will continue to be monitored.

Program 12

Renew Circuit Breakers (2024–2025)

July 2023

newfoundland labrador hydro



Renew Circuit Breakers (2024–2025)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") replaces or refurbishes failing or failed terminal station assets, including circuit breakers, to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

The circuit breakers selected for refurbishment and replacement in 2024 and 2025 are part of Hydro's long-term asset management plan for circuit breaker replacement and refurbishment. The circuit breakers proposed for refurbishment and replacement under this program were identified using a similar methodology as that reflected in Hydro's Terminal Station Asset Management Overview ("Asset Management Overview"), included as an Appendix to Schedule 1.[1]

This proposal is for the refurbishment and replacement of 69 kV class (including 46 kV), 138 kV, and 230 kV circuit breakers. The refurbishment and replacement of the identified circuit breakers is required to ensure system reliability, safety, and—in the case of the oil circuit breakers—compliance with federal environmental *PCB Regulations* related to removing polychlorinated biphenyls ("PCB").[2]

Hydro maintains two different types of circuit breakers— oil and SF_6—that operate at three voltage classes.[3]

Oil circuit breakers will be replaced to ensure compliance with federal environmental legislation. They will be replaced with sulphur hexafluoride ("SF_6") circuit breakers. The SF_6 circuit breakers identified for refurbishment are approximately halfway through their existing useful life or have been identified as

[1] Hydro proposed the activities within this program under the Terminal Station Renewal (2023–2024) program, filed as "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022, vol. II, prog. 3.
[2] The *Canadian Environmental Protection Act, 1999,* SC 1999, c 33 includes *PCB Regulations* (SOR/2008-273), which provide end-of-use dates for various concentrations of PCBs.
[3] The three voltage classes of circuit breakers are 66/69 kV, 138 kV and 230 kV. The 46 kV circuit breakers are in the same voltage class of equipment as 66/69 kV circuit breakers. Two 25 kV breakers require replacement due to the presence of PCBs and will be included in this cycle for operational efficiencies.

requiring refurbishment, based on their condition, to extend the life of the asset. Hydro currently plans to replace four breakers and refurbish six breakers within this 2024–2025 program.[4]

This program has a multi-year approach, with completion planned in 2025 at an estimated cost of $2,963,200.

[4] To avail of operational efficiencies, this cycle of the program includes the replacement of two 25 kV breakers due to the suspected presence of PCBs.

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Appendix A: Renew Circuit Breakers Program: 2024–2028 Plan

1.0 Introduction

Circuit breakers are critical components of the power system. Located in terminal stations, circuit breakers perform switching actions that are necessary to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of circuit breakers is essential to protect and maintain the stability of the power system.

2.0 Program Description and Justification

In line with Hydro's established plan for the replacement of circuit breakers, SF_6 circuit breakers will be refurbished after approximately 20 years of service and will be considered for replacement at or near 40 years. Hydro's long-term plan for circuit breakers is as follows:

- Replacement of oil circuit breakers by the end of 2025 to ensure compliance with federal environmental legislation;
- Refurbishment of SF_6 circuit breakers after 20 years of service; and
- Consideration of replacement of SF_6 circuit breakers after approximately 40 years of service, based on their condition at that time.

This program is required for Hydro to provide safe, reliable electrical service in an environmentally responsible manner. To comply with federal environmental *PCB Regulations*, oil circuit breakers will not be refurbished and are scheduled for replacement before December 31, 2025. To ensure the appropriate balance between cost and reliability for customers, Hydro is focused on optimizing the useful life of its in-service SF_6 circuit breakers. As such, refurbishment is typically scheduled after 20 years of service and replacement is considered at approximately 40 years of service, depending on the condition and operational history of the circuit breaker. For 2024, Hydro is proposing the refurbishment or replacement of ten breakers under this program.

3.0 Asset Overview

3.1 Asset Background

Hydro maintains two different types of circuit breakers— oil and SF_6—that operate at three voltage classes.

Each type of circuit breaker has unique operating characteristics. Oil circuit breakers extinguish the electrical arc created inside the circuit breaker using insulating oil. SF_6 circuit breakers use SF_6 gas as an insulating medium to extinguish electrical arcs created during switching.

Circuit breakers are comprised of two primary components:

1) Interrupting device, which includes the arc-quenching medium; and

2) Insulating material and the operating mechanism.

Oil circuit breakers and SF_6 circuit breakers are designed and constructed differently; as such, refurbishment requirements vary for each type of circuit breaker. The SF_6 circuit breakers typically require refurbishment at approximately 20 years (i.e., halfway through the expected useful life). Oil circuit breakers must be replaced rather than refurbished due to the federal environmental *PCB Regulations* requiring the removal of PCBs, which are contained in the bushings of oil circuit breakers.

As of the end of 2022, Hydro has 2 air-blast circuit breakers,[5] 209 SF_6 circuit breakers, and 18 oil circuit breakers in its 46 kV and above circuit breaker fleet. Within the circuit breaker fleet, Hydro has 37 circuit breakers in service that range from 40 to 60 years of age. A number of the circuit breakers within Hydro's system have been operational for more than 30 years, with a significant number nearing or having already surpassed the expected useful life of such assets.[6] The probability of circuit breaker failure increases with age.

3.2 Asset Condition

Asset condition for circuit breakers is defined by risk of failure and quantified in Table 1.

Table 1: Asset Condition for Circuit Breakers

Asset Condition Category	Risk of Failure
5	>90%
4	50-90%
3	10-50%
2	1-10%
1	1%

[5] The final two air-blast circuit breakers in Hydro's fleet are scheduled for replacement under the Upgrade Circuit Breakers (2022-2023) - Various, filed as "2022 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 17, 2021 (originally filed August 2, 2021), vol. II, tab 18, approved as per the *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 37(2021), December 20, 2021.

[6] Expected useful life is estimated to be 40 years.

In alignment with Hydro's current asset management philosophy, SF_6 circuit breakers have their condition assessed as the breaker approaches 40 years of age. As a result, the inclusion criteria for asset condition scoring in this section only includes SF_6 circuit breakers with an age of 35 years or greater. Breakers that are being refurbished at mid-life have not been included in the asset condition scoring, as this is strictly age-based. Chart 1 presents the asset condition categories for breakers with an age of 35 years or greater.

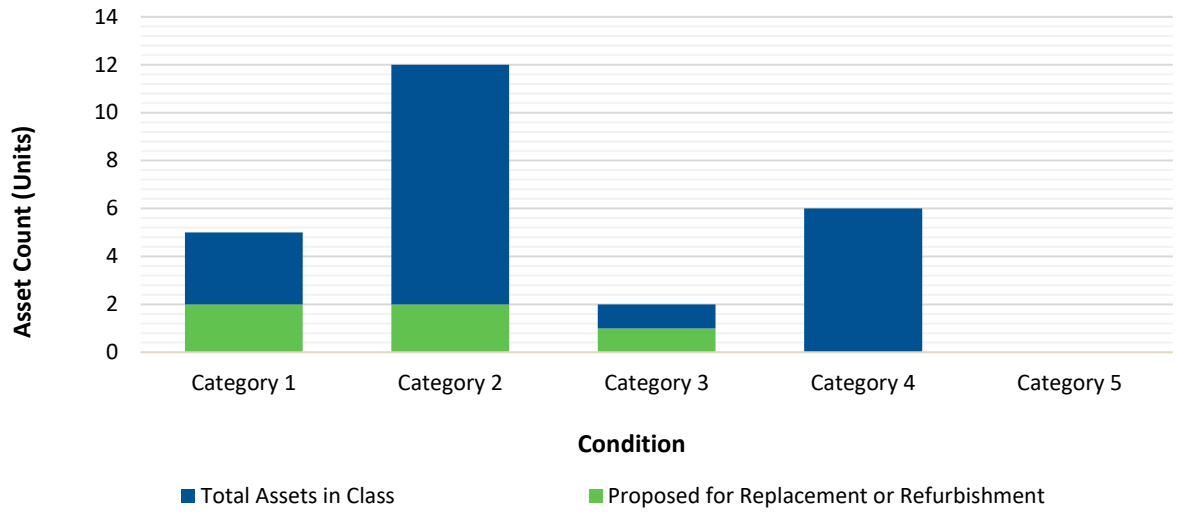


Chart 1: Asset Condition

It is noted that while this program is proposing the replacement or refurbishment of ten breakers in this 2024 program, only five breakers are of an age where they would be included in the asset condition assessment, as indicated in Chart 1. These five are planned for refurbishment to extend their service life an additional ten years as opposed to higher-cost replacements. Of the remaining five breakers, one is due for its 20-year overhaul and the other four must be replaced due to suspected PCB contamination.

3.3 Asset Ages

The age of the circuit breakers proposed for replacement or refurbishment as of 2023 is provided in Chart 2. Four breakers are being replaced and six breakers are being refurbished as part of the 2024 program. The breakers being refurbished are between 40 and 45 years old, with another due for its 20-year refurbishment in 2025. The breakers being replaced are 37 to 51 years old, with replacement required due to suspected PCB contamination.

Chart 2 provides the asset age for all assets covered under the 2024 program.

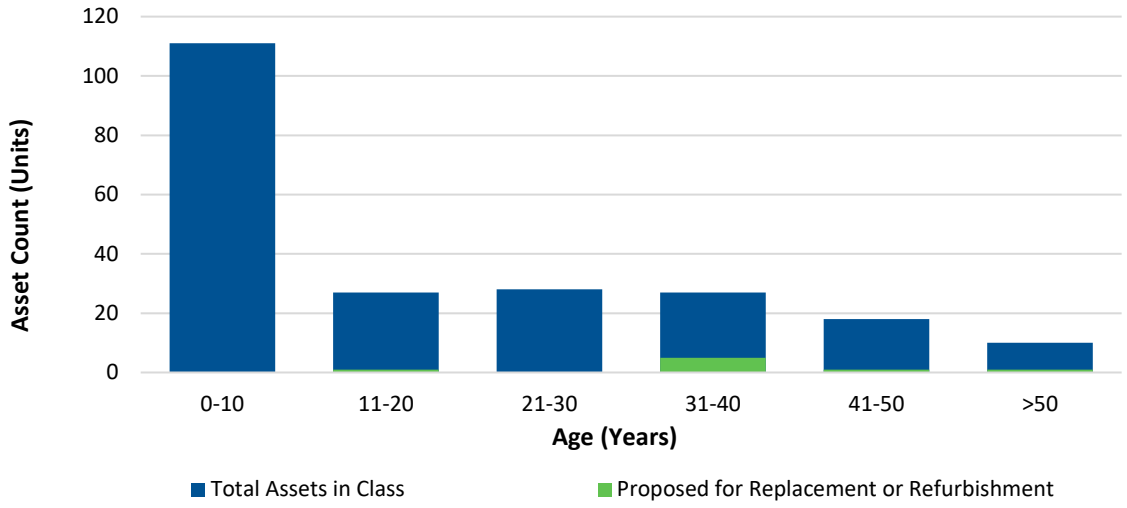


Chart 2: Asset Counts by Asset Age

4.0 Trending[7]

4.1 Assets Installed/Replaced/Upgraded

Under this program, breakers are refurbished or replaced based on age and condition. Chart 3 and Chart 4 provide the historical, current, and forecast assets to be replaced or refurbished, respectively.

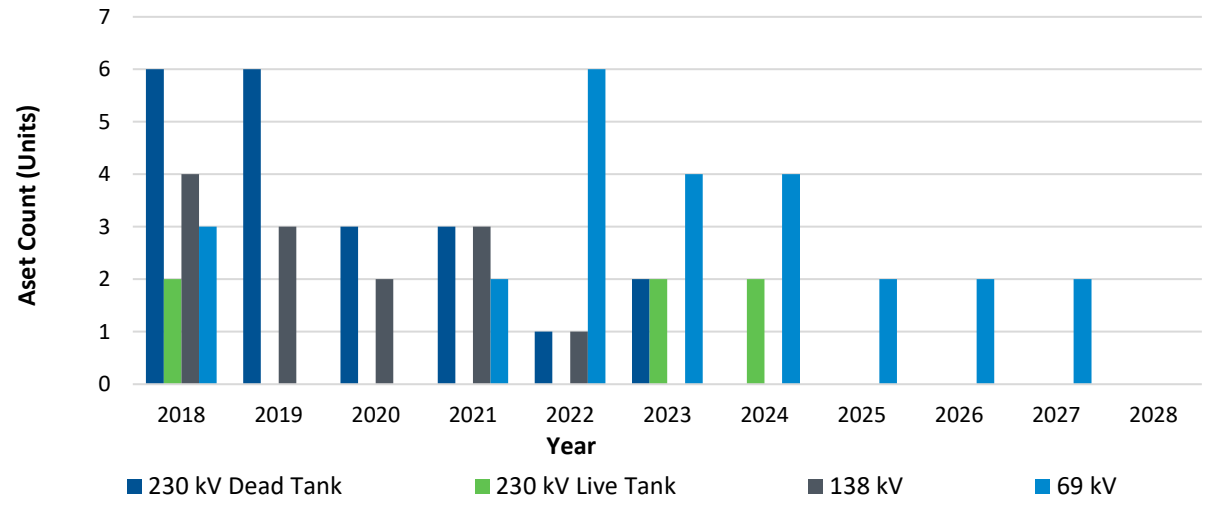


Chart 3: Historical and Forecast Assets Replaced

The number of 138 kV and 230 kV circuit breaker replacements has generally decreased since 2018 and will continue to decrease. The majority of circuit breakers in these voltage classes were air-blast circuit

[7] While Hydro is intending to replace two 25 kV breakers, due to the suspected presence of PCBs, under this program this cycle for operational efficiencies, these breakers are not included in any of the trending charts herein.

breakers that were replaced between 2015 and 2022. The number of 69 kV breaker replacements peaked in 2022 and will continue to decrease into the future, as Hydro removes all oil circuit breakers to maintain compliance with federal environmental legislation.

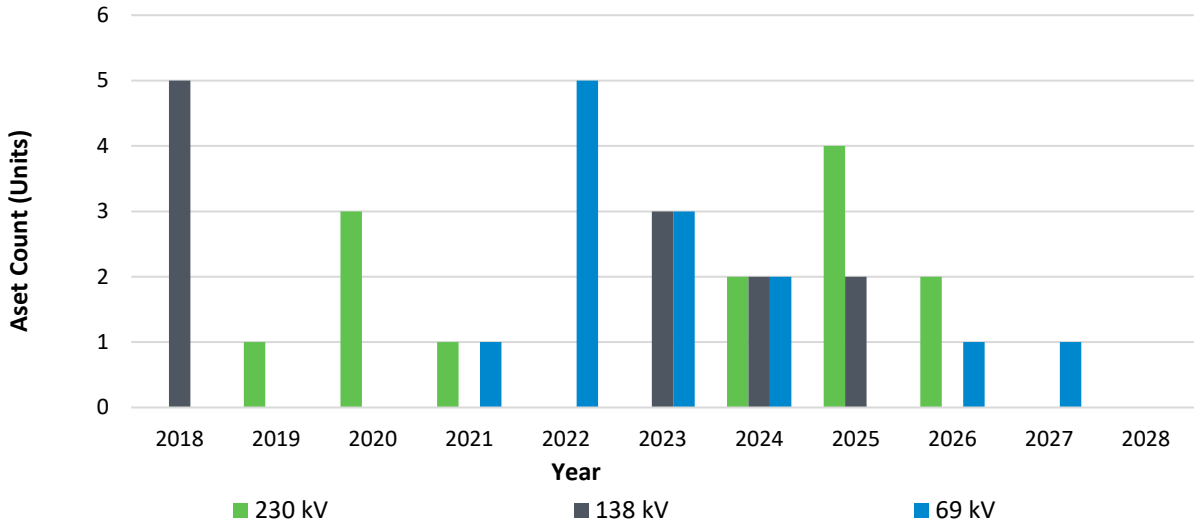


Chart 4: Historical and Forecast Assets Refurbished (Units)

The number of circuit breakers being proposed for refurbishment varies from year-to-year. Circuit breakers are planned for refurbishment at approximately 20 years of age or based on condition. However, as SF_6 breakers come due, a further condition assessment will be completed to determine if life extension can be achieved through refurbishment.

4.2 Historical and Forecast Average Unit Costs

Chart 5 and Chart 6 show the average unit costs for replacements and refurbishments, respectively. While the unit cost for breaker replacements is consistent for each voltage class year-over-year, the costs vary significantly by breaker voltage class, as shown in Chart 5. The 230 kV live tank breaker replacement costs have been lower than average as they generally exclude any cable replacements or protection upgrades.

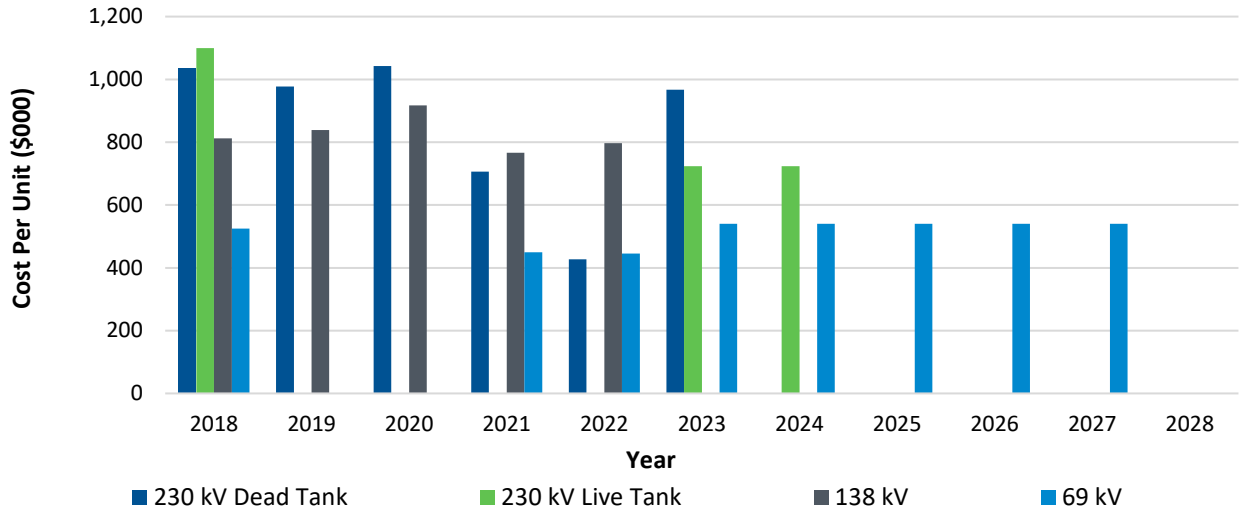


Chart 5: Average Unit Costs of Assets Replaced

The breaker refurbishment costs vary between breaker type and manufacturer; as such, unit costs per year can show variability depending on the types of breakers refurbished.

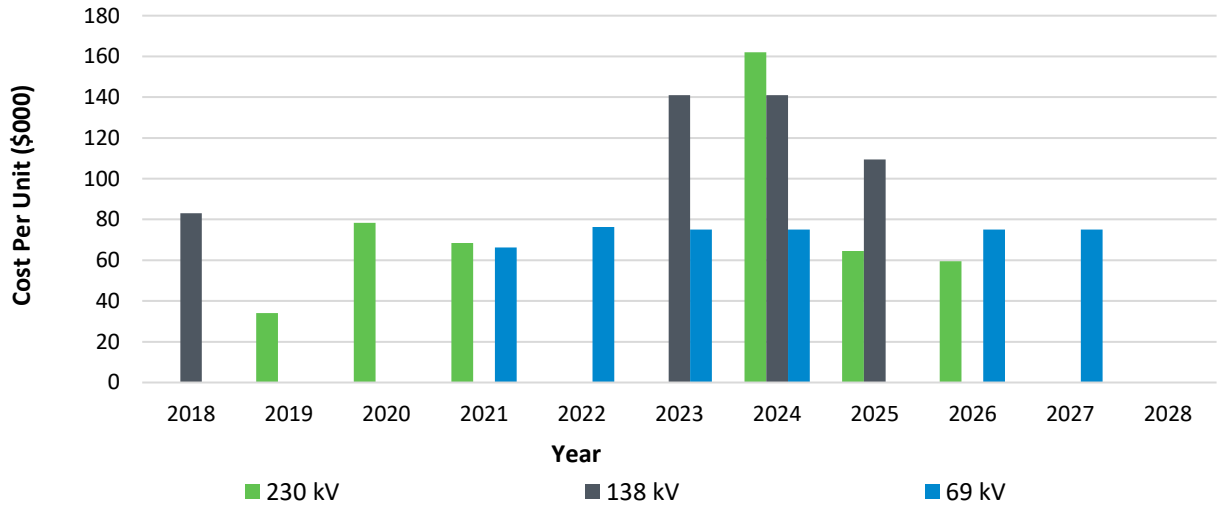


Chart 6: **Average Unit Costs of Assets Refurbishment**

The refurbishment work planned for 138 kV and 230 kV breakers in 2024 and 2025 reflects the refurbishment cost for ELF-type breakers, which have a higher cost than other manufacturers. Other forecasted costs are relatively consistent with previous actual costs.

5.0 Historical Reliability

A listing of sustained forced outages for the last five years is shown in Table 2.

Table 2: Circuit Breaker Outages and Durations from 2018 to 2022 (minutes)

Start Date	Breaker	Outage Duration
21-Dec-2022	St. Anthony B1C3	731
10-Dec-2022	St. Anthony B1C3	817
21-Oct-2022	Cow Header B1L27	36
1-Sep-2022	Indian River B1L363	868
2-Jul-2022	Happy Valley 13-1	2
8-Jun-2022	Happy Valley 13-1	19
10-May-2022	Peter's Barren B1L41	5
24-Dec-2021	Doyle's SB1L15	4
21-Nov-2021	St. Anthony B1T1	10
23-Oct-2021	St. Anthony B1C1	4
1-Sep-2021	Springdale B1L22	3
20-Aug-2021	Holyrood B8L39	2
27-Jul-2021	Indian River B1L23	1
27-Jul-2021	Indian River B1L24	1
9-May-2021	Buchans L28L32	521
30-Jul-2020	Doyle's B1L15	78
22-Apr-2020	Hardwoods B1B2	46
17-Mar-2020	Springdale B1L22	90
10-Dec-2019	St. Anthony B1L61	114
10-Dec-2019	Stony Brook B1L31	10
3-Dec-2019	Oxen Pond B5C1	4,238
3-Jun-2019	Berry Hill L26L27	505
27-Feb-2019	Bay d'Espoir B3T5	19,624
8-Jan-2019	Sunnyside B1L02	213
9-Nov-2018	Bear Cove B1R1	295
4-Nov-2018	Cow Head B1L27	583
9-Jul-2018	Doyles B1L15	18
21-May-2018	Bay d'Espoir B4B5	216

6.0 Analysis

6.1 Evaluation of Alternatives

The following alternatives were considered:

- Pace reduction; and
- Continue program at current pace.

6.1.1 Pace Reduction

Hydro reviews its circuit breaker renewal program regularly to determine if the pace can be reduced while maintaining reliable service to its customers. Pace reduction cannot be achieved with oil circuit breakers that have suspected PCB contamination due to the 2025 regulated deadline. However, for SF_6 breakers, pace reduction is demonstrated through Hydro's asset management philosophy, revised in 2020, to complete further condition assessment of circuit breakers to achieve additional life through a lower-cost alternative of refurbishment. Since 2020, Hydro has deferred ten SF_6 breaker replacements in favour of performing refurbishment. As a result, Hydro believes its philosophy of doing further condition assessments and increasing the life of breakers beyond 40 years is resulting in pace reduction in comparison to the previously documented long-term plans. Further pace reduction is not a viable option as it will increase the risk of failure and will have a negative impact on system reliability.

6.1.2 Continue Program at Current Pace

As outlined herein, the refurbishment and replacement of circuit breakers in a planned, strategic manner is prudent and supports the reliable and safe operation of the assets. Such an approach enables Hydro to manage resource requirements and system outages to support its mandate to provide safe, reliable, least-cost electricity in an environmentally responsible manner.

6.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

6.3 Recommended Alternative

Hydro recommends the refurbishment and replacement of circuit breakers as proposed. This approach is consistent with the methodology and philosophy outlined in Hydro's Terminal Station Asset Management Overview and will ensure the safe and reliable operation of the circuit breaker fleet while effectively balancing costs.

6.3.1 Risk of Asset Stranding

With potential future load growth in Labrador, there is a risk that the Wabush Terminal Station breakers scheduled for replacement due to suspected PCB contamination may not be required for the full extent

of their useful life.[8] If developments in Labrador West occur in the near term, newly installed breakers will be considered for deployment in a different terminal station location or become spares. There is no known risk that the other circuit breakers under this program will be stranded before their useful life has been reached.

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 3.

Table 3: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	5	3	**15**
Post-Execution	5	1	**5**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**3.4**

7.0 Scope of Work

Hydro's five-year plan for the Renew Circuit Breakers program is provided in Appendix A. Based on current condition and asset data, Hydro plans to replace four circuit breakers and refurbish six circuit breakers under this program, with completion scheduled by the end of 2025. Based on asset condition and outage and resource availability at the time of execution, Hydro may advance or defer the replacement of specific assets to ensure efficient and effective implementation of this program.

7.1 Program Budget

The estimate for the 2024–2025 program is shown in Table 4.

[8] Hydro is evaluating new load requests in Labrador. Load growth in Labrador is governed by Newfoundland and Labrador Hydro (2020). *Network Additions Policy – Labrador Interconnected System*. <https://nlhydro.com/wp-content/uploads/2021/03/Network-Additions-Policy.pdf>, as approved by the Board in "*Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 7(2021)," Board of Commissioners of Public Utilities, March 17, 2021.

Table 4: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	0.0	540.0	0.0	**540.0**
Labour	162.2	1,011.1	0.0	**1,173.3**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	897.8	0.0	**897.8**
Other Direct Costs	7.1	47.8	0.0	**54.9**
Interest and Escalation	6.1	157.7	0.0	**163.8**
Contingency	8.5	124.9	0.0	**133.4**
Total	**183.9**	**2,779.3**	**0.0**	**2,963.2**

Chart 7 provides the five-year historical expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028. As shown in Chart 7, the number of circuit breakers being proposed for replacement in a given year has been decreasing since 2018[9] and will continue to decrease as Hydro's remaining circuit breakers are replaced. Subsequently, the budget is trending lower in future years due to fewer breakers meeting the criteria for replacement.

Due to the effects of the COVID-19 pandemic, the number of circuit breaker replacements executed in 2020 was lower than planned, resulting in reduced expenditures and deferral of some breakers to 2021 and 2022.

The forecast expenditure for 2027 is below average, as there are currently no assets planned for replacement or refurbishment in the 2027–2028 iteration of this program. As a result, the expenditure in 2027 is the second year of the 2026–2027 program only.

This program budget covers all types and voltage classes of breakers; as such, it will inherently show variability depending on the number, type, and voltage class of breakers addressed each year.

[9] Total expenditures in 2018 are higher than average due to a larger number of refurbishments and replacements completed in that year.

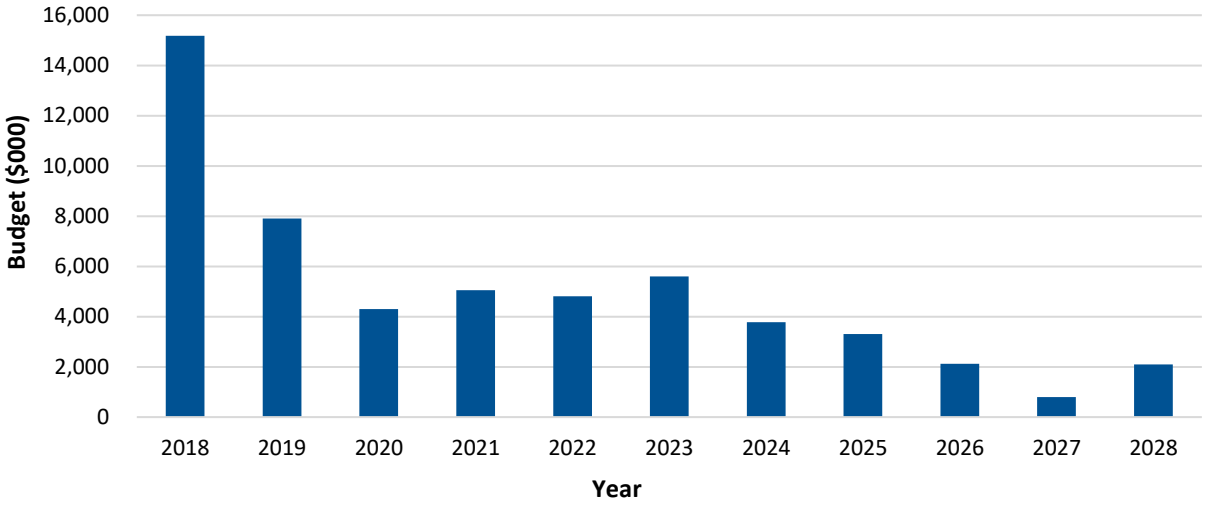


Chart 7: Historical and Forecast Program Budget

7.2 Program Schedule

The schedule for the 2024–2025 program is shown in Table 5.

Table 5: Program Schedule

Activity	Start Date	End Date
Planning:		
Initial planning and scheduling.	January 2024	February 2024
Procurement:		
Order breakers and long lead items.	May 2024	June 2025
Detailed Design:		
Conduct site visits.	October 2024	November 2024
Complete detailed design.	November 2024	March 2025
Procurement:		
Tender and award contract(s).	March 2025	May 2025
Construction/Commissioning:		
Breaker replacements and refurbishments.	June 2025	October 2025
Closeout:		
Complete closeout documentation.	November 2025	December 2025

8.0 Conclusion

This proposal is seeking approval for the refurbishment and replacement of ten circuit breakers by the end of 2025. The refurbishment and replacement of the identified circuit breakers is required to ensure system reliability, safety, and compliance with federal environmental *PCB Regulations*.

Appendix A

Renew Circuit Breakers Program

2024–2028 Plan

newfoundland labrador hydro

Assets planned for replacement or refurbishment from 2024 to 2027 under the Renew Circuit Breakers program are provided in Table A-1 to Table A-4. There are currently no assets planned for replacement or refurbishment in the 2027–2028 iteration of this program; as such, the assets shown in Table A-4 reflect the assets included in the second year of the 2026–2027 program only.

Table A-1: Assets Planned for Replacement or Refurbishment in 2024

Name	Voltage (kV)	Activity
Bay d'Espoir B2T4	230	Replacement
Bay d'Espoir B3T6	230	Replacement
Deer Lake B2L25	138	Refurbishment
Hardwoods B7T2	69	Refurbishment
Holyrood B12L18	230	Refurbishment
Howley B1L24	69	Refurbishment
Indian River B1L363	69	Refurbishment
Upper Salmon L34T1	230	Refurbishment
Wabush Terminal Station B3L5A	46	Replacement
Wabush Terminal Station B4L5B	46	Replacement
Wabush Terminal Station B4T5	46	Replacement

Table A-2: Assets Planned for Replacement or Refurbishment in 2025

Name	Voltage (kV)	Activity
Deer Lake B3L47	230	Refurbishment
Happy Valley B14L15	25	Replacement
Happy Valley T2B14	25	Replacement
Hardwoods B8T3	69	Replacement
Howley B1L43	138	Refurbishment
Massey Drive B1L48	230	Refurbishment
South Brook L22T1	138	Refurbishment
Stephenville B1L09	230	Refurbishment
Wabush Terminal Station B3B4	69	Replacement
Western Avalon B1T1	230	Refurbishment

Table A-3: Assets Planned for Replacement or Refurbishment in 2026

Name	Voltage (kV)	Activity
Buchans B2L64	69	Refurbishment
Oxen Pond B2T2	69	Replacement
Upper Salmon L34L63	230	Refurbishment
Wabush Terminal Station B4L34	69	Replacement
Western Avalon B1T2	230	Refurbishment

Table A-4: Assets Planned for Replacement or Refurbishment in 2027

Name	Voltage (kV)	Activity
Hardwoods B7C1	69	Refurbishment
Wabush Terminal Station B4L35	46	Replacement
Wabush Terminal Station B4L6	46	Replacement

Program 13

Renew Distribution Feeders (2024–2025)

July 2023

newfoundland labrador hydro

Renew Distribution Feeders (2024–2025)

Location: Bottom Waters Line 4 and St. Brendan's Line 1

Investment Classification: Renewal

Asset Category: Distribution

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") maintains its distribution feeder network through preventive maintenance activities, as part of its Asset Management Program. One such activity is the inspection and grading of feeder assets on a condition-based scale. As a significant number of Hydro's feeder assets are categorized as deteriorating, a need has emerged for a program to address this, complementary to the Worst-Performing Feeders program.[1]

Renew Distribution Feeders is a condition-based asset renewal program.[2] This would allow for large-scale refurbishment of deteriorated assets along a feeder or group of feeders identified as being at, or close to, the end of their useful service lives, thus increasing safety and addressing potential failures before they occur. If feeders are left to continue to deteriorate to the point of "critical" categorization, there are risks to reliability due to continued poor performance.

For the 2024–2025 scope of the Renew Distribution Feeders program, Hydro is proposing to refurbish Bottom Waters Line 4 ("BWT-L4") and St. Brendan's Line 1 ("SBN-L1") distribution feeders. These feeders were identified for refurbishment using inspection data, engineering assessment and asset management strategies. The components selected for replacement include deteriorated poles, crossarms, transformers, and conductors that have been identified as being at, or close to, the end of their useful service lives.

This program has a multi-year approach, with completion planned in 2025 at an estimated cost of $2,532,400.

[1] Hydro's Worst-Performing Feeders program selects feeders for upgrade based on its five-year average performance in three key reliability indices, while the proposed Renew Distribution Feeders program would select feeders for upgrade based on as a condition-based scale.

[2] Hydro is resuming the former "Distribution System Upgrades" program, which was suspended in 2021 as part of Hydro's cost management efforts.

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1.0 Introduction

Hydro owns and operates distribution systems in the rural communities it serves. Each distribution system typically consists of a substation coupled with wood pole distribution feeder(s) that supply power from the substation to service drops throughout a community.

The Renew Distribution Feeders program targets the distribution feeders for capital upgrades based on asset conditions. For 2024–2025, Hydro is proposing to refurbish distribution feeders located in the St. Brendan's and Bottom Waters systems.

These feeders were identified for refurbishment using inspection data, engineering assessment, and asset management strategies. The components selected for replacement include deteriorated poles, crossarms, transformers, and conductors that have been identified as being at, or close to, the end of their useful service lives. It has also been identified that some of the existing line components are substandard—no longer conforming to Hydro's standard for line applications. This could lead to unplanned power outages upon their failure.

The continued deterioration of the components identified for replacement creates a risk of line component failure. Failure of such components will negatively affect the reliability performance of the line, potentially resulting in unplanned power outages to customers. These line components also create safety hazards, specifically the danger of working on or around deteriorated poles.

2.0 Program Description and Justification

The proposed Renew Distribution Feeders program is a condition-based asset renewal program, which would become a part of Hydro's annual preventive maintenance activities.

Hydro implements an annual inspection program to identify deteriorated structures, line components, and equipment throughout its distribution systems. This inspection is completed by Hydro personnel and any corrective maintenance required is reported, analyzed, scheduled, and completed. Hydro's inspection grading system for distribution equipment is ranked on a scale of 1 to 5, as shown in Table 1.

Table 1: Distribution Asset Grading System

Condition	Grading
New Condition	1
Seasoned	2
Aging	3
Deteriorating	4
Critical	5

Following inspections, localized service deficiencies are addressed and small-scale infrastructure replacements are accommodated through the Distribution System in-Service Failures, Miscellaneous Upgrades, and Street Light program; however, this program is generally not intended to cover large-scale scopes of work, such as feeder replacement or refurbishment.

Hydro initiated the Upgrade Worst-Performing Distribution Feeders program in 2019, which addresses poor reliability performance; it is not based on the condition of components. Historically, Hydro used a condition assessment-based approach to identify components of its distribution systems that needed to be refurbished to ensure reliable operation; however, with the introduction of the Worst-Performing Distribution Feeders program, the former condition-based refurbishment program was terminated as a cost management measure. As a result, the number of distribution components graded as 4 or "deteriorating" continues to grow, as they are not being addressed under the existing programs. It is anticipated that many of these components will be assessed as Grade 5 or "critical" over the next several years.

Therefore, Hydro proposes to undertake the Renew Distribution Feeders program to address the need to upgrade or replace deteriorated assets. Work proposed under this program includes individual refurbishment plans for feeders where deterioration is most pronounced. Hydro will also endeavour to group work in areas where there is a concentration of deteriorated assets to avail of execution efficiencies.

3.0 Asset Overview

3.1 Asset Background

3.1.1 BWT-L4 Feeder

BWT-L4 is a three-phase, 25 kV distribution feeder that originates from the Burlington Substation; it was originally constructed in the 1960s and services approximately 450 customers.

BWT-L4 runs from the Burlington Substation for approximately 3.5 kilometres along Bridge Street, supplying customers in the community of Burlington. It then proceeds approximately 9 kilometres along Route 413, supplying customers in the community of Middle Arm. BWT-L4 also has an approximately 0.5 kilometre-long tap, which provides power to the community of Smith's Harbour. The location of the BWT-L4 feeder is shown in Figure 1.



Figure 1: Layout – BWT-L4

3.1.2 SBN-L1 Feeder

SBN-L1 is a 4.16 kV distribution feeder that originates from the substation at the St. Brendan's Diesel Generating Station; it was originally constructed in the 1960s and services approximately 150 customers. This feeder supplies power to the isolated communities of Shoal Cove, Haywards Cove, Dock Cove, Shalloway Cove, and Penney's Cove. The location of the SBN-L1 feeder is shown in Figure 2.



Figure 2: Layout – SBN-L1

3.2 Asset Condition

3.2.1 BWT-L4 Feeder

The BWT-L4 feeder was constructed over 50 years ago. Recent inspection records indicate BWT-L4 has several deteriorated poles, crossarms, and pole-mounted transformers.

As well, this feeder has approximately 6 kilometres of three-phase line consisting of a #4 copper conductor, which was installed at the time of original construction. Due to the wear and stretching of the conductor over its life, it poses a risk of breakage during peak loads, windstorms, and while line work is ongoing.

Chart 1 shows BWT-L4 pole assets by condition rating.

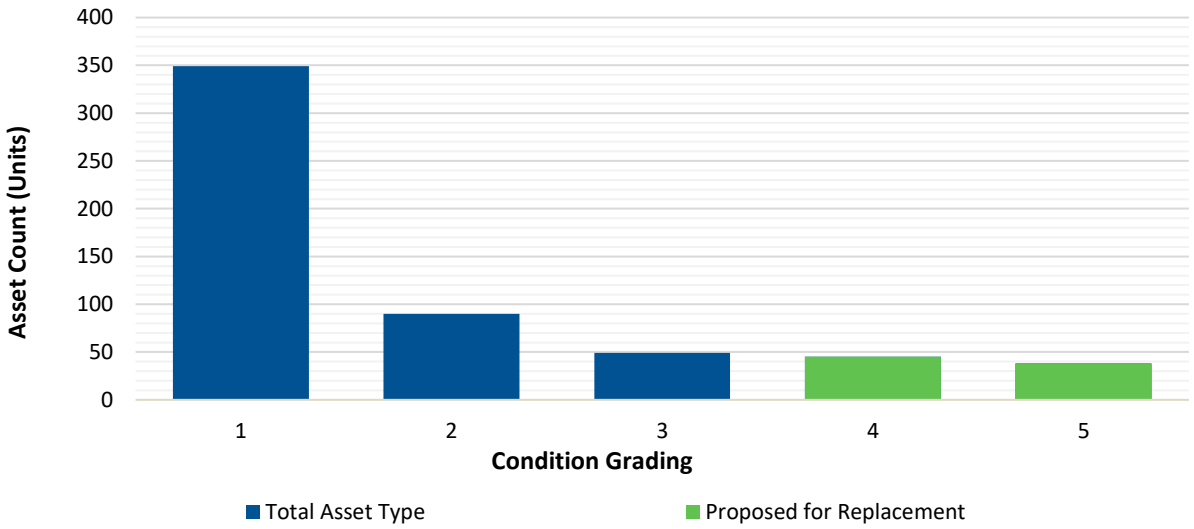


Chart 1: Asset Condition Grading – BWT-L4

3.2.2 SBN-L1 Feeder

The SBN-L1 feeder was constructed over 50 years ago. Recent inspections have identified a significant number of deficiencies on this feeder, including deteriorated poles, transformers, and overhead conductors.

This feeder has approximately 9 kilometres of single-phase line consisting of a #2 ACSR[3] conductor, which is non-standard and prone to failure. ACSR is not recommended for saltwater environments because of the potential for excessive corrosion caused by oxidization between the steel core and the aluminum outer strands. As SBN-L1 runs along the Island's coastline, the sections of non-standard conductors require replacement. As well, this feeder has approximately 1.6 kilometres of single-phase line consisting of #4 copper neutral installed at the time of original construction that must be replaced.

Chart 2 shows SBN-L1 pole assets by condition rating.

[3] Aluminum-conductor steel reinforced ("ACSR").

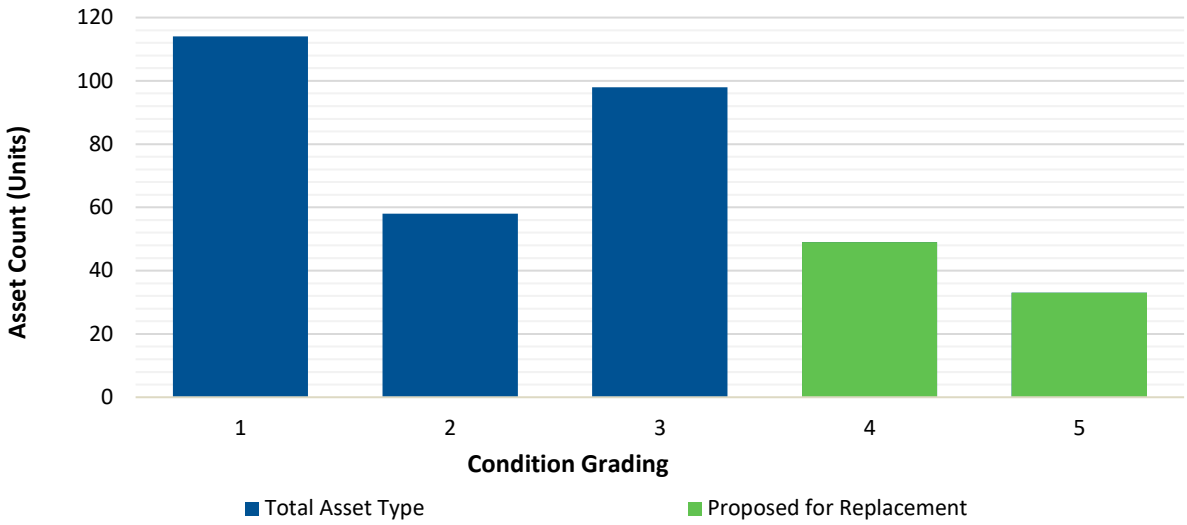


Chart 2: Asset Condition Grading – SBN-L1

Examples of a deteriorated pole, crossarms, and transformer tank, such as those observed during recent inspections of BWT-L4 and SBN-L1, are provided as Figure 3 to Figure 5.



Figure 3: Example of a Deteriorated Pole



Figure 4: Example of a Deteriorated Crossarm



Figure 5: Example of a Deteriorated Transformer Tank

3.3 Asset Ages

The feeders covered under this program have numerous types of assets; the age of which varies as the feeders are continuously updated through planned and unplanned replacement or refurbishment activities. The BWT-L4 and SBN-L1 feeders have some assets dating back to the 1960s.

Chart 3 and Chart 4 provide pole assets by age for BWT-L4 and SBN-L1.

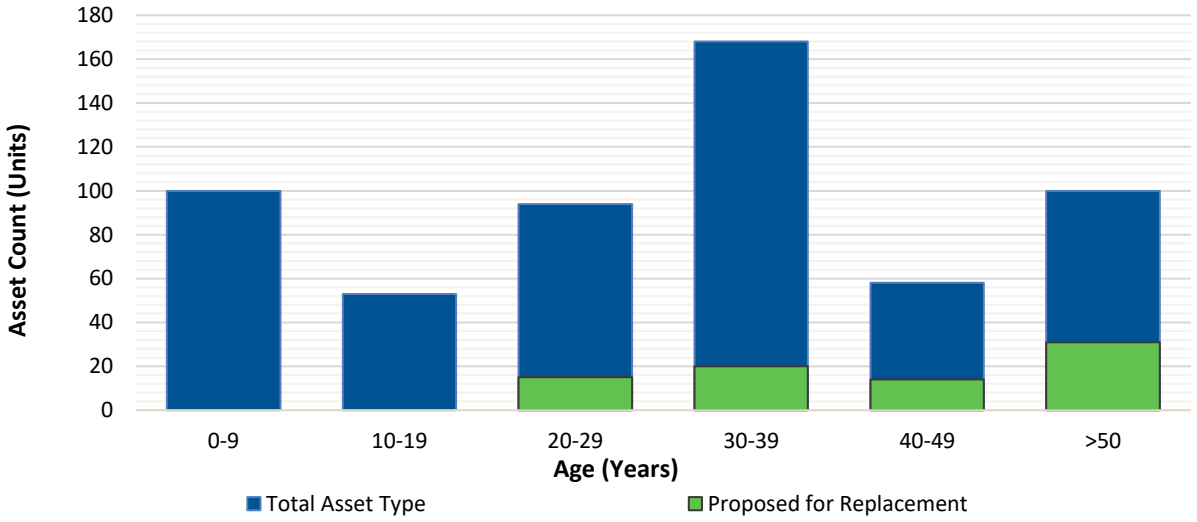


Chart 3: Asset Counts by Asset Age – BWT-L4

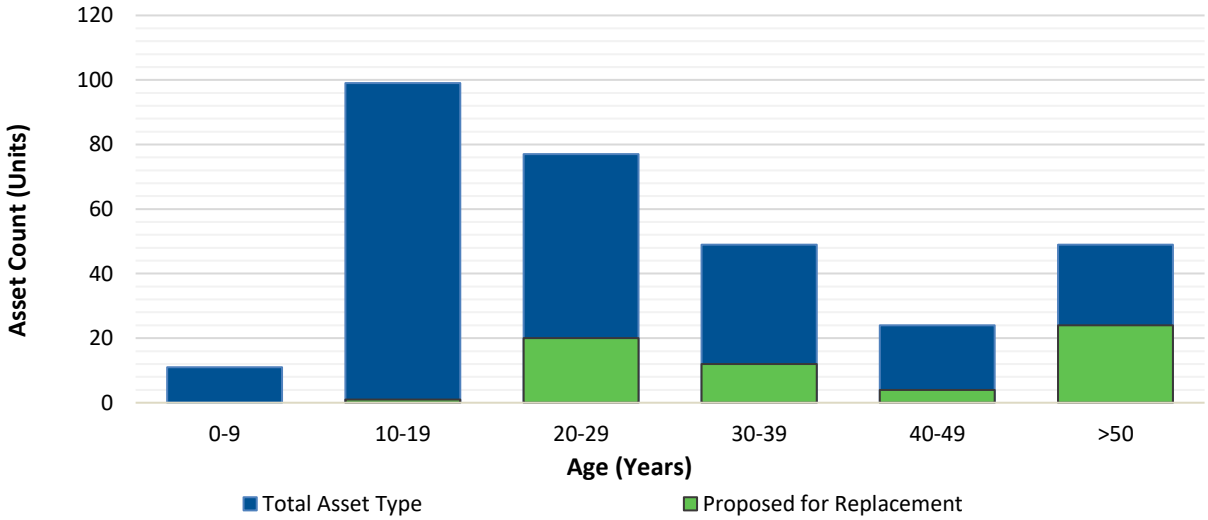


Chart 4: Asset Counts by Asset Age – SBN-L1

3.4 Condition-Based Remaining Life

The assets to be replaced under this program have failed, are nearing the point of failure, or are obsolete and have reached the end of their remaining useful life. The remaining line components not addressed under this program are deemed to be in adequate to good condition and have expected remaining useful lives ranging from 6 years (until the next preventive maintenance cycle) to 20 years or more.

4.0 Trending

As this is a new program proposed for 2024, Hydro does not yet have the requested historical trending data. Hydro will use the data collected during the execution of this program to determine appropriate trending patterns and provide this information as required in future iterations of this program.

5.0 Historical Reliability

As this program will function as a condition-based asset renewal program, the analysis of reliability data is not applicable. Hydro will use the data collected during the execution of this program to determine appropriate tracking metrics and, where appropriate, will provide this information as required in future iterations of this program. Hydro's overall system reliability, as well as reliability segmented by the Labrador and Island systems, is provided in Hydro's Capital Budget Overview.

If the refurbishment work proposed in this program is not completed, the condition of the assets will continue to deteriorate to the point of failure, resulting in unscheduled power outages and impacting reliability. Hydro anticipates that the continued execution of this program will demonstrate a decrease for the Distribution In-Service Failures, Miscellaneous Upgrades, and Street Lights program.

6.0 Analysis

Hydro considered the following alternatives:

- Pace reduction;
- Continue program at current pace; and
- Alternative strategies.

6.1 Evaluation of Alternatives

6.1.1 Pace Reduction

If the required upgrade work were deferred to a future year, it would further contribute to the growing number of deficiencies, negatively impacting future costs and would present an increased risk to distribution system reliability. This could potentially result in increased costs associated with unplanned work or outage response. In addition, deferring this program would create a safety hazard for workers and the public, as Hydro does not allow distribution line components to remain in service until failure. Therefore, deferral is not a viable option.

6.1.2 Continue Program at Current Pace

Replacing the deteriorated line components identified in this program ensures that feeders with a concentration of deteriorated assets at, or close to, the end of their useful service lives are addressed in a timely manner. This would allow for large-scale refurbishment of deteriorated assets to address potential failures before they occur, increasing safety and avoiding customer outages and costs related to unplanned work or outage responses.

6.1.3 Alternative Strategies

Hydro has considered building a new distribution line; however, each feeder has existing line components that are still operable such as poles, conductors, insulators, and crossarms. Construction of an entirely new line would result in the premature retirement of those existing, functional assets. The complete replacement of the existing feeders requires a level of investment that is not required for the continuation of safe, reliable, and least-cost service and is not considered a viable option.

Hydro also considered expansion of its Upgrade Worst-Performing Feeders program to target more feeders based on reliability rather than condition. Hydro determined that this approach is not appropriate, as feeder performance can be impacted by numerous factors and is not limited to asset condition. Hydro must proactively address deteriorating distribution infrastructure to prevent negative reliability impacts on its customers, and to prevent public safety hazards associated with failing infrastructure.

6.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

6.3 Recommended Alternative

Hydro recommends continuing the program at the current pace and replacing the deteriorated line components, with the upgrade of BWT-L4 and SBN-L1 beginning in 2024.

6.3.1 Risk of Asset Stranding

Hydro does not anticipate a change in service requirements in these areas; therefore, the risk of asset stranding is low.

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 2.

Table 2: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	4	**12**
Post-Execution	3	2	**6**
		Risk Mitigated	**6**
		Risk Mitigated per $1 Million	**2.4**

7.0 Scope of Work

An overview of the work to be completed under this program beginning in 2024 is as follows:

- Replace 165 deteriorated poles;
- Replace 19 deteriorated crossarms;
- Replace 8 pole-mounted distribution transformers;
- Replace approximately 6 kilometres of three-phase primary copper conductors;
- Replace approximately 1.6 kilometres of copper neutral wire; and
- Replace approximately 9 kilometres of single-phase primary #2 ACSR conductors.

7.1 Program Budget

The estimate for the 2024–2025 program is shown in Table 3.

Table 3: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	289.9	464.0	0.0	**753.9**
Labour	157.7	502.6	0.0	**660.3**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	610.4	0.0	0.0	**610.4**
Other Direct Costs	32.5	1.8	0.0	**34.3**
Interest and Escalation	87.7	179.8	0.0	**267.5**
Contingency	109.1	96.9	0.0	**206.0**
Total	**1,287.3**	**1,245.1**	**0.0**	**2,532.4**

Hydro is proposing this program to start in 2024. Chart 5 shows the proposed 2024 budget and the forecast budget through 2028.

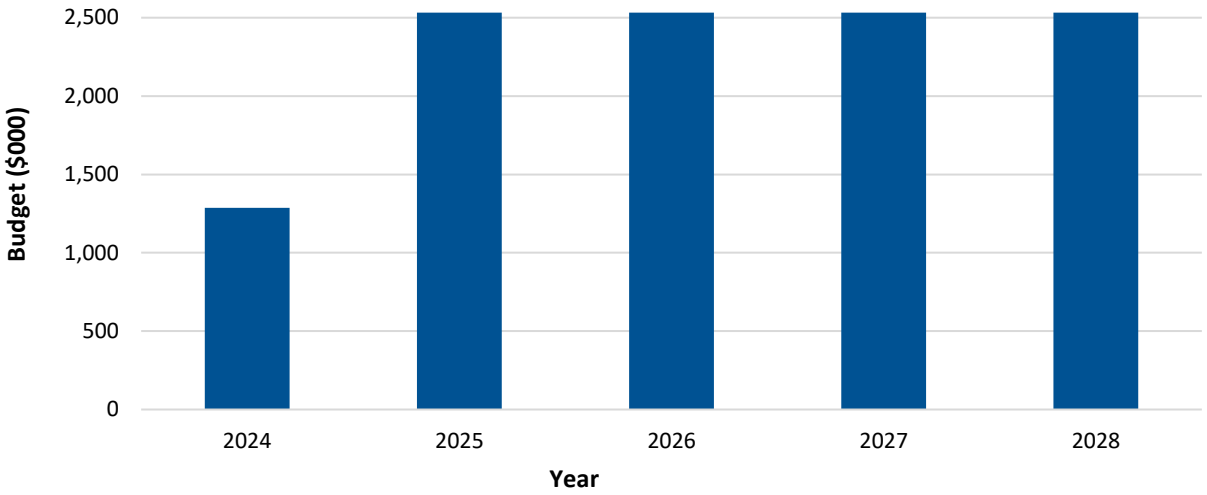


Chart 5: 2024 and Forecast Program Budget

7.2 Program Schedule

The schedule for the 2024–2025 program is shown in Table 4.

Table 4: Program Schedule

Activity	Start Date	End Date
Planning:		
Resource planning.	January 2024	January 2025
Design:		
Conduct site visits and detailed design.	January 2024	May 2025
Procurement:		
Materials ordered.	April 2024	May 2025
Construction:		
Construction.	July 2024	September 2025
Commissioning:		
Refurbish work commissioned.	July 2024	September 2025
Closeout:		
Complete closeout documentation.	September 2025	November 2025

8.0 Conclusion

Proactive refurbishment of Hydro's distribution feeders is required to support Hydro's legislated mandate to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner. Hydro proposes to implement a Renew Distribution Feeders program, which would function as a condition-based asset renewal program, allowing for large-scale refurbishment of deteriorated assets along a feeder, identified as being at, or close to, the end of their useful service lives, maintaining safety and addressing potential failures before they occur and create negative impacts to reliability. This 2024-2025 program is required to refurbish the BWT-L4 and SBN-L1 distribution feeders.

Program 14

Hydraulic In-Service Failures (2024)

July 2023

newfoundland labrador hydro

Hydraulic In-Service Failures (2024)

Location: Various

Investment Classification: Renewal

Asset Category: Hydraulic Plant

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has an Asset Management Program that governs the life cycle of its hydraulic generation assets. This program monitors, maintains, refurbishes, replaces, and disposes of assets to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

Generally, Hydro identifies and plans the refurbishment and replacement work that will be required for its hydraulic assets in time for inclusion within the annual capital budget applications ("CBA"). However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or the determination of faster-than-anticipated equipment deterioration.

Hydro is proposing that within the Hydraulic In-Service Failures program, it will undertake the immediate capital refurbishment and replacement work required for its hydraulic generation assets to maintain safe and reliable operation and to ensure the availability of capital spares required to support such work.

The estimated cost for work executed under this 2024 program is $1,500,000, which is based on the average expenditure over the past three years, from 2020 to 2022.

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1.0 Introduction

Hydro conducts asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize the disruption of service and to avoid unsafe working conditions due to equipment failure. An objective of Hydro's Asset Management Program is to identify refurbishment and replacement activities that require approval by the Board of Commissioners of Public Utilities ("Board") in time to be included in Hydro's annual CBA. Identification is done through the preventive maintenance program using various condition-based assessments and testing procedures.

Hydro has had success in projecting the deterioration rate of equipment for submission of refurbishment or replacement work into CBAs. However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or the determination of faster-than-anticipated equipment deterioration. These situations can be caused by events such as vandalism, storm damage, lightning, accidental damage, abnormal system operations, cavitation, corrosion, wear of mechanical components, existing installation deficiencies, etc. Hydro uses historical data and engineering judgment to predict the magnitude of in-service failure expenditures.

2.0 Program Description and Justification

Due to the nature of hydraulic equipment and infrastructure, unanticipated failures and deterioration will occur. Under the Hydraulic In-Service Failures program, Hydro is proposing to undertake the immediate capital refurbishment and replacement work required for its hydraulic generating assets, as needed, to maintain safe and reliable operation and to ensure the availability of capital spares required to support such work. At this time, Hydro does not have any planned capital spare acquisitions under this program; however, throughout 2024, Hydro may purchase capital spares identified by asset management personnel as requiring immediate procurement to offset deficiencies in its capital spares.

Deferral of work that is justified under this program could result in a detrimental impact to customer power supply or unacceptable risk to worker or public safety.

Depending on the relevant circumstances, required work will be evaluated to determine the appropriate form of execution as an in-service failure, an allowance for unforeseen item, or a supplemental project.

3.0 Asset Overview

3.1 Asset Background

The assets requiring immediate, unplanned replacement or refurbishment work in a given year cannot be identified in advance. The hydraulic generating assets covered within the Hydraulic In-Service Failures program are generally included in the following five broad asset classes:

- Hydraulic generating units;
- Hydraulic structures;
- Reservoirs;
- Site buildings and services; and
- Auxiliary equipment.

For further information on the work executed under the Hydraulic In-Service Failures (2022) program, please refer to Hydro's "Capital Expenditures and Carryover Report for the Year Ended December 31, 2022."[1]

3.2 Asset Condition

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure.

3.3 Condition-Based Remaining Life

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure; therefore, these assets have reached the end of their serviceable life.

3.4 Asset Age

The age of assets potentially covered under this program varies. Unplanned replacement or refurbishment activities due to failure may be necessary at any time during the asset life cycle.

[1] "Capital Expenditures and Carryover Report for the Year Ended December 31, 2022," Newfoundland and Labrador Hydro, March 30, 2023, sec. 10.0, Table 7, pp.55–56. <http://pub.nl.ca/indexreports/expenditure/From%20NLH%20-%202022%20Capital%20Expenditures%20and%20Carryover%20Report%20-%202023-03-31.PDF>

4.0 Trending

Hydro implemented the Hydraulic In-Service Failures program in 2018. Since that time, on average, Hydro has initiated 12 unplanned projects per year under the program.

4.1 Assets Installed/Replaced/Upgraded

The number of unplanned In-Service Failures projects initiated under the program over the past five years is provided in Chart 1. Details of each project, and the associated assets and costs, are filed within Hydro's annual Capital Expenditures and Carryover Report.

Hydro anticipates that unplanned failures will continue to occur given the age and number of hydraulic assets covered under the program. Hydro continues to plan the budget for this program based on historical information.

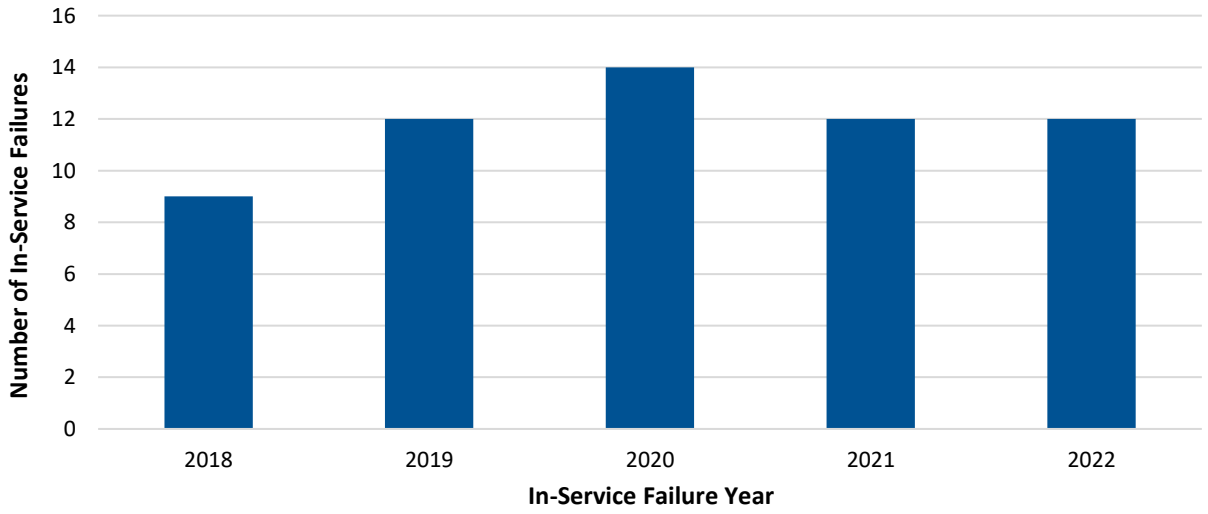


Chart 1: In-Service Failure Frequency

4.2 Historical and Forecast Average Unit Costs

Historical and forecast program costs are provided in Chart 2 in Section 7.1. Due to the nature of this program and the range of assets covered, average unit cost information is not applicable. An increase in program cost is forecast based on the anticipated escalation of both material and labour costs.

5.0 Historical Reliability

Hydro tracks performance data for its hydraulic units using the Derated Adjusted Forced Outage Rate ("DAFOR").[2,3] This program plays a key role in allowing Hydro to minimize the DAFOR of its hydraulic units to ensure the provision of reliable service to customers. As this program addresses a wide range of asset types and the specific assets to be addressed within this program for 2024 are not known, historical reliability data for the individual assets covered within this program is not applicable.

6.0 Analysis

6.1 Evaluation of Alternatives

Depending on the nature of each failure or incipient failure, Hydro reviews viable technical alternatives to determine the most appropriate solution to address the unplanned event while balancing urgent safety and operational risks.

Due to the urgent nature of work executed under this program, seeking approval through a supplemental capital expenditures application or deferring the work for inclusion in the next CBA are not viable alternatives. The alternative of executing required unplanned work under the Allowance for Unforeseen Items Account is also considered on a case-by-case basis, subject to the requirements set out by the Board for the use of the account.

6.2 Risk of Asset Stranding

Assets replaced or refurbished under this program have an inherently low risk of asset stranding. The assets covered under this program are critical to Hydro's ability to meet customer requirements. The risk of asset stranding would be considered on a case-by-case basis, if applicable.

6.3 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for 2024 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

[2] DAFOR is a metric that measures the percentage of time that a unit or group of units is unable to generate at its maximum continuous rating due to forced outages or unit deratings.
[3] Filed quarterly with the Board, most recently the "Quarterly Report on Performance of Generating Units for the Twelve Months Ended March 31, 2023," Newfoundland and Labrador Hydro, April 28, 2023.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	5	**15**
Post-Execution	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**8.0**

7.0 Scope of Work

Work executed under the 2024 program will be reported to the Board in Hydro's 2024 Capital Expenditures and Carryover Report.[4]

7.1 Program Budget

The estimate for the 2024 program is shown in Table 2. The estimate is based on the average expenditures from 2020 to 2022. The details of each project covered under this program, including the associated assets and costs and the total program expenditures for each year, are filed with the Board within Hydro's annual Capital Expenditures and Carryover Report.

Table 2: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	1,006.6	0.0	0.0	**1,006.6**
Labour	443.4	0.0	0.0	**443.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	50.0	0.0	0.0	**50.0**
Interest and Escalation	0.0	0.0	0.0	**0.0**
Contingency	0.0	0.0	0.0	**0.0**
Total	**1,500.0**	**0.0**	**0.0**	**1,500.0**

The Hydraulic In-Service Failure program started in 2018. Chart 2 shows the historical expenditures since the program was initiated, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast budget through 2028. As Hydro cannot predict the quantity and the nature of failures to be addressed within this program for future years, Hydro has forecast future expenditures for this program based on the 2023 program budget with cost escalation applied.

[4] Hydro's 2024 Capital Expenditures and Carryover report is to be filed on or before April 1, 2025.

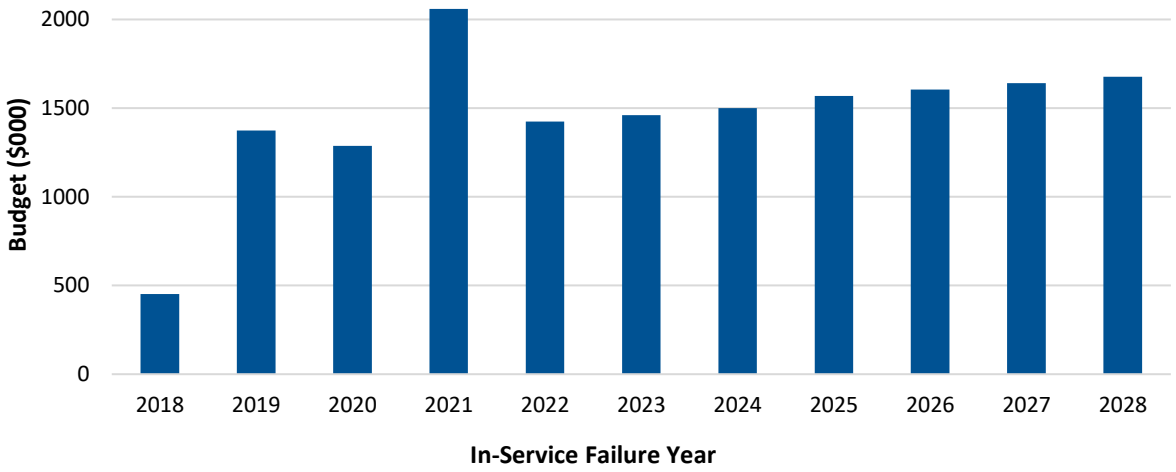


Chart 2: Historical and Forecast Program Budget[5]

7.2 Program Schedule

Work schedules are established subsequent to an unplanned failure or incipient failure event. There are no capital spares acquisitions currently planned under this program for 2024.

8.0 Conclusion

The Hydraulic In-Service Failures program allows Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable operations, in an environmentally responsible manner. This program will also allow Hydro to continue proactively managing the pool of capital spare equipment to support hydraulic operations.

[5] The significant program cost in 2021 is associated with an unplanned project executed at the Upper Salmon Hydroelectric Generating Station that required expenditures exceeding $1.3 million.

Replace Disconnects (2024–2025)

July 2023



Replace Disconnects (2024–2025)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") replaces or refurbishes failing or failed terminal station assets, including disconnect switches, to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

Hydro's philosophy for the assessment of equipment and the selection and justification of projects and programs is outlined in the Terminal Station Asset Management Overview ("Asset Management Overview"), included as an Appendix to Schedule 1.[1]

Hydro considered pace reduction, pace acceleration, and continuation of the program at its current pace. Hydro has determined that the current pace of this program, and the underlying criteria, are necessary to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner. Under this program, Hydro proposes the replacement of disconnect switches that meet Hydro's established criteria for replacement based on a combination of factors including age, obsolescence, and deteriorated condition. Under its 2024–2025 program, Hydro plans to replace 14 disconnect switches located within terminal stations across its system.

This program has a multi-year approach, with completion planned in 2025 at an estimated cost of $1,485,500.

[1] Hydro proposed the activities within this program under the Terminal Station Renewal (2023–2024) program, filed as part of the "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022, vol. II, prog. 3.

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Appendix A: Replace Disconnects Program: 2024–2028 Plan

1.0 Introduction

High-voltage disconnect switches ("disconnect switches") are used as a means of electrically isolating equipment within a terminal station or as a means of bypassing equipment to maintain service during maintenance activities. Disconnect switches are an important part of the Work Protection Code,[2] as they provide utility workers with a visible air gap (i.e., visible isolation). Proper operation of disconnect switches is essential for a safe work environment and terminal station reliability.

2.0 Program Description and Justification

All of the disconnect switches planned for replacement in the Replace Disconnects (2024–2025) program are currently in service.

As detailed in the Asset Management Overview, Hydro replaces disconnect switches when damaged beyond refurbishment, when parts required for refurbishment are unavailable due to obsolescence, when it is not economical to refurbish, or when switches are damaged or defective and have reached a service life of 50 years.

3.0 Asset Overview

3.1 Asset Background

All of the disconnect switches planned for replacement in this program are currently in service. These units will be between 47 and 59 years of age at the scheduled time of replacement some of which have experienced operational deficiencies over the years and part obsolescence has become a concern.

3.2 Asset Condition

Hydro monitors the condition of its disconnect switches by conducting regular visual and infrared inspections to determine the existence of hot spots. Reports from station personnel also identify issues such as mechanical problems and broken insulators.

[2] This system is used to produce necessary documentation to safely isolate pieces of equipment that require maintenance.

3.3 Condition-Based Remaining Life

Disconnect switches that experience failures are repaired, if feasible, as part of ongoing maintenance activities, provided that required parts are available. Disconnect switches that have operating deficiencies and have reached a service life of 50 years or more are replaced under this program.

3.4 Asset Ages

Chart 1 provides asset ages for all assets covered under the program.

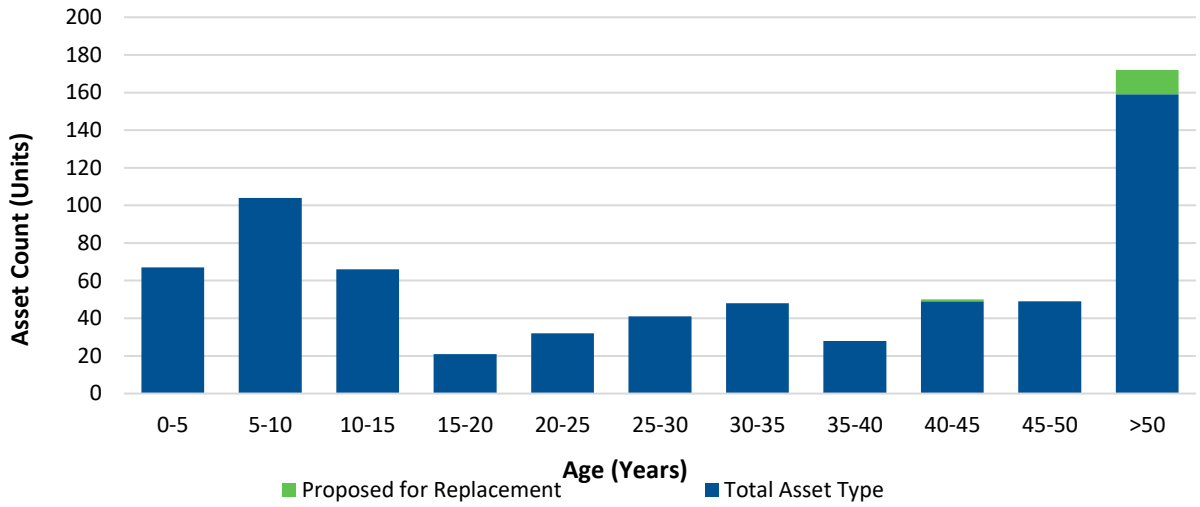


Chart 1: Asset Counts by Asset Age

4.0 Trending

4.1 Assets Installed/Replaced/Upgraded

Chart 2 provides the five-year historical, current, and five-year forecast number of assets installed/replaced/upgraded per year. The number of disconnect switches requiring replacement will vary as switches reach the end of their service life and as deficiencies are identified. As such, the quantity of disconnect switches replaced per year varies.

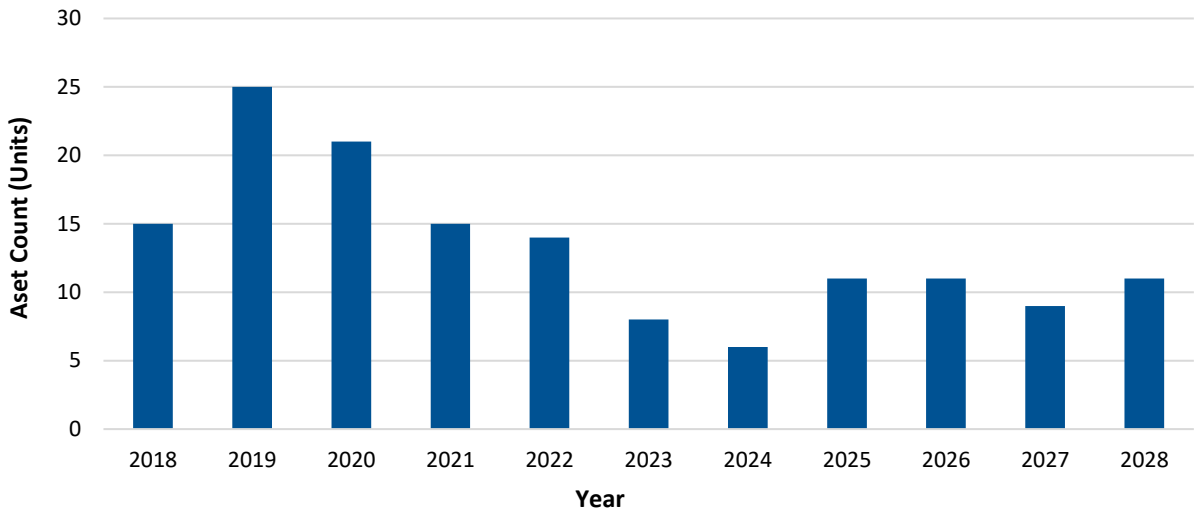


Chart 2: Historical and Forecast Assets Installed/Replaced/Upgraded

4.2 Historical and Forecast Average Unit Costs

Chart 3 provides the five-year historical, current, and five-year forecast average unit cost of asset installation/replacement/upgrades in each year. The number and type of disconnect switches requiring replacement will vary as switches reach the end of their service life and as deficiencies are identified. As such, the average cost per unit varies.

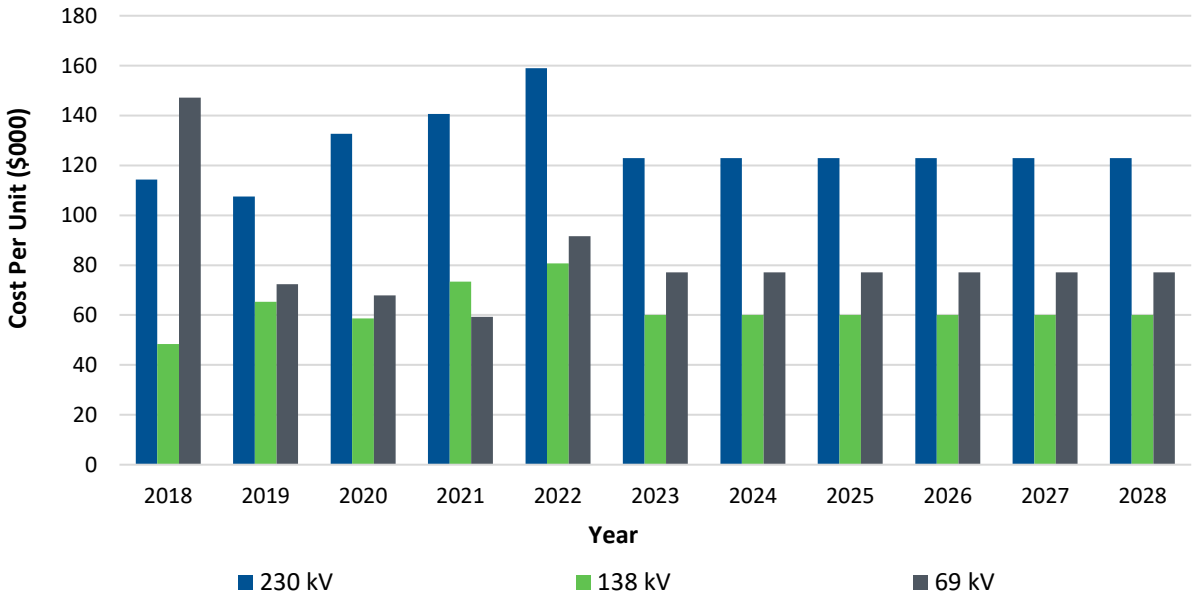


Chart 3: Average Unit Costs of Assets Installed/Replaced/Upgraded

5.0 Historical Reliability

Hydro does not currently record disconnect switch outage statistics; therefore, historical reliability data for the assets covered within this program is not available.

6.0 Analysis

6.1 Evaluation of Alternatives

For the assets recommended for replacement within this program, the following alternatives were considered:

- Pace reduction;
- Pace advancement; and
- Continue program at current pace.

Hydro has not identified any other alternatives for this program.

6.1.1 Pace Reduction

Reducing the pace of replacement for the disconnect switches identified in this proposal would extend the in-service time of these units past Hydro's identified replacement criteria and increase the risk of in-service failures. This would present an increased risk to terminal station reliability and threaten the safe working environment. As such, pace reduction is not considered a viable alternative at this time.

6.1.2 Pace Advancement

Hydro has developed the replacement program considering system criticality, ability to execute, and resource and outage constraints. As such, pace advancement for disconnect switch replacement is not an option.

6.1.3 Continue Program at Current Pace

Proceeding with the identified upgrades ensures that the assets identified as candidates for capital intervention in this proposal would be replaced based on age and condition in a timely manner, as per Hydro's established practices, providing sufficient time to ensure least-cost procurement and installation.

6.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

6.3 Recommended Alternative

Hydro recommends the replacement of the identified disconnect switches to minimize the potential of in-service failures at the affected operational sites.

6.3.1 Risk of Asset Stranding

Hydro has no plans to retire the stations identified within this program from service; therefore, the risk of asset stranding is low.

6.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	5	3	**15**
Post-Execution	5	1	**5**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**6.7**

7.0 Scope of Work

Hydro's five-year plan for the Replace Disconnects program is provided in Appendix A. Based on current condition and asset data, Hydro proposes the replacement of disconnect switches that meet Hydro's established criteria for replacement based on a combination of factors including age, obsolescence, and deteriorated condition. The scope of this program includes engineering design, procurement, installation, and commissioning of disconnect switches. All of these units are planned for replacement before the end of 2025. Based on asset condition and outage and resource availability at the time of execution, Hydro may advance or defer the replacement of specific assets to ensure efficient and effective implementation of this program.

7.1 Program Budget

The estimate for the 2024–2025 program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	0.0	518.3	0.0	**518.3**
Labour	89.4	602.8	0.0	**692.2**
Consultant	21.8	19.9	0.0	**41.7**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.5	26.0	0.0	**26.5**
Interest and Escalation	4.5	74.4	0.0	**78.9**
Contingency	11.2	116.7	0.0	**127.9**
Total	**127.4**	**1,358.1**	**0.0**	**1,485.5**

Chart 4 shows the five-year historical expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028. Variability in budgets can be attributed to the quantity and voltage class of disconnects to be replaced in a given year.

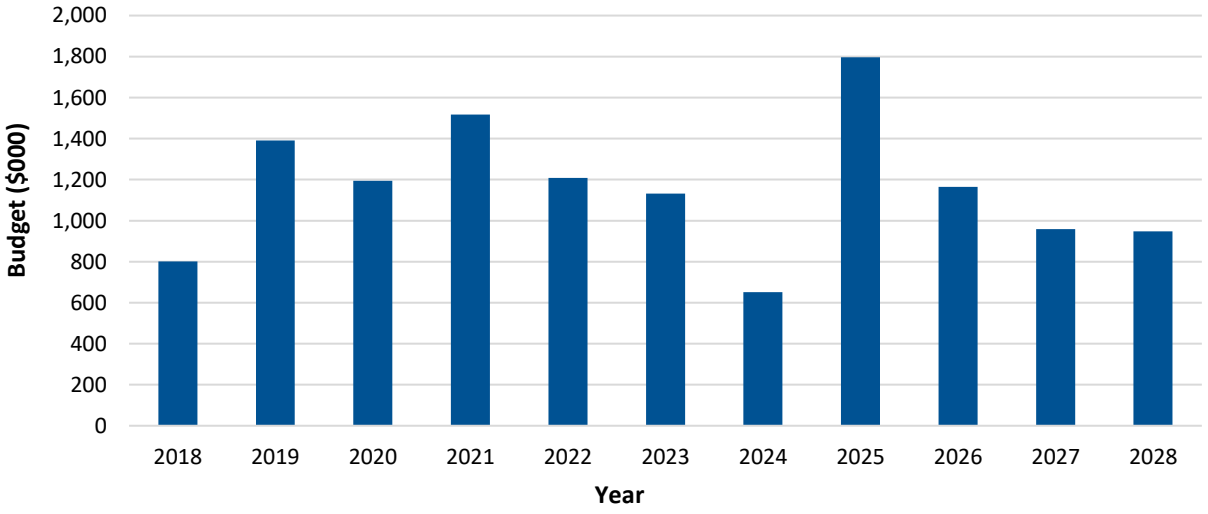


Chart 4: Historical and Forecast Program Budget

7.2 Program Schedule

The schedule for the 2024–2025 program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Initial planning and scheduling.	January 2024	February 2024
Design:		
Conduct site visits and complete detailed design.	March 2024	April 2024
Procurement:		
Order disconnects and miscellaneous materials.	May 2024	December 2024
Construction:		
Replace disconnect switches.	May 2025	September 2025
Commissioning:		
Commission disconnect switches.	May 2025	September 2025
Closeout:		
Complete closeout documentation.	November 2025	December 2025

8.0 Conclusion

Under the 2024-2025 program, 14 disconnect switches require replacement, as they meet the applicable replacement criteria. Only 1 of these does not meet the age criterion of 50 years or more but has been identified for replacement due to operating deficiencies. The other 13 disconnect switches meet the age criterion, with 12 of those also having no replacement parts available due to obsolescence, and the 1 remaining switch also having operating deficiencies.

Appendix A

Replace Disconnects Program

2024–2028 Plan





Assets planned for replacement from 2024 to 2028 under the Replace Disconnects program are provided in Table A-1 to Table A-5.

Table A-1: Assets Planned for Replacement in 2024

Name	Voltage (kV)
Bay d'Espoir B2B3-2	230
Bay d'Espoir B3T6-1	230
Massey Drive B5T2	230
Oxen Pond B4B5	69
Oxen Pond B2B3	69
Stony Brook L04L32-2	230

Table A-2: Assets Planned for Replacement in 2025

Name	Voltage (kV)
South Brook L22T1-1	138
Sunnyside B1L03-1	230
Stony Brook L05L31-1	230
Stony Brook L05L31-2	230
Stony Brook L05L35-1/L05G	230
Stony Brook L05L35-2/L35G	230
Wabush Terminal Station B1L23-2/L23G	230
Wabush Terminal Station B1L24-2	230
Wabush Terminal Station B1T1/T1G	230
Wabush Terminal Station L24G	230
Western Avalon B4L64-2/L64G	138

Table A-3: Assets Planned for Replacement in 2026

Name	Voltage (kV)
Doyles B1L15-1	69
Massey Drive B1L28-1	230
Massey Drive B1L28-2/L28G	230
Stony Brook B2L04-1	230
Stony Brook B2L04-2/L04G	230
Stony Brook B3L130-1	138
Stony Brook B3L130-2/L130G	138
Stony Brook B3T1-1	138
Wabush Terminal Station B1L23-1	230
Wabush Terminal Station B1L24-1	230
Wabush Terminal Station B1T3/T3G	230
Wabush Terminal Station B4L34-1	69

Table A-4: Assets Planned for Replacement in 2027

Name	Voltage (kV)
Bottom Brook L400T2-1/L400G	69
Holyrood B15T7	230
Happy Valley B13L03-1	138
Hardwoods B2T3	230
Sunnyside L02L07 -2	230
Stony Brook B1L31-1	230
Stony Brook B1L31-2/L31G	230
Stony Brook B1L35-1	230
Western Avalon B1L17-1	230

Table A-5: Assets Planned for Replacement in 2028

Name	Voltage (kV)
Doyles B1T1-1	69
Doyles L14AG	138
Doyles L14T1/L14G	138
Massey Drive B2L352-1	69
Massey Drive B2L356-1	69
Massey Drive B3L351-1	69
Massey Drive B3L357-1	69
Oxen Pond C1G1	69
Oxen Pond C1G2	69
Western Avalon B3T4	230
Western Avalon B3T5	230

Terminal Station In-Service Failures (2024)

July 2023



Terminal Station In-Service Failures (2024)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has an Asset Management Program that governs the life cycle of its terminal station assets. This program monitors, maintains, refurbishes, replaces, and disposes of assets to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

Generally, Hydro identifies and plans the refurbishment and replacement work that will be required for its terminal station assets in time for inclusion within the capital budget application ("CBA"). However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or the determination of faster-than-anticipated equipment deterioration.

Hydro is proposing that within the Terminal Station In-Service Failures program, it will undertake the immediate capital refurbishment and replacement work required for its terminal station assets to maintain safe and reliable operation and to ensure the availability of capital spares required to support such work.

The estimated cost for work executed under this program in 2024 is $1,300,000, which is based on the average expenditure over the three years from 2019 to 2021. The expenditures in 2022 were not included as they were significantly larger than usual, primarily due to the failure of a transformer at the Bay d'Espoir Hydroelectric Generating Facility.[1]

[1] While Hydro considers the "Terminal Station In-Service Failures (2022)" program expenditure to be an outlier, Hydro will re-evaluate the inclusion of the 2022 data in future program budgets if expenditures continue to exceed the 2019–2021 average.

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1.0 Introduction

Hydro conducts asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize the disruption of service and to avoid unsafe working conditions due to equipment failure. An objective of Hydro's Asset Management Program is to identify refurbishment and replacement activities that require approval by the Board of Commissioners of Public Utilities ("Board") in time to be included in Hydro's annual CBA. The identification is done through the preventive maintenance program using various condition-based assessments and testing procedures.

Hydro has had success in projecting the deterioration rate of equipment for submission of refurbishment or replacement work into CBAs. However, there are situations where immediate refurbishment or replacement must be completed due to the occurrence of an actual failure, the identification of an incipient failure, or the determination of faster-than-anticipated equipment deterioration. These situations can be caused by events such as vandalism, storm damage, lightning, accidental damage, abnormal system operations, corrosion, etc. Hydro uses historical data and engineering judgment to predict the magnitude of in-service failure expenditures.

2.0 Program Description and Justification

Due to the nature of terminal station equipment and infrastructure, unanticipated failures and deterioration will occur. Under the Terminal Station In-Service Failures program, Hydro is proposing to undertake the immediate capital refurbishment and replacement work required for its terminal station assets, as needed, to maintain safe and reliable operation and to ensure the availability of capital spares required to support such work. At this time, Hydro does not have any planned capital spare acquisitions under this program; however, throughout 2024, Hydro may purchase capital spares identified by asset management personnel as requiring immediate procurement to offset deficiencies in its capital spares.

Deferral of work that is justified under this program could result in a detrimental impact to customer power supply or unacceptable risk to worker or public safety.

Depending on the relevant circumstances, required work will be evaluated to determine the appropriate form of execution as an in-service failure, an allowance for unforeseen item, or a supplemental project.

3.0 Asset Overview

3.1 Asset Background

The assets requiring immediate, unplanned replacement or refurbishment work in a given year cannot be identified in advance. The assets covered within the Terminal Station In-Service Failures program are generally included in the following broad asset classes:

- Instrument transformers;
- Disconnect switches;
- Surge arresters;
- Insulators;
- Grounding systems;
- Power transformers;
- Circuit breakers;
- Station service equipment;
- Battery banks and chargers;
- Station lighting;
- Synchronous condensers and associated equipment;
- Equipment foundations;
- Protection, control, and monitoring systems;
- Site buildings and services; and
- Auxiliary equipment.

For further information on the work executed under the Terminal Station In-Service Failures (2022) program, please refer to Hydro's "Capital Expenditures and Carryover Report for the Year Ended December 31, 2022."[2]

3.2 Asset Condition

Assets replaced or refurbished under this program have experienced unplanned failure or exhibited signs of incipient failure.

3.3 Condition-Based Remaining Life

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure; therefore, these assets have reached the end of their serviceable life.

3.4 Asset Ages

The age of assets potentially covered under this program varies. Unplanned replacement or refurbishment activities due to failure may be necessary at any time during the asset lifecycle.

4.0 Trending

Hydro implemented the Terminal Station In-Service Failures program in 2017. Since that time, Hydro has initiated, on average, 12 unplanned projects per year under the program.

4.1 Assets Installed/Replaced/Upgraded

The number of unplanned In-Service Failures projects initiated under the program over the past five years is provided in Chart 1.[3] Details of each project, and the associated assets and costs, are filed with the Board within Hydro's annual Capital Expenditures and Carryover Report.

Hydro anticipates that unplanned failures will continue to occur given the age and number of terminal station assets covered under the program. Hydro continues to plan the budget for this program based on historical information.

[2] "Capital Expenditures and Carryover Report for the Year Ended December 31, 2022," Newfoundland and Labrador Hydro, March 30, 2023, sec. 9.0, Table 6, pp.51–54. <http://pub.nl.ca/indexreports/expenditure/From%20NLH%20-%202022%20Capital%20Expenditures%20and%20Carryover%20Report%20-%202023-03-31.PDF>

[3] The 2022 expenditures consolidated as "Projects under $50,000" are being treated as one singular project.

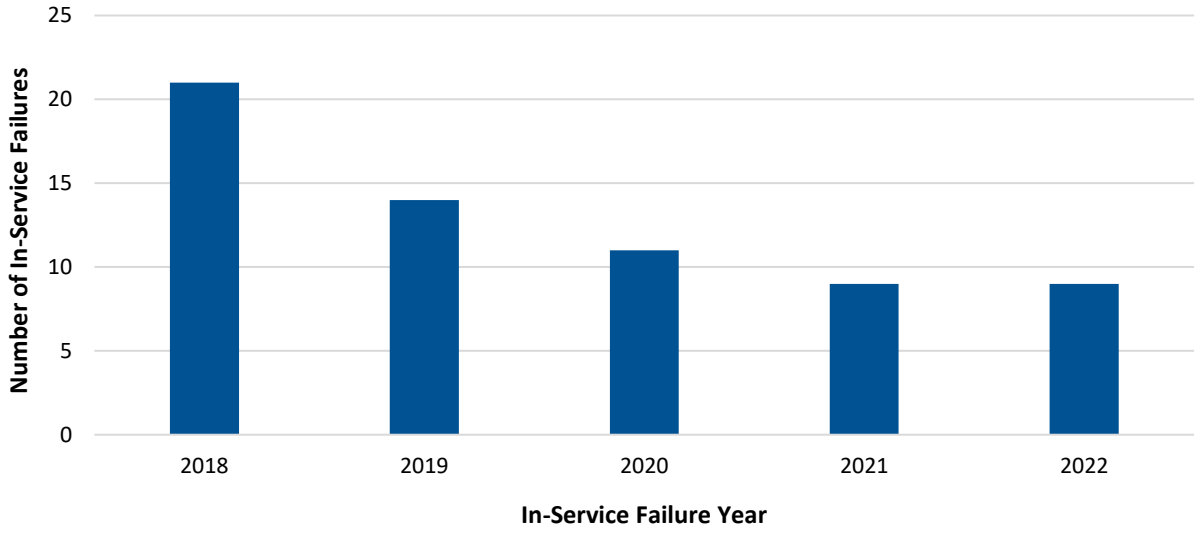


Chart 1: In-Service Failure Frequency

4.2 Historical and Forecast Average Unit Costs

Historical and forecast program costs are provided in Chart 2 in Section 7.1. Due to the nature of this program and the range of assets covered, average unit cost information is not applicable. An increase in program cost is forecast based on the anticipated escalation of both material and labour costs.

5.0 Historical Reliability

As this program addresses a wide range of asset types, the specific assets to be addressed within this program for 2024 are not known. As such, historical reliability data for the individual assets covered within this program is not applicable.

6.0 Analysis

6.1 Evaluation of Alternatives

Depending on the nature of each failure, or incipient failure, Hydro reviews viable technical alternatives to determine the most appropriate solution to address the unplanned event while balancing urgent safety and operational risks.

Due to the urgent nature of work executed under this program, seeking approval through a supplemental capital expenditures application or deferring the work for inclusion in the next CBA are not viable alternatives. The alternative of executing required unplanned work under the Allowance for

Unforeseen Items Account is also considered on a case-by-case basis, subject to the requirements set out by the Board for the use of the account.

6.2 Risk of Asset Stranding

Assets replaced or refurbished under this program have an inherently low risk of asset stranding. The assets covered under this program are critical to Hydro's ability to meet customer requirements. Hydro does not currently plan to retire any of its terminal stations. The risk of asset stranding would be considered on a case-by-case basis, if applicable.

6.3 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	5	**15**
Post-Execution	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**9.2**

7.0 Scope of Work

Work executed under this program in 2024 will be reported to the Board in Hydro's 2024 Capital Expenditures and Carryover Report.[4]

7.1 Program Budget

The estimate for the 2024 program is shown in Table 2. The estimate is based on the average expenditures from 2019 to 2021. The expenditures in 2022 were not included, as this year is considered an outlier due to the significant costs associated with the failure of Bay d'Espoir Transformer T5, Hydro will re-evaluate the inclusion of the 2022 data in future program budgets if expenditures continue to exceed the 2019–2021 average. The details of each project covered under this program, including the

[4] Hydro's 2024 Capital Expenditures and Carryover Report is to be filed on or before April 1, 2025.

associated assets and costs, as well as the total program expenditures for each year, are filed with the Board within Hydro's annual Capital Expenditures and Carryover Report.

Table 2: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	655.1	0.0	0.0	**655.1**
Labour	136.8	0.0	0.0	**136.8**
Consultant	47.6	0.0	0.0	**47.6**
Contract Work	400.0	0.0	0.0	**400.0**
Other Direct Costs	11.0	0.0	0.0	**11.0**
Interest and Escalation	49.5	0.0	0.0	**49.5**
Contingency	0.0	0.0	0.0	**0.0**
Total	**1,300.0**	**0.0**	**0.0**	**1,300.0**

The Terminal Station In-Service Failure Program started in 2017. Chart 2 shows the five-year historical expenditures since 2018, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028. As Hydro cannot predict the quantity and the nature of failures to be addressed within this program for future years, Hydro has forecast future expenditures for this program based on the 2023 program budget with cost escalation applied.

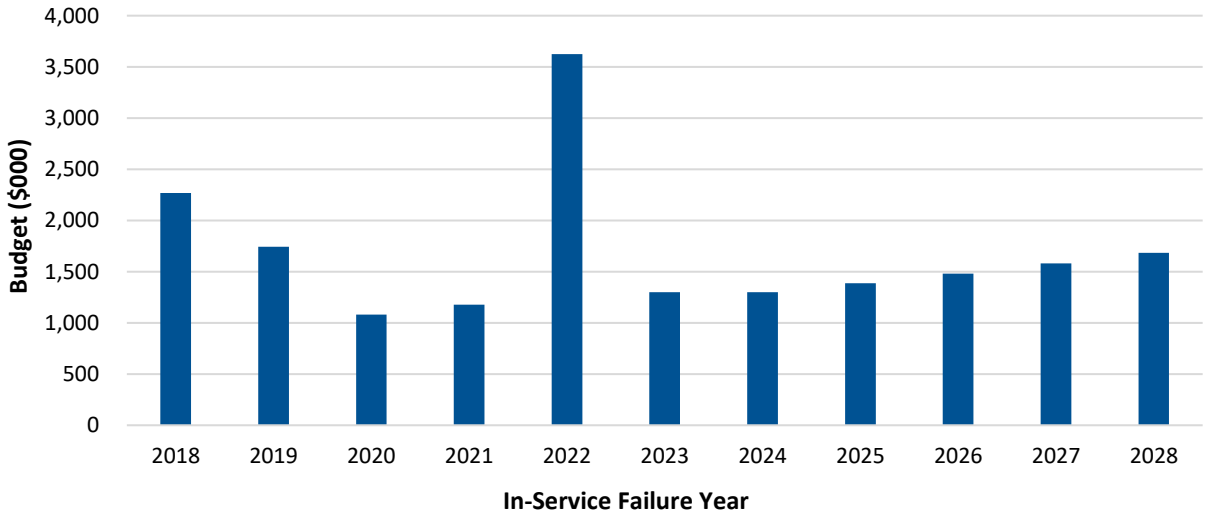


Chart 2: Historical and Forecast Program Budget

7.2 Program Schedule

Work schedules are established subsequent to an unplanned or incipient failure event. Hydro does not have any planned capital spare acquisitions under this program in 2024.

8.0 Conclusion

The Terminal Station In-Service Failures program allows Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable operations in an environmentally responsible manner. This program will also allow Hydro to continue to proactively manage the pool of capital spare equipment to maintain the integrity and reliability of the electrical system.

Program 17

Replace Instrument Transformers (2024–2025)

July 2023

newfoundland labrador hydro

Replace Instrument Transformers (2024–2025)

Location(s): Various

Investment Classification: Renewal

Asset Category: Terminal Station

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") replaces or refurbishes failing or failed terminal station assets, including instrument transformers, to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

Hydro's philosophy for the assessment of equipment and the selection and justification of projects and programs related to the replacement or refurbishment of assets is outlined in the Terminal Station Asset Management Overview ("Asset Management Overview"), included as an Appendix to Schedule 1.[1]

Under this program, Hydro proposes the replacement of 13 instrument transformers, which are located within terminal stations across Hydro's system. Of the instrument transformers identified, 5 are being replaced to ensure compliance with federal environmental *PCB Regulations*, as these units are suspected of being contaminated with polychlorinated biphenyls ("PCB") and must be removed by 2025.[2] The other identified transformers within the program have been proposed for replacement due to age, as the risk of failure is too high for them to remain in service.

This program has a multi-year approach, with completion planned in 2025 at an estimated cost of $869,700.

[1] Hydro proposed the activities within this program under the Terminal Station Renewal (2023–2024) program, filed as part of the "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022.
[2] The *Canadian Environmental Protection Act, 1999,* SC 1999, c 33 includes *PCB Regulations* (SOR/2008-273), which provide end-of-use dates for various concentrations of PCBs.

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Appendix A: Replace Instrument Transformers Program: 2024–2028 Plan

1.0 Introduction

Current and potential transformers measure currents and voltages and scale these values such that they can be read by metering and protective relaying equipment. Current transformers and potential transformers are collectively identified as instrument transformers.

2.0 Program Description and Justification

Instrument transformers included in the Replace Instrument Transformers program are used continuously to measure current or voltage in a terminal station. Instrument transformers are critical components allowing the protection, control, and metering systems within their terminal stations to function properly.

Hydro's Asset Management Overview outlines that the justification for replacements in this program can be age-based or condition-based. Hydro targets replacement at 40 years of age to reduce the risk of in-service failures and minimize service interruptions.

Hydro monitors instrument transformers for physical and electrical deterioration by conducting regular visual inspections of the units as part of its station inspection program as well as regularly scheduled station infrared inspections and electrical insulation testing. Physical deterioration includes conditions such as oil leaks, rusting, or small chips and cracks in the insulation. Electrical deterioration is identified by conducting power factor testing at intervals, which is used to establish the rate and level of insulation degradation.

Under the scope of the 2024–2025 program, of the 13 instrument transformers, 8 will be replaced based on age. Extending the in-service time of these units past the manufacturer-recommended design life increases the risk of in-service failures. The remaining 5 instrument transformers will be replaced based on both age and suspected PCB contamination. Federal environmental *PCB Regulations* necessitate that by December 31, 2025, no instrument transformers will have a PCB concentration greater than 50 mg/kg.

3.0 Asset Background

The performance of these assets has been normal.

3.1 Asset Ages

The asset ages presented in Chart 1 represent the age of the asset at the time of filing. It is noted that several instrument transformers categorized in the 35–40 grouping are presently 39 years old, and will meet the age criteria in 2025 when they are due for replacement.

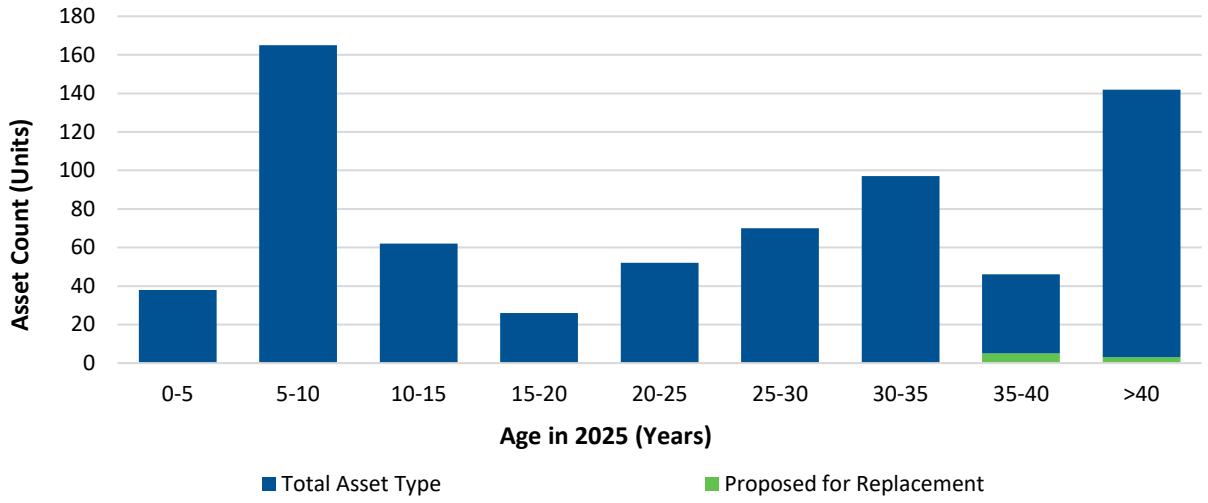


Chart 1: Asset Counts by Asset Age (Units)

4.0 Analysis

4.1 Recommended Alternative

For the assets recommended for replacement, refurbishment, and modernization within this program, the following alternatives were considered:

- Pace reduction; and
- Continue program at current pace.

For the instrument transformers that are suspected of PCB contamination, pace reduction is not an acceptable alternative as these units are suspected of being PCB-contaminated. Reducing the pace of replacement for the instrument transformers located in the remaining sites would extend the in-service time of these units past the manufacturer's recommended design life and increase the risk of in-service failures. For these reasons, pace reduction is not considered a viable alternative at this time.

Hydro recommends the replacement of the identified instrument transformers to minimize the potential of in-service failures at the affected operational sites. Under this alternative, the instrument

transformers would be replaced based on age and condition as per Hydro's established practices. This alternative provides sufficient time to ensure least-cost procurement and installation.

4.1.1 Risk of Asset Stranding

Hydro has no plans to retire from service the stations identified within this program; therefore, the risk of asset stranding is low.

4.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	4	**12**
Post-Execution	3	1	**3**
		Risk Mitigated	**9**
		Risk Mitigated per $1 Million	**10.3**

5.0 Scope of Work

Hydro's five-year plan for the Replace Instrument Transformers program is provided in Appendix A. Based on current conditions and asset data, Hydro plans to replace 13 instrument transformers under the 2024–2025 program, with completion scheduled by the end of 2025. Based on asset condition and outage and resource availability at the time of execution, Hydro may advance or defer the replacement of specific assets to ensure efficient and effective implementation of this program.

5.1 Program Budget

The estimate for the 2024–2025 program is shown in Table 2.

Table 2: Replace Instrument Transformers ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	0.0	315.1	0.0	**315.1**
Labour	111.3	263.6	0.0	**374.9**
Consultant	21.8	19.9	0.0	**41.7**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	3.0	14.7	0.0	**17.7**
Interest and Escalation	5.2	40.1	0.0	**45.3**
Contingency	13.6	61.4	0.0	**75.0**
Total	**154.9**	**714.8**	**0.0**	**869.7**

Chart 2 provides the five-year historical program expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028. The program scope up to 2021 included several instrument transformers that were suspected to contain PCBs. The 2024–2025 program scope also includes several units that are suspected of being PCB-contaminated. There is a reduction in the forecast budget beyond 2025, as all of the suspected PCB-contaminated units will have been removed.

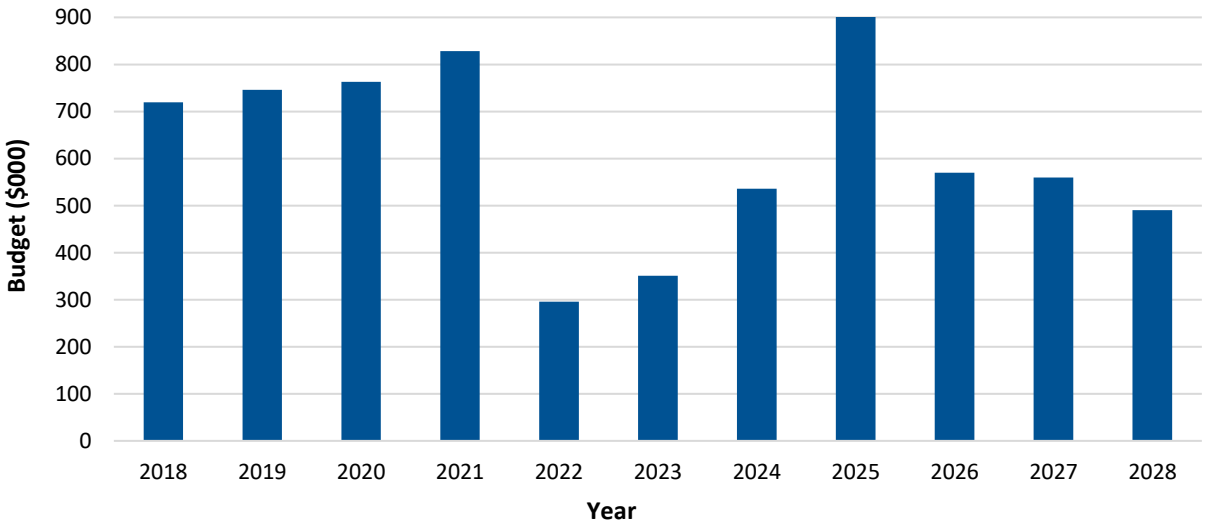


Chart 2: Historical and Forecast Program Budget

5.2 Program Schedule

The schedule for the 2024–2025 program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning: Scope, schedule, cost, risk, quality, and communication planning.	January 2024	March 2024
Design: Detailed design and site visits.	February 2024	March 2024
Procurement: Procurement of long lead items.	April 2024	May 2024
Construction: Replacement of instrument transformers.	July 2025	September 2025
Commissioning: Commissioning of new instrument transformers.	July 2025	September 2025
Closeout: Complete closeout documentation.	October 2025	November 2025

6.0 Conclusion

Under the 2024–2025 program, 13 instrument transformers require replacement, as they meet the applicable replacement criteria. At the time of replacement, all noted assets would meet the age criterion of 40 or more years with 5 assets also meeting the condition criterion of suspected PCB contamination, as required for compliance with federal environmental *PCB Regulations*.

Appendix A

Replace Instrument Transformers Program

2024–2028 Plan



Assets planned for replacement from 2024 to 2028 under the Replace Instrument Transformers program are provided in Table A-1 to Table A-5.

Table A-1: Assets Planned for Replacement in 2024

Name	Voltage (kV)
Deer Lake T2 ‘B’ Phase Potential Transformer	138
Hardwoods B2L42 ‘A’ Phase Current Transformer	230
Hardwoods B2L42 ‘B’ Phase Current Transformer	230
Hardwoods B2L42 ‘C’ Phase Current Transformer	230
Wabush Terminal Station B1L24 ‘A’ Phase Current Transformer	230
Wabush Terminal Station B1L24 ‘B’ Phase Current Transformer	230
Wabush Terminal Station B1L24 ‘C’ Phase Current Transformer	230

Table A-2: Assets Planned for Replacement in 2025

Name	Voltage (kV)
Cat Arm TL247 ‘C’ Phase Potential Transformer	230
Holyrood B12L18 ‘A’ Phase Current Transformer	230
Holyrood B12L18 ‘B’ Phase Current Transformer	230
Holyrood B12L18 ‘C’ Phase Current Transformer	230
Holyrood B13B15 ‘A’ Phase Current Transformer	230
Holyrood B13B15 ‘B’ Phase Current Transformer	230
Stony Brook B1 ‘B’ Phase Potential Transformer	230
Wabush Terminal Station B1L23 ‘A’ Phase Current Transformer	230
Wabush Terminal Station B1L23 ‘B’ Phase Current Transformer	230
Wabush Terminal Station B1L23 ‘C’ Phase Current Transformer	230
Western Avalon B1 ‘A’ Phase Potential Transformer	230
Western Avalon B1 ‘B’ Phase Potential Transformer	230
Western Avalon B1 ‘C’ Phase Potential Transformer	230

Table A-3: Assets Planned for Replacement in 2026

Name	Voltage (kV)
Berry Hill TL227 ‘A’ Phase Potential Transformer	69
Berry Hill TL227 ‘C’ Phase Potential Transformer	69
Deer Lake TL247 ‘B’ Phase Potential Transformer	230
Sunnyside 100L ‘C’ Phase Potential Transformer	138
Stony Brook TL222 ‘B’ Phase Potential Transformer	138
Wabush Terminal Station Capacitive Variable Transformer 1-1	230
Wabush Terminal Station Capacitive Variable Transformer 1-2	230
Wabush Terminal Station Capacitive Variable Transformer 1-3	230
Wabush Terminal Station L23 ‘B’ Phase Capacitive Variable Transformer	230
Wabush Terminal Station L24 ‘B’ Phase Capacitive Variable Transformer	230

Table A-4: Assets Planned for Replacement in 2027

Name	Voltage (kV)
Buchans TL233 ‘C’ Phase Current Transformer	230
Grandy Brook TL250 ‘A’ Phase Potential Transformer	138
Grandy Brook TL255 ‘A’ Phase Current Transformer	138
Hinds Lake TL243 ‘B’ Phase Potential Transformer	138
Howley TL243 ‘B’ Phase Potential Transformer	138
Hardwoods B2 ‘B’ Phase Potential Transformer	230
Massey Drive B1 ‘A’ Phase Potential Transformer	230
Massey Drive B1 ‘B’ Phase Potential Transformer	230
Upper Salmon TL234 ‘A’ Phase Potential Transformer	230
Upper Salmon TL234 ‘B’ Phase Potential Transformer	230
Upper Salmon TL234 ‘C’ Phase Potential Transformer	230

Table A-5: Assets Planned for Replacement in 2028

Name	Voltage (kV)
Come By Chance B1B2 (B1) ‘B’ Phase Current Transformer	230
Come By Chance B1B2 (B1) ‘C’ Phase Current Transformer	230
Come By Chance B1B2 (B1/TL207 Side) ‘A’ Phase Current Transformer	230
Come By Chance B1B2 (B2) ‘B’ Phase Current Transformer	230
Come By Chance B1B2 (B2) ‘C’ Phase Current Transformer	230
Come By Chance B1B2 (B2/TL237 Side) ‘A’ Phase Current Transformer	230
Come By Chance TL207 ‘A’ Phase Potential Transformer	230
Come By Chance TL207 ‘B’ Phase Potential Transformer	230
Roddickton Woodchip TL257 ‘B’ Phase Potential Transformer	69

Perform Software Upgrades and Minor Enhancements (2024)

July 2023



Perform Software Upgrades and Minor Enhancements (2024)

Location: Hydro Place

Investment Classification: General Plant

Asset Category: Information Systems

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") must keep software applications current to ensure reliability, security, and continued vendor support. Vendors regularly release updates to accommodate security patches, bug fixes, and feature enhancements. In-house-built applications also need to be upgraded using modern programming frameworks to maintain compatibility with other dependent applications.

In 2024, Hydro proposes to upgrade the line frequency analyzer software, components of meter reading software (including a mobile version), the customer service web application, and various in-house-built applications used by the Energy Control Centre ("ECC"). The 2024 program also includes a new secured browser user interface for the Energy Management System ("EMS"). The 2024 program also provides for upgrades or minor enhancements to software applications in response to unforeseen requests associated with changing business needs.

The estimated cost for work executed under this program in 2024 is $864,200.

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1.0 Introduction

This program involves upgrading and enhancing software systems and applications used by the Hydro Operational Technology ("OT") group to maintain the EMS, as well as applications that support processes in specific business areas such as customer service, drafting, and Transmission and Rural Operations. This program also provides for minor upgrades or enhancements to software applications in response to unforeseen requests associated with changing business needs.

2.0 Program Description and Justification

Hydro utilizes many software systems and applications to support its business needs. Software applications and functional requirements are diverse and quickly evolving, as are the technology platforms used by these software applications. This program supports Hydro's ability to respond to changing business needs and allows for continual improvement of Hydro's systems and their functionality for users.

For 2024, Hydro proposes to upgrade the line frequency analyzer software, components of meter reading software (including a mobile version), and the customer service web application. Hydro also looks to update various in-house-built applications used by the ECC, including a contingency analysis application; an application used to track, schedule, and manage equipment outages; and an application to track software requests from the business. The 2024 program also includes a new secured user interface for the EMS. Unforeseen requests received in 2024 for justifiable upgrades and enhancements will be completed within the approved budget for this program, where possible. Such unplanned work will be reported in Hydro's 2024 Capital Expenditures and Carryover Report.[1]

3.0 Asset Background

Hydro's OT software systems and applications consist of engineering drafting tools, control systems, geographic information systems, financial calculators, planning tools, network analysis tools, and customer utility systems. These systems and applications are used by employees daily to manage the business and are reviewed regularly to effectively plan necessary upgrades and enhancements.

[1] Hydro's 2024 Capital Expenditures and Carryover Report is to be filed on or before April 1, 2025.

The software systems and applications planned for installation or upgrade in 2024 are described herein.

- Line Frequency Analyzer: An application used to monitor system frequency in three primary locations;
- Secured User Interface for EMS: A browser-based user interface that allows users to securely interface with Hydro's EMS;
- Meter Reading Software Component Upgrade, including a Mobile Version: An application used for automated meter reading that collects consumption data on energy metering devices and interfaces with the Enterprise Resource Planning system for billing;
- Customer Service Web Portal Upgrade: A web application that allows customers to manage their account information; and
- In-House-Built Applications: Databases currently in use that are using deprecated technologies that require replacement using secure/supported platforms. In 2024, this includes the contingency analysis application; an application to track, schedule, and manage equipment outages; and an application used to track software requests from the business.

3.1 Asset Ages

Software systems and applications managed under this program have variable ages and unpredictable lifecycles. Upgrade and enhancement requirements are driven by technology advancements, changes in business requirements, and vendor-released version upgrades.

4.0 Analysis

4.1 Recommended Alternative

Hydro recommends upgrading and enhancing the identified software systems in 2024. This alternative is the only viable option to address the required changes. Deferral of these upgrades is not recommended as it could lead to software failure, the loss of visibility by the ECC operators, and/or additional cyber security vulnerabilities.

4.1.1 Risk of Asset Stranding

The software proposed to be upgraded or enhanced under this program are critical applications to the EMS. These continually evolving software systems and applications are used daily; as such, there is minimal risk for asset stranding.

4.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	5	**15**
Post-Execution	3	2	**6**
		Risk Mitigated	**9**
		Risk Mitigated per $1 Million	**10.4**

5.0 Scope of Work

A preliminary analysis has identified the software systems and applications that require upgrades, enhancements and additional licensing as follows:

- Line frequency analyzer;
- Secured user interface for EMS;
- Meter reading software component upgrade, including mobile version;
- Customer service web application upgrade;
- Various in-house-built applications that are used by the ECC; and
- Unforeseen requests.

The detailed program scope will be confirmed during the planning and design stages of the program. The scope of additional unforeseen requests received in 2024 will be determined once the request is reviewed and justified for inclusion in the program.

5.1 Program Budget

The estimate for the 2024 program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	100.0	0.0	0.0	**100.0**
Labour	324.3	0.0	0.0	**324.3**
Consultant	334.3	0.0	0.0	**334.3**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	29.7	0.0	0.0	**29.7**
Contingency	75.9	0.0	0.0	**75.9**
Total	**864.2**	**0.0**	**0.0**	**864.2**

Chart 1 shows the five-year historical expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028. This chart shows that there has been a significant program budget increase since 2020 due in part to increased demand on OT systems and vendors releasing updates to enhance functionality and security. As a result, Hydro will need to perform additional upgrades on in-house-built solutions to accommodate these updates.

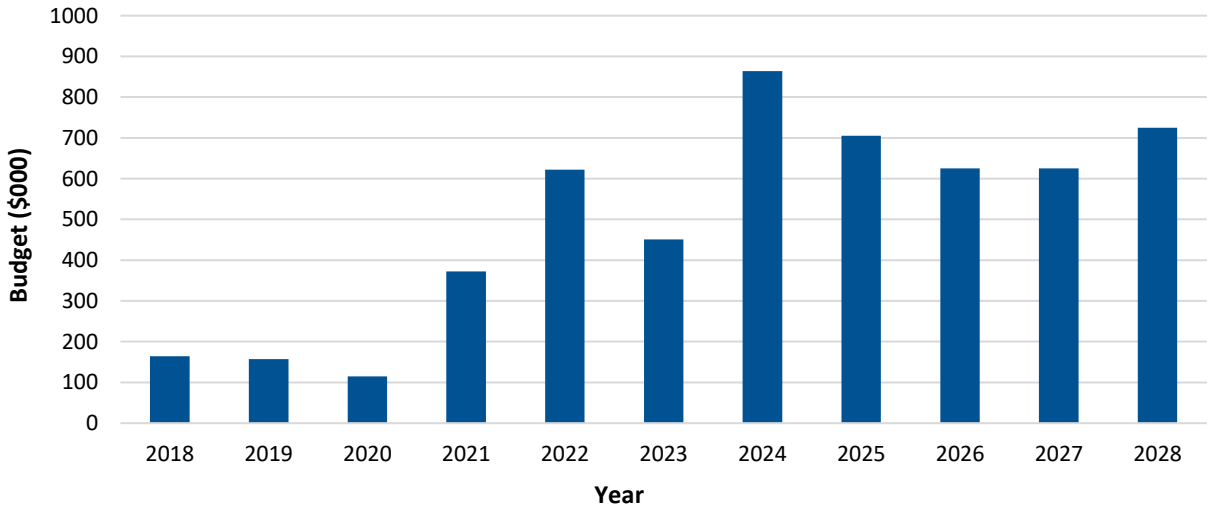


Chart 1: Historical and Forecast Program Budget

5.2 Program Schedule

The schedule for the 2024 program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Detailed scope definition and review schedule.	January 2024	June 2024
Design:		
Complete detailed design and create a program plan.	February 2024	July 2024
Procurement:		
Award requests for proposals (if required) and secure resources.	February 2024	August 2024
Construction:		
Build software enhancements.	May 2024	November 2024
Commissioning:		
Go live with enhancements.	June 2024	November 2024
Closeout:		
Complete closeout documentation.	November 2024	December 2024

6.0 Conclusion

Hydro maintains many software systems and applications to support its business processes. Upgrades and enhancements are planned regularly to improve the functionality and security of systems and applications. This program includes planned upgrades and enhancements and allows Hydro to respond to additional unforeseen requests for system improvements that cannot be deferred to a subsequent year.

Overhaul Diesel Units (2024)

July 2023



Overhaul Diesel Units (2024)

Location: Various

Investment Classification: Renewal

Asset Category: Generation

Executive Summary

To support the continued safe and reliable operation of diesel units, Newfoundland and Labrador Hydro ("Hydro") is proposing the overhaul of five diesel engines in 2024 utilizing a usage-based schedule.

The two main components of a diesel generation unit ("genset") overhaul include the engine and alternator. Diesel engines are overhauled or replaced, depending on cost, approximately four times during the life of the genset, while the alternator is overhauled once. Units that operate at 1,200 rpm are overhauled at a frequency of 30,000 operating hours[1] and units that operate at 1,800 rpm are overhauled at 20,000 hours. Overhauls are required to ensure each engine can meet its expected life of 120,000 hours for 1,200 rpm units and 100,000 hours for 1,800 rpm units.

Hydro has 23 diesel generating stations, 19 of which are the sole source of power to a community. Regular overhauls ensure Hydro fulfills its mandate of providing reliable service to all customers.

Under the 2024 program, Hydro is proposing to overhaul five gensets.

The estimated cost for work executed under this 2024 program is $829,200.

[1] The 1,200 rpm unit overhaul interval increased from 20,000 hours to 30,000 hours, as described in "2020 Capital Budget Application," Newfoundland and Labrador Hydro, August 1, 2019, vol. II, tab 13.

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1.0 Introduction

Hydro has 23 diesel generating stations, serving approximately 4,400 customers. Of these stations, 19 are isolated and the sole source of power to a community. The number of gensets at each generating station ranges from three to six while the rated output of the units ranges from 40 kW to 2,500 kW. The gensets across the system range in age from less than 1 year to 52 years and currently range in operating hours from 1,425 hours to over 110,500 hours.[2]

The genset models proposed for overhaul within this program are anticipated to reach or exceed the number of operating hours for recommended overhauls based on the rotational speed of the unit in 2024. All of Hydro's gensets operate at either 1,200 rpm or 1,800 rpm.

2.0 Program Description and Justification

Hydro's diesel generating stations are isolated and in most cases are the sole sources of power to a community. This program is required to maintain the reliable operation of the components of these stations. Hydro has maintained overhauls at 20,000 operating hours for 1,800 rpm engines and has moved to 30,000 operating hours for 1,200 rpm engines, based on the reliable performance and the condition of parts observed during previous overhauls. Hydro will assess the impact of the change in overhaul interval for 1,200 rpm engines based on the performance and condition of the engines when overhauled to ensure this change in timing is proving appropriate. To defer or skip an overhaul would increase the risk of an engine or generator failure, resulting in reduced reliability of the generating station. Hydro is proposing to overhaul five diesel units in 2024.

3.0 Asset Background

A diesel genset is the combination of a diesel engine with an electric alternator,[3] used to generate electrical energy as shown in Figure 1.

[2] As of December 31, 2022.
[3] An alternator is an electric generator that converts mechanical energy to electrical energy in the form of alternating current.

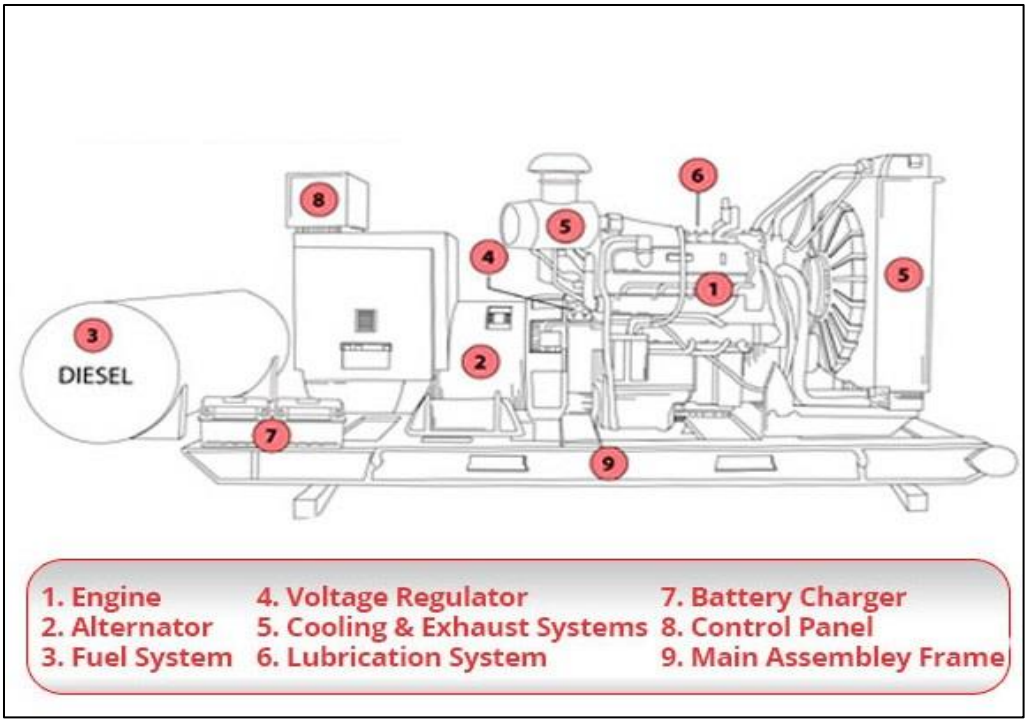


Figure 1: Diesel Genset

Gensets can be classified in one of three ways depending on their mode of operation—continuous, prime, and standby/emergency. Continuous and prime gensets are very similar—they both function as a main source of power and are designed to operate continuously or for extended periods. The major difference between the two is that continuous gensets are designed to operate continually with a consistent load while prime gensets are designed to operate for long durations at variable load. Standby/emergency gensets are to be run only when there is an outage or in a backup situation. Hydro purchases prime power gensets based on the mode of operation for use in its isolated locations.

3.1 Asset Ages

Diesel units across Hydro's system range in age from less than 1 year to 52 years and currently range in operating hours from 1,425 hours to over 110,500 hours. Gensets are overhauled based on operating hours.

Gensets that operate at 1,800 rpm are overhauled after 20,000 hours of service and units that operate at 1,200 rpm are overhauled after 30,000 hours. Chart 1 provides asset age for all assets covered under the program.

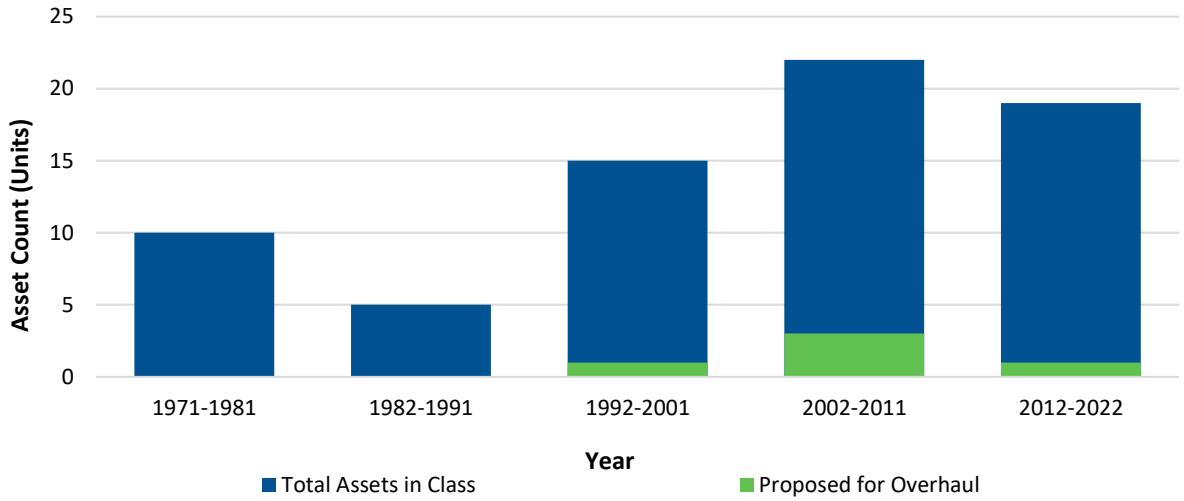


Chart 1: Asset Counts by Asset Age

4.0 Analysis

4.1 Recommended Alternative

Hydro recommends completing the planned overhauls to maintain the reliable operation of its diesel generating stations. The overhaul of diesel units based on Hydro's existing criteria is consistent with the recommendations of the original equipment manufacturer and Hydro's experience and is necessary to proactively maintain the assets to ensure safe and reliable service.

4.1.1 Risk of Asset Stranding

Hydro's diesel generating stations are isolated and in most cases are the sole sources of power to a community. As such, the risk of asset stranding is low.

4.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024 program in accordance with Hydro's Capital Risk Assessment process, as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	4	4	**16**
Post-Execution	4	2	**8**
		Risk Mitigated	**8**
		Risk Mitigated per $1 Million	**9.6**

5.0 Scope of Work

The 2024 Overhaul Diesel Units program includes the planned overhaul of five diesel unit models. As the cost of parts may fluctuate, Hydro will determine the cost of the overhaul parts and replacement engines in early 2024 and select the least-cost option with acceptable delivery timelines. If an overhaul occurs, it will include the replacement or refurbishment of items such as pistons, liners, main bearings, connecting rod bearings, fuel injectors, oil coolers, turbochargers, water pumps, oil pumps, cylinder heads, fuel lines, fuel pumps, and gaskets.

Occasionally, a unit in one of the diesel generating stations across Hydro's operating area will experience an issue that necessitates an unplanned overhaul or reaches the number of operating hours earlier than anticipated. Where appropriate, Hydro may complete such an overhaul under this program and, if possible, defer the overhaul of one of the planned units.

5.1 Program Budget

The estimate for the 2024 program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	541.0	0.0	0.0	**541.0**
Labour	152.4	0.0	0.0	**152.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	42.9	0.0	0.0	**42.9**
Interest and Escalation	19.2	0.0	0.0	**19.2**
Contingency	73.7	0.0	0.0	**73.7**
Total	**829.2**	**0.0**	**0.0**	**829.2**

Chart 2 shows the five-year historical program expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast budget costs through 2028.

Genset units range in size from 40 kW to 2,500 kW. Overhaul costs vary significantly based on engine ratings and usage; as such, the number and size of units overhauled in a year create budget variability.

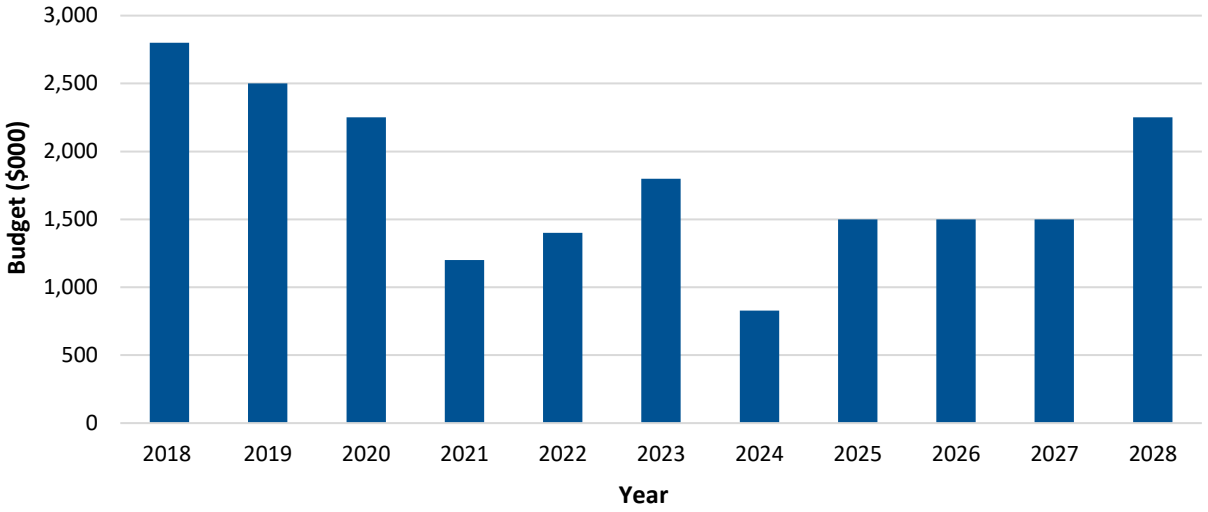


Chart 2: Historical and Forecast Program Budget

5.2 Program Schedule

The schedule for the 2024 program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Schedule annual overhauls.	February 2024	September 2024
Procurement:		
Purchase overhaul components.	March 2024	October 2024
Installation:		
Complete overhaul.	April 2024	November 2024
Commissioning:		
Testing after overhaul.	April 2024	November 2024
Closeout:		
Release for service and asset assignment.	December 2024	December 2024

6.0 Conclusion

To support the continued safe and reliable operation of Hydro's diesel units, Hydro is proposing the overhaul of five diesel engines in 2024. Units are scheduled for overhaul based on the number of hours used in comparison to their rpm rates. Overhauls are critical to maximizing the life expectancy of units to limit larger replacement costs. Hydro has determined—based on the cost of replacement parts, installation, and travel—that it may be cost-effective to replace an engine instead of overhauling it if a

replacement engine is available with acceptable delivery. As the cost of parts can fluctuate, Hydro will execute the least-cost alternative for each of the engine overhauls.

Replace Mobile Equipment (2024–2025)

July 2023



Replace Mobile Equipment (2024–2025)

Location: Various

Investment Classification: General Plant

Asset Category: Tools and Equipment

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") operates a fleet of mobile equipment comprised of approximately 113 snowmobiles, 83 all-terrain vehicles ("ATVs"), 14 forklifts, 87 light-duty trailers,[1] 47 heavy-duty trailers, and other miscellaneous heavy-duty equipment, e.g., excavators, compressors, etc. The fleet is distributed across Hydro's operating areas throughout the province and is utilized daily to support staff engaged in the maintenance and repair of the electrical system.

This program provides for the replacement of mobile equipment that meets the established replacement criteria. As is demonstrated in this proposal, there is no other alternative, as equipment purchased under this program is required for remote operations to support the reliability of the electrical system. This program will contribute to the reliable operation of Hydro's mobile equipment fleet.

In accordance with Hydro's replacement criteria in relation to this program, Hydro proposes the replacement of 7 ATVs, 3 light-duty trailers (12' to 16'), 2 heavy-duty trailers, and 1 forklift.

This program has a multi-year approach, with completion planned in 2025 at an estimated cost of $816,600.

[1] Light-duty trailers include 12' to 16' and 22' to 24' categories.

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1.0 Introduction

Hydro employees work throughout the province, including many locations that require alternative modes of transportation. As such, Hydro's staff requires reliable mobile equipment to effectively fulfil their duties. Under this program, mobile equipment is replaced as required per Hydro's replacement criteria for the reliable operation of its mobile equipment fleet.

2.0 Program Description and Justification

The mobile equipment fleet is strategically distributed across Hydro's operating areas throughout the province. This equipment—including snowmobiles, ATVs, trailers and more—is utilized daily by staff engaged in the maintenance and repair of the electrical system and shared amongst work groups as required. As equipment ages, it experiences increased downtime that could negatively impact emergency outage response times or planned maintenance.

In consultation with other utilities that are part of the Canadian Utility Fleet Council, Hydro has established its mobile equipment replacement guidelines that consider the age and operating conditions of the equipment. Hydro's replacement criteria are shown in Table 1.

Table 1: Hydro's Replacement Criteria for Mobile Equipment

Equipment	Age (Years)
Snowmobiles/ATVs: Transmission Line Crews	3–5
Snowmobiles/ATVs: Other	5–10
Light-Duty Trailers 12'-16'	6–10
Light-Duty Trailers 22'-24'	5-8
Heavy-Duty Trailers	12–18

In addition to age, Hydro considers the equipment's condition before its replacement, as usage of the equipment varies. Miscellaneous equipment, such as forklifts, has no formally defined replacement criteria. Replacement is based on equipment condition, age, and availability of spare parts and service.

3.0 Asset Background

Hydro operates a fleet of mobile equipment comprised of approximately 113 snowmobiles, 83 ATVs, 87 light-duty trailers, 47 heavy-duty trailers, 14 forklifts, and other miscellaneous equipment. Mobile equipment is required to maintain access to remote assets that are not accessible by other means and

to transport equipment when required. Equipment identified for replacement would meet the criteria specified in Table 1 and is replaced based on asset age and operating condition, as exposure to winter conditions, salt corrosion, and usage of the equipment vary.

3.1 Asset Ages

As equipment ages, it experiences increased downtime that could negatively impact emergency outage response times or planned maintenance. In many cases, mobile equipment is regularly operated under rough conditions and is subject to accelerated wear and tear. Mobile equipment is inspected in accordance with the preventive maintenance schedule and all maintenance and repairs are performed by third-party service providers as needed.

ATV asset age, count, and units proposed for replacement under this program are provided in Chart 1. Some of the ATV units beyond the established replacement age are in good operating condition. Hydro considers equipment condition in addition to age before its replacement, as usage and operating condition of the equipment vary.

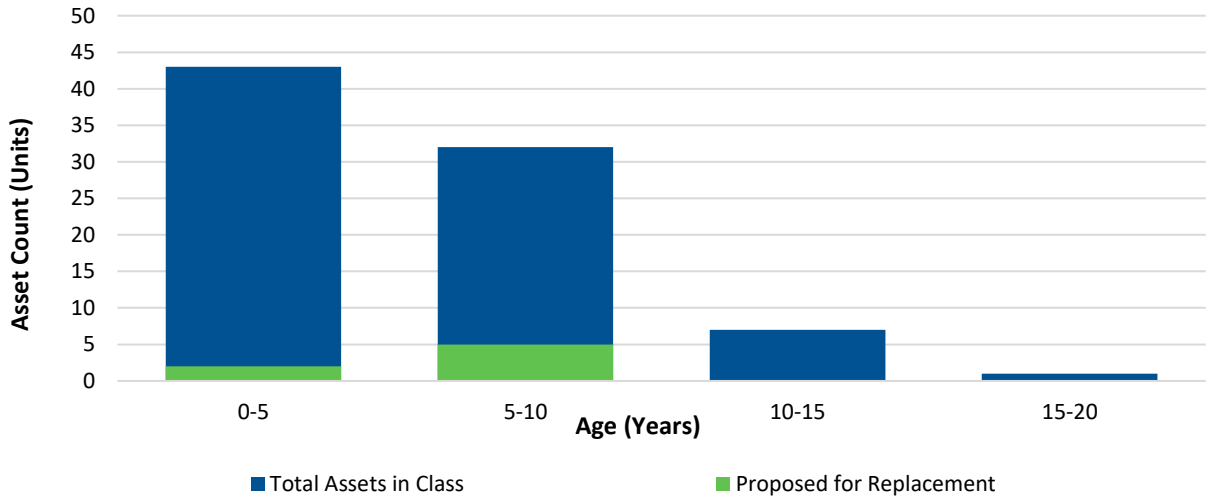


Chart 1: Asset Counts by Asset Age – ATVs

Snowmobile asset age and count are provided in Chart 2. There are no planned replacements in this asset category for this year.

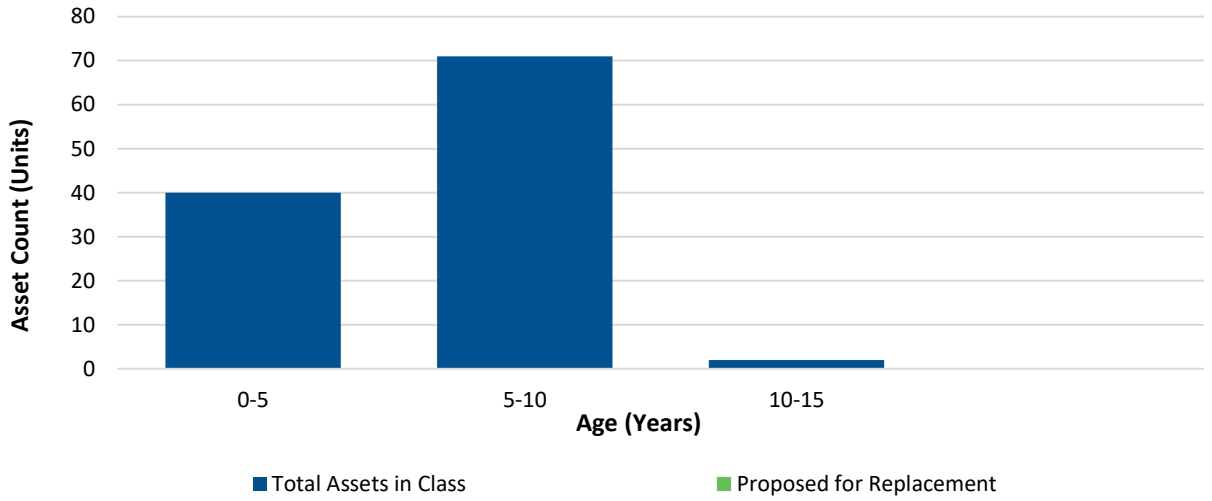


Chart 2: Asset Counts by Asset Age – Snowmobiles

Chart 3 provides light-duty trailer 12’ to 16’ asset age, count, and units proposed for replacement under this program. The proposed replacement in the 25—30-year age range was mostly used in warmer months during capital refurbishment jobs. As such, it experienced less exposure to winter conditions and salt corrosion, which prolonged its life past that of usual units.

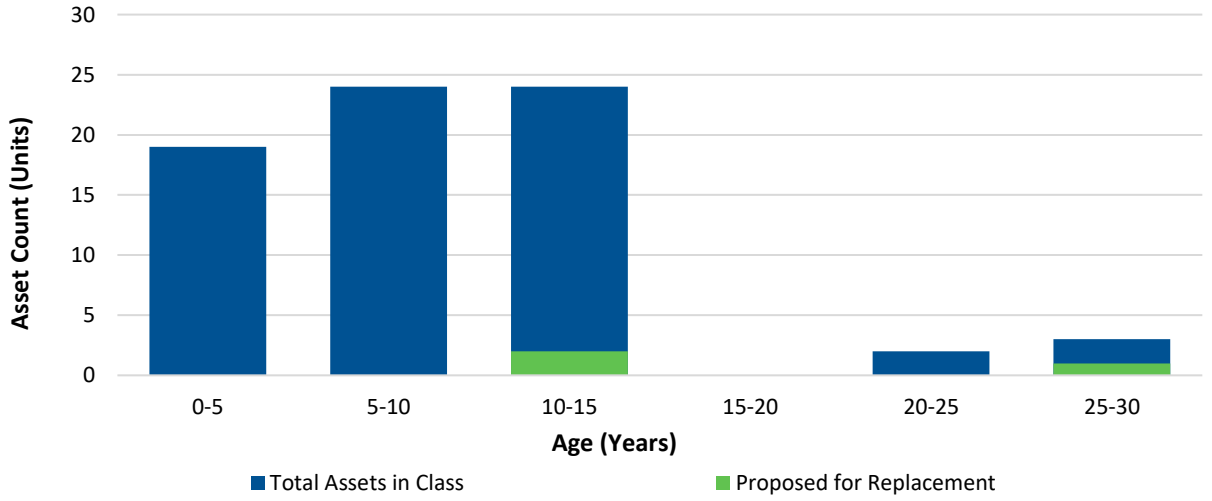


Chart 3: Asset Counts by Asset Age – Light-Duty Trailers 12’-16’

Chart 4 provides light-duty trailer 22’ to 24’ asset age and count. There are no planned replacements in this asset category for this year.

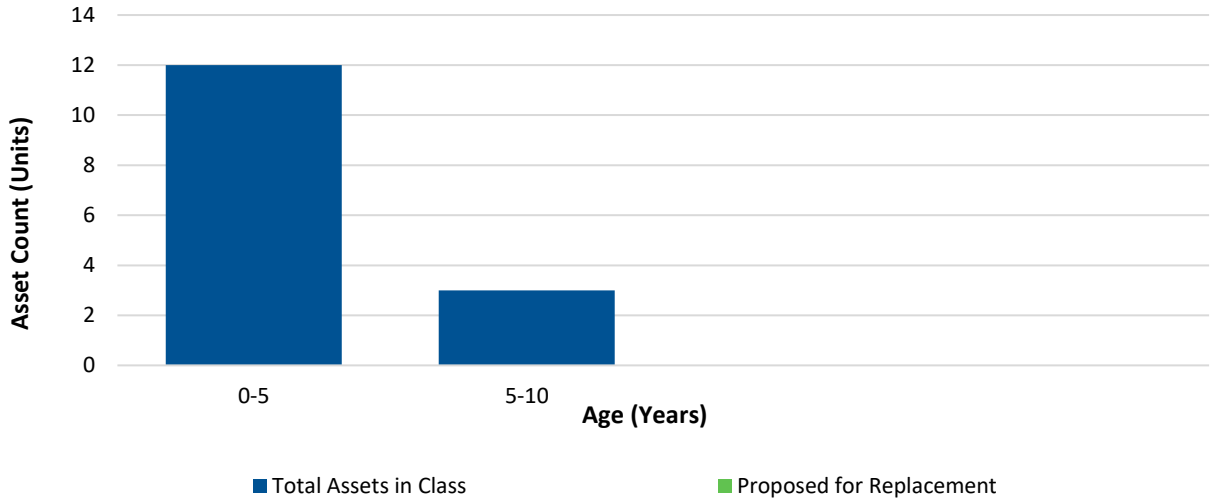


Chart 4: Asset Counts by Asset Age – Light-Duty Trailers 22’–24’

Chart 5 provides heavy-duty trailer asset age and count. There are two planned replacements in this asset category for this year. Several heavy-duty trailers beyond established replacement age are in good operating condition, as exposure to winter conditions, salt corrosion and usage of the equipment varies.

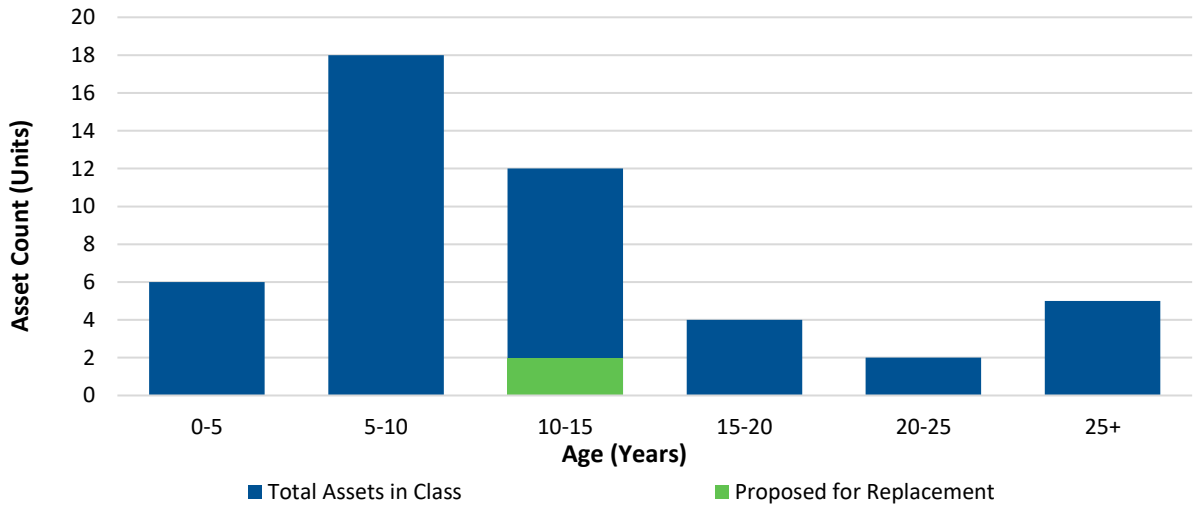


Chart 5: Asset Counts by Asset Age – Heavy-Duty Trailers

Chart 6 provides forklift asset age, count, and units proposed for replacement under this program. There is one planned replacement in this asset category for this year.

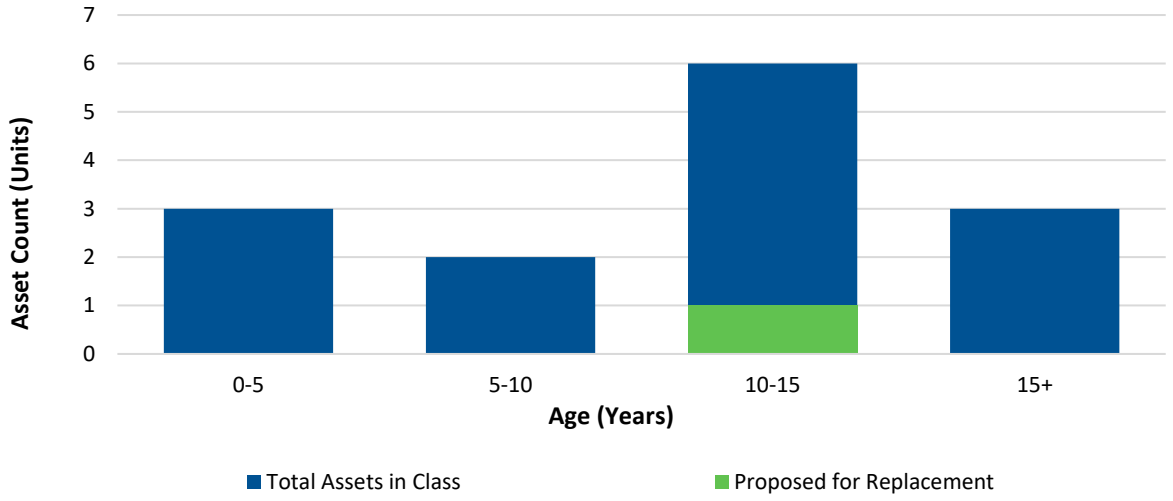


Chart 6: Asset Counts by Asset Age – Forklift

Chart 7 provides asset age and count for miscellaneous heavy-duty equipment covered under this program. There are no planned replacements in this asset category for this year.

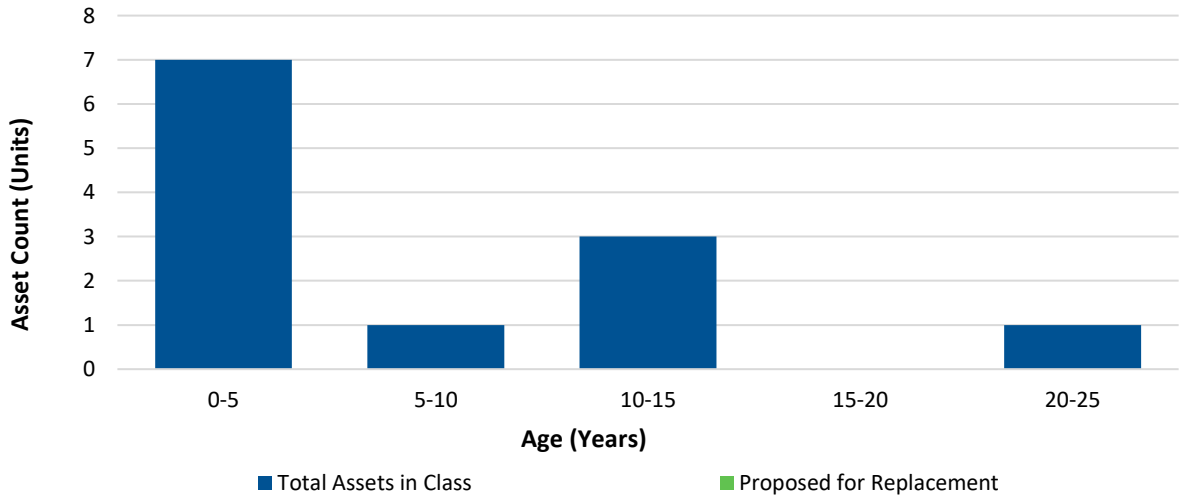


Chart 7: Asset Counts by Asset Age – Miscellaneous Heavy-Duty Equipment

4.0 Analysis

4.1 Recommended Alternative

Hydro recommends the continuation of this program at its current pace to ensure the timely replacement of mobile equipment required to support Hydro's operations. Replacement of mobile equipment, based on Hydro's replacement age criteria along with asset condition, is necessary to ensure the safe and reliable operation of mobile equipment, which is required to safely and reliably operate Hydro's electrical system.

Hydro has determined the current criteria are appropriate based on consultation with other utilities and the condition of the units upon replacement. A reduction of pace to delay the replacement of mobile equipment to future years is not a viable option for this program because the equipment purchased is required for remote operations to support the reliability of the electrical system.

4.1.1 Risk of Asset Stranding

This program is necessary to maintain a safe and reliable fleet. Hydro does not foresee any changes in its requirements for mobile equipment; therefore, the risk of asset stranding is low.

4.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for this 2024–2025 program in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 2.

Table 2: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	4	**12**
Post-Execution	3	1	**3**
		Risk Mitigated	**9**
		Risk Mitigated per $1 Million	**11.0**

5.0 Scope of Work

The 2024–2025 program proposes the replacement of 7 ATVs, 3 light-duty trailers, 2 heavy-duty trailers, and 1 forklift, in accordance with Hydro's replacement criteria.

5.1 Program Budget

The estimate for the 2024–2025 program is shown in Table 3.

Table 3: Program Estimate ($000)

Program Cost	2024	2025	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	31.3	11.5	0.0	**42.8**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	161.8	512.5	0.0	**674.3**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	6.0	23.8	0.0	**29.8**
Contingency	17.8	51.9	0.0	**69.7**
Total	**216.9**	**599.7**	**0.0**	**816.6**

Chart 8 shows the five-year historical expenditures, the forecast 2023 expenditures, the proposed 2024 program budget, and the forecast costs through 2028.

Mobile equipment replacement is determined by considering the age and condition of the asset. The composition of assets replaced will vary from year to year, resulting in budget variability due to the type and quantity of equipment purchased.

The cost increase in 2025 is the result of increasing unit costs as a result of inflationary pressures combined with overlapping program budgets due to increased equipment delivery timeframes.

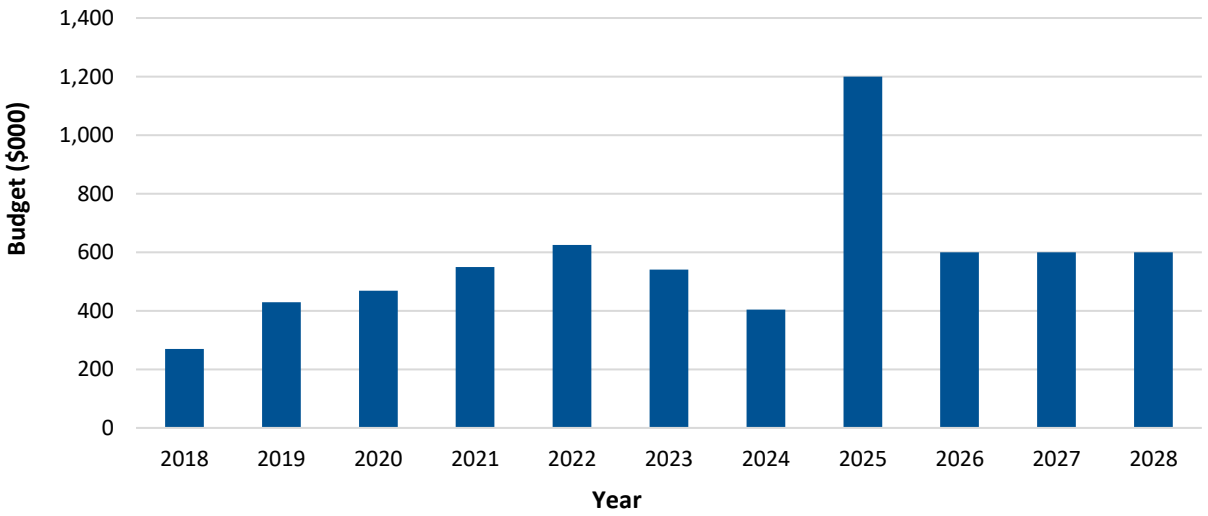


Chart 8: Historical and Forecast Program Budget

5.2 Program Schedule

The schedule for the 2024–2025 program is shown in Table 4.

Table 4: Program Schedule

Activity	Start Date	End Date
Planning: Open work orders and plan and develop detailed schedules.	January 2024	February 2024
Procurement: Tender and award to purchase mobile equipment.	February 2024	March 2024
Commissioning: Receive and commission mobile equipment.	September 2024	May 2025
Closeout: Close work order, complete all documentation, and complete lessons learned.	October 2024	June 2025

6.0 Conclusion

Hydro utilizes a fleet of reliable mobile equipment to maintain the electrical system. Failure to replace the mobile equipment will lead to increased maintenance costs, less reliable equipment, and safety concerns for all users.

Projects

Projects





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Schedule 6: Capital Programs and Projects

Projects	**Project**
• []	1
• Refurbish Intake 1 (2024–2025) - Bay d'Espoir	2
• Flatten Downstream Slope (2024–2025) - Hinds Lake	3
• Refurbish Surge Tank 1 (2024–2025) - Bay d'Espoir	4
• Replace Powerhouse 1 Roof (2024–2025) - Bay d'Espoir	5
• Refurbish Fuel Oil Storage Tank 4 (2024) - Holyrood	6
• Replace VHF Radio System (2024–2025)	7
• Purchase Accommodations Trailer (2024–2025) - Makkovik and Cartwright	8
• Replace MDR8000 Microwave Radios (2024–2025)	9
• Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025) - Holyrood	10
• Purchase 50' Material Handler Aerial Device on Track Unit (2024–2026) - Happy Valley-Goose Bay	11
• Replace Grader Unit V9829 (2024) - Bay d'Espoir	12
• Replace Power Line Carrier (2024–2025) - TL247	13
• Automate Bulk Metering (2024–2026)	14

PROJECT REMOVED

Purchase Spare Generator Step-Up Transformer (2024–2026)

July 2023



Refurbish Intake 1 (2024–2025)

Bay d’Espoir

July 2023



Refurbish Intake 1 (2024–2025)

Location: Bay d'Espoir

Investment Classification: Renewal

Asset Category: Hydraulic Plant

Executive Summary

The Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir Facility") is home to seven generating units that are housed in two generating plants—Powerhouse 1 and Powerhouse 2. The development produces an average of 2,650 GWh annually, making it the largest hydroelectric development on the Island.

The station, from which service began in 1967, relies on penstocks to supply water to each of the generating units. The Bay d'Espoir Facility has four penstocks that supply water to seven generating units, with Powerhouse 1 consisting of six hydro units fed by three penstocks. Each penstock has an intake, which provides water control for the generation plants downstream.

Past assessments have concluded that all three intakes that service Powerhouse 1 are nearing the end of their service life and need intervention to continue to operate reliably. Bay d'Espoir Intake 1 has been in service since 1967 and has performed well; however, some components are approaching the end of their service life. Deterioration of critical components such as the gate main rollers, roll paths, side-rollers, and seals, directly affects the operation of the gate. If not addressed, this can be a threat to the reliability of the powerhouse and penstock.

Newfoundland and Labrador Hydro ("Hydro") considered the following alternatives for this project:

- Deferral of remedial action;
- Refurbishment of Intake 1 structure and gate;
- Refurbishment of Intake 1 structure with gate replacement; and
- Alternative strategies.

The alternative to refurbishing the intake structure with a gate replacement was determined to be the least-cost option to satisfy Hydro's long-term operational needs. As a result, Hydro proposes

refurbishing Bay d'Espoir Intake 1, which will include the replacement of key components and the restoration of the concrete structure.

This project was originally proposed in 2017 to be completed in 2018–2019; however, due to the prioritization of other critical work, this project was delayed and eventually cancelled. To maximize resources and outage availability, Hydro determined it was most efficient to complete this work during the extended outage required for the Bay d'Espoir Penstock 1 section replacement and weld refurbishment ("Bay d'Espoir Penstock 1 Life Extension") project in 2025.[1]

This project has a multi-year approach, with completion planned in 2025 at an estimated project cost of $3,344,000.

[1] Approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 6(2023), Board of Commissioners of Public Utilities, April 12, 2023.

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Attachment 1: "Cancellation of Previously-Approved Capital Projects at Bay d'Espoir," Newfoundland and Labrador Hydro, February 26, 2021.

1.0 Introduction

The refurbishments of the Bay d'Espoir Intakes were originally proposed within Hydro's Hydraulic Generation Refurbishment and Modernization program, filed as part of its annual capital budget application ("CBA")—Intake 1 (2018 CBA),[2] Intake 2(2019 CBA),[3] and Intake 3(2020 CBA).[4,5] In 2021, Hydro filed correspondence with the Board of Commissioners of Public Utilities ("Board") to cancel the refurbishments of Intakes 1 and 2.[6] Hydro noted that the work on Intake 3 would continue, while proposals would be developed for the refurbishments to Intakes 1 and 2 following an analysis to determine an appropriate timeframe for execution.

Hydro completed the required engineering and fabrication to enable the replacement of Intake Gate 1; however, due to the prioritization of other critical work on the system, Hydro was unable to replace the gate in 2019 as scheduled. In 2020, Hydro experienced delays related to the COVID-19 pandemic that resulted in missing the outage window required to replace Intake Gate 2. Work proceeded on Intake 3 in 2021; the intake was refurbished and the gate was successfully replaced.

With the approval of the Bay d'Espoir Penstock 1 Life Extension project in 2023, Hydro determined it would be most efficient to cluster the Refurbish Intake 1 (2024–2025) – Bay d'Espoir project and complete the Intake 1 refurbishment during the extended outage required for the approved project. As such, Hydro is proposing the completion of Refurbish Intake 1 (2024–2025) – Bay d'Espoir project to coincide with the extended outage of the Bay d'Espoir Penstock 1 Life Extension project in 2025.

2.0 Project Description and Justification

The scope of this project is to refurbish Bay d'Espoir Intake 1, including the replacement or refurbishment of several main components: the intake gate, embedded parts, superstructure, and hoist.

[2] "2018 Capital Budget Application," Newfoundland and Labrador Hydro, rev. October 3, 2017 (originally filed July 27, 2017), vol. II, tab 1, approved as per *Public Utilities Act*, RSNL, 1990, c P-47, Board Order No. P.U. 5(2018), Board of Commissioners of Public Utilities, February 23, 2018.
[3] "2019 Capital Budget Application," Newfoundland and Labrador Hydro, rev. October 9, 2018 (originally filed July 31, 2018), vol. II, tab 1, approved as per *Public Utilities Act*, RSNL, 1990, c P-47, Board Order No. P.U. 46(2018), Board of Commissioners of Public Utilities, December 10, 2018.
[4] "2020 Capital Budget Application," Newfoundland and Labrador Hydro, August 1, 2019, vol. II, tab 1, approved as per *Public Utilities Act*, RSNL, 1990, c P-47, Board Order No. P.U. 6(2020), Board of Commissioners of Public Utilities, February 21, 2020.
[5] Each refurbishment was estimated to take two years to complete.
[6] Please refer to Appendix A "Cancellation of Previously Approved Capital Projects at Bay d'Espoir," Newfoundland and Labrador Hydro, February 26, 2021.

This project is required to maintain the reliable operation of Bay d'Espoir Intake 1. Deterioration of critical components such as the gate main rollers, roll paths, side rollers, and seals directly affects the operation of the gate, which can threaten the reliability of the powerhouse and penstock if not addressed. The impact of gate failures will likely lead to a loss of production and, in the event of catastrophic failure, damage to the penstock and other downstream components is likely to occur.

Timing for this project is optimal for taking advantage of clustering opportunities, as Hydro can avail of operational efficiencies and align this work with the extended outage required in 2025 for the approved Bay d'Espoir Penstock 1 Life Extension project.

3.0 Asset Overview

3.1 Asset Background

Bay d'Espoir Intake 1 was commissioned in 1967 and supplies water to Penstock 1. Penstock 1 transports water to Units 1 and 2, which have a combined generation capacity of 153 MW.

As shown in Figure 1, Intake 1 is comprised of many moving and embedded parts that together control the water flow into the penstock. The main component of Intake 1 is the gate, which is formed by a welded steel frame with a downstream skin plate and concrete ballast. Each gate has 4 pre-loaded side rollers and 12 main rollers. The gate is operated with a cable hoist attached to a single central lifting point.

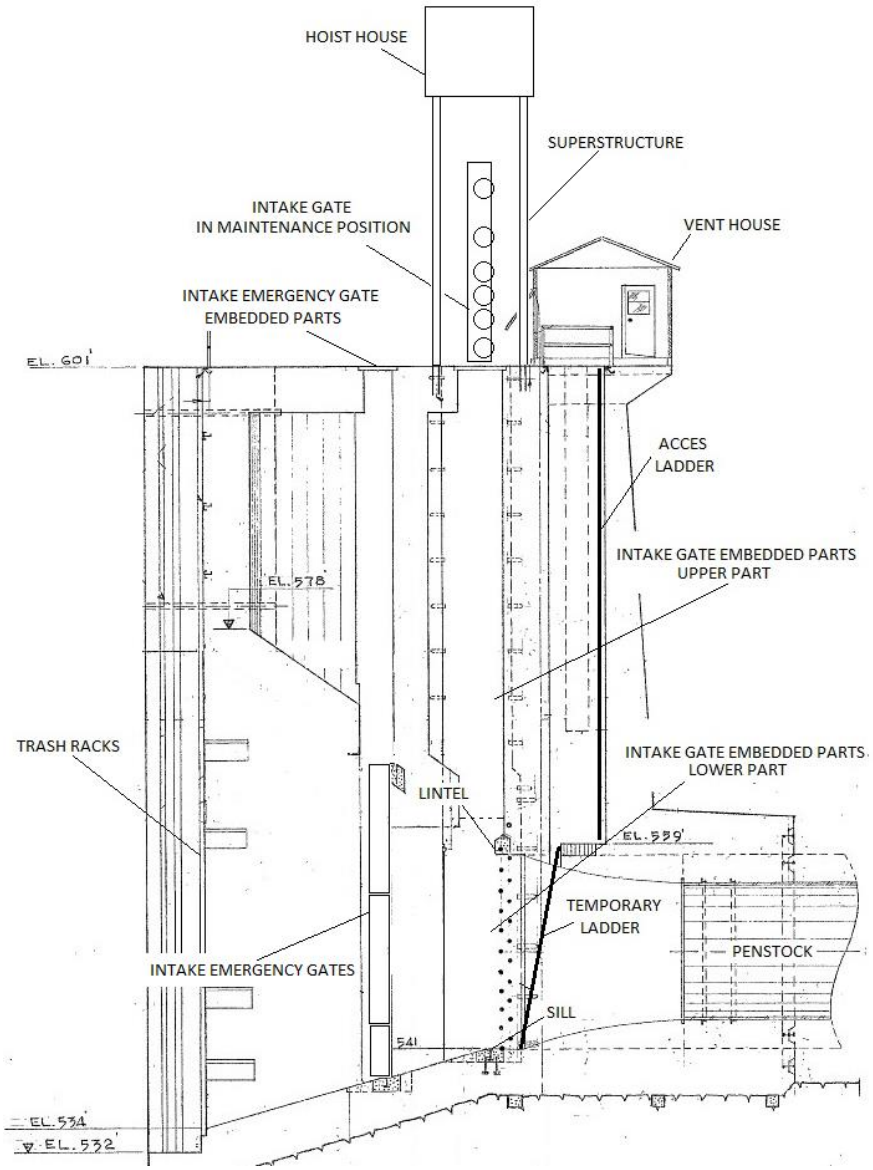


Figure 1: Bay d'Espoir Intake Structure

The primary purpose of the intake gate is to stop water from entering the penstock for emergency or maintenance purposes. For this reason, the gate must be able to lower under its own weight in case of an emergency and the cable hoist must be able to open the gate to slowly fill the penstock as required under full water pressure.[7]

[7] The Bay d'Espoir Facility uses the intake gate as a third control device to manage water flow. The wicket gates and the generator spherical valve are the two main control systems.

The intake gate is dewatered for maintenance and inspections using the intake emergency gates. Six emergency gates[8] are needed to completely seal an intake and are installed using a master log and a mobile crane.

3.2 Historical Reliability

The intake gate was designed by Dominion Bridge and followed industry best practices for material quality and design principles known at the time of construction.

In the past 30 years, Hydro has experienced two major incidents at the Bay d'Espoir intakes. Both incidents were similar and occurred at the intakes during a penstock water-up. An analysis revealed that the intake gates had travelled past their prime positions, filling the penstock too quickly. This created a pressure wave that was sent back through the penstock, ultimately destroying the vent house. Safety measures were implemented to address the issue, including the implementation of an automated filling procedure in which a Programmable Logic Controller uses real-time pressure data in the penstock to control the height of the intake gate.

3.3 Asset Condition

Intake 1 has performed well over its 56-year service life; however, there are now components of this structure that must be replaced or refurbished. The Intake 1 inspection completed as part of Hydro's "2018 Capital Budget Application" indicated varying levels of deterioration, particularly in submerged and embedded components, which included concrete erosion and corrosion on embedded parts and gate components.[9] Critical components showing deterioration include main rollers, roll paths, side rollers, and seals as seen in Figure 2 and Figure 3.

[8] The six intake emergency gates include two sets of three gates. The two bottom gates are solely used at the intake, while the others can be used as draft tube gates at the powerhouse as needed. The two top gates are equipped with valves to refill the void between the emergency gates and control gate to elevate differential pressure, allowing the emergency gates to be removed.

[9] Please refer to Attachment 3 of Hydro's response to PUB-NLH-018 revision 1 of its "2018 Capital Budget Application" proceeding.
< http://pub.nl.ca/applications/NLH2018Capital/rfis/PUB-NLH-018%20-%20Revision%201.PDF>

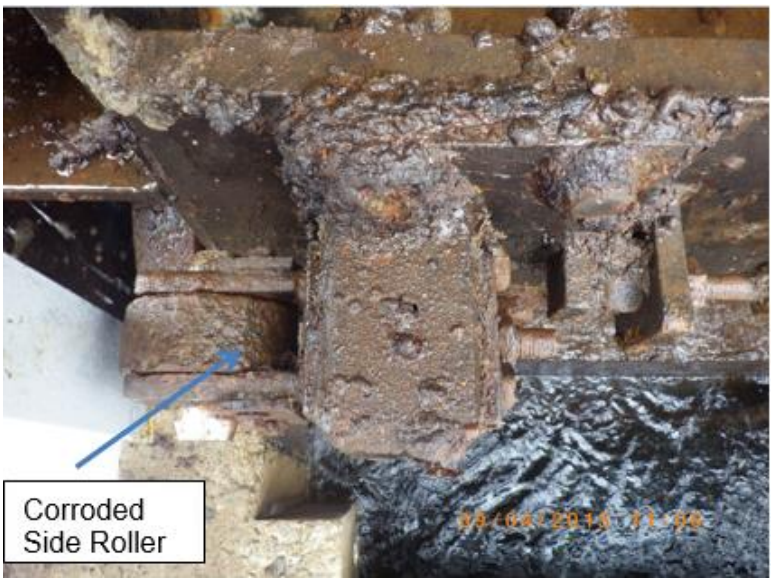


Figure 2: Intake Gate Side Roller Condition



Figure 3: Pitting Corrosion on Main Roller

3.4 Condition-Based Remaining Life

The intake gate has a typical life span of 50 to 60 years. Intake Gate 1 is 56 years old and will reach the end of its service life by 2025.

4.0 Analysis

4.1 Evaluation of Alternatives

The proposed alternatives for this project include:

- Deferral;
- Refurbishment of intake structure and gate;
- Refurbishment of intake structure with gate replacement;
- Alternative strategies.

4.1.1 Deferral

Intake 1 is an integral part of the Bay d'Espoir Facility; it provides water control for Units 1 and 2, which have a combined generation capacity of 153 MW.

To maximize resources and outage availability, Hydro decided to defer this project to coincide with the execution of the Bay d'Espoir Penstock 1 Life Extension project in 2025; however, this work cannot be delayed any further. This work is required to maintain the safe and reliable operation of Intake 1. Further deferral poses a safety hazard and risks the operation of Units 1 and 2. Should the intake gate fail, loss of production is likely and in the event of catastrophic failure, damage to the penstock and other downstream components is likely to occur. Such a decrease in generation capacity could impact Hydro's ability to satisfy customer demand and adversely impact the reliability of the Island Interconnected System.

4.1.2 Refurbishment of Intake Structure and Gate

The scope of this alternative includes the refurbishment of the intake gate, concrete, embedded parts, and roller paths as well as the replacement of superstructure hardware and the gate hoist. The refurbished gate would have an anticipated service life of 25 years.

4.1.3 Refurbishment of Intake Structure with Gate Replacement

The scope of this alternative includes the refurbishment of the concrete, embedded parts, and roller paths as well as the replacement of the intake gate, superstructure hardware, and the gate hoist. The new gate would have an anticipated service life of 50 years or more.

4.1.4 Alternative Strategies

Hydro can avail of operational efficiencies and cluster this project with the extended outage required in 2025 for the approved Penstock 1 refurbishment.

4.2 Least-Cost Evaluation

Hydro performed a least-cost evaluation to determine the least-cost option for this project. The viable alternatives for this project that were considered in a least-cost evaluation included:

- Refurbishment of intake structure and gate; and
- Refurbishment of intake structure with gate replacement.

A summary of the least-cost evaluation is presented in Table 1.[10] The lowest cost option is the gate replacement.

Table 1: Least-Cost Evaluation Summary ($000)

Alternatives	NPV[11]	NPV Difference between the Alternative and the Least-Cost Alternative
Gate Replacement	499	-
Gate Refurbishment	572	73

4.3 Recommended Alternative

Based on the least-cost evaluation, it is recommended to proceed with the refurbishment of the Intake 1 structure with gate replacement. Hydro is clustering this project with the Bay d'Espoir Penstock 1 Life Extension project to avail of operational efficiencies due to the extended outage window.

4.3.1 Risk of Asset Stranding

The Bay d'Espoir Facility produces an average of 2,650 GWh annually, making it the largest hydroelectric development on the Island. As the primary source of hydroelectricity for the Island Interconnected System, there are no plans to retire the generating assets at the Bay d'Espoir Facility; therefore, Hydro considers the risk of asset stranding to be low.

[10] The least-cost evaluation only compared the gate portion of the project, as the intake refurbishment portion is the same for both alternatives. A period of 50 years was used for this analysis.
[11] Net Present Value ("NPV").

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 2.

Table 2: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	5	3	**15**
Post-Execution	5	1	**5**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**3.0**

5.0 Scope of Work

The scope of work for this project spans two years, starting in 2024.

In 2024, the scope includes:

- Develop and award contracts for consultant engineering;
- Develop detailed design and work packages; and
- Develop procurement contracts for the materials and equipment required.

In 2025, the scope includes:[12]

- Replacement of the intake superstructure hardware;
- Replacement of the gate hoist motor and manual hoist system;
- Refurbishment of the second stage concrete, embedded parts, and roll paths; and,
- Replacement of the intake gate.

5.1 Project Budget

The estimate for the 2024–2025 project is shown in Table 3.

[12] This approach is similar to the execution strategies developed during the rehabilitation of Intake 3 in 2020–2021. The replacement of Intake Gate 1 will utilize the same design as that of Intake 3.

Table 3: Project Estimate ($000)

Project Cost	2024	2025	Beyond	Total
Material Supply	0.0	120.0	0.0	**120.0**
Labour	124.9	382.2	0.0	**507.1**
Consultant	100.0	132.0	0.0	**232.0**
Contract Work	0.0	1,893.0	0.0	**1,893.0**
Other Direct Costs	8.1	39.2	0.0	**47.3**
Interest and Escalation	15.8	248.8	0.0	**264.6**
Contingency	23.3	256.7	0.0	**280.0**
Total	**272.1**	**3,071.9**	**0.0**	**3,344.0**

5.2 Project Schedule

The schedule for the 2024–2025 project is shown in Table 4.

Table 4: Project Schedule

Activity	Start Date	End Date
Planning Develop a detailed plan for intake refurbishment and gate replacement.	February 2024	May 2024
Procurement Consultant engineering, procure materials, and replacement parts.	February 2024	May 2025
Construction Perform the refurbishment and required replacements.	June 2025	September 2025
Commissioning Commission new equipment.	September 2025	September 2025
Closeout: Document closeout and lessons learned completion.	October 2025	November 2025

6.0 Conclusion

Intake 1 is approaching the end of its service life and requires major refurbishment. This project is required to ensure the future reliable operation of Units 1 and 2 at the Bay d'Espoir Facility and aligns with the approved Bay d'Espoir Penstock 1 Life Extension project's extended outage in 2025. Unit 1 and Unit 2 have been servicing the Island Interconnected System since 1967; this rehabilitation project will ensure the reliable operation of the gate and associated structure.

Attachment 1

Cancellation of Previously-Approved Capital Projects - Bay d'Espoir Hydroelectric Generating Facility

Newfoundland and Labrador Hydro

February 26, 2021



newfoundland labrador hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

February 26, 2021

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Cancellation of Previously Approved Capital Projects at Bay d'Espoir

Newfoundland and Labrador Hydro ("Hydro") is providing this correspondence to advise the Board of Commissioners of Public Utilities ("Board") that, at this time, Hydro will not be proceeding with the following scopes of work which were approved as part of the Hydraulic Generation Refurbishment and Modernization Program in Hydro's 2018 and 2019 Capital Budget Applications ("CBA"):[1]

- The interior portion of the refurbishment of Bay d'Espoir Surge Tank 1;
- The Bay d'Espoir Intake Gate 1 portion of the Refurbish and Replace Control Gates Infrastructure project; and
- The Bay d'Espoir Intake Gate 2 portion of the Hydraulic Structures Program.

Hydro still intends to complete these portions of the project scope; however, for reasons further explained in this correspondence, the anticipated timeframe for completion of these components has changed materially from that which was reflected in the 2018 and 2019 CBA proposals. Therefore, Hydro believes it is appropriate to cancel the projects at this time and propose the scopes for approval in the future. Hydro has evaluated the impacts of deferring these projects from a safety and reliability perspective and has completed any work it considered to be a potential safety risk in the near term. Hydro will continue to monitor asset performance to limit reliability risks to customers.

Current Status of the Refurbishment of Bay d'Espoir Surge Tank 1

Hydro's original proposal was for the refurbishment of the interior and exterior of the Bay d'Espoir Surge Tank 1. The scope of the project included refurbishment of interior tank surfaces and surge tank bottom bowl, exposed exterior tank surfaces, and tower legs. Additionally, a structural analysis of the surge tank's interior structural steel was to be completed.

Hydro completed the exterior portion of this scope of work in 2018 as scheduled but has since been unable to complete the work due to the prioritization of other critical work on the system and the impacts of the COVID-19 pandemic. Hydro is evaluating whether completing this work during execution of the Penstock 1 refurbishment would be the most productive use of outage time and other resources.

[1] Bay d'Espoir Surge Tank 1 and Intake Gate 1 were approved in Board Order No. P.U. 5(2018). Intake Gate 2 was approved in Board Order No. P.U. 46(2018).

As per Hydro's June 3, 2020 correspondence to the Board,[2] Hydro has engaged a consultant to support the Front-End Engineering Design work for the Penstock 1 refurbishment. Once this work is complete, Hydro will present its project proposal, including costs, to the Board for review and approval. Hydro will provide an update as to the status of this work in its 2022 CBA.

Current Status of the Replacement of Bay d'Espoir Intake Gates 1, 2 and 3

Hydro's strategy for the replacement of Intake Gates 1, 2 and 3[3] at Bay d'Espoir was to procure a new gate to replace Intake Gate 1, refurbish the gate that was removed to replace Intake Gate 2, and repeat this process for Intake Gate 3, keeping the last refurbished gate as a spare. The original planned sequence was that Intake Gate 1 would be replaced in 2019, Intake Gate 2 would be replaced in 2020, and Intake Gate 3 would be replaced in 2021.

Hydro has completed the engineering and fabrication for the replacement of Intake Gate 1; however, due to the prioritization of other critical work on the system, Hydro was unable to replace the gate in 2019 as scheduled. In 2020, Hydro experienced delays related to the COVID-19 pandemic which caused Hydro to miss the outage window required to replace Intake Gate 2.

Intake Gate 3 is scheduled for 2021 and, at this time, Hydro does not foresee any issues which would prohibit it from completing this work as scheduled. As the three intake gates at Bay d'Espoir are identical, Hydro intends to replace Intake Gate 3 in 2021 using the gate that was fabricated and originally intended to be used to replace Intake Gate 1. Hydro will then refurbish the existing Intake Gate 3 and use it to replace Intake Gate 1. As with the interior work on Surge Tank 1, Hydro is evaluating whether this work should be completed during the extended outage for the Penstock 1 refurbishment. The refurbished Intake Gate 1 will be used to replace Intake Gate 2. Hydro will undertake a similar evaluation to determine whether the most efficient approach is to complete this work at the same time that Hydro completes the Penstock 2 refurbishment. The timing of the Penstock 2 refurbishment remains under evaluation. Hydro intends to refurbish the last gate removed and will maintain it as a spare.

Summary of Costs Incurred

Table 1 provides a summary of the amounts approved and incurred for each of the project scopes.

Table 1: Summary of Approved and Incurred Costs

Project Scope	Approved Project Cost	Project Cost Incurred	Difference
Bay d'Espoir Surge Tank 1	$3,564,000	$2,107,136	$1,456,864
Bay d'Espoir Intake Gate 1	$2,312,100	$240,857	$2,071,243
Bay d'Espoir Intake Gate 2	$2,083,600	$97,846	$1,985,754
Bay d'Espoir Intake Gate 3	$2,477,300	$734,142	$1,743,158
Total	**$10,437,000**	**$3,179,981**	**$7,257,019**

The costs incurred to date for the refurbishment of Surge Tank 1 relate to the inspection of tank and substructure, safety upgrades, and the application of a new exterior coating system.

[2] "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020.
[3] Bay d'Espoir Intake Gate 3 was proposed as part of Hydro's Hydraulic Generation Refurbishment and Modernization Program in its 2020 CBA, which was approved in Board Order No. P.U. 6(2020).

Costs incurred to date for Intake Gates 1 and 2 relate to engineering work that was commenced prior to the projects being cancelled. Engineering deliverables produced to date have been retained and will still be of value to customers as the gates are replaced.

The costs associated with the gate that was initially procured to replace Intake Gate 1 have been transferred to Intake Gate 3, as that is now expected to be the first gate replaced.

Cancelled Scopes

Given the duration of carryover and the evaluation of potential logistical benefits that may be gained by executing the work on the interior of Surge Tank 1 and Intake Gate 1 at the same time as the Penstock 1 refurbishment, Hydro is proposing to cancel these portions of the project scopes at this time. Once Hydro has completed its Front-End Engineering Design work for the Penstock 1 refurbishment, Hydro will be in a better position to determine whether it is most appropriate to include these scopes of work with its proposal for refurbishment of Penstock 1 or to proceed with a separate application for the interior of Surge Tank 1 and the Intake Gate 1 work scopes. Similarly, Hydro is proposing to cancel the work scope associated with Intake Gate 2 and will evaluate the merits of including this scope in its application for the Penstock 2 refurbishment.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO



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Project 3

Flatten Downstream Slope (2024–2025)

Hinds Lake

July 2023

newfoundland labrador hydro

Flatten Downstream Slope (2024–2025)

Location: Hinds Lake

Investment Classification: Renewal

Asset Category: Hydraulic Plant

Executive Summary

The Hinds Lake Power Canal Dyke ("Hinds Lake Dyke") was constructed and put into service in the 1980s during the construction of the Hinds Lake Hydroelectric Generating Station ("Hinds Lake Station"). The structure is a key component of the power canal that transports water from the Hinds Lake Reservoir to the Hinds Lake Station intake.

In 2018 and 2021, slope stability analysis was performed at multiple locations along the Hinds Lake Dyke. Results of the analysis indicated that these areas do not meet the requirements of the Canadian Dam Association ("CDA") guidelines, specifically relating to the factor of safety for slope stability. Improvements will be required to flatten the downstream slopes of the dyke and prevent the possibility of future slope movement or dyke breach. A failure of the Hinds Lake Dyke would result in the complete loss of generation capabilities at the Hinds Lake Station, equating to the loss of 75 MW of generation for several months. Such a decrease in generation capacity could impact Newfoundland and Labrador Hydro's ("Hydro") ability to meet customer demand and adversely impact the reliability of the Island Interconnected System.

In consideration of the stability analyses conducted, the following alternatives were considered:

- Deferral; and
- Upgrade life extension.

Upgrade life extension was determined to be the only viable option to satisfy Hydro's long-term operational needs, as the Hinds Lake Dyke forms an essential part of the Hinds Lake Hydroelectric Development ("Hinds Lake Development") and must be maintained in reliable working condition.

This project has a multi-year approach, with completion planned in 2025 at an estimated cost of $3,229,500.

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Attachment 1: "Slope Stability Analysis of 2 Slides at Hinds Lake Power Canal Dyke (HD-PC) with Proposed Repair Solution," SNC-Lavalin Group Inc., January 31, 2019.

Attachment 2: "HD-PC and HD-9 Slope Stability Analysis," SNC-Lavalin Group Inc., August 18, 2021.

1.0 Introduction

The Hinds Lake Station is located on the west coast of the Island, on the eastern shore of Grand Lake. With a maximum generation capacity of 75 MW, the Hinds Lake Development contributes an average annual production of approximately 340 GWh to the Island Interconnected System. The Hinds Lake Dyke, constructed and put into service in the 1980s, forms a critical part of the Hinds Lake Development.

As part of Hydro's commitment to maintaining a Dam Safety Program that mitigates risk associated with dams and related hydraulic structures, Hydro ensures its dams comply with all applicable dam safety legislation and regulatory requirements. Hydro also takes into consideration best practices as recommended in guidelines published by the CDA, established for dam owners to use as the guiding principles for the construction, maintenance, and surveillance of dam structures.

During a weekly routine inspection of the Hinds Lake Dyke structure in 2018, two small slope slides of approximately 8 metres by 8 metres were discovered at two locations, Location A and Location B, along the downstream slope.[1] Subsequently, these small slides were repaired to their existing slope to address the immediate concern for the structure. A slope stability analysis was completed in 2018 by SNC-Lavalin Group Inc. ("SNC-Lavalin") to determine if further remediation work was required to ensure the long-term performance of the Hinds Lake Dyke, the findings of which are summarized in Attachment 1. The slope stability analysis conducted at the slide locations determined that the downstream slopes did not meet the factor of safety for slope stability set out in the CDA guidelines.

During the 2018 analysis, a cross-section location, Location C,[2] was also analyzed, as a failure had previously occurred there in 1982. The initial analysis indicated that the downstream slope of the structure did not meet the minimum factors of safety as per the CDA guidelines. This analysis was further refined in 2021, with a review completed by SNC-Lavalin of the analysis for Location C and an additional analysis completed for Location D.[3] The scope of work also included a high-level sensitivity analysis of the options to stabilize the slope. The findings of the 2021 analysis are summarized in Attachment 2, which confirmed the findings of the 2018 analysis, which showed that in these locations, the downstream slope did not meet the factor of safety for slope stability set out in the CDA guidelines.

[1] Location 1+989 ("Location A") and location 2+069 ("Location B").
[2] Location 4+385 ("Location C").
[3] Location 4+530 ("Location D").

As such, Hydro is proposing to flatten the downstream slopes of the Hinds Lake Dyke, to bring the dyke structure into alignment with the current CDA guidelines factor of safety for slope stability.

To mitigate the risk of failure until an appropriate solution could be developed, Hydro will continue the dam safety program's weekly inspections of the structure, as well as the completion of two comprehensive engineering inspections annually.

2.0 Project Description and Justification

This project involves the flattening of the downstream slope of the Hinds Lake Dyke at two specific locations, between Station 1[4] and Station 2.[5] The 2018 and 2021 stability analyses of the structure in these locations provided results that failed to meet the minimum required factors of safety outlined in the CDA guidelines. The flattening of the slope will be accomplished by importing granular materials that are to be installed over the existing sloped surface. To illustrate the final geometry of the slopes following the flattening activities, general visualizations have been provided in Figure 1 and Figure 2.

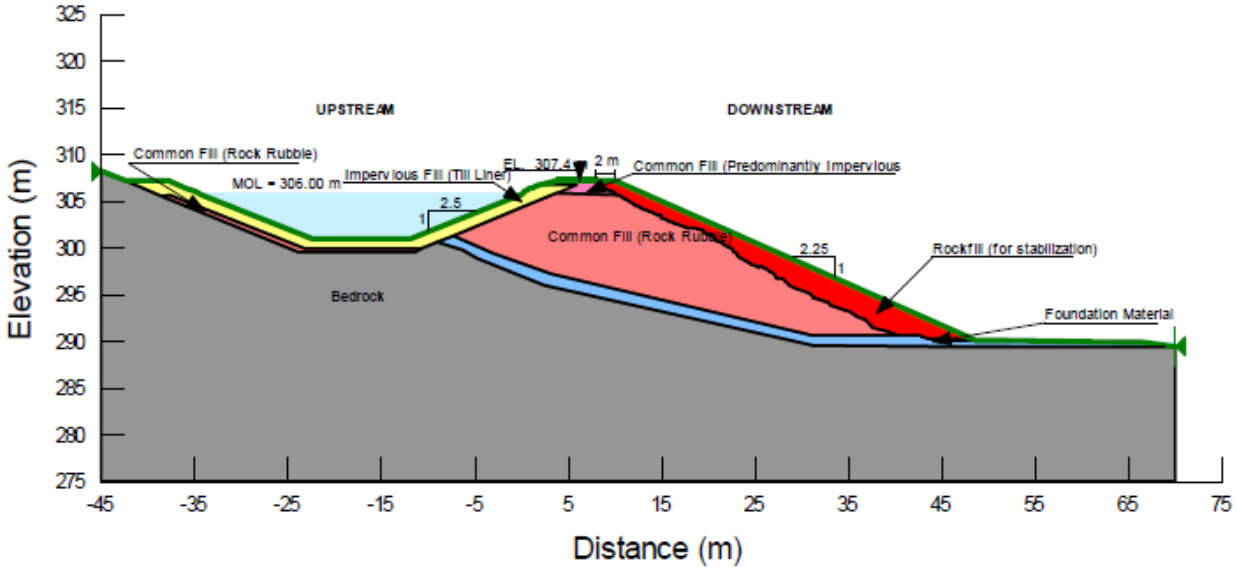


Figure 1: Proposed Geometry of Downstream Slope at Location B[6]

[4] Station 1+950 to 2+100 ("Station 1").
[5] Station 4+200 to 4+600 ("Station 2").
[6] New material shown in red.

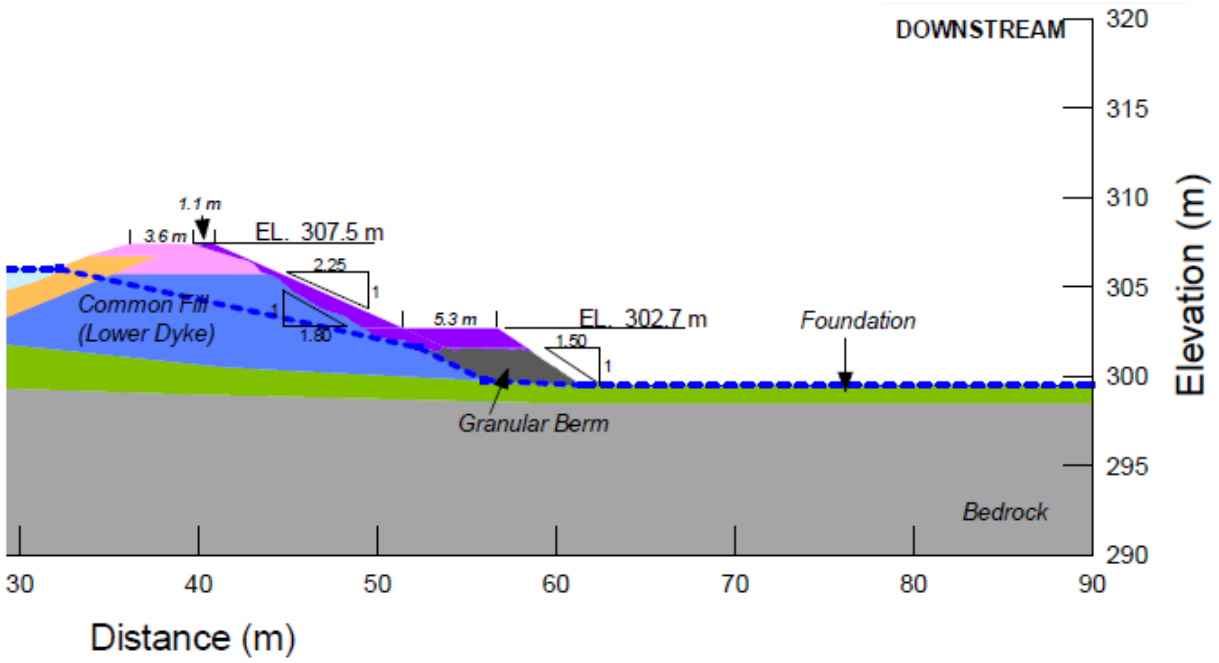


Figure 2: Proposed Geometry of Downstream Slope at Location C[7]

Results from both slope stability analyses show that the locations identified for this project do not meet the factor of safety for slope stability requirements set out in the CDA guidelines. These areas will be addressed by flattening the downstream slopes to prevent the possibility of future slope movement or breach of the Hinds Lake Dyke, while also extending the service life of the structure. A failure of this dyke would have an impact on Hydro's ability to meet the electrical demand on the Island Interconnected System. It would result in a complete loss of generation capabilities at the Hinds Lake Station, which would equate to the loss of 75 MW of generation for several months.

This project is required, as it will bring the existing structure into compliance with the CDA guidelines and extend the useful service life of the Hinds Lake Dyke to ensure the continued reliable operation of the Hinds Lake Station.

3.0 Asset Overview

3.1 Asset Background

The Hinds Lake Dyke is a side hill structure, constructed with earth and rock excavation material placed downhill to form part of the Hinds Lake Power Canal. The Hinds Lake Dyke has not undergone any major

[7] New material shown in purple.

refurbishments since the failure repair in 1982. The maximum height of the dyke is approximately 12 metres; roughly 900,000 cubic metres of materials were required during the initial construction of the structure in 1980.

The power canal is approximately six kilometres in length and carries water from the Hinds Lake Reservoir to the Hinds Lake Station intake. The invert, uphill, and downhill slopes of the canal are lined with impervious glacial till to form a water barrier.

An aerial visualization of the Hinds Lake Dyke is provided as Figure 3.

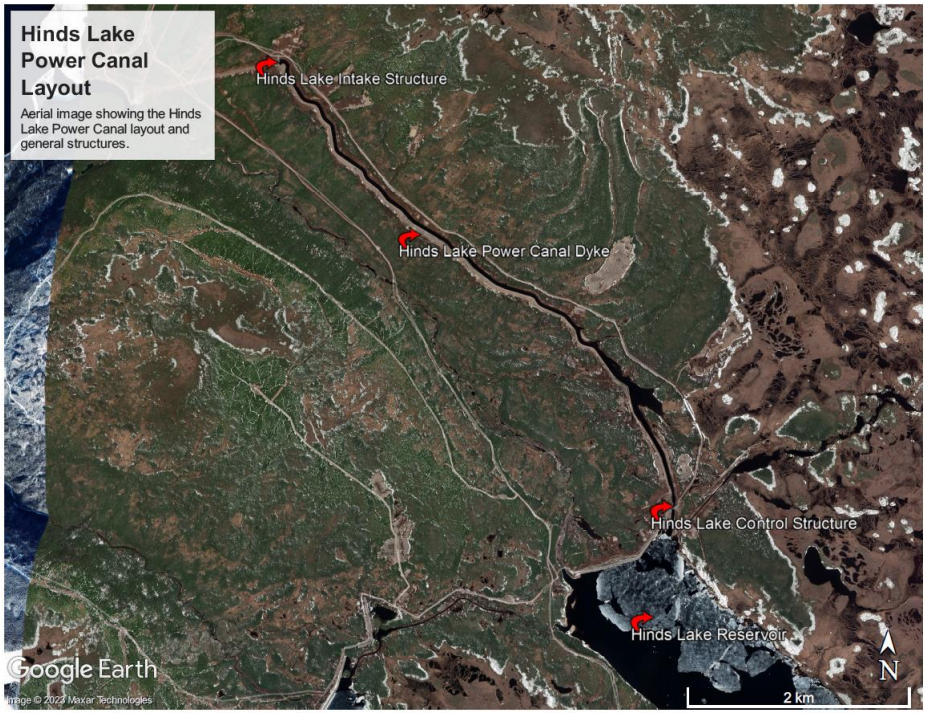


Figure 3: Aerial Visualization of the Hinds Lake Power Canal Dyke

3.2 Historical Reliability

A breach of the Hinds Lake Dyke occurred in 1982, resulting in critical rehabilitation and reconstruction work to return the structure to service. Since that time, the Hinds Lake Dyke has received careful, documented inspections during regular site visits.

Two slope slides occurred at Locations A and B in April of 2018 that required repair to prevent further damage to the downstream slope of the power canal dyke. Subsequent analysis has identified two main locations between Station 1 and Station 2 that fail to meet the minimum factors of safety as per the CDA guidelines.

3.3 Asset Condition

A recent Audit Dam Safety Review ("ADSR"), completed in 2019 by an external consultant, indicates that the Hinds Lake Dyke is generally in satisfactory condition. The downstream slope is well protected by a rockfill layer and the slope has a variable grade ranging from shallow to steep sections. During the completion of the ADSR, a stability analysis was completed that identified some locations of downstream slope that did not meet the factor of safety for slope stability as set out in the CDA guidelines.

A recent inspection of the repairs completed at Location A identified some minor settlement of the downstream crest edge.

4.0 Analysis

4.1 Evaluation of Alternatives

The Hinds Lake Dyke has not undergone any major refurbishments since the failure repair in 1982. Recent slope stability analyses have highlighted areas of concern that do not meet the minimum factors of safety for slope stability as per the CDA guidelines. Construction improvements are required to address these concerns. In consideration of this, the following alternatives were considered:

- Deferral; and
- Upgrade life extension.

4.1.1 Deferral

Two separate studies were conducted as part of SNC-Lavalin's slope stability analyses, each of which recommended the flattening of the downstream slopes of the Hinds Lake Dyke. This work will bring the dyke structure into alignment with the current CDA guidelines as it specifically relates to the factor of safety for slope stability. In the event of a breach of the power canal, outflow would proceed downstream along Hinds Brook and into Grand Lake. While no permanent residents are located downstream, there is the potential for loss of life due to the transient population in the area, which would include Hydro's operations staff or members of the public involved in recreational activities. The breach of the structure would result in minor loss or deterioration of fish and wildlife habitat but it is anticipated that this would be restored naturally in a relatively short period.

There have already been two slope slides observed and repaired in recent years, which indicates a risk of re-occurrence in the future. Recent inspection has noted minor downstream crest edge movement in

the area of the repair completed at Location A. The structure must be maintained in reliable operating condition, as the dyke is an essential part of the Hinds Lake Development. Loss of the canal would result in the complete loss of generation capabilities at the Hinds Lake Station, which would equate to the loss of 75 MW of generation for several months.

For these reasons, deferral of this project is not a viable alternative.

4.1.2 Upgrade Life Extension

Flattening the downstream slope of the Hinds Lake Dyke between Station 1 and Station 2 will serve to increase the factor of safety for slope stability at these locations, which will align them with the current CDA guidelines. This will also ensure the continued reliable operation of the Hinds Lake Power Canal.

4.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation for this project.

4.3 Recommended Alternative

Hydro recommends the upgrade life extension alternative—flattening the downstream slope of the Hinds Lake Dyke at two locations. This will ensure adherence to industry best practices and the CDA guidelines, as well as the continued reliable operation of the Hinds Lake Power Canal.

4.3.1 Risk of Asset Stranding

The Hinds Lake Station has a maximum generation capacity of 75 MW and contributes an average annual production of approximately 340 GWh to the Island Interconnected System. The Hinds Lake Dyke is a critical piece of infrastructure for the continued successful operation of the Hinds Lake Development, forming the power canal channel, which transports water to the Hinds Lake Station for electricity generation.

Hydro has no plans to retire the generating asset at Hinds Lake; as such, the risk of asset stranding is very low.

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for this 2024–2025 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	5	3	**15**
Post-Execution	5	1	**5**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**3.1**

5.0 Scope of Work

The scope of this project includes engineering design and civil construction to flatten the downstream slope of the Hinds Lake Dyke at two locations. The scope of work includes the following:

- Completion of detailed engineering design;
- Completion of an engineering assessment of penstock loading for site access;
- Sourcing and/or production of granular materials for placement;
- Upgrade access road for site access;
- Supply and place granular materials on the downstream slope of the Hinds Lake Dyke at location Station 1; and
- Supply and place granular materials on the downstream slope of the Hinds Lake Dyke at Station 2.

5.1 Project Budget

The estimate for the 2024–2025 project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	**2024**	**2025**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	**0.0**
Labour	62.3	132.2	0.0	**194.5**
Consultant	170.1	111.4	0.0	**281.5**
Contract Work	1.0	2,015.5	0.0	**2,016.5**
Other Direct Costs	4.0	59.5	0.0	**63.5**
Interest and Escalation	14.9	236.5	0.0	**251.4**
Contingency	23.8	398.3	0.0	**422.1**
Total	**276.1**	**2,953.4**	**0.0**	**3,229.5**

5.2 Project Schedule

The schedule for the 2024–2025 project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning: Budget review, scope statement, schedule, risk assessments, and health, safety, and environment plans.	January 2024	March 2024
Design: Detailed engineering design and tender package preparation.	March 2024	October 2024
Procurement: Tendering and award.	November 2024	January 2025
Construction Planning: Contractor submittal review, material production, and material procurement.	February 2025	May 2025
Construction: Complete construction contract.	June 2025	September 2025
Closeout: Project completion, lessons learned, interest cut-off, and as-built documentation.	October 2025	December 2025

6.0 Conclusion

The Hinds Lake Dyke has undergone slope stability analyses in multiple locations, which have indicated that the factor of safety for slope stability is not met as per the CDA guidelines. The structure must be maintained in reliable operating condition, as the dyke is an essential part of the Hinds Lake Development.

The proposed project will bring the Hinds Lake Dyke into alignment with CDA guideline requirements, ultimately extending the service life of the asset and reducing the risk of downstream slope deterioration or failure.

Attachment 1

Slope Stability Analysis of 2 Slides at Hinds Lake Power Canal Dyke (HD-PC) With Proposed Repair Solution

SNC-Lavalin Group Inc.

January 31, 2019

newfoundland labrador hydro

SNC·LAVALIN	TECHNICAL NOTE 2 SLIDES – HINDS LAKE POWER CANAL DYKE – SLOPE STABILITY ANALYSIS 655474-1000-4GEB-0001	Prepared by: P. Saint-Hilaire		
		Rev	Date	Page
		00	2019-01-31	i

Document Title : **SLOPE STABILITY ANALYSIS OF 2 SLIDES AT HINDS LAKE POWER CANAL DYKE (HD-PC) WITH PROPOSED REPAIR SOLUTION**

Client: **Newfoundland and Labrador Hydro, A Nalcor Energy Company**

Project: **Hinds Lake Structures – Slides Analysis at HD-PC**



Prepared by : Patrick Saint-Hilaire
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00	2019-01-31	Revised final version

SNC·LAVALIN	TECHNICAL NOTE 2 SLIDES – HINDS LAKE POWER CANAL DYKE – SLOPE STABILITY ANALYSIS 655474-1000-4GEB-0001	Prepared by: P. Saint-Hilaire		
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1.0 INTRODUCTION

During a weekly inspection conducted on April 30th by Newfoundland and Labrador Hydro (NLH), two (2) slope slides of around 8m by 8m were observed at sections 1+989 (slide #1) and 2+069 (slide #2) on the downstream side of the Hinds Lake Power Canal Dyke (HD-PC). These slides were also observed by SNC-Lavalin during a site visit on June 19th 2018 (Appendix A) and a detailed survey of these slides was later provided by NL Hydro to SNC-Lavalin.

The slope stability of the Hinds Lake Power Canal Dyke was evaluated at the two slide locations (1+989 and 2+069). Results show that the current slopes at the slide locations do not meet the CDA Guidelines requirements for slope stability condition. A proposed repair solution to meet the CDA Guidelines requirements is therefore presented in this note.

2.0 DESIGN CRITERIA

The design criteria for this technical note are the same as presented in the Audit Dam Safety Review (SLI, 2018) and are based on the CDA Guidelines.

Table 2-1: Min. factors of safety (FS) for slope stability analysis as recommended by the CDA Guidelines

Loading Conditions	Required Minimum Factor of Safety	Slope
Steady State Seepage with MOL	1.5	Upstream and Downstream
Steady State Seepage with MFL	1.3	Upstream and Downstream
Full or Partial – Rapid Drawdown	1.2 to 1.3	Upstream
Earthquake (MOL,k_h)	1.0	Upstream and Downstream

MOL: Maximum Operating Level
MFL: Maximum Flood Level
K_h: Horizontal Seismic Coefficient

2.1 Seismic Data

The most recent seismic hazard data corresponding to the location of the slides at HD-PC was obtained from the Geological Survey of Canada (GSC), a Natural Resources Canada division (NRC, 2016) and is presented in Appendix B.

A Peak Ground Acceleration (PGA) of 0.025g for an Earthquake Design Ground Motion (EDGM) of 1:1000 year was considered for this site that is classified as “Significant” according to the latest DSR (Hatch 2011).

3.0 SLOPE STABILITY ANALYSIS

3.1 Studied Cases

A slope stability analysis of the downstream slope of HD-PC was carried out at both slide locations (1+989 and 2+069). Analyses were first carried out considering the current geometry (as surveyed after the slope slides occurred) under static loading for the downstream slope.

Analyses where then conducted for both upstream and downstream sides on cross-sections representing the proposed repaired geometry (with addition of a rockfill berm on the downstream side). These analyses consider all the possible loading conditions (Normal Water Level, Flood Water Level, Rapid Drawdown of canal and seismic condition). Table 3-1 presents a summary of all the analyzed cases and associated required minimum factors of safety.

Table 3-1: Analyzed cases and required minimum factors of safety (FS)

Type of Analysis	Condition	Water Level (m)	Slopes	FS min
Static	Normal*	306.00**	Upstream and Downstream	1.5
	Flood	306.45	Upstream and Downstream	1.3
	Rapid Drawdown	305.70	Upstream	1.3
Pseudo-static	Earthquake	306.00**	Upstream and Downstream	1.0

* Slope stability for the existing slides was conducted only for the downstream slope, under normal static condition and for a Maximum Normal Water Level of 306.00 m.

** Water level of 306.00 m corresponds to the Maximum Operating Level (MOL) of the canal.

For the pseudo-static analysis representing seismic loading (earthquake condition), the Hynes-Griffin and Franklin (1984) method was used. This method consists in using 80% of the material strength (for materials susceptible of having high pore water pressures during an earthquake) and a horizontal seismic coefficient (k_h) corresponding to 50% of the Peak Ground Acceleration (PGA). This method is also based on the assumptions that 1m of seismic displacement is acceptable for most earth dams.

3.2 Dyke Sections Geometry

A recent topographical survey at the location of the two slides (1+989 and 2+069) of the Hinds Lake Power Canal Dyke was provided by NL Hydro. This survey carried out in June 2018 covers the area of HD-PC between sections 1+856 and 2+145. The description of the material layers were taken from drawing “B1-1453-104-C-114” (Newfoundland and Labrador Hydro, 1978). The elevation for bedrock and overburden were estimated from drawing “B1-1453-104-C-118”. Geometry of the two slides is presented on Figure 3-1 and Figure 3-2. These sections were used to assess the current slope stability at the location of the slides and to assess the stability of the proposed repair geometry.

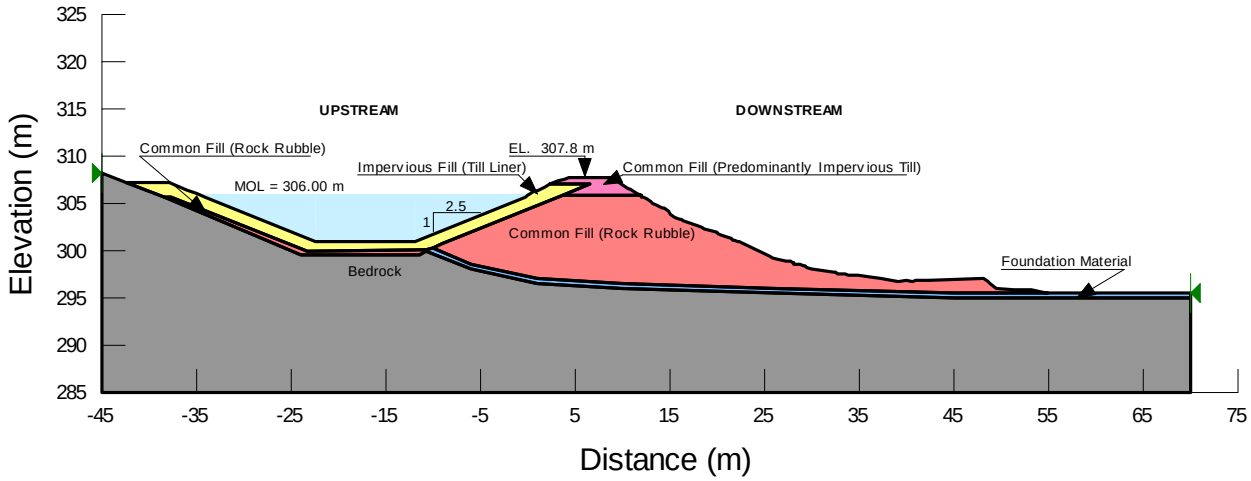


Figure 3-1: Geometry used for slope stability analysis of slide #1 at 1+989. Actual slope grade after failure is approximately 1.6H:1V

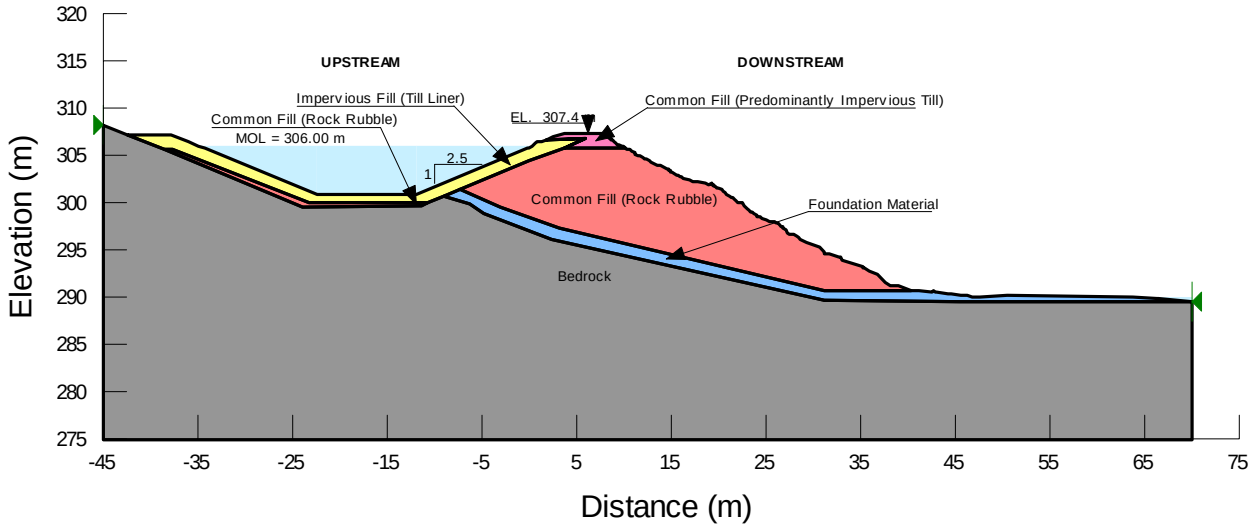


Figure 3-2: Geometry used for slope stability analysis of Slide #2 at 2+069. Actual slope grade after failure is approximately 1.8H:1V

3.3 Geotechnical Properties of Materials

The geotechnical properties of the materials used in this technical note are presented in Table 3-2. The properties used in the previous slope stability analysis in the latest DSR (Hatch, 2011) were reviewed and are considered suitable (SLI, 2018).

Table 3-2: Stability Analysis – Materials geotechnical properties

Materials	Moist Unit Weight, γ (kN/m^3)	Saturated Unit Weight, γ_{sat} (kN/m^3)	Cohesion, c (kPa)	Friction angle, ϕ' (°)
Impervious Fill (Till Liner)(1)	22	22.5	0	32
Washed/Unwashed Filter (Coarse Filter)	20	21	0	33
Rockfill	18.5	20.6	0	40
Foundation Material	20	21	0	31
Common Fill (predominantly impervious Till)(1)	22	22.5	0	33
Common Fill (Rock Rubble)	18.5	20.6	0	38
Bedrock	Impenetrable			
Rockfill (for stabilization)(2)	17.3	19.6	0	45

Notes:
(1) Mechanical material properties of this material have been reduced by 80% for pseudo-static analysis as recommended by Hynes-Griffin and Franklin (1984)
(2) Rockfill used for stabilization of slides

Upstream Maximum Operating Level (MOL) of Hinds Lake Power Canal Dyke is at elevation 306.00 m. Maximum Flood Level (MFL) is 306.45 m and the Lower Supply Level (LSL) is 305.70 m. The downstream water level is considered at the foundation surface elevation.

3.4 Seepage Conditions

A seepage analysis was conducted at each slides section to have a better representation of the water table in the canal embankment and to obtain a more accurate distribution of the pore water pressures. Software SEEP/W, version 8.14 (Geostudio 2012, GEO-SLOPE International Ltd) was used for the analysis. The hydrogeological properties used in this technical note are typical values for similar materials. These values are presented in Table 3-3. These seepage analyses remain approximate considering that no piezometric data and little hydrogeological information were

available. These analyses consider that the different layers are in good condition. The same properties were used in the latest ADSR by SNC-Lavalin (2018).

Table 3-3: Stability analysis – Materials hydrogeological properties

Materials	Saturated Hydraulic Conductivity, K_{sat} (m/s)
Impervious Fill (Till Liner)	$1x10^{-7}$
Washed/Unwashed Filter (Coarse Filter)	$1x10^{-3}$
Rockfill	$1x10^{-3}$
Foundation Material	$5x10^{-6}$
Common Fill (predominantly impervious Till)	$1x10^{-7}$
Common Fill (Rock Rubble)	$1x10^{-3}$
Bedrock	$1x10^{-10}$
Rockfill (for stabilization)	$1x10^{-3}$

3.5 Methodology

The slope stability calculations were achieved by using the SLOPE/W software (version 8.14) of GEO-SLOPE International Ltd. The analysis is based on the limiting equilibrium approach for a two dimensional model using the Morgenstern-Price method. The Mohr-Coulomb model has been used to characterize the shear strength model of the soils and materials, and the pore water pressures across the embankment are represented by a piezometric line determined by the seepage analysis carried out with the SEEP/W software (version 8.14) of GEO-SLOPE International Ltd.

3.6 Existing conditions

As indicated in latest ADSR (SLI, 2018), the slope stability at both slide locations do not meet the minimum required FS of 1.5 for the stability of the downstream slope in static condition with a Maximum Operating Level (MOL) of 306.00 m. Factors of Safety of 1.35 and 1.22 were respectively obtained at 1+989 (slide#1) and at 2+069 (slide #2) and are smaller than the required value of 1.5. The stability analysis results for the existing conditions at the slides location are presented in Appendix C and summarized in Table 3-4 below.

Table 3-4: Slope stability analysis results for HD-PC slides. Existing conditions at 1+989 and 2+069

Station	Loading Condition	Water Level in Reservoir (m)	Required Min. Factor of Safety	Computed Factor of Safety
HD-PC 1+989 (Slide #1)	Static - Normal	306.00	1.5	1.35
HD-PC 2+069 (Slide #2)	Static - Normal	306.00	1.5	1.22

3.7 Stabilization and Reparation Work

In order to meet required factors of safety as recommended by the CDA guidelines, stabilization and reparation works are required on the downstream slope of the canal at the location of these two slides. The addition of a rockfill cover with a slope of 2.25H:1V should be enough to meet the required FS as indicated by the slope stability results. This additional rockfill cover, acting as a stabilization berm, has a width of 2 m at the crest elevation and covers the entire downstream slope with a grade of 2.25H:1V as presented on Figure 3-3 and Figure 3-4.

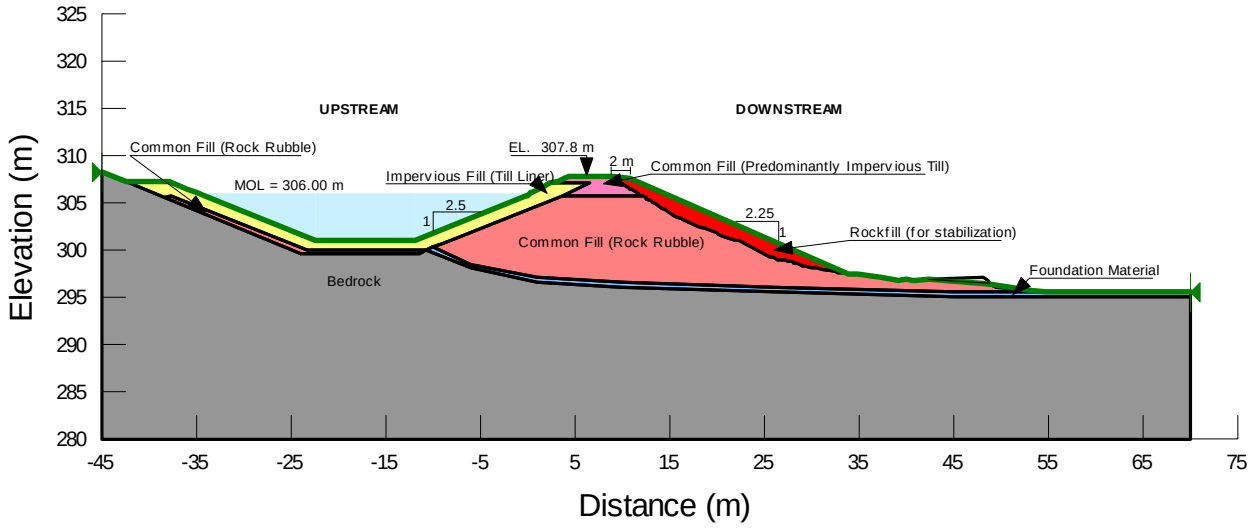


Figure 3-3: Proposed geometry of downstream stabilization berm for HD-PC at slide #1 (1+989)

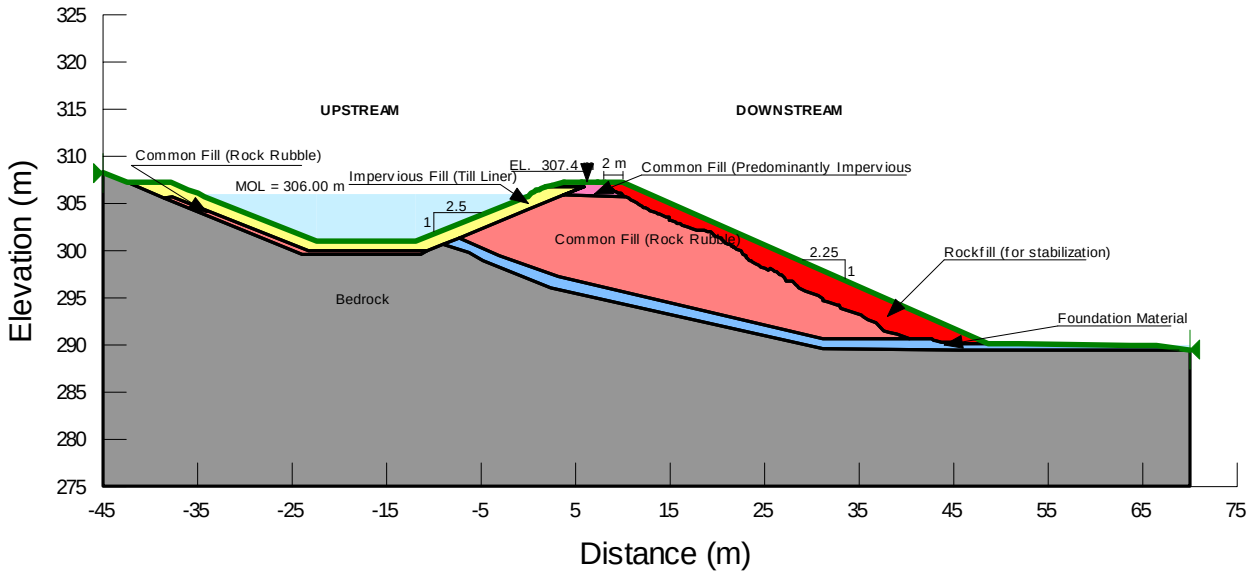


Figure 3-4: Proposed geometry of downstream stabilization berm for HD-PC at slide #2 (2+069)

The slope stability analysis results corresponding to the stabilized and repaired sections are presented in Appendix D and summarized in Table 3-5.

Table 3-5: Stability analysis results for HD-PC slides. Repaired sections at 1+989 and 2+069

Station	Loading Condition	Water Level in Reservoir (m)	Required Min. Factor of Safety	Factor of Safety	
				Upstream	Downstream
HD-PC 1+989 (Slide #1)	Static - Normal	306.00	1.5	1.88	1.88
	Static - Flood	306.45	1.3	2.21	1.88
	Static - Rapid Drawdown	306.00 to 305.70	1.2 to 1.3	1.72	N/A
	Pseudo-static	313.94	1.0	1.45	1.81
HD-PC 2+069 (Slide #2)	Static - Normal	306.00	1.5	2.11	1.82
	Static - Flood	306.45	1.3	2.70	1.82
	Static - Rapid Drawdown	306.00 to 305.70	1.2 to 1.3	1.86	N/A
	Pseudo-static	313.94	1.0	1.63	1.57

These slope stability results indicate that the computed factors of safety for the upstream and downstream slopes are greater than the required FOS for all of the calculated cases (Static and Pseudo-static).

The slope stability of the proposed repaired geometry meets the CDA guidelines requirements and is consequently considered to be satisfactory

3.7.1 Physical characteristics of the stabilization rockfill material

The rockfill for the proposed stabilization berm should be a quarried granular material of size 0 to 300 mm with particles having angular and sharp edges to ensure a high internal friction. This rockfill should meet the following gradation requirements:

Table 3-6: Gradation requirements for stabilization rockfill at HD-PC

Sieve size (mm)	Percent Passing by weight (%)
300	100
200	70-100
150	50-80
20	10-35
5	0-20
0.080	0-5

The materials forming the rockfill should also meet the physical properties requirements presented in Table 3-7.

Table 3-7: Minimum physical properties requirements for granular rockfill

Test	Requirement
Micro Deval abrasion test (ASTM D6928)	35% max.
Los Angeles abrasion test (ASTM C31, ASTM C535)	50% max.

3.7.2 Placement of the rockfill for stabilization

Placement of the granular material for the rockfill stabilization berm does not need to be compacted by heavy compactors. However, a minimal compaction from tamping with excavator buckets and from rolling of loaded construction trucks on the placed granular material should be carried out on lifts not higher than 300 mm. The granular material should also be placed in a manner that ensures that the particles are uniformly distributed (reasonably well-graded) so that smaller particles fill the voids between the larger particles and result in well-keyed, dense, and uniform layers. Rearrangement (by hand, by an excavator bucket or by using other construction equipment such as small vibrating plates) to obtain an acceptable distribution over the slope may also be required.

3.7.3 Quantities estimate

The proposed stabilization solution at the location of the slides of the downstream slope of HD-PC consists in placing a rockfill granular berm. A representation of this granular berm with a width of 2 m at the crest and with a slope of 2.25H:1V is presented on Figure 3-3 and on Figure 3-4. To make sure the entire section of the downstream slope where the slides occurred is protected from possible similar slides in the future, this solution should be applied from stations 1+950 and 2+110, covering a total length of 160 m on the downstream slope of HD-PC.

An estimate of the required volume of rockfill material to implement this berm has been carried out based on the topographical survey provided by NL Hydro. This volume is estimated to be 6,000 m^3.

4.0 CONCLUSION

Two slides occurred on the downstream slope of the Hinds Lake Power Canal Dyke during the latest spring. The slope stability analysis at these sections showed that the minimum requirements for slope stability as presented by the CDA Guidelines were not met. A stabilization solution, which consist of placing a rockfill layer (of approximatively 1 m to 3.5 m thick) on the downstream side with a slope of 2.25H:1V and a width of 2 m at the crest elevation, was proposed to repair the actual slides and provide an appropriate stabilization to the section located between 1+950 and 2+110.

Slope stability analyses considering the presence of this rockfill berm on the downstream slope indicate that the CDA Guidelines are satisfied with the implementation of this proposed solution. Seepage analyses were also conducted, to estimate the location of the water table and pore water distributions in the power canal embankment materials and were used as an input for the slope stability analyses of the downstream slope of HD-PC.

The slope stability of the proposed repaired geometry in static condition for normal, flood, and rapid drawdown are satisfactory, as well as the pseudo-static analysis corresponding to an Earthquake Design Ground Motion of 1:2500 year.

Required rockfill material volume for the stabilization berm should be a quarried granular material of size 0 to 300 mm, and the required volume is estimated to be 6,000 m^3 to cover a length of 160 m where stabilization works are required. Placement of this stabilization rockfill material does not need

to be compacted by heavy compactors but should be placed and tamped with the excavator bucket and compacted from rolling of loaded construction trucks on the placed granular material, on lifts not higher than 300 mm, to ensure a minimum compaction. The granular material should also be placed to ensure that the particles are uniformly distributed to avoid segregation of the material. Rearrangement (by hand, by an excavator bucket or by using other construction equipment such as small vibrating plates) to obtain an acceptable distribution over the slope may be required.

5.0 REFERENCES

Canadian Dam Association (CDA), (2007). Dam safety guidelines 2013 edition. Canadian Dam Association.

HATCH, Nov. 2011, Hinds Lake Dam Safety Review.

Hynes-Griffin and Franklin (1984). “Rationalizing the seismic coefficient method”. US Army Corps of Engineers.Misc. paper GL-84-13.

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Newfoundland and Labrador Hydro (NLH), 1980. As Built Drawings.

SNC-Lavalin, 2018, Hinds Lake Structures – Audit Dam Safety Review.

Appendix A

Slides Photos

SNC·LAVALIN	TECHNICAL NOTE 2 SLIDES – HINDS LAKE POWER CANAL DYKE – SLOPE STABILITY ANALYSIS 655474-1000-4GEB-0001	Prepared by: P. Saint-Hilaire		
		Rev	Date	Page
		00	2019-01-31	A-1



Photo A-1 : General view of slide #1 (1+989) from the dyke toe during 2018 site inspection.

SNC·LAVALIN	TECHNICAL NOTE 2 SLIDES – HINDS LAKE POWER CANAL DYKE – SLOPE STABILITY ANALYSIS 655474-1000-4GEB-0001	Prepared by: P. Saint-Hilaire		
		Rev	Date	Page
		00	2019-01-31	A-2



Photo A-2 : General view of slide #1 (1+989) from the downstream slope during 2018 site inspection.

SNC·LAVALIN	TECHNICAL NOTE 2 SLIDES – HINDS LAKE POWER CANAL DYKE – SLOPE STABILITY ANALYSIS 655474-1000-4GEB-0001	Prepared by: P. Saint-Hilaire		
		Rev	Date	Page
		00	2019-01-31	A-3



Photo A-3 : General view of slide #1 (1+989) from the crest during 2018 site inspection.



Photo A-4 : General view of slide #1 (1+989) from the crest during weekly inspection by Nalcor (30/04/2018).



Photo A-5 : General view of slide #2 (2+069) from the dyke toe (2018 site inspection).



Photo A-6 : General view of slide #2 (2+069) from the crest (2018 site inspection).



Photo A-7 : General view of slide #2 (2+069) from the crest during weekly inspection by Nalcor Hydro (30/04/2018).



Photo A-8 : General View of Slide #2 (2+069) from the downstream slope during weekly inspection by Nalcor Hydro (30/04/2018).

Appendix B

Seismic Hazard

SNC·LAVALIN	TECHNICAL NOTE 2 SLIDES – HINDS LAKE POWER CANAL DYKE – SLOPE STABILITY ANALYSIS 655474-1000-4GEB-0001	Prepared by: P. Saint-Hilaire		
		Rev	Date	Page
		00	2019-01-31	B-1

2015 National Building Code Seismic Hazard Calculation

INFORMATION: Eastern Canada English (613) 995-5548 français (613) 995-0600 Facsimile (613) 992-8836
Western Canada English (250) 363-6500 Facsimile (250) 363-6565

August 02, 2018

Site: 49.0721 N, 57.1648 W User File Reference: HD-PC Hinds Lake Power Canal Dyke at 2 080

Requested by: Louis-Philippe Grimard, SNC-Lavalin

National Building Code ground motions: 2% probability of exceedance in 50 years (0.000404 per annum)

Sa(0.05)	Sa(0.1)	**Sa(0.2)**	Sa(0.3)	**Sa(0.5)**	**Sa(1.0)**	**Sa(2.0)**	**Sa(5.0)**	**Sa(10.0)**	**PGA (g)**	**PGV (m/s)**
0.050	0.072	**0.074**	0.068	**0.062**	**0.043**	**0.024**	**0.0061**	**0.0028**	**0.042**	**0.053**

Notes. Spectral (Sa(T), where T is the period in seconds) and peak ground acceleration (PGA) values are given in units of g (9.81 m/s^2). Peak ground velocity is given in m/s. Values are for "firm ground" (NBCC 2015 Site Class C, average shear wave velocity 450 m/s). NBCC2015 and CSAS6-14 values are specified in **bold** font. Three additional periods are provided - their use is discussed in the NBCC2015 Commentary. Only 2 significant figures are to be used. ***These values have been interpolated from a 10-km-spaced grid of points. Depending on the gradient of the nearby points, values at this location calculated directly from the hazard program may vary. More than 95 percent of interpolated values are within 2 percent of the directly calculated values.***

Ground motions for other probabilities:

Probability of exceedance per annum	0.010	0.0021	0.001
Probability of exceedance in 50 years	40%	10%	5%
Sa(0.05)	0.0056	0.018	0.028
Sa(0.1)	0.0097	0.027	0.042
Sa(0.2)	0.012	0.032	0.047
Sa(0.3)	0.012	0.031	0.044
Sa(0.5)	0.011	0.029	0.042
Sa(1.0)	0.0058	0.020	0.029
Sa(2.0)	0.0027	0.010	0.016
Sa(5.0)	0.0006	0.0024	0.0039
Sa(10.0)	0.0005	0.0011	0.0017
PGA	0.0055	0.017	0.025
PGV	0.0060	0.022	0.034

References

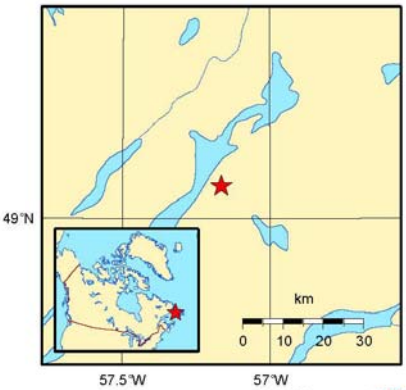
National Building Code of Canada 2015 NRCC no. 56190;
Appendix C: Table C-3, Seismic Design Data for Selected Locations in Canada

User's Guide - NBC 2015, Structural Commentaries NRCC no. xxxxxx (in preparation)
Commentary J: Design for Seismic Effects

Geological Survey of Canada Open File 7893 Fifth Generation Seismic Hazard Model for Canada: Grid values of mean hazard to be used with the 2015 National Building Code of Canada

See the websites www.*EarthquakesCanada.ca* and www.*nationalcodes.ca* for more information

Aussi disponible en français



Natural Resources Canada Ressources naturelles Canada

Canada

Figure B-1 : Seismic Hazard Calculation at slides location.

SNC·LAVALIN	TECHNICAL NOTE 2 SLIDES – HINDS LAKE POWER CANAL DYKE – SLOPE STABILITY ANALYSIS 655474-1000-4GEB-0001	Prepared by: P. Saint-Hilaire		
		Rev	Date	Page
		00	2019-01-31	C

Appendix C

Stability Analysis

Existing Conditions

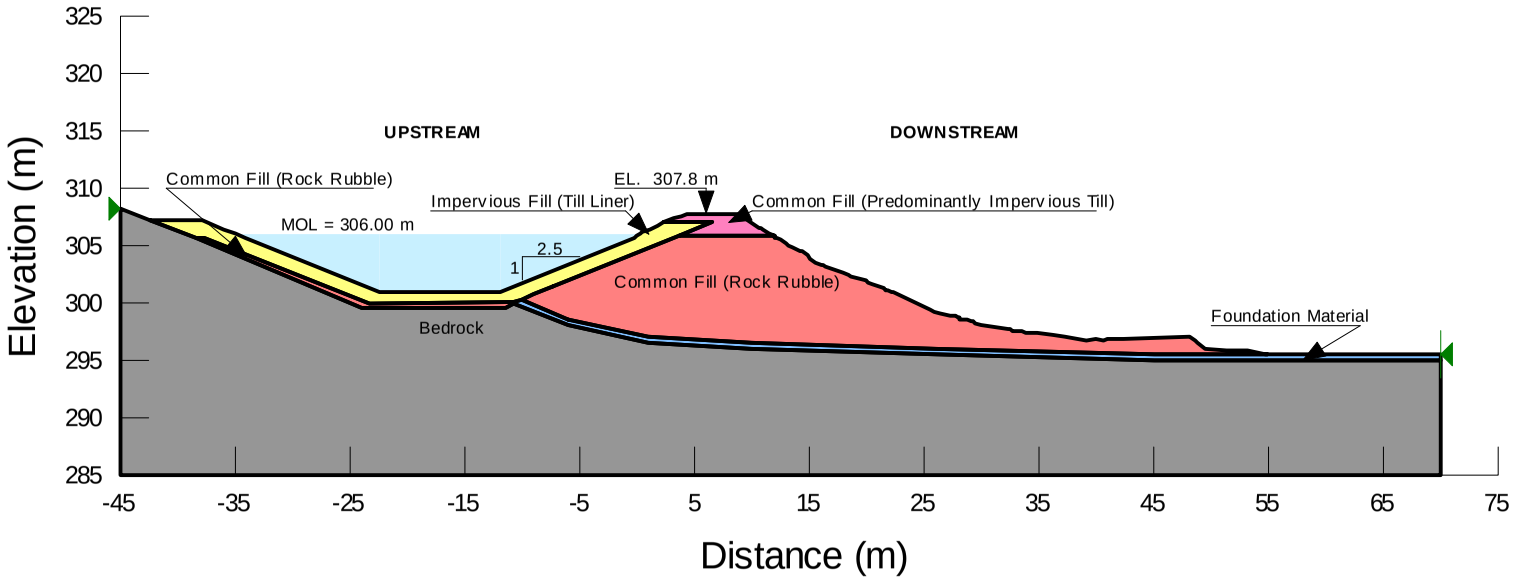


Figure C-1: Geometry used in the stability analysis for Hinds Lake Power Canal (HD-PC) for slide #1 (1+989).

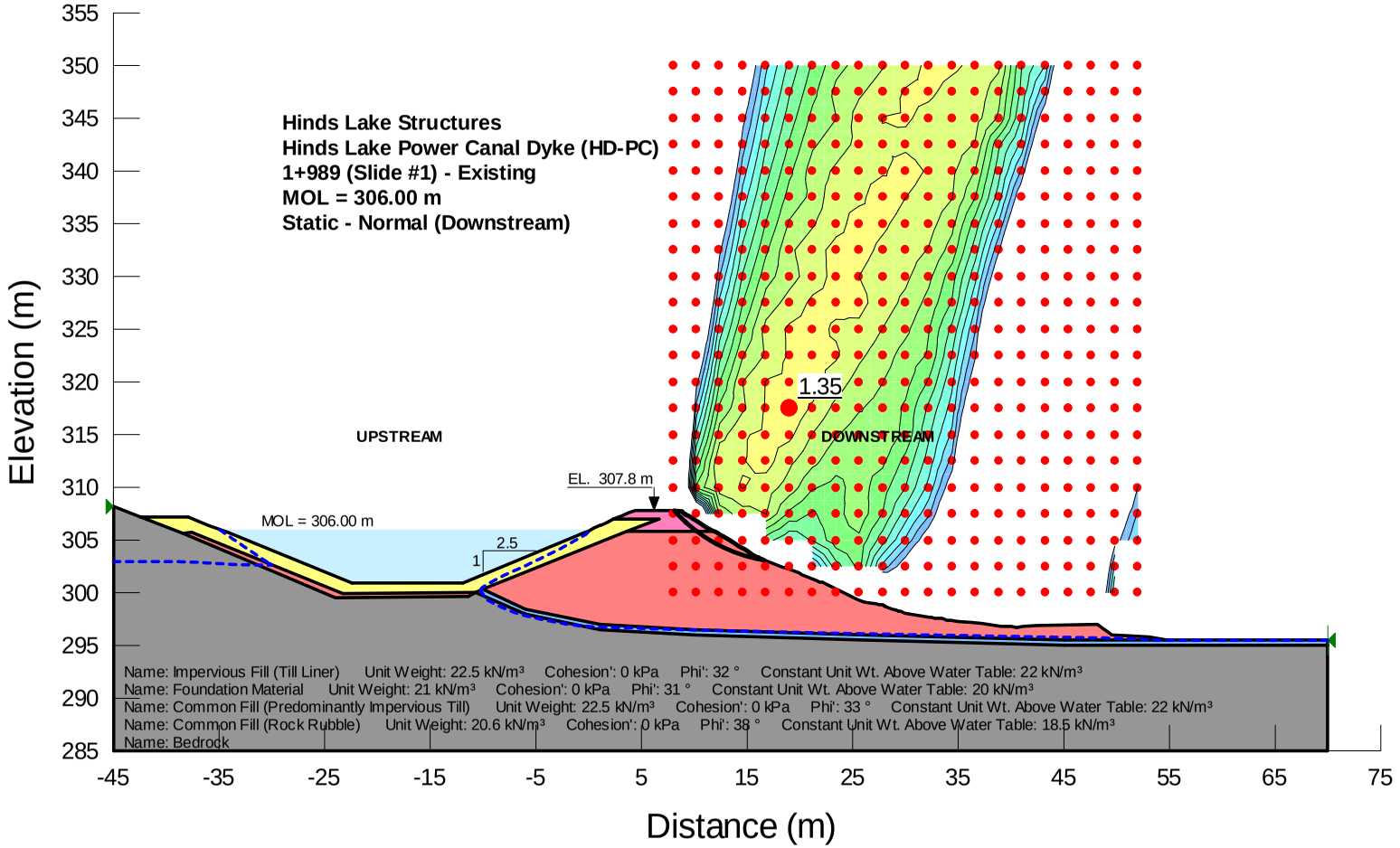


Figure C-2: Hinds Lake Power Canal (HD-PC) downstream slope stability analysis for slide #1 (1+989) in static conditions at Maximum Operating Level (MOL).

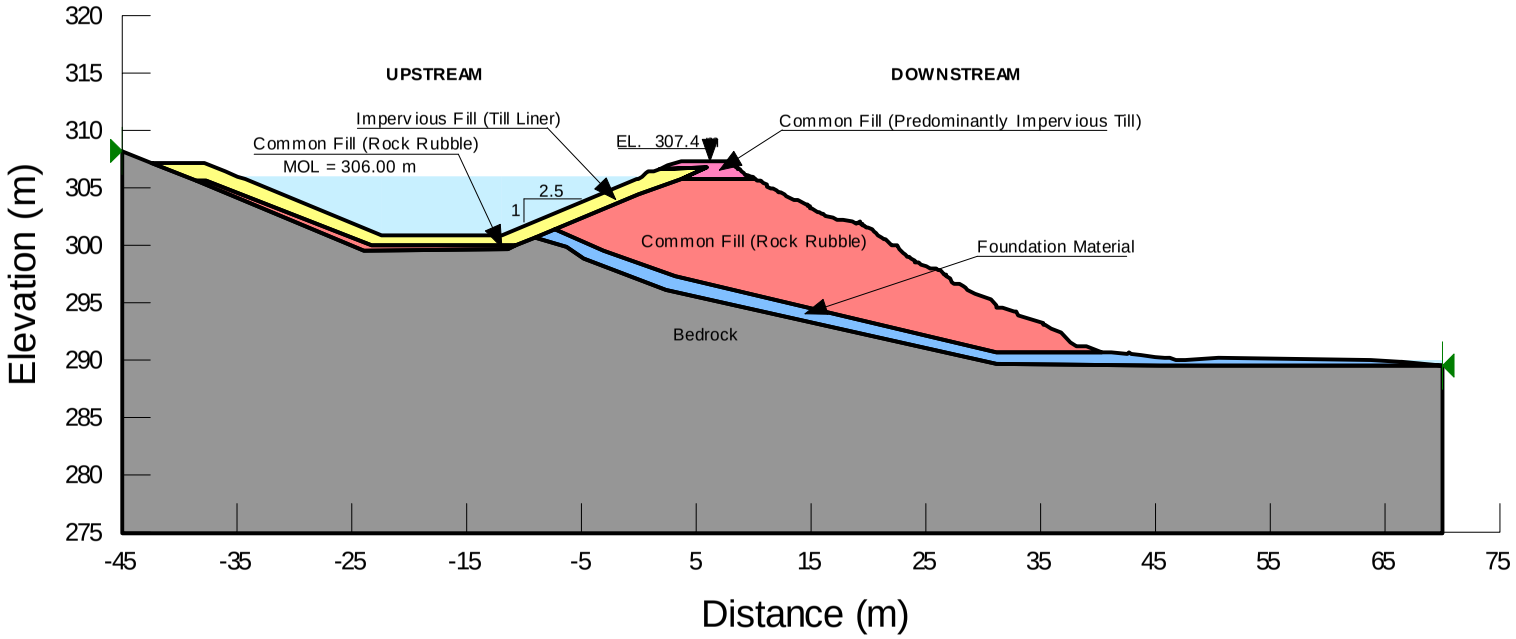


Figure C-3: Geometry used in the stability analysis for Hinds Lake Power Canal (HD-PC) for slide #2 (2+069).

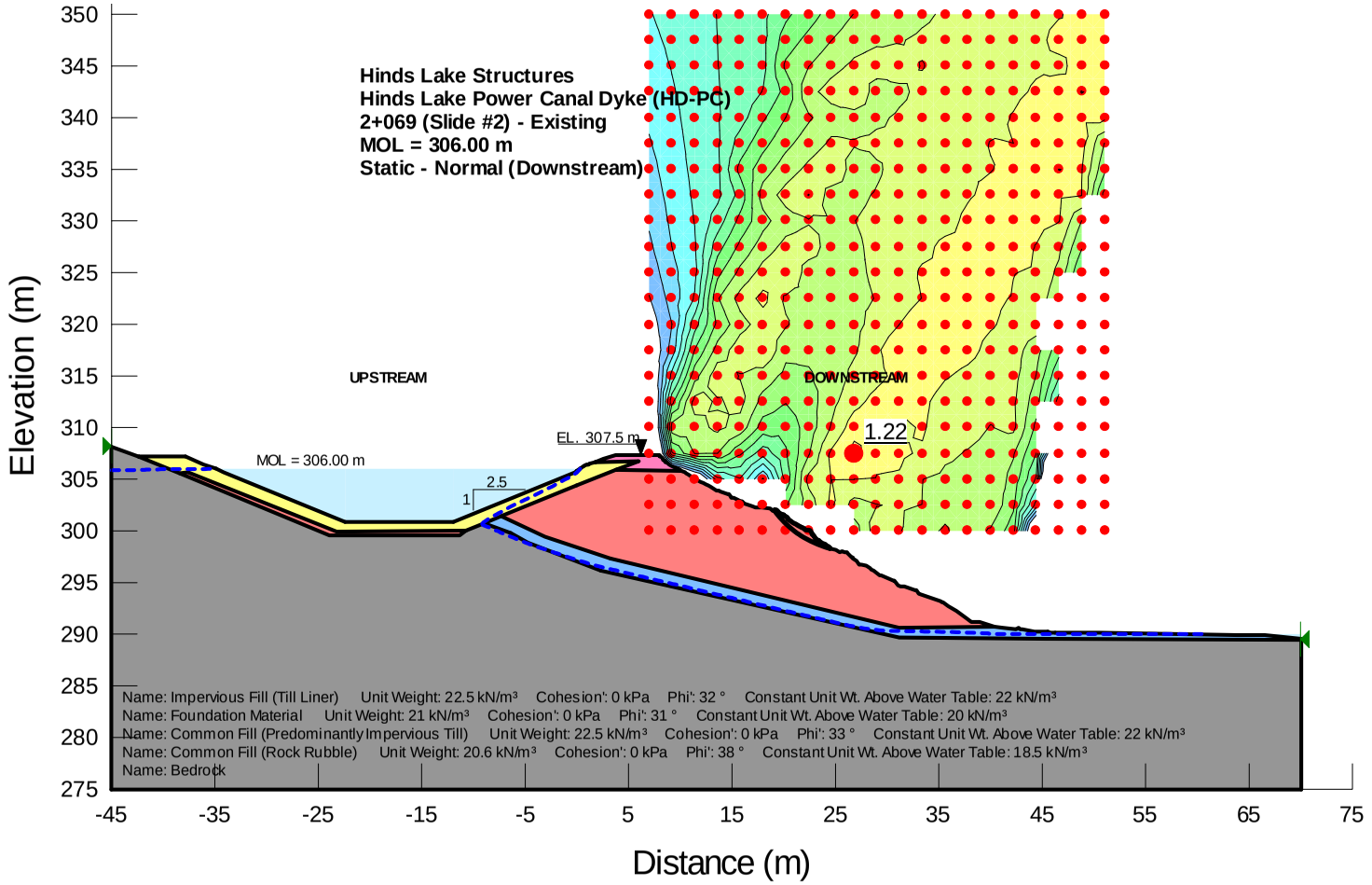


Figure C-4: Hinds Lake Power Canal (HD-PC) downstream slope stability analysis for slide #2 (2+069) in static conditions at Maximum Operating Level (MOL).

SNC·LAVALIN	TECHNICAL NOTE 2 SLIDES – HINDS LAKE POWER CANAL DYKE – SLOPE STABILITY ANALYSIS 655474-1000-4GEB-0001	Prepared by: P. Saint-Hilaire		
		Rev	Date	Page
		00	2019-01-31	D

Appendix D

Stability Analysis

Stabilization and Reparation Work

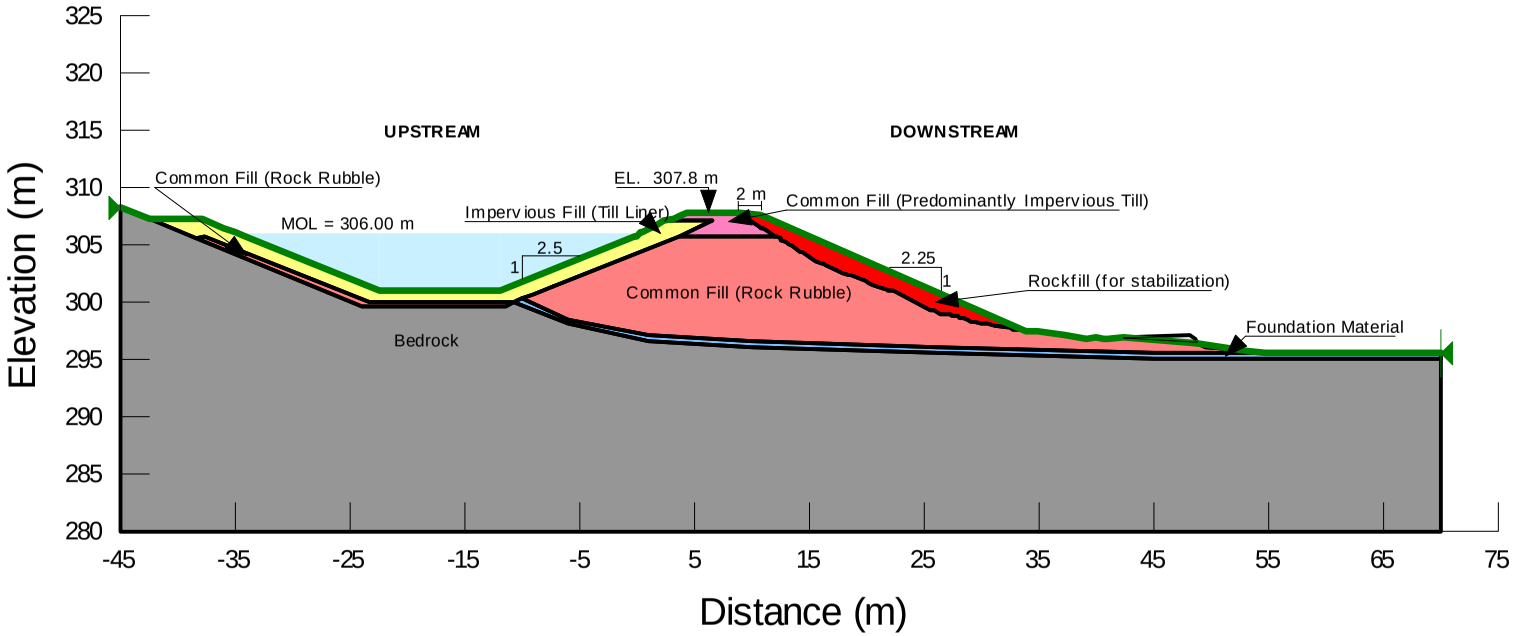


Figure D-1: Proposed geometry of downstream stabilization berm for Hinds Lake Power Canal (HD-PC) at slide #1 (1+989).

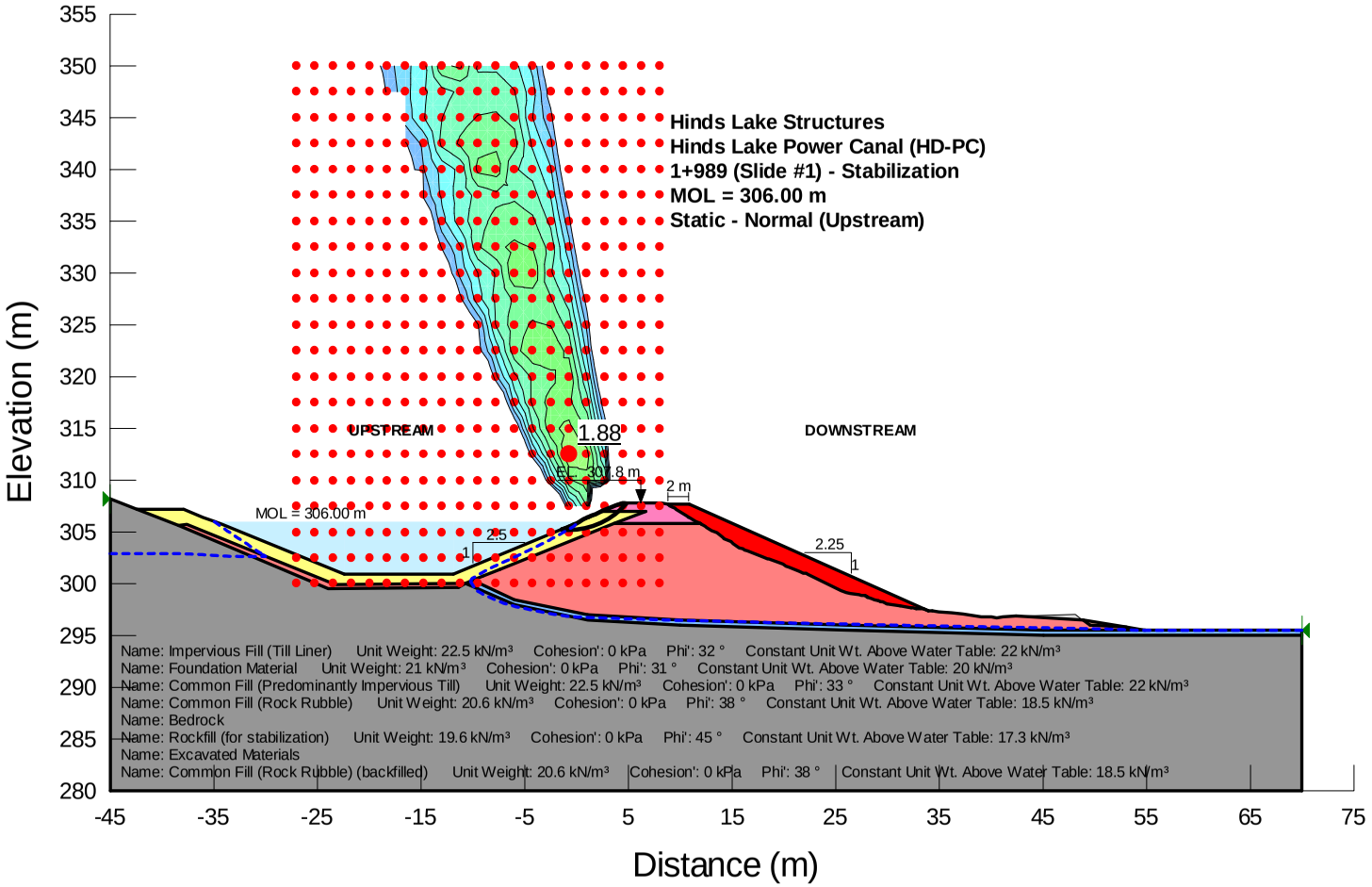


Figure D-2: Hinds Lake Power Canal (HD-PC) upstream slope stability analysis for slide #1 (1+989) in static conditions at Maximum Operating Level (MOL).

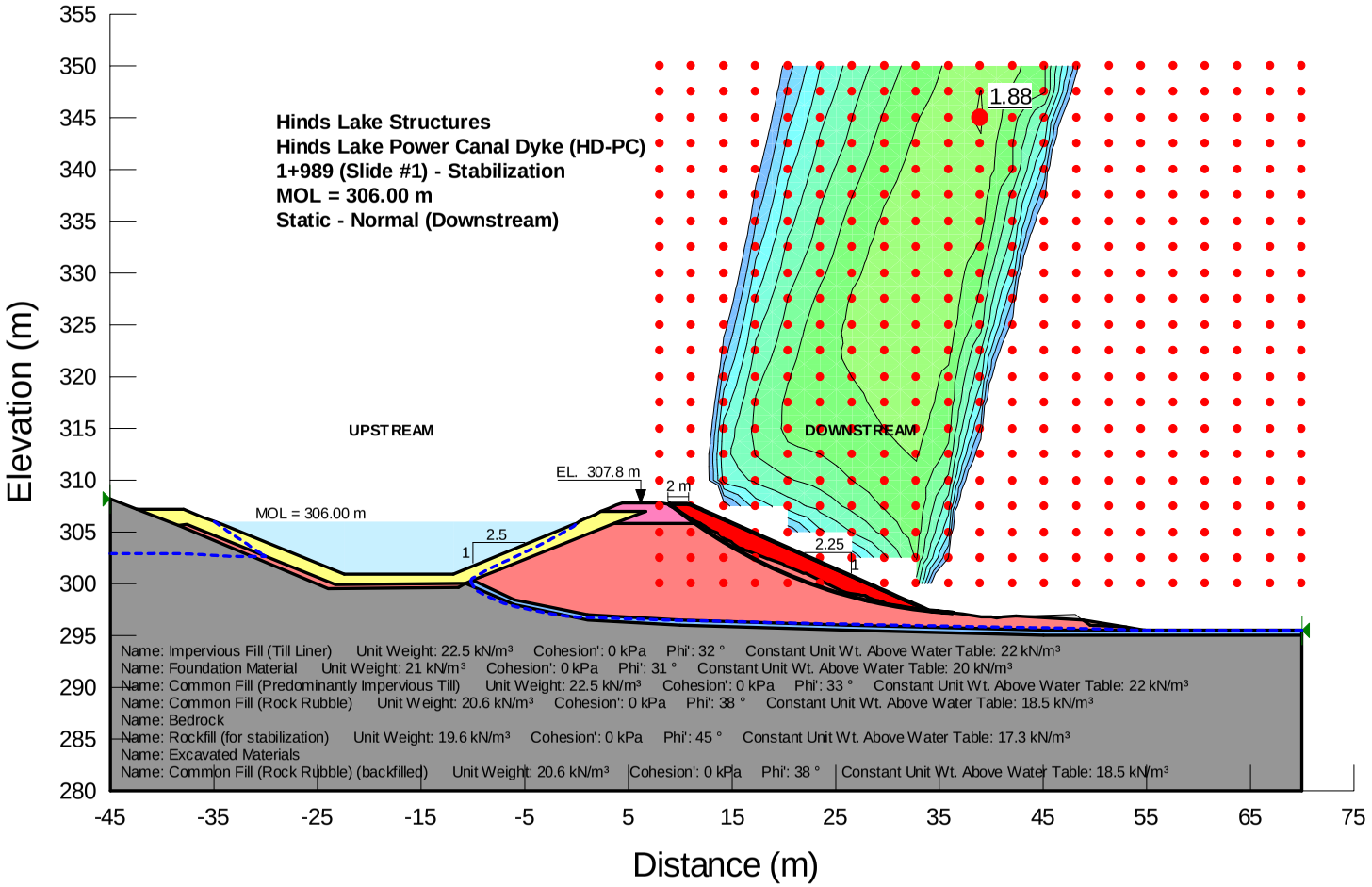


Figure D-3: Hinds Lake Power Canal (HD-PC) downstream slope stability analysis for slide #1 (1+989) in static conditions at Maximum Operating Level (MOL).

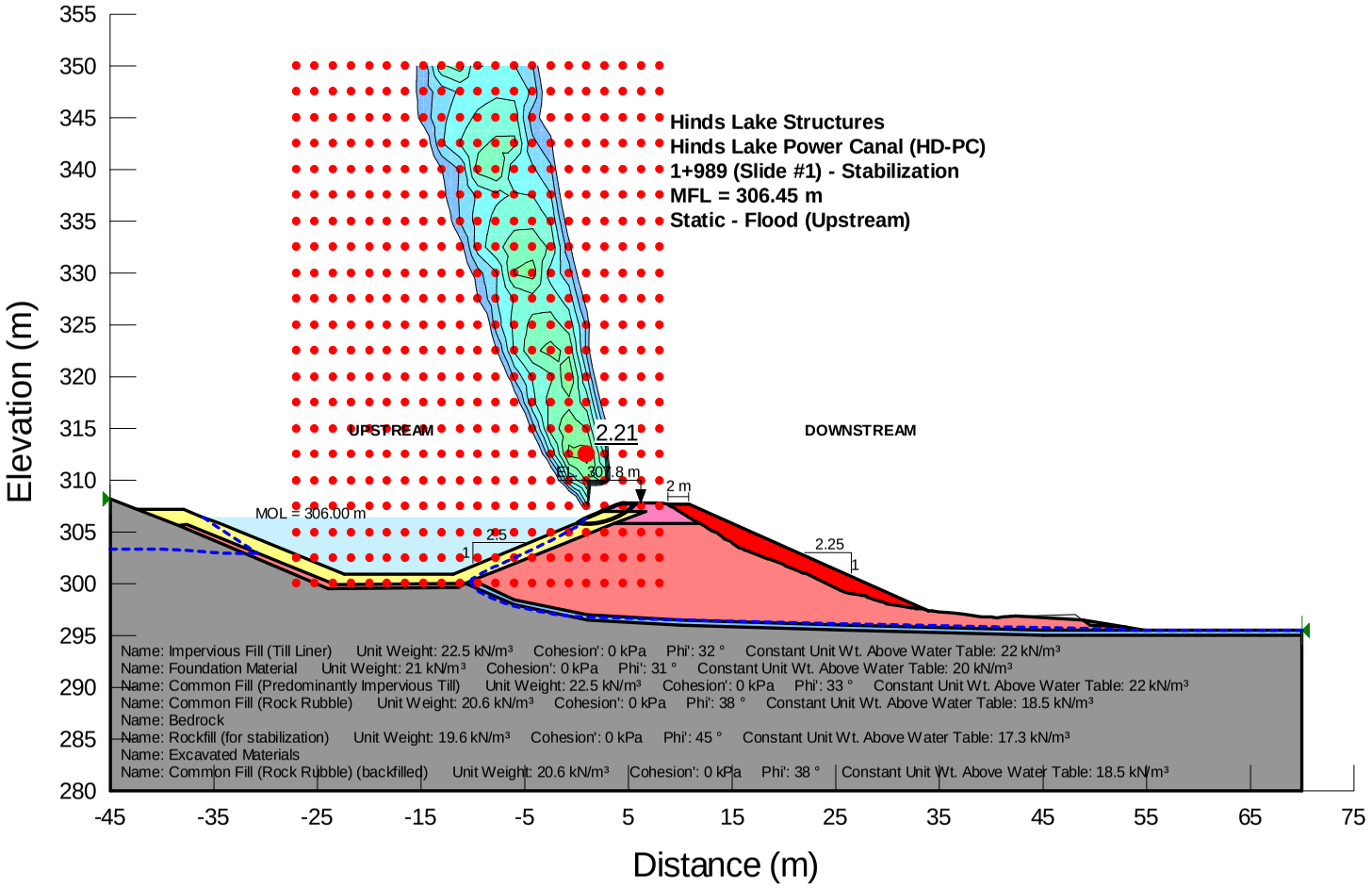


Figure D-4: Hinds Lake Power Canal (HD-PC) upstream slope stability analysis for slide #1 (1+989) in static conditions at Maximum Flood Level (MFL).

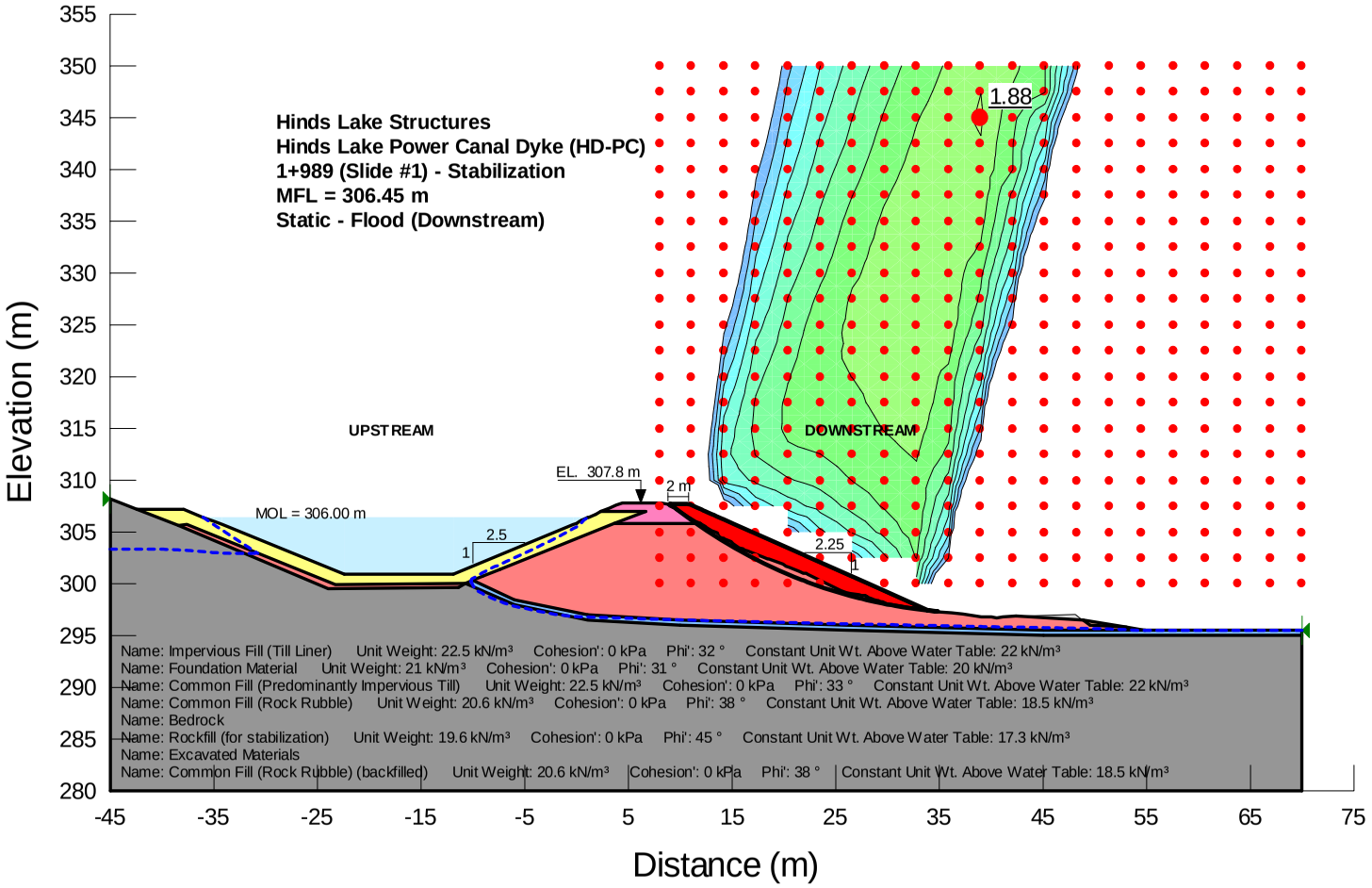


Figure D-5: Hinds Lake Power Canal (HD-PC) downstream slope stability analysis for slide #1 (1+989) in static conditions at Maximum Flood Level (MFL).

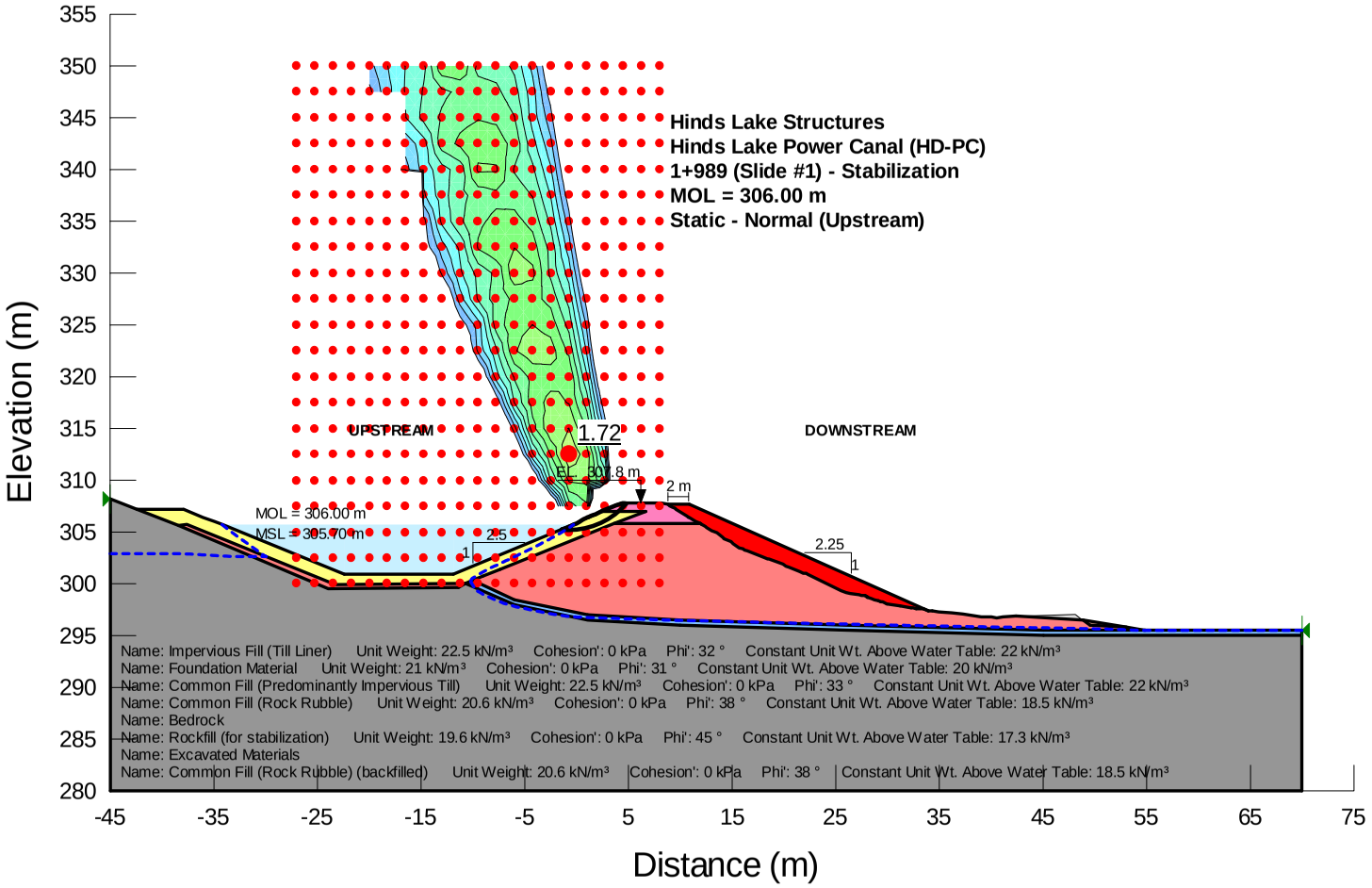


Figure D-6: Hinds Lake Power Canal (HD-PC) upstream slope stability analysis for slide #1 (1+989) in static conditions at rapid drawdown from Maximum Operating Level (MFL) to Lower Supply Level (LSL).

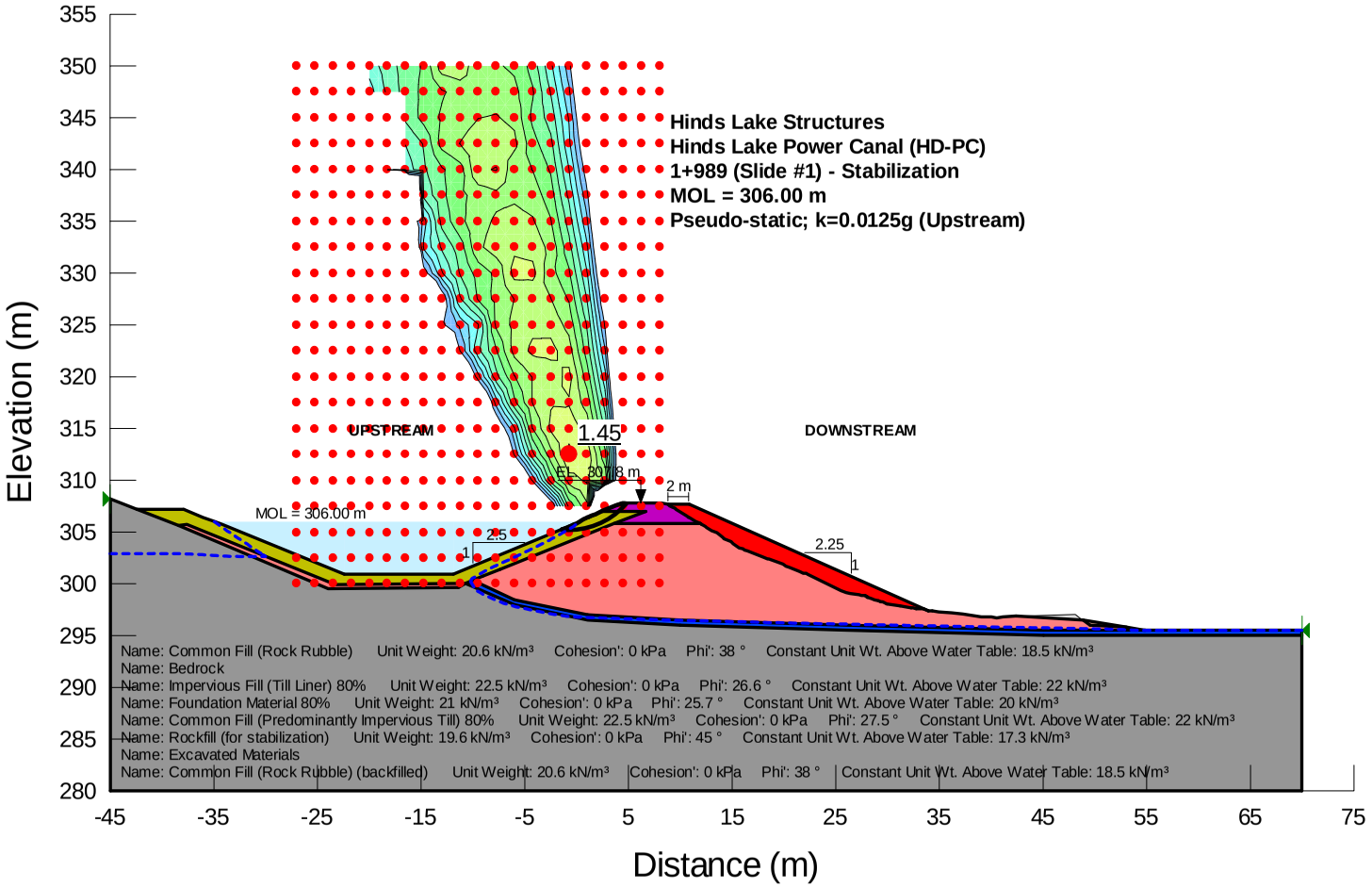


Figure D-7: Hinds Lake Power Canal (HD-PC) upstream slope stability analysis for slide #1 (1+989) in pseudo-static conditions at Maximum Operating Level (MOL) and with a Horizontal Seismic Coefficient (k_h) of 0.0125g.

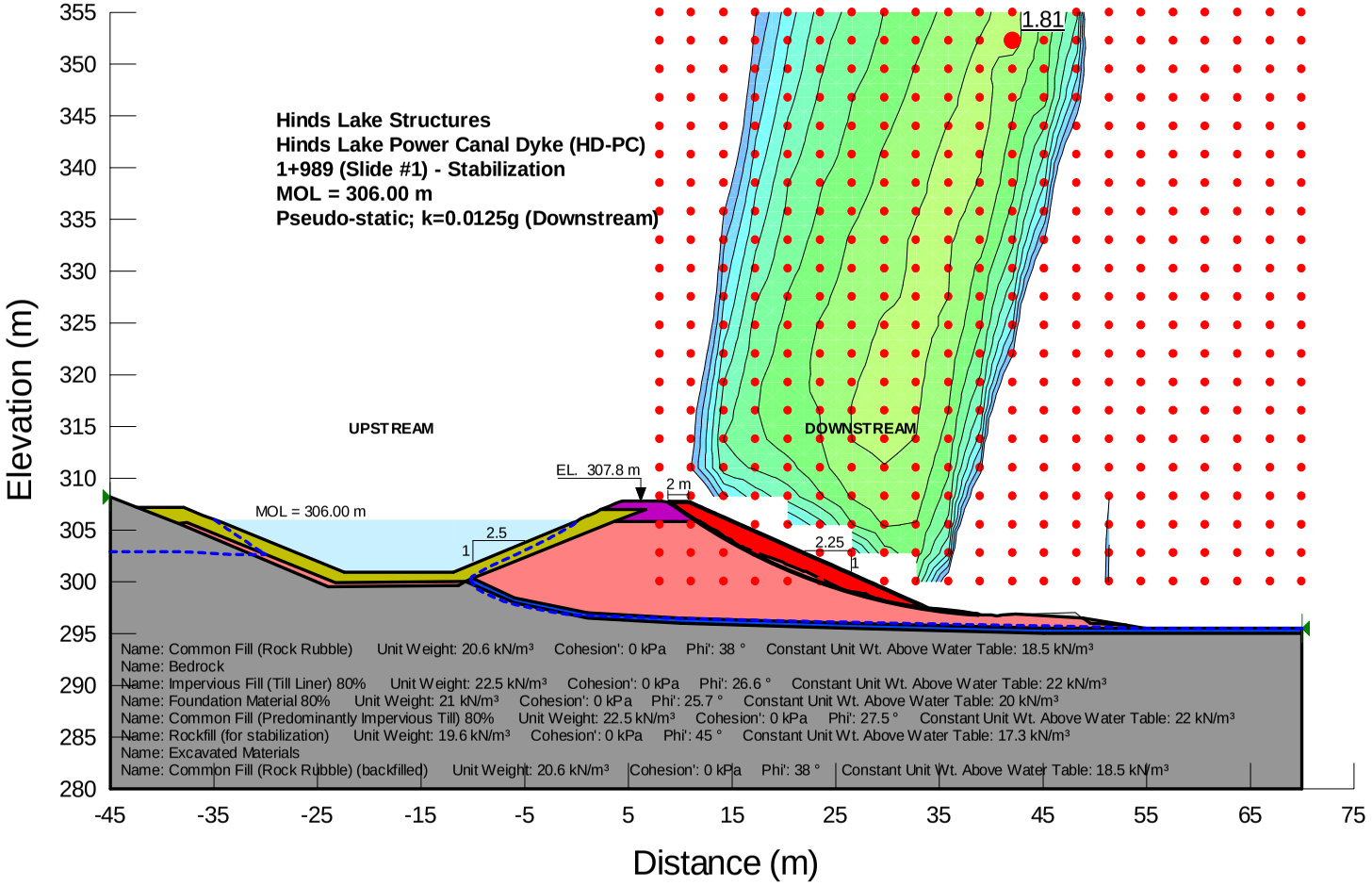


Figure D-8: Hinds Lake Power Canal (HD-PC) downstream slope stability analysis for slide #1 (1+989) in pseudo-static conditions at Maximum Operating Level (MOL) and with a Horizontal Seismic Coefficient (k_h) of 0.0125g.

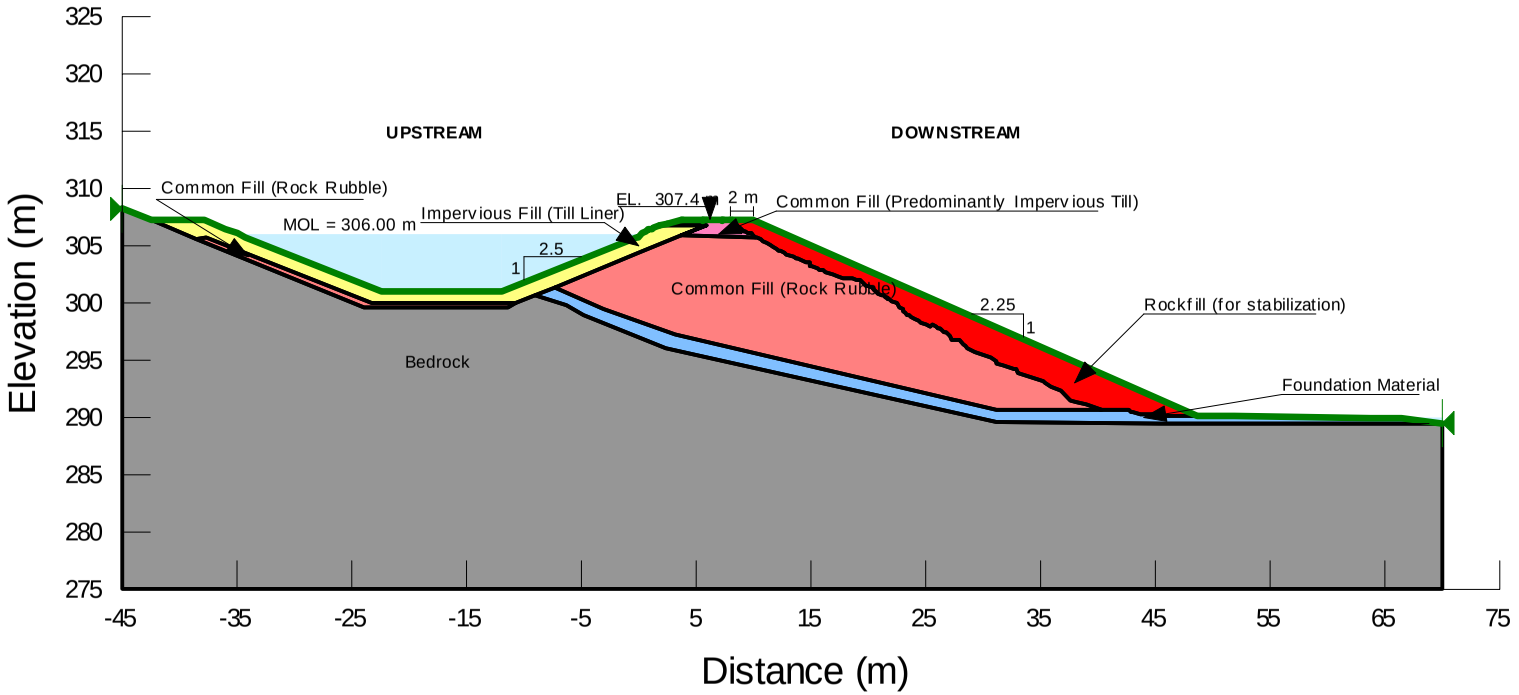


Figure D-9: Proposed geometry of downstream stabilization berm for Hinds Lake Power Canal (HD-PC) at slide #2 (2+069).

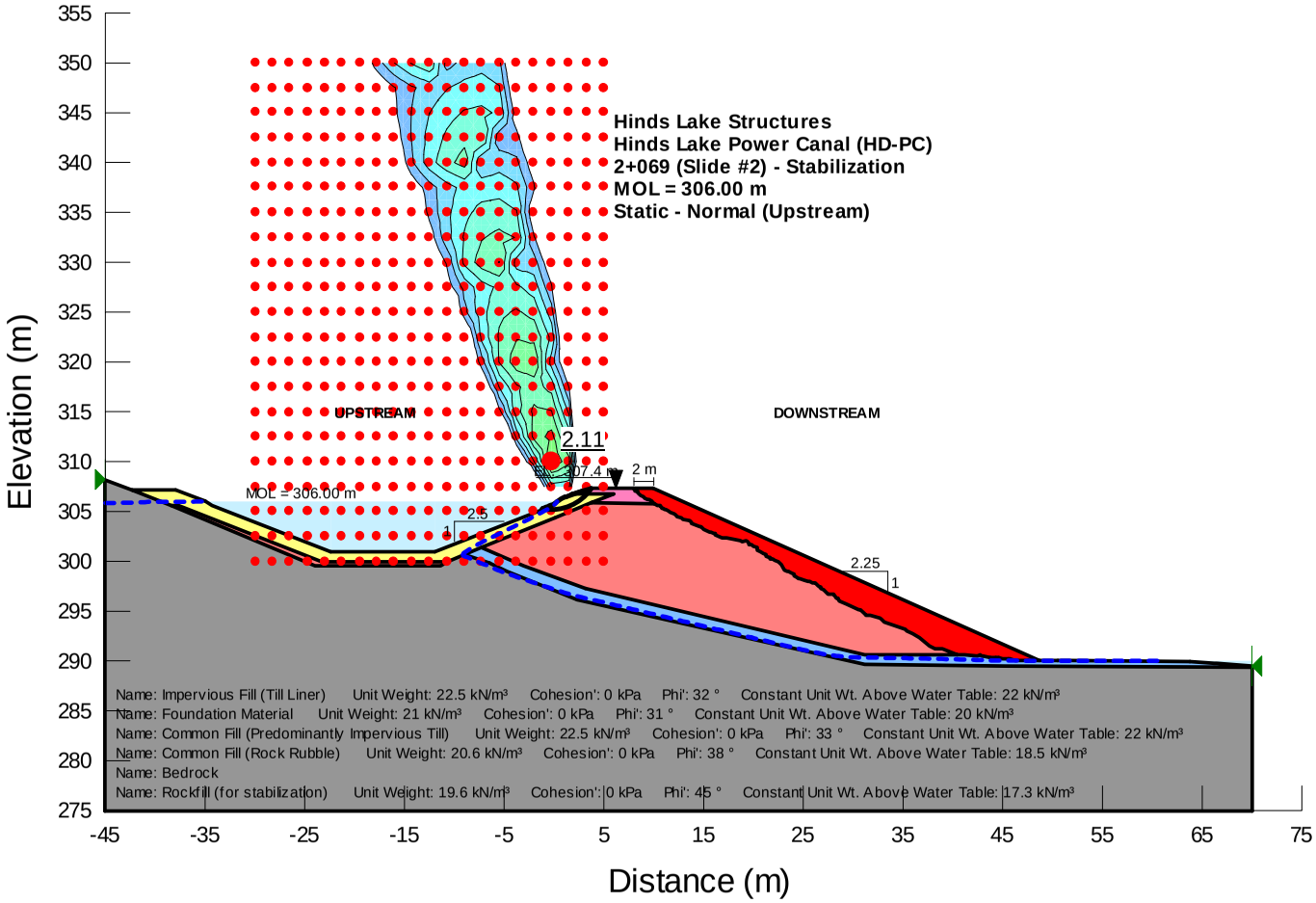


Figure D-10: Hinds Lake Power Canal (HD-PC) upstream slope stability analysis for slide #2 (2+069) in static conditions at Maximum Operating Level (MOL).

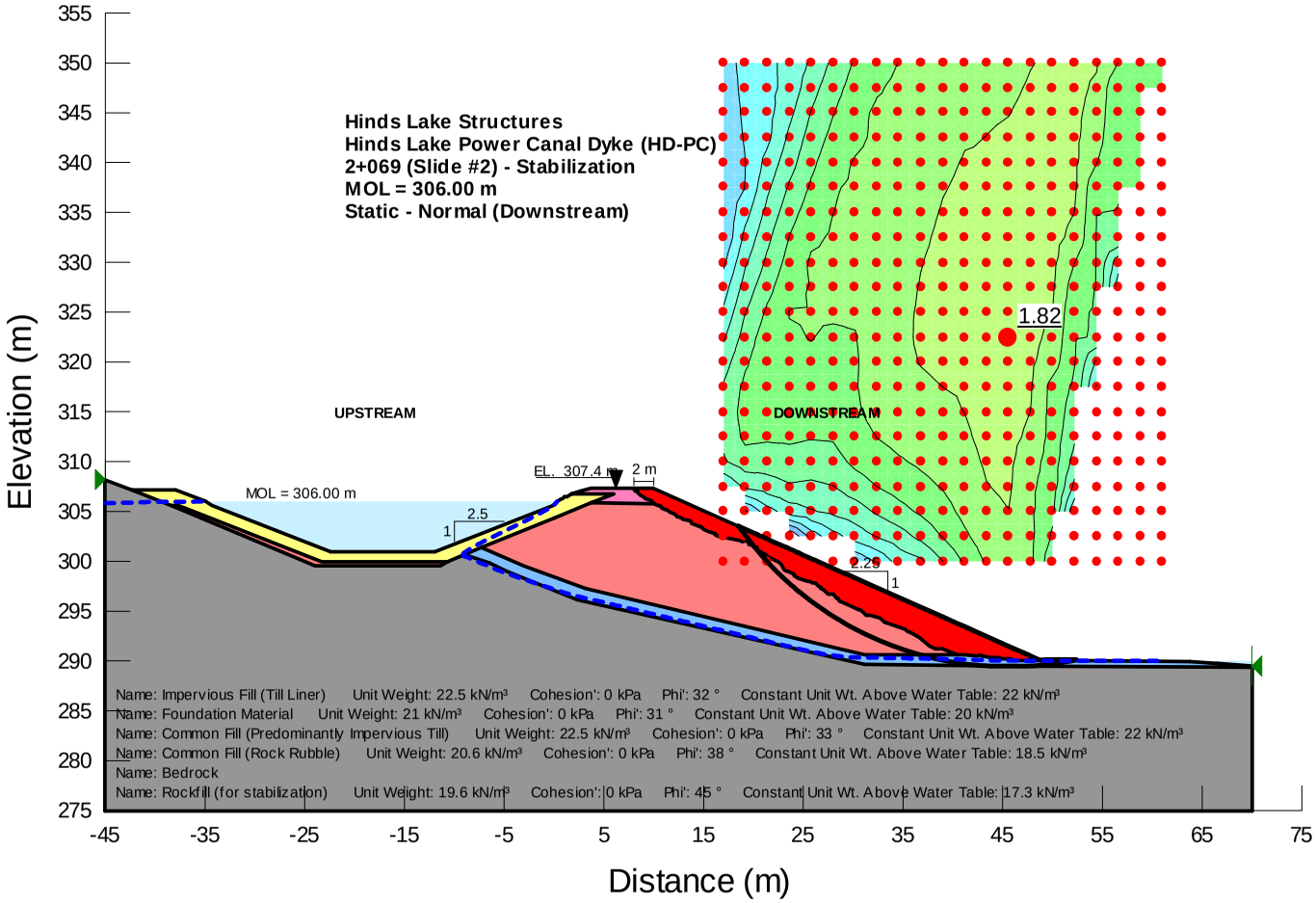


Figure D-11: Hinds Lake Power Canal (HD-PC) downstream slope stability analysis for slide #2 (2+069) in static conditions at Maximum Operating Level (MOL).

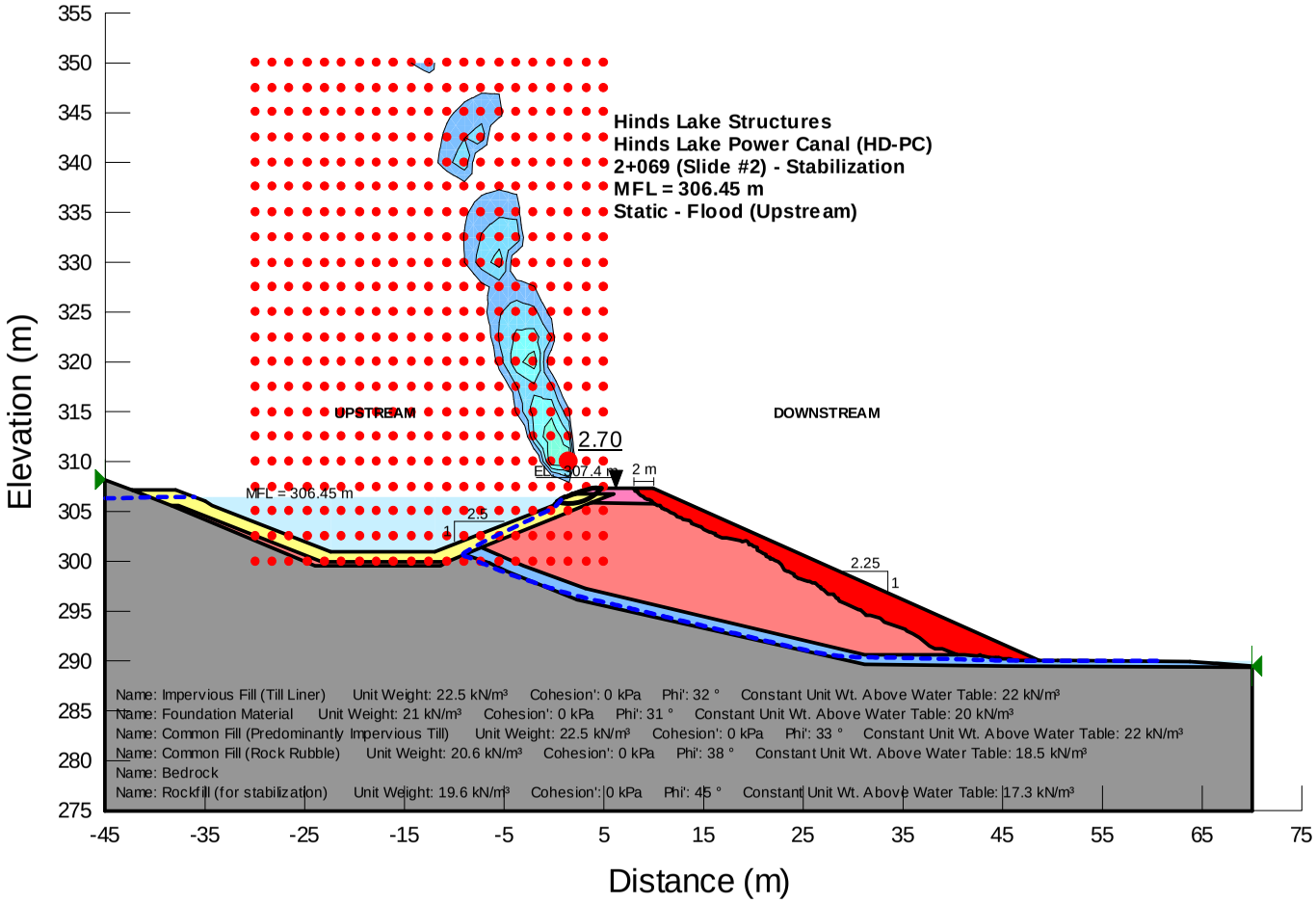


Figure D-12: Hinds Lake Power Canal (HD-PC) upstream slope stability analysis for slide #2 (2+069) in static conditions at Maximum Flood Level (MFL).

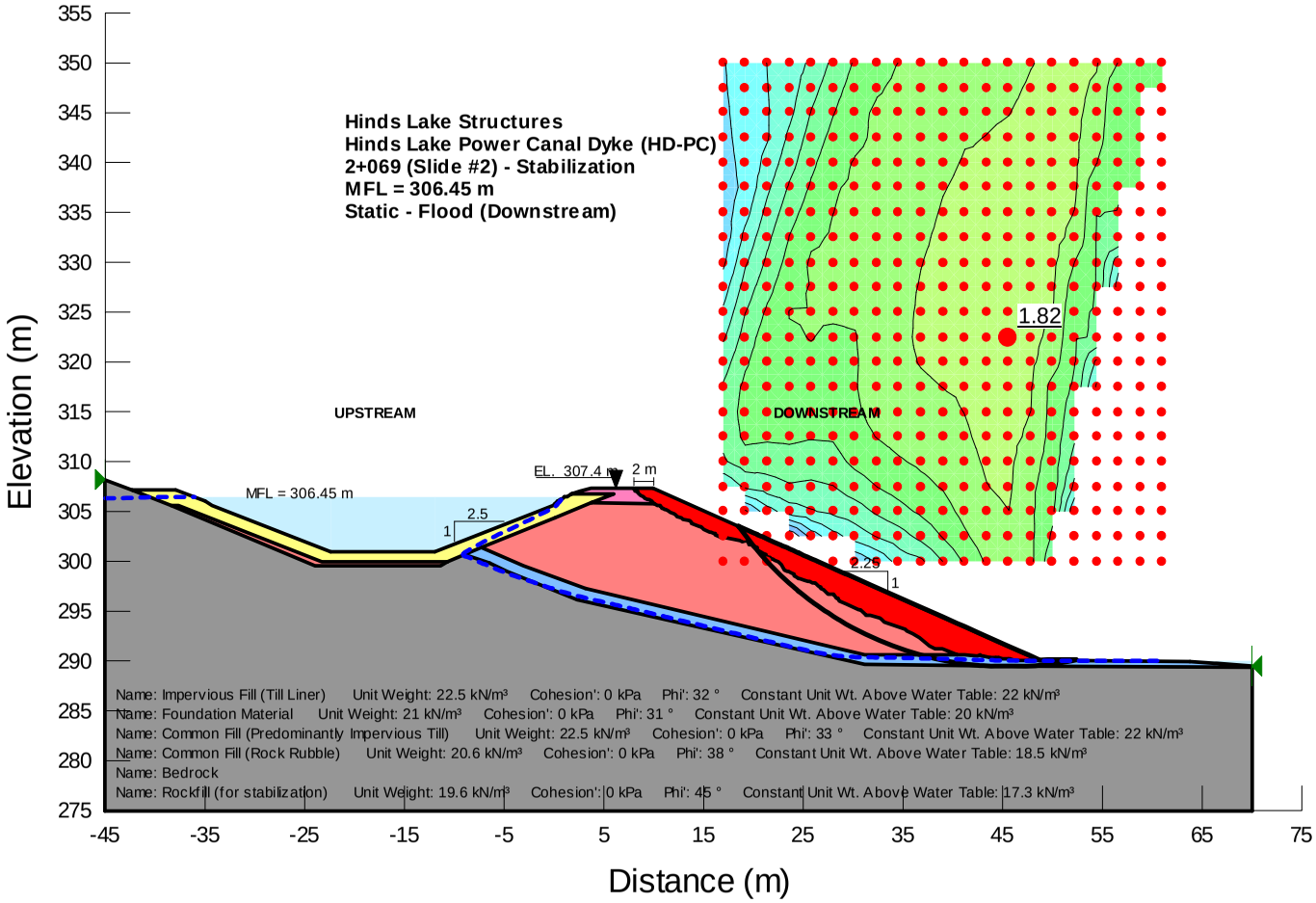


Figure D-13: Hinds Lake Power Canal (HD-PC) downstream slope stability analysis for slide #2 (2+069) in static conditions at Maximum Flood Level (MFL).

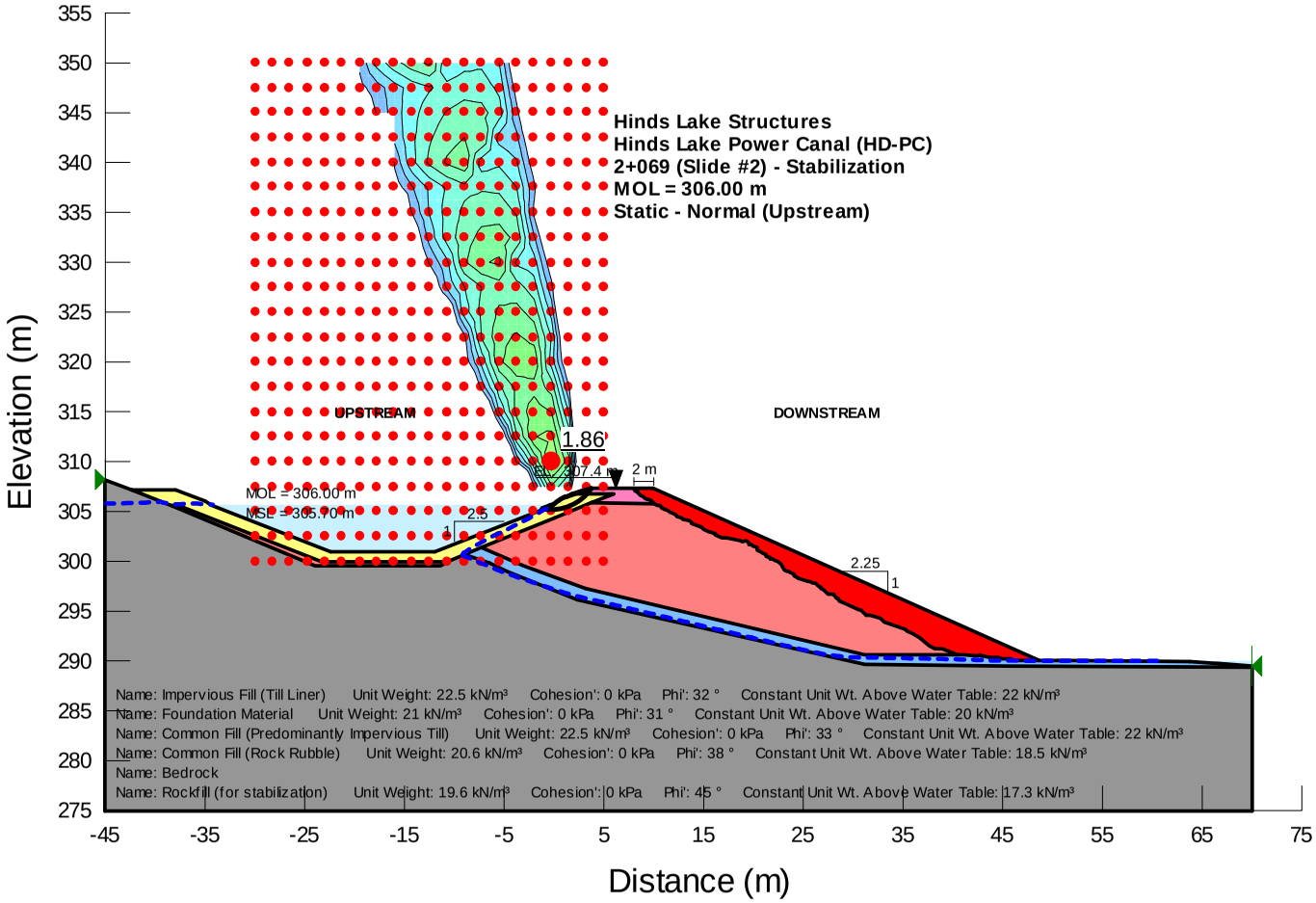


Figure D-14: Hinds Lake Power Canal (HD-PC) upstream slope stability analysis for slide #2 (2+069) in static conditions at rapid drawdown from Maximum Operating Level (MFL) to Lower Supply Level (LSL).

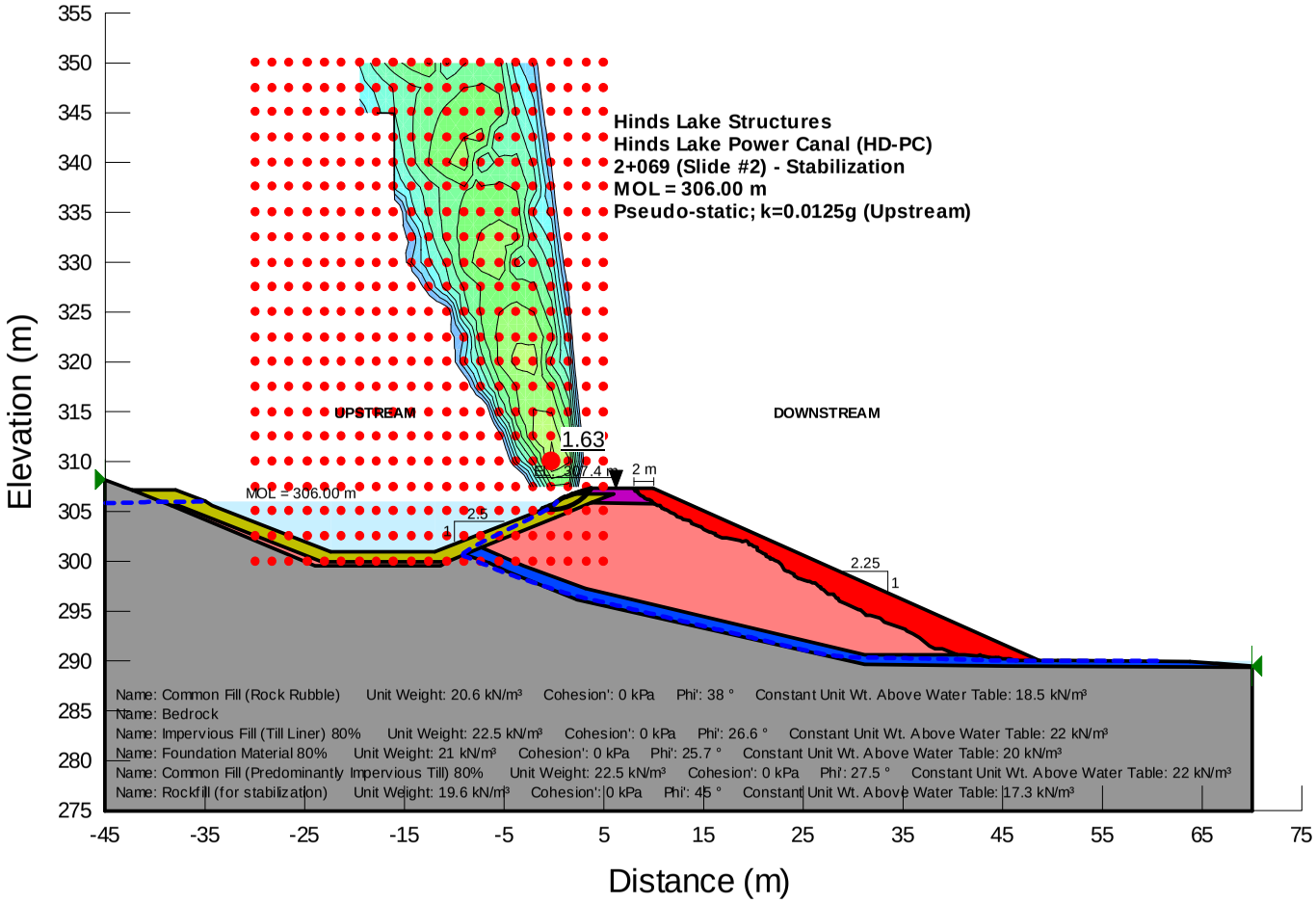


Figure D-15: Hinds Lake Power Canal (HD-PC) upstream slope stability analysis for slide #2 (2+069) in pseudo-static conditions at Maximum Operating Level (MOL) and with a horizontal seismic coefficient (k_h) of 0.0125g.

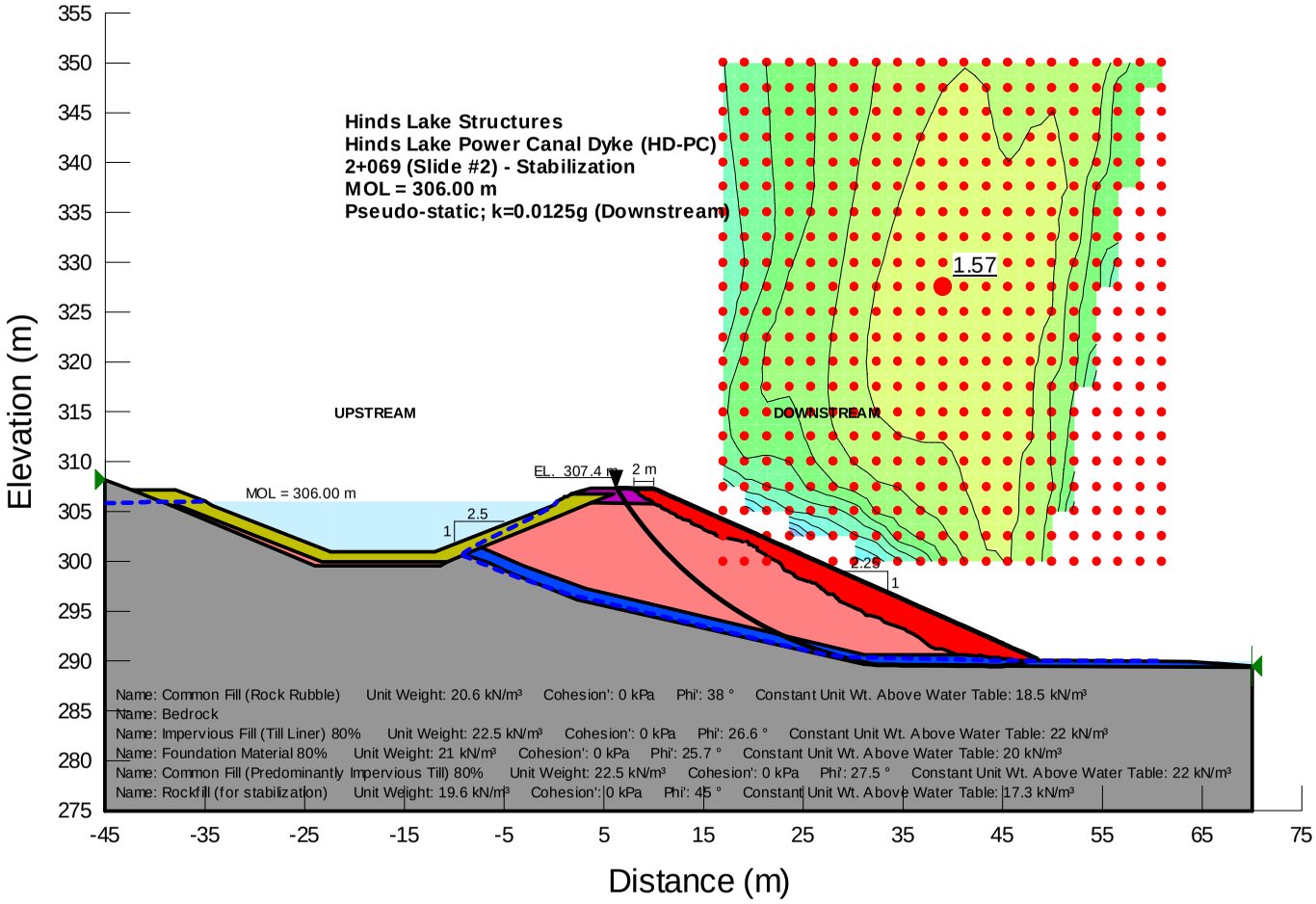


Figure D-16: Hinds Lake Power Canal (HD-PC) downstream slope stability analysis for slide #2 (2+069) in pseudo-static conditions at Maximum Operating Level (MOL) and with a horizontal seismic coefficient (k_h) of 0.0125g.

Attachment 2

HD-PC and HD-9 Slope Stability Analysis

SNC-Lavalin Group Inc.

August 18, 2021



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		00	2021-08-18	i

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Project : **Hinds Lake Development**

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1.0 INTRODUCTION

1.1 Context

As part of their dam safety program and in concordance with guidelines by the Canadian Dam Association (CDA), Newfoundland and Labrador Hydro (NLH) mandated SNC-Lavalin inc. (SLI) to perform various slope stability analyses at structures of the Hinds Lake hydroelectric development. The structures are Hinds Lake Power Canal Dyke (HD-PC), at stations 4+385 and 4+530, and Eclipse Dam (HD-9). The scope of work and objectives of the current mandate, per NLH's request for proposal (RFP) dated November 10, 2020, are detailed in section 1.2.

1.2 Scope of Work and Objectives

The objective of the current mandate is to review and complete slope stability analyses in alignment with the CDA Guidelines (CDA, 2007, revised in 2013). Also, the current report evaluates the slope stability at two (2) sections along HD-PC where signs of instabilities have been observed and proposes stabilization options. The scope of work and objectives are summarized below.

1) Hinds Lake Power Canal Dyke (HD-PC), stations 4+385 and 4+530:
    - Review and comment on past slope stability analyses at station 4+385 performed by SLI (2019a);
    - Perform slope stability analyses at station 4+530;
    - Complete sensitivity analyses for three (3) slope stabilization options, as defined by NLH in the RFP documentation, at stations 4+385 and 4+530;
    - Comment and provide recommendations on any observed deficiencies.
2) Eclipse Dam (HD-9):
    - Perform slope stability analyses at the critical section of the dam using recent topographic survey data;
    - Comment and provide recommendations on any observed deficiencies.

Prepare a technical report including the slope stability analysis results, assessment of slope stabilization options for HD-PC, comments and recommendations.

1.3 Report Content

This report presents, in the following order: the project background and information used (section 2.0); the slope stability analyses at HD-9 and HD-PC (stations 4+385 and 4+530) for the existing conditions (section 3.0) and the analysis for slope stabilization options at HD-PC (section 4.0). Then, conclusions and recommendations are formulated.

The report also includes two appendices:

APPENDIX A – Slope Stability Analysis for Existing Conditions

- HD-9;
- HD-PC (stations 4+385 and 4+530).

APPENDIX B – Slope Stability Analysis for the Selected Stabilization Option

- HD-PC (stations 4+385 and 4+530).

2.0 BACKGROUND

2.1 Documents Provided

The background data used in this mandate was extracted from previous project reports (SLI, 2019a; 2019b). The reports and documentation used are listed in table 2-1 while the as-built drawings of 1980 used are listed in table 2-2. Note that no monitoring data at the Hinds Lake structures was provided or reviewed as part of the current mandate.

A recent topographic survey was also provided for Eclipse Dam (HD-9). The exact date of the survey is unknown. The topographic data from the June 2018 survey of Hinds Lake Power Canal Dyke (HD-PC) provided as part of past studies SLI (2019a; 2019b) was used for the current mandate.

Table 2-1 : List of Consulted Documents

Title	Date	Prepared by
Slope Stability Analysis of 2 Slides at Hinds Lake Power Canal Dyke (HD-PC) with Proposed Repair Solution	2019	SNC-Lavalin
Hinds Lake Structures Audit Dam Safety Review	2019	SNC-Lavalin
Dam Register for Hinds Lake Structures	2014	NLH
Hinds Lake Dam Safety Review – Final Report	2011	Hatch
Hinds Lake Development – Power Canal Construction Report (partial report)	1985	Shawmont Newfoundland Limited
A Photographic Record of the Breech in Hinds Lake Power Canal	1982	Bruneau Resources Management Limited
Hinds Lake Development – Canal Dyke Repair Program – Vol. 3 – Geotechnical Data (partial report).	1982	Shawmont-Lavalin Joint Venture
Hinds Lake Development – Canal Dyke Repair Program – Vol. 2 – Design of the Power Canal.	1982	Shawmont-Lavalin Joint Venture

Table 2-2 : List of Consulted Drawings

No.	Description	Date	Prepared by
1453-000-C-100	General Site Plan & Drainage Area	1980	Shawmont-Lavalin Joint Venture
1453-104-C-114	Power Canal Impervious Liner – Section Types	1980	Shawmont-Lavalin Joint Venture
1453-104-C-115	Power Canal Impervious Liner Details	1980	Shawmont-Lavalin Joint Venture
1453-104-C-117	Power Canal Plan View – Layout Details	1980	Shawmont-Lavalin Joint Venture
1453-104-C-118	Power Canal Longitudinal Profiles – Overburden & Bedrock in Cuts	1980	Shawmont-Lavalin Joint Venture
1453-123-C-100	General Site Plan Eclipse Dam	1980	Shawmont-Lavalin Joint Venture
1453-123-C-101	Eclipse Dam Plan, Profile & Cross-Sections	1980	Shawmont-Lavalin Joint Venture

2.2 Structures Description

The Hinds Lake hydroelectric development is located in the Long Range Mountains, between Grand Lake and the town of Buchans, on the island of Newfoundland and was commissioned in 1980. Hinds Lake Generating Station has a single 75 MW unit, a net head of 214 m, a rated flow of 40 m³/s and an average annual energy production of 340 GWh. A total of 12 dams and dykes are located along the reservoir and the power canal. The main flood control device is the Hinds Lake Spillway (HD-1S). There are 2 overflow spillways and 3 culverts for uncontrolled flow release from the reservoir. Figure 2-1 presents the location of some of the water retaining structures at the Hinds Lake hydroelectric development.

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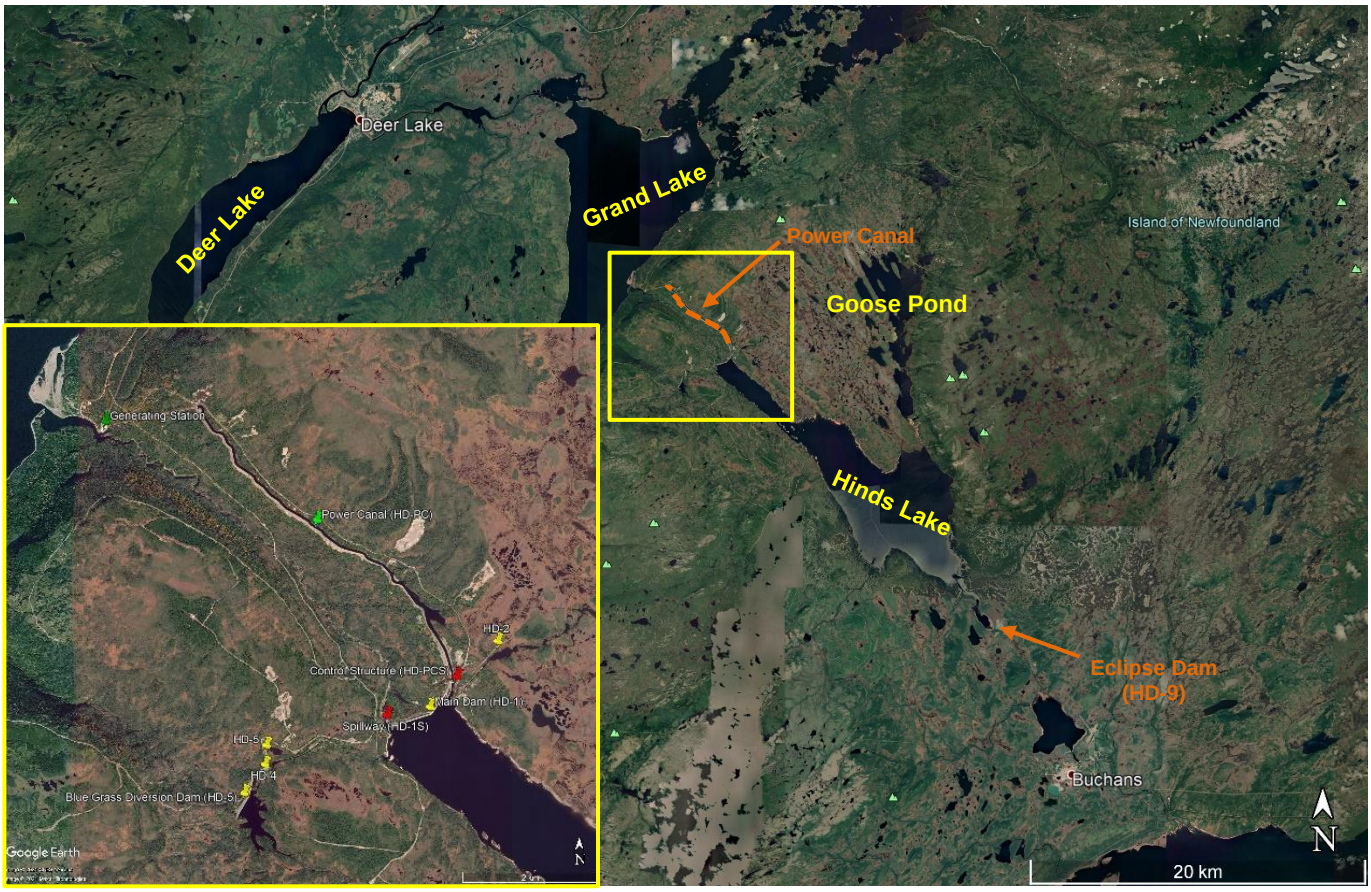


Figure 2-1: General View of Structures at Hinds Lake Hydroelectric Development (adapted from Google Earth, 2021)

Eclipse Dam is located at the south east limit of Hinds Lake hydroelectric development. It is a homogeneous till embankment dam comprising a drainage blanket at its downstream toe. The downstream slope is covered by protective gravel. Constructed in 1980, it is founded on overburden material except for a cut-off trench that was excavated to bedrock. A granular berm was added at the toe of the dam in 1983 where seepage was observed. It has a maximum height of approximately 16 m and is about 660 m long. The dam classification of this structure is "*High*", according to the latest CDA dam classification (Hatch, 2011).

The Power Canal Dyke is a side hill construction with the earth and rock excavation material placed downhill, in dyke embankment (cut and fill) configuration. The invert, uphill and downhill slopes of the canal are lined with impervious glacial till to form a water barrier. The canal is about 6 km long and carries water from the Hinds Lake Reservoir to the Intake of the Generating Station. The structure was built between 1978 and 1980. The maximum height of the dyke is about 15 m and about 900,000 m^3 of fill was required for its construction. The foundation beneath the Power Canal Dyke consists mainly either of bedrock or of glacial till overburden that varies from a few inches up to 6 m in thickness, along the canal. The dam classification of this structure is "*Significant*", according to the latest CDA dam classification (Hatch, 2011).

2.3 Previous Studies

The reports listed in table 2-1 include the most recent studies regarding HD-PC and Eclipse Dam (HD-9). The 2011 Dam Safety Review (DSR) consists of the most recent revision of the dam classification of the structures. Also, freeboard assessment and hydraulic capacity of the reservoir and spillway structures were last conducted by Hatch (2011) and it was noted that all CDA requirements were satisfied at that time. However, it is worth mentioning that flood studies were not updated since the design studies prior to construction of the hydroelectric development in the late 70's.

An Audit Dam Safety Review (ADSR) was conducted by SLI in 2019 (SLI, 2019a). Two (2) shallow slides occurred along the downstream slope of the Power Canal Dyke, at stations 1+989 and 2+069, respectively, shortly before the ADSR site inspection. The slides were shallow (i.e., skin slide) with a size of about 4 m wide x 8 m long x 0.3 m deep. An additional technical note proposing a repair option was then issued (SLI, 2019b). The stabilization solution that was proposed consisted in reshaping the downstream slope to 2.25H:1V with the addition of a new rockfill cover.

The current scope of work originates from the main findings of the ADSR conducted in 2019 (SLI, 2019a), notably:

- Inconsistencies were observed for the geometry of HD-PC and HD-9 between data presented in Hatch (2011), NLH's dam register (NLH, 2014) and the as-built drawings of 1980;
- Slope stability calculations at station 4+385 of HD-PC, where the downstream slope is steeper than the as-built drawings (grade of 1.8H:1V), indicates that factor of safety for long term stability values are lower than the acceptance criteria. Similar conditions are present at station 4+530, where the lower part of the slope is steep;
- Inconsistencies, mainly in terms of geometry, were observed in the slope stability calculations for HD-9 in Hatch (2011).

It is also important to keep the historical performance of the structure in mind. For HD-9, following construction, a downstream toe berm was added or repaired in 1983, 1989, 1990 and 1991. For HD-PC, a breach failure occurred in January 1982. This breach was approximately centered at station 4+665, only a few yards south-east of the sector studied as part of the current mandate, and important rehabilitation/reconstruction works were performed in this area as a result. Ever since, this portion of the HD-PC is carefully inspected during regular site visits and specifically commented in previous DSRs. Additional background data for the HD-PC is presented and discussed further in section 4.

3.0 SLOPE STABILITY ANALYSIS FOR EXISTING CONDITION

3.1 Numerical Method

Two-dimensional slope stability analyses were performed for this study using the limit equilibrium method of slices. In the limit equilibrium approach, the mass above the failure surface is divided into several slices and the equations of statics (summation of moments, vertical forces, horizontal forces and interslice forces) are resolved by considering the mechanical equilibrium for all slices. Then, the available shear resistance along the entire sliding plane is compared to the mobilized shear strength to compute the factor of safety.

The limit equilibrium stability analyses were performed using the software SLOPE/W from the GeoStudio Suite 2016, developed by GEO-SLOPE International Ltd, Calgary, Canada.

The Morgenstern-Price calculation method was selected, along with the grid and radius method for the slip surface definition. A minimum slip surface depth of 1 m was fixed to allow for the identification of relatively shallow critical slip surfaces as well as deeper ones. While this slip surface depth appears small and is often dismissed in the assessment of dyke stability, in this case it is considered representative of a potential slip that would have dam safety implications, in part due to the narrow width of the structure, to the historical performance (uncontrolled seepage, breach) and to the significant impact of the phreatic surface assumption for which piezometer data is not available.

3.2 Selected Cross Sections

3.2.1 HD-PC

The evaluated cross sections at Hinds Lake Power Canal Dyke (HD-PC) are located at stations 4+385 and 4+530. As mentioned earlier, the selection of these sections originates from the findings of the 2019 ADSR conducted by SLI (2019a).

The slope stability of cross section at station 4+385 was evaluated in 2019 because a breach occurred close to this location, in 1982, and the June 2018 survey indicated that the downstream slope is relatively steep at a grade of 1.8H:1V. As a result, the factor of safety (FS) at this section (at MOL for static loading) was found to be lower than the required minimum at 1.39. The model geometry at station 4+385 is illustrated on figure 3-1.

The cross section at station 4+530 was not evaluated in 2019, but the topographic data indicated that the lower half of the downstream slope of the Power Canal Dyke, at this station, had a grade of approximately 1.3H:1V. Further evaluation of the stability at this location was therefore deemed warranted given the fact that the computed factor of safety at station 4+385 was found to be unsatisfactory for a less steep grade. The model geometry at station 4+530 is illustrated on figure 3-2.

The Power Canal Dyke was built by cut and fill. Based on documents consulted, the main common fill is heterogenous. This common fill consists either of a mixture of rock fragments inside a glacial till matrix or of rockfill material from the nearby bedrock excavation. It is unclear which of the above scenario applies to each sector under study. After review of the available reports listed in table 2-1, it has been assumed for stability analysis that the common fill was predominantly constituted of till, with larger particles pushed toward the downstream slope where the large particles are still predominantly in a till matrix. This assumption is considered for both stations 4+385 and 4+530, and is mainly based on observations of the dyke's cross section following the 1982 breach at station 4+665 (see Figure 4-2) and other historical photographs (such as Figure 4-3 and Figure 4-7). Note that this differs from considerations by Hatch (2001) and SLI (2019a; 2019b) where the main fill was taken as predominantly constituted of rockfill (i.e., rock rubble) and, also, to a certain degree from other historical reports such as in reference 9 and the

original design calculations referenced therein. Nevertheless, SLI considers that the assumption used in the current study is adequately supported by documentation and reflects the more conservative stability condition as opposed to a rockfill zone (higher phreatic surface, lower shear strength). As discussed further in this section, this assumption also impacts the selected strength parameters and location of the phreatic surface within the Power Canal Dyke.

Also, in NLH's Dam Register, it is mentioned that the toe berm is made of sand covered by rock rubble (i.e. inverted filter). The exact geometry of the toe berm remains unknown. For the sake of simplicity, the toe berm is modelled as a single region with averaged strength parameters.

The geometry of the numerical models used in the current study at HD-PC are shown below.

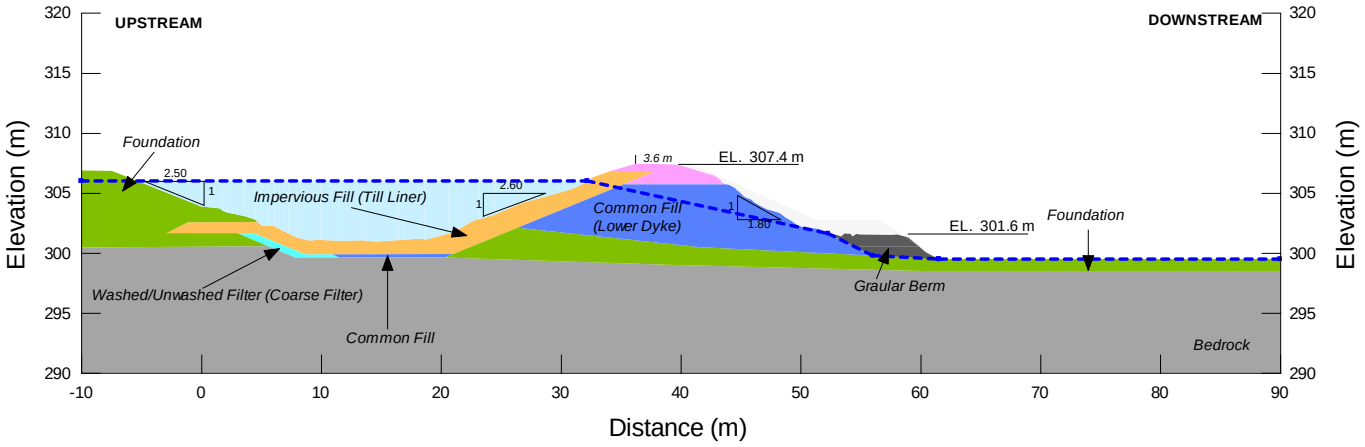


Figure 3-1 : HD-PC - Model Geometry for the Existing Conditions at Station 4+385

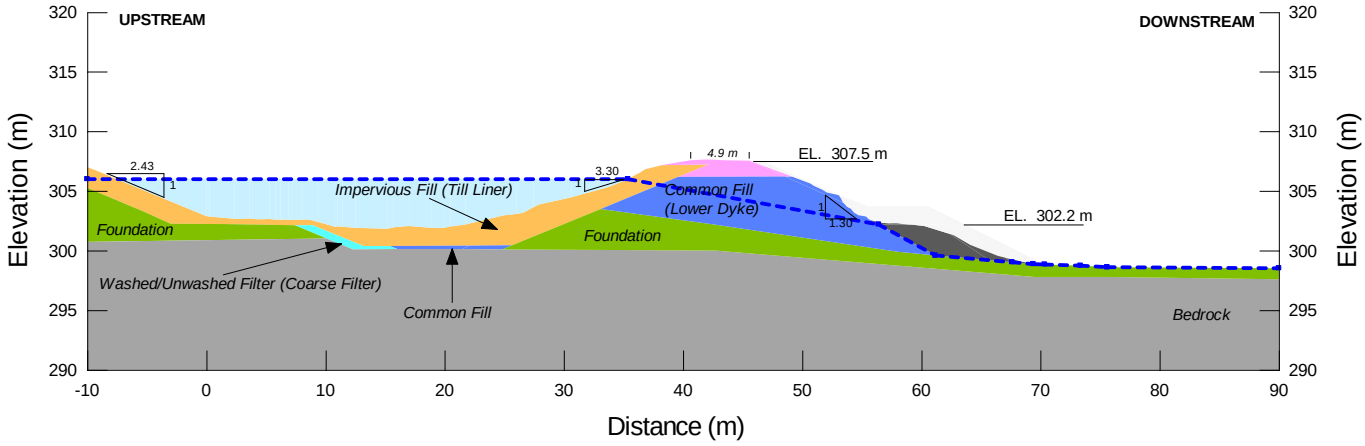


Figure 3-2 : HD-PC - Model Geometry for the Existing Conditions at Station 4+530

3.2.2 HD-9

The evaluated cross section at Eclipse Dam (HD-9) is located at station 0+475. In the 2011 DSR, the evaluated cross section was located at station 0+500, which is the critical cross section in terms of height based on the longitudinal foundation profile presented on the 1980 as-built drawing 1453-123-C-101. However, the recent topographic survey, as provided by NLH during the course of the mandate, indicates that the total height of the dam (i.e., elevation difference between the crest and the downstream toe) is slightly greater at station 0+475. Moreover, the grade of the downstream slope also appears slightly steeper at station 0+475 (2.38H:1V) than at station 0+500 (2.48H:1V). Note that a difference in the grade of the upstream slope above the water line was also observed. Indeed, a grade of approximately 2.24H:1V was measured at station 0+500 in comparison to a grade of 2.40H:1V at station 0+475. As a result of these slight differences and given the proximity between both cross sections, a representative hybrid cross section was modelled using:

- The elevation of the foundation at the centerline of the dam at station 0+500;
- The elevation of the granular berm at the toe of the dam at station 0+475;
- The downstream slope at a grade of 2.38H:1V, as observed at station 0+475;
- The upper portion of the upstream slope at a grade of 2.24H:1V, as observed at station 0+500.

Note that the lower portion of the upstream slope (i.e., below the water line) was not surveyed. It was therefore assumed that the location of the upstream toe from the typical cross section of the 1980 as-built drawing is correct. Linearly linking the upstream toe of the dam with the surveyed portion of the upstream slope resulted in a grade of 2.38H:1V for the portion of the upstream slope below the water line.

Also, in NLH's Dam Register, it is mentioned that the toe berm is made of sand covered by rockfill. The exact geometry of the toe berm remains unknown. For the sake of simplicity, as for HD-PC, the toe berm is modelled as a single region with averaged strength parameters.

The model geometry of HD-9, for the existing conditions, is illustrated on figure 3-3.

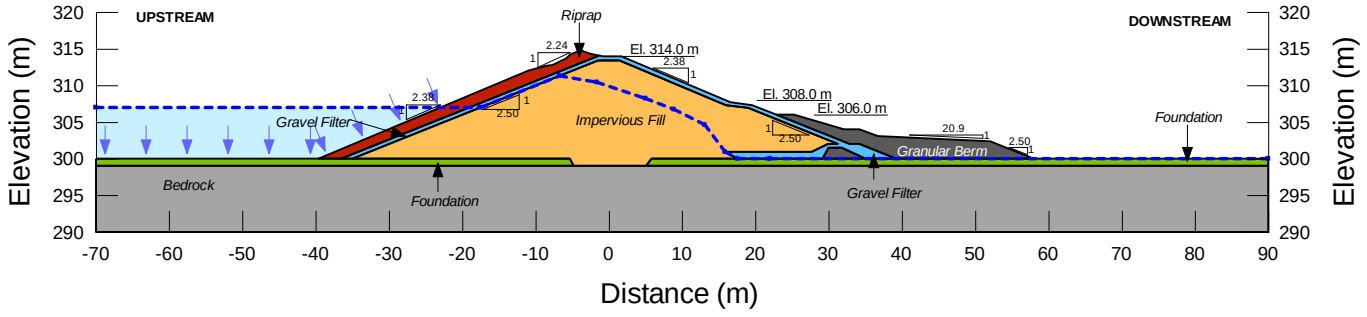


Figure 3-3: HD-9 - Model Geometry for the Existing Conditions at Station 0+475

3.3 Material Properties

Given the lack of geotechnical data to be reviewed in this mandate, the material properties considered in the 1982 breach repair design report, 2011 DSR and 2019 ADSR were considered, but some were adjusted. For instance, the 1982 design report (SLJV, 1982b) considered the internal friction angle (Φ') of the till liner, the till fill and the till foundation as being 36º, while Hatch (2011) used 32º, 35º (38º mentioned in the text but 35º in the figures of appendix I) and 31º, and SLI (2019a) used 32º, 38º and 31º. The material properties used in prior studies and for the current slope stability analysis are summarized in table 3-1. Materials in *italics* are specific to HD-PC and are typically more conservative than those used during the design phase (SLJV, 1982b).

As mentioned in section 3.2.1, the parameters of common fill used in previous studies vary depending on the assumed nature of the material. For the current study, it is assumed that common fill is predominantly till, and the friction angle is thus set at the lower value mentioned in the 1982 design report (i.e., Φ' = 36º).

An internal friction angle of 32º for the till liner could reflect, to some degree, the degradation of this material following impounding since the liner is exposed to freeze-thaw in its upper section and ice damage. It is also appropriate considering certain elements of construction methods as reported in reference 10 (final compaction up-and-down the slope; multiple construction joints resulting from ramps; 30% of field density test results below the specified 95%). This value remains unchanged from Hatch (2011) and SLI (2019a; 2019b).

For the granular toe berm, without knowing the exact geometry and method of placement for the inverted filter materials, an average friction angle of 36º was assumed (i.e., average value between a compact clean sand, 33º and a poor quality rockfill, 40º). Upon review, the friction angle of the foundation material was kept unchanged, from 2011 and 2019, at 31º. While the foundation is assumed to be mainly constituted of glacial till, design report SLJV, (1982b) mentions that the canal also crossed alluvium deposits at some locations. As mentioned further in section 4.1, this might be the case for the sections under study. This is also a conservative assumption for the strength properties of the foundation material.

Finally, no attempt has been made to back calculated a friction angle for the common fill in order to achieve a factor of safety of about 1 or 1.1 for the existing conditions. This is because it is considered that existing steep downstream slopes at stations 4+385 and 4+530 are considered to be mainly due to fill oversteepening during construction, to surface run-off, freeze and thaw actions or other local conditions, as will be explained in more details in section 4.1.

Table 3-1 : Material Properties for Current Slope Stability Analyses (HD-PC at stations 4+385 and 4+530 and HD-9)

Material	γ_{sat}[1] (kN/m³)	γ[2] (kN/m³)	Model	c'[3] (kPa)	Φ'[4] (°)			
					SLJV (1982b)	Hatch (2011)	SLI (2019a)	SLI (2021)
HD-9 Impervious Fill *HD-PC Till Liner*	22.5	22.0	Mohr-Coulomb	0	36	32	32	32
Riprap	19.6	17.3	Mohr-Coulomb	0	-	45	45	45
Washed/Unwashed Filter (Coarse Filter)	21.0	20.0	Mohr-Coulomb	0	36	33	33	33
Gravel Filter	20.5	19.0	Mohr-Coulomb	0	-	35	35	35
Common Fill (Upper Dyke)	22.5	22.0	Mohr-Coulomb	0	36	33	33	33
Common Fill (Lower Dyke)	20.8	18.5	Mohr-Coulomb	0	36	35[5]	38	36
Granular Toe Berm *Granular Berm*	20.6	18.5	Mohr-Coulomb	0	36	40	40	36
Foundation Material	21.0	20.0	Mohr-Coulomb	0	36	31	31	31
Bedrock	Impenetrable							

Notes
[1] γ_{sat}: Saturated unit weight;
[2] γ: Total unit weight (i.e., above phreatic surface).
[3] c': Effective cohesion (i.e., drained condition).
[4] Φ': Effective internal friction angle (i.e., drained condition).
[5] Hatch (2011) lists Φ' as 38° in table 6-10. However, Φ' used for slope stability analysis is 35°, as presented in their appendix I.

3.4 Hydraulic Conditions

3.4.1 HD-PC

In SLI (2019a; 2019b) the phreatic conditions within the Power Canal Dyke were established from finite element seepage analysis using SEEP/W, another module of the GeoStudio Suite 2016, developed by GEO-SLOPE International Ltd, Calgary, Canada. As mentioned in section 3.2.1, the current study assumes that the common fill material is predominantly constituted of till with larger particles found toward the downstream slope at both stations 4+385 and 4+530 as opposed to predominantly rockfill in previous studies. Therefore, adjustments to the piezometric lines form Hatch (2011) and developed in SLI (2019a; 2019b) are required.

The engineering report for the repair works at station 4+665 (SLJV, 1982b) includes flow nets to confirm the suitability of the proposed stabilization methods. It was decided to implement a similar piezometric line in the current numerical models. For instance, it is assumed that no seepage exits above the top of the existing toe berm. So, the piezometric line was manually established as a linear head loss between the upstream face and the downstream slope intersection with the top of the existing granular toe berm. Under the toe berm, the piezometric line is located at the top of the ground surface.

Note that the modelled phreatic conditions do not reflect an ideal performance of the impervious liner, where most head loss would occur in the liner[1]. This evaluation is out of the current scope of work. No functional piezometer is installed at HD-PC; therefore, those assumptions cannot be correlated with actual monitoring data. Finally, note that reference documents suggest significant heterogeneity in the common fill (see Figure 4-2 and Figure 4-3) that would have a major impact (variability) on the position of the phreatic surface.

Table 3-2 summarizes the operating water levels at HD-PC.

3.4.2 HD-9

No piezometric data is available at Eclipse Dam. Therefore, the phreatic surface within the impervious till fill was established manually on the basis that the performance of the drainage blanket was adequate. Note that for homogeneous dams such as HD-9, piezometric data is extremely valuable as the position of the phreatic surface directly impacts the factor of safety of the downstream slope. For the current study, the phreatic surface was established close to the downstream slope of the dam, but no monitoring data is available to confirm or invalidate this assumption. It is worth mentioning that NLH confirmed that there is no sign of seepage on the downstream slope of the embankment.

Table 3-2 summarizes the operational water levels at HD-9.

Table 3-2 : Operating Water Levels (from Hatch, 2011; SLI, 2019a)

Structure	MOL(1) (m)	MFL(2) (m)	LSL(3) (m)
HD-PC	306.00	306.45	305.70
HD-9	311.30	311.80	306.00

Notes
[1]MOL: Maximum Operating Level.
[2]MFL: Maximum Flood Level.
[3]LSL: Low Supply Level.

3.5 Loading Cases and Required Factor of Safety

The minimum factors of safety (FS_{min}) for slope stability analysis according to CDA Guidelines are summarized in table 3-3. Note that for HD-9, the stability of the upstream slope was also evaluated for the reservoir at mid-slope level (i.e., median elevation between the crest and the upstream toe). The static loading condition was evaluated for steady-state seepage and rapid drawdown.

[1]Note that if one assumes that the common fill is predominantly till, then the permeability contrast between the liner and the common fill would be much less than if common fill was predominantly rockfill. The head loss would thus be distributed between the liner and the common fill, and the linear assumption would not be unreasonable.

Table 3-3 : Minimum Required Factors of Safety (CDA, 2007, revised 2013)

Loading condition	Description	FS_{min} (1)	Slope	Reference CDA
Static	Temporary loading. Floods.	1.3	Upstream Downstream	Table 6-2
Static	Long-term or normal operating conditions. Steady-state seepage. Normal operation reservoir levels.	1.5	Upstream Downstream	Table 6-2
Static	Full or partial rapid drawdown	1.2 to 1.3(2)	Upstream	Table 6-2
Pseudo-static(3)	Simulation of seismic loading. Normal operation conditions.	1.0	Upstream Downstream	Table 6-3

Notes
[1]Minimum factor of safety is the factor required to reduce operational shear strength parameters to bring a potential sliding mass into a state of limit equilibrium using accepted methods of analysis.
[2]Higher factors of safety may be required if drawdown occurs relatively frequently during normal operation.
[3]Contrary to recommendations by Hynes-Griffin and Franklin (1984), no shear strength reduction was considered for pseudo-static analysis.

3.6 Seismic Data

Given the dam classification of HD-9 being "*High*", which is the most critical among structures of the Hinds Lake hydroelectric development according to the latest classification review from the 2011 DSR (Hatch, 2011), the Earthquake Design Ground Motion (EDGM) should be equivalent to an annual exceedance probability (AEP) of 1:2,475 years (CDA, 2007, revised in 2013). The same EDGM was retained for assessment of the pseudo-static stability at HD-PC despite the dam classification being "*Significant*".

According to the procedure proposed by Hynes-Griffin and Franklin (1984), the horizontal seismic coefficient (k_h) to be used in pseudo-static analysis corresponds to half of the peak ground acceleration (PGA) on bedrock or peak rock acceleration (PRA) obtained from the 2015 National Building Code Seismic Hazard Calculation database NRC (2016). However, because HD-PC and HD-9 are founded on glacial till, it was assumed the foundation corresponded to a site Class B. As a result, the horizontal seismic coefficient (k_h) to be used in pseudo-static analysis is 0.02 g (i.e., $PGA_{Class\ B}$ = 0.04 g) for a 1:2,475 years EDGM.

Note that for pseudo-static analysis, no shear strength reduction due to development of excess pore water pressure was assumed for any of the materials at both HD-PC and HD-9. A liquefaction potential analysis is beyond the scope of this mandate.

3.7 Results and Discussion

The results of slope stability analyses at HD-PC and HD-9, for the existing conditions, are summarized in table 3-4. All slope stability figures are presented in appendix A.

3.7.1 HD-9

For HD-9, note that the computed factor of safety of the upstream slope for the normal operating condition (i.e., MOL) that was found to be below the required minimum (1.47) in the 2011 DSR is now computed as 1.61 for the current study (see figure A-1). As mentioned in section 3.3, the material properties used in the current analyses are unchanged from those used by Hatch (2011). Moreover, Hatch (2011) fixed the minimum slip surface depth at 7 m, which typically has the effect of increasing the computed factor of safety due to the neglect of potentially shallower critical slip surfaces. These elements raise questions as to why the computed FS from the current study satisfies the

CDA Guidelines, while Hatch's did not for similar parameters and a theoretically more stable slip surface (deeper). Upon further verifications, it was observed that the upstream slope of the stability model presented on figure 10 of appendix I of Hatch (2011) is actually steeper than the 2.5:H:1V grade indicated on the model. A cursory measurement of the inclination of the upstream slope on this figure indicates an upstream slope of 2.11H:1V, which is steeper than the 2.38H:1V (lower portion) and 2.24H:1V (upper portion) grades modelled for the present mandate (see figure 3-3) and significantly steeper than the 2.5H:1V slope indicated on the 1980 as-built drawing 1453-123-C-101. For a slope inclination of 2.11H:1V the current study calculates a FS of about 1.42 for the normal operating condition (which is similar to Hatch's 2011 result). This might also explain the difference for the rapid drawdown scenario (1.33 vs 1.20). Finally, note that the static loading condition with the reservoir level at mid-slope level was not analyzed by Hatch (2011). As can be seen in the previous table, this loading scenario is the critical one in terms of FS for static loading (FS = 1.51), but still satisfies CDA requirements.

Therefore, if the assumptions considered in this report are deemed representative, the slope stability analyses conducted as part of the current mandate for HD-9 indicate that this structure satisfies CDA slope stability guidelines for all evaluated loading conditions. To confirm the assumptions used in this report, a bathymetric survey of the upstream slope as well as piezometric surface measurements below the downstream slope would be useful (piezometer installations). The need for piezometers should be assessed as part of the next Dam Safety Review, with the benefit of a site inspection and full review of design and performance information.

One should note the slope stability of the upstream slope only marginally exceeds the CDA requirement for the long-term scenario as well as the rapid-drawdown scenario. As a reminder, the section in SLOPE/W was modeled conservatively using worst case slope in a hybrid cross section.

3.7.2 HD-PC

For HD-PC at sta. 4+385, the downstream slope presents a factor of safety of 1.3 for the normal operating condition (i.e., MOL), which does not satisfy CDA requirements. The same is true of the downstream slope of station 4+530 at MOL and MFL water levels, where the computed factor of safety is 1.23. Then, if the assumptions considered in this report are representative, the other loading conditions meet or exceed the required factor of safety according to CDA Guidelines.

Also, the range of variation of the canal water level is quite narrow, i.e. between 305.7 m and 306.45 m, from the LSL to the MFL. NLH should review how often the LSL is reached to assess if this loading case should be considered as a steady state instead of temporary condition. The rationale for this is that the LSL condition yields a FS below 1.5 for the upstream slope stability.

The stabilization options described in section 4.0 aim at stabilizing the downstream slope at both evaluated stations of HD-PC, in accordance with CDA requirements.

Table 3-4 : Results of Slope Stability Analyses for the Existing Conditions

Structure (Station)	Loading Condition	FS_{min} required	FS(1)	
			Upstream slope	Downstream slope
HD-PC 4+385	Static Steady-state seepage (MOL = 306.00 m)	1.5	1.57	**1.30**
	Static Steady-state seepage (MFL = 306.45 m)	1.3	1.62	1.30
	Static Rapid drawdown (LSL = 305.70 m)	1.2 to 1.3	1.41	-
	Pseudo-static (k_h = 0.02 g) Steady-state seepage (MOL = 306.00 m)	1.0	1.46	1.25
HD-PC 4+530	Static Steady-state seepage (MOL = 306.00 m)	1.5	1.55	**1.23**
	Static Steady-state seepage (MFL = 306.45 m)	1.3	1.59	**1.23**
	Static Rapid drawdown (LSL = 305.70 m)	1.2 to 1.3	1.42	-
	Pseudo-static (k_h = 0.02 g) Steady-state seepage (MOL = 306.00 m)	1.0	1.47	1.18
HD-9 0+475	Static Steady-state seepage (MOL = 311.30 m)	1.5	1.61	1.57
	Static Steady-state seepage (MFL = 311.80 m)	1.3	1.62	1.57
	Static Steady-state seepage (Mid-slope = 307.00 m)	1.5	1.51	-
	Static Rapid drawdown (LSL = 306.00 m)	1.2 to 1.3	1.33	-
	Pseudo-static (k_h = 0.02 g) Steady-state seepage (MOL = 311.30 m)	1.0	1.47	1.49

Note
[1]**Red** FS represent scenarios that do not meet CDA requirements; underlined FS are scenarios that marginally meet the criteria.

4.0 STABILIZATION OPTIONS FOR HD-PC

4.1 Existing Conditions

4.1.1 General

The Power Canal Dyke was built by cut and fill. The embankment was placed mainly on a foundation of in-situ till or bedrock after stripping of the unsuitable organic material, topsoil and roots. From the 2019 ADSR, it appears that the downstream slope of the Power Canal Dyke is generally in good condition. The downstream slope is protected by a rockfill cover made of particles ranging from 50 to 300 mm in particle size. Globally, the slope presents a variable grade ranging from 3.7H:1V to steeper values of around 1.7H:1V. Steeper portions may be locally observed (e.g., at station 4+530). Note that no site inspection was performed as part of the current mandate and that reliance on observations made by others was required. However, with the exception of the two shallow slides at sta. 1+989 and 2+069, no sign of deterioration was noted during the site visit of summer 2018 made by SLI staff other than the downstream slope inclination appearing steeper than the as-built drawings.

The sector covered by the current mandate of stabilization option assessment is located nearby a sector along the Power Canal where a failure occurred following construction, in 1982 (i.e., between stations 4+650 and 4+700).

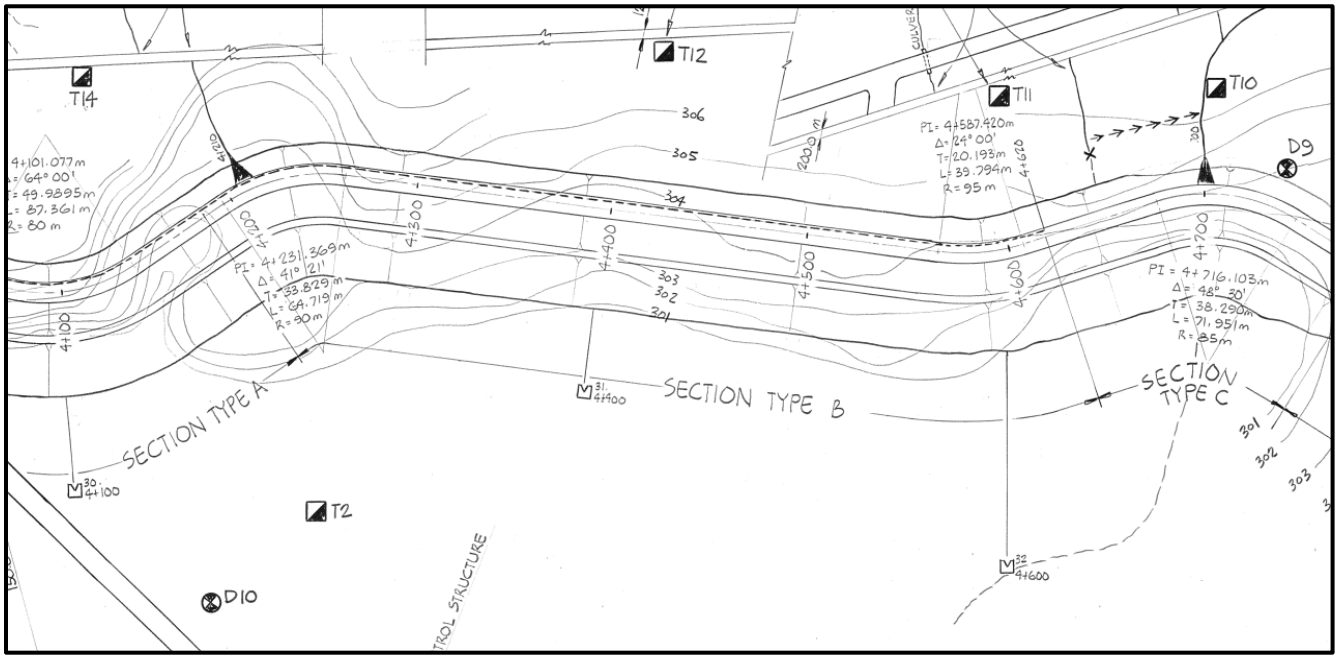


Figure 4-1 : Plan View of Sector Under Study from Drawing 1453-104-C-117

As can be seen on figure 4-1, any intervention on the downstream slope at station 4+385 will impact the slope geometry at station 4+530 and vice versa. Therefore, the stabilization solution has to be globally implemented between stations 4+200 to 4+600, approximately.

The current mandate does not include a technical review to determine the probable cause of the recurrent maintenance issues along the downstream slope of the Power Canal. So, in this mandate SLI did not review all the background data from the 2019 ASDR (SLI, 2019a). However, the documentation listed in table 2-1 was consulted

to obtain a global understanding of the past performance of the dyke, which is crucial to assess the adequacy of the proposed stabilization options. Excluding vegetation control operations mentioned in NLH's dam register (NLH, 2014), several interventions or observations were noted in the sector between stations 4+200 to 4+700, since construction. Other historical events of interest that might be applicable to the stations under study are also listed below. These include the following:

- Intervention/observation 1:
    - Following the first filling of the canal in 1980, seepage was noted at the downstream toe of the Power Canal Dyke at stations 2+522 and 2+607 (Figure 4-3). It was assumed that the source of the leakage was between elevations 305.5 m and 307.0 m (i.e. in the embankment, not through the foundation). The contractor dumped till material on the upstream face to stop the seepage and it was also opted to lower the water level in the canal. During first filling, the two drainpipes at 2+500 were flowing full. Seepage was also observed at station 3+300 (seepage exit at el. ±303 m; a vortex was observed in the canal) and then at 3+400 and 3+150. Even if these events did not occur at the stations under study, it is still relevant to understand the performance of the dyke.
- Intervention/observation 2:
    - 1982: On January 30, a breach occurred from station 4+650 to 4+670 (centered at about station 4+665). During repairs, between February and October 1982, an inverted filter was placed at the downstream toe of the dyke from station 4+280 to 4+780. The top of the berm was set at elevation 301.0 m between stations 4+580 and 4+780. Between stations 4+280 and 4+580, the downstream berm consists of 1.0 m of sand overlain by 1.0 m of rock rubble. On the upstream slope, the till liner was replaced from station 4+450 to 4+815. A transition zone was added between the upstream till liner and the common fill materials. A rockfill protection was also added on the upstream slope between stations 4+600 to 4+800.
- Intervention/observation 3:
    - 1985: Access road at the toe of the power canal dyke completed.
- Intervention/observation 4:
    - 1987: A downstream sand berm was placed in the canal from station 4+200 to 4+225. Eroded areas on the upstream slope were also repaired at station 4+400. Longitudinal cracking was noted along the upstream shoulder at station 4+480.
- Intervention/observation 5:
    - 1990: Inverted filter berms added from station 4+570 to 4+790.
- Intervention/observation 6:
    - 1994: Large slide occurred at stations 3+970 to 3+985. The slide characteristics are unknown.
- Intervention/observation 7:
    - 2004: Seeping water was noted at station 4+410.
- Intervention/observation 8:
    - 2005: Settlements noted along the upstream crest at station 4+500 to 4+600. Beaver activity causing high readings at weirs near station 4+570.

- Intervention/observation 9:
    - 2018: Two shallow slides occurred during the spring of 2018 at stations 1+989 and 2+069 (Figure 4-7).

Moreover, there are no functional piezometers located in the vicinity of the sector under study. Three (3) weirs or flow pipes are located at stations 4+360, 4+450 and 4+570. The data was not provided to SLI for review.

Finally, it was observed from the June 2018 topographic survey that the downstream slope is quite variable between stations 4+200 and 4+600. From the 2018 survey, the average slope inclination is about 2.3 H:1V with extreme values (min. and max.) ranging from 1.8H:1V to 2.9H:1V. The toe berm is also quite variable in terms of width and elevation. The highest elevation of the toe berm, or of the existing ground at the downstream toe, is close to station 4+220 (306.04 m). The elevation of the berm then varies between 300.71 m and 303.49 m.

4.1.2 Comments on Downstream Slope Stability

From the background documentation consulted in this mandate (see table 2-1), some elements are noted that could have a non-negligible impact on the downstream slope stability and performance of the Power Canal Dyke in the sector of stations 4+385 and 4+530. The following comments can be made:

- Possible concentrated flow under the Power Canal Dyke:
    - From the topographic contours of original ground shown on as-built drawing 1453-104-C-117 (see figure 4-1), there are low points around stations 4+400 and 4+700. This might be the explanation for the need for an inverted filter at both locations. Drawing 1453-104-C-118 confirms that the segment between stations 4+200 and 5+200 is in a low point. Also, there are several streams entering the canal from the uphill face between stations 4+100 and 4+200 and between stations 4+580 and 4+700. These observations lead us to believe that the hydrogeological aspect of the sector have had a considerable impact on the historical performance of the Power Canal Dyke, including due to discrete features at low natural drainage paths.
- Internal erosion:
    - According to the 1985 construction report, the glacial till liner is made of a well-graded 0-100 mm materials with a fine content ranging from 11.4 % to 30.9 % (90% of all 191 grain sizes samples).
    - From the pictures presented in the 2019 ASDR and SLJV (1982a), it appears that the common fill is a relatively heterogenous material. It is predominantly a mix of till with rock particles (see Figure 4-2 and figure 4-2 that confirms this statement;
        - Note that Figure 4-2 shows a layer of segregated coarser material that may not meet filter criteria with adjacent material. Similar conditions could be present elsewhere in the structure. From the construction report, it appears the finer material was placed against the till blanket and the coarser material place towards the downstream slope.
    - No bedrock treatment was done during construction. Following the dyke breach in 1982, seepage was observed in the fractured bedrock below the till invert, or in the coarser zone located in the fill materials.
    - During the site investigation following the 1982 breach, pockets of organic matter, wood stumps and coarser zones were observed in the foundation below the fill materials.

- Surprisingly, from drawing 1453-104-C-114, while there is a 300 mm thick cover of filter material between the uphill face and the till blanket, there is no such zone placed between the impervious till blanket and the heterogenous common fill. The compatibility of these two materials is crucial for the internal stability of the Power Canal Dyke subjected to seepage forces.
- From the construction report of 1985:
  - It is mentioned that the grading of the materials used for the common fill and the glacial till (liner) did not require a transition zone. After the 1982 breach, a transition zone was included in the area of the breach only (see figure 4-5).
  - A filter was used at some locations, against the uphill face, including a drainage pipe (see figure 4-6) that day light near the embankment toe. Drawing 1453-104-C-115 shows that this drainage pipe crosses the Power Canal dyke up to the downstream side. These pipes are monitored for seepage flow and sediment.
- The dyke was constructed to an average elevation of 305.5 m in 1979 then raised to 307.5 m in the following construction seasons (see observation 1 in the previous section).
- Work took place during winter, namely the emergency repair works for the breach in 1982.
- The construction methods used to place the materials, such as pushing the materials from the top to the bottom of the slope can lead to segregation (see figures 4-4 and 4-6).

- Because of the dyke geometry, there is no frost protection cover for the impervious till blanket material along the upstream slope and only little beneath the dyke crest. Frost penetration into the till blanket is undesirable since it may result in the formation of ice lenses and uplift of the till materials, leading to subsequent damages to the impervious blanket and possibly to the entire embankment upon thawing. In addition, high canal levels that coincide with a harsh winter could result in frozen zones extending all the way to the downstream side of the dyke and make the dyke susceptible to piping (i.e., concentrated leak).
- Run-off on the downstream slope due to unfavorable crest geometry.
- No piezometer in the sector to confirm the upstream till blanket efficiency and piezometric levels in the Power Canal Dyke.
- Beaver activity.

The elements listed above have to be taken in account for selection of an appropriate slope stabilization solution.

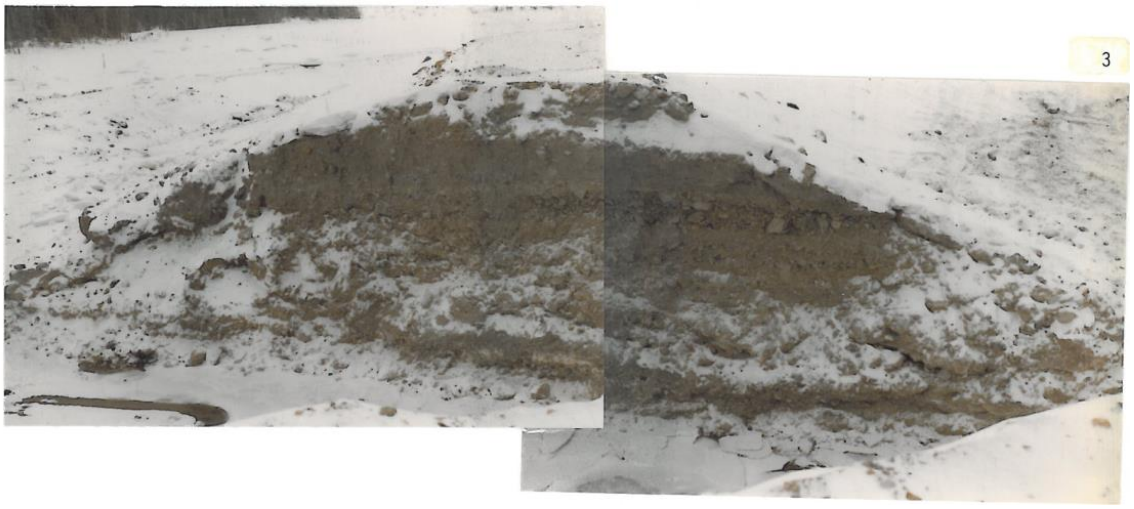


Figure 4-2 : Power Canal Dyke Face of Breach in 1982 (SLJV, 1982a)

(note the concentration of segregated coarser close to the dyke crest)



Figure 4-3 : Power Canal Dyke – Leaks in Dyke November 6, 1980 (SLJV, 1982a).

(note heterogeneity and segregation of material)



Figure 4-4 : Placement of Glacial Till Liner Against the Power Canal's Upstream Face. Dozer Pushing Materials from Top to Bottom (SLJV, 1985)



Figure 4-5: Transition in Materials in the Repaired Breach Section from Left to Right; Coarse Rockfill, Fine Filter and Till Liner (SLJV, 1985)



Figure 4-6 : Filter Material on Invert and Uphill Faces. Dumping of Material at the Crest and the Dozer Pushing Materials from Top to Bottom (SLJV, 1985)



Figure 4-7 : General View of the Slide at sta. 2+069 (SLI, 2019)

4.2 Mitigation Scenarios from RFP Documents

The RFP documentation requires the analysis of three (3) options for slope stabilization at stations 4+385 and 4+530. These options include:

a) The addition of material at the downstream toe to flatten the slope;

b) The removal of material by pulling back the downstream slope and reducing the crest width;

c) The pull back of the upstream slope.

These three (3) options were evaluated, keeping in consideration the background data as outlined in the previous section. After a preliminary analysis of these options, they were discussed in the progress meeting held with NLH on December 18, 2020. The main outcomes are the following:

- Option A:
  - Increasing the height of the downstream berm is an effective way to stabilize the slope;
  - The width of the downstream berm is minimal at station 4+530 (3.6 m) in comparison to station 4+385 (5.6 m);
  - The downstream berm is used as an access road;
  - NLH specifically asked for the footprint of the existing berm to not be increased due to the presence of a water body and/or weirs and flow pipe installations downstream of the dyke.
- Option B:
  - The idea of reducing the crest width toward the upstream originates from the fact that the width of the crest at station 4+530 is 5.0 m compared to station 4+385, which is 3.6 m;
  - The main technical issue with this option is that the main body of the embankment would have to be excavated from about station 4+600 toward station 4+385. Since the upper till zone would be reduced and the major regrading/excavation works would have to be performed in the heterogeneous fill, this option is not recommended because of dam safety issues that might arise. As outlined earlier, several interventions have taken place in the concerned sector, dating back to 1982.
- Option C:
  - This option is not recommended for several reasons, such as:
    - It would require excavation works in the upstream till blanket, which is not recommended because of dam safety issues that might arise;
    - Underwater excavation and fill placement will be required;
    - Building a fill over a sector where longitudinal cracking and settlements were observed in the past, near the upstream edge, is not recommended and
    - It might impact the efficiency of the canal from a hydraulic point of view. Hydraulic studies will be necessary to confirm if this option is feasible.

SLI recommended to move forward with analysis of Option A. This option is the least risky of the three (3) options proposed by NLH. Thus, the interventions to stabilize the slope will not reduce the existing width of the crest and the selected options will be a combination of flattening the downstream slope and the reshaping of the downstream toe

berm. The design criteria and assumptions used to develop stabilization alternatives are presented in the following section.

4.3 Preliminary Design Criteria and Assumptions

Following initial evaluation of stabilization solutions proposed by NLH, the scenario of adding fill materials at the downstream toe to flatten the slope was further explored. To define a preliminary stabilization solution, the baseline design criteria that were used to develop stabilization options are as follows:

- Crest:
  - Width: The existing width is not reduced. After initial reshaping of the downstream slope, fill material will be added on the entire length of the slope;
  - Elevation: Increase in some areas to have a crest at elevation 307.5 m, as shown on the as-built drawings of 1980. Also, a slight 2% reprofiling of the crest toward the upstream side is required to avoid erosion damage caused by run-off water.
- Downstream slope inclination:
  - Reshaped the downstream slope between 2.25H:1V to 2.5H:1V, depending on elevation of the downstream toe berm. These grades are equivalent to the average existing slopes between stations 4+220 and 4+600, as indicated by data from the June 2018 survey;
  - A single slope inclination for both stations to ensure ease of construction.
- New fill materials:
  - Well-graded crushed stone. This material is selected to meet the following requirements:
    - Free draining;
    - High shear resistance for slope stability;
    - Potentially compatible with the existing common fill, to act as a filter material and reduce the risk related to internal erosion;
    - Resistant to erosion from precipitations and runoff;
    - Minimize segregation during placement.
  - A thickness of 450 mm of fill material added on the downstream slope (perpendicular to the slope face), from the crest to the top of berm. This results in a widening of the crest by about 1.1 m to 1.2 m for a slope reshaped at 2.25 or 2.5H:1V, respectively.
- Toe berm:
  - Elevation: as it is or higher;
  - Downstream slope inclination: 1.5H:1V;
  - Longitudinal slope: 10% or flatter;
  - Footprint: no increase;
  - Width: minimum of 3.6 m (actual minimum width). SLI recommends a minimum width of at least 4.5 m to accommodate vehicle or machinery traffic in winter conditions.

- Stability: Fulfillment of CDA guideline criteria.

Moreover, for NLH to be aware of the limitations of the slope stability analyses presented herein, here is a list of the key assumptions that were necessary due to gaps in information or because such analysis was out of the scope of the current mandate:

- Phreatic conditions: in the absence of piezometric data, it was assumed that a phreatic surface, as established in the 1982 repair works report, is representative of actual conditions. Since it is assumed that no seepage exits above the existing top of the toe berm's level, there is no need for placement of a filter on the downstream slope, between the new fill and the existing main fill. NLH should review the historic inspection records to make sure that seepage above the existing top of berm elevation was not observed;
- Extent of the downstream berm: it was assumed that seepage exits beneath the existing inverted filter berm's footprint;
- Material compatibility/internal erosion assessment: this verification is highly recommended. Without proper data to review (e.g., grain-size distribution curves and/or quality control tests during construction), mitigation scenarios may be required, and the stabilization solution proposed in this report reviewed;
- Frost protection of the upstream till blanket and common fill: this verification is highly recommended. Without proper data to review, mitigation scenarios may be required, and the stabilization solution proposed in this report reviewed;
- Canal operation water level and design flood level: as outlined by Hatch (2011), the hydraulic study was conducted in the late 70's. An update of this study would be beneficial to ensure that the maximum operation level is still adequate. The findings of this study could also be used to assess freeboard and adequacy of the upstream slope protection. It is assumed that if the reservoir levels were to increase due to an increased inflow design flood, it would affect the reservoir but not beyond the control gate entering the canal;
- Freeboard requirements: it was assumed that elevation of the crest at 307.5 m, as shown on the as-built drawings of 1980, fulfills the CDA guidelines in terms of freeboard requirements.

4.4 Proposed Stabilization Options

Following the selection of preliminary design criteria as stated above, a sensitivity analysis was completed for the slope inclinations (2.25H:1V or 2.5H:1V) and the downstream berm raises (0 to 1.5 m) to determine which combinations satisfy the geometric criteria (berm width, etc.). Table 4-1 presents the results.

Table 4-1: Geometrical Sensitivity Analysis

Slope	D/S berm raise (m)	Station 4+385			Station 4+530		
		Footprint increase (m)	D/S berm Elevation (m)	D/S berm Width (m)	Footprint increase (m)	D/S berm Elevation (m)	D/S berm Width (m)
2.25H:1V	0	0	301.6	**4.5**	0	302.2	2.5
	0.50	0	302.1	**4.9**	0	302.7	**4.6**
	0.75	0	302.3	**5.1**	0	303.0	**4.8**
	1.00	0	302.6	**5.3**	0	303.2	**4.9**
2.50H:1V	0	0	301.6	2.5	0	302.2	1.8
	0.50	0	302.1	2.9	0	302.7	2.9
	0.75	0	302.3	3.2	0	303.0	3.1
	1.00	0	302.6	3.4	0	303.2	3.4
	1.50	0	303.1	**4.0**	0	303.7	**3.9**

Note:
[1]Shaded cells outline the scenarios that fulfill the preliminary design criteria in terms of dyke geometry.

One can see that a slope of 2.25H:1V instead of 2.5H:1V leaves more space to accommodate vehicle or machinery traffic, which is especially important in winter conditions. Considering the maintenance activities that have been required since construction, in 1980, this aspect is deemed important. Also, only a raise of the downstream berm of 0.5 m, at station 4+530, and no raise, at station 4+385, is required to fulfill the preliminary design criteria regarding the dyke geometry when considering a slope of 2.25H:1V.

To settle on a single stabilization solution applicable from about stations 4+200 to 4+600, and for ease of construction, the following stabilization scenario is recommended:

- Crest elevation set at 307.5 m, excluding a 2% reprofiling toward the upstream side. The crest is to be reprofiled with well-graded crushed stone;
- The downstream berm toe is kept as it is and the berm is reshaped with an outside slope at 1.5H:1V. Then, the berm is raised to elevation 302.7 m. A longitudinal slope transition (inclination at 10% max.) is required to tie-in with the existing toe berm prior to station 4+200 and after following 4+600. A 200 mm thick layer of well-graded crushed stone is considered for road topping above the berm;
- Adding a 450 mm thick layer of crushed stone over the entire downstream slope, at an inclination of 2.25H:1V;
- A provision for clean sand filter material is recommended in case of needs when the berm will be reshaped.

This stabilization scenario can be visualized on figures 4-8 and 4-9. Note that for the sake of simplicity, some construction details are neglected in the following models. These details are:

- Initial regrading of the downstream slope prior to placement of fill for stabilization;
- Initial reshaping of the existing toe berm;
- Crushed stone material for regrading of the crest with a 2% cross slope;
- Crushed stone material for road topping material.

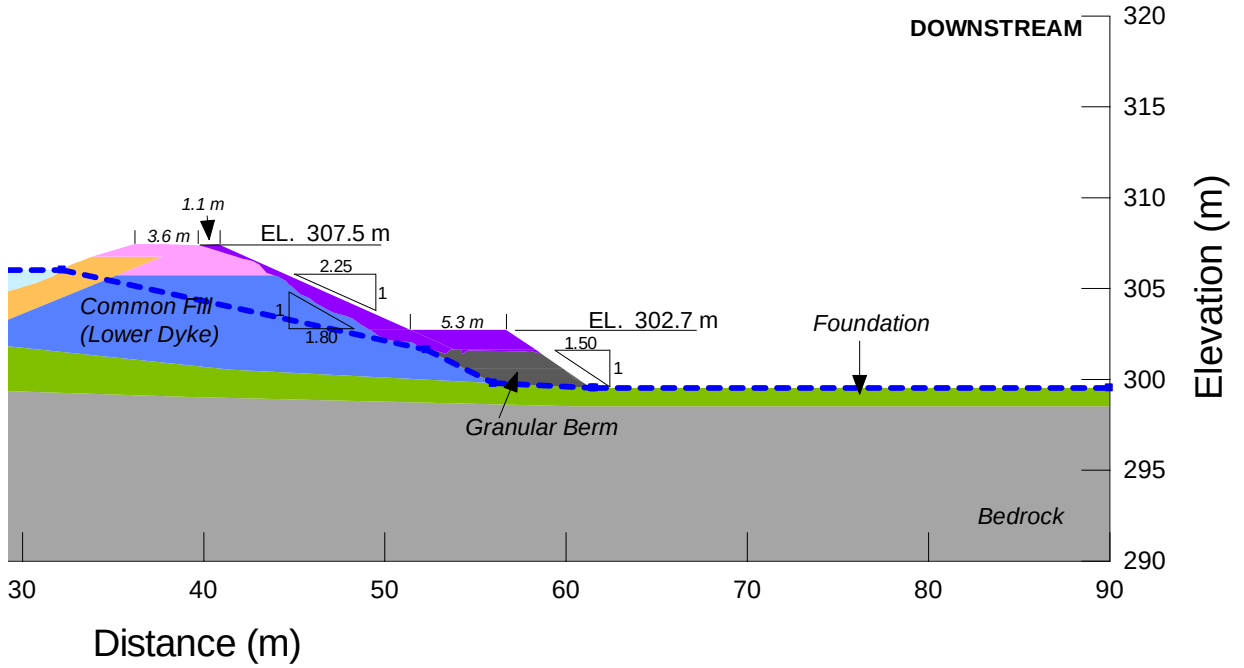


Figure 4-8: HD-PC - Proposed Stabilization Solution – Station 4+385

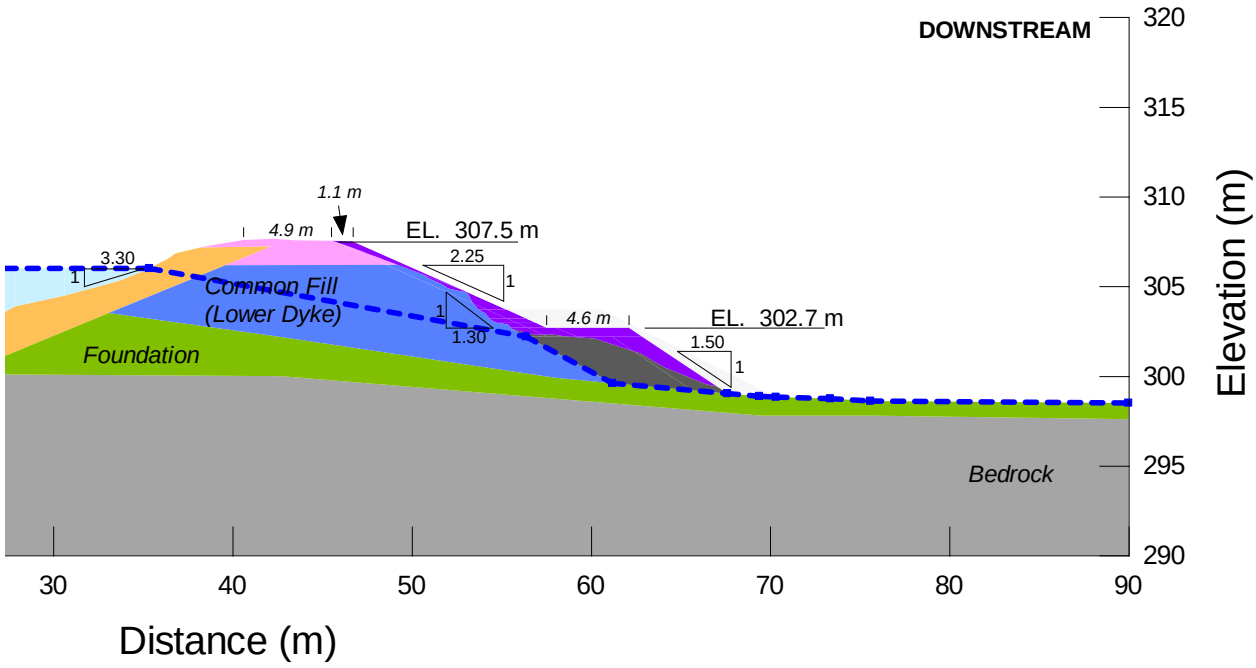


Figure 4-9: HD-PC - Proposed Stabilization Option – Station 4+530

As mentioned in section 4.2, since only a stabilization scenario from the RFP documentation has been analyzed (Option A), no high-level cost estimate was necessary. The implementation of the proposed stabilization scenario from Sta 4+200 to Sta 4+600 will result in the following estimated fill volume to be sourced:

- Well graded crushed stone (road topping) = 550 m^3
- Well graded crushed stone (over downstream slope and toe berm) = 7,500 m^3
- Cleaned sand filter materials = 600 m^3

A minimum contingency of 25% is recommended over these quantities because of the high-level calculations and assumptions that were considered.

4.5 Slope Stability Results of Proposed Solution

Results of slope stability analyses conducted for the stabilized downstream slope per Option A are presented in table 4-2. The corresponding figures are presented in appendix B.

Table 4-2: Downstream Slope Stability Analysis – Proposed Stabilization Scenario – Option A

Loading Condition	Description	FS_{min} required	Station	
			4+385	4+530
Static	Long-term Steady-state seepage. Maximum Operating Level = 306.0 m	1.5	1.73	1.60
Pseudo-static (k_h = 0.02 g)	Long-term Steady-state seepage. Maximum Operating Level = 306.0 m	1.0	1.62	1.50

As can be seen in table 4-2, if all the assumptions presented in section 4.3 are valid, the computed factors of safety are above the CDA requirements for all evaluated loading conditions.

It is important to note that small critical slip surfaces are computed along the 1.5H:1V slope of the rockfill berm for both stations. As can be seen on figures B-1 and B-3, these small critical slip surfaces present factors of safety of 1.31 and 1.28 for cross sections 4+385 and 4+530, respectively. These FS do not fulfill CDA requirements. However, these slip surfaces are not considered critical for the global stability of the Power Canal Dyke. At this stage of the study, the proposed stabilization solution is deemed adequate. The downstream slope of the rockfill berm could be slightly flattened, therefore reducing the width of the road at the top of the berm, or the footprint slightly increased if possible, to make the berm slope meet the criteria, if desired.

Consideration to possible field investigations to characterize the overburden foundation along the Power Canal Dyke should also be given, in order to assess the internal friction angle (Φ') of the till. The value of 31° used by Hatch (2011), SLI (2019a) and in the current study is deemed conservative, but the lack of data negates the possibility of increasing this value other than arbitrarily. It is interesting to note a value of 36° was employed during the design phase (SLJC, 1982b), based on literature review and experiences on similar projects. The use of such value, or 33° as it the case for the upper main fill, would result in FS higher than 1.5 for the downstream berm.

5.0 CONCLUSION AND RECOMMENDATIONS

The key conclusions and recommendations resulting from the slope stability analyses at HD-9 and HD-PC (stations 4+385 and 4+530) of the Hinds Lake hydroelectric development are presented in the following sub-sections.

The analyses presented in the current report indicate that HD-9 and HD-PC (stations 4+200 to 4+600), while operated safely and maintained in a safe condition, need some additional engineering analysis or repair works to confirm good dam performance and compliance to the current CDA Guidelines.

5.1 Eclipse Dam (HD-9)

5.1.1 Observations and Conclusions

- Geometry of the critical cross section at HD-9 was updated based on data from the most recent topographic survey, except for the portion of the upstream slope below reservoir level;
- Due to the lack of data, material properties remained unchanged from those used in the analyses performed by Hatch (2011);
- No piezometer is installed at HD-9;
- CDA requirements are met for all evaluated loading conditions if the assumptions used are valid.

5.1.2 Recommendations

- Review the PMF studies with the latest climatic data. This will allow for the determination of the IDF water level and subsequent assessment of available freeboard;
- Research NLH's archives for information regarding the main fill materials and rockfill toe berm. For instance, there is discrepancy between geometry in Hatch (2011) and NLH dam register about materials in the rockfill berm (sand below rockfill);
- It is recommended that the next Dam Safety Review assess the need to install piezometers in the embankment, at the critical location, to determine the location of the phreatic surface within the embankment and assess performance of the drainage blanket;
    - in the impervious fill below the crest level;
    - in the downstream slope berm (el. 308.0 m); in the toe drain and above in the impervious fill;
    - in the foundation material below the rockfill berm; during drilling, in any cases of artesian condition in the bedrock, another piezometer should be added at this location.
- Proceed with a bathymetric survey to determine the profile of the upstream slope below the water line;
- Update the slope stability analyses once the survey and piezometric data are available;
- Determine piezometer thresholds that control slope stability.

5.2 Hinds Lake Power Canal (HD-PC)

5.2.1 Observations and Conclusions

- The factor of safety of the downstream slope, for normal operating conditions, does not satisfy CDA requirements at stations 4+385 and 4+530;
- No functional piezometer is installed near the sections under study;
- Due to gaps in data, some material properties were left unchanged from previous studies while others were adjusted from those used in the analyses performed by Hatch (2011) and SLI (2019a; 2019b), based on some historical documentation;
- As mentioned in section 4.1.2, there is no filter or transition zone between the till liner and the main embankment's common fill;
- There is also no frost protection cover for the till liner;
- In the last 40 years, several interventions were required for the dyke to perform well;
- Stabilization options were evaluated, and the potential solution consists of reprofiling the downstream slope at a grade of 2.25H:1V by addition of fill material and increasing the height of the rockfill berm at the toe to elevation 302.7 m;
- For the potential solution, CDA stability requirements are met for all evaluated loading conditions, if the assumptions used are valid;
- It is noted that this stabilization option only addresses the deficiency in terms of slope stability and does not address other potential failure modes such as seepage control and internal erosion.

5.2.2 Recommendations

- Proceed with a complete background data review of available design and construction reports in the sector under study to confirm the adequacy of the cross section as modeled, the strength parameters and the suitability of the proposed stabilization method;
- Review the PMF studies with the latest climatic data. This will allow for the determination of the IDF water level and subsequent assessment of available freeboard;
- Consider the installation of piezometers to confirm the modelled phreatic surface and the effectiveness of the till liner and the common fill performance in drawing down the phreatic surface;
- Proceed with the detailed design of the stabilization option including:
    - Determining design fill gradations;
    - Validation of the volume of materials to be sourced;
    - Preparation of a drawing, including a plan view and cross sections of the stabilization works and technical specifications;
    - Preparation of a field instruction, including a method statement of the works.
- Evaluate if the findings of this report apply to other sectors along the Power Canal Dyke. If it is the case, conduct a risk management framework. In this process, a list of potential risks is generated, with

associated causes, possible control measures and highlight the priorities for further action. Then a priority ranking helps to identify the most important risks and decide on the appropriate allocation of attention and resources to more detailed analyses. The risk analysis also helps to define appropriate risk treatment strategies;

- Proceed with the stability analysis of the uphill face, if such study is not already available. The impact of an uphill slide on the existing freeboard must be considered.
- NLH should determine how often the LSL is reached to assess if this loading case should be considered as a permanent instead of temporary condition.

In summary, for HD-PC, our review of documentation suggests that besides slope stability FS not satisfying the CDA guidelines there could be other elements causing stability issues (such as freeze and thaw) and there could be other potential deficiencies related to seepage and internal erosion (exposure of till liner to frost, lack of filter, heterogenous common fill with segregation of materials). We recommend that NLH conduct a risk-assessment study to identify and classify potential failure modes. The results of this work would then be used to plan and prioritize monitoring, surveillance, rehabilitation and/or maintenance works.

6.0 REFERENCES

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9. Shawmont-Lavalin Joint-Venture. (1982b). Hinds Lake Development – Canal Dyke Repair Program – Vol. 2– Design of the Power Canal. SLJV-19-82. November 1982.
10. Shawmont-Lavalin Joint Venture. (1985). Hinds Lake Development – Power Canal Construction Report (partial report). SMR-14-85. May 1985.
11. SNC-Lavalin. (2019a). Final Report – Audit Dam Safety Review – Hinds Lake Structures. 655474-0000-40ER-0001_00. January 2019.
12. SNC-Lavalin. (2019b). Slope Stability Analysis of 2 Slides at Hinds Lake Power Canal Dyke (HD-PC) with Proposed Repair Solution. 655474-1000-4GEB-0001_00. January 31, 2019.

Appendix A : Slope Stability Analysis for Existing Conditions

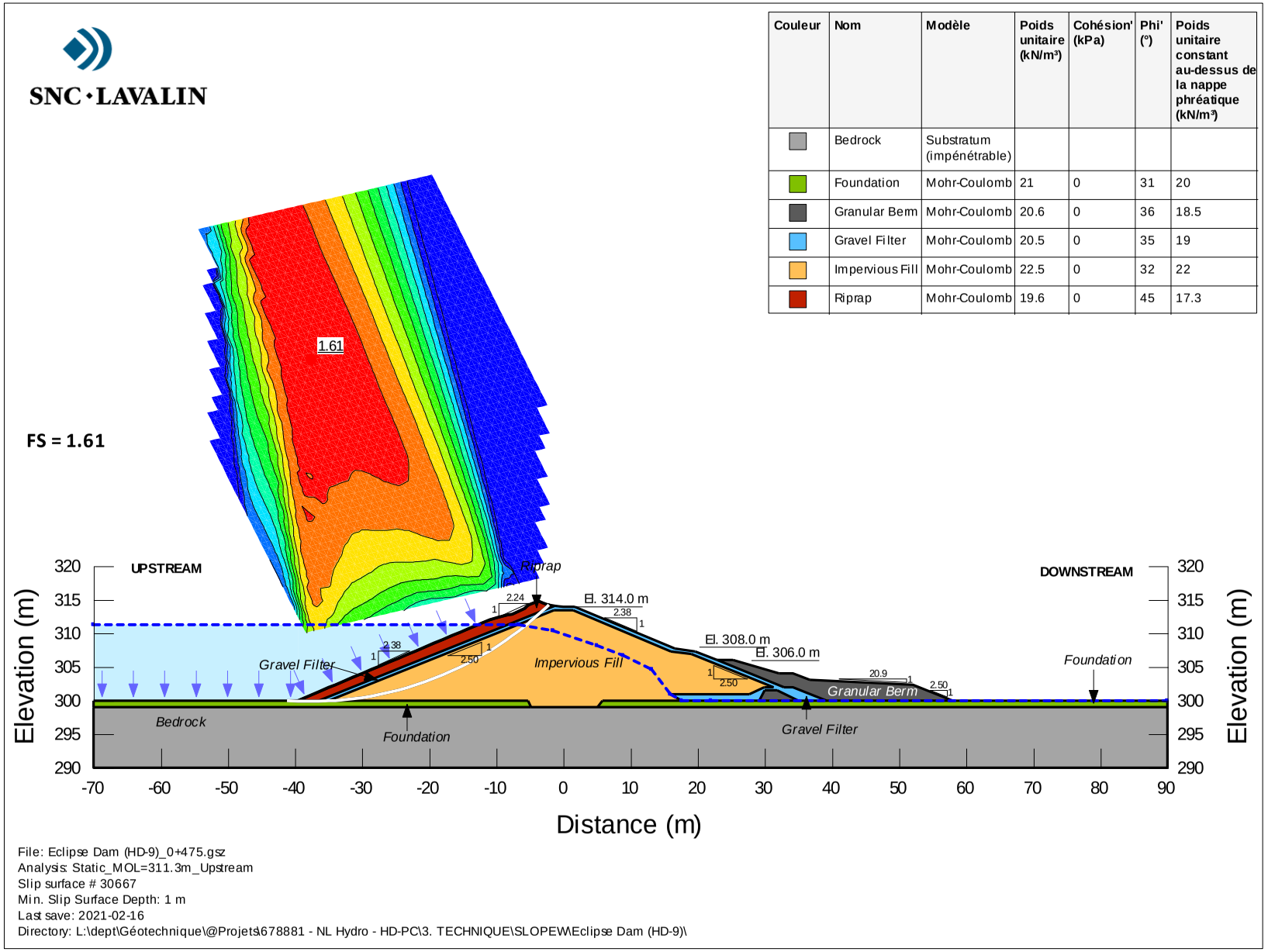


Figure A-1: HD-9 – Existing Conditions - Static Loading and Maximum Operating Level (MOL = 311.30 m) – Upstream Slope

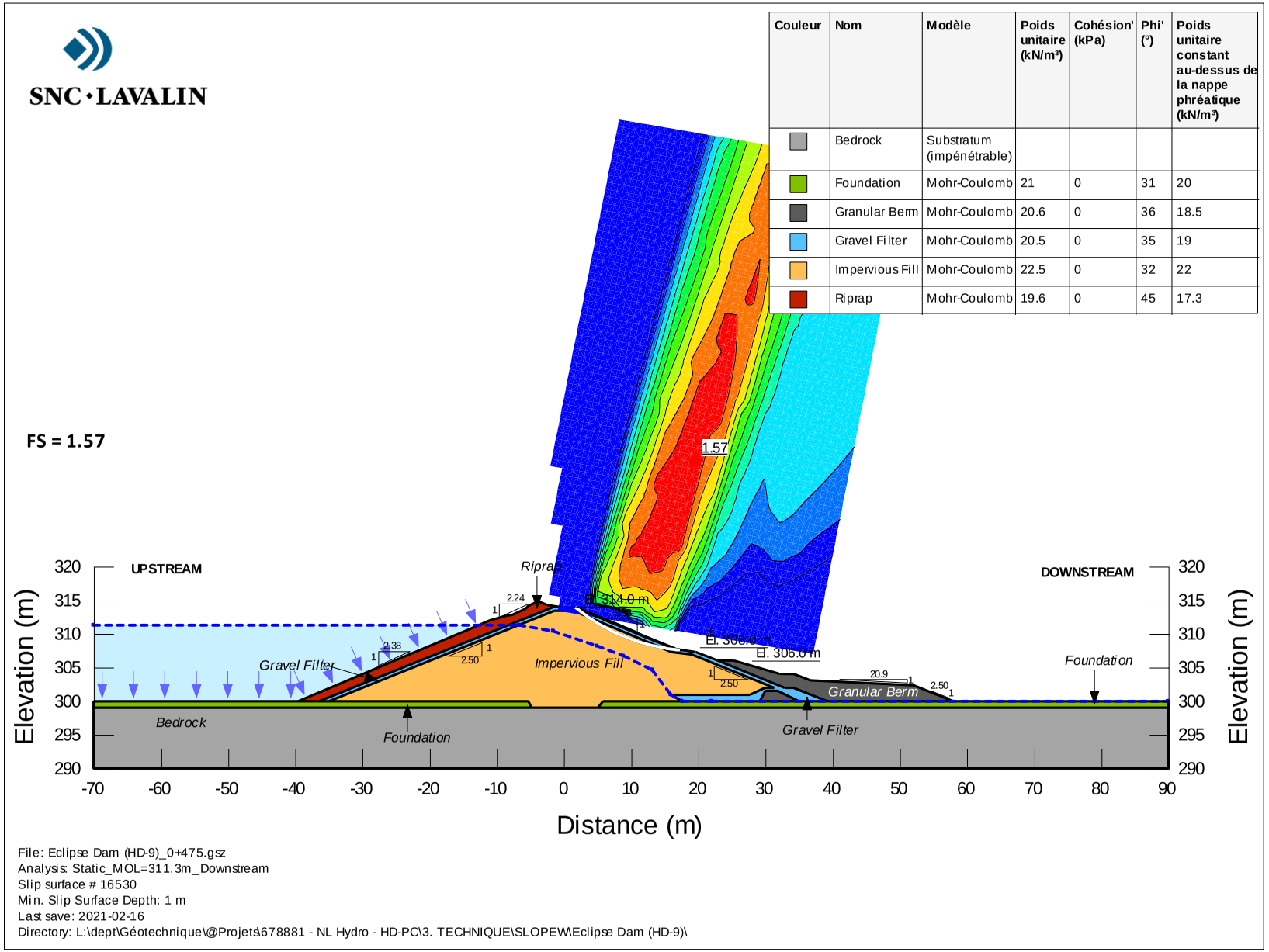


Figure A-2: HD-9 – Existing Conditions - Static Loading and Maximum Operating Level (MOL = 311.30 m) – Downstream Slope

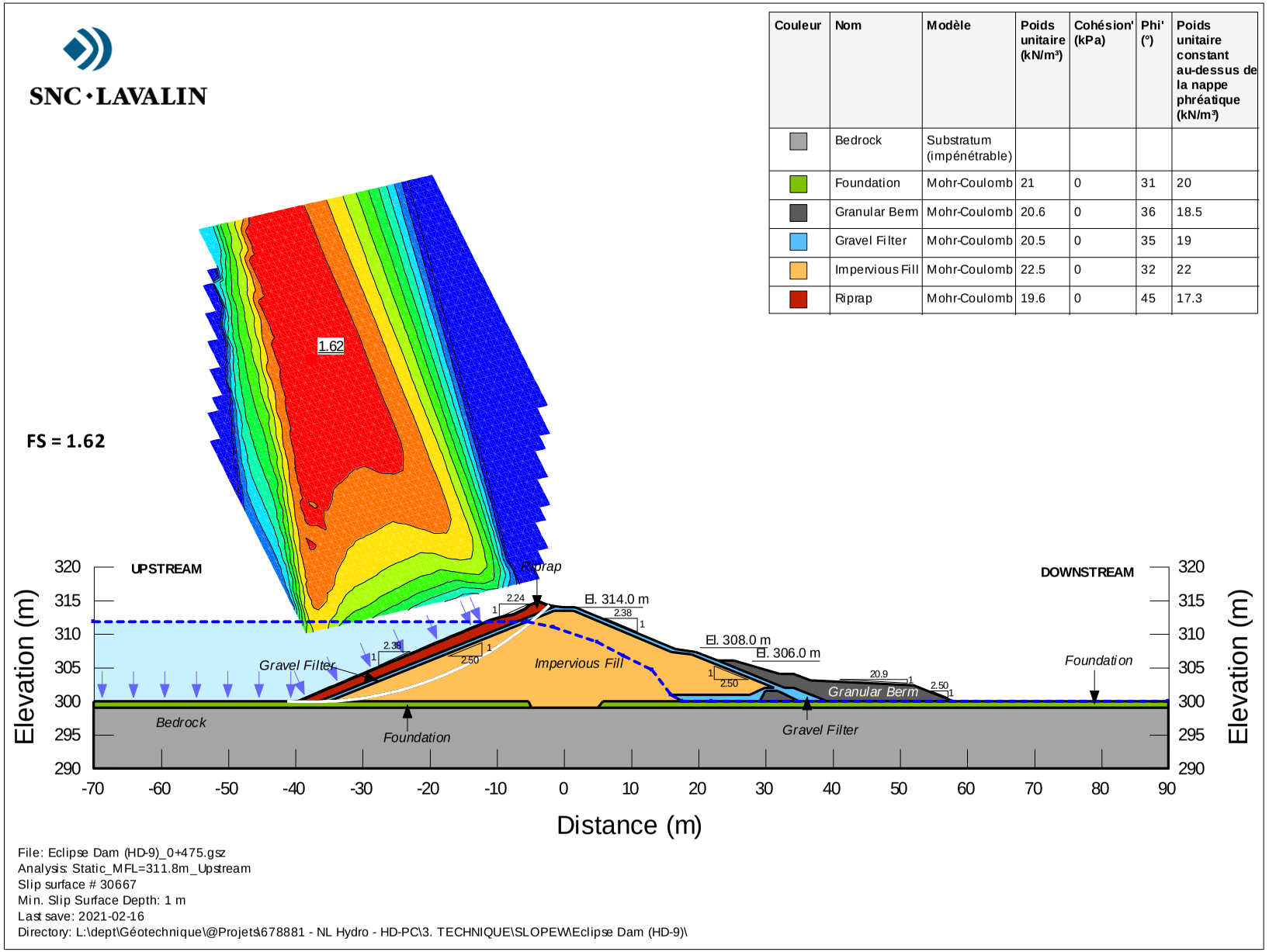


Figure A-3: HD-9 – Existing Conditions - Static Loading and Maximum Flood Level (MFL = 311.80 m) – Upstream Slope

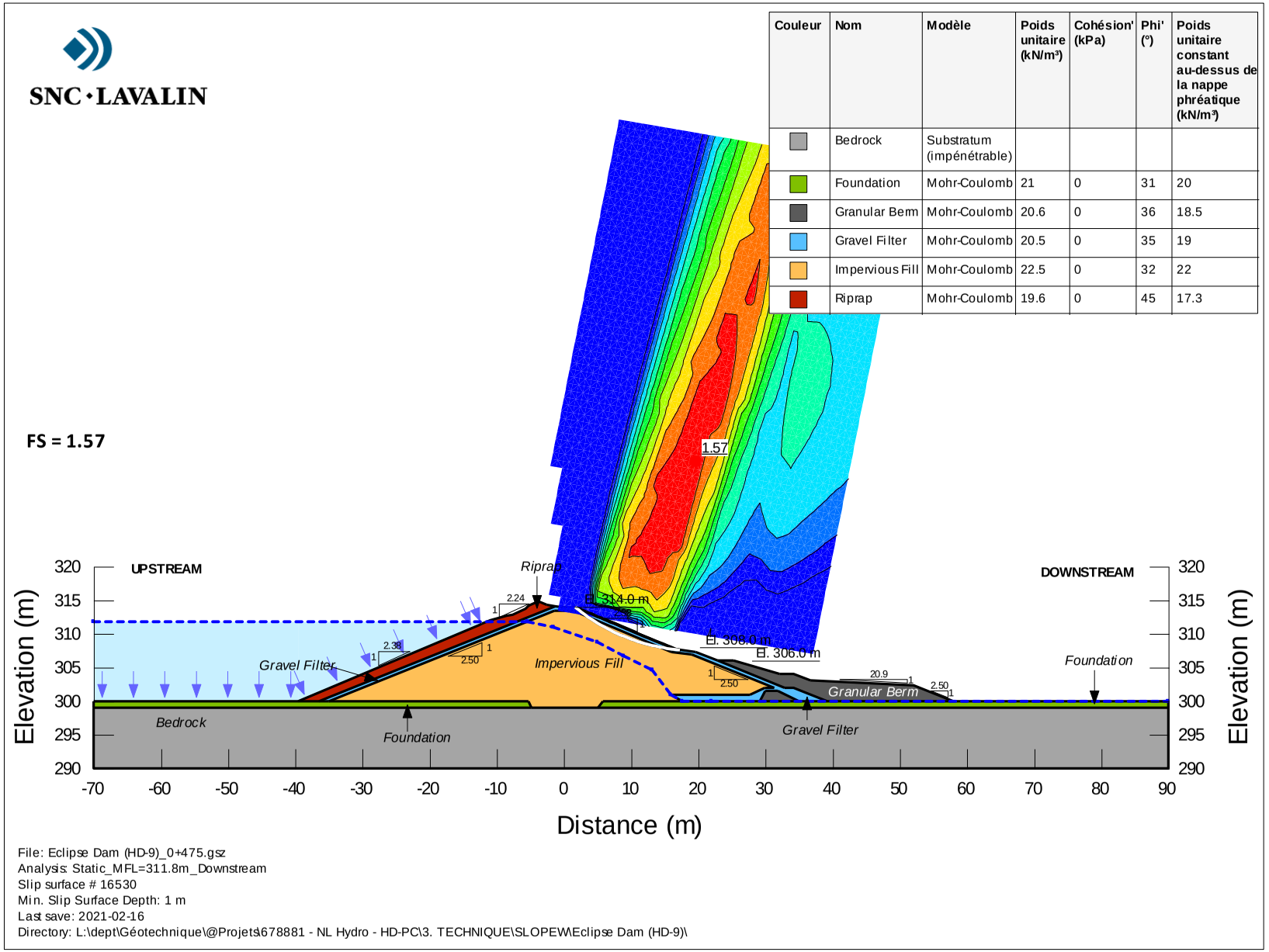


Figure A-4: HD-9 – Existing Conditions - Static Loading and Maximum Flood Level (MFL = 311.80 m) – Downstream Slope

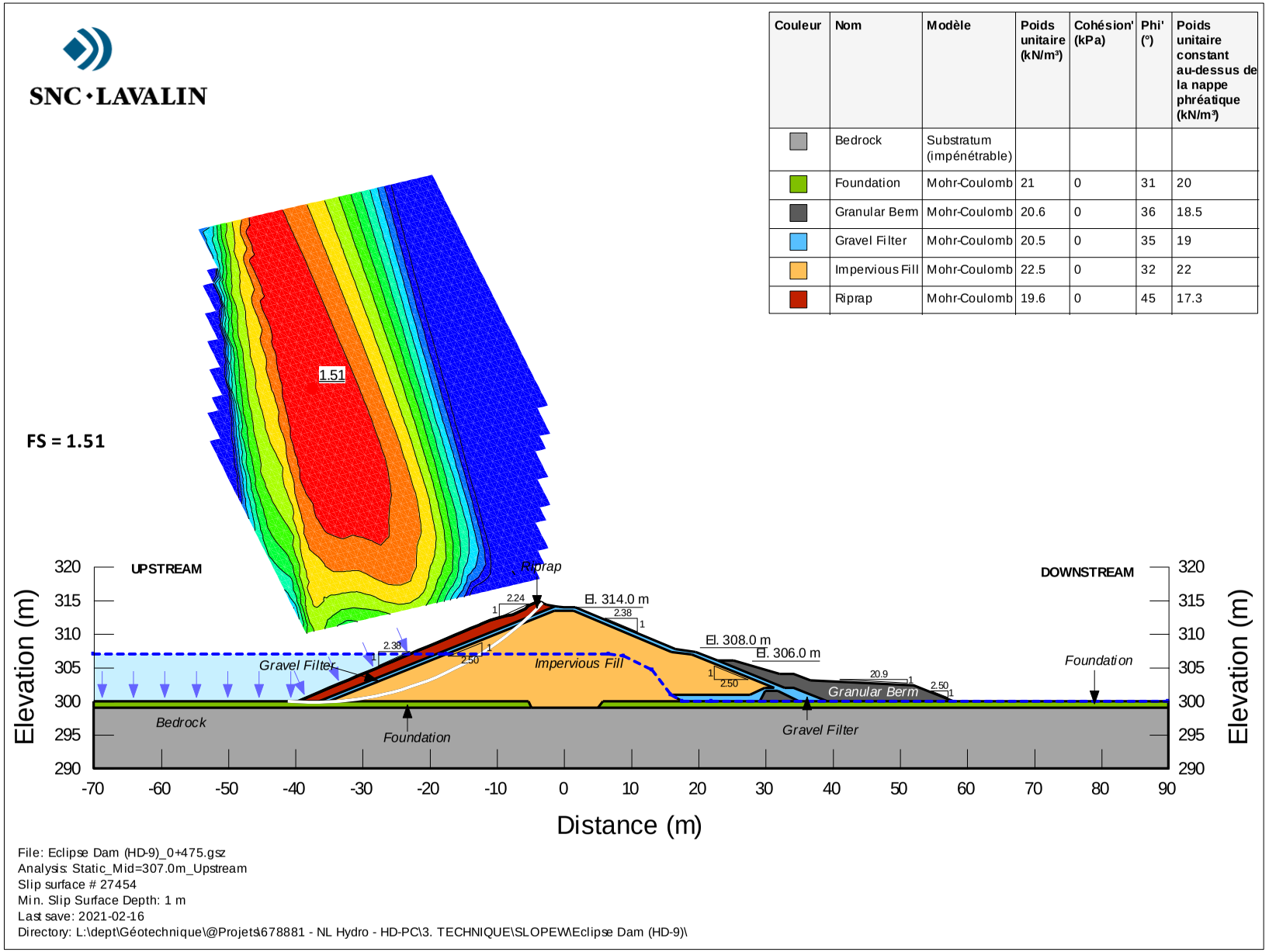


Figure A-5: HD-9 – Existing Conditions - Static Loading and Reservoir at Mid-slope Level (Mid = 307.00 m) – Upstream Slope

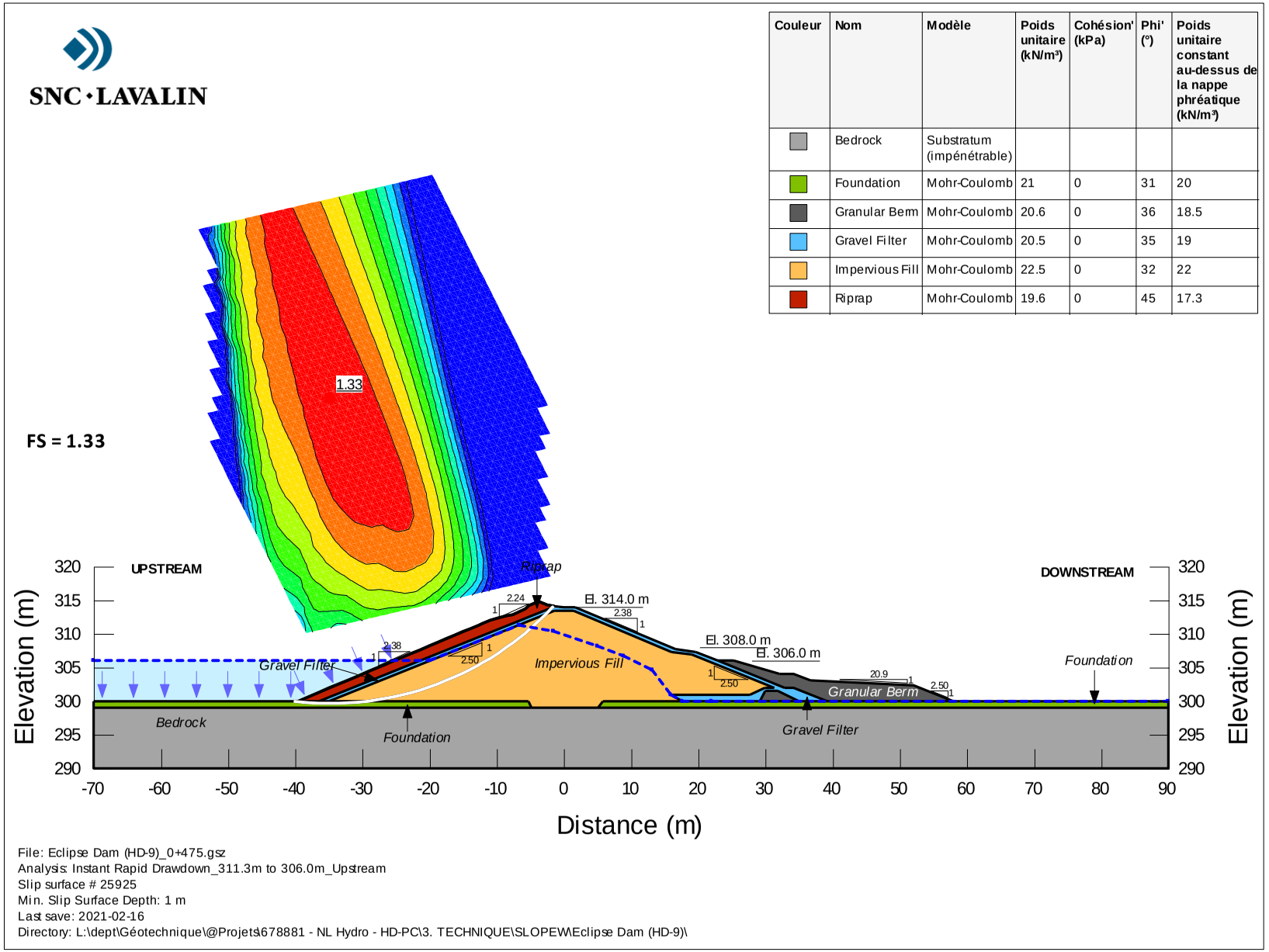


Figure A-6: HD-9 – Existing Conditions - Static Loading and Rapid Drawdown to Low Supply Level (LSL = 306.00 m) – Upstream Slope

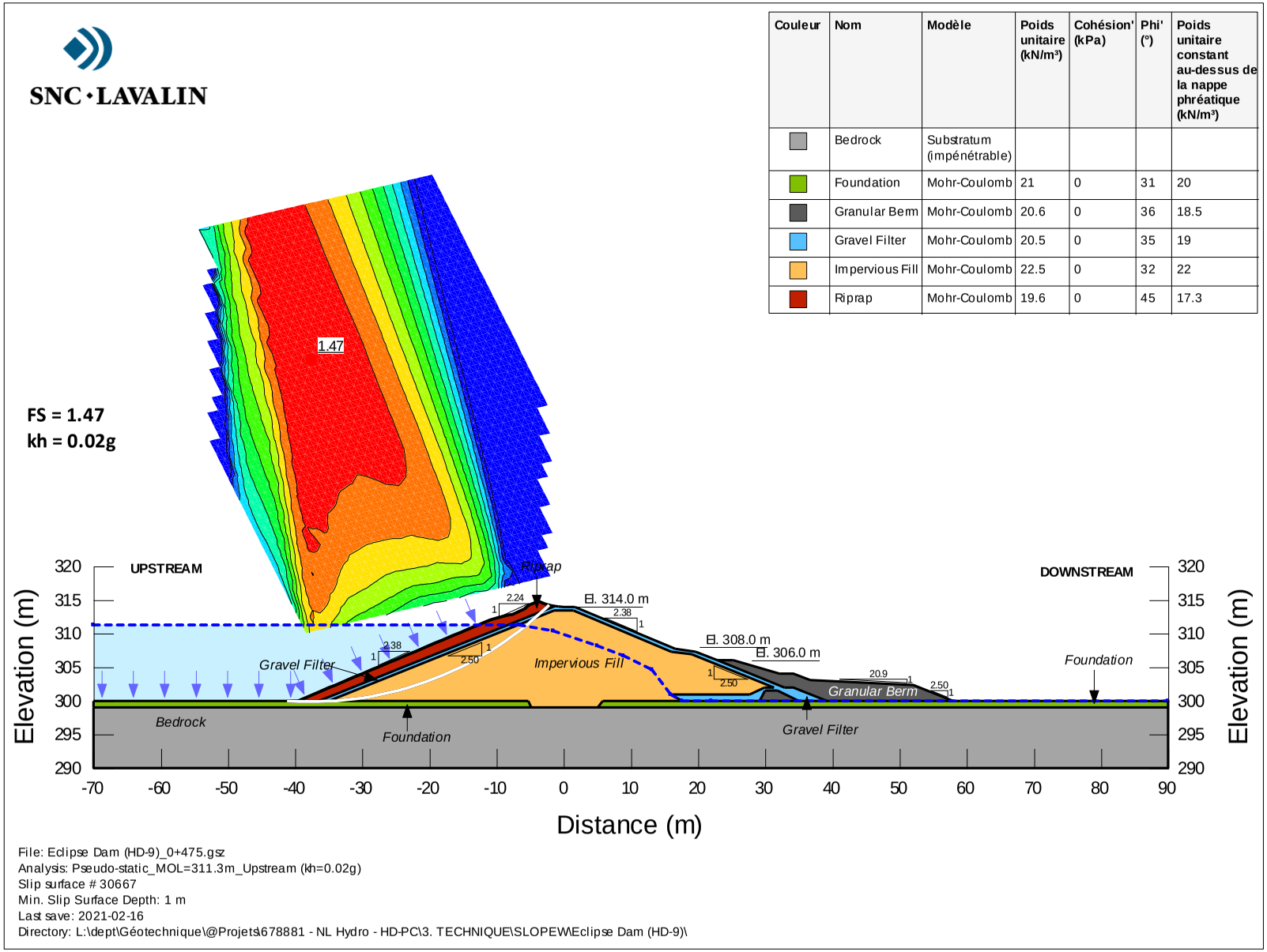
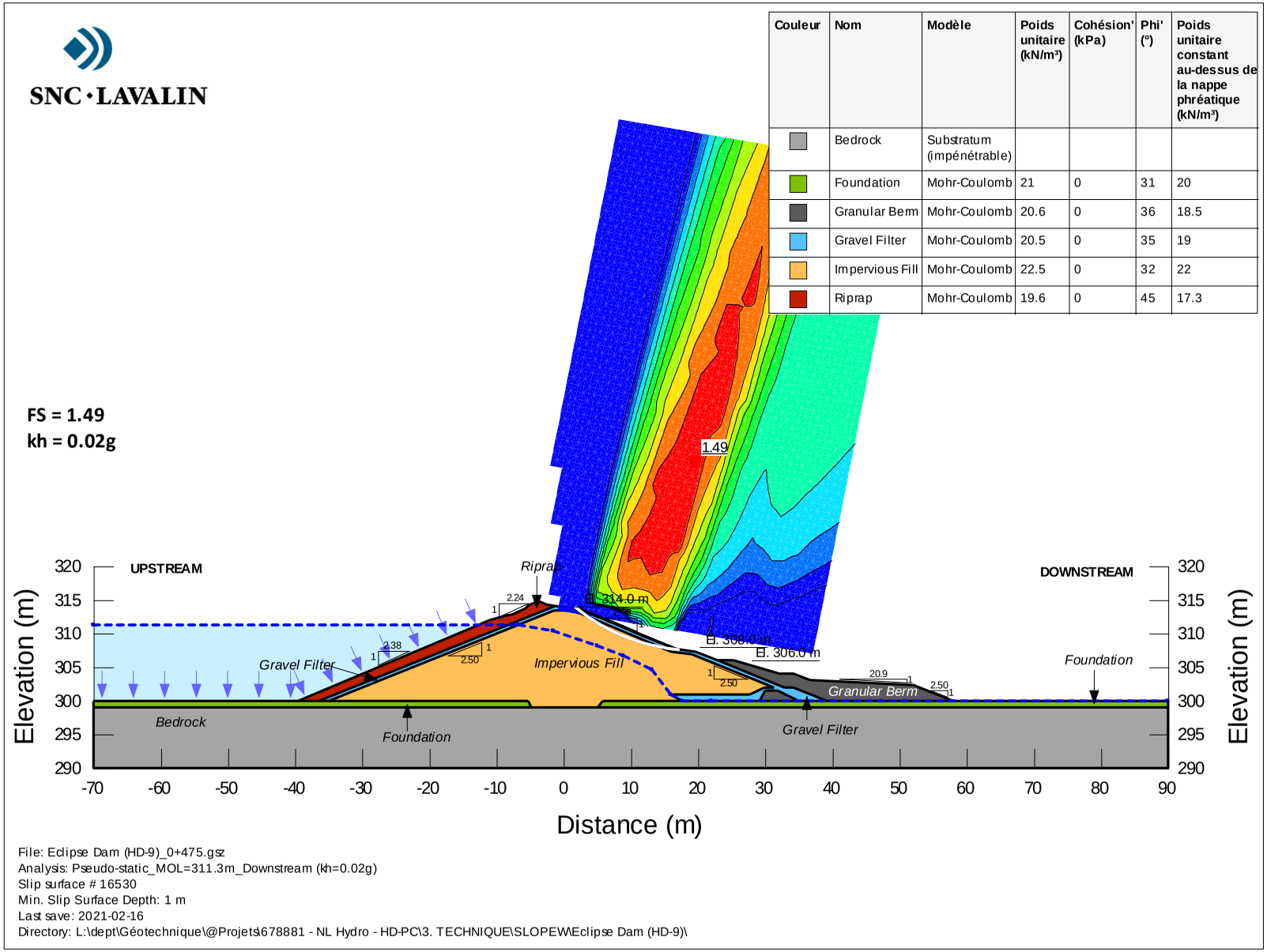


Figure A-7: HD-9 – Existing Conditions – Pseudo-static Loading (k_h=0.02 g) and Maximum Operating Level (MOL = 311.30 m) – Upstream Slope



Couleur	Nom	Modèle	Poids unitaire (kN/m³)	Cohésion' (kPa)	Phi' (°)	Poids unitaire constant au-dessus de la nappe phréatique (kN/m³)
	Bedrock	Substratum (impénétrable)				
	Foundation	Mohr-Coulomb	21	0	31	20
	Granular Berm	Mohr-Coulomb	20.6	0	36	18.5
	Gravel Filter	Mohr-Coulomb	20.5	0	35	19
	Impervious Fill	Mohr-Coulomb	22.5	0	32	22
	Riprap	Mohr-Coulomb	19.6	0	45	17.3

Figure A-8: HD-9 – Existing Conditions – Pseudo-static Loading (k_h=0.02 g) and Maximum Operating Level (MOL = 311.30 m) – Downstream Slope

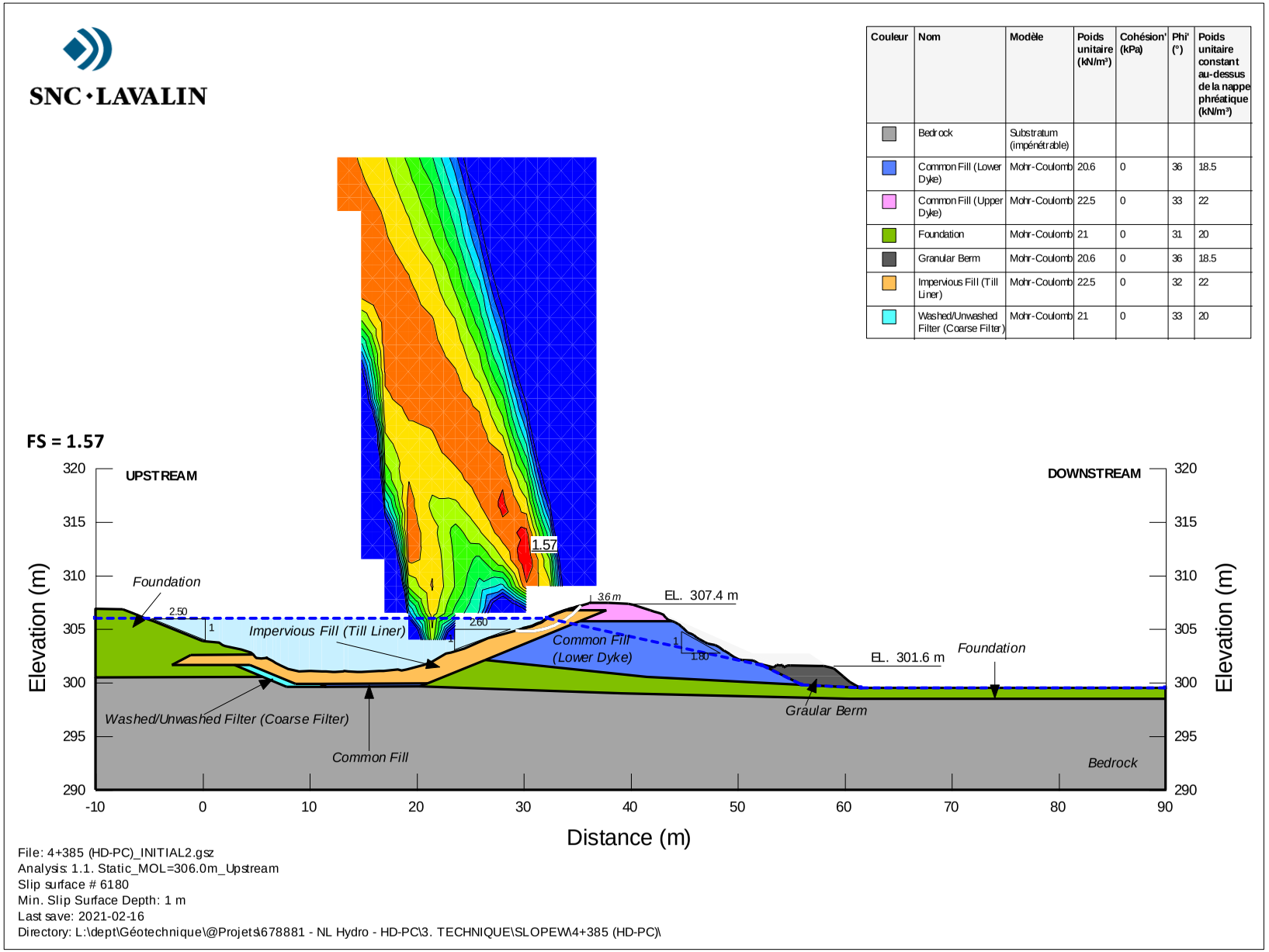


Figure A-9: HD-PC (4+385) – Existing Conditions - Static Loading and Maximum Operating Level (MOL = 306.00 m) – Upstream Slope

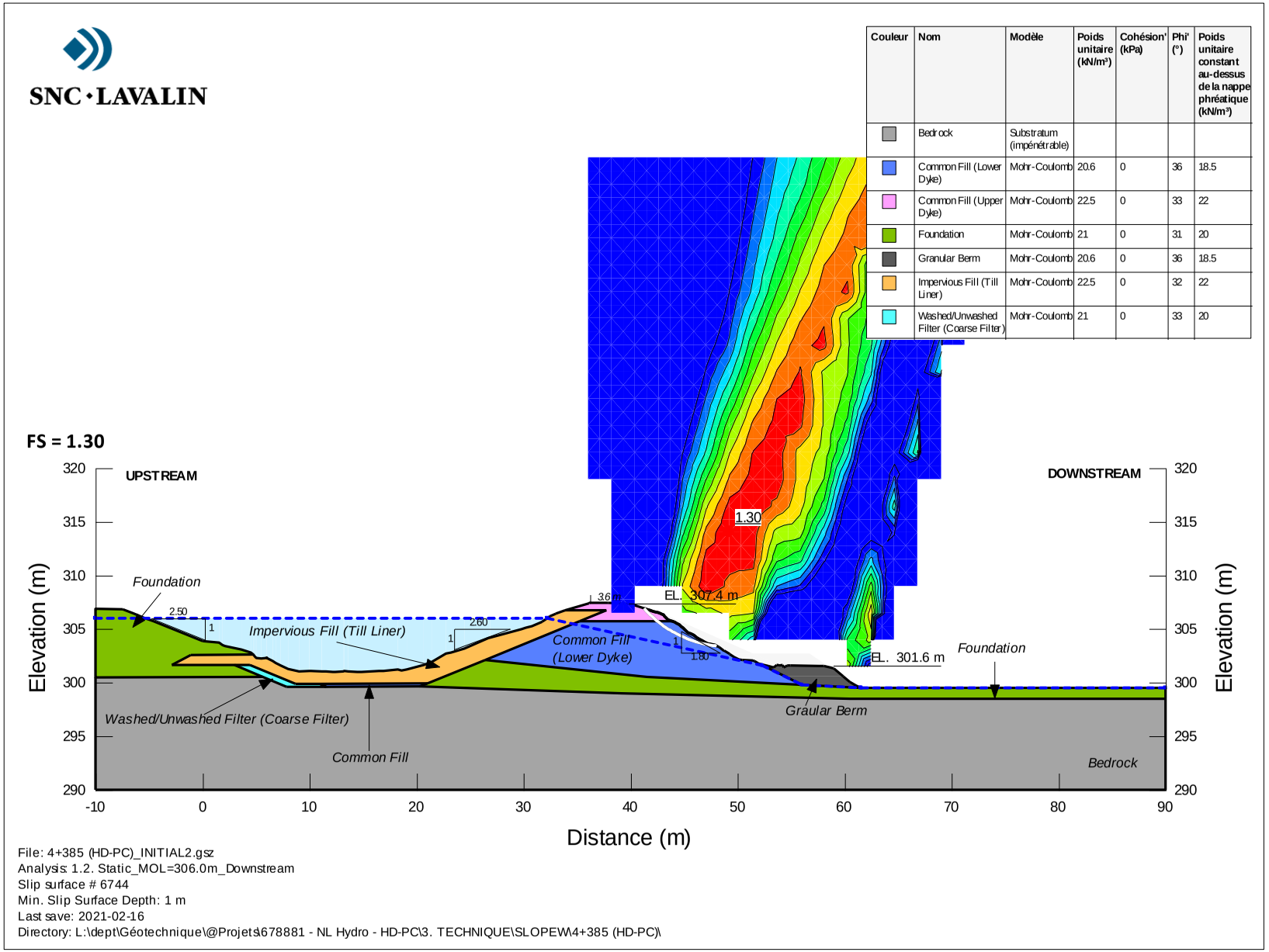


Figure A-10: HD-PC (4+385) – Existing Conditions - Static Loading and Maximum Operating Level (MOL = 306.00 m) – Downstream Slope

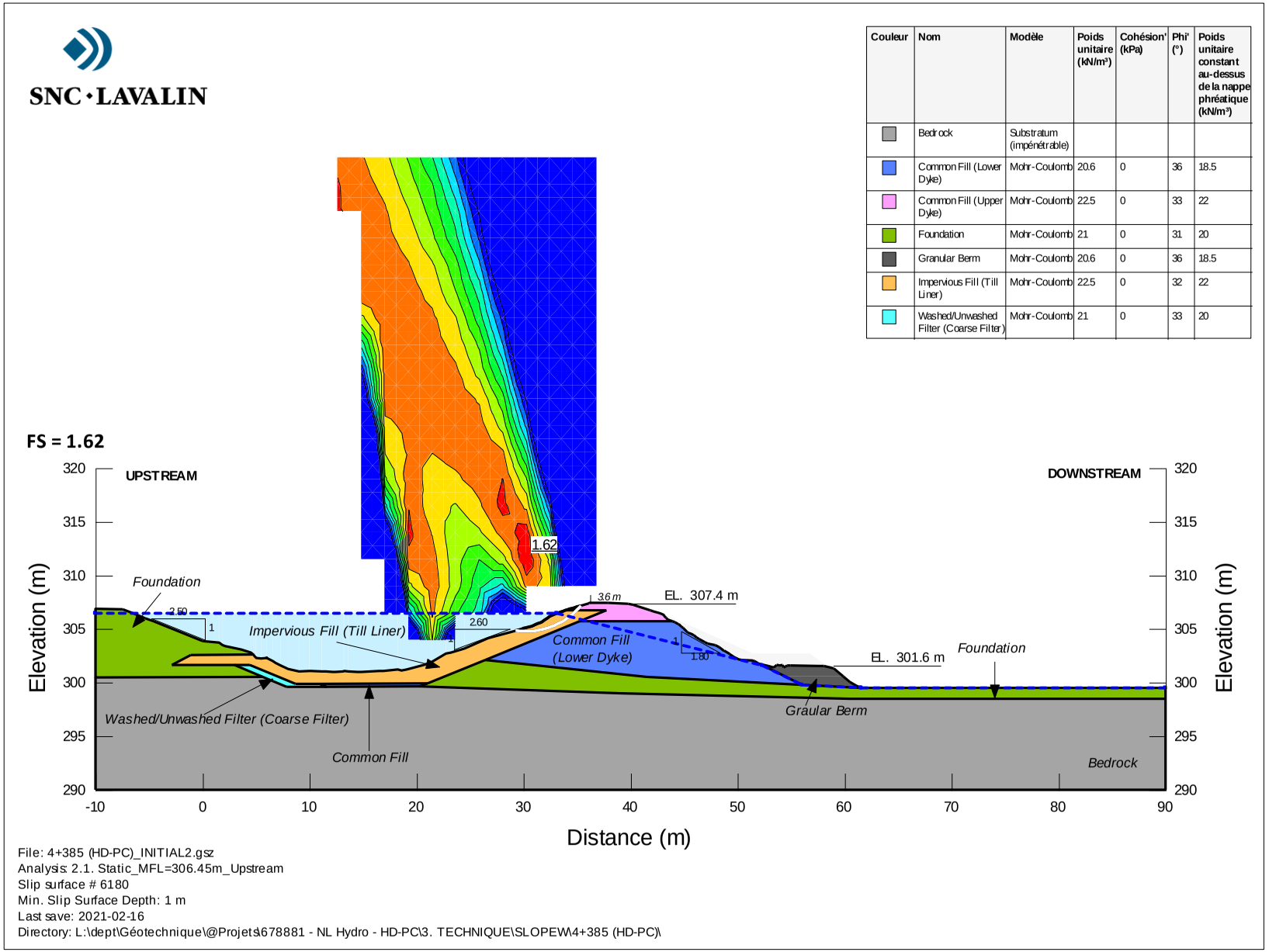


Figure A-11: HD-PC (4+385) – Existing Conditions - Static Loading and Maximum Flood Level (MFL = 306.45 m) – Upstream Slope

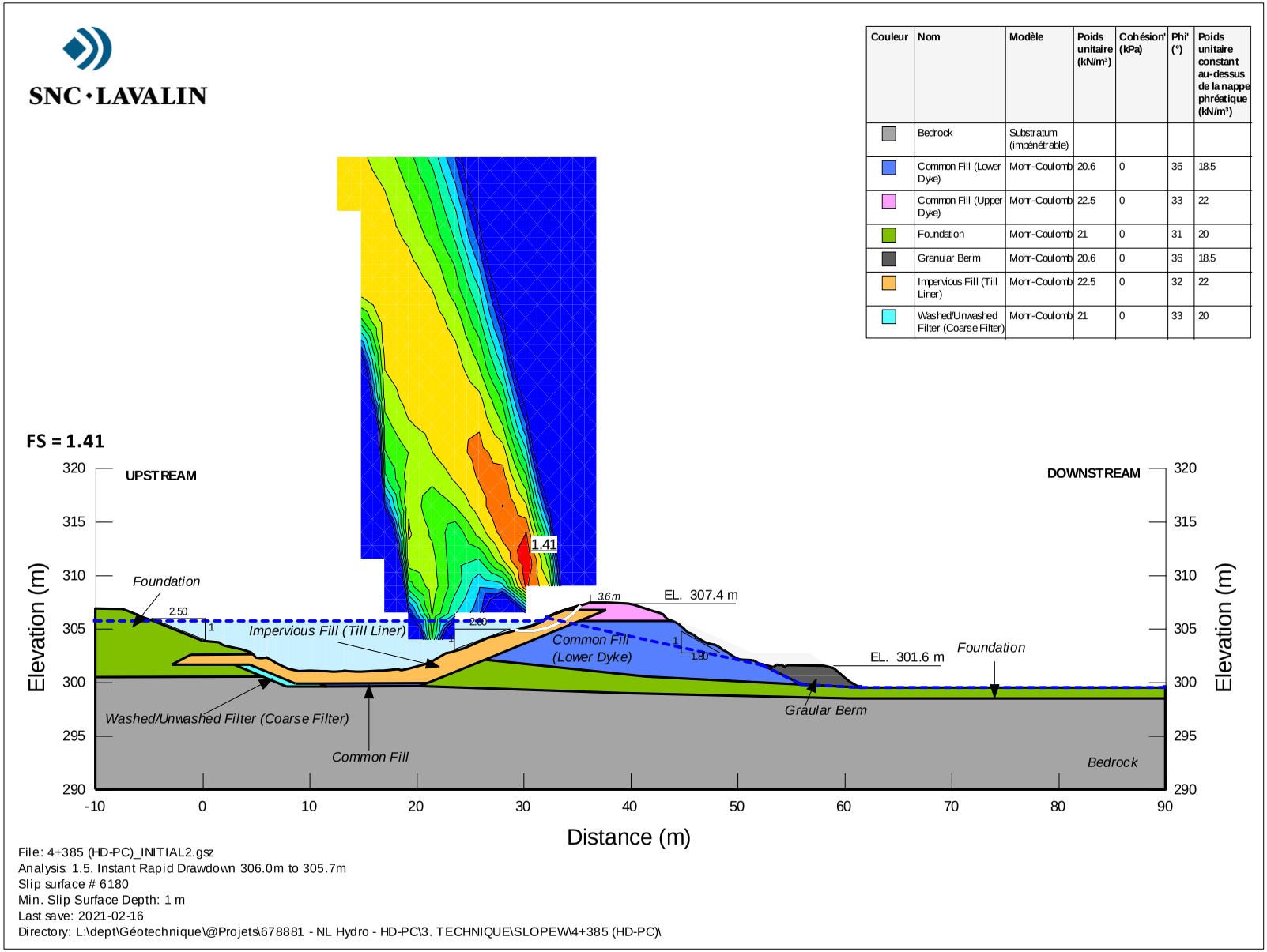


Figure A-12: HD-PC (4+385) – Existing Conditions - Static Loading and Rapid Drawdown to Low Supply Level (LSL = 305.70 m) – Upstream Slope

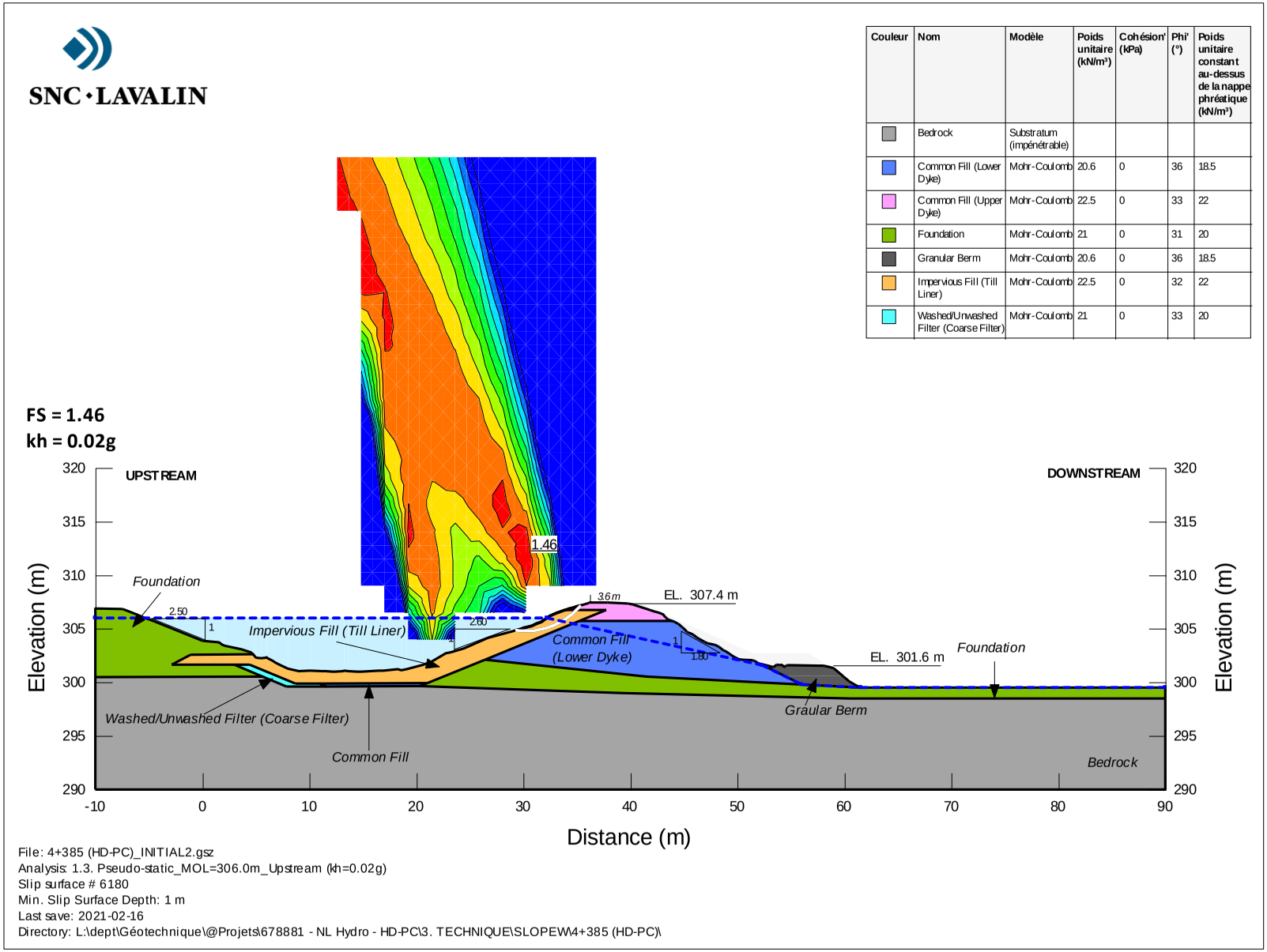


Figure A-13: HD-PC (4+385) – Existing Conditions – Pseudo-static Loading (k_h=0.02 g) and Maximum Operating Level (MOL = 306.00 m) – Upstream Slope

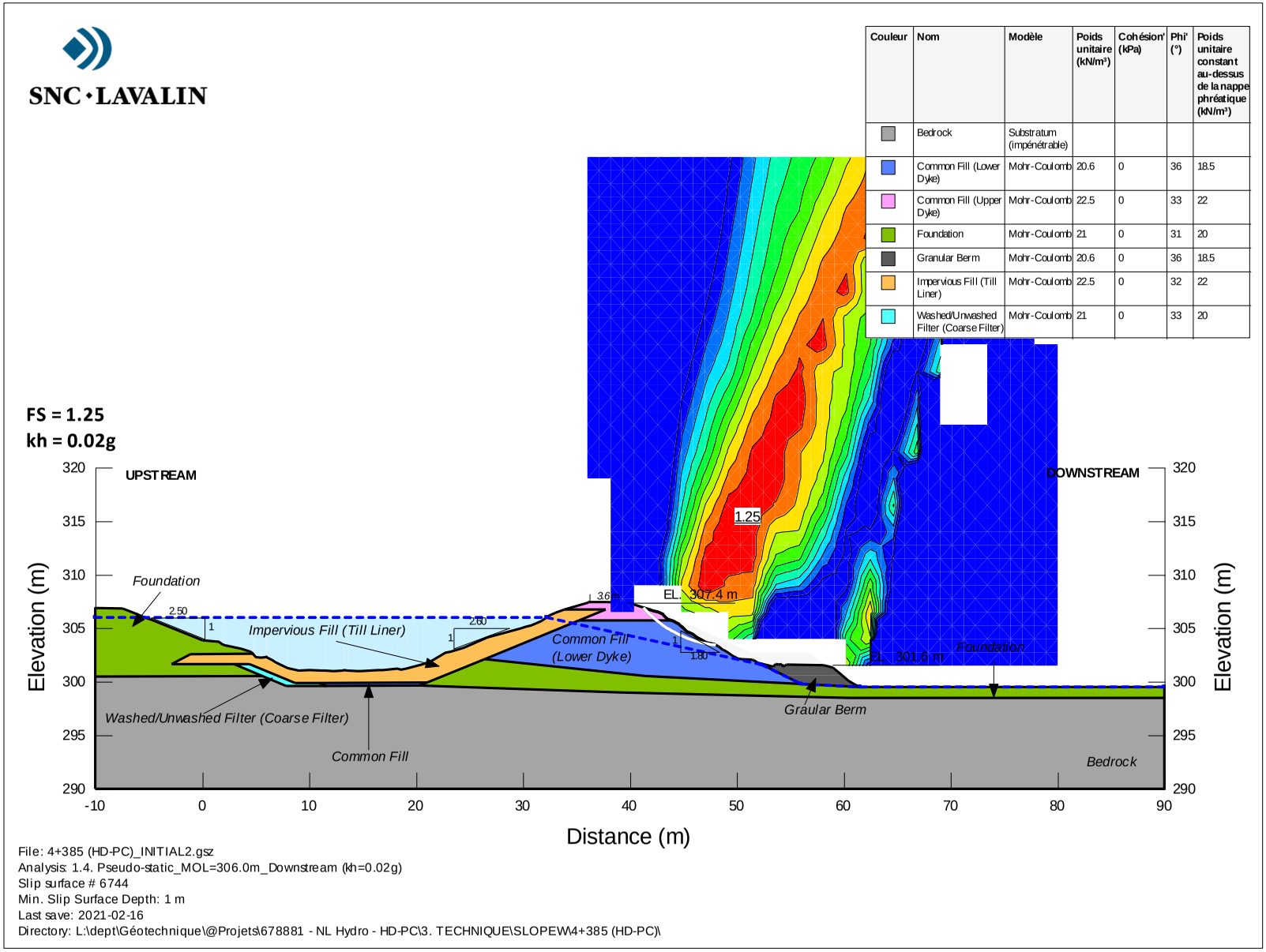


Figure A-14: HD-PC (4+385) – Existing Conditions – Pseudo-static Loading (k_h=0.02 g) and Maximum Operating Level (MOL = 306.00 m) – Downstream Slope

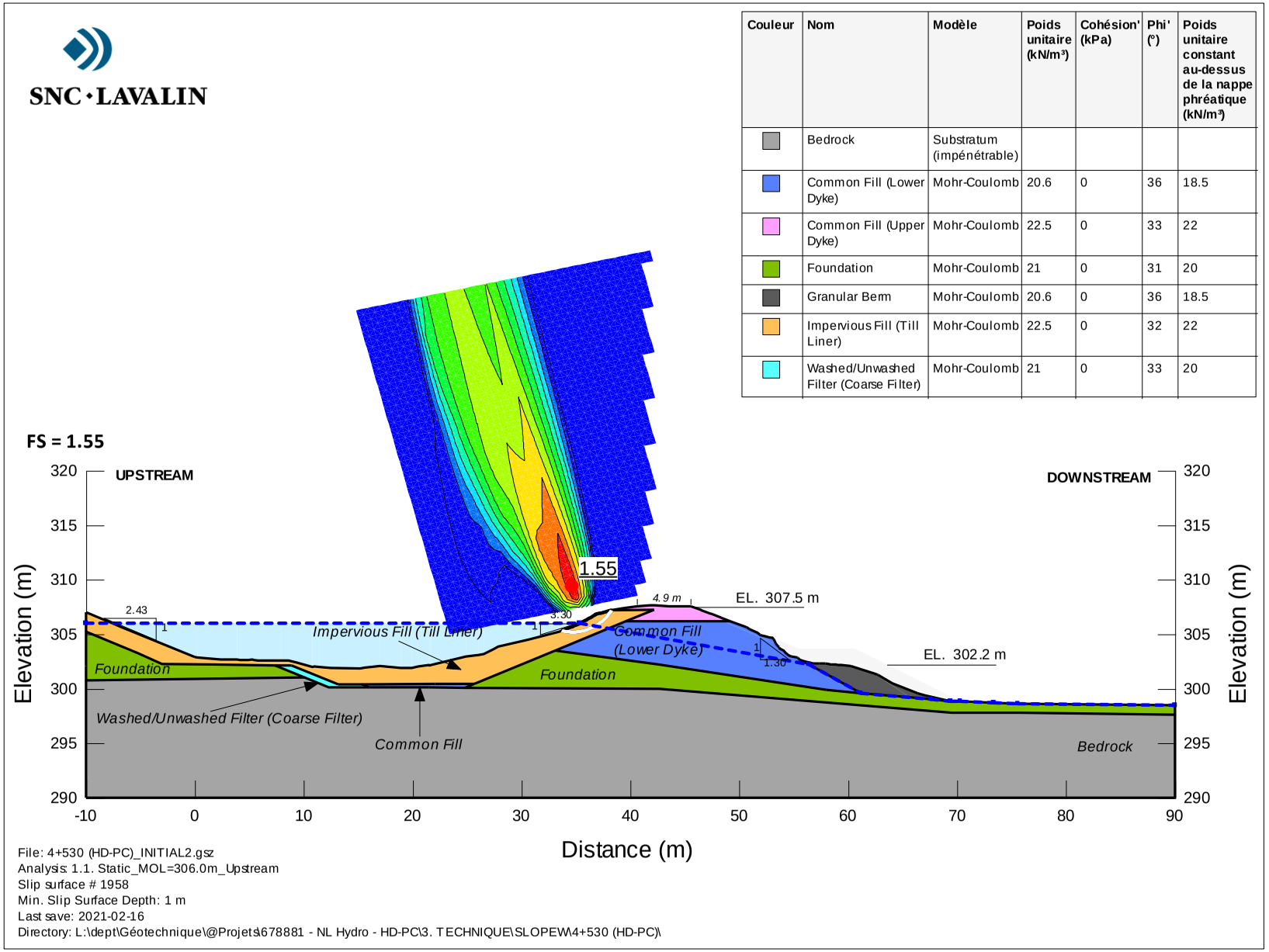


Figure A-15: HD-PC (4+530) – Existing Conditions - Static Loading and Maximum Operating Level (MOL = 306.00 m) – Upstream Slope

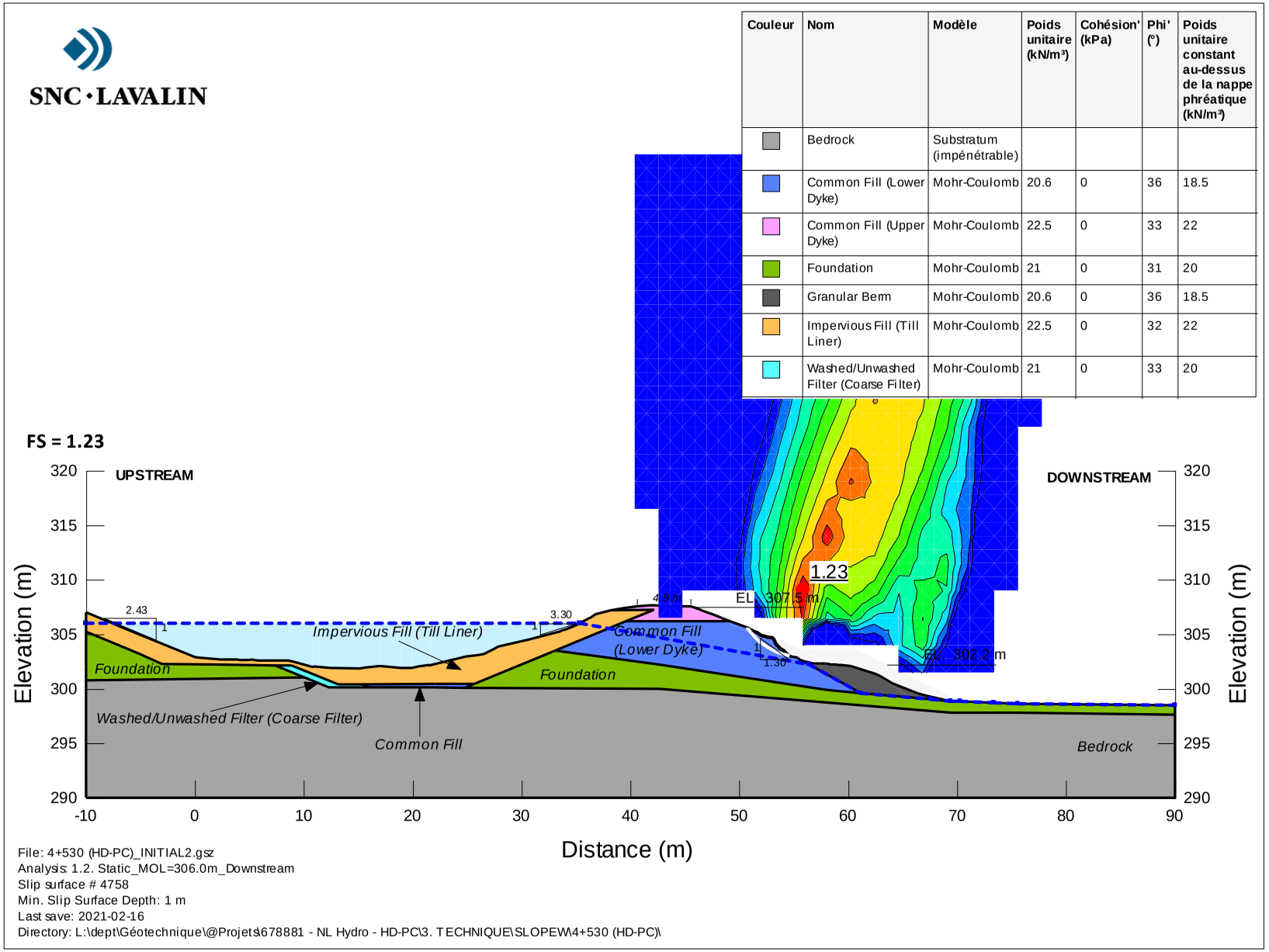


Figure A-16: HD-PC (4+530) – Existing Conditions - Static Loading and Maximum Operating Level (MOL = 306.00 m) – Downstream Slope

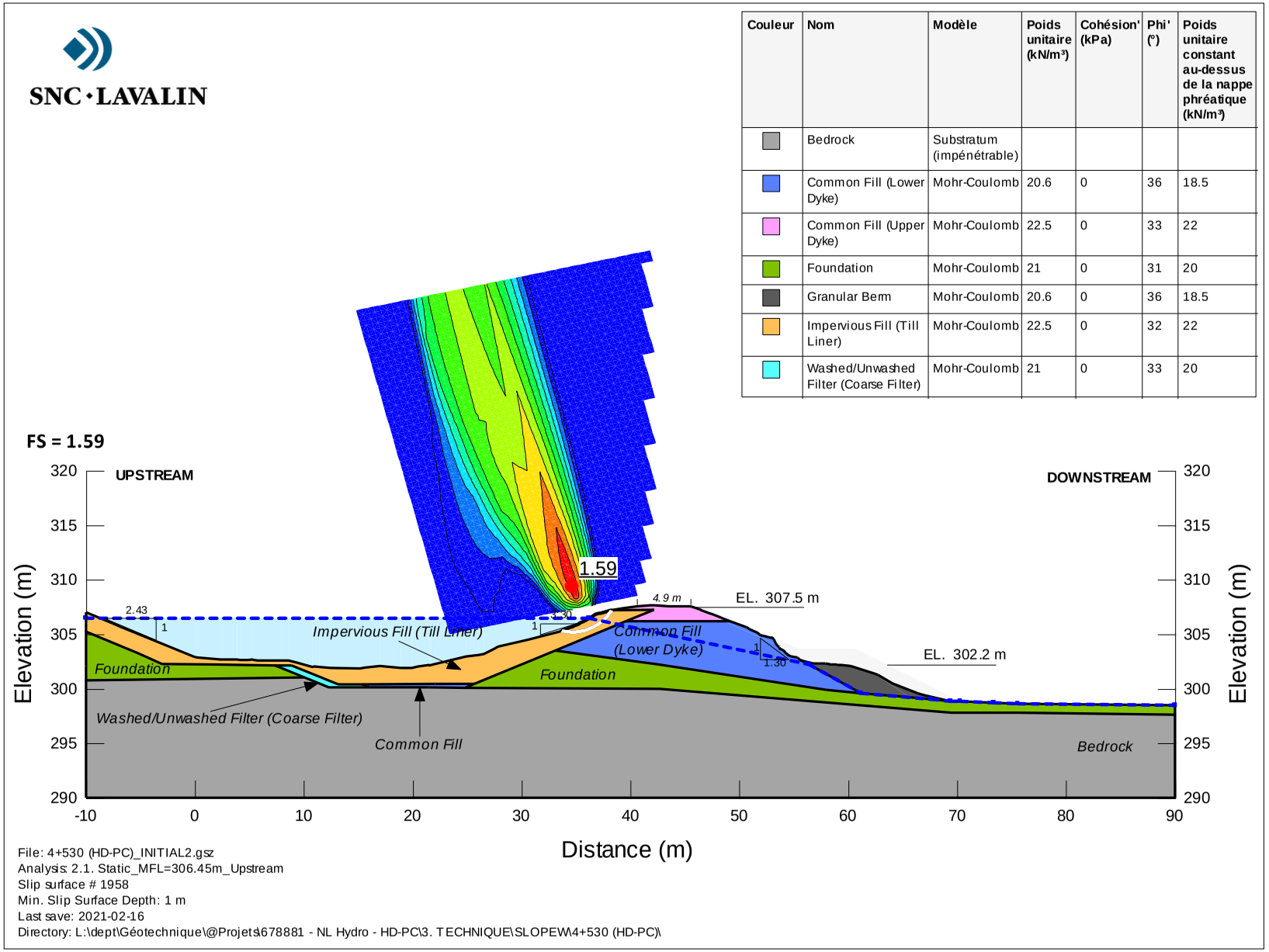


Figure A-17: HD-PC (4+530) – Existing Conditions - Static Loading and Maximum Flood Level (MFL = 306.45 m) – Upstream Slope

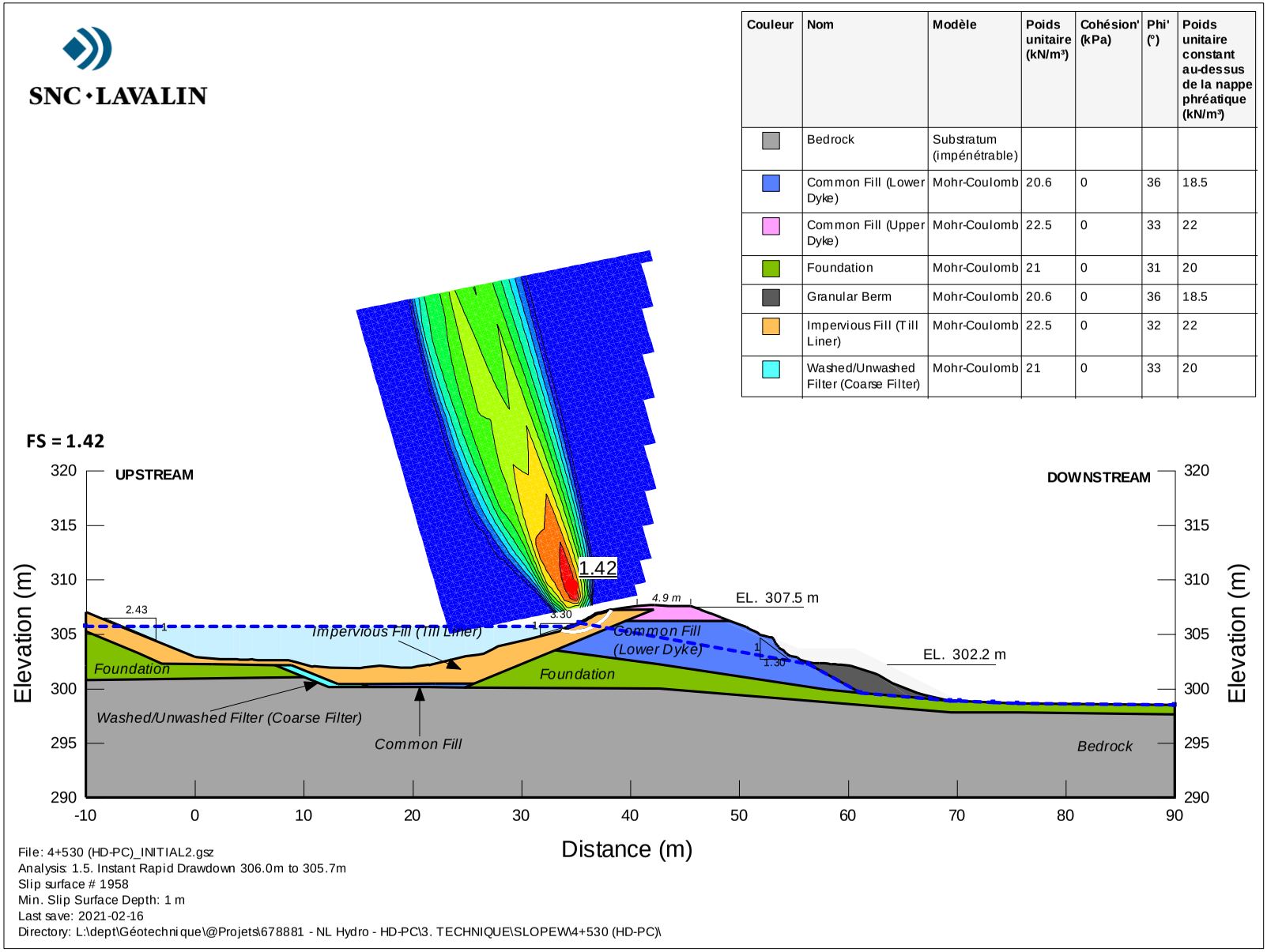


Figure A-18: HD-PC (4+530) – Existing Conditions - Static Loading and Rapid Drawdown to Low Supply Level (LSL = 305.70 m) – Upstream Slope

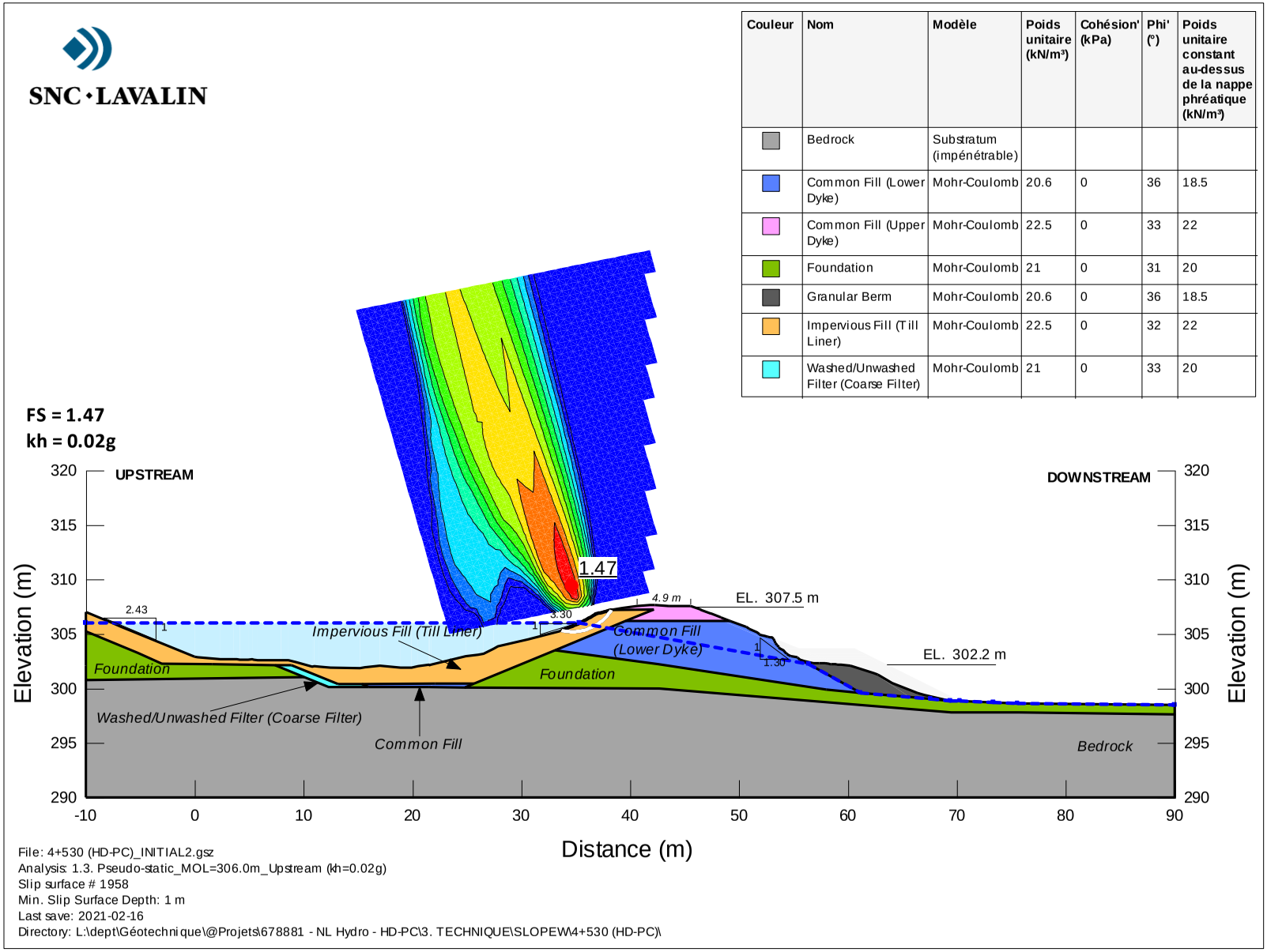


Figure A-19: HD-PC (4+530) – Existing Conditions – Pseudo-static Loading (k_h=0.02 g) and Maximum Operating Level (MOL = 306.00 m) – Upstream Slope

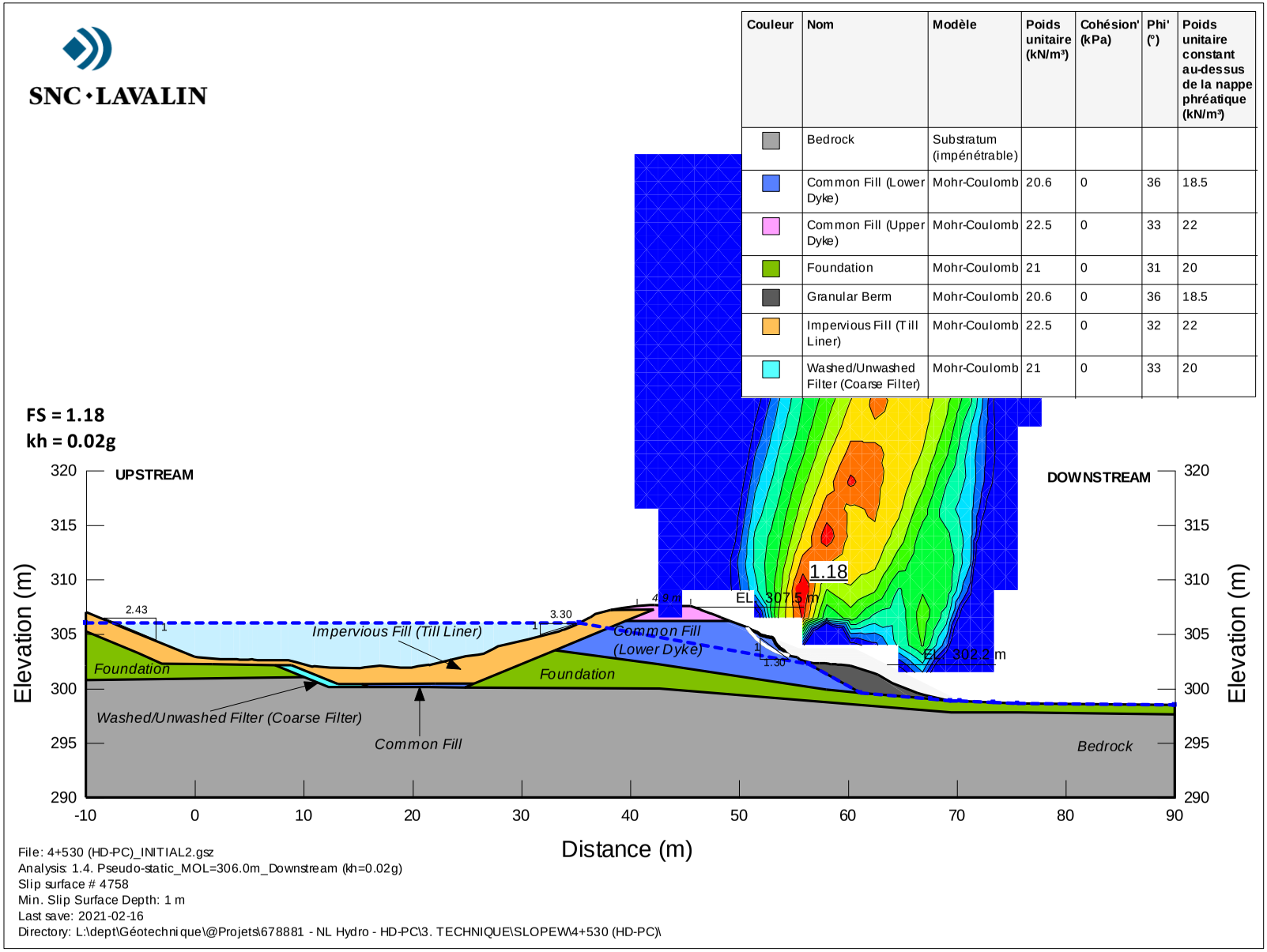
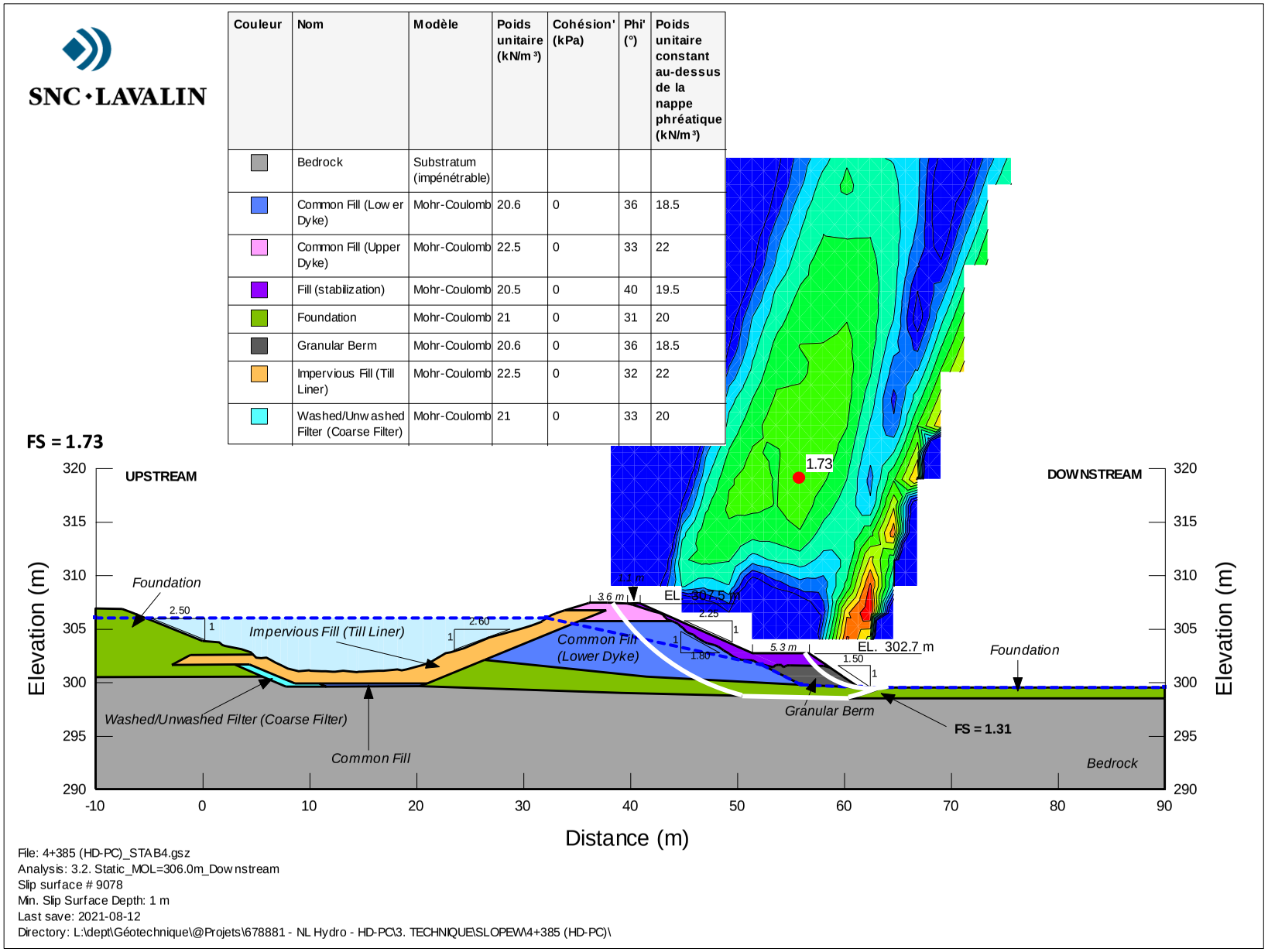


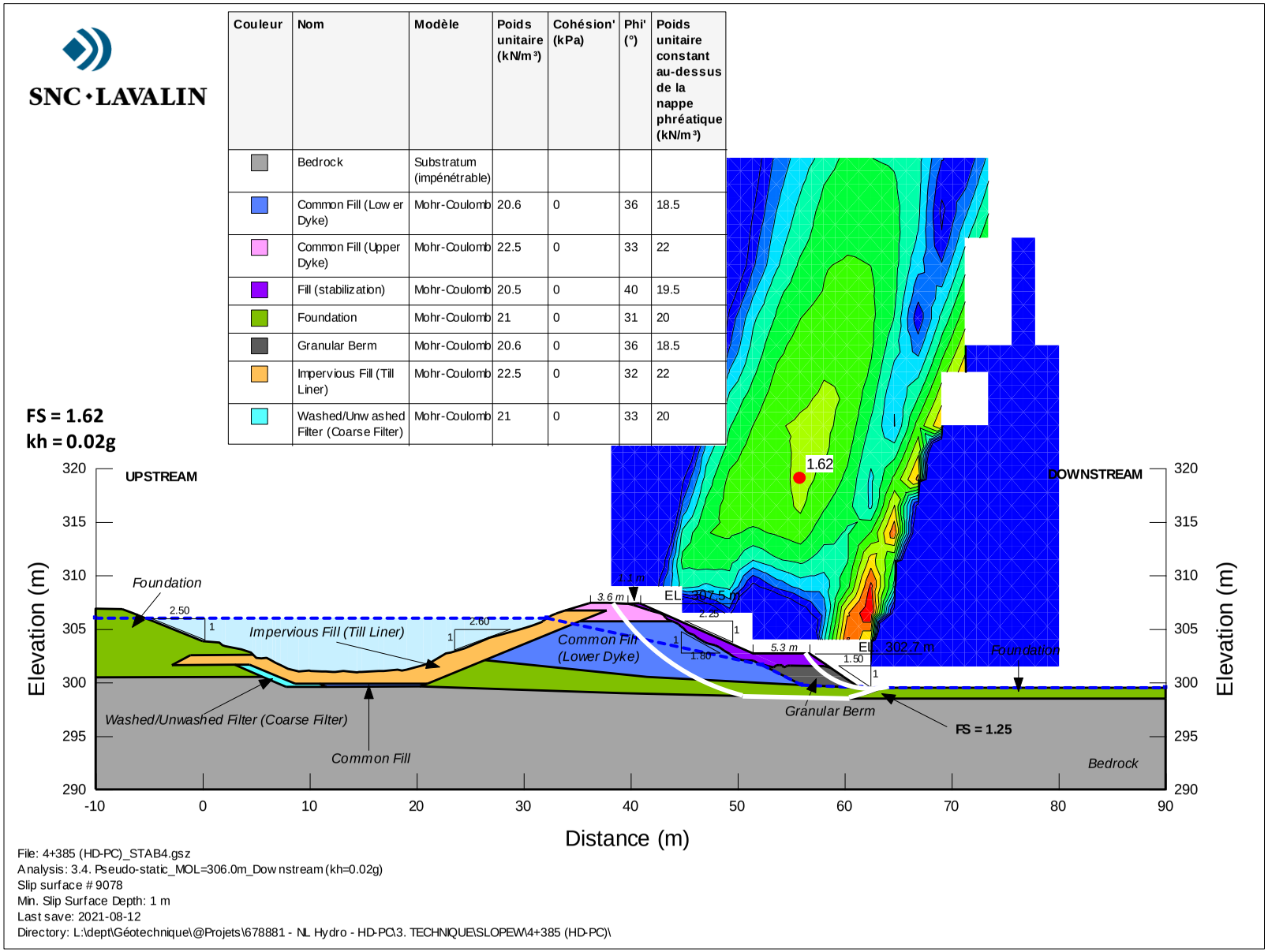
Figure A-20: HD-PC (4+530) – Existing Conditions – Pseudo-static Loading (k_h=0.02 g) and Maximum Operating Level (MOL = 306.00 m) – Downstream Slope

Appendix B : Slope Stability Analysis for the Selected Stabilization Option



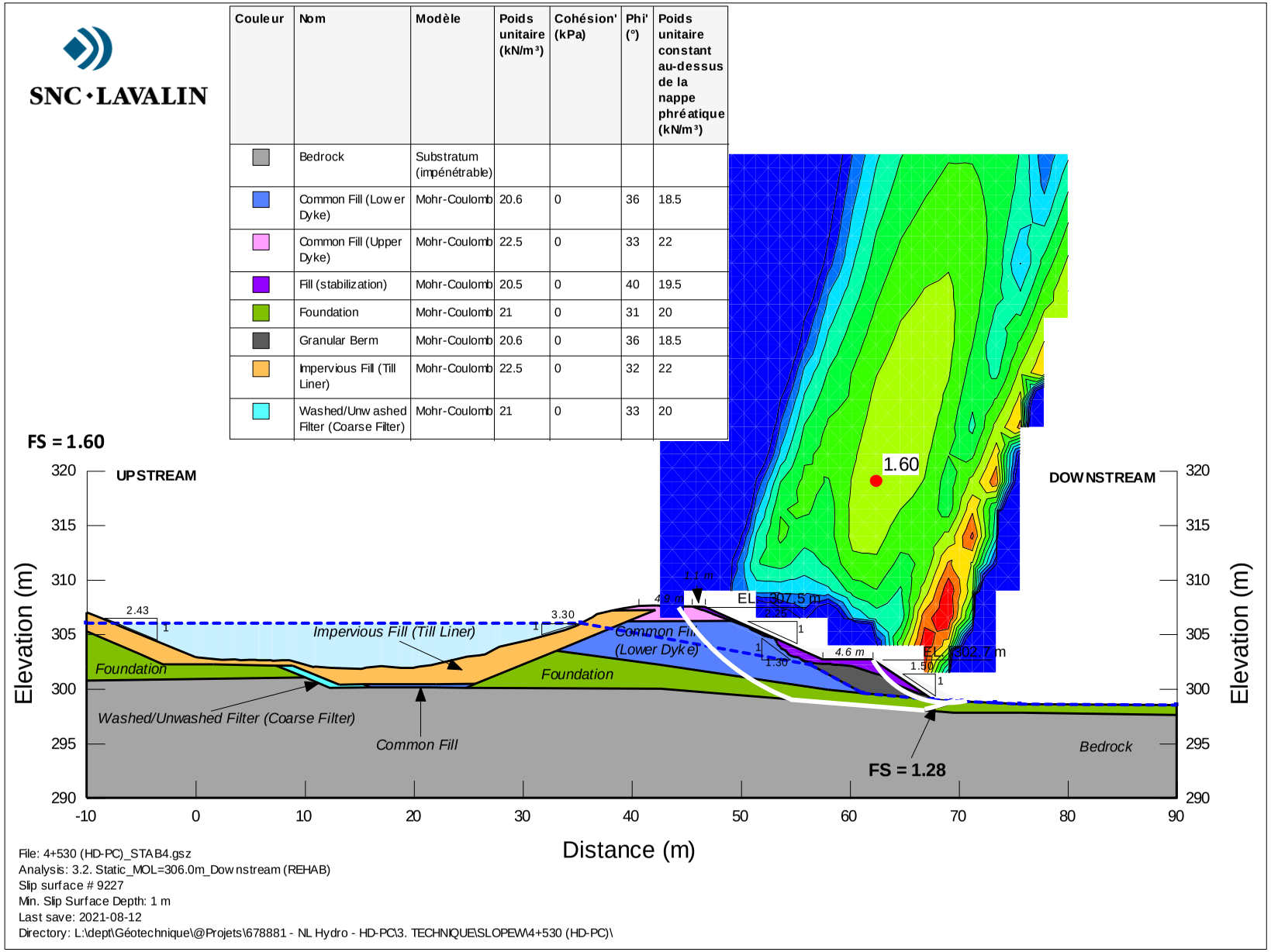
Couleur	Nom	Modèle	Poids unitaire (kN/m³)	Cohésion' (kPa)	Phi' (°)	Poids unitaire constant au-dessus de la nappe phréatique (kN/m³)
	Bedrock	Substratum (impénétrable)				
	Common Fill (Lower Dyke)	Mohr-Coulomb	20.6	0	36	18.5
	Common Fill (Upper Dyke)	Mohr-Coulomb	22.5	0	33	22
	Fill (stabilization)	Mohr-Coulomb	20.5	0	40	19.5
	Foundation	Mohr-Coulomb	21	0	31	20
	Granular Berm	Mohr-Coulomb	20.6	0	36	18.5
	Impervious Fill (Till Liner)	Mohr-Coulomb	22.5	0	32	22
	Washed/Unwashed Filter (Coarse Filter)	Mohr-Coulomb	21	0	33	20

Figure B-1: HD-PC (4+385) – Stabilized Alternative- Static Loading and Maximum Operating Level (MOL = 306.00 m) – Downstream Slope



Couleur	Nom	Modèle	Poids unitaire (kN/m³)	Cohésion' (kPa)	Phi' (°)	Poids unitaire constant au-dessus de la nappe phréatique (kN/m³)
	Bedrock	Substratum (impénétrable)				
	Common Fill (Low er Dyke)	Mohr-Coulomb	20.6	0	36	18.5
	Common Fill (Upper Dyke)	Mohr-Coulomb	22.5	0	33	22
	Fill (stabilization)	Mohr-Coulomb	20.5	0	40	19.5
	Foundation	Mohr-Coulomb	21	0	31	20
	Granular Berm	Mohr-Coulomb	20.6	0	36	18.5
	Impervious Fill (Till Liner)	Mohr-Coulomb	22.5	0	32	22
	Washed/Unw ashed Filter (Coarse Filter)	Mohr-Coulomb	21	0	33	20

Figure B-2: HD-PC (4+385) – Stabilized Alternative – Pseudo-static Loading (k_h=0.02 g) and Maximum Operating Level (MOL = 306.00 m) – Downstream Slope



Couleur	Nom	Modèle	Poids unitaire (kN/m³)	Cohésion' (kPa)	Phi' (°)	Poids unitaire constant au-dessus de la nappe phréatique (kN/m³)
	Bedrock	Substratum (impénétrable)				
	Common Fill (Lower Dyke)	Mohr-Coulomb	20.6	0	36	18.5
	Common Fill (Upper Dyke)	Mohr-Coulomb	22.5	0	33	22
	Fill (stabilization)	Mohr-Coulomb	20.5	0	40	19.5
	Foundation	Mohr-Coulomb	21	0	31	20
	Granular Berm	Mohr-Coulomb	20.6	0	36	18.5
	Impervious Fill (Till Liner)	Mohr-Coulomb	22.5	0	32	22
	Washed/Unwashed Filter (Coarse Filter)	Mohr-Coulomb	21	0	33	20

Figure B-3: HD-PC (4+530) – Stabilized Alternative- Static Loading and Maximum Operating Level (MOL = 306.00 m) – Downstream Slope

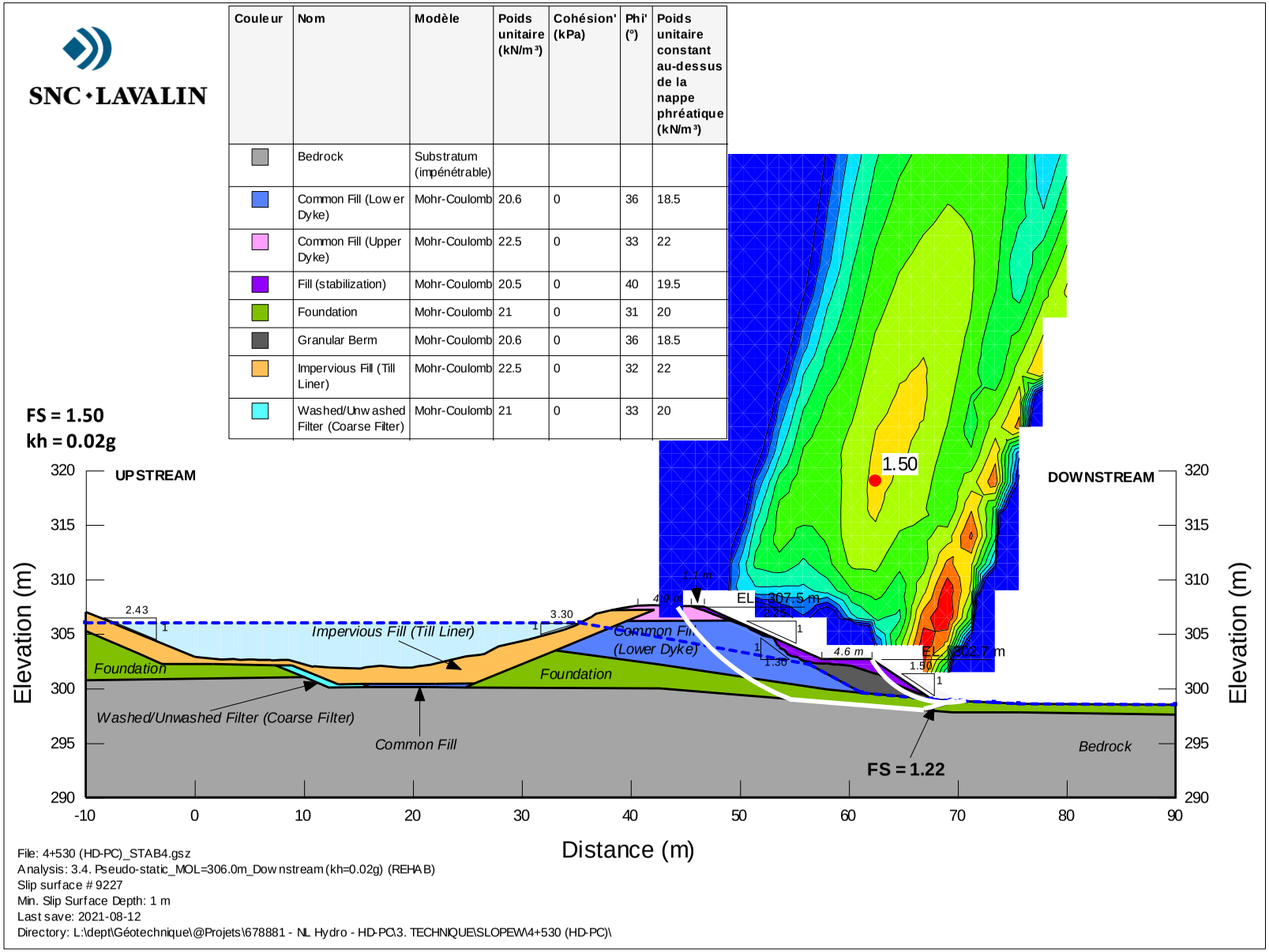


Figure B-4: HD-PC (4+530) – Stabilized Alternative – Pseudo-static Loading (k_h=0.02 g) and Maximum Operating Level (MOL = 306.00 m) – Downstream Slope

Project 4

Refurbish Surge Tank 1 (2024–2025)

Bay d’Espoir

July 2023

newfoundland labrador hydro

Refurbish Surge Tank 1 (2024–2025)

Location: Bay d'Espoir

Investment Classification: Renewal

Asset Category: Hydraulic Plant

Executive Summary

The Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir Facility") is home to seven generating units that are housed in two generation plants—Powerhouse 1 and Powerhouse 2. The development produces an average of 2,650 GWh annually, making it the largest hydroelectric development on the Island.

The Bay d'Espoir Facility, from which service began in 1967, relies on penstocks to supply water to each of the generating units. In total, four penstocks supply water to seven units, with Powerhouse 1 consisting of six hydro units fed by three penstocks. Each penstock has a surge tank installed on the line to protect the system against incidences of sudden increased pressure. In the event of a pressure spike, the water in the surge tank rises quickly to release the pressure in the penstock and, subsequently, mitigate the risk of damage to the penstock and intake structure.

Newfoundland and Labrador Hydro ("Hydro") obtained approval to complete Surge Tank 1 refurbishment as part of its "2018 Capital Budget Application,"[1] as a result of a 2015 condition assessment completed by Hatch Ltd. ("Hatch"),[2] which noted several deficiencies and suggested refurbishments for the tank ("2015 Condition Assessment"). Hydro was unable to execute the entire scope of the project due to the prioritization of other critical work on the system, as well as the impacts of the COVID-19 pandemic. Refurbishment of the tank's exterior components was completed in accordance with the report recommendations; however, to maximize resources and outage availability, all interior refurbishment work was deferred to coincide with the extended outage required for the

[1] "2018 Capital Budget Application," Newfoundland and Labrador Hydro, rev. October 3, 2017 (originally filed July 27, 2017), vol. II, tab 1, approved as per *Public Utilities Act*, RSNL, 1990, c P-47, Board Order No. P.U. 5(2018), Board of Commissioners of Public Utilities, February 23, 2018.

[2] "BDE Surge Tank #1 Condition Assessment," Hatch Ltd., rev. January 29, 2016, is included as Attachment 1 of this proposal.

execution of the Bay d'Espoir Penstock 1 section replacement and weld refurbishment ("Bay d'Espoir Penstock 1 Life Extension") project[3] in 2025. Hydro considered the following alternatives for this project:

- Deferral;
- Upgrade life extension; and
- Like-for-like replacement.

Upgrade life extension was determined to be the only viable option to satisfy Hydro's long-term operational needs. As a result, Hydro is proposing the completion of the outstanding interior refurbishment work for Surge Tank 1. The completion of this work will restore the integrity of the surge tank, extend its service life, and ensure its continued, reliable operation for the next 20 years.

This project has a multi-year approach, with completion planned in 2025 at an estimated project cost of $2,287,200.

[3] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 6(2023), Board of Commissioners of Public Utilities, April 12, 2023.

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List of Attachments

Attachment 1: "BDE Surge Tank #1 Condition Assessment," Hatch Ltd., rev. January 29, 2016.

Attachment 2: "Cancellation of Previously-Approved Capital Projects at Bay d'Espoir," Newfoundland and Labrador Hydro, February 26, 2021

1.0 Introduction

The Bay d'Espoir Facility is located on the south coast of the Island, approximately 15 kilometres from the community of St Alban's.

The Bay d'Espoir Facility was constructed in two stages, the first of which concluded in 1967 and included the construction of Surge Tanks 1 and 2.[4] The three surge tanks are located approximately 645 metres downstream of the penstock intakes, as shown in Figure 1 and Figure 2.

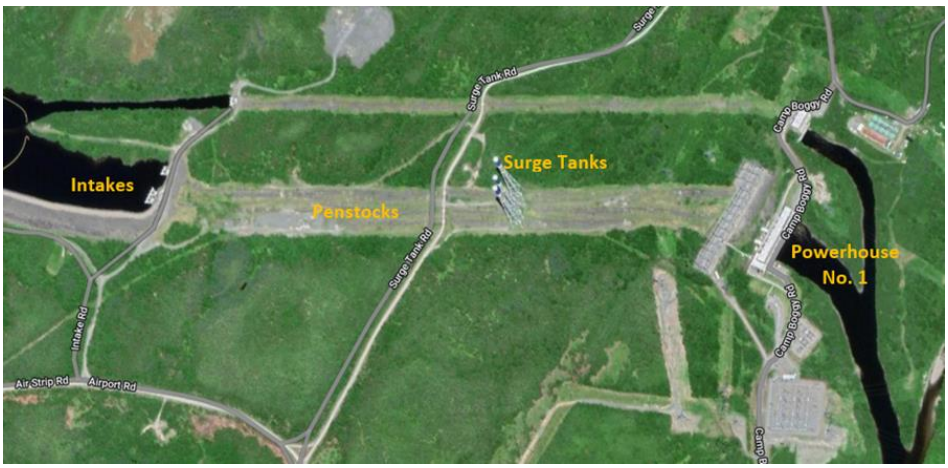


Figure 1: General Layout of the Bay d'Espoir Facility



Figure 2: Bay d'Espoir Surge Tanks

[4] Surge Tank 3 was constructed in 1970 as part of Stage II.

The surge tanks are an integral part of the Bay d'Espoir Facility's hydraulic system, serving to protect the penstocks from sudden increases in water pressure. In support of the Surge Tank 1 refurbishment project, in its 2015 Condition Assessment, Hatch recommended the refurbishment of the surge tank and noted several deficiencies including:

- Deterioration of the surge tank coating system;
- Corrosion of the tank shell; and
- Localized corrosion of various structural components such as legs, bracing, and compression rings.

Hydro originally obtained approval of the recommended refurbishments as part of its "2018 Capital Budget Application;" however, due to the prioritization of other critical work on the system and the impacts of the COVID-19 pandemic, Hydro was unable to execute the entire project scope. The refurbishment of the tank's exterior components was completed in accordance with the 2015 Condition Assessment recommendations; however, all interior refurbishment work was deferred, as detailed in Attachment 2.[5] Hydro has since determined that it was most efficient to complete this work during the extended outage required for the Bay d'Espoir Penstock 1 Life Extension project.

2.0 Project Description and Justification

Surge Tank 1 was constructed in 1967 and the coating system on the interior tank surface was refurbished in 1985. At 38 years old, the interior coating system has reached the end of its service life and no longer provides its intended level of protection. This has resulted in the corrosion of the interior surface of plate steel and associated welds.

Failure of the coating system leaves the steel vulnerable to corrosion and deterioration. If refurbishments are deferred, continued corrosion on the steel surface and welds will ultimately lead to the formation of leaks and/or jeopardize the structural integrity of the surge tank. In the event of a weld failure, the surge tank would require significant and immediate repairs, resulting in an extended outage

[5] "Cancellation of Previously-Approved Capital Projects at Bay d'Espoir," Newfoundland and Labrador Hydro, February 26, 2021.

to two units.[6] Such a decrease in generation capacity could impact Hydro's ability to satisfy customer demand, and adversely impact the reliability of the Island Interconnected System.

This project involves the refurbishment of the surge tank interior, which is required to restore the integrity of the steel tank shell and protect it against corrosion. The proposed refurbishment will extend the service life of the surge tank and ensure that its integrity is maintained for the next 20 years.

3.0 Asset Overview

3.1 Asset Background

Bay d'Espoir Powerhouse 1 contains six hydro units fed by three penstocks, with each penstock controlling the flow of water to two units.[7] Each penstock has a surge tank installed approximately 645 meters downstream of the intake to protect the system against sudden spikes in water pressure, such as water hammer, which can result from generator load rejection. During a sudden increase in water pressure within the penstock, the water in the surge tank rises quickly to release the pressure and prevent water hammer damage to the penstock and intake structure. As a result of this function, the interior surface of the surge tank is subject to changing wet and dry conditions producing an environment ideal for corrosion.

Each surge tank rises approximately 112 metres above ground and is supported by braced legs, which are designed to resist hurricane-force winds and earthquakes. The diameter of each tank is 7.6 metres and is made up of approximately 1,300 tons of steel. The surge tanks and risers are insulated up to the static water level and are electrically heated in winter to prevent icing.

Surge Tank 1 was constructed in 1967 with its interior shell receiving an epoxy coating system in 1985. There have been no touch-ups or recoats since; at 38 years old, the coating system has reached the end of its service life.

3.2 Historical Reliability

Bay d'Espoir Surge Tank 1 has proven reliable during its service life, operating as per its original design criteria since installation. In its 2015 Condition Assessment, Hatch noted the current coating system has

[6] Surge Tank 1 provides protection to Penstock 1. A failure of this surge tank would result in an outage to Bay d'Espoir Units 1 and 2, which have a combined generation capacity of 153 MW.
[7] Penstock 1 transports water to Bay d'Espoir Units 1 and 2, Penstock 2 to Units 3 and 4, and Penstock 3 to Units 5 and 6.

deteriorated and the steel shell is showing signs of degradation. Refurbishment is recommended to extend the service life of the tank to ensure its continued reliable operation.

3.3 Asset Condition

The 2015 Condition Assessment identified several issues with Surge Tank 1 and its refurbishment was recommended. The assessment identified deterioration of the exterior and interior surge tank coating system, corrosion of the interior surge tank shell, and localized corrosion of various exterior structural components. The exterior refurbishments were completed in 2018; however, the interior work was deferred. Photos of the interior tank shell corrosion are provided as Figure 3 and Figure 4.



Figure 3: Corrosion of the Tank Shell Interior, Surge Tank 1



Figure 4: Coating Failure on Interior Tank Welds, Surge Tank 1

4.0 Analysis

4.1 Evaluation of Alternatives

Surge Tank 1 has not undergone any major upgrades since it was recoated in 1985. The 2015 Condition Assessment highlighted several deficiencies and its refurbishment was recommended. In consideration of this, the following alternatives were analyzed:

- Deferral;
- Upgrade life extension; and
- Like-for-like replacement.

4.1.1 Deferral

Bay d'Espoir Surge Tank 1 is an integral part of the Bay d'Espoir Facility's hydraulic system, serving to protect the penstocks and upstream structures from damage due to sudden spikes in water pressure. The noted failure of the interior coating system leaves the steel vulnerable to corrosion and rapid deterioration, which could compromise the structural integrity of the tank shell. To maximize resources and outage availability, all interior refurbishment work was deferred to coincide with the extended outage required for the Bay d'Espoir Penstock 1 Life Extension project in 2025; however, this work cannot be delayed any further. The failure of Surge Tank 1 would result in an extended outage to Bay d'Espoir Units 1 and 2, creating an unacceptable risk to system reliability.

For this reason, deferral of the proposed refurbishment work is not considered a viable alternative.

4.1.2 Upgrade Life Extension

Completion of the recommended refurbishments to the surge tank interior will increase the service life of the asset and ensure that it is maintained in reliable operating condition for the next 20 years.

4.1.3 Like-for-Like Replacement

Full-scale replacement of Surge Tank 1 is not necessary, as the completion of the proposed interior refurbishment will extend the service life of the tank and ensure its continued reliable operation. For this reason, like-for-like replacement of the existing surge tank is not a viable alternative.

4.2 Least-Cost Evaluation

As part of the "2018 Capital Budget Application," Hydro completed a cost-benefit analysis to evaluate coating restoration alternatives. These alternatives included the completion of a full coating system restoration or the completion of spot repairs to address isolated sections of the existing coating system.

The analysis determined that the completion of a full coating system restoration was the least-cost alternative. As further degradation of the coating system over the past five years is likely to have occurred, it is assumed that the alternative to complete a full refurbishment of the coating system has continued to increase in favour since the analysis.

4.3 Recommended Alternative

The surge tanks are an integral part of the Bay d'Espoir Facility's hydraulic system, as they protect the penstocks from sudden spikes in water pressure. The existing interior coating system of Surge Tank 1, applied to protect the steel tank shell against corrosion, has not undergone any major refurbishment since its original application in 1985.

The failure of the coating system, noted in a 2015 condition assessment, leaves the steel shell vulnerable to corrosion and exponential deterioration. Failure to complete the recommended refurbishment and reinstatement of the protective coating system will result in the continued corrosion of the steel shell, which could ultimately compromise the structural integrity of the tank. Given its age and condition, a complete refurbishment of the interior coating system is recommended.

4.3.1 Risk of Asset Stranding

The Bay d'Espoir Facility produces an average of 2,650 GWh annually, making it the largest hydroelectric development on the Island. As the primary source of hydroelectricity for the Island Interconnected System, there are no plans to retire the generating assets at the Bay d'Espoir Facility; therefore, Hydro considers the risk of asset stranding to be negligible.

It is anticipated that the proposed refurbishments will increase the service life of the asset and ensure that it is maintained in reliable operating condition for the next 20 years.

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	5	3	**15**
Post-Execution	5	2	**10**
		Risk Mitigated	**5**
		Risk Mitigated per $1 Million	**2.2**

5.0 Scope of Work

This project involves the completion of refurbishments to the interior of Bay d'Espoir Surge Tank 1, which is required to restore the integrity of the surge tank, extend its service life, and ensure its reliable operation for the next 20 years.

The scope of work includes the refurbishment and reinstatement of the protective coating system within Surge Tank 1.

5.1 Project Budget

The estimate for the 2024–2025 project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	**2024**	**2025**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	**0.0**
Labour	40.3	45.4	0.0	**85.7**
Consultant	112.5	193.9	0.0	**306.4**
Contract Work	0.0	1,530.0	0.0	**1,530.0**
Other Direct Costs	3.2	3.2	0.0	**6.4**
Interest and Escalation	9.6	167.1	0.0	**176.7**
Contingency	10.2	171.8	0.0	**182.0**
Total	**175.8**	**2,111.4**	**0.0**	**2,287.2**

5.2 Project Schedule

The schedule for the 2024–2025 project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Budget review, scope statement, schedule, and risk assessment.	January 2024	March 2024
Design:		
Detailed design and tender package preparation.	May 2024	December 2024
Procurement:		
Procurement of rolled steel plate reinforcing material.	February 2025	May 2025
Construction:		
Complete interior refurbishments.	July 2025	August 2025
Closeout:		
Project completion, interest cut-off, and lessons learned.	November 2025	December 2025

6.0 Conclusion

The Bay d'Espoir Facility is the largest hydroelectric facility on the Island, with Powerhouse 1 consisting of six hydro units fed by three penstocks. Each penstock has a surge tank installed on the line to protect the system against incidences of sudden increased pressure, which is critical to the operation of the facility.

The failure of the interior protective coating system of Surge Tank 1 has resulted in widespread corrosion inside the tank. The interior coating system must be reinstated to mitigate the risks associated with the continued progression of corrosion. If left unaddressed, continued corrosion will result in further deterioration of the surge tank interior, which could result in the formation of leaks and jeopardize the structural integrity of the asset. Any requirement to complete unplanned corrective maintenance to address issues with the surge tank interior will result in an extended outage to Bay d'Espoir Units 1 and 2, significantly reducing available generation capacity and potentially impacting the reliability of the Island Interconnected System.

The proposed refurbishment is required to restore the integrity of the surge tank, extend its service life, and ensure its reliable operation for the next 20 years.

Attachment 1

Surge Tank #1 Condition Assessment Final Report – Bay d'Espoir Hydroelectric Generating Facility

Hatch Ltd.

Revision 1: January 29, 2016



HATCH

Newfoundland and Labrador Hydro

Final Report

For

BDE Surge Tank #1 Condition Assessment

H349210-00000-200-230-0001
Rev. 1
January 29, 2016

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Newfoundland and Labrador Hydro

Final Report

For

BDE Surge Tank #1 Condition Assessment

H349210-00000-200-230-0001
Rev. 1
January 29, 2016

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Newfoundland and Labrador Hydro
BDE Surge Tank #1 Condition Assessment
H349210

Final Report

BDE Surge Tank #1 Condition Assessment

H349210-00000-200-230-0001

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Newfoundland and Labrador Hydro
BDE Surge Tank #1 Condition Assessment
H349210

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Appendix A Tank UT Results and Comparison

A.1 Tank Shell UT Map
A.2 Tank UT Results
A.3 Leg UT Results

Appendix B Tacten Report

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1. Introduction

In April 2015, Hatch was engaged by Newfoundland and Labrador Hydro (NL Hydro) to perform a condition assessment of Surge Tank #1 at the Bay D'Espoir (BDE) hydroelectric generating station. The BDE hydroelectric generating station main powerhouse consists of six generating units fed from three penstocks. Each penstock has a surge tank, numbered #1, 2 and 3. Surge Tank #1 is connected to generating Units #1 and #2.

The purpose of the condition assessment was to inspect all critical areas of the surge tank from a mechanical, electrical, and structural perspective, including the tank riser and tank wells and dished head, cathodic protection system, surface coatings, primary structural connection points, primary structural welds, expansion joint, stiffeners, thermal insulation, hot water heating system, tank roof, ladder and fall arrest, foundations and grounding system. Where necessary, UT was performed to accentuate visual inspection. The inspection consisted of an internal inspection and external inspection.

Hatch engaged Tacten to perform the inspection. See Appendix B for Tacten's inspection reports. Site inspections were performed during the week of May 4, 2015 to May 8, 2015 by James Callanan, Ben Daniels and Wolfgang Holtzmann of Tacten. Michael Pyne of Hatch was on site during the inspection. NL Hydro provided a confined space attendant during the inspection. The inspection was primarily visual with ultrasonic thickness (UT) readings taken at the tank top, tank legs, tank shell at the top balcony, and the bowl. Tacten's inspection report and the on-site photos were used to develop the final condition assessment report.

In addition to the site inspections, Hatch performed the following activities for the condition assessment:

- Review of existing drawings as provided by NL Hydro. The drawings were primarily used to determine component thickness and in developing a familiarity with the surge tank for the site visits.
- Review of previous inspection and condition assessment documents along with operation and maintenance manuals.

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2. External Inspection

2.1 Roof

The exterior of the tank top has partial coating breakdown as seen in Figure 2-1. It is recommended that the tank top be refurbished by high pressure water blast and re-coat. Further details are provided in Section 5.

UT readings were taken on the tank top. The reference drawings did not indicate the thickness of the roof top plate. The UT readings were consistent and suggest a 7.11 mm plate.

Although Tacten expressed no concern over the existing roof anchors, they appear to be welded to the tank top plate only and not to any structural sections. It is recommended that a detailed design check be performed on the existing roof anchors to determine adequacy. If the roof anchors are deemed suitable from the design check, it is recommended that all attachment welds undergo non destruction examination (NDE). The roof anchors should be taken out of service until this is completed.



Figure 2-1: Tank Roof/Ladder and Hatchway Showing Partial Coating Breakdown

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2.2 Shell

The visual inspection of the surge tank shell above the external insulation system indicated signs of coating breakdown and minor corrosion as shown in Figure 2-2. However, upon completing coating adhesion tests, it appears that the primer is the only coating system that exhibits proper adhesion, with poor bonding between the topcoat and primer. See the adhesion test results in Table 2-1. Any value below 250 psi would be considered as not adhered and should be removed. The readings show the red coating has better adhesion results than the white coating. This difference is potentially due to the red coating adding additional protection from the elements and UV (The red coating is applied over the white coating).



Figure 2-2: Tank Roof Shell Showing Intact Coating

Table 2-1: Shell Coating Adhesion Test Results

Coating System	Adhesion Result (PSI)
Red Coating	330
White Coating	200
Primer Coating	1420

The original drawings indicate the tank shell is made up of 14 courses of steel plate with varying nominal thicknesses. Courses 14 through 8 are made up of 9.5 mm thick plates. Five UT readings were performed at the top, middle and bottom of every accessible course. Readings were arranged by course number and compared to the drawing nominal thickness. The results show minor differences when compared with the reference drawings. Refer to Appendix A for a detailed overview of UT locations and values for the tank shell.

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This minor discrepancy in the UT readings and the reference drawings can be explained by any number of factors including, but not limited to:

1. Inaccurate UT readings

To ensure UT readings were as accurate as possible, readings were taken at various locations. Due to the sample size and consistency of the readings, it is unlikely that the inaccuracy of UT readings is a strong contributing factor.

2. Loss of material due to corrosion

There is no indication of corrosion (other than surface corrosion) on the outside of the surge tank shell. The coating system on the inside of the surge tank is also intact with little indication of corrosion.

Courses 7 through 2 would require drilling of inspection ports or removal of insulation panels to obtain UT readings from the exterior. Obtaining UT readings from the Interior could not been accomplished without additional rigging/rope access personnel and substantially more time. At the time of the inspection drilling inspection ports was ruled out and high winds did not allow for the removal of insulation panels. Therefore it is recommended that during the execution of future interior work, additional UT readings be taken for courses 7 through 2 to determine the actual shell plate thickness. If the actual shell plate thickness deviates from the reference drawings, a detailed structural analysis of the surge tank is recommended.

2.3 External Cladding

Overall, the external cladding was intact excluding connection points between the legs and course 2 as shown in Figures 2-3 and 2-4 and the bowl to riser connection as shown in Figure 2-6. This shows the silicone has failed and there could be possible water ingress in these locations.



Figure 2-3: General Condition of Leg Connection Points, Possible Water Ingress, Silicone Failing

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Figure 2-4: General Condition of Leg Connection Points, Possible Water Ingress, Silicone Failing



Figure 2-5: General Condition of Cladding on Lower Balcony

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Figure 2-6: Potential Water Ingress between Bowl and Riser Connection



Figure 2-7: Surge Tank Shell and Top of Riser External Insulation

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Figure 2-8: Riser and Structural Support

2.4 Balconies

2.4.1 Upper and Lower Balcony

The upper and lower balconies appear to be in good condition with some localized coating breakdown and corrosion. The walkway from the ladder to the lower balcony shown in Figure 2-9 does not have a gate or chain at the ladder access point, which is a safety issue that should be corrected.

It is recommended that both balconies, along with walkways and railings, be refurbished by high pressure water blast and re-coat. Further details are provided in Section 5.

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Figure 2-9: Lower Balcony Missing Barrier Door and Coating Breakdown



Figure 2-10: General Condition Lower Balcony Railing, Coating Breakdown

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Figure 2-11: General Condition Lower Balcony Floor, Coating Breakdown



Figure 2-12: Upper Balcony, Coating Breakdown and Corrosion on Floor

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Figure 2-13: Upper Balcony, Coating Breakdown on Rail



Figure 2-14: Upper Balcony

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2.5 Lower Rest Platform (Crow's Nest)

The lower rest platform (referred to as the crow's nest by NL Hydro personnel) had some minor surface corrosion as shown in Figures 2-15 and 2-16. The grating hatch was functional.



Figure 2-15: Lower Rest Platform (Crow's Nest)



Figure 2-16: Lower Rest Platform (Crow's Nest)

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2.6 Structural Support

2.6.1 Legs and Struts

The legs and struts appear to be in good condition with some minor coating breakdown. It appears that the coating system was touched up in the past.

However, upon completing coating adhesion tests (Table 2-2) it appears that the primer is the only coating system that exhibits proper adhesion. Any value below 250 psi would be considered as not adhered and should be removed. When trying to complete adhesion testing on the grey coating, a numerical value was not obtained as the sample was removed during attachement. This occurred in two areas.

It is recommended that the areas of coating breakdown be refurbished by high pressure water blast and re-coat. Further details are provided in Section 5.

Table 2-2: Legs and Struts Coating Adhesion Test Results

Coating System	Adhesion Result (PSI)
Grey Coating	Failed
Primer	1420



Figure 2-17: Structural Support

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Five UT readings were performed for each leg, and compared to the drawing nominal thickness. The results show minor differences when compared with the reference drawings. Refer to Appendix A for a detailed overview of UT locations and values for the tank legs.

2.6.2 Diagonal Bracing

All diagonal bracing showed minimal signs of wear and appear to be in good condition with very little deterioration as shown in Figure 2-18.

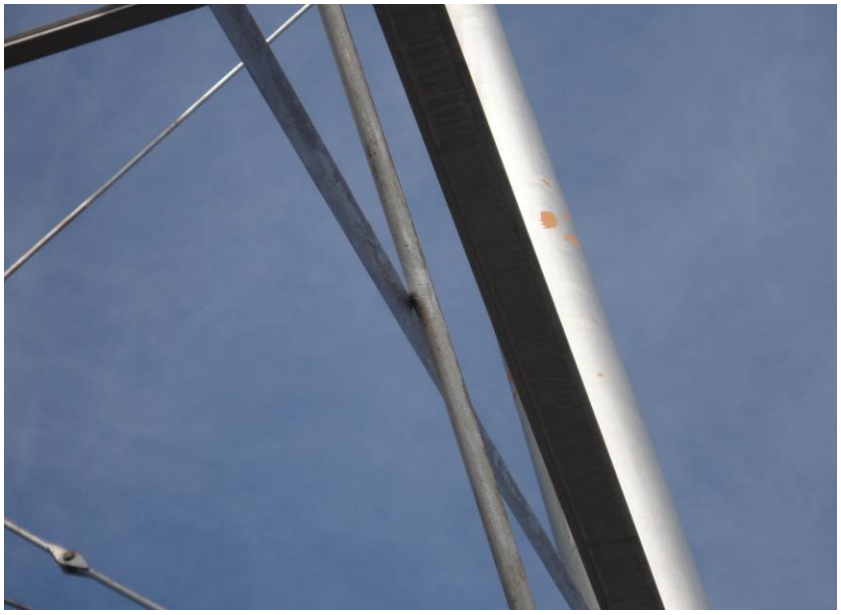


Figure 2-18: Typical Cross Member with Very Little Wear Present

2.6.3 Connections

The connections appear to be in good condition as shown in Figure 2-19.

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Figure 2-19: Typical Structural Support Connection

2.6.4 Foundations (Above Grade)

The inspection of the riser and leg foundations was limited to a visual inspection of the portion above grade. No excavation was performed to inspect below grade and no destructive testing (i.e., cores for compression testing) was carried out.

The concrete appears to be in generally good condition with some cracking that in most cases has been filled with a sealant. It was reported that crack sealing was carried out on a regular basis during routine maintenance. The sealant prevents water infiltration and further deterioration; however, it also prevents inspection of the cracks to determine width and depth. No reports were provided indicating when the cracks developed or probable cause of the cracking (e.g., Alkali Aggregate Reaction, freeze/thaw cycles, etc.). Cracks should be monitored to determine if they are getting larger or more numerous.

There was some minor efflorescence noted in a few areas with a larger area of efflorescence in one area on the side opposite surge tank 2. There are no visible signs of overstressing or areas where the concrete has deteriorated to a point where portions of concrete have spalled off except for some minor surface deterioration in a few areas where water may not drain properly.

Overall the visible foundation concrete appears to be in satisfactory condition.

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Figure 2-20: Riser Foundation



Figure 2-21: Leg Foundation and Anchor Bolt Arrangement

2.6.5 Anchor Bolts

Anchor bolts appear to be in good condition with some minor coating breakdown. Since the anchor bolts are coated with a similar system as the tank legs, It is recommended that they be refurbished by high pressure water blast and re-coat. Further details are provided in Section 5.

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Figure 2-22: Anchor Bolts

2.7 Ladder

The ladder appears to be in good condition with some minor coating breakdown as shown in Figure 2-24.



Figure 2-23: Access Ladder (a)

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Figure 2-24: Access Ladder (b)



Figure 2-25: General Condition of Ladder Brackets

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Figure 2-26: General Condition of Ladder on Tank Portion of Tower



Figure 2-27: General Condition of Ladder on Tank Portion of Tower, Coating Breakdown

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3. Internal Inspection

3.1 Tank Top

The tank top as shown in Figure 3-1 is constructed with a series of stiffener ribs covered with lap jointed plates. The coating system on the tank top interior shows evidence of coating breakdown.



Figure 3-1: Tank Top Interior (a)



Figure 3-2: Tank Top Interior (b)

3.2 Shell

From the top of the shell to roughly the mid-height as shown in Figure 3-3, the coating system appears to be intact with some minor localized breakdown.

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There was also coating breakdown and corrosion along the weld seams.



Figure 3-3: Tank Shell Interior at Mid-height before Water Line



Figure 3-4: Tank Shell Interior at Mid-height Extended View

It is recommended that the tank shell interior be wet abrasive blasted, sweep blasting the entire surface and blasting localized areas to bare metal, then re-coated. Further details are provided in Section 5.

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3.3 Tank Bowl

As shown in Figure 3-5 and Figure 3-6 below (photos taken during the inspection), it appears that the tank bowl is coated similar to the riser.

The existing coating appears to be in good condition with some localized coating breakdown. It is recommended that the tank shell interior be wet abrasive blasted, sweep blasting the entire surface and blasting localized areas to bare metal, then re-coated. Further details are provided in Section 5.



Figure 3-5: Interior of Tank Bowl Below Water Line



Figure 3-6: Tank Bowl Riser Connection

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3.4 Riser

The riser appears to be in good condition with minimal coating breakdown as shown in Figure 3-7, 3-8, 3-9 and 3-10.

The existing coating appears to be in good condition. It is recommended that the tank shell interior be wet abrasive blasted, sweep blasting the entire surface and blasting localized areas to bare metal, then re-coated. Further details are provided in Section 5.



Figure 3-7: Riser Cross Braces Evidence of Missing and Bent Bolts



Figure 3-8: Riser Inside Coating

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Figure 3-9: Base of Risers Connection to Penstock (a)



Figure 3-10: Base of Risers Connection to Penstock (b)

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4. Ancillary Items

4.1 Cathode Protection

The cathode protection (CP) system is intended to be a secondary corrosion protection to the coating system. The coating system on the interior of the tank and riser appears to have performed well and is still in good condition, with some minor localized coating breakdown.

A functional analysis of the CP system was not performed during the site inspection. Based on the Tacten inspection report the cathodic protection system is in disrepair and most likely not functional. Wires and ropes have become intertwined and there are broken/missing components. It is our opinion the CP system is not functional and poses a hazard to the turbine runner and other components, and it is recommended that it be removed.

4.2 Hot Water Heating System

The hot water heating system piping insulation appears to be in good condition with the exception of a few areas as shown in Figure 4-1 and Figure 4-3.

These areas have damaged cladding or insulation bags installed and could potentially allow water ingress. It is recommended that these areas be repaired.



Figure 4-1: Insulation and Cladding Not Reinstated

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Figure 4-2: Insulation Bags or Damaged Areas Where Water Ingress is Possible (a)



Figure 4-3: Insulation Bags or Damaged Areas Where Water Ingress is Possible (b)

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Figure 4-4: Insulation Bags or Damaged Areas Where Water Ingress is Possible (c)

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5. Summary of Recommendations

5.1 Hatch Recommendations

1. Roof - As a minimum it is recommended that the tank roof coating be refurbished in accordance with the NACE inspection recommendations of Section 5.2. A detailed design check should also be performed on the existing roof anchors to determine adequacy. If the roof anchors are deemed suitable from the design check, it is recommended that all attachment welds undergo non destruction examination (NDE). The roof anchors should be taken out of service until this is completed.
2. Shell (exterior) - As a minimum it is recommended that during the execution of future interior work, additional UT readings be taken for courses 7 through 2 to determine the actual shell plate thickness. If the actual shell plate thickness deviates from the reference drawings, a detailed structural analysis of the surge tank is recommended.
3. Lower and Upper Balcony - As a minimum it is recommended that the lower and upper balconies be refurbished in accordance with the NACE inspection recommendations of Section 5.2. A new gate should also be installed on the lower balcony.
4. Legs and Struts – As a minimum it is recommended that the areas of coating breakdown be refurbished in accordance with the NACE inspection recommendations of Section 5.2.
5. Shell (Internal) - As a minimum it is recommended that the shell coatings be refurbished in accordance with the NACE inspection recommendations of Section 5.2
6. Tank Bowl - As a minimum it is recommended that areas with coating breakdown be refurbished in accordance with the NACE inspection recommendations of Section 5.2.
7. Riser - As a minimum it is recommended that areas with coating breakdown be refurbished in accordance with the NACE inspection recommendations of Section 5.2.
8. Cathodic Protection – it is recommended that the CP system and all associated components be removed.
9. Hot Water Heating System - It is recommended that the areas of damaged insulation and improper flashing be repaired.
10. A cost benefit analysis should be completed to compare recoating vs spot recoating to determine which is more cost effective.

5.2 NACE Inspector Recommendations

1. Tank Interior - The interior of the surge tank should be wet abrasive blasted, sweep blasting the entire surface and blasting those areas that require it to bare metal A moisture cure coating would be appropriate for the application environment and anticipated high humidity during surface preparation and coating operations. Wasser MioZinc 100 applied to all bare metal areas and weld seams as spot recoating, and two coats of MC Tar would be applied over the entire interior surface.

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2. Tank exterior - The legs, beams and bracing should be prepared by high pressure water jetting at 5000 psi to remove all grey paint that is not tightly adhered (Adhesion of 250 psi or greater). All areas that show signs of corrosion or failure of the primer coat should be prepared to SSPC-SP2 and SSPC-SP 3 and primed accordingly. The moisture cure system is advantageous as it is suited for the surface preparation and service environment. WasserMioZinc 100, MioMastic 100, and MC Luster would be appropriate for exterior service.

3. The tank landings, ladders and roof should be prepared by high pressure water jetting at 5000 psi to remove all cracking paint that is not tightly adhered (Adhesion of 250 psi or greater). All areas that show signs of corrosion or failure of the primer coat should be prepared to SSPC-SP2 and SSPC-SP 3 and primed accordingly. The moisture cure system is advantageous here as it is suited for the surface preparation and service environment. Wasser MioZinc 100, MioMastic 100, and MC Luster would be appropriate for exterior service.

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6. Cost Estimates

Preliminary (+30/-20%) cost estimates were prepared for the recommendations outlined in Section 5. A 25% contingency is included. All cost estimates exclude owners cost, such as procurement and construction management.

The cost estimates for the surface preparation, coating and containment for the interior and exterior of Surge Tank #1 are presented in Table 6-1. Weather will be a major cost and schedule risk during the execution of this work. This estimate assumes no weather related issues or delays.

The cost estimates for the desktop studies/design reviews are presented in Table 6-2. The cost estimates for desktop studies/design reviews excludes any cost associated with the findings of these studies/reviews, i.e. replacement/upgrade cost.

The cost estimates for the structural/ mechanical upgrades are presented in Table 6-3.

It is assumed the structural/ mechanical upgrades will be executed under a separate contract with one mobilization and demobilization. Weather will be a major cost and schedule risk during the execution of this work. This estimate assumes no weather related issues or delays.

Table 6-1: Coating and Coating Inspection Cost

	Direct Cost	Contingency (25%)	Total Cost
Surface preparation and painting, including containment	$1,100,000	$275,000	$1,375,000
Interior coating assessment and refurbish areas of coating breakdown	$800,000	$200,000	$1,000,000
		Total	**$2,375,000**

Table 6-2: Desktop Study/Design Review Cost

	Direct Cost	Contingency (25%)	Total Cost
Design assessment of existing roof anchors	$8,000	$2,000	$10,000
		Total	**$10,000**

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Table 6-3: Structural/Mechanical Upgrades Cost

Description	Total
Construction Costs	
Mobilization/ Demobilization	$10,000
New gate on lower balcony	$5,000
Repair damaged insulation on piping	$12,000
Remove CP system	$30,000
NDE on existing roof anchors	$4,000
Additional UT readings on interior of tank	$5,000
Sub-Total	**$66,000**
Contingency (25%)	$16,500
Sub-Total	**$82,500**
Engineering & Construction Supervision (15%)	$12,375
Total Estimated Construction Cost	**$94,875**

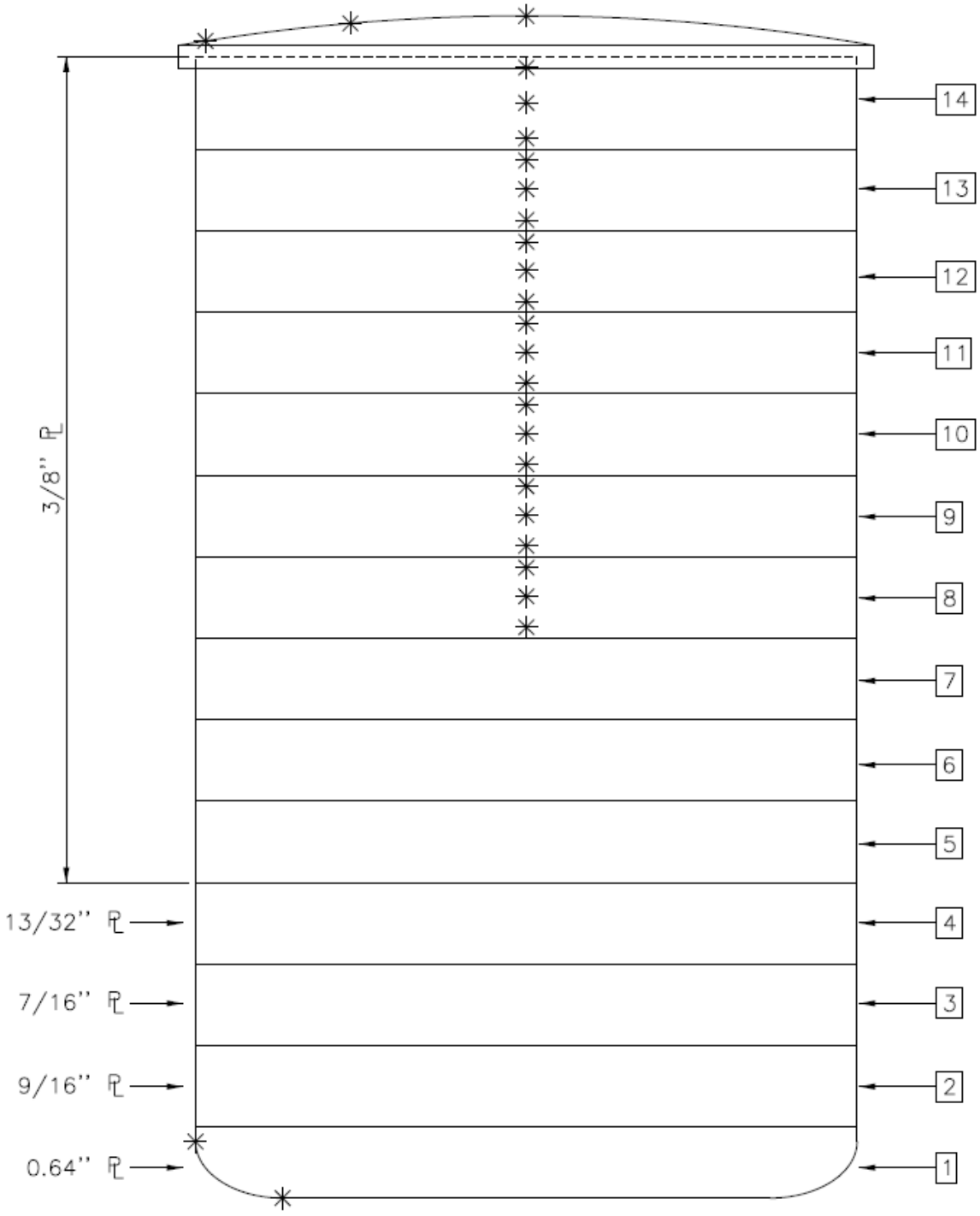
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Appendix A
Tank UT Results and Comparison

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Newfoundland and Labrador Hydro
BDE Surge Tank #1 Condition Assessment
H349210

A.1 Tank Shell UT Map



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A.2 Tank UT Results

Shell Course #	Average UT Reading (mm)	Drawing Nominal (mm)	% Difference
Roof	6.867	N/A	N/A
14	9.285	9.525	-2.52
13	8.893	9.525	-6.63
12	8.844	9.525	-7.15
11	8.838	9.525	-7.22
10	8.634	9.525	-9.35
9	9.024	9.525	-5.26
8	8.928	9.525	-6.27
1 (Bowl)	18.339	16.256	12.81

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A.3 Leg UT Results

Can #	Reading	Average	Drawing Nominal	Percent Difference
1	0.637	0.636	0.640	-0.594
	0.637			
	0.640			
	0.632			
	0.635			
2	0.538	0.539	0.550	-2.073
	0.534			
	0.538			
	0.539			
	0.544			
3	0.540	0.545	0.550	-0.982
	0.543			
	0.550			
	0.550			
	0.540			
4	0.585	0.590	0.600	-1.633
	0.596			
	0.590			
	0.585			
	0.595			
5	0.570	0.572	0.600	-0.982
	0.573			
	0.572			
6	0.580	0.579	0.600	-3.444
	0.578			
	0.580			
7	0.575	0.575	0.600	-4.167
	0.570			
	0.580			
8	0.605	0.603	0.600	0.556
	0.602			
	0.603			
9	0.601	0.601	0.600	0.111
	0.600			
	0.601			
10	0.640	0.648	0.640	1.302

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Newfoundland and Labrador Hydro
BDE Surge Tank #1 Condition Assessment
H349210

Can #	Reading	Average	Drawing Nominal	Percent Difference
	0.654			
	0.651			
11	0.651	0.654	0.640	2.135
	0.650			
	0.660			
12	0.658	0.660	0.680	-2.892
	0.653			
	0.670			
13	0.653	0.653	0.680	-4.020
	0.653			
	0.652			
14	0.650	0.644	0.680	-5.245
	0.643			
	0.640			
15	0.647	0.645	0.680	-5.147
	0.645			
	0.643			
16	0.652	0.654	0.680	-3.873
	0.653			
	0.656			
17	0.690	0.696	0.680	2.402
	0.700			
	0.699			
18	0.698	0.694	0.680	2.108
	0.690			
	0.695			
19	0.704	0.707	0.680	3.971
	0.708			
	0.709			
20	0.680	0.678	0.680	-0.245
	0.675			
	0.680			
21	0.685	0.687	0.720	-4.583
	0.690			
	0.686			
22	0.710	0.717	0.720	-0.463
	0.720			

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Newfoundland and Labrador Hydro
BDE Surge Tank #1 Condition Assessment
H349210

Can #	Reading	Average	Drawing Nominal	Percent Difference
	0.720			
23	0.870	0.871	0.880	-1.061
	0.870			
	0.872			
24	0.850	0.851	0.880	-3.295
	0.855			
	0.848			
25	0.955	0.953	0.880	8.295
	0.953			
	0.951			

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Appendix B
Tacten Report

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INSPECTION OF SURGE TANK AND PENSTOCK #1

Bay d'Espoir Generating Station

TACTEN

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1.0 Introduction

Tacten industrial Inc. mobilized to Bay d'Espoir on May 3, 2015 to complete an inspection on surge tank and penstock for unit #1. Using rope access, it included a visual inspection on the internal & external condition of tank and internal condition of the penstock. Additionally ultrasonic thickness measurements were performed at various locations of the tank and penstock as well as adhesion testing on the tank.

1.1 Inspection Summary

The external visual inspection was performed on surge tank #1, concentrating on the checkered portion of the tank shell, tank riser, tank top, ladder system including the rotating ladder at the tank top, hot water heating system, legs, cross braces and structural connections.

The internal inspection of the tank included the tank top, bowl, internal structural members, cathodic protection system and riser.

The internal inspection of the penstock included the shell, weld seems, penetrations and scroll case.

Ultrasonic inspection was carried out on the tank top, tank shell, legs, leg connections and penstock.

A general inspection was performed on the ladder system and hot water heating system. Overall the ladder system was in good condition, coating breakdown and minor corrosion was present. The first balcony around the tank had gate at the ladder access point. The hot water system was in overall good condition with the exception of several connection points where there are insulation bags or damaged cladding potentially allowing water ingress leading from the control shed to the base of the legs.

The tank top had coating breakdown and corrosion. The swivel ladder and hatch opening for the tank were all operational.

The cathodic protection system is damaged and the wiring is severed.

The exterior of the surge tank had minor coating breakdown and showed signs of minor corrosion. The rest area, upper and lower

balconies had coating breakdown and corrosion. The bottom balcony braces all showed signs of warping and corrosion. The Tank legs, horizontal steel beams were found to be in good structural condition all showed coating breakdown, all cross bracing showed signs of friction at the intersections. There is also breakdown in the silicone seals at leg penetrations and riser to bowl connection (cladding).

The coating on the interior of the penstock is beyond end of life, there is no bond to the substrate any longer. The penstock is however getting some protection from corrosion from a thick layer of sludge. When the sludge is removed the coating is removed at the same time revealing bright shiny metal with no signs of active corrosion. It was noted throughout the penstock that the sludge has reached the point where it is heavy enough to fall off in sheets.

The exterior coating of the surge tank is in poor shape and the topcoat on the legs is peeling down to primer. Adhesion testing revealed a poor bond between the topcoat and the primer. The primer however has a good bond to the substrate and is protecting the legs from corrosion. On the tank itself the coating has general cracking over the entire surface, this is likely due to age through UV breakdown. Adhesion testing results in this area revealed acceptable results on some areas of the tank where the cracking was less prominent.

Coating System	Red Coating	White Coating	Primer Coating	Grey Coating
Adhesion Result (Psi)	330	200	1420	Failed

The interior coatings of the surge tank are fair to good condition, there are large areas of coating breakdown from the water line down in to the bowl to riser connection. Above the water line the coating is in good condition. Adhesion testing results on the inside of the tank indicated acceptable results for spot repair and over coating on the interior of the tank and riser.

The cathodic protection system is in a state of disrepair with broken and missing pieces, tangled ropes and wires and would likely be ineffective in its current state. All components should be pulled from the interior of the tank to prevent the pieces from migrating through the turbine.

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2.0 External Inspection Results

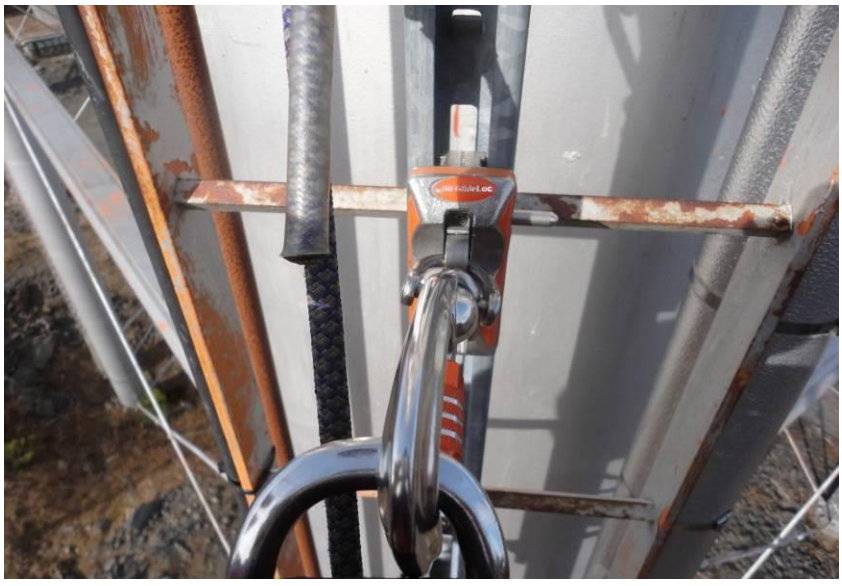
2.1 Ladder System

Overall the ladder system was in good condition, coating breakdown and minor corrosion was present.

General condition of ladder, coating breakdown present.



General condition of ladder, coating breakdown present.



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General condition of ladder brackets.



General condition of ladder on tank portion of the tower.



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2.2 Hot Water Heating System

The system was in overall good condition with the exception of connection points # 3, 5, 8, 11, 13, 15, 18, 19, 21 where there are insulation bags or damaged cladding potentially allowing water ingress leading from the control shed to the base of the legs.

Sample photo showing insulation and cladding not reinstated.



Following three photographs show insulation bags or damaged areas that could potentially lead to water.



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2.3 Rest Area

The rest area is in good condition, minor coating breakdown.

Photo of bottom brackets.



General Condition of rest area from above.



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2.4 First Balcony

Missing barrier door and coating breakdown.



General condition of balcony and rails, coating breakdown.



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General condition of balcony and rails, coating breakdown.



General condition of 4 turnbuckles on balcony, coating breakdown and slightly bent.



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General condition of cladding on 1st balcony level.



Silicone breakdown (360 degrees), potential water ingress between bowl and riser connection



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2.5 Second Balcony

Coating breakdown on balcony and railings



Coating breakdown on balcony and railings



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Lower hinge missing on balcony gate



General condition of all 4 leg connection points, possible water ingress, silicone failing.



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General condition of all 4 leg connection points, possible water ingress, silicone failing.



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2.6 Tank Top

General condition of ladder and ladder connections.



General condition of ladder and ladder connections.



Condition of tank roof/ladder and hatchway.

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2.7 Riser Exterior

Exterior cladding of riser is in good condition. Banding Missing #6 in first connection, 2nd connection #4, 3rd connection #1 is loose and hanging.

General condition of connection points to riser.



General condition of cladding on riser.



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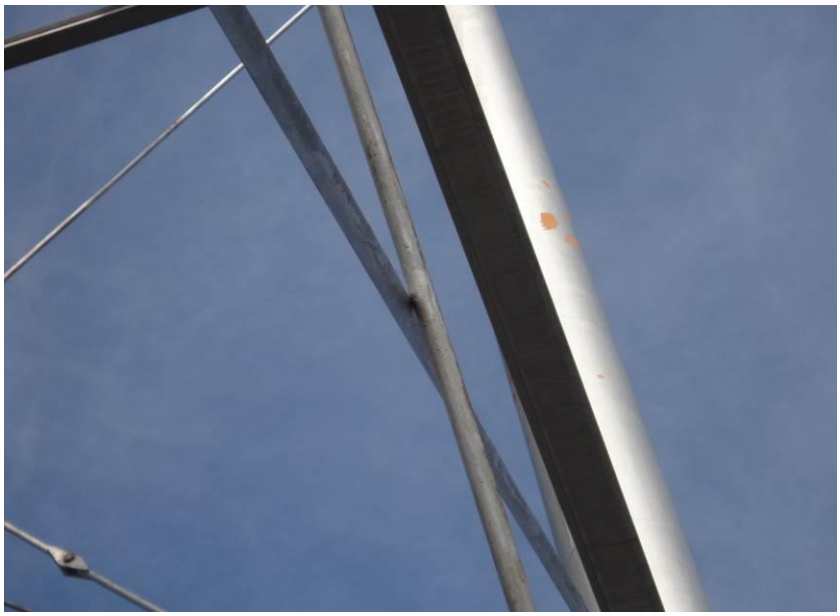
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2.8 Legs and Cross braces

General condition of connections into legs. Minor coating breakdown.



General condition of cross braces on the surge tank.



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3.0 Internal Inspection Results

3.1 Tank Top

General condition of underside of tank roof. Coating breakdown.



General condition of underside of tank roof. Coating breakdown.



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3.2 Tank Shell

General condition of tank top before water line. Minor coating breakdown and minor corrosion present on welds.



General condition of tank top before water line. Minor coating breakdown and minor corrosion present on welds.



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General condition below the water line.



General condition of the bowl.



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3.3 Riser

General view of cathodic protection system from top of riser.



General condition of riser cross braces and coatings inside of riser. Bent and missing bolts.



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General condition of coatings inside of riser.



Base of riser's connection to penstock.



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Base of riser's connection to penstock.



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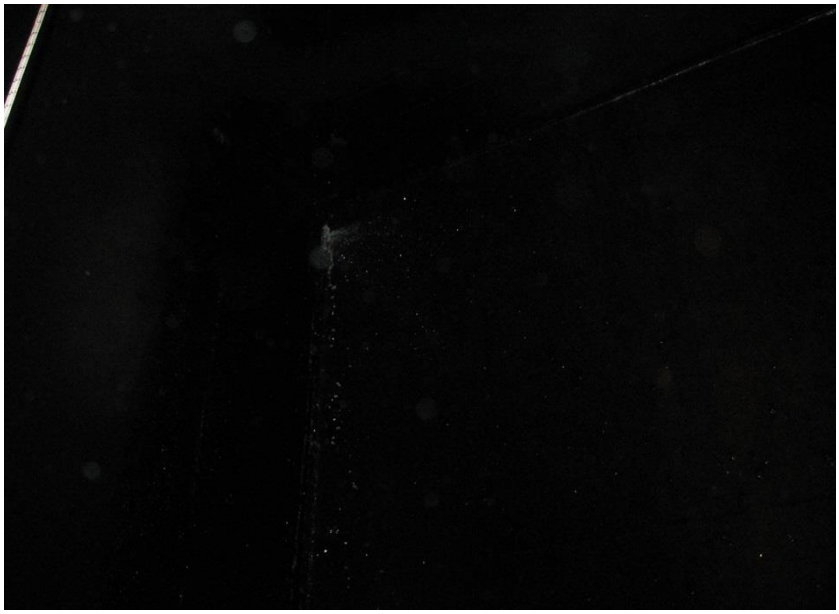
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4.0 Penstock

General condition of ladder leading from head gate to bottom of penstock, corrosion present.



Facing the head gate, Top left, bottom left and bottom right water flow is present.



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Facing the head gate, Top left, bottom left and bottom right water flow is present.



Facing the head gate, Top left, bottom left and bottom right water flow is present.



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Weld connections at 1a.



General condition of coating throughout the penstock.



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General condition of coating throughout the penstock.



General condition of coating throughout the penstock.



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Access hatch at bottom of surge tank.



Penetration in Can 8a.



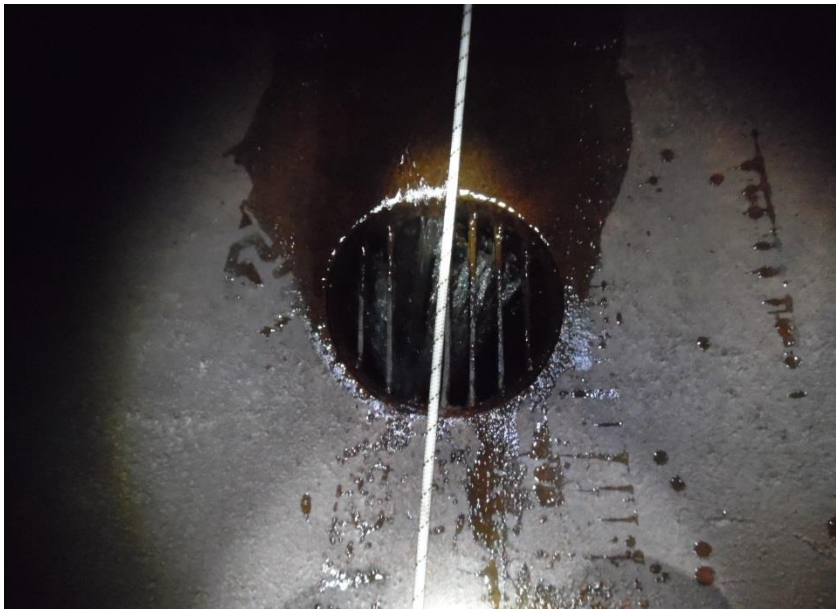
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Penetration in the scroll case.



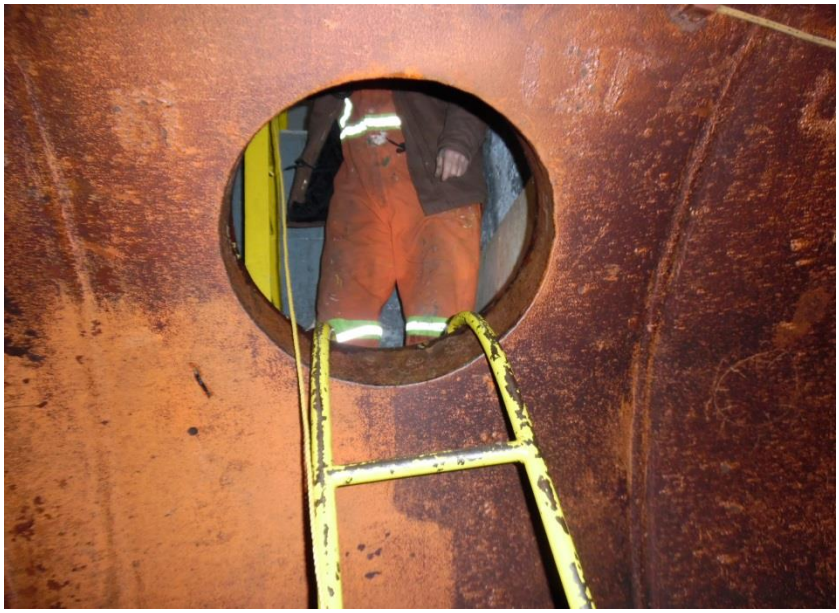
Penetration in the scroll case.



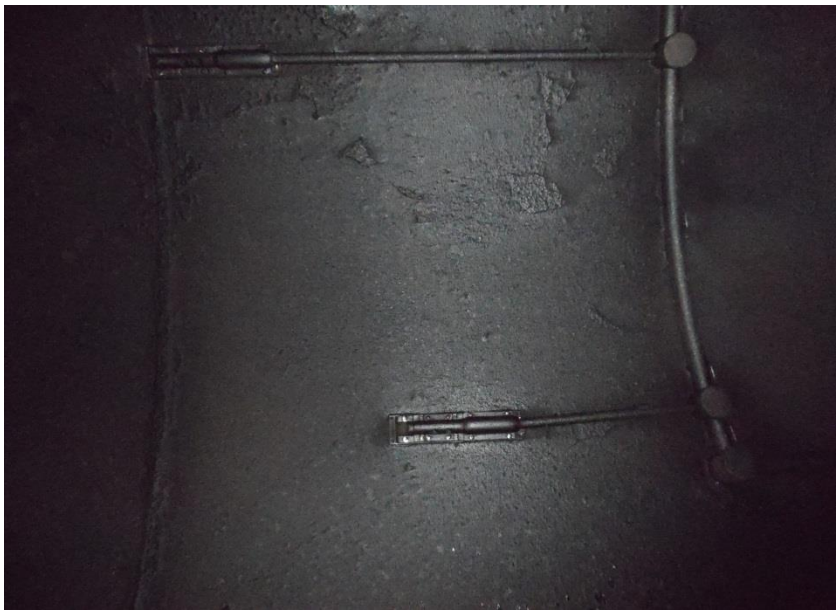
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Exit hatch in scroll case.



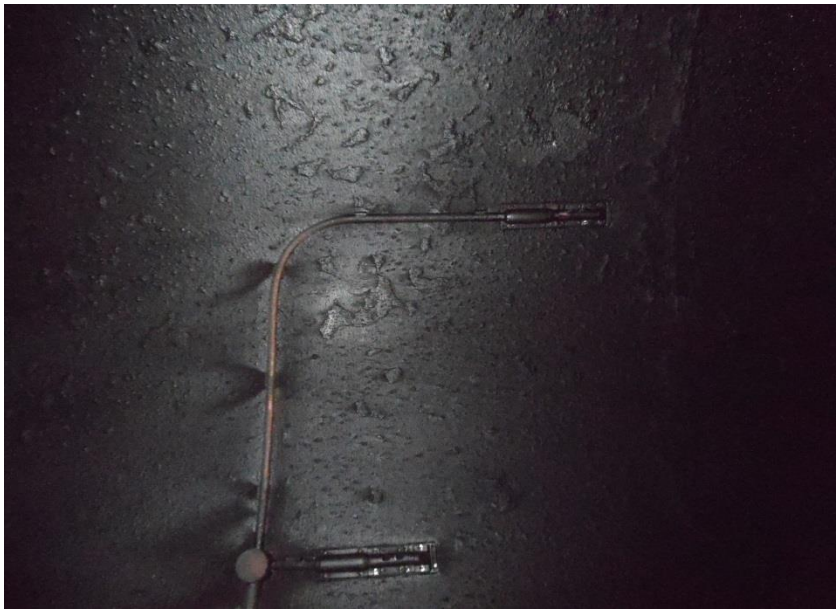
General condition of flow meter sensors in Can 9a.



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General condition of flow meter sensors in Can 9a.



General condition of scroll casing.



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General condition of scroll casing.



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5.0 Ultrasonic Thickness Gauging

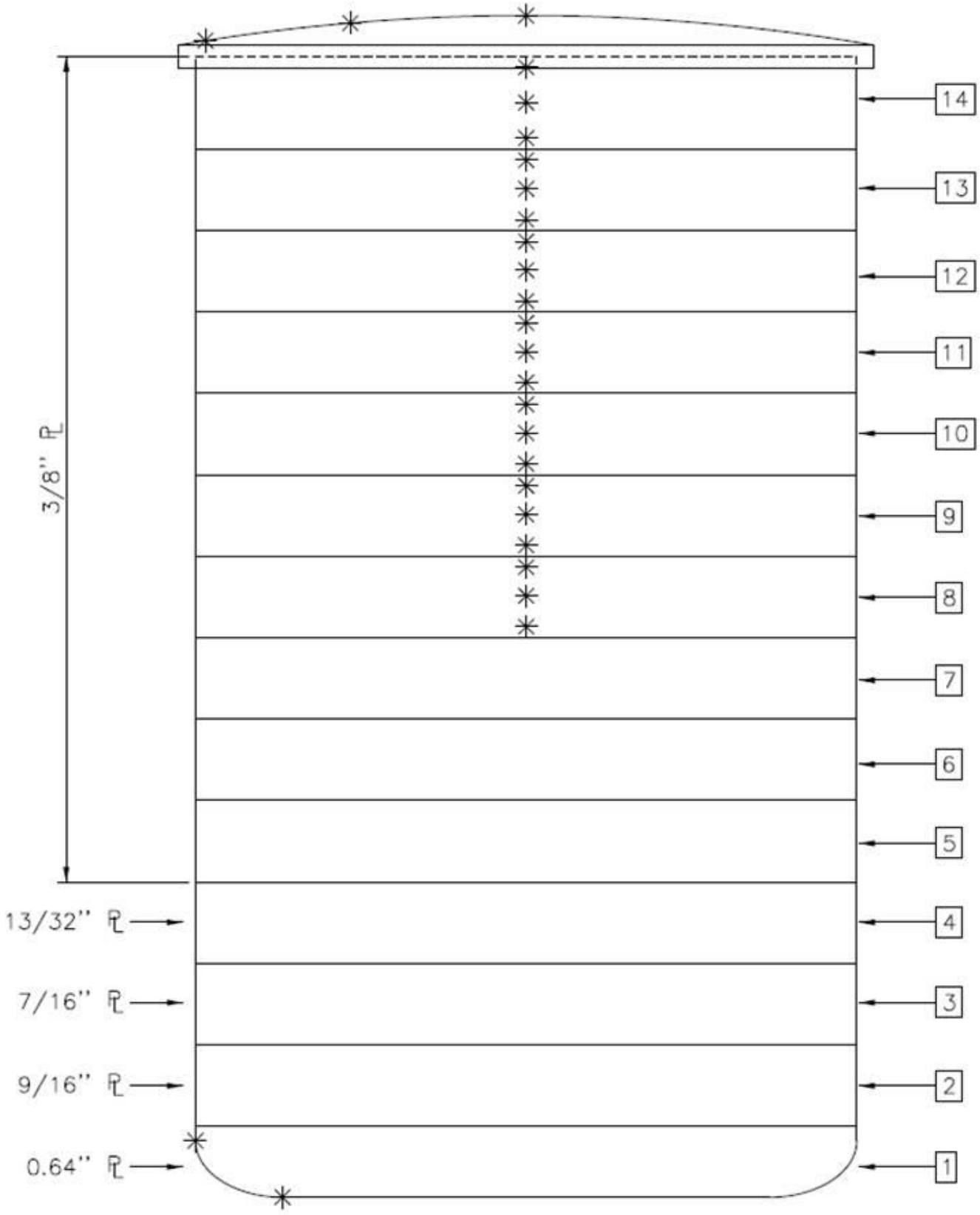
Calibration Block CS: #09-1266
Probe: KBA560 #01YC278
Ultrasonic Machine: Krautkramer DMS2 #12544

5.1 Tank Shell UT Results

Description: Readings were recorded as per below sketch on the following page

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Shell Course #	Top	Middle	Bottom	Average	Drawing Nominal	Percent Difference
	0.280	0.280	0.265			
	0.280	0.280				
Roof	0.260	0.275	0.270	0.270		
	0.240	0.280	0.260			
	0.280	0.275	0.260			
	0.379	0.397	0.350			
	0.366	0.370	0.347			
14	0.372	0.388	0.350	0.366	0.375	-2.524
	0.367	0.368	0.347			
	0.372	0.365	0.345			
	0.335	0.357	0.359			
	0.345	0.351	0.346			
13	0.351	0.357	0.354	0.350	0.375	-6.631
	0.347	0.353	0.357			
	0.343	0.356	0.341			
	0.346	0.355	0.348			
	0.350	0.347	0.332			
12	0.355	0.370	0.333	0.348	0.375	-7.147
	0.352	0.348	0.359			
	0.351	0.342	0.335			
	0.373	0.367	0.338			
	0.330	0.349	0.339			
11	0.350	0.348	0.344	0.348	0.375	-7.218
	0.346	0.351	0.339			
	0.342	0.363	0.340			
	0.333	0.341	0.332			
	0.339	0.337	0.334			
10	0.353	0.359	0.326	0.340	0.375	-9.351
	0.346	0.353	0.327			
	0.348	0.341	0.330			
	0.340	0.343	0.361			
	0.341	0.365	0.348			
9	0.343	0.380	0.370	0.355	0.375	-5.262
	0.339	0.360	0.361			
	0.343	0.370	0.365			
	0.353	0.355				
	0.342	0.352				
8	0.340	0.359		0.352	0.375	-6.267
	0.349	0.361				
	0.351	0.353				
	0.732	0.758				
	0.754	0.704				
1	0.758			0.722	0.640	12.813
	0.700					
	0.648					

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5.2 Leg 1 UT Results

Can #	Reading	Average	Drawing Nominal	Percent Difference
1	0.637	0.636	0.640	-0.594
	0.637			
	0.640			
	0.632			
	0.635			
2	0.538	0.539	0.550	-2.073
	0.534			
	0.538			
	0.539			
	0.544			
3	0.540	0.545	0.550	-0.982
	0.543			
	0.550			
	0.550			
	0.540			
4	0.585	0.590	0.600	-1.633
	0.596			
	0.590			
	0.585			
	0.595			
5	0.570	0.572	0.600	-0.982
	0.573			
	0.572			
6	0.580	0.579	0.600	-3.444
	0.578			
	0.580			
7	0.575	0.575	0.600	-4.167
	0.570			
	0.580			
8	0.605	0.603	0.600	0.556
	0.602			
	0.603			
9	0.601	0.601	0.600	0.111
	0.600			
	0.601			
10	0.640	0.648	0.640	1.302
	0.654			
	0.651			

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Can #	Reading	Average	Drawing Nominal	Percent Difference
11	0.651	0.654	0.640	2.135
	0.650			
	0.660			
12	0.658	0.660	0.680	-2.892
	0.653			
	0.670			
13	0.653	0.653	0.680	-4.020
	0.653			
	0.652			
14	0.650	0.644	0.680	-5.245
	0.643			
	0.640			
15	0.647	0.645	0.680	-5.147
	0.645			
	0.643			
16	0.652	0.654	0.680	-3.873
	0.653			
	0.656			
17	0.690	0.696	0.680	2.402
	0.700			
	0.699			
18	0.698	0.694	0.680	2.108
	0.690			
	0.695			
19	0.704	0.707	0.680	3.971
	0.708			
	0.709			
20	0.680	0.678	0.680	-0.245
	0.675			
	0.680			
21	0.685	0.687	0.720	-4.583
	0.690			
	0.686			
22	0.710	0.717	0.720	-0.463
	0.720			
	0.720			
23	0.870	0.871	0.880	-1.061
	0.870			
	0.872			
24	0.850	0.851	0.880	-3.295
	0.855			
	0.848			
25	0.955	0.953	0.880	8.295
	0.953			
	0.951			

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5.3 Leg Connection UT Results

Leg 1 is the ladder leg then going counter clockwise.

These readings were taken in a 5 point reading above and below the welds at the leg connections to the surge tank.

Leg 1	0.696	0.681	0.681	0.698	0.678
Leg 2	0.682	0.674	0.681	0.7	0.697
Leg 3	0.682	0.702	0.68	0.678	0.699
Leg 4	0.679	0.685	0.672	0.669	0.69

5.4 Penstock UT Results

The readings in the penstock were taken in a 5 point pattern at the 8 o'clock and 4 o'clock.

12 o'clock being the penstock roof looking towards the powerhouse) in the following areas:

1A					
8 o'clock	0.51	0.504	0.493	0.451	0.503
4 o'clock	0.514	0.521	0.512	0.517	0.496
2A					
8 o'clock	0.419	0.461	0.422	0.412	0.422
4 o'clock	0.437	0.42	0.405	0.435	0.413
5A					
8 o'clock	0.544	0.584	0.565	0.57	0.57
4 o'clock	0.59	0.583	0.55	0.564	0.57
10A					
8 o'clock	1.756	1.758	1.769	1.77	1.781
4 o'clock	1.773	1.775	1.781	1.774	1.781

6.0 Recommendations

Penstock - The penstock should be water blasted or wet abrasive blasted if there is not a suitable profile present after cleaning for proper application of the protective coating system. A moisture cure coating would be appropriate for the application environment and anticipated high humidity during surface preparation and coating operations. Wasser MioZinc 100 and 2 coats of MC Tar would be suitable for this surface preparation and service environment.

Tank Interior - The interior of the surge tank should be wet abrasive blasted, sweep blasting the entire surface and blasting those areas that require it to bare metal A moisture cure coating would be appropriate for the application environment and anticipated high humidity during surface preparation and coating operations. Wasser MioZinc 100 applied to all bare metal areas and weld seams and 2 coats of MC Tar would be suitable for this surface preparation and service environment.

Tank exterior - The legs, beams and bracing should be prepared by high pressure water jetting @5000psi to remove all grey paint that is not tightly adhered (Adhesion of 250 psi or greater). All areas that show signs of corrosion or failure of the primer coat should be prepared to SSPC-SP2 and SSPC-SP 3 and primed accordingly. The moisture cure system is advantageous here as well as it is suited for the surface preparation and service environment Wasser MioZinc 100, MioMastic 100, MC Luster would be appropriate for exterior service.

The tank landings, ladders and roof should be prepared by high pressure water jetting @5000psi to remove all cracking paint that is not tightly adhered (Adhesion of 250 psi or greater). All areas that show signs of corrosion or failure of the primer coat should be prepared to SSPC-SP2 and SSPC-SP 3 and primed accordingly. The moisture cure system is advantageous here as well as it is suited for the surface preparation and service environment Wasser MioZinc 100, MioMastic 100, MC Luster would be appropriate for exterior service.

Other suitable coating systems exist, however this is the system that was used on surge tank #3 and proved to be beneficial to the schedule based on its characteristics.

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Attachment 2

Cancellation of Previously-Approved Capital Projects - Bay d'Espoir Hydroelectric Generating Facility

Newfoundland and Labrador Hydro

February 26, 2021



newfoundland labrador hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

February 26, 2021

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Cancellation of Previously Approved Capital Projects at Bay d'Espoir

Newfoundland and Labrador Hydro ("Hydro") is providing this correspondence to advise the Board of Commissioners of Public Utilities ("Board") that, at this time, Hydro will not be proceeding with the following scopes of work which were approved as part of the Hydraulic Generation Refurbishment and Modernization Program in Hydro's 2018 and 2019 Capital Budget Applications ("CBA"):[1]

- The interior portion of the refurbishment of Bay d'Espoir Surge Tank 1;
- The Bay d'Espoir Intake Gate 1 portion of the Refurbish and Replace Control Gates Infrastructure project; and
- The Bay d'Espoir Intake Gate 2 portion of the Hydraulic Structures Program.

Hydro still intends to complete these portions of the project scope; however, for reasons further explained in this correspondence, the anticipated timeframe for completion of these components has changed materially from that which was reflected in the 2018 and 2019 CBA proposals. Therefore, Hydro believes it is appropriate to cancel the projects at this time and propose the scopes for approval in the future. Hydro has evaluated the impacts of deferring these projects from a safety and reliability perspective and has completed any work it considered to be a potential safety risk in the near term. Hydro will continue to monitor asset performance to limit reliability risks to customers.

Current Status of the Refurbishment of Bay d'Espoir Surge Tank 1

Hydro's original proposal was for the refurbishment of the interior and exterior of the Bay d'Espoir Surge Tank 1. The scope of the project included refurbishment of interior tank surfaces and surge tank bottom bowl, exposed exterior tank surfaces, and tower legs. Additionally, a structural analysis of the surge tank's interior structural steel was to be completed.

Hydro completed the exterior portion of this scope of work in 2018 as scheduled but has since been unable to complete the work due to the prioritization of other critical work on the system and the impacts of the COVID-19 pandemic. Hydro is evaluating whether completing this work during execution of the Penstock 1 refurbishment would be the most productive use of outage time and other resources.

[1] Bay d'Espoir Surge Tank 1 and Intake Gate 1 were approved in Board Order No. P.U. 5(2018). Intake Gate 2 was approved in Board Order No. P.U. 46(2018).

As per Hydro's June 3, 2020 correspondence to the Board,[2] Hydro has engaged a consultant to support the Front-End Engineering Design work for the Penstock 1 refurbishment. Once this work is complete, Hydro will present its project proposal, including costs, to the Board for review and approval. Hydro will provide an update as to the status of this work in its 2022 CBA.

Current Status of the Replacement of Bay d'Espoir Intake Gates 1, 2 and 3

Hydro's strategy for the replacement of Intake Gates 1, 2 and 3[3] at Bay d'Espoir was to procure a new gate to replace Intake Gate 1, refurbish the gate that was removed to replace Intake Gate 2, and repeat this process for Intake Gate 3, keeping the last refurbished gate as a spare. The original planned sequence was that Intake Gate 1 would be replaced in 2019, Intake Gate 2 would be replaced in 2020, and Intake Gate 3 would be replaced in 2021.

Hydro has completed the engineering and fabrication for the replacement of Intake Gate 1; however, due to the prioritization of other critical work on the system, Hydro was unable to replace the gate in 2019 as scheduled. In 2020, Hydro experienced delays related to the COVID-19 pandemic which caused Hydro to miss the outage window required to replace Intake Gate 2.

Intake Gate 3 is scheduled for 2021 and, at this time, Hydro does not foresee any issues which would prohibit it from completing this work as scheduled. As the three intake gates at Bay d'Espoir are identical, Hydro intends to replace Intake Gate 3 in 2021 using the gate that was fabricated and originally intended to be used to replace Intake Gate 1. Hydro will then refurbish the existing Intake Gate 3 and use it to replace Intake Gate 1. As with the interior work on Surge Tank 1, Hydro is evaluating whether this work should be completed during the extended outage for the Penstock 1 refurbishment. The refurbished Intake Gate 1 will be used to replace Intake Gate 2. Hydro will undertake a similar evaluation to determine whether the most efficient approach is to complete this work at the same time that Hydro completes the Penstock 2 refurbishment. The timing of the Penstock 2 refurbishment remains under evaluation. Hydro intends to refurbish the last gate removed and will maintain it as a spare.

Summary of Costs Incurred

Table 1 provides a summary of the amounts approved and incurred for each of the project scopes.

Table 1: Summary of Approved and Incurred Costs

Project Scope	Approved Project Cost	Project Cost Incurred	Difference
Bay d'Espoir Surge Tank 1	$3,564,000	$2,107,136	$1,456,864
Bay d'Espoir Intake Gate 1	$2,312,100	$240,857	$2,071,243
Bay d'Espoir Intake Gate 2	$2,083,600	$97,846	$1,985,754
Bay d'Espoir Intake Gate 3	$2,477,300	$734,142	$1,743,158
Total	**$10,437,000**	**$3,179,981**	**$7,257,019**

The costs incurred to date for the refurbishment of Surge Tank 1 relate to the inspection of tank and substructure, safety upgrades, and the application of a new exterior coating system.

[2] "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020.
[3] Bay d'Espoir Intake Gate 3 was proposed as part of Hydro's Hydraulic Generation Refurbishment and Modernization Program in its 2020 CBA, which was approved in Board Order No. P.U. 6(2020).

Costs incurred to date for Intake Gates 1 and 2 relate to engineering work that was commenced prior to the projects being cancelled. Engineering deliverables produced to date have been retained and will still be of value to customers as the gates are replaced.

The costs associated with the gate that was initially procured to replace Intake Gate 1 have been transferred to Intake Gate 3, as that is now expected to be the first gate replaced.

Cancelled Scopes

Given the duration of carryover and the evaluation of potential logistical benefits that may be gained by executing the work on the interior of Surge Tank 1 and Intake Gate 1 at the same time as the Penstock 1 refurbishment, Hydro is proposing to cancel these portions of the project scopes at this time. Once Hydro has completed its Front-End Engineering Design work for the Penstock 1 refurbishment, Hydro will be in a better position to determine whether it is most appropriate to include these scopes of work with its proposal for refurbishment of Penstock 1 or to proceed with a separate application for the interior of Surge Tank 1 and the Intake Gate 1 work scopes. Similarly, Hydro is proposing to cancel the work scope associated with Intake Gate 2 and will evaluate the merits of including this scope in its application for the Penstock 2 refurbishment.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/sk

ecc: **Board of Commissioners of Public Utilities**
Jacqui Glynn
PUB Official Email

Newfoundland Power
Kelly C. Hopkins
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Stephen F. Fitzgerald, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis

Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Dean A. Porter, Poole Althouse

Labrador Interconnected Group
Senwung Luk, Olthuis Kleer Townshend LLP
Julia Brown, Olthuis Kleer Townshend LLP

Replace Powerhouse 1 Roof (2024–2025)

Bay d’Espoir

July 2023

Replace Powerhouse 1 Roof (2024–2025)

Location: Bay d'Espoir

Investment Classification: General Plant

Asset Category: Hydraulic Plant

Executive Summary

The Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir Facility") is home to seven generating units that are housed in two generating plants—Powerhouse 1 and Powerhouse 2. The development produces an average of 2,650 GWh annually, making it the largest hydroelectric development on the Island.

The Powerhouse 1 roof was replaced in 1992; since that time, Newfoundland and Labrador Hydro ("Hydro") has performed annual inspections of the roof and completed maintenance as required. The roof has not been the subject of any major upgrades or refurbishments since the replacement in 1992 and, at 31 years old, it is nearing the end of its service life.

The Powerhouse 1 roof is comprised of two sections, commonly referred to as the Powerhouse roof and the Office Complex roof. In 2015, a condition assessment noted that the Office Complex roof was nearing the end of its service life and its replacement was recommended within five to seven years, while it was recommended to reassess the Powerhouse roof in five years.

Since 2015, the condition of the Powerhouse 1 roof has continued to deteriorate and has reached the end of its service life. Life extension options for the existing roof have been exhausted, as inspections show the reoccurrence of leaks in areas that were previously refurbished.

Delays in the completion of corrective actions will result in the continued deterioration of the membrane, compromising the integrity of the Powerhouse 1 roof and posing a threat to the sensitive electrical and mechanical equipment housed within the facility. Powerhouse 1 is responsible for the production of 450 MW of hydroelectricity; a roofing failure resulting in the infiltration of water could damage sensitive, critical equipment, potentially causing a unit outage.

In consideration of this, the following alternatives were considered:

- Deferral;
- Upgrade life extension; and
- Like-for-like replacement.

Like-for-like replacement was determined to be the only viable option to satisfy Hydro's long-term operational needs. As the proposed roof replacement requires the removal of the existing fall protection system, Hydro will replace the fall protection system in conjunction with the roof, to avoid future disturbance of the membrane. Hydro is proposing to cluster this project for execution with the Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir project[1]—also included in Hydro's 2024 Capital Budget Application—to maximize execution efficiency, as both scopes involve the Office Complex roof. The powerhouse roofing system is critical to preventing the ingress of water and protecting the sensitive equipment housed therein. As a result, Hydro is proposing the replacement of the Powerhouse 1 roofing membrane to maintain the integrity of the building.

This project has a multi-year approach, with completion planned in 2025 at an estimated cost of $1,959,400.

[1] The "Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir" project is a multi-year project, with estimated completion in 2025. As the estimated cost for this project is under $750,000, it has been included in the listing of Proposals Under $750,000.

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List of Attachments

Attachment 1: "Visual Inspection and Thermal Image Scan, Roofs of Powerhouse 1 and Powerhouse 2, Milltown, Bay d'Espoir," Exploits Engineering Consultants Ltd, October 2015

1.0 Introduction

The Bay d'Espoir Facility is located on the south coast of the Island, approximately 15 kilometres from the community of St Alban's. The facility is home to seven generating units, housed in two generating plants—Powerhouse 1 and Powerhouse 2. The development produces an average of 2,650 GWh annually, making it the largest hydroelectric development on the Island. Powerhouse 1 is responsible for the production of 450 MW of hydroelectricity; service began in 1967.

The Powerhouse 1 roof was replaced in 1992, with no major refurbishment work completed since. Hydro completes annual inspections of the roof and performs corrective maintenance as required; however, in recent years, the formation of leaks in the Powerhouse 1 roof has increased in frequency.

A condition assessment, completed by Exploits Engineering Consultants Ltd. in 2015,[2] noted that a portion of the Powerhouse 1 roofing system located above the office complex, the Office Complex roof, was nearing the end of its service life and recommended its replacement within five to seven years. The remaining section of the roof located above the generation hall, the Powerhouse roof, was noted to be in good condition with reassessment recommended in five years. Throughout the past seven years, the condition of the Powerhouse 1 roof has continued to deteriorate, as evidenced by Hydro's annual inspections.

The entirety of the Powerhouse 1 roof membrane has developed cracks and evident membrane discoloration in multiple areas, a result of poor drainage and subsequent water ponding. In recent years, numerous roof leaks have formed throughout the facility, disrupting operations within the Office Complex and jeopardizing the sensitive electrical equipment housed in the generation hall.

Hydro is proposing the replacement of the existing Powerhouse 1 roofing system to restore its integrity, prevent the occurrence of leaks, and mitigate the risk associated with water infiltration.

2.0 Project Description and Justification

The Powerhouse 1 roof was replaced in 1992 with a roofing system consisting of a vapour retarder, insulation layer, four-ply felts, and two waterproofing coats. At 31 years old, the roofing system has reached the end of its service life and in recent years has experienced an increase in the formation of

[2] The "Visual Inspection and Thermal Image Scan Roofs of Powerhouse #1 and Powerhouse #2 Milltown, Bay d'Espoir," Exploits Engineering Consultants Ltd., October 2015, is provided as Attachment 1.

leaks, disrupting daily operations and posing a risk to the sensitive equipment housed within Powerhouse 1. The continued formation of leaks and ingress of water could result in equipment damage and unit outages, removing a major generation source from the Island Interconnected System.

This project involves replacing the Powerhouse 1 roofing system, which is required to ensure the integrity of the roof and mitigate the risks associated with the infiltration of water. The proposed replacement will ensure that the integrity of the roof is maintained for the next 25–30 years.

As the proposed roof replacement will require the removal of the existing fall protection system, Hydro is proposing to avail of this opportunity to complete its replacement. Replacing the fall protection system, in conjunction with roof replacement, will permit the installation of the system while avoiding future disturbance of the roofing membrane—a disturbance that could result in the reoccurrence of leaks. Given the synergies that exist between the two scopes of work, Hydro believes that the replacement of the fall protection system is the prudent course of action. The fall protection system will provide safe access to the roof for the completion of required maintenance activities.

3.0 Asset Overview

3.1 Asset Background

The Powerhouse 1 roof, replaced in 1992, is comprised of two sections commonly referred to as the Powerhouse roof and the Office Complex roof, as shown in Figure 1.

The Powerhouse roof is a long rectangular surface with an approximate area of 1,189 m^2 and the Office Complex roof is an L-shaped surface located at the south end of Powerhouse 1 with an approximate area of 471 m^2. Both roofs contain a fall protection system, rooftop ventilation units, curbs, and roof drains.



Figure 1: BDE Powerhouse 1 Roof Layout

3.2 Historical Reliability

Hydro performs an annual inspection of the Powerhouse 1 roof and completes regular maintenance to ensure the reliability of the roofing system over the course of its 31-year service life. In recent years, an influx of issues has raised concerns suggesting the roofing system has exceeded its useful service life.

3.3 Asset Condition

The Powerhouse 1 roofing system has been in service for the past 31 years. Recently, the number of issues has increased, including the formation of blisters in the roofing membrane, cracks in the membrane, and the formation of leaks, as shown in Figure 2. Since 2017, there have been seven recorded corrective actions to address roof leaks.

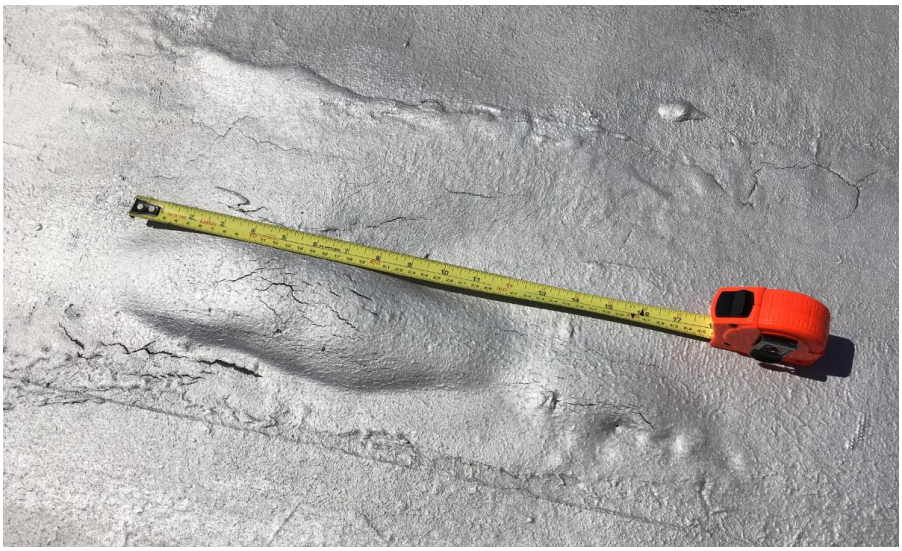


Figure 2: Blisters and Cracks in the Roof Membrane

At 31 years old, the roofing system has outlived its service life. Corrective maintenance performed to address noted deficiencies, such as patching and recoating as required, provides temporary relief. These measures are often taken in response to a leak. Corrective maintenance can no longer be considered a viable means to preserve the integrity of the building envelope.

3.4 Condition-Based Remaining Life

The roofing system is 31 years old and has reached the end of its useful life, as demonstrated by the recent history of leaks indicating that the roofing system has failed.

4.0 Analysis

4.1 Evaluation of Alternatives

The Powerhouse 1 roofing system has not undergone any major upgrades since it was replaced in 1992. The roof has reached the end of its service life, increasing the formation of leaks. In consideration of this, the following alternatives were analyzed:

- Deferral;
- Upgrade life extension;
- Like-for-like replacement.

4.1.1 Deferral

The Bay d'Espoir Powerhouse 1 roofing system has exceeded its service life and is no longer able to provide an adequate level of weather protection. Since 2017, Hydro has completed numerous repairs to address leaks in the facility, which have provided only short-term relief from water infiltration before the leaks reoccur.

Leaks disrupt operations within the facility and jeopardize the operation of sensitive electrical equipment housed in the generation hall, with the potential to impact system reliability. A generation outage at the Bay d'Espoir Facility could be highly detrimental to the Island Interconnected System or could result in increased costs associated with standby generation or procurement of import energy, if available.

Failure to complete the proposed replacement will result in the continued deterioration of the roofing system and the reoccurrence of leaks throughout the facility, increasing the risk of damage to electrical equipment and jeopardizing the provision of reliable service to the Island Interconnected System. For this reason, deferral of the proposed work is not considered a viable alternative.

4.1.2 Upgrade Life Extension

Hydro completes annual inspections and regular corrective maintenance on the roofing system to minimize the ingress of water and prolong the life of the existing roof. However, these options have now been exhausted as inspections are showing the reoccurrence of leaks in areas that were previously refurbished. As such, upgrade life extension is no longer considered a viable option.

4.1.3 Like-for-Like Replacement

The Powerhouse 1 roofing system has reached the end of its service life. Replacement of the existing system with a comparable built-up roofing system[3] will restore the integrity of the exterior envelope of the facility for the next 25–30 years and reduce the risks associated with water infiltration. Hydro is proposing to cluster this project for execution with the Replace Powerhouse 1 Air Conditioning Unit (2024–2025) – Bay d'Espoir project to maximize execution efficiency, as both scopes involve the Office Complex roof.

4.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

4.3 Recommended Alternative

Like-for-like replacement has been determined to be the only viable option to satisfy Hydro's long-term operational needs.

The Powerhouse 1 exterior envelope is required to provide a weather-tight facility in which to house the equipment for the Bay d'Espoir Facility. The existing roofing system has not undergone any major refurbishment since its installation in 1992. Given its age and condition, a complete replacement is recommended.

4.3.1 Risk of Asset Stranding

The Bay d'Espoir Facility produces an average of 2,650 GWh annually, making it the largest hydroelectric development on the Island. As the primary source of hydroelectricity for the Island Interconnected System, there are no plans to retire the generating assets at the Bay d'Espoir Facility; therefore, Hydro considers the risk of asset stranding to be negligible.

It is anticipated that the proposed work will restore the service life of the roofing system and ensure its reliable performance for the next 25–30 years.

[3] Built-up roofing is a roofing system where multiple layers of asphalt are applied between ply sheets (or felts) over the roof deck and insulation.

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	4	**12**
Post-Execution	3	1	**3**
		Risk Mitigated	**9**
		Risk Mitigated per $1 Million	**4.6**

5.0 Scope of Work

This project involves the replacement of the existing roofing membrane system and the replacement of the existing rooftop fall protection system.

5.1 Project Budget

The estimate for the 2024–2025 project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	**2024**	**2025**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	**0.0**
Labour	47.6	50.6	0.0	**98.2**
Consultant	73.6	132.6	0.0	**206.2**
Contract Work	0.0	1,375.7	0.0	**1,375.7**
Other Direct Costs	0.6	5.2	0.0	**5.8**
Interest and Escalation	6.2	98.7	0.0	**104.9**
Contingency	12.2	156.4	0.0	**168.6**
Total	**140.2**	**1,819.2**	**0.0**	**1,959.4**

5.2 Project Schedule

The work will be executed as a two-year project. It is anticipated that detailed engineering will conclude in 2024, with tendering and execution taking place in 2025.

The schedule for the 2024–2025 project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning: Budget review, scope statement, schedule, and risk assessment.	January 2024	March 2024
Design: Consultant engagement, detailed design, and tender package preparation.	May 2024	February 2025
Procurement: Tender and award.	February 2025	April 2025
Construction: Powerhouse 1 roof replacement.	August 2025	October 2025
Commissioning: Final inspection and acceptance.	September 2025	October 2025
Closeout: Project completion, interest cut-off, and lessons learned.	October 2025	November 2025

6.0 Conclusion

The Bay d'Espoir Facility produces an average of 2,650 GWh annually, making it the largest hydroelectric development on the Island. In recent years, the reoccurrence of leaks in the Powerhouse 1 roofing system has caused disruptions in daily facility operations and placed sensitive electrical equipment housed in the generation hall at risk. The potential exists for leakages to result in generation unit outages at the Bay d'Espoir Facility, which could be highly detrimental to the Island Interconnected System and result in additional costs to replace energy and capacity.

The Powerhouse 1 roofing system has reached the end of its service life. The proposed roof replacement is required to restore the integrity of the Powerhouse 1 building envelope and prevent the reoccurrence of leaks in the facility.

Attachment 1

Visual Inspection and Thermal Image Scan
Roofs of Powerhouse #1 and Powerhouse #2
Milltown, Bay d'Espoir

Exploits Engineering Consultants Ltd.

October 2015

Visual Inspection and Thermal Image Scan
Roofs of Powerhouse #1 and Powerhouse #2
Milltown, Bay d'Espoir


Powerhouse #1and Office Complex


Powerhouse #2

Prepared for:

Report Prepared By:

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October 2015

EECL # 15-064

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1.0 Introduction:

On October 6, 2015 Ken Jackson and Brian Pardy from Exploits Engineering Consultants Ltd. (EECL), accompanied by Ray Buffett (NLH Civil Technician), visited the Powerhouse #1 and #2 buildings to perform a visual inspection and thermal image scan of the respective roofs. Both buildings are located at the Bay d'Espoir Hydroelectric Generating Station, Camp Boggy Road, Milltown, Bay d'Espoir.



Bay d'Espoir Hydroelectric Generating Station

2.0 History:

Powerhouses Nos. 1 and 2 were constructed between 1966 and 1968. Both roofs have been upgraded since their original construction.

The Powerhouse #1 roofs were upgraded in 1992 with a full replacement, including new vapour retarder, insulation, four ply felts and waterproofing coating (2 coats). NLH has continued regular maintenance on this roof with patching and re-coating as required.

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The Powerhouse #2 roof was upgraded in 1997 with a full replacement, including new vapour retarder, insulation, three ply felts and waterproofing coating (2 coats). NLH has continued regular maintenance on this roof with patching and re-coating as required.

3.0 Background:

Exploits Engineering was contracted to provide a condition assessment of the Powerhouse #1 and Powerhouse #2 roofs. Information for the report was collected by visual inspections and thermal image scans of the roof areas. This report includes recommendations related to any issues uncovered or observed.

3.1 Property Description:

.1 Powerhouse #1

Powerhouse #1 has two roofs commonly referred to as the **Powerhouse Roof** and the attached **Office Complex Roof**. The Powerhouse Roof is a long rectangular roof surface with an approximate area of 1189m^2. The Office Complex Roof is an L-shaped surface that is located at the South end of Powerhouse #1. Its total area is 471m^2. Both roofs contain roof top units, curbs and roof drains throughout as shown on the attached roof plan (see Appendix A).



.2 Powerhouse #2

Powerhouse #2 has a rectangular roof surface with an approximate area of 623m^2. This roof contains roof top units, curbs and roof drains throughout as shown on the attached roof plan (see Appendix A).



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3.2 Weather and Building Conditions:

.1 The weather on October 6, 2015 was clear and sunny with very little cloud cover. The roofs were exposed to direct sunlight all day creating good conditions for heat loading of the roof surface. The temperature was approximately 17° C during the day, cooling somewhat after sunset. The roofs were completely dry and there had been no significant rainfall prior to the inspections. Conditions for thermography were good.

3.3 Test Equipment:

.1 Imager Model: Flir Therm Cam T420bx

.2 Moisture Meter: Tramex Roof and Wall Scanner.

3.4 Limitations:

.1 There are localized existing conditions that create a temperature differential when viewed with the thermal imaging camera. These conditions are typically limited to surface staining and material/colour differences in roofing membranes as a result of patching. A temperature differential at these locations is not indicative of moisture below the roof surface.



Roof Staining



Roof Patching

.2 The Tramex meter is used to confirm moisture in anomalies identified with a thermal scan. Due to the electrically conductive material present in the waterproofing coating, the Tramex moisture meter could not be used as it produced inaccurate readings.

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4.0 Observations:

Visual inspections and thermal image scans were completed on both of the powerhouse #1 and #2 roofs. Anomalies were noted and are shown on the attached roof plans (Appendix A). The digital photos and infrared imagery are included in Sections 5.0 and 6.0 of this report.

4.1 Powerhouse Roof #1:

The **Powerhouse Roof** (#1) is in good condition and has been well maintained over the years. There is evidence of patching along with re-application of the waterproofing coating.

The lower roof area surface (**Office Complex Roof**) exhibits extensive cracking and staining. The cracks do not appear to extend into the roofing membrane, and are confined to the waterproofing coating. There are also areas of discoloration due to water-ponding on the roof surface. Some re-caulking has been completed at the wall/roof flashing transitions and along joints in the concrete walls, as shown in the Images below.

Note that for this evaluation the roof areas were divided into grid patterns using numbers and letters to help locate thermal images (see roof plans in Appendix A).



Re-caulking of Wall Joint



Re-caulking at Top of Flashing

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4.2 Powerhouse Roof # 2:

The **Powerhouse Roof #2** is in good condition and has been well maintained over the years. There is evidence of patching and there are visible areas of discoloration due to water ponding on the roof surface. Areas of surface cracking are documented on the roof plan (See Appendix A), but it should be noted that the cracking appears to be only present in the waterproofing coating and not in the underlying roofing membrane.

5.0 Visual Observations:

5.1 Powerhouse Roof #1 (Powerhouse Roof):



Photo 1: Overall View of the Powerhouse Roof Looking North



Photo 2: Cracking in Waterproofing Coating At the Perimeter Parapet Wall



Photo 3: Surface Discoloration Due to Water Ponding



Photo 4: Cracking in Waterproofing Coating At the Exhaust Fan

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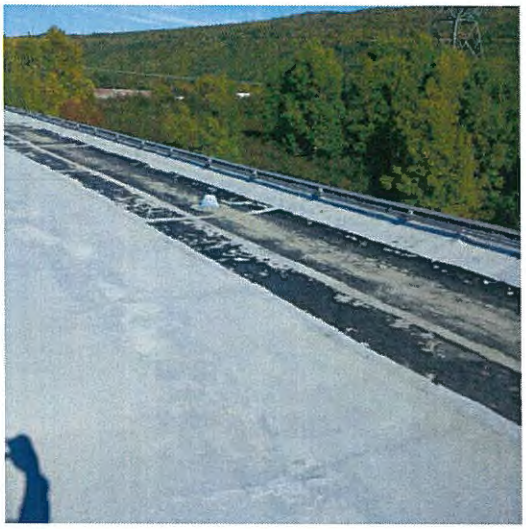


Photo 5: Water Proofing Coating Was Not Applied to the Dark Roof Surface Area Shown Due to Water Ponding in This Area



Photo 6: Expansion Joint

5.2 Powerhouse Roof #1 (Office Complex Roof):



Photo 7: Cracking in Waterproofing Coating at Parapet Corner



Photo 8: Waterproofing Coating Spalding at Corner Wall

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Photo 9: Roof Drain at Air Handling Unit



Photo 10: Typical Cracking in Waterproofing Coating



Photo 11: Cracking in Waterproofing Coating At Roof Vent



Photo 12: View Along South Wall with Air Handling Unit

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Photo 13: Discoloration due to Water Pond



Photo 14: View Along West Wall looking North



Photo 15: Discoloration of Membrane At Air Handling Unit Westside



Photo 16: Patched Area At Air Handling Unit

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Photo 17: Area of Patching At Life Line



Photo 18: Area of Patching and Cracking in Waterproofing Coating At Roof Drain



Photo 19: Re-caulking Along Wall/Roof Flashing and Concrete Wall Joint



Photo 20: Area of Patching and Cracking in Waterproofing Coating along South Wall

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6.0 Thermal Imagery:

6.1 Powerhouse #1 (Powerhouse Roof):

Exploits Engineering Consultants Ltd.

Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

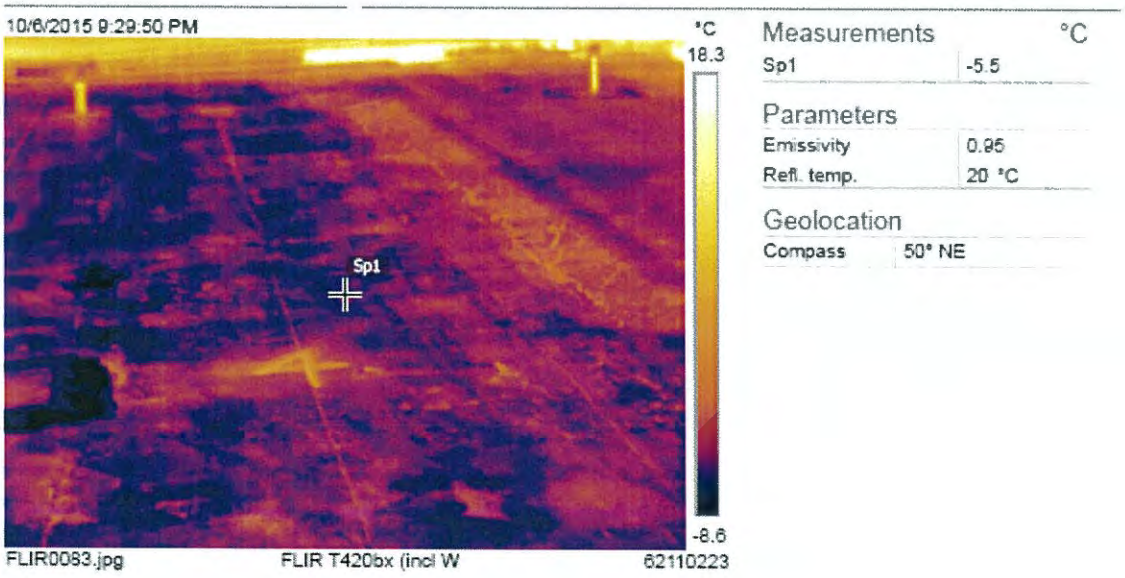




Image TS-1 was taken at grid 4 looking northeast towards grid 5. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

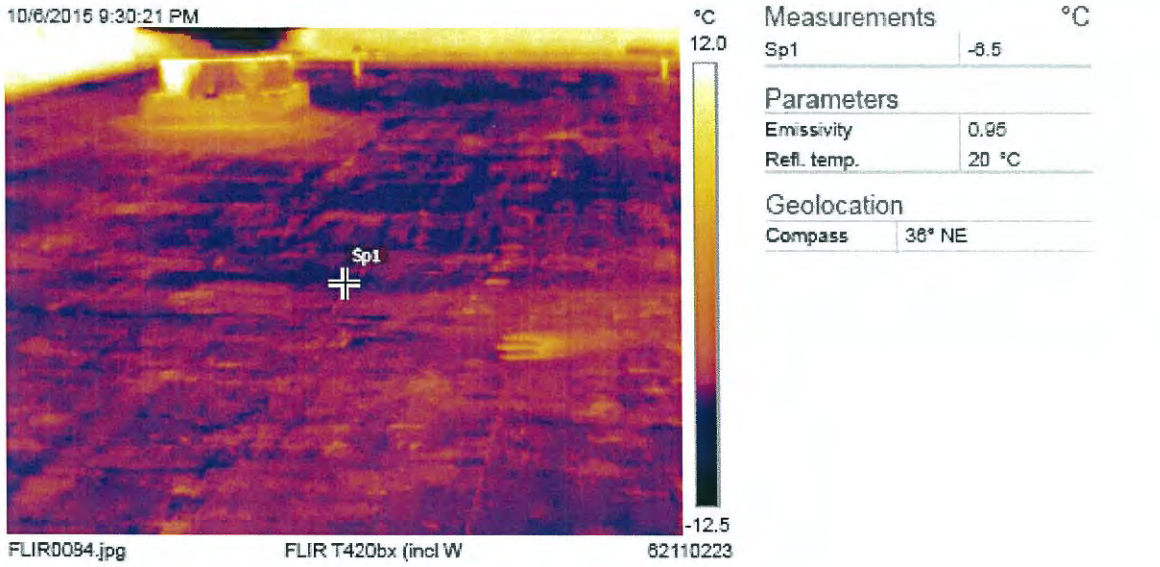




Image TS-2 was taken at grid 3 looking northwest towards grid 5. The lighter area at the exhaust fan is related to higher temperatures from the exhausted air at this location and is not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

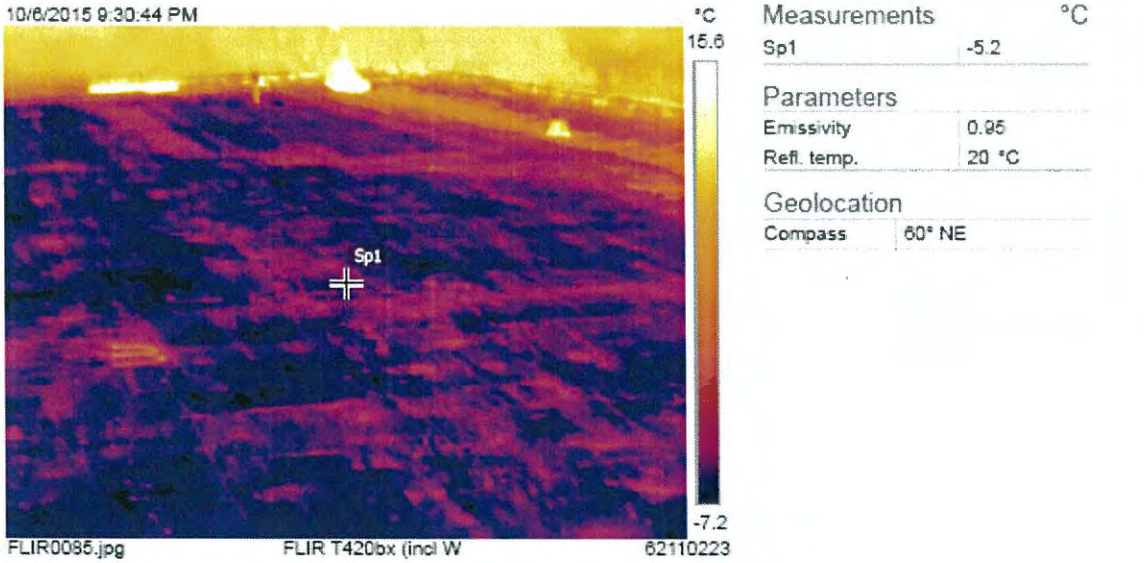




Image TS-3 was taken at grid 3 looking northeast towards grid 5. The lighter areas are caused by higher temperatures at the dark coloured roofing membrane and roof drains.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

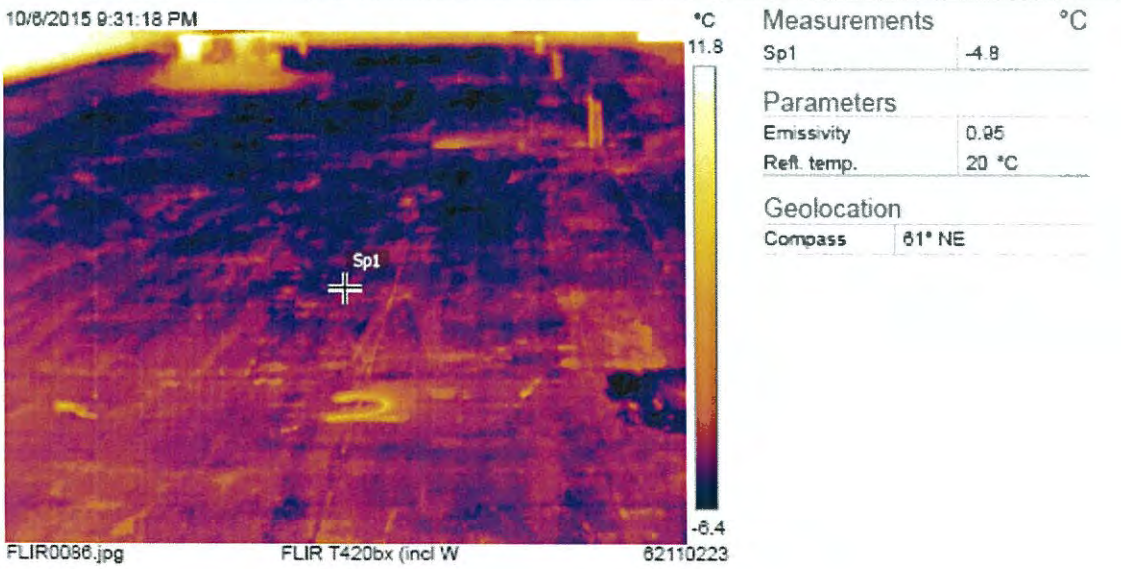




Image TS-4 was taken at grid 2 looking northwest toward grids 4 and 5. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

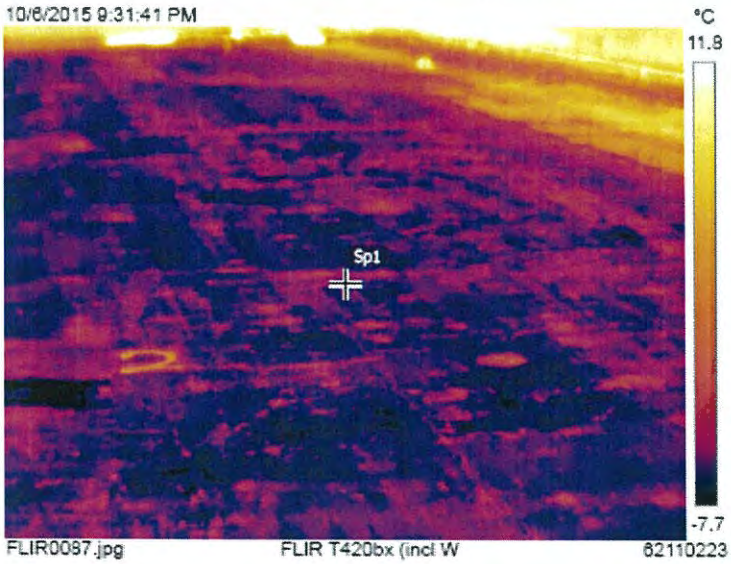




Image TS-5 was taken at grid 2 looking northeast toward grids 4 and 5. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

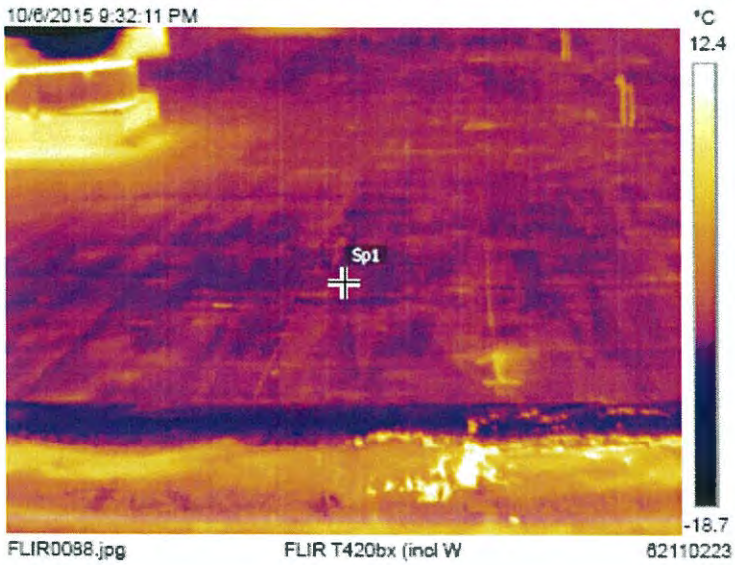


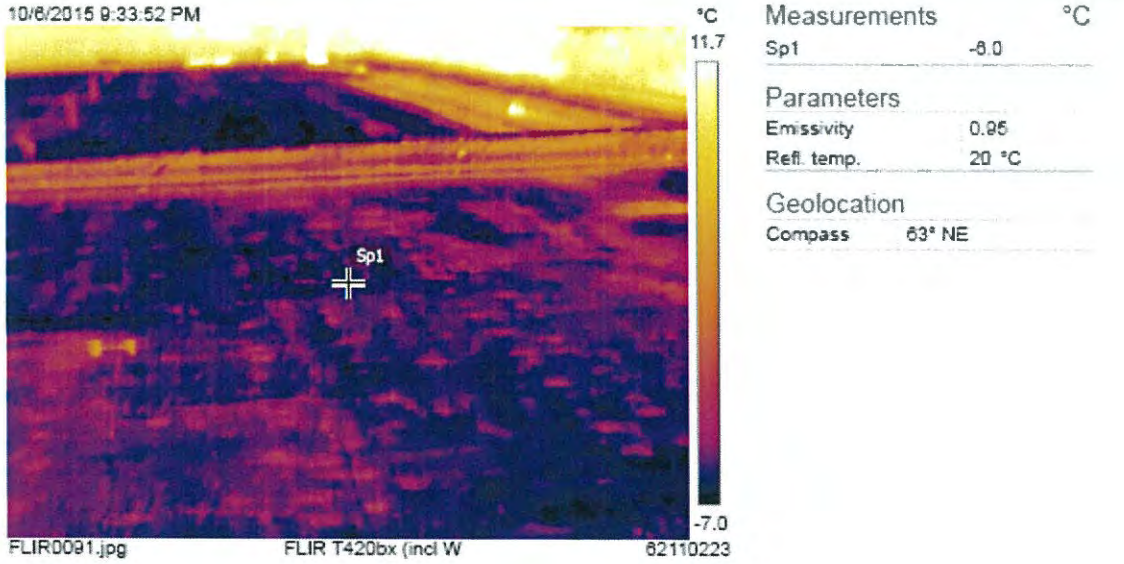


Image TS-6 was taken at grid 1 looking northwest toward grid 2. Higher temperatures from exhausted air are evident at the exhaust fan visible in the upper left corner.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir



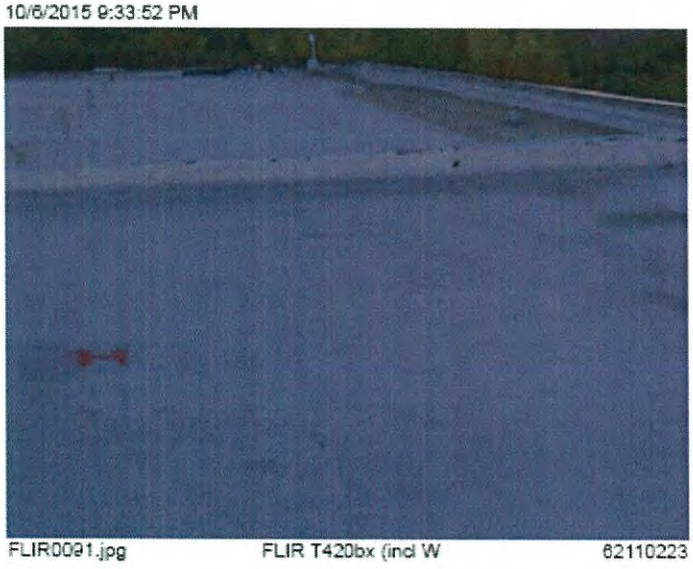


Image TS-7 was taken at grid H looking northeast. Higher heat loss is evident due to reduced insulation at the expansion joint. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

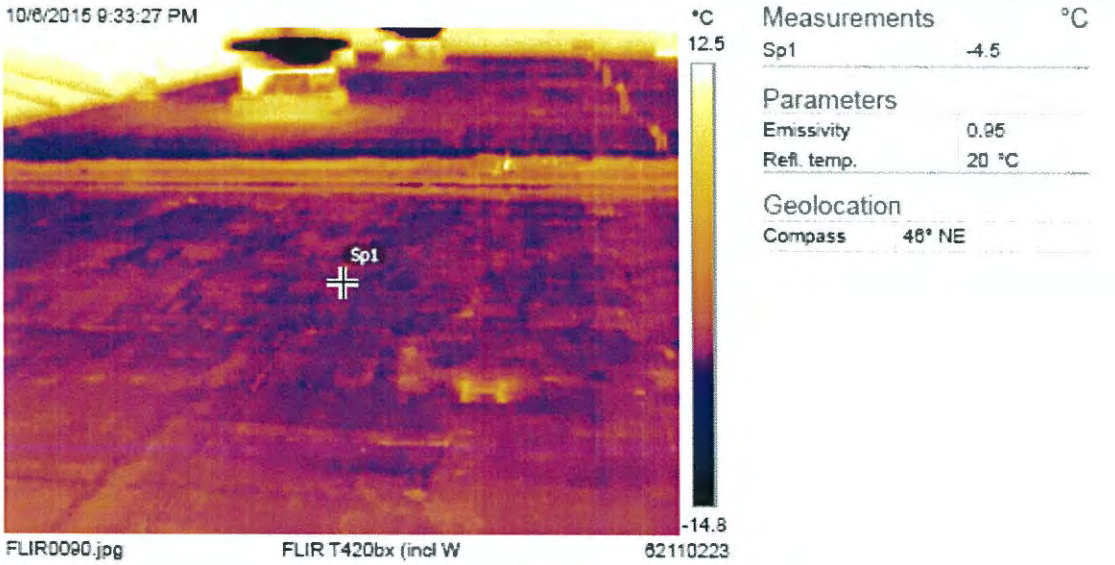


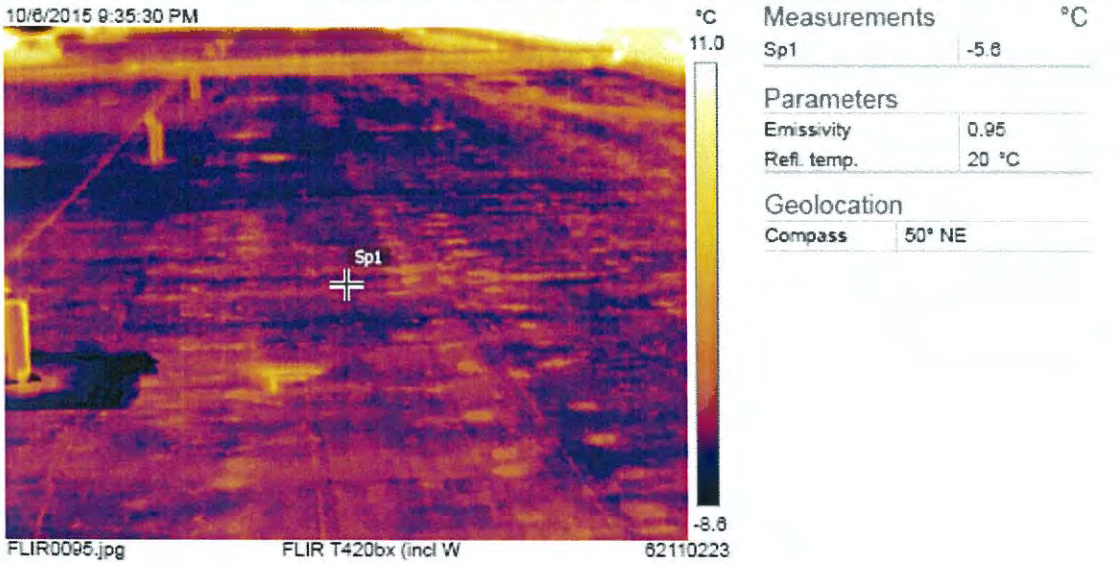


Image TS-8 was taken at grid H looking northwest. The expansion joint and exhaust fans are visible in background.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir





ImageTS-9 was taken at grid F looking northeast. The Life line is visible to the left in the photo. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

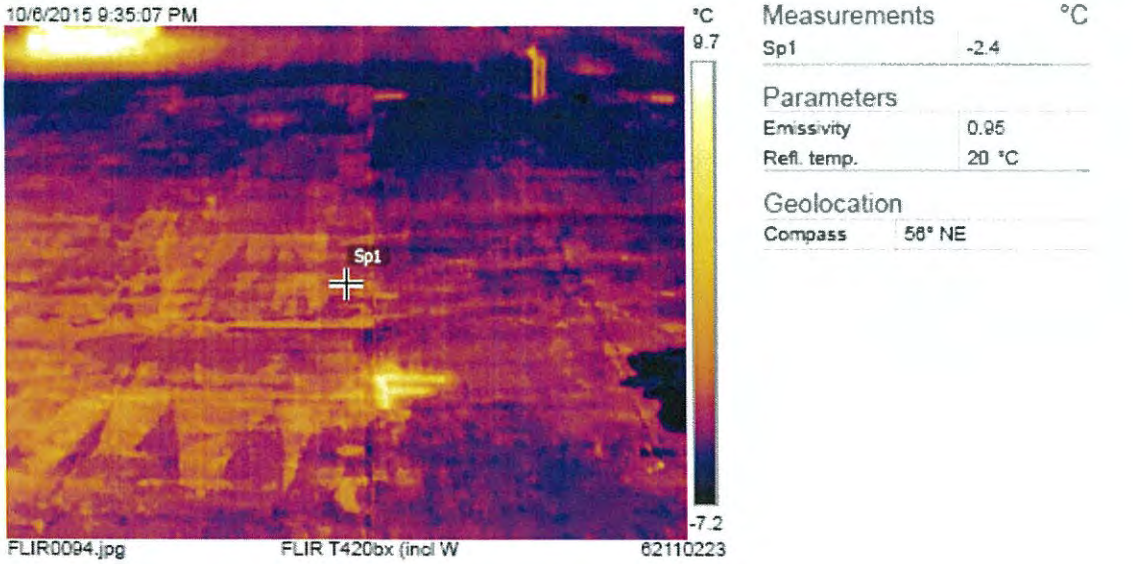




Image TS-10 was taken at grid F looking north. A small temperature differential is evident due to discolouration of the roof surface. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

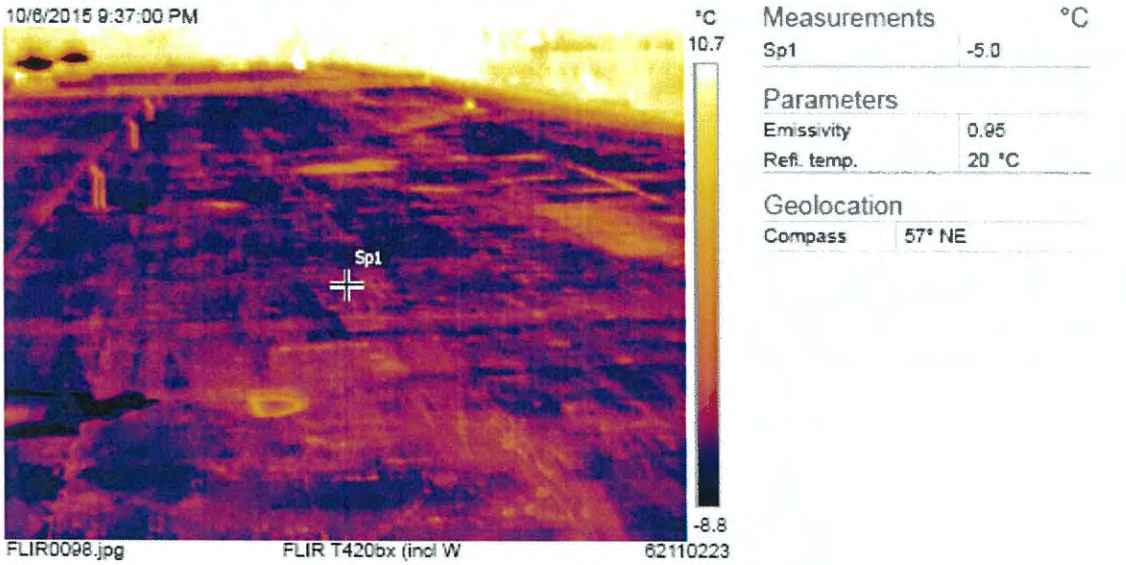




Image TS-11 was taken at grid D looking northeast. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

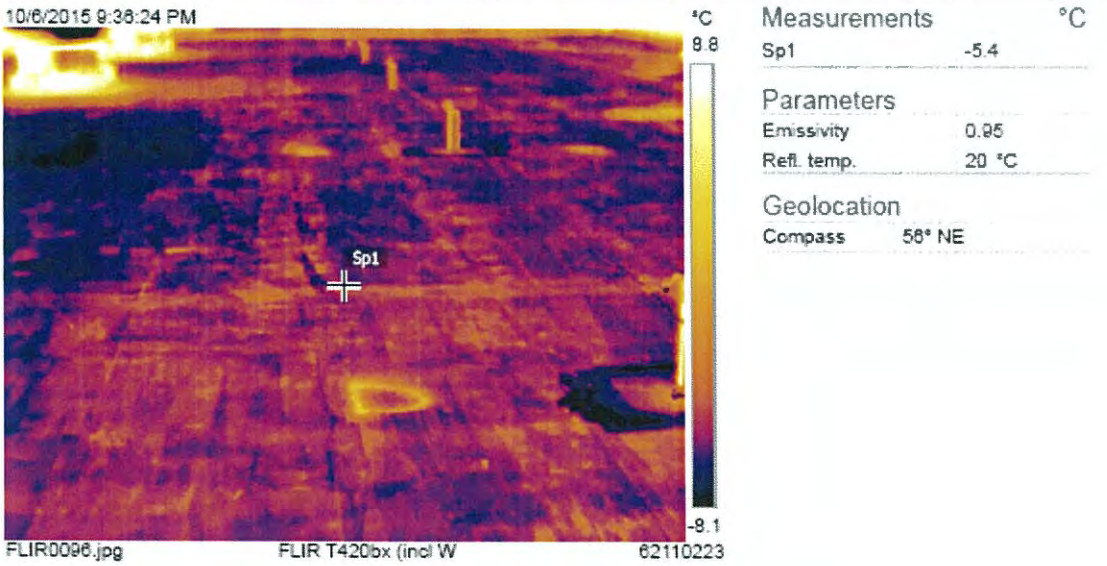




Image TS-12 taken at grid D looking northwest. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

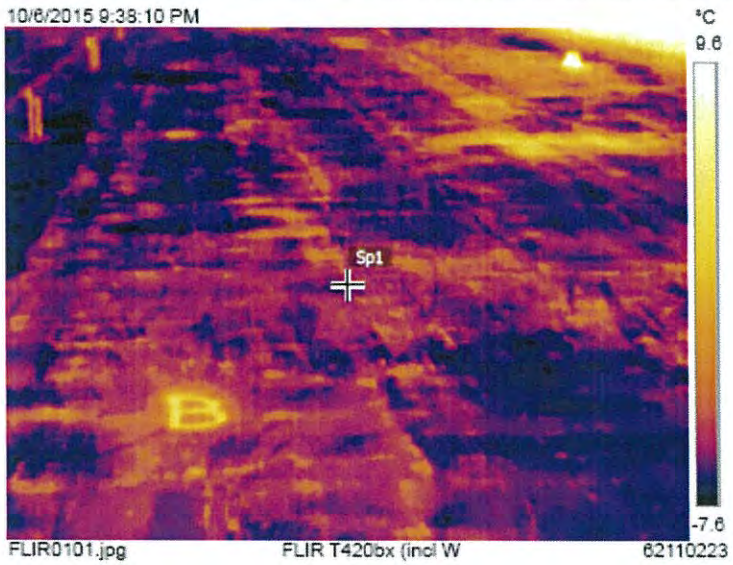




Image TS-13 was taken at grid B looking northeast. The roof drain is visible in upper right corner. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

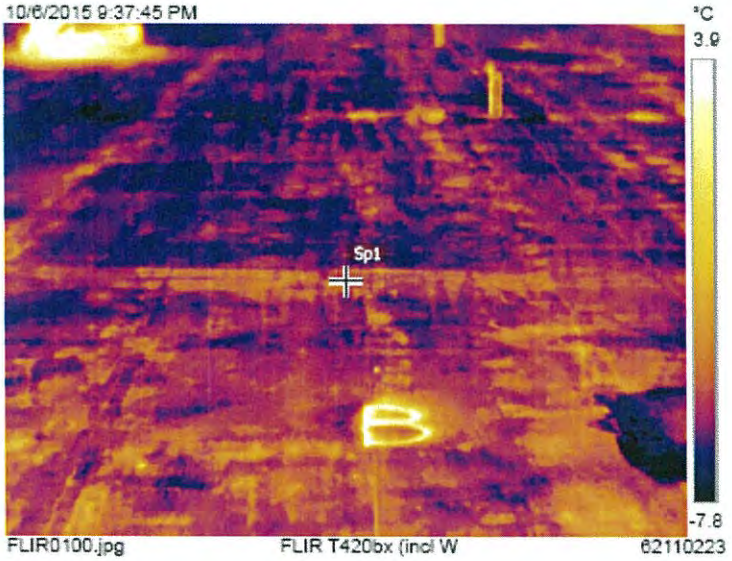




Image TS-14 taken at grid B looking northwest. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir





Image TS-15 was taken at grid B looking southeast. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

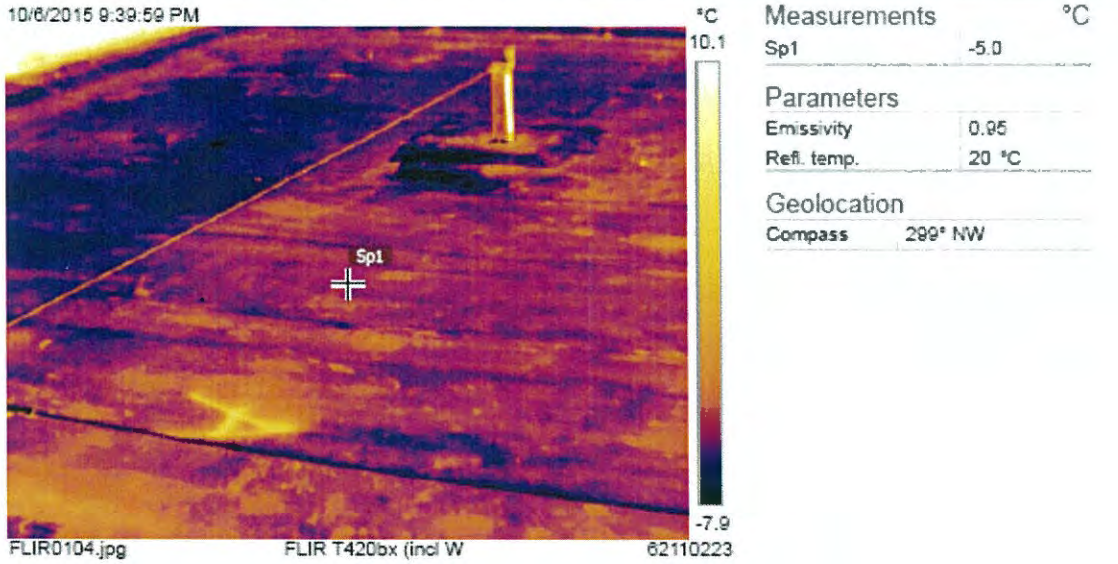




Image TS-16 was taken at grid A looking west. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Upper roof)
Milltown, Bay D'espoir

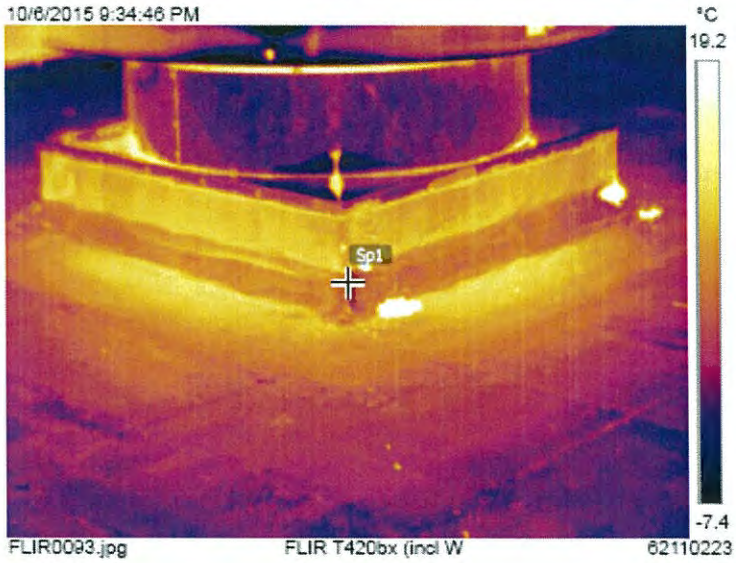




Image TS-17 shows an exhaust fan curb. Note that higher temperatures are evident from the warm exhausted air.

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6.2 Powerhouse #1 (Office Complex Roof):

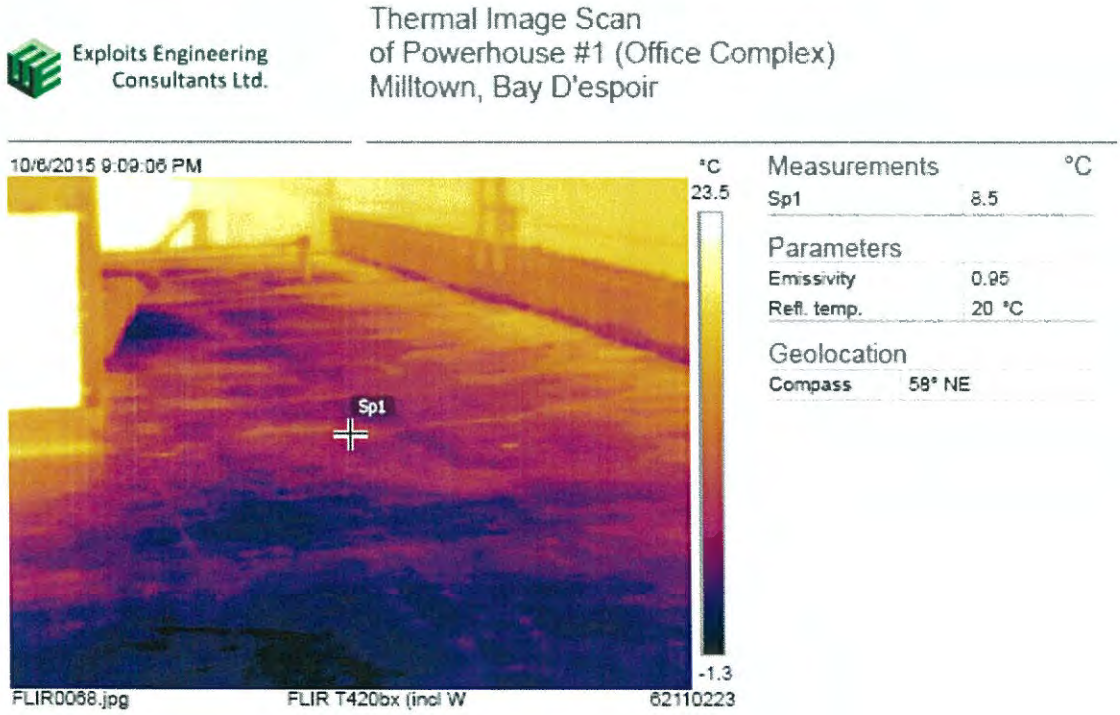




Image TS-18 shows the west side of the Office Complex Roof looking north between the A/C unit and the upper powerhouse wall. The concrete wall functions as a thermal mass and contributes to higher temperatures at the roof to wall transition.

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Thermal Image Scan
of Powerhouse #1 (Office Complex)
Milltown, Bay D'espoir

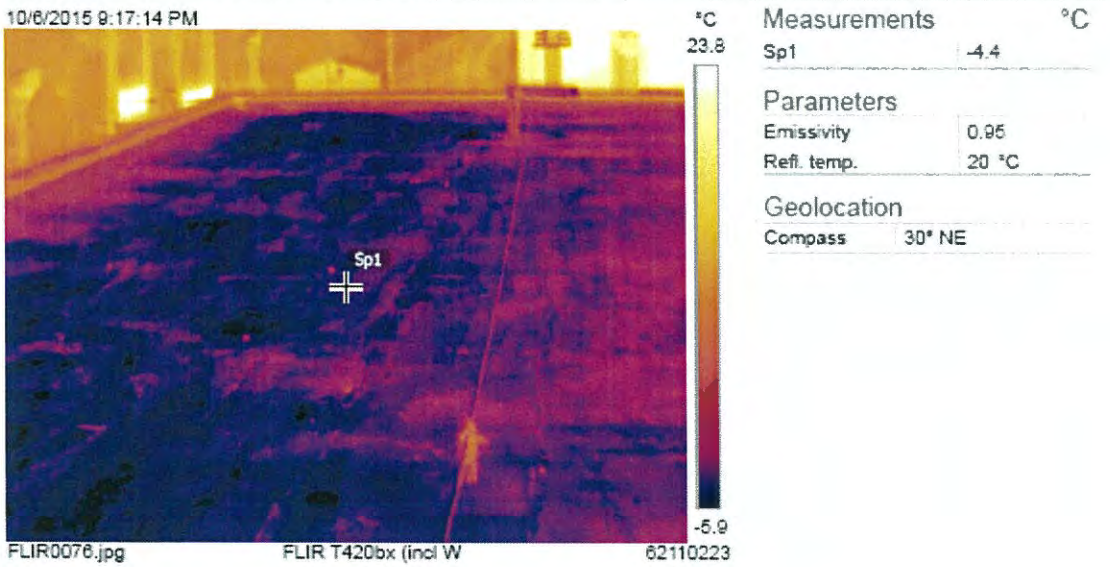




Image TS-19 shows the west side of the Office Complex Roof looking north. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Office Complex)
Milltown, Bay D'espoir





Image TS-20 is taken from the west side of the Office Complex Roof looking east at the A/C unit. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Office Complex)
Milltown, Bay D'espoir

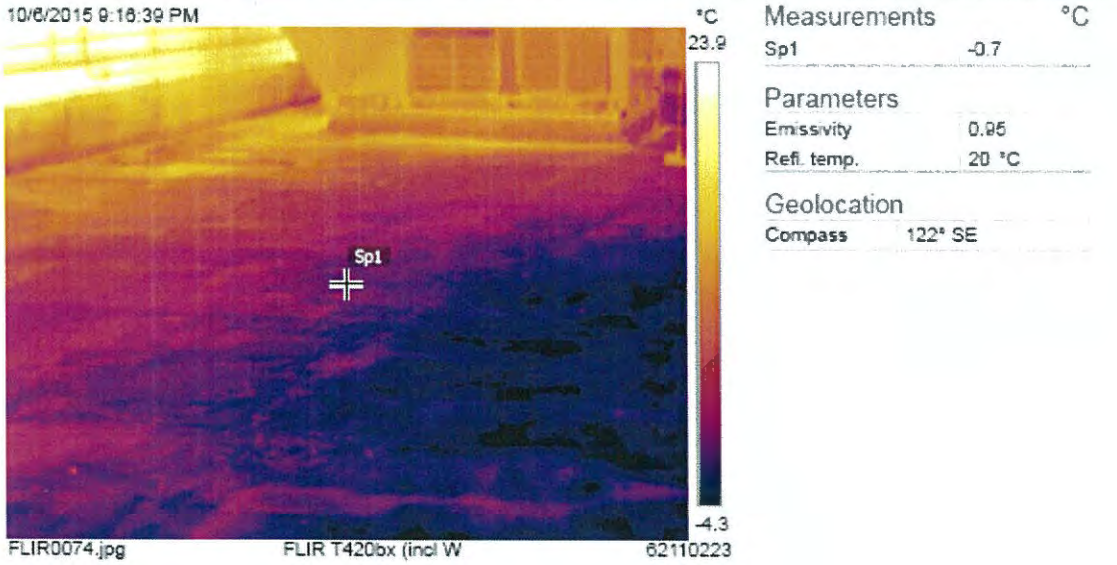




Image TS-21 is taken from the west side of the Office Complex Roof looking east at the A/C unit. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
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Milltown, Bay D'espoir

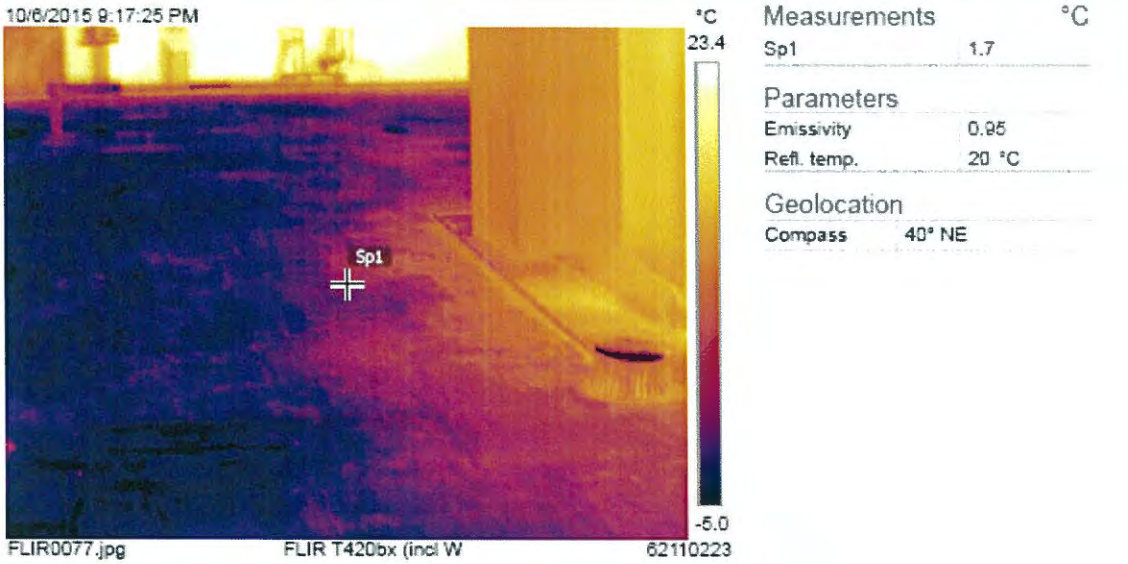




Image TS-22 is taken on the west side of the Office Complex Roof looking north with the A/C unit visible on the right. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Office Complex)
Milltown, Bay D'espoir

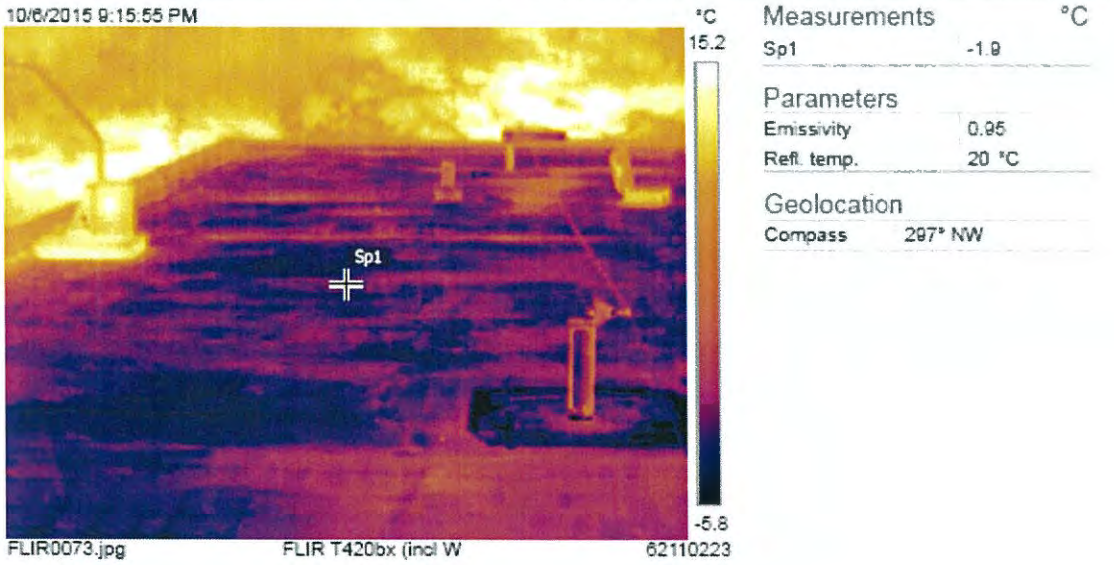




Image TS-23 was taken on the east side of the Office Complex Roof looking to the west. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Office Complex)
Milltown, Bay D'espoir

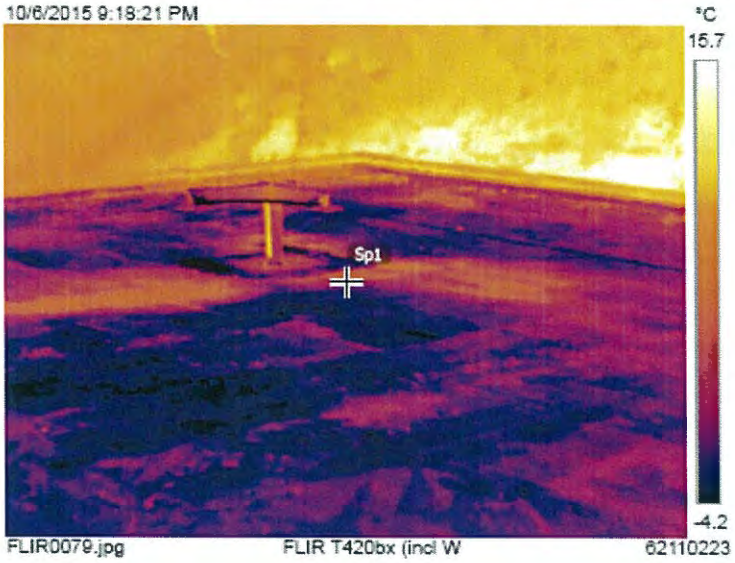




Image TS-24 was taken at the middle section of the Office Complex Roof looking southeast. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #1 (Office Complex)
Milltown, Bay D'espoir

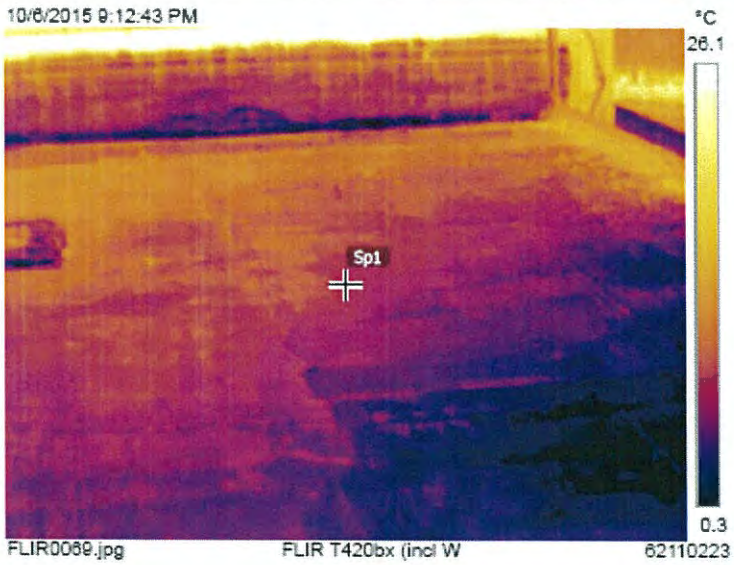




Image TS-25 was taken on the east side of the Office Complex Roof looking north towards the upper powerhouse wall. Warmer roof temperatures are evident and are to be expected adjacent to the concrete wall.

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6.3 Powerhouse #2:

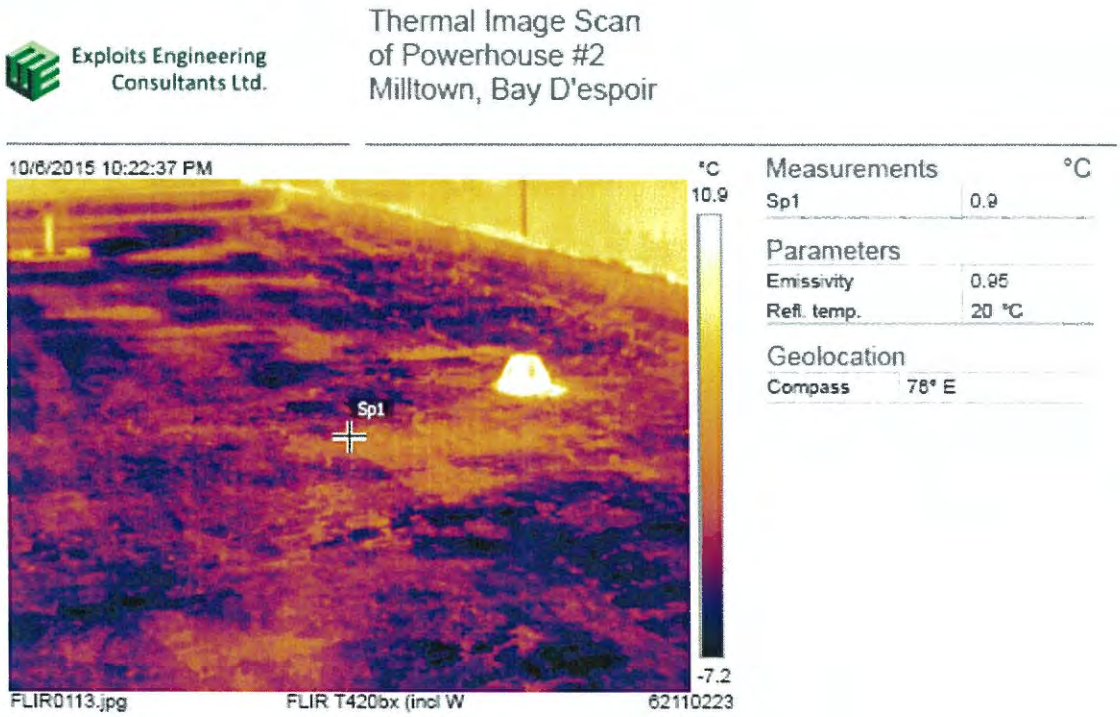




Image TS-26 was taken at grid 2 looking northeast. Higher temperatures are evident at the roof drain shown to the right in the Image. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #2
Milltown, Bay D'espoir

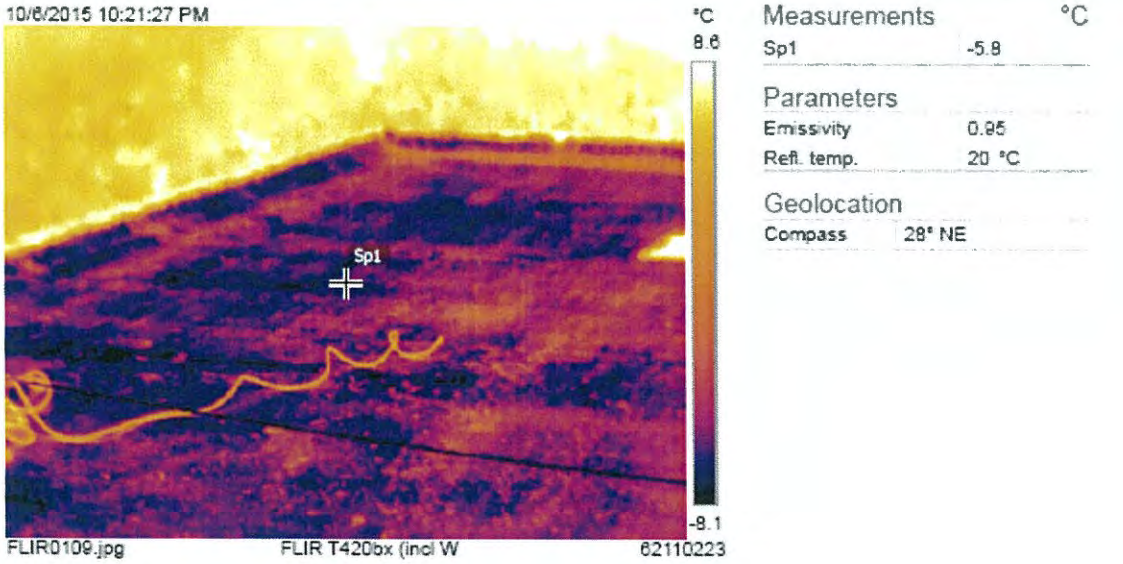




Image TS-27 was taken at grid 2 looking towards the northwest corner. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
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Milltown, Bay D'espoir

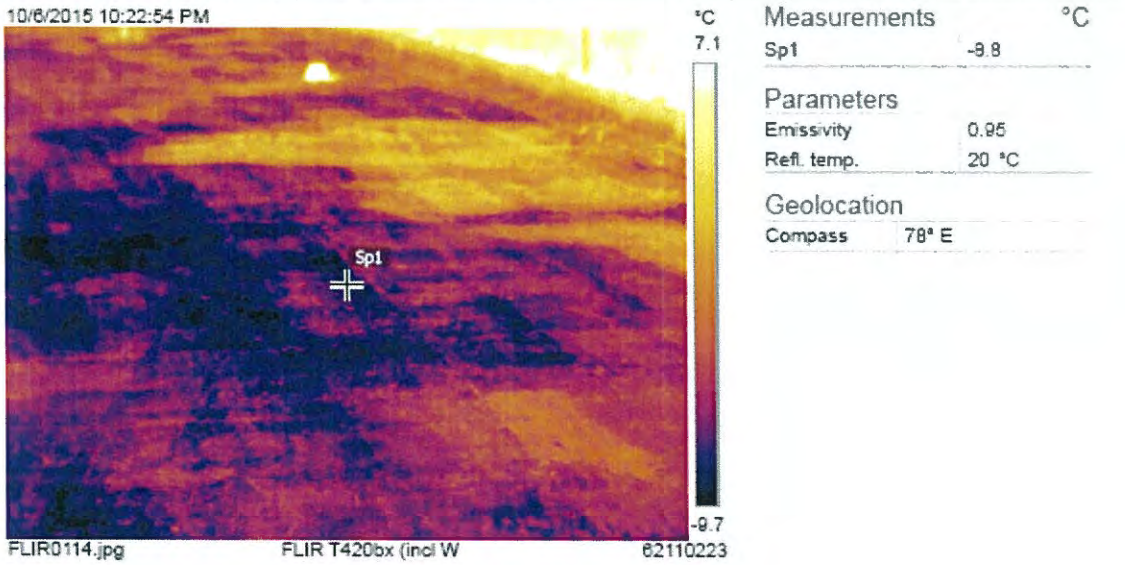


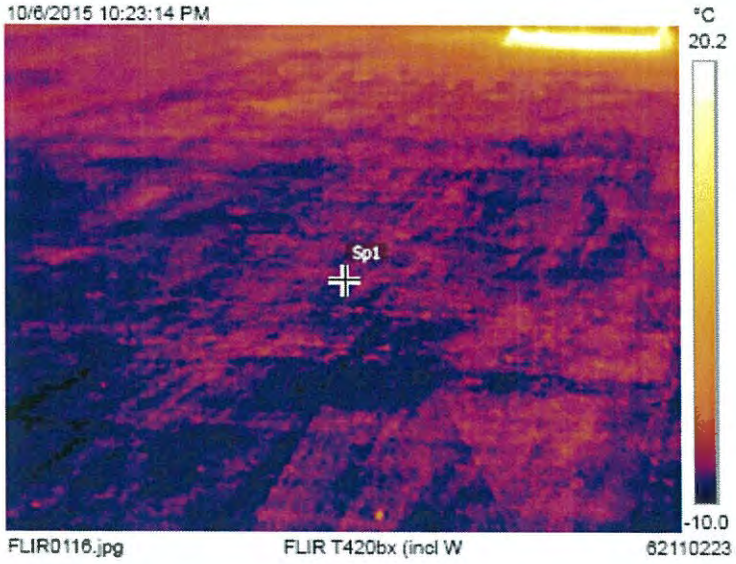


Image TS-28 was taken at grid 4 looking northeast. Higher temperatures are evident at the areas of dark discolouration. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
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Milltown, Bay D'espoir



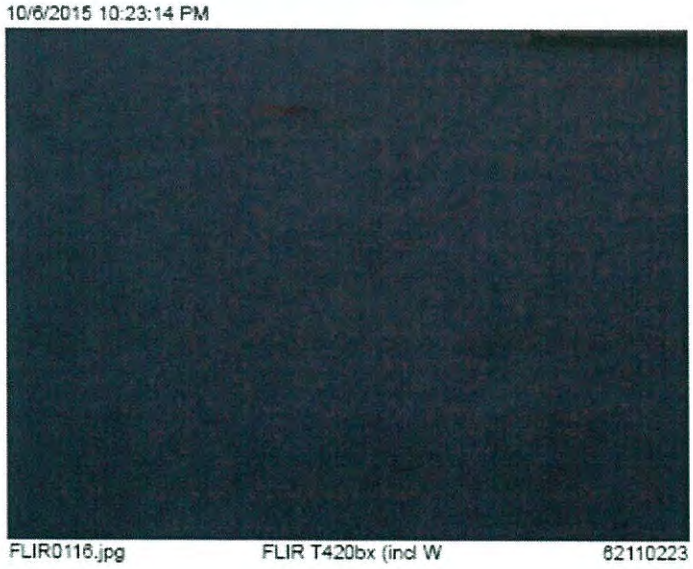
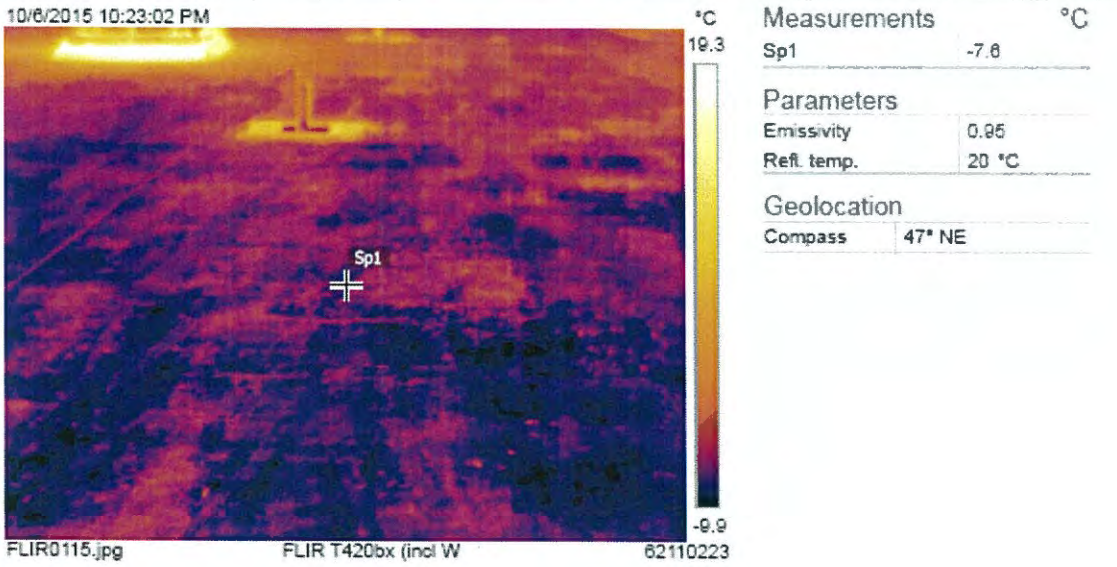


Image TS-29 was taken at grid 4 looking southwest. The higher temperatures evident at the exhaust fan are related to the warm air discharge at that location.

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Thermal Image Scan
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Milltown, Bay D'espoir



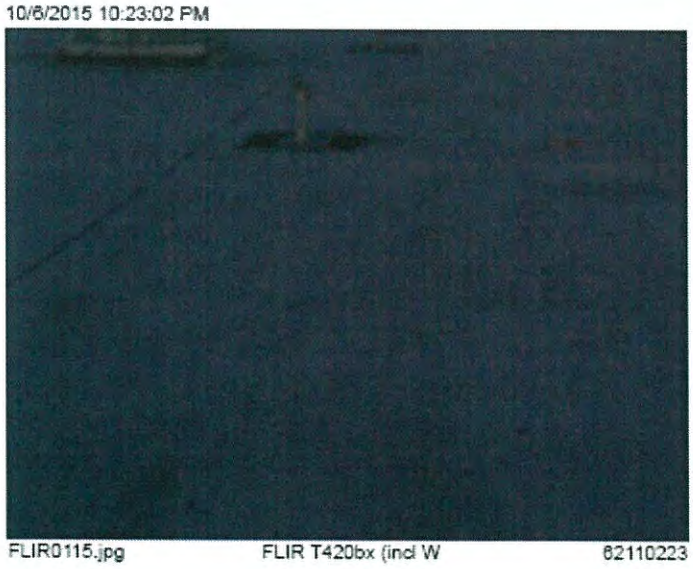
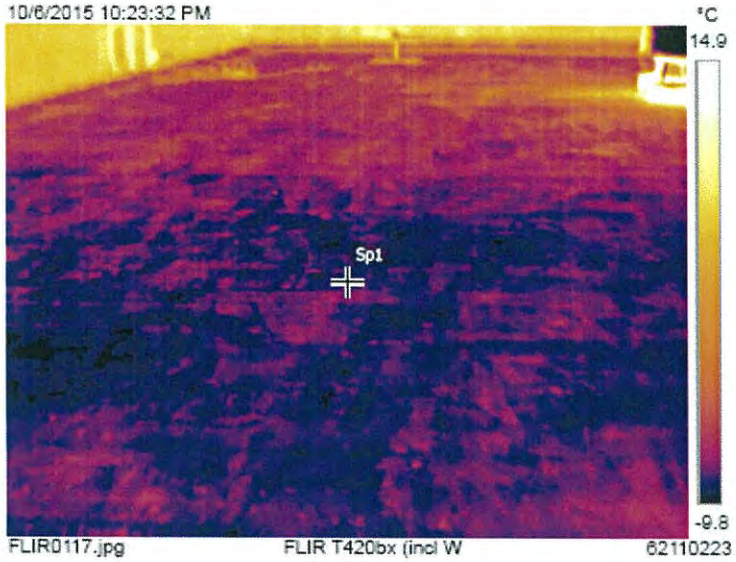


Image TS-30 was taken at grid 4 looking northwest. The higher temperatures evident at the exhaust fan are related to the warm air discharge at that location.

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Thermal Image Scan
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Milltown, Bay D'espoir



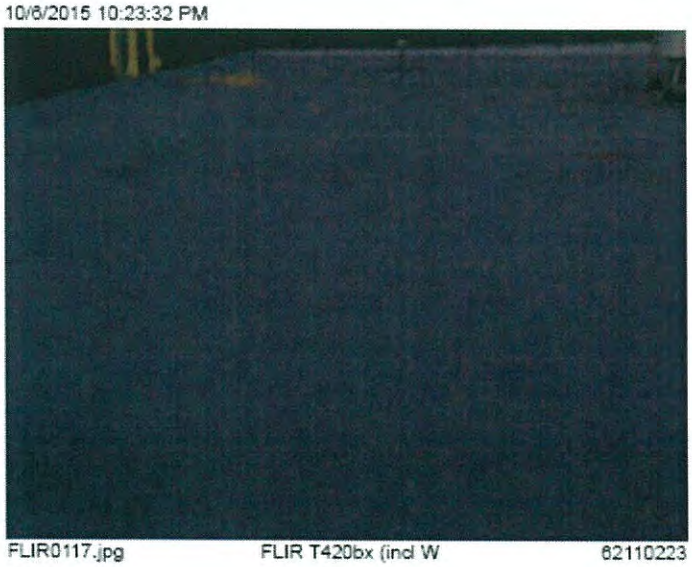


Image TS-31 was taken at the west side of Powerhouse Roof #2 looking towards the access ladder. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
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Milltown, Bay D'espoir

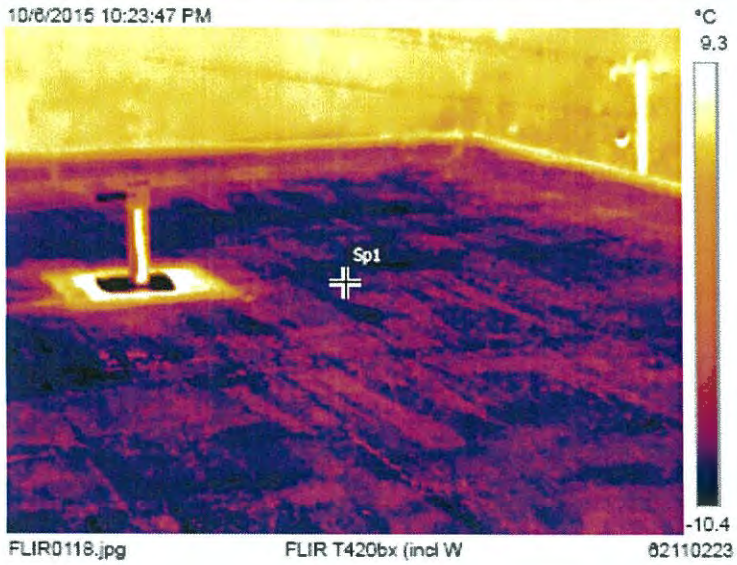




Image TS-32 was taken at grid 5 looking towards the southwest corner. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
of Powerhouse #2
Milltown, Bay D'espoir

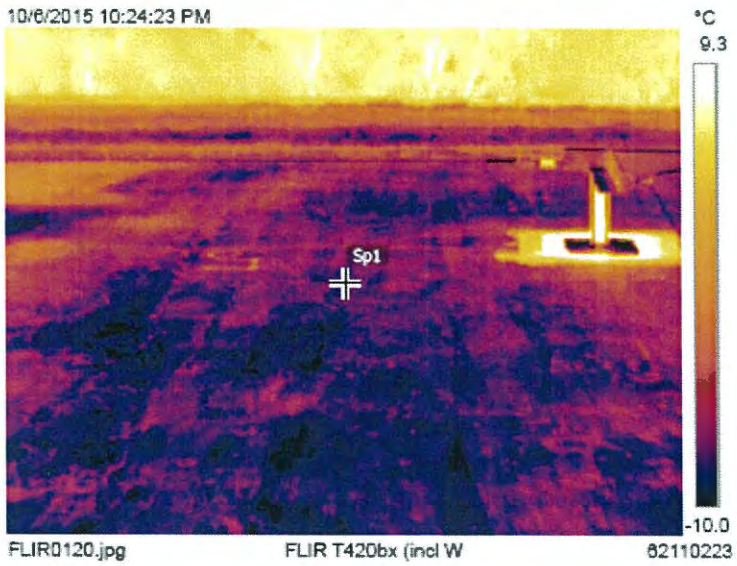




Image TS-33 was taken at grid 5 looking towards the south parapet. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
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Milltown, Bay D'espoir

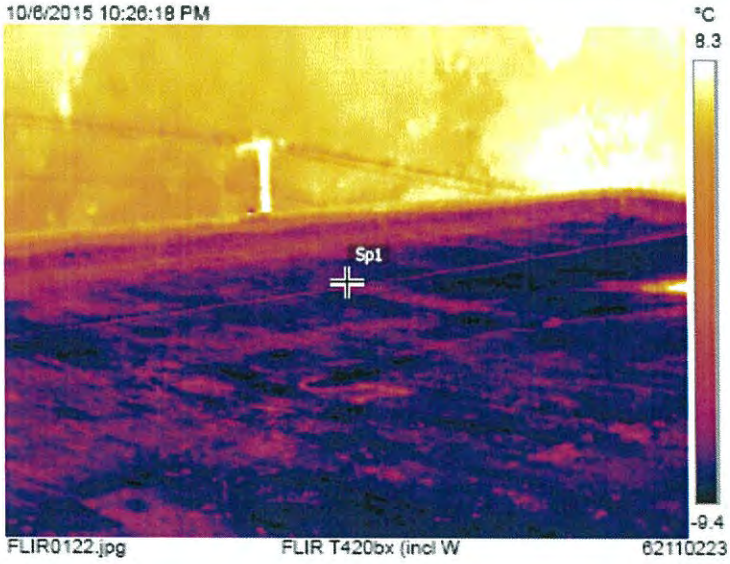




Image TS-34 was taken at grid 4 looking towards the southeast corner. The lighter areas in the thermal image may be attributed to the discoloration of the roofing membrane and are not necessarily indicative of moisture beneath the roof surface.

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Thermal Image Scan
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Milltown, Bay D'espoir

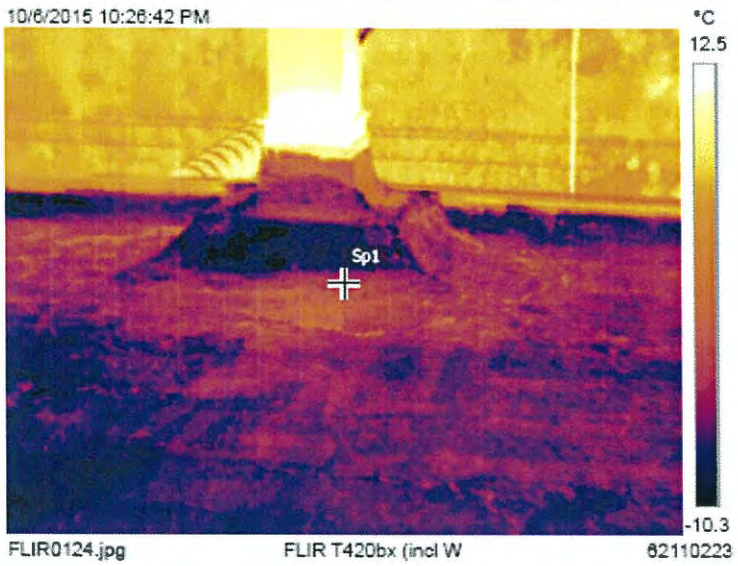




Image TS-35 was taken at the west side of the roof at the base of the steel column.

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Thermal Image Scan
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Milltown, Bay D'espoir

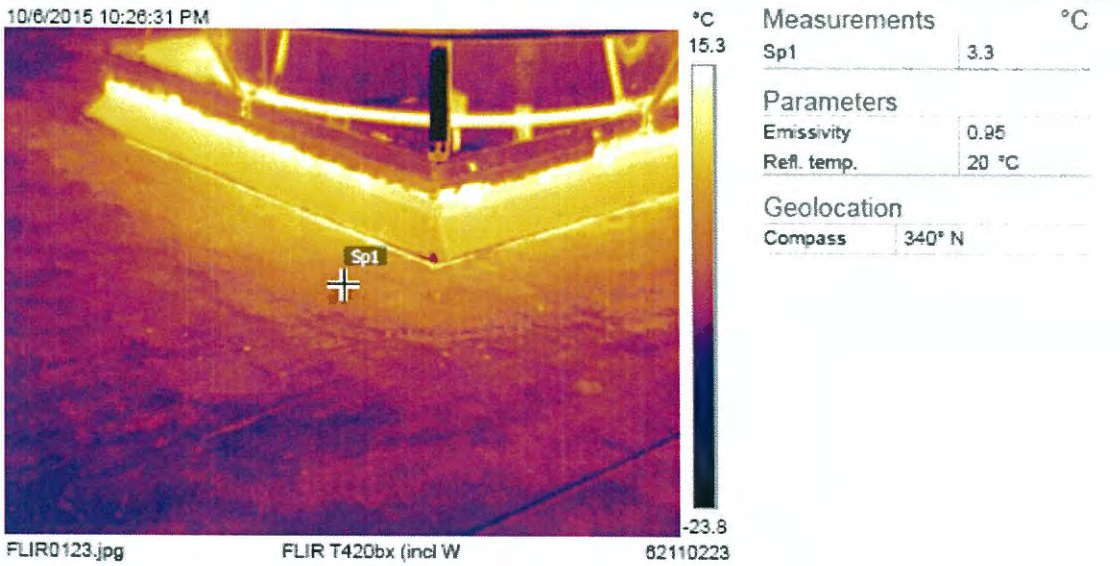




Image TS-36 was taken at the exhaust fan base. Higher temperatures are evident from the warm exhausted air.

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7.0 Limitations of Condition Assessment:

This report reflects EECL's observations and opinions based on a visual inspection and thermal image scans of the roof areas related to this contract. The inspections did not employ destructive methods of analysis such as core sampling which would be recommended as a next step had there been suspect water infiltration.

8.0 Condition Assessment and Recommendations:

8.1 Thermal Image Scans

The thermal image scans of all roof areas did not detect any anomalies that would indicate potential moisture beneath the roof surface.

8.2 Visual Inspection

The visual inspections of all roof areas indicate that:

1. The exposed roofing materials and flashings are being well maintained.
2. The expansion joint membrane covering both Powerhouse Roofs remains flexible and shows no signs of cuts, breaks or other damage.
3. Surface cracking is evident in the waterproofing coating that has been applied to all roof areas. This damage is most pronounced on the Office Complex Roof.
4. All roof drains are clear and appear to be draining properly.
5. Flashing around roof top units is in good condition.
6. Roof to wall flashings on the Office Complex Roof contain small sections of failed caulking.
7. There is one small area of surface de-lamination of the waterproof coating on the Office Complex Roof (See Photo #8).
8. The Powerhouse #1 Roof (Powerhouse Roof) is in good condition.
9. The Powerhouse #2 Roof is in good condition.
10. The Powerhouse #1 Roof (Office Complex Roof) is in fair condition.

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8.3 Recommendations (Maintenance and Repair):

1. Continue the on-going NL Hydro roofing maintenance program on all roof areas.
2. Repair any missing or damaged caulking in wall seams and at roof/wall flashings on the Office Complex Roof.
3. Monitor the roof waterproof coatings for cracking and de-lamination, and repair as required.
4. Continue the annual re-application of waterproofing coating as per the HL Hydro maintenance protocol.
5. Monitor roof drains on a regular basis to ensure that they do not become blocked by debris.
6. Confirm that all drains flow freely.
7. Monitor the building interiors for any evidence of newly developed leaks. If a leak develops then identify the source and have the leak repaired immediately. Also see Section 8.4, below.

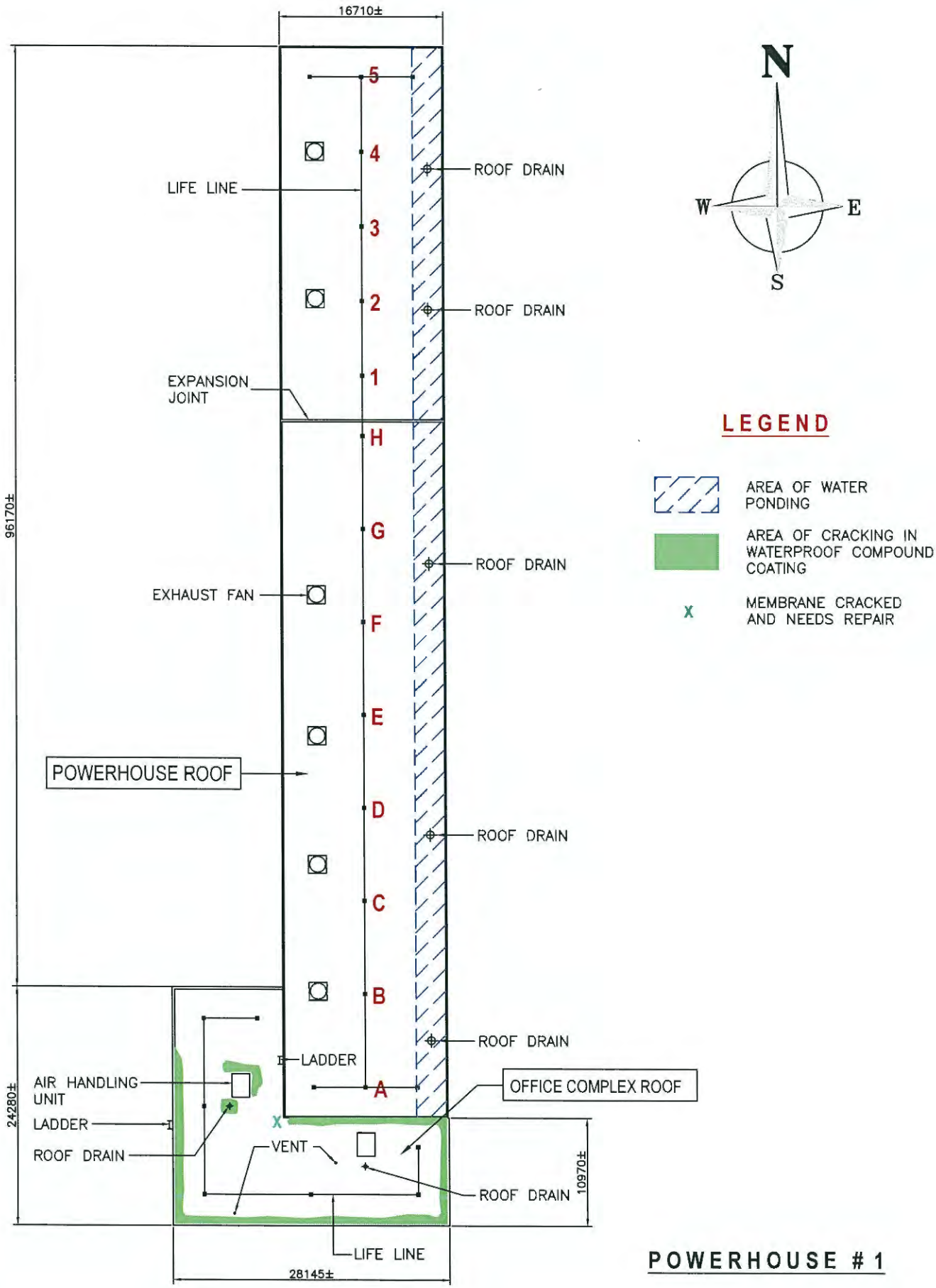
8.4 Recommendations (Roof Replacement)

1. The Powerhouse #1 Roof (Office Complex Roof) is in fair condition and it is estimated to have a life expectancy in the range of five to seven years. It is recommended that roof replacement be considered within this time frame. If any major leaks develop in the interim then that recommendation should be re-evaluated.

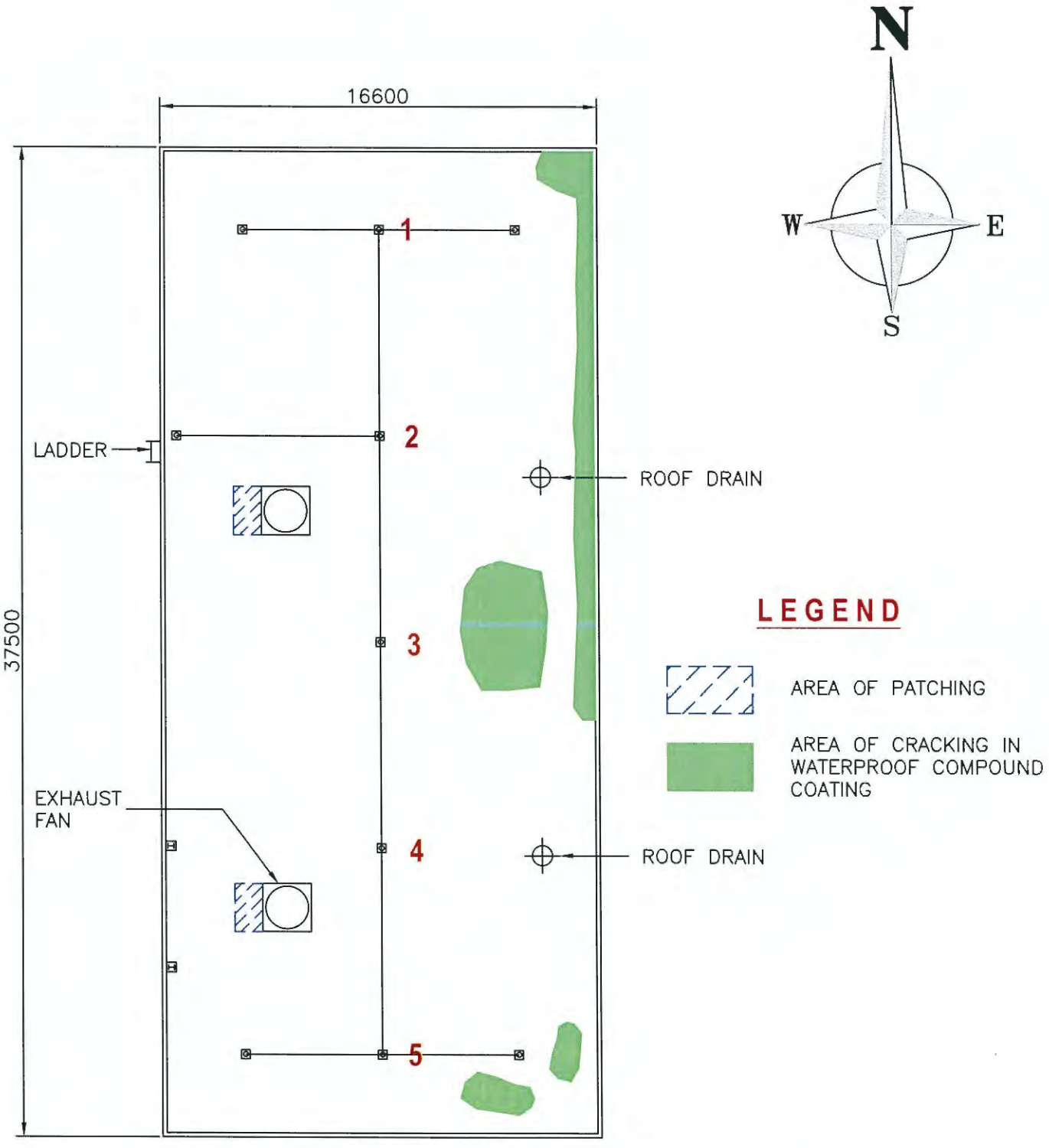
2. The Powerhouse #1 Roof with exception of Office Complex Roof identified in 8.4.1, and the Powerhouse #2 Roof, are both in good condition. It is recommended that they be re-assessed in five years time as per the regular NL Hydro protocol. If any major leaks develop in the interim then that recommendation should be re-evaluated.

EXPLOITS ENGINEERING CONSULTANTS LIMITED
2 Mill Road, Grand Falls – Windsor, NL A2A 1B7
P: 709-489-9150 f: 709-489-9185

Appendix 'A' – Plans



POWERHOUSE # 1



POWERHOUSE # 2

Refurbish Fuel Oil Storage Tank 4 (2024)

Holyrood

July 2023

newfoundland labrador hydro

Refurbish Fuel Oil Storage Tank (2024)

Location: Holyrood

Investment Classification: Mandatory

Asset Category: Thermal Plant

Executive Summary

The Holyrood Thermal Generating Station ("Holyrood TGS") has four large No. 6 fuel oil vertical storage tanks, identified as Tanks 1, 2, 3, and 4. The last out-of-service inspection of Tank 4 was completed in 2010. As per the requirements of the Certificate of Approval ("COA")[1] to operate, issued by the Government of Newfoundland and Labrador's Department of Environment and Climate Change ("Government"), Tank 4 must be drained, cleaned, and re-inspected at regular intervals.[2] This certificate is provided as Attachment 1. The No. 6 fuel oil storage tanks are subject to deterioration due to corrosion; a leak or oil spill could cause major environmental and operational issues. Failure to comply with the terms and conditions of the COA could result in the cessation of all generating activities at the Holyrood TGS.

To mitigate generation-related capital investment at the Holyrood TGS, Newfoundland and Labrador Hydro ("Hydro") engaged an external consultant to complete a remaining life assessment of the tank. Based on the findings of the assessment, Government agreed to defer the next out-of-service inspection to 2024, as outlined in Attachment 2. Further deferral is not a viable option; therefore, Tank 4 must be drained, cleaned, and re-inspected before the 2024–2025 winter operating season to maintain its certification.

As per the "Reliability and Resource Adequacy Study – 2022 Update,"[3] the Holyrood TGS shall remain available for a "Bridging Period"[4] until 2030 or until such time that sufficient alternative generation is commissioned, adequate performance of the Labrador-Island Link ("LIL") is proven, and generation

[1] Pursuant to the *Environmental Protection Act*, SNL 2002, c. E-14.2, s.83.
[2] As required under NLR 58/03.
[3] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[4] Hydro considers the Bridging Period to be from 2023 to 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

reserves are met. To ensure that the Holyrood TGS is fully available for generation at its maximum output when required, a minimum of three fuel storage tanks must remain in reliable operating condition. Considering the Holyrood TGS has four No. 6 fuel oil storage tanks and has had three of four tanks in service since 2021, the refurbishment of Tank 4 is required in advance of the 2024–2025 operating season to keep three tanks in operation.[5]

In consideration of this, the following alternatives were considered:

- Deferral;
- Upgrade life extension;
- Like-for-like replacement; and
- Alternative strategies.

To satisfy the terms and conditions of the COA and ensure the reliable operation of the Holyrood TGS, Hydro must proceed with the proposed draining, cleaning, out-of-service inspection, and refurbishment to upgrade the life extension of Tank 4.

The estimated cost for work executed under this project is $1,920,000.

[5] Tank No. 1 was initially removed from service in 2021 but has since been put back in service and Tank 2 removed from service as a result of *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 30(2022), Board of Commissioners of Public Utilities, October 7, 2022.

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List of Attachments

Attachment 1: "Certificate of Approval Pursuant to the *Environmental Protection Act*, SNL 2002, c. E-14.2, s.83," Government of Newfoundland and Labrador – Department of Environment and Climate Change, June 30, 2022.

Attachment 2: "HTGS Tank 4 Inspection Interval," Government of Newfoundland and Labrador – Department of Environment and Climate Change, September 16, 2021.

1.0 Introduction

The Holyrood TGS has four large No. 6 fuel oil vertical storage tanks, identified as Tanks 1, 2, 3, and 4. Based on the anticipated reduction in production at the Holyrood TGS, the facility moved to a three-tank operation as of 2021.

The No. 6 fuel oil tanks are subject to deterioration due to corrosion. A leak of fuel oil from the storage tanks could result in a major environmental incident and cause significant operational issues. As per the terms and conditions of the COA, as issued by Government, and in accordance with common industry practice, the fuel oil storage tanks are subject to the American Petroleum Institute Standard 653[6] ("API 653") for tank inspection, repair, alteration, and reconstruction. This requirement is outlined in Attachment 1. Under API 653, tanks are required to undergo an in-service tank inspection every five years, with an out-of-service inspection completed at the tank's ten-year service life and every ten years thereafter.[7] Subsequent out-of-service inspection intervals can be extended beyond ten years pending the completion of a tank remaining life assessment.

The last out-of-service inspection for Tank 4 was completed in 2010. In 2019, Hydro engaged TEAM Industrial Services to complete an assessment of the tank to determine whether the out-of-service inspection interval could be extended. Based on the findings of the assessment and in collaboration with the Government, the Tank 4 inspection interval was ultimately deferred to 2024.

Hydro has committed to maintaining the availability of the Holyrood TGS for a "Bridging Period" until 2030 or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met. To ensure that the Holyrood TGS is fully available for generation at its maximum capacity, three fuel storage tanks are required to remain in service.

2.0 Project Description and Justification

This project consists of the cleaning, draining, inspection, and refurbishment of fuel oil storage Tank 4 at the Holyrood TGS.

[6] American Petroleum Institute. (2014). API Standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction* (5th ed.).
[7] In-service tank inspections do not require the tank to be drained. Out-of-service tank inspections are completed after draining the fuel and cleaning the tank.

As per the terms and conditions of the COA, in accordance with common industry practice, the fuel oil storage tanks are subject to API 653. As Tank 4 last underwent an inspection in 2010, it must be inspected in 2024 to satisfy the requirements of the COA. Failure to complete the inspection will violate the terms and conditions of the COA and could result in the cessation of all generating activities at the Holyrood TGS.

3.0 Asset Overview

3.1 Asset Background

The first phase of construction of the Holyrood TGS fuel oil tank farm was completed in 1969, including the construction of Tanks 1 and 2, all associated fuel oil transfer pipelines, and the earthen containment dyke. A second phase of construction followed in 1977, which included the construction of Tanks 3 and 4 and their associated piping.

All four tanks are vertical, uninsulated, and identical in size, with a diameter of 180 feet and a height of 48 feet. Excluding dead storage,[8] each tank stores approximately 200,000 barrels of serviceable No. 6 fuel oil, which is used for steam production on all three thermal generating units at the Holyrood TGS.

Each tank contains two suction heaters and one platform heater. These heaters heat the No. 6 fuel oil inside the tank to prevent it from freezing, ensuring it is accessible for delivery through the 18-inch supply line that feeds the day tank. Fuel is circulated from the day tank to the burners of the power boilers during production. Flow to the suction heaters is controlled using an isolation valve on each heater with a valve stem extended to the top of the tank.

[8] Dead storage is defined as the portion of total storage capacity that is equal to the volume of oil below the lowest outlet valve. This oil cannot be accessed under normal operating conditions. Dead storage is used as a means to collect debris or contaminants found in the oil to ensure this is not transferred to the units.

4.0 Analysis

4.1 Evaluation of Alternatives

Tank 4 has not undergone an inspection since 2010. The tank's inspection interval was deferred to 2024 with the approval of the Government; however, it must be inspected in 2024 to satisfy the requirements of the COA. In consideration of this, the following alternatives were analyzed:

- Deferral;
- Upgrade life extension;
- Like-for-like replacement; and
- Alternative strategies.

4.1.1 Deferral

The deferral of this project will render Tank 4 out of service as of September 2024, due to the expiry of the COA. This will result in the Holyrood TGS moving to a two-tank operation. A downgrade of the storage facility at the Holyrood TGS to two tanks reduces the total storage capacity. Given the lead time between fuel order and delivery, in the event of a sudden change in generation requirements, it would be unlikely Hydro could expedite fuel delivery. In addition to capacity and the coordination constraints on fuel delivery, the transition to a two-tank operation poses a significant operational risk and introduces reliability risk in the event of equipment failure.[9] Therefore, the deferral of this project presents an unacceptable risk to the reliable operation of the Holyrood TGS and is not considered a viable alternative.

4.1.2 Upgrade Life Extension

As per the requirement for the extension of Tank 4's operation, the tank must be drained, cleaned, and inspected before the tank certification expires in September 2024. After the tank draining and cleaning, a refurbishment must be completed on Tank 4 to extend the tank certification and ensure the tank's

[9] For further details on the risk posed to the Holyrood TGS by two-tank operation, please refer to "Application for Approval of Various Supplemental Capital Projects at the Holyrood Thermal Generation Station," Newfoundland and Labrador Hydro, June 6, 2022, sch. 2, sec. 3.2. <http://www.pub.nl.ca/applications/NLH2022Capital/NLH2022Capital_SUPP_HolyroodThermal/app/From%20NLH%20-%20Approval%20of%20Various%20Supplemental%20Capital%20Projects%20at%20the%20Holyrood%20Thermal%20Generation%20Station%20-%202022-06-06.PDF>

fitness for service until such time that the Holyrood TGS is no longer required to serve as a generation source.

4.1.3 Like-for-Like Replacement

The purchase of a like-for-like replacement is more costly than the refurbishment of the existing tank. The completion of the proposed cleaning, inspection, and refurbishment will extend the service life of Tank 4 beyond the required period that the Holyrood TGS must remain available for generation. Therefore, like-for-like replacement of the existing tank is not a viable alternative.

4.1.4 Alternative Strategies

Hydro has considered the transition to a two-tank operation, pre-arranged prioritized delivery in the event of increased generation requirements, and off-site storage as alternatives to tank refurbishment. Neither of these alternate strategies would alleviate the operational, environmental, and reliability risks associated with two-tank operation at the Holyrood TGS. When considering these risks, in addition to the risks associated with vessel availability and fuel oil specifications, Hydro does not believe that these options are viable or prudent to ensure the reliable operation of the Holyrood TGS as a generating facility.[10]

4.2 Least-Cost Evaluation

Hydro has not identified any viable alternative strategies to facilitate a least-cost evaluation.

4.3 Recommended Alternative

Tank 4 must remain in service to maintain the appropriate COA at the Holyrood TGS. As the tank has not undergone an inspection since 2010, it must be inspected before September 2024 to satisfy the terms and conditions of the COA. Failure to complete the inspection could result in the cessation of all generating activities at the Holyrood TGS. Therefore, Hydro recommends proceeding with the upgrade life extension alternative to drain, clean, and inspect the tank in 2024.

[10] For additional details, please refer to Hydro's response to PUB-NLH-002 filed as part of the "Application for Approval of Various Supplemental Capital Projects at the Holyrood Thermal Generation Station" proceeding. <http://www.pub.nl.ca/applications/NLH2022Capital/NLH2022Capital_SUPP_HolyroodThermal/responses/PUB-NLH-002.PDF>

4.3.1 Risk of Asset Stranding

The risk of asset stranding is less imminent because of the decision to extend Holyrood TGS to remain available through the Bridging Period. As Hydro expects continued operation of all three units at the Holyrood TGS through the Bridging Period until its capacity can be replaced to ensure reliable operation for customers, capital expenditures for this facility to operate as a generator continue to be required. Depreciation is required to be calculated on an accelerated basis (i.e., monthly depreciation = capital investment ÷ remaining months of service life).[11]

5.0 Scope of Work

This project involves the completion of an out-of-service tank inspection for Tank 4 at the Holyrood TGS to ensure the tank's fitness for service in accordance with API 653.

The scope of work will include the following:

- Tank cleaning and degassing;
- Tank out-of-service inspection;
- Tank floor plate patching, as required;
- Tank roof plate patching, as required;
- Cleaning and testing of suction heaters;
- Suction heater valves/stem extension, if required;
- Additional refurbishments, as identified during the inspection; and
- Final inspection and tank recertification.

The scope of work on Tank 4 will be completed by external contractors with support from Hydro engineering and other internal labour as required.

[11] As a result of the extension of the Holyrood TGS through the Bridging Period, Hydro intends to make an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account in 2023.

5.1 Project Budget

The estimate for the 2024 project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2024	2025	Beyond	Total
Material Supply	19.9	0.0	0.0	**19.9**
Labour	179.1	0.0	0.0	**179.1**
Consultant	81.0	0.0	0.0	**81.0**
Contract Work	1,381.1	0.0	0.0	**1,381.1**
Other Direct Costs	0.7	0.0	0.0	**0.7**
Interest and Escalation	87.6	0.0	0.0	**87.6**
Contingency	170.6	0.0	0.0	**170.6**
Total	**1,920.0**	**0.0**	**0.0**	**1,920.0**

5.2 Project Schedule

The proposed scope of work will be executed as follows:

- Detailed engineering, tender, and award of tank inspection contract will be completed early in the second quarter; and
- Execution of the work will be completed early in the fourth quarter, to enable the tank to be returned to service before the winter operating season.

In the past, similar projects to refurbish the Holyrood TGS No. 6 fuel oil storage tanks were executed as two-year projects, due to significant lead times on the steel required for new tank floor plates. However, this steel is now locally available, reducing the material lead time and allowing for the Tank 4 refurbishment to be completed as a single-year project.

The schedule for the 2024 project is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning: Budget review, scope statement, schedule development, and risk assessment.	January 2024	February 2024
Design: Engage consultant, detailed engineering, and prepare the tender package.	February 2024	March 2024
Procurement: Tender and award Tank 4 cleaning, inspection, and refurbishment.	March 2024	April 2024
Construction: Complete Tank 4 cleaning, inspection, and refurbishment.	May 2024	October 2024
Commissioning: Final inspection and recertification.	October 2024	October 2024
Closeout: Prepare closeout documentation.	October 2024	November 2024

6.0 Conclusion

As per the terms and conditions of the COA and in accordance with common industry practice, the fuel oil storage tanks at the Holyrood TGS are subject to API 653. Tank 4 must be inspected in 2024 to satisfy the requirements of the COA. Failure to complete the inspection will violate the terms and conditions of the COA and could result in the cessation of all generating activities at the Holyrood TGS.

Attachment 1

Certificate of Approval Pursuant to the *Environmental Protection Act*, SNL, 2002, c. E-14.2, s. 83

Government of Newfoundland and Labrador – Department of Environment and Climate Change

June 30, 2022



Newfoundland Labrador

GOVERNMENT OF
NEWFOUNDLAND AND LABRADOR
Department of Environment and Climate Change

CERTIFICATE OF APPROVAL

Pursuant to the Environmental Protection Act, SNL 2002 c E-14.2 Section 83

Issue Date: ***June 30, 2022*** Approval No. AA22-065671

Expiration: ***June 30, 2027*** File No. 716.008, 716.050.1

Proponent: **Newfoundland and Labrador Hydro**
P.O. Box 29
Holyrood, NL
A0A 2R0

Attention: Rod Healey, Manager Environment Operations

Re: **Holyrood Thermal Generating Station**

Approval is hereby given for the operation of the Holyrood Thermal Generating Station, including a power house with three thermal generating units, one combustion turbine, six diesel generating units, wastewater treatment plant, hazardous waste landfill, storage of used oil and used glycol in containers and associated works located at Holyrood, NL.

This Certificate of Approval does not release the proponent from the obligation to obtain appropriate approvals from other concerned provincial, federal and municipal agencies. Nothing in this Certificate of Approval negates any regulatory requirement placed on the proponent. Where there is a conflict between conditions in this Certificate of Approval and a regulation, the requirements in the regulation shall take precedence. Approval from the Department of Environment and Climate Change shall be obtained prior to any significant change in the design, construction, installation, or operation of the facility, including any future expansion of the works. This Certificate of Approval shall not be sold, assigned, transferred, leased, mortgaged, sublet or otherwise alienated by the proponent without obtaining prior approval from the Minister.

This Certificate of Approval is subject to the terms and conditions as contained therein, as may be revised from time to time by the Department. Failure to comply with any of the terms and conditions may render this Certificate of Approval null and void, may require the proponent to cease all activities associated with this Certificate of Approval, may place the proponent and its agent(s) in violation of the *Environmental Protection Act*, and will make the proponent responsible for taking such remedial measures as may be prescribed by the Department. The Department reserves the right to add, delete or modify conditions to correct errors in the Certificate of Approval or to address significant environmental or health concerns.

MINISTER

TERMS AND CONDITIONS FOR APPROVAL No. AA22-065671
June 30, 2022

General

1. This Certificate of Approval is for the operation of the Holyrood Thermal Generating Station including a power house with three thermal generating units, one combustion turbine and six diesel generating units as outlined in Table 1, wastewater treatment plant, hazardous waste landfill, storage of used oil and used glycol in containers and associated works located at Holyrood, NL. Extensive future expansion or change of activities will require a separate Certificate of Approval.

Table 1: Generating Units

Thermal Generating Units			
Unit No.	**Commissioned/Upgraded**	**Power Rating (MW)**	**Manufacturer**
1	1969/1988/89	150/175	Combustion Engineering
2	1969/1988/89	150/175	Combustion Engineering
3	1980	150	Badcock & Wilcox
Combustion Turbine (CT)			
1	2014	123	Siemens - D5A
Diesel Generating Units			
1	2014	2.00	Caterpillar - XQ 2000 Mobile
2	2014	2.00	Caterpillar - XQ 2000 Mobile
3	2014	2.00	Caterpillar - XQ 2000 Mobile
4	2014	2.00	Caterpillar - XQ 2000 Mobile
5	2014	2.00	Caterpillar - XQ 2000 Mobile
6	2014	2.00	Caterpillar - XQ 2000 Mobile

2. Any inquiries concerning this Approval shall be directed to the St. John's office of the Pollution Prevention Division (telephone: (709) 729-2556; or facsimile: (709) 729-6969).

3. In this Certificate of Approval:

- **accredited** means the formal recognition of the competence of a laboratory to carry out specific functions;
- **acutely lethal,** in respect of an effluent, means that the effluent at 100% concentration kills more than 50% of the rainbow trout subjected to it for a period of 96 hours, when tested in accordance with Reference Method EPS 1/RM/13; or more than 50% of the Daphnia magna subjected to it for a period of 96 hours, when tested in accordance Reference Method EPS 1/RM/14;
- **administrative boundary** means the boundary surrounding the Holyrood Thermal Generating Station outside of which the ambient air quality standards, outlined in Schedule A of the ***Air Pollution Control Regulations, 2022***, apply;
- **air contaminant** means any discharge, release, or other propagation into the air and includes, but is not limited to, dust, fumes, mist, smoke, particulate

matter, vapours, gases, odours, odorous substances, acids, soot, grime or any combination of them;

- **ALT (acute lethality test)** means a test conducted to determine whether an effluent is acutely lethal;
- **associated product** means petroleum or a derivative of it, except gasoline, which is in a liquid state at ambient temperature and pressure;
- **BOD_5** means biochemical oxygen demand (5 day test);
- **CEMS** means the continuous emissions monitoring system used to measure gaseous releases of SO_2, NO_x, CO_2, CO and O_2 from each boiler;
- **CO** means carbon monoxide;
- **CO_2** means carbon dioxide;
- **Combustion Turbine (CT)** means the 123 MW combustion turbine;
- **Department** means the Department of Environment and Climate Change and its successors;
- **DGSNL** means Digital Government and Service NL and its successors;
- **EDMS** means Environmental Data Management System;
- **effluent discharge criteria** (EDC) means the maximum allowable levels for the parameters listed in Table 4;
- **grab sample** means a quantity of undiluted sample collected at any given time. In this Approval it refers to used oil and effluent;
- **hazardous waste** means a product, substance or organism that is intended for disposal or recycling, including storage prior to disposal or recycling, and that:
  (a) is listed in Schedule III of the *Export and Import of Hazardous Waste Regulations under the Canadian Environmental Protection Act, 1999*;
  (b) is included in any of Classes 2 to 6, and 8 and 9 of the *Transportation of Dangerous Goods Regulations* under the *Transportation of Dangerous Goods Act, 1992*; or
  (c) exhibits a hazard classification of a gas, a flammable liquid, an oxidizer, or a substance that is dangerously reactive, toxic, infectious, corrosive or environmentally hazardous;
- **HYDRO** means Newfoundland and Labrador Hydro;
- **landfill operations manual** means the Hydro Procedure Manual for the Controlled Waste Landfill (most recent version);
- **leak or leakage** means any discharge of gasoline, associated product or used glycol from a storage tank system, pipeline, tank vessel, tank car or tank vehicle, other than through the usual function for which the storage tank system, pipeline, tank vessel, tank car or tank vehicle was designed;

- **licensed** means has a Certificate of Approval issued by the Minister to conduct an activity;
- **liquid waste** is defined by the *Slump Test* (Canadian Standards Association test method A23.2-5C for determining the slump of concrete). The liquid waste slump test involves placing the waste in a 30 cm open inverted cone. The cone is removed and the immediate decrease (slump) in height of the waste material is measured. If the material slumps such that the original height is reduced by 15 cm or more, the waste is considered liquid;
- **leachate holding pond** means the detention pond for leachate control prior to transfer to the on-site wastewater treatment plant;
- **malfunction** means any sudden, infrequent and not reasonably preventable failure of air pollution control equipment, wastewater treatment equipment, process equipment, or a process to operate in a normal or usual manner. Failures, caused in part by poor maintenance or careless operation, are not malfunctions;
- **Minister** means the Minister of the Department;
- **MW** means megawatt;
- **NO_x** means oxides of nitrogen;
- **NO_2** means nitrogen dioxide;
- **O_2** means oxygen;
- **oil separator** means a device used to separate and remove oily wastes from oil and water mixtures;
- **Plan** means the specific plan as identified in the section of this Approval within which it is used. For example, in the *Waste Management Plan* section it refers to the Waste Management Plan;
- **$PM_{2.5}$** means particulate matter with a diameter of 2.5 µm or less;
- **PPMV** means parts per million by volume;
- **proficiency testing** means the use of inter-laboratory comparisons to determine the performance of individual laboratories for specific tests or measurements;
- **QA/QC** means Quality Assurance/Quality Control;
- **register(ed)**, in the context of storage tanks, means that information regarding the storage tank system has been submitted to a DGSNL office and a registration number has been assigned to the storage tank system. In the context of dispersion modelling, registered means submitted to and approved by the Department in accordance with departmental policy and guidelines. In the context of environmental site assessment and impacted site management work, registered means approved by the Department in accordance with

departmental policy and guidelines;

- **regulated substance** means a substance subject to discharge limit(s) under the *Environmental Control Water and Sewage Regulations, 2003*;
- **Site Professional** means an individual who is registered with the Department to oversee environmental site assessment, remediation and contaminated site management work in Newfoundland and Labrador;
- **SO_2** means sulfur dioxide;
- **spill or spillage** means a loss of gasoline, associated product or used glycol in excess of 70 litres from a storage tank system, pipeline, tank vessel or vehicle, or an uncontrolled release of any volume of a regulated substance onto or into soil or a body of water;
- **stack** means a chimney, flue, conduit or duct arranged to conduct an air contaminant into the environment;
- **storage tank system** means a tank and all vent, fill and withdrawal piping associated with it installed in a fixed location and includes a temporary arrangement;
- **TDS** means total dissolved solids;
- **TPH** means total petroleum hydrocarbons, as measured by the Atlantic PIRI method;
- **TPM** means total particulate matter with diameters less than 100µm;
- **TSS** means total suspended solids;
- **used glycol** means glycol that, through use, storage or handling, can no longer be used for its original purpose;
- **used oil** means oil that, through use, storage or handling, can no longer be used for its original purpose; and
- **wastewater treatment plant (WWTP)** means HYDRO's treatment plant for wastewater streams resulting from periodic cleaning of boiler fireside equipment, and includes the periodic basin, the batch reactor, filter press and all associated works.

4. All necessary measures shall be taken to ensure compliance with all applicable acts, regulations, policies, guidance documents and guidelines, including the following, or their successors:

- *Environmental Protection Act*;
- *Water Resources Act*;
- *Air Pollution Control Regulations, 2022*;
- *Environmental Control Water and Sewage Regulations, 2003*;
- *Halocarbon Regulations*;
- *Storage and Handling of Gasoline and Associated Products Regulations, 2003*;

- *Used Oil and Used Glycol Control Regulations;*
- *Storage of PCB Waste Regulations, 2003;*
- *Ambient Air Monitoring Guidance Document;*
- *Effluent Schedule Determination Policy for Industries;*
- *Sampling of Water and Wastewater - Industrial Effluent Applications Guidance Document;*
- *Accredited Laboratory Policy;*
- *Compliance Determination Guidance Document;*
- *Stack Emission Testing Guidance Document;*
- *Plume Dispersion Modelling Guidance Document; and*
- *Guidance Document for the Management of Impacted Sites.*

This Approval provides terms and conditions to satisfy various requirements of the above listed acts, regulations, policies, guidance documents and guidelines. If it appears that any of the pertinent requirements of these acts, regulations, policies and guidelines are not being met, then a further review of the works shall be conducted, and suitable pollution control measures may be required by the Minister.

5. All reasonable efforts shall be taken to minimize the impact of the operation on the environment. Such efforts include:

   - minimizing the area disturbed by the operation,
   - minimizing air, water or soil pollution,
   - finding alternative uses, acceptable to the Department, for waste or rejected materials,
   - removing equipment or structures when they no longer have further use, and
   - considering the requirement for the eventual rehabilitation of disturbed areas when planning the development of any area on the facility property.

6. HYDRO shall provide to the Department, within a reasonable time, any information, records, reports or access to data requested or specified by the Department.

7. HYDRO shall keep all records or other documents required by this Approval at the thermal generating station for a period of not less than three (3) years, beginning the day they were made. These records shall be made available for review by officials of the Department or DGSNL when requested.

8. Should HYDRO wish to deviate in any way from the terms and conditions of this Certificate of Approval, a written request detailing the proposed deviation shall be made to the Minister. HYDRO shall comply with the most current terms and conditions until the Minister has authorized otherwise. In the case of meeting a deadline requirement, the request shall be made at least 60 days ahead of the applicable date as specified in this Approval or elsewhere by the Department.

Waste Management

9. The management of waste generated at the facility is subject to compliance with the ***Environmental Protection Act***. All non-industrial waste shall be stored in a manner acceptable to the Department and, on at least a weekly basis, be disposed of:

   - at an authorized waste disposal site, with the permission of the owner/operator of the site; or
   - by some other means acceptable to the Department.

If required, industrial waste shall be disposed of by a licensed operator.

10. HYDRO shall ensure that all volatile chemical and solvent wastes, if they cannot be reused, are placed in suitable covered containers for disposal in a manner acceptable to the Department. Disposal of liquid wastes at waste disposal sites in the province is not permitted.

11. Disposal of hazardous waste in a municipal or regional waste disposal site in this Province is prohibited. Transporters of hazardous waste shall have an approval issued by the Minister. Those generating hazardous waste shall have a waste generator's number issued by the Department and shall also complete the required information outlined in the Waste Manifest Form.

Waste Management Plan

12. HYDRO shall continue to implement the Waste Management Plan dated ***June 2019*** for the operation of the Holyrood Thermal Generating Station, including all revisions. Every year the Plan shall be reviewed and revised as necessary, accounting for expanding or alteration of activities. All proposed revisions shall be submitted to the Department for review. The Department will acknowledge receipt of the Plan and/or revisions, and shall provide any review comments within a reasonable time frame.

Noise

13. HYDRO shall continue to implement the Noise Management Plan dated ***October 2019*** for the operation of the Holyrood Thermal Generating, including all revisions. Every year the Plan shall be reviewed and revised as necessary. All proposed revisions shall be submitted to the Department for review. The Department will acknowledge receipt of the Plan and/or revisions, and shall provide any review comments within a reasonable time frame.

Chemical Operations

14. All chemical loading and blending shall be done inside the facility, with no chemical containers being opened outside. All vessels will be blanketed to eliminate vapour or odour releases.

Spill Prevention and Containment

15. Areas in which chemicals are used or stored shall have spill containment systems constructed with impermeable floors, walls, dykes or curbs as applicable and be configured, maintained, inspected and repaired as follows:

- they shall not discharge to the environment;
- they shall have an effective secondary containment capacity of at least 110% of the chemical storage tank capacity, in the case of a single storage container;
- if there is more than one storage container, the spill containment system shall be able to retain no less than 110% of the capacity of the largest container or

100 % of the capacity of the largest container plus 10% of the aggregate capacity of all additional containers, whichever is greater;
- they shall be kept clear of material that may compromise the containment capacity;
- they may include a floor drain system provided that the floor drains, and the place or device to which they drain, are configured in such a manner that the required effective secondary containment capacity is maintained;
- every year they shall be visually inspected for their liquid containing integrity, and repairs shall be made when required; and
- once every ten years, spill containment systems shall be inspected, by a means other than visual inspection, for their liquid containing integrity, and repairs shall be made when required.

Contingency Plan

16. HYDRO shall continue to implement the Contingency Plan dated ***October 19, 2019*** for the operation of the Holyrood Thermal Generating Station, including all revisions. This Plan describes the actions to be taken in the event of a spill of a toxic or hazardous material. Copies of the Plan shall be placed in convenient areas throughout the facility so that employees can easily refer to it when needed. HYDRO shall ensure that all employees are aware of the Plan and understand the procedures and the reporting protocol to be followed in the event of an emergency. An annual response exercise is recommended for response personnel. Every year, as a minimum, the Plan shall be reviewed and revised as necessary. Any proposed significant revisions shall be submitted to the Department for review. Changes which are not considered significant include minor variations in equipment or personnel characteristics which do not affect implementation of the Plan.

17. Every time HYDRO implements the Contingency Plan, information shall be recorded for future reference. This will assist in reviewing and updating the Plan. The record is to consist of all incidents with environmental implications, and include such details as:

- date;
- time of day;
- type of incident (i.e. liquid spill, gas leak, granular chemical spill, equipment malfunction, etc.);
- actions taken;
- problems encountered; and
- other relevant information that would aid in later review of the Plan performance.

Each incident report shall be submitted to the Department as per the ***Reporting*** section.

Decommissioning and Restoration

18. A preliminary Decommissioning Plan, entitled "*Decommissioning and Demolition of the Holyrood Thermal Generating Station, dated July 29, 2016*" was submitted to the Department on February 23, 2018. A detailed Decommissioning Plan that includes measures to restore areas disturbed by the operation shall be submitted to the Department for review at least six (6) months prior to the cessation of operations at

the Thermal Generating Station. For guidance on the preparation of the Decommissioning Plans, refer to Appendix A.

19. As part of the site decommissioning and restoration process, HYDRO shall employ a registered Site Professional to complete a site-wide environmental site assessment, as defined in the ***Guidance Document for the Management of Impacted Sites***. Should impacts be identified, HYDRO shall proceed through the process outlined in the Guidance Document to achieve regulatory site closure.

Fuel Usage, Fuel Storage & Offloading

20. HYDRO is permitted to accept and combust ultra-low sulfur diesel oil in the CT.

21. HYDRO shall not combust heavy fuel oil with sulfur content greater than **0.7%** by weight in the thermal generating station.

22. HYDRO is permitted to accept and burn alternative fuel only with the written approval of the Department.

23. The diesel fuel offloading, storage and handling area for the CT shall have an impermeable surface with an oil containment or collection system routed towards an oil separator. Care shall be taken to prevent spillage on the ground and to the surrounding environment, particularly streams and other water bodies.

24. HYDRO shall maintain, and submit to the Department on a monthly basis as per the ***Reporting*** section, the following information:

- Name of supplier, date and volume of each shipment of ultra-low sulfur diesel oil received; and
- Hourly diesel oil usage of CT in litres per hour.

25. HYDRO shall analyze each delivery of heavy fuel oil for the parameters listed in Table 2. Analysis shall be on a representative sample of the heavy fuel oil received.

Table 2: Heavy Fuel Oil Analysis Program

Parameters			Frequency
A.P.I Gravity @60 °F Pour Point Sulfur% by Weight Sediment % by Weight Aluminum Sodium	Density (kg/m^3 @ 15 °C) Viscosity cSt @ 50 °C BTU's per US Gallon Water % by Volume Nickel Vanadium	Flash Point Ash % by Weight Asphaltenes % by Weight Silicon	**Every Batch Delivered**

26. HYDRO shall maintain, and submit to the Department as per ***Reporting*** section, a record of all heavy fuel oil received. The record shall include:

- name of the supplier;
- date and volume of the heavy fuel oil offloaded;
- the certificate of analysis for each batch of heavy fuel oil delivery received; and
- the name of the laboratory where analysis was performed.

Combustion Turbine Operations

27. HYDRO shall maintain, and submit to the Department on a monthly basis as per the ***Reporting*** section, the following information:

- date and hours of operation of the CT;
- date and time of start-up and shutdown of the CT;
- specification of all maintenance performed on the CT and/or associated water injection system, including the date and time the work commenced and completed; and
- total litres of water flow per hour for each hour of the day when the CT is in operation.

28. The CT facility shall have an impermeable surface with an oil containment or collection system routed to an oil separator.

29. All floor drains from the main building of the CT shall be directed to the oil separator prior to release into the Indian Pond.

30. HYDRO shall operate the CT water treatment plant as per manufacturer standards.

Diesel Generators

31. HYDRO shall operate no more than any five (5) of the six (6) diesel generators at **87% load** from **6:00 AM** to **10:00 AM** and from **4:00 PM** to **8:00 PM** to generate up to **8 MW** of power from ***November 1*** to ***April 30*** for peaking purposes.

32. HYDRO shall operate no more than any five (5) of the six (6) diesel generators at **67% load**, 24 hours a day, 365 days a year to generate up to **6 MW** of power for emergency purposes.

Storage Tanks

33. All on site storage of petroleum shall comply with the ***Storage and Handling of Gasoline and Associated Products Regulations, 2003***, or its successor. Storage tank systems shall be registered with DGSNL.

34. HYDRO shall implement the API Standard 653, "*Tank Inspection, Repair, Alteration and Reconstruction*" in accordance with common industry practice.

35. HYDRO shall submit an inventory of all petroleum and chemical storage tanks located at Holyrood Thermal Generating Station at Holyrood, NL to the Department for review by ***August 31, 2023***. This inventory shall include the following information:

- site plan showing tank location,
- storage tank system photos, including manufacturer's labels,
- registration number (where applicable),
- identification number,

- material stored,
- capacity,
- annual throughput,
- tank material,
- tank type,
- tank diameter,
- tank height,
- tank colour,
- roof type,
- year of manufacture,
- date of installation,
- date of last inspection,
- failure history,
- maintenance history,
- secondary containment capacity, and
- date of next planned inspection.

An update of the complete storage tank inventory including any changes to it shall be submitted to the Department within three (3) months of the change having occurred.

Used Oil and Used Glycol

36. Used oil and used glycol shall not be mixed and shall be stored in separate:

- closed containers;
- registered tanks; or
- tanks that have an active approval from DGSNL.

37. Used oil and used glycol shall be disposed of by a company licensed for the handling and disposal of such products.

38. Information on used oil and used glycol that is generated at the facility shall be submitted to the Department for review by ***January 31*** of each year. This shall include a description of:

- the type(s) of oil and/or glycol used;
- the approximate total volume of used oil and/or used glycol generated during the previous year; and
- the method of disposal for the used oil and/or used glycol.

39. In the event that used oil and/or used glycol generated off-site is stored in the on-site storage tank(s). the information listed above shall also be required for the off-site systems.

40. The use or operation of an oil separator requires registration under the ***Used Oil and Used Glycol Control Regulations***. Applications for registration shall be submitted to, and registration numbers are assigned by, DGSNL.

41. All oil separators shall be checked routinely and maintained in accordance with the manufacturer's instructions to ensure they are working properly. A log of these checks shall be maintained by HYDRO.

Wastewater Flows and Treatment

42. The Thermal Generating Station's once-through cooling water shall be obtained from Indian Pond, and shall be discharged directly to Conception Bay.

43. The Thermal Generating Station's south-east floor drains shall be routed through an oil separator (OS-1) and then to Indian Pond through the storm water collection system.

44. The Thermal Generating Station's south-west floor drains shall be routed through a grease trap and an oil separator (OS-2) and then to the cooling water discharge piping associated with Unit No. 1 & 2.

45. The Thermal Generating Station's north-east and north-west floor drains shall be routed through a grease trap and oil separator (north-east OS-4 & north-west OS-3) and then to a 900 m^3 equalization basin (Continuous Basin).

46. All wastewater generated from backwashing in the CT water treatment plant from the backwashing shall be routed to the CT oil separator (CT-OS) prior to discharge into Indian Pond.

47. Wastewater streams resulting from the Thermal Generating Station's daily operations, including raw water clarification, filter backwashes, boiler blowdown and other similar activities shall be directed to the Continuous Basin. Any flow or drainage from the Continuous Basin shall be routed to the new oil separator (OS-5) before discharging into Indian Pond.

48. Demineralizer regeneration wastewater flows may be directed to the seal pit associated with Units No. 1 & 2, during such times at least one cooling water pump shall be active.

49. Wastewater streams resulting from periodic events where water is used to clean the Thermal Generating Station's boiler fireside equipment, including air pre-heater wash flows, fireside boiler wash flows and boiler acid wash flows, shall be directed to a 900 m^3 equalization basin (Periodic Basin). Any flow or drainage from the Periodic Basin shall be directed to the wastewater treatment plant.

50. Any flow or drainage from the wastewater treatment plant shall be discharged to the cooling water intakes for Units No. 1 & 2 or Unit 3.

51. Effluent from the dewatering of filter cake shall be re-cycled through the wastewater treatment plant.

52. All solid waste generated from the CT water treatment plant and the Thermal Generating Station wastewater treatment plant operations shall be directed to the hazardous waste landfill.

Effluent Monitoring and Discharge

53. HYDRO shall perform an effluent monitoring program as per Table 3. All results shall be submitted to the Department as per the ***Reporting*** section.

Table 3: Effluent Monitoring Program			
Location	**EDMS Location Code**	**Parameters**	**Frequency**
WWTP	00068	Aluminum Iron Magnesium Nickel Vanadium pH TSS	Grab sample prior to each batch release †
		ALT	Grab sample from each batch following new addition of wastewater to the periodic basin
Continuous Basin Outfall	00069	Iron Nickel Vanadium pH TSS TPH	Weekly Grab
		ALT	Monthly Grab
OS-1	00070	Iron Nickel Vanadium pH TSS TPH	Weekly Grab
OS-2	00071	Iron Nickel Vanadium pH TSS TPH	Weekly Grab
CT-OS (Prior to discharge into Indian Pond)	00072	TPH TDS TSS BOD_5 pH	Weekly (Whenever there is discharge)
† Grab samples for all parameters shall be taken from the batch reactor at the same time.			

54. If effluent from wastewater treatment plant fails the ALT, HYDRO shall collect a grab sample from the next batch of effluent from the wastewater treatment plant and conduct an ALT, even if there has been no addition to the Periodic Basin.

55. HYDRO shall record on a continuous basis the volume of influent to the Periodic Basin. The results shall be submitted to the Department as per the ***Reporting*** section.

56. Refer to Table 4 for the effluent discharge criteria.

Table 4: Effluent Discharge Criteria	
Parameter	**Allowable Limits ***
Arsenic	0.50
Barium	5.00
Boron	5.00
BOD	20.00
Cadmium	0.05
Chromium	1.00
Copper	0.30
Iron	10.00
Lead	0.20

Mercury	0.005
Nitrates	10.00
Nitrogen (ammoniacal)	2.00
Nickel	0.50
Phenol	0.10
Phosphates (total as P_2O_5)	1.00
pH	5.5 – 9.0 pH units
Selenium	0.01
Silver	0.05
TDS	1000.00
TSS	30.00
TPH	15.00
Vanadium	0.50
Zinc	0.50
* All units are expressed in mg/L unless otherwise stated.	

57. If effluent is determined to be acutely lethal for three consecutive ALTs, HYDRO shall implement a Toxicity Identification Evaluation (TIE) to identify the toxin, and from this develop measures to prevent or reduce the toxin. The report, written as a result of these identification activities, shall be submitted to the Department for review, ***within 60 days*** of the third consecutive failed ALT result. After review of the report, the Department may place additional requirements upon the proponent for treatment of effluent prior to discharge.

Water Chemistry Analysis

58. HYDRO shall perform a water chemistry analysis program for the thermal generating station four times per calendar year and not less than thirty (30) days apart, as per Table 5. All results shall be submitted to the Department as per the ***Reporting*** section.

59. HYDRO shall perform a water chemistry analysis program for the CT on a monthly basis, whenever the CT water treatment plant and/or CT is in operation, as per Table 5. All results shall be submitted to the Department as per the ***Reporting*** section.

Table 5: Water Chemistry Analysis Program

Location	EDMS Location Code	Parameters
Cooling Water Intake at Indian Pond (Grab Sample)	00073	**General Parameters** – must include the following: nitrate + nitrite, nitrate, nitrite, pH, TSS, DOC, conductance, colour, TDS (calculated), orthophosphate, potassium, carbonate ($CaCO_3$), hardness ($CaCO_3$), bicarbonate ($CaCO_3$), magnesium, sodium, phenolics, sulfate, calcium, sulphide, BOD_5, reactive silica, alkalinity, ammonia, phosphorous, chloride, turbidity
Cooling Water Outfall Stream, Prior to Release into Conception Bay (Grab Sample)	00074	
Continuous	00069	**Metals Scan** - must include the following:

Basin Outfall Stream, Prior to Release into Indian Pond (Grab Sample)		Aluminium	boron	iron	nickel	tin
		antimony	cadmium	lead	selenium	titanium
		arsenic	chromium	manganese	silver	uranium
		barium	cobalt	molybdenum	strontium	vanadium
CT Effluent Prior to Discharge into Indian Pond	00072	beryllium	copper	mercury	thallium	zinc
		bismuth				
OS-1	00070					

60. HYDRO shall inform the Department of the date and duration of any usage of the **Copper Ion Injection** in their system, as per ***Reporting Section***.

Environmental Effects Monitoring

61. HYDRO shall continue to conduct an Environmental Effects Monitoring study to monitor the impacts of the discharge of cooling water, the continuous basin's water and the wastewater treatment plant treated water on Conception Bay. The study design shall be submitted to the Department for review by ***June 30, 2023.*** The results of the completed study shall be submitted to the Department for review by ***June 30, 2025.***

Hazardous Waste Landfill Operations

62. HYDRO shall operate the hazardous waste landfill in the manner as described in the ***Landfill Operations Manual.*** Any revision or changes to the ***Landfill Operations Manual*** shall be submitted to the Department for review and approval prior to such revision or changes being made.

63. Only waste identified in the ***Landfill Operations Manual*** shall be placed in the hazardous waste landfill. These include: bottom and fly ash, periodic basin sludge, continuous basin sludge, wastewater treatment plant filter-cake, filter sand, raw-water treatment ion exchange resins, and clean-up from chemical spills.

64. Liquid waste shall not be disposed of in the hazardous waste landfill, unless otherwise authorized in writing by the Department.

65. The Department reserves the right to require some form of pre-treatment of waste before placement in the site.

66. HYDRO shall periodically review opportunities for reuse and/or recycling of the waste types disposed of in the landfill.

67. HYDRO shall maintain a landfill security fence with a sign affixed to the fence identifying the site as a hazardous waste containment system. This sign shall identify the owner of the landfill and a contact phone number. The sign and its placement shall be acceptable to the Department.

68. No activities shall occur within the fenced area of the landfill, except for the deposition of waste; extraction of leachate; or other maintenance requirements of

the landfill cap or the landfill.

69. HYDRO shall conduct an annual inspection program as per the ***Landfill Operations Manual.***

70. Leachate accumulated in each of the hazardous waste landfill collection systems, including the leachate holding pond, shall be removed as required so that leachate does not overflow the collection system.

71. Any flow or drainage from the leachate holding pond shall be directed to the Periodic Basin. Leachate shall not be discharged directly to the environment without prior authorization by the Department.

Hazardous Waste Landfill Monitoring

72. HYDRO shall perform an Environmental Monitoring Program as depicted in the ***Landfill Operations Manual,*** including monitoring of: groundwater quality and levels, surface water quality, leachate leakage, liner integrity and physical movement of the landfill.

73. HYDRO shall perform a Groundwater Monitoring Program as per Table 6. This monitoring program shall be performed throughout the operational life of the landfill, and during the twenty five (25) years following closure.

Table 6: Groundwater Monitoring Program

Location	EDMS Location Code	Parameters			Frequency
Monitoring Wells:					
BH-1	00075				
BH-2	00076	Aluminum	Iron	Magnesium	**Every Four Months**
BH-3	00077	Nickel	Vanadium		
BH-4	00078				
BH-5	00079				
BH-6	00080				
BH-7	00081				
Monitoring Wells:		Antimony	Arsenic	Barium	**Annually**
		Beryllium	Bismuth	Cadmium	
BH-1	00075	Cobalt	Calcium	pH	
BH-2	00076	Chromium	Copper	Lead	
BH-3	00077	Manganese	Mercury	Molybdenum	
BH-4	00078	Phosphorus	Potassium	Selenium	
BH-5	00079	Silver	Sodium	Zinc	
BH-6	00080	VOC's	TDS		
BH-7	00081				

74. HYDRO shall perform a Surface Water Monitoring Program as per Table 7. This monitoring program shall be performed throughout the operational life of the landfill, and during the twenty five (25) years following closure.

Table 7: Surface Water Monitoring Program				
Location	**EDMS Location Code**	**Parameters**		**Frequency**
Surface Well 1	00082	VOCs		**Annually**
Surface Well 2	00083	Cadmium	Chromium (total)	**Monthly (provided water is flowing in the ditches during the month)**
Surface Well 3	00084	Iron	Lead	
Surface Well 4	00085	Mercury	Nickel	
Surface Well 5	00086	Vanadium	pH	
Surface Well 6	00087	TDS	TSS	

75. The total monthly flow:

- from the primary and secondary leachate collection systems;
- from the leachate holding pond to the Periodic Basin; and
- through the primary cell and holding pond leak detection manholes;

shall be accurately measured and recorded. This record and all results from the Groundwater and Surface Water Monitoring Programs shall be submitted to the Department as per the ***Reporting*** section.

76. HYDRO shall submit an Annual Landfill Operating Report to the Department by ***February 28*** of the subsequent year. This report shall include:

- results of the Environmental Monitoring Program; and
- summaries of all materials placed in the landfill site including:
  - waste characterization reports,
  - volumes of waste deposited in the landfill,
  - source(s) of the waste,
  - identification of contaminants of concern, and
  - copies of the hazardous waste manifest forms.

Ambient Air

77. HYDRO shall operate an ambient air monitoring program as per the conditions in this Approval and its amendments. Approval shall be obtained from the Department prior to purchase or installation of any monitoring equipment.

78. Site locations and parameters to be monitored are outlined in Table 8.

Table 8: Ambient Air Monitoring Program		
Monitoring Sites	**EDMS Location Code**	**Parameter**
Butter Pot	00088	$PM_{2.5}$, SO_2, NO_x, NO_2
Green Acres	00089	TPM, $PM_{2.5}$, SO_2, NO_x, NO_2
Indian Pond	00090	TPM, $PM_{2.5}$, SO_2, NO_x, NO_2
Lawrence Pond	00091	TPM, $PM_{2.5}$, SO_2, NO_x, NO_2
Lower Indian Pond Drive	00092	TPM, $PM_{2.5}$, SO_2, NO_x, NO_2
Main Gate	00093	TPM, $PM_{2.5}$

79. Ambient air monitoring shall be done in accordance with the ***Ambient Air Monitoring Guidance Document (GD-PPD-065)***, or its successors.

80. Non-continuous TPM shall be determined by the United States EPA Test Method: "Reference Method for the Determination of Suspended Particulate Matter in the Atmosphere (High-Volume Method), or alternate method approved by the Department. The frequency of non-continuous TPM sampling shall coincide with the 6-day National Air Pollution Surveillance (NAPS) schedule. All results from the non-continuous TPM sampling shall be submitted to the Department as per the ***Reporting*** section.

81. HYDRO shall operate, calibrate and maintain a meteorological station at **Green Acres** site in accordance with the guidelines specified in the United States EPA document "Quality Assurance Handbook for Air Pollution Measurement Systems - Volume IV: Meteorological Measurements Version 2.0 (Final)," EPA- 454/B-08-002, or its successors. Parameters to be measured and recorded shall include as a minimum:

- wind speed,
- wind direction,
- ambient air temperature,
- relative humidity,
- barometric pressure, and
- precipitation.

All records shall be made available to the Department upon request.

82. Information regarding calibrations, site visits and maintenance for all continuous ambient air monitors shall be recorded into the DR DAS electronic logbook. Specific information regarding non-continuous TPM monitors, including but not limited to slopes, intercepts, initial and final masses, times, flows, etc. shall be submitted electronically, as per the ***Reporting*** section.

Continuous Emissions Monitoring System

83. Emissions from each boiler at the Thermal Generating Station shall be measured and recorded using an automated CEMS that meets the requirements of Environment Canada's *Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation (EPS 1/PG/7)*, or its successor. Notwithstanding this, application of specific requirements of EPS

1/PG/7 to the CEMS may be modified subject to approval by the Department.

84. Monthly CEMS data reports containing one-hour arithmetic averages of emission rates of SO_2, NO_x, CO (all three expressed in ppmv), CO_2 and O_2 (both expressed in %) shall be submitted in digital format, as per the ***Reporting*** section.

Pollution Control Equipment

85. All pollution control equipment shall be maintained and operated as per manufacturer's specifications for best performance.

86. HYDRO shall not operate the CT unless the NO_x control system associated with the CT is in full operation.

Administrative boundary

87. The ambient air quality standards specified in Schedule A of the ***Air Pollution Control Regulations, 2022*** shall apply to all points outside of HYDRO's Holyrood Thermal Generating Station administrative boundary. The administrative boundary is defined as the area encompassed by the coordinates contained in Appendix B, a total area of approximately **0.2687 km^2**. All coordinates are referenced to NAD83 UTM Zone 22.

Stack Emissions Testing and Dispersion Modelling

88. Stack emissions testing shall be done in accordance with the ***Stack Emission Testing Guidance Document (GD-PPD-016.1)***. Dispersion modelling shall be done in accordance with the ***Plume Dispersion Modelling Guidance Document (GD-PPD-019.2)***. Determination of frequency of stack emissions testing and dispersion modelling shall be done in accordance with the ***Compliance Determination Guidance Document (GD-PPD-009.4)***.

89. HYDRO shall be required to complete the next stack emissions testing once every four years if it has been shown, via a registered dispersion model, that the operation is in compliance with section 3(2) and Schedule A of the ***Air Pollution Control Regulations, 2022***. If it has been shown, via a registered dispersion model, that the operation is not in compliance with section 3(2) and Schedule A of the ***Air Pollution Control Regulations, 2022***, then the facility shall complete stack emissions testing every two years.

90. Stack emissions testing results shall be submitted to the Department within ***75 days*** of completion of the sampling.

91. Plume dispersion modelling results shall be submitted to the Department within ***120 days*** of approval of the stack emissions testing results by the Department.

Annual Air Emissions Reporting

92. HYDRO shall submit an annual Air Emission Report to the Department by ***June 1***

of the subsequent year. This report shall include:

- total fuel consumption;
- the weighted average sulfur content of the fuel:
- the fuel specific gravity;
- the estimated, or, if available, the monitored annual emissions of the following flue gas constituents: SO_2, NO_x, NO_2, CO and particulate; and
- the actual calculations including factors, formulae and/or assumptions used.

Analysis and QA/QC

93. Unless otherwise stated herein, all solids and liquids analysis performed pursuant to this Approval shall be done by either a contracted commercial laboratory or an in-house laboratory. Contracted commercial laboratories shall have a recognized form of accreditation. In-house laboratories have the option of either obtaining accreditation or submitting to an annual inspection by a representative of the Department, for which HYDRO shall be billed for each laboratory inspection in accordance with Schedule 1 of the ***Accredited Laboratory Policy (PD:PP2001-01.02)***. Recommendations of the Department stemming from an annual inspection shall be addressed within 6 months, otherwise further analytical results shall not be accepted by the Department.

94. If HYDRO wishes to perform in-house laboratory testing and submit to an annual inspection by the Department then a recognized form of proficiency testing recognition shall be obtained for compliance parameters for which this recognition exists. The compliance parameters are listed in the ***Effluent and Monitoring*** section. If using a commercial laboratory, HYDRO shall contact that commercial laboratory to determine and to implement the sampling and transportation QA/QC requirements for those activities.

95. The exact location of each sampling point shall remain consistent over the life of the monitoring programs, unless otherwise approved by the Department.

96. HYDRO shall bear all expenses incurred in carrying out the environmental monitoring and analysis required under conditions of this Approval.

Monitoring Alteration

97. The Department has the authority to alter monitoring programs or require additional testing at any time when:

- pollutants might be released to the surrounding environment without being detected;
- an adverse environmental effect may occur; or
- it is no longer necessary to maintain the current frequency of sampling and/or the monitoring of parameters.

98. HYDRO may, at any time, request that monitoring programs or requirements of this Approval be altered by:

- requesting the change in writing to the Department; and
- providing sufficient justification, as determined by the Department.

The requirements of this Approval shall remain in effect until altered, in writing, by the Department.

Reporting

99. Monthly reports containing the environmental compliance monitoring and sampling information required in this Approval shall be received by the Department in digital format within 30 calendar days of the reporting month. All related laboratory reports shall be submitted with the monthly report in Extensible Markup Language (XML) format and Adobe Portable Document Format (PDF). Digital report submissions shall be uploaded through the EDMS web portal. The Pollution Prevention Division shall provide details of the portal web address and submission requirements.

100. Each monthly report shall include a summary of all environmental monitoring components and shall include an explanation for the omission of any requisite data. The monthly summary reports shall be in Microsoft Word or Adobe PDF and shall be uploaded through the EDMS web portal with the data submissions

101. All incidents of:

- *Contingency Plan* implementation; or
- non-conformance of any condition within this Approval; or
- spillage or leakage of a regulated substance; or
- effluent discharge criteria being, or suspected of being, exceeded; or
- verbal/written complaints of an environmental nature from the public received by HYDRO related to the Thermal Generating Station, whether or not they are received anonymously;

shall be immediately reported, within one working day, to the Department.

A written comprehensive incident report, including a detailed description of the incident, a summary of contributing factors, and an Action Plan to prevent future incidents of a similar nature, shall be prepared. The report shall include a description of actions already taken and future actions to be implemented, and shall be submitted to the Department within thirty days of the date of the initial incident.

102. Any spillage or leakage of gasoline, associated product or used glycol shall be reported immediately through the Environmental Emergencies 24-hour report line at 1-800-563-9089.

Liaison Committee

103. The Department recognizes the benefits, and at times the necessity, of accurate, unbiased communication between the public and industrial operations, which have an impact on the properties and residents in the area. The Department encourages the formation and regular meeting of a Liaison Committee comprised of representatives of HYDRO, the Department and independent members of the general population of Holyrood and Conception Bay South. Regular meetings of the Liaison Committee will provide a clear conduit of communication between concerned citizens and HYDRO.

Expiration

104. This Certificate of Approval expires ***June 30, 2027.***

105. Should HYDRO wish to continue to operate the Holyrood Thermal Generating Station beyond this expiry date, a written request shall be submitted to the Department for the renewal of this Approval. Such request shall be made prior to ***January 1, 2027.***

APPENDIX A

Industrial Site Decommissioning and Restoration Plan Guidelines

As part of the Department of Environment and Climate Change's ongoing commitment to minimize the residual impact of industrial activities on the environment of the province, the Department requires that HYDRO shall develop a Decommissioning and Restoration Plan for the Thermal Generating Station at Holyrood, Newfoundland and its associated property. The guidelines listed below are intended to provide some general guidance as to the expectations of the Department with regard to the development of the Plan, and to identify areas that are of particular concern or interest. The points presented are for consideration, and are open to interpretation and discussion.

Decommissioning and Restoration Plans are intended to present the scope of activities that a company shall undertake at the time of final closure and/or decommissioning of the industrial properties. Where it is useful and practical to do so the company is encouraged to begin undertaking some of the activities outlined in the Plan prior to final closure and decommissioning. The objectives of the restoration work to be undertaken can be summarized as follows:

- to ensure that abandoned industrial facilities do not endanger public health or safety;
- to prevent progressive degradation and to enhance the natural recovery of areas affected by industrial activities;
- to ensure that industrial facilities and associated wastes are abandoned in a manner that will minimize the requirement for long term maintenance and monitoring;
- to mitigate, and if possible prevent, the continued loadings of contaminants and wastes to the environment. The primary objective shall be to prevent the release of contaminants into the environment. Where prevention is not practical due to technical or economic limitations then activities intended to mitigate the consequence of such a release of contaminants shall become the objective of restoration work;
- to return affected areas to a state compatible with the original undisturbed condition, giving due consideration to practical factors including economics, aesthetics, future productivity and future use; and
- to plan new facilities so as to facilitate eventual rehabilitation.

The Decommissioning and Restoration Plan should:

- identify areas of known historical or current contamination;
- identify past or existing operational procedures and waste management practices that have, or may have, resulted in site contamination;
- highlight the issues or components to be addressed;
- identify operational procedures and waste management practices that can prevent or reduce site contamination;
- consider future land use, regulatory concerns and public concerns;
- enable estimation of the resources and time frame required to decommission the facility and restore the site to a condition acceptable to the Department;
- enable financial planning to ensure the necessary funds for decommissioning and restoration are set aside during the operational life of the facility, and;
- include arrangements for appropriate project management to ensure successful completion of the decommissioning and restoration program.

APPENDIX B

HYDRO Administrative Boundary Coordinates

341903.0	5257750.4
341925.9	5257759.4
341972.8	5257727.0
341962.6	5257711.0
342036.6	5257660.9
342232.8	5257494.1
342162.6	5257271.8
342095.8	5257245.3
341947.8	5257207.3
341949.6	5257201.9
341957.0	5257196.4
341949.3	5257185.4
341926.5	5257202.1
341918.4	5257200.3
341700.2	5257177.4
341694.0	5257177.7
341659.1	5257166.3
341593.5	5257072.8
341563.4	5257088.4
341513.5	5257117.4
341528.6	5257149.4
341509.6	5257158.7
341544.1	5257250.4
341563.9	5257298.8
341571.2	5257314.4
341584.6	5257339.8
341612.8	5257383.6
341662.4	5257454.4
341685.8	5257484.8
341704.4	5257507.1
341748.2	5257599.8
341750.0	5257614.9
341756.9	5257644.8
341770.7	5257678.4
341789.5	5257710.2
341844.4	5257789.4
341903.0	5257750.4

Cc: Mr. Gary Kennell
Environment and Climate Change Canada
6 Bruce Street
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A1N 4T3

Mr. Wayne Lynch - Regional Director
Digital Government and Service NL
McCurdy Complex
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Chief Administrative Officer
Town of Holyrood
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Chief Administrative Officer
Town of Conception Bay South
P.O. Box 280
CBS, NL
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Attachment 2

HTGS Tank 4 Inspection Interval

Government of Newfoundland and Labrador – Department of Environment and Climate Change

September 16, 2021



Newfoundland Labrador

Government of Newfoundland and Labrador
Department of Environment and Climate Change
Pollution Prevention Division

September 16, 2021

Mr. Rod Healey
Manager, Environment Operations
Environmental Services
Newfoundland & Labrador Hydro
Hydro Place, 500 Columbus Drive
P.O. Box 12400
St. John's, NL
A0A 2R0

Dear Mr. Healey:

RE: HTGS Tank No. 4 Inspection Interval

The Department has thoroughly reviewed all information provided to date by NL Hydro and TEAM Industrial Services (TEAM) regarding the next internal inspection date for Tank No. 4 at the Holyrood Thermal Generation Station.

TEAM's recommendation to extend the date of the next API-653 out-of-service inspection of this tank to September 2024 is acceptable to the Department. As is required for the extension to the Tank No. 2 out-of-service inspection, annual in-service inspections of Tank No. 4 shall be performed in the interim.

We trust this is satisfactory.

Sincerely,

Dexter Pittman, P. Eng.
Manager of Environmental Compliance

Replace VHF Radio System (2024–2025)

July 2023

newfoundland labrador hydro

Replace VHF Radio System (2024–2025)

Location: Various

Investment Classification: General Plant

Asset Category: Telecontrol

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") operates very high frequency ("VHF") radio equipment that connects to Bell Mobility's PassPort Trunked Mobile Radio System ("TMRS"). The TMRS consists of a series of province-wide interconnected repeaters,[1] which allows users to communicate in a one-to-one or one-to-many fashion anywhere that radio connectivity to a repeater is available. The VHF radio system is used for both primary and backup voice communications by operations personnel and work crews to facilitate the operation and maintenance of the electrical system and to communicate in emergencies.

Hydro's fleet of end-user terminals (i.e., VHF radios) that connect to the TMRS consists of fixed, mobile, and portable units. The TMRS will be decommissioned by Bell in August 2024. Hydro must develop a replacement solution to ensure continued access to voice communication by personnel and work crews travelling to and working in remote locations where cellular coverage is not available.

Hydro is proposing the replacement of the VHF radio system with a combination of mobile and fixed satellite phones with Push-to-talk ("PTT") capabilities as well as fixed cellular phones. There are no viable alternatives for voice communication that will provide the required coverage to meet Hydro's needs.

This project has a multi-year approach, with completion planned in 2025 at an estimated cost of $1,552,200.

[1] A repeater is a device that receives and retransmits radio signals, extending the transmission range.

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1.0 Introduction

Hydro's VHF radio system consists of a series of interconnected repeaters province-wide, which allow voice communications between dispersed locations in a duplex operation[2] anywhere that radio connectivity to a repeater is available. Users can also communicate in a simplex operation[3] without the need for a repeater; however, this method is limited to a range between users of approximately five kilometres.

Hydro's fleet of end-user terminals (i.e., VHF radios) that connect to the TMRS consists of approximately 83 fixed units, 229 mobile units, and 139 handheld portable units. The VHF radio system is used for both primary and backup voice communications by personnel and work crews to facilitate work execution, operation and maintenance of the electrical system, and to communicate in emergencies.

This project proposes the replacement of Hydro's VHF radio system with PTT-capable satellite phones for mobile applications and a combination of fixed PTT-capable satellite phones and cellular phones for applicable Hydro offices, depots, plants, and terminal stations.

2.0 Project Description and Justification

This project is required to replace the functionality previously provided by Hydro's VHF radio system to provide users with fixed and mobile units for voice communication.

Hydro's current contract with Bell Mobility for the TMRS expires on August 12, 2024. Bell has stated that the contract will not be extended and the TMRS will be decommissioned in 2024. As part of the TMRS decommissioning, the repeaters forming the province-wide connection will be removed, meaning that the existing VHF radios will only be able to communicate in simplex operation with a range of approximately five kilometres. This type of operation will not provide Hydro with the necessary voice communication functionality and coverage for its operating area. The functionality provided by the TMRS is required to operate Hydro's fleet of VHF radios; therefore, a replacement must be put in place.

Hydro evaluated all locations where fixed assets currently exist to determine if the asset was still required. In locations where fixed stations are still needed, existing assets will be replaced by alternate equipment, which may take the form of fixed satellite or fixed cellular phones depending on cellular

[2] Communication between users in a one-to-one or one-to-many fashion.
[3] Direct communication with other users.

availability. This solution will maintain, and in some cases increase, the coverage currently provided by the VHF radio system while also increasing voice communication reliability during a disaster situation.

Hydro proposes to replace 45 of the current 83 fixed VHF radios with either a fixed PTT-capable satellite phone or a fixed cellular phone. Fixed cellular phones will be installed where cellular coverage is available.

Hydro identified users who currently rely on existing VHF radios for mobile voice communications and who would require alternate equipment. Based on this evaluation, Hydro proposes to replace 229 of the current 368 vehicle-mounted and handheld VHF radios with PTT-capable satellite phones.

The useful life expectancy for the replacement equipment is ten years.

Reductions in the number of required end-user terminals proposed for replacement compared to the current number of VHF radios is due to the increased availability of cellular coverage since the TMRS was initially put in place. Personnel and work crews now typically use cellular communication as their primary form of voice communication. VHF radio is used as a backup or where cellular coverage is not available. Due to the geography of Hydro's operating area, there are numerous locations where cellular coverage is still not available or reliable.

This project is required to ensure continued access to voice communications for both primary and backup usage by personnel and work crews to facilitate work execution and the operations and maintenance of the electrical system. This includes critical emergency communications when travelling or operating outside of cellular coverage areas or in the presence of a disaster situation where cellular communication has been affected.

3.0 Asset Overview

3.1 Asset Background

Hydro's fleet of end-user terminals (i.e., VHF radios) that connect to the TMRS consists of the following:

- Approximately 83 fixed units (base stations), which are installed in buildings such as terminal and generating stations;
- Approximately 229 mobile units, which are installed in vehicles; and
- Approximately 139 portable units (handheld).

The majority of these units were put into service during the initial rollout of the TMRS, which received its final acceptance in 2009.

3.2 Historical Reliability

The VHF equipment has proven reliable during its service life, with individual units repaired or replaced as necessary. For portable units, batteries have been replaced regularly as their capacities diminished.

3.3 Asset Condition

Hydro's VHF equipment is operational; however, replacement is required as the existing third-party system is being decommissioned, which will render this equipment unable to meet Hydro's functional requirements.

4.0 Analysis

4.1 Evaluation of Alternatives

The following alternatives were evaluated:

- Deferral;
- Upgrade life extension;
- Like-for-like replacement;
- Satellite and cellular phones; and
- Subscribe to the Government of Newfoundland and Labrador's ("Government") new Province-Wide Radio System ("PWRS").

4.1.1 Deferral

Deferral is not a viable option for this project, as Bell will be decommissioning the TMRS in 2024. Once decommissioned, the VHF radio system will no longer be functional and will be unable to provide voice communications as required by Hydro for work execution, operations and maintenance, or emergency and disaster recovery—creating an unacceptable risk to safety and system reliability.

4.1.2 Upgrade Life Extension

An upgrade for the purpose of life extension is not a viable option for this project, as the TMRS will be decommissioned by Bell in 2024, rendering the VHF radio system unable to meet Hydro's functional requirements.

4.1.3 Like-for-Like Replacement

Like-for-like replacement is not a viable option for this project. It would not be feasible for Hydro to install its own VHF radio system to provide the required coverage without the use of Bell's TMRS.

4.1.4 Satellite and Cellular Phones

Under this option, approximately 60% of Hydro's existing VHF radios would be replaced by either mobile or fixed PTT-capable satellite phones or fixed cellular phones.

4.1.5 Alternative Strategies

Province-Wide Radio System

The Government is in the process of installing a new ultra-high frequency ("UHF") radio system across the province; however, UHF radio technology provides less coverage than VHF and does not provide the coverage required for Hydro's operating territory. For this reason, Government's PWRS is not a viable option for this project.

4.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

4.3 Recommended Alternative

Based on the evaluation of alternatives, Hydro recommends the replacement of the VHF radio system with a combination of PTT-capable satellite phones and fixed cellular phones. There are currently no viable alternatives to replace the VHF radio system and provide the coverage and functionality required by Hydro. Replacing this system with PTT-capable satellite phones or fixed cellular phones will ensure Hydro maintains the required coverage for reliable operations or in emergencies.

4.3.1 Risk of Asset Stranding

Hydro does not foresee the removal of the requirement for this type of communication. In the future, satellite communications through cellular phones may become widely available; however, Hydro's

adoption of this technology is contingent upon Hydro's service areas having cellular service, which is not anticipated to occur during the life cycle of the proposed equipment. Once this technology is widely available, Hydro can begin to switch from PTT-capable satellite phones to cellular phones with satellite capabilities if deemed to be lower cost. This could be controlled on a phone-by-phone basis leaving no unnecessary asset stranding.

For these reasons, Hydro considers the risk of asset stranding to be low.

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2025 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	5	**15**
Post-Execution	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**7.7**

5.0 Scope of Work

To replace the functionality previously provided by the VHF radio system, Hydro proposes to install a combination of mobile and fixed PTT-capable satellite phones as well as a small number of fixed cellular phones. Mobile installations will include vehicle-mounting kits with vehicle antennas and fixed installations will include desk-mounting kits, antennas, cellular boosters, and cabling.

The project deliverables are outlined as follows:

- Create tenders to procure all required equipment and service agreements;
- Create and award the tender for mobile vehicle satellite system installations;
- Commission and verify operability; and
- Prepare user documentation.

5.1 Project Budget

The estimate for the 2024–2025 project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2024	2025	Beyond	Total
Material Supply	820.1	0.0	0.0	**820.1**
Labour	116.9	93.2	0.0	**210.1**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	139.9	93.9	0.0	**233.8**
Other Direct Costs	18.7	16.0	0.0	**34.7**
Interest and Escalation	56.4	67.2	0.0	**123.6**
Contingency	109.6	20.3	0.0	**129.9**
Total	**1,261.6**	**290.6**	**0.0**	**1,552.2**

5.2 Project Schedule

This will be a two-year project with procurement taking place in 2024. The installation will also begin in 2024 upon receipt of material, with the project being completed in 2025. The schedule for this project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Open project and generate initial project schedule.	February 2024	February 2024
Design:		
Verify equipment quantities for procurement and develop material tender for satellite equipment.	February 2024	February 2024
Procurement:		
Award material tender and order satellite equipment.	March 2024	March 2024
Procurement:		
Create and award installation tender(s).	April 2024	April 2024
Order other required equipment, cellular phones, boosters, cabling, etc.	April 2024	May 2024
Receive equipment.	May 2024	July 2024
Construction:		
Installation of fixed site satellite and cellular systems by internal resources.	May 2024	September 2025
Installation of vehicle satellite systems by approved the tenderer.	September 2024	October 2025
Closeout:		
Complete project closeout documentation.	November 2025	December 2025

6.0 Conclusion

Hydro's current VHF radio system, TMRS, will be decommissioned by Bell in August 2024, requiring Hydro to develop and implement a replacement solution. A replacement for the VHF radio system is required to ensure continued access to voice communication by personnel and work crews to facilitate work execution, operations and maintenance of the electrical system, and to provide critical emergency communication when travelling or operating outside of cellular coverage areas. To mitigate safety and system reliability risks tied to this required voice communication, Hydro recommends the replacement of the VHF radio system with a combination of PTT-capable satellite phones and fixed cellular phones.

Project 8

Purchase Accommodations Trailers (2024–2025)

Makkovik and Cartwright

July 2023

Purchase Accommodations Trailers (2024–2025)

Location: Makkovik and Cartwright

Investment Classification: General Plant

Asset Category: Generation

Executive Summary

The communities of Cartwright and Makkovik are part of Newfoundland and Labrador Hydro's ("Hydro") Labrador Isolated Diesel System, whereby each community has a diesel generating station that serves as its sole generation source. Both communities are located on the Labrador coast with limited means of access. There is no road access to the community of Makkovik, with travel via aircraft or boat providing the only means of access. Cartwright is accessible by boat, aircraft, and, most recently, roadway. To ensure that the diesel generating stations are properly maintained and in reliable operating condition, crews are required to travel to these communities to complete routine maintenance activities, emergency repairs, and conduct capital refurbishment work.

Hydro does not presently have dedicated site accommodations in either community. This, compounded with the absence of a hotel in Cartwright and the limited availability of hotel space in Makkovik,[1] has required Hydro to procure private rental arrangements to secure adequate lodging for its employees. A recent decrease in the availability of rental properties has resulted in Hydro's inability to secure adequate, reliable site accommodations for its employees. This poses a risk to system reliability. On occasions where there are no accommodations available in Makkovik, crews are often required to fly in and out of the community to complete their work. While this has provided a short-term solution, this approach cannot be adopted in the long term due to safety, productivity, and cost concerns. In addition, the ability to fly depends greatly upon suitable weather conditions. Should aircraft be unable to fly, it could result in crews being stranded in the community without lodging and/or delays in accessing the community for the completion of critical work.

[1] The hotel in Makkovik has a total five bedrooms.

The unavailability of lodging in Cartwright requires crews to seek accommodation in the neighbouring community of Port Hope Simpson, located 200 kilometres away. This commute results in longer work days and reduced productivity as well as incurred costs associated with increased travel.

To ensure that critical maintenance work can be completed and provide for the health and welfare of employees, adequate site accommodations are necessary. Subsequently, Hydro is proposing the purchase and installation of pre-fabricated accommodation units in the communities of Cartwright and Makkovik. The accommodations will provide an appropriate living arrangement, which meets the current industry standard for employee lodging.

This project has a multi-year approach, with completion planned in 2025 at an estimated cost of $1,551,100.

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1.0 Introduction

The communities of Cartwright and Makkovik are located on the coast of Labrador. Hydro diesel generating stations are the sole source of generation for the communities. Crews are required to visit the sites regularly to complete routine maintenance, emergency repairs, and capital refurbishment work.

The communities pose separate but related challenges to accessibility and accommodation. Makkovik is inaccessible by road, with aircraft or boats providing the only means of access. While Cartwright does have road access, the nearest community that offers accommodation options is located 200 kilometres away.

Given the remoteness of the communities and the logistical issues associated with site access, crews are often required to remain in the community for the duration of their work. Hydro has typically availed of private rental arrangements to secure lodging for its staff travelling to these communities; however, these options are becoming increasingly difficult to obtain. Crews have resorted to flying via daily scheduled flights to and from the communities for routine work and by helicopter for emergency work. The ability to fly depends greatly upon weather conditions. Should the aircraft be unable to fly, crews could become stranded in the community without lodging, and/or cause delays in accessing the community for the completion of critical maintenance work. While driving is occasionally an option for Cartwright, the 200-kilometre drive to the nearest accommodations in Port Hope Simpson provides additional logistical challenges, increased costs, and is taxing on personnel in their execution of work. This is particularly true during the harsh winter months when road conditions deteriorate.

Although daily commutes have provided a short-term solution, this approach cannot be adopted in the long term.

2.0 Project Description and Justification

A lack of suitable accommodations in the communities of Cartwright and Makkovik places Hydro and its staff in a vulnerable position.

Hydro’s personnel travel to these locations at least five times annually to complete regularly scheduled maintenance. Visits to these sites increase should there be a requirement to complete unscheduled equipment repairs or capital work. The current lack of suitable accommodations is affecting Hydro's

ability to do its work and is creating hardship for crews. Crews have had to resort to flying to and from the job site daily via scheduled flights for routine work and helicopters for emergency work. In the case of Cartwright, crews are frequently required to drive to the nearest available accommodations in Port Hope Simpson, which is 200 kilometres away.

Considering the aircraft's ability to fly depends greatly upon the weather, travel in and out of the community may not be available when required, potentially stranding crews in the community without appropriate lodging and/or delaying access to the community to complete critical work. Furthermore, driving 200 kilometres from Cartwright to Port Hope Simpson results in long workdays for employees, reducing productivity and increasing safety risks.

To address the shortage of lodging and provide safe, reliable accommodations for its employees in Cartwright and Makkovik, Hydro proposes the purchase and installation of a dedicated four-bedroom, pre-fabricated accommodation unit in each community.

3.0 Asset Overview

3.1 Asset Background

The communities of Cartwright and Makkovik offer limited viable accommodation options. The lone hotel in Makkovik contains only five bedrooms, which are often unavailable, particularly during the summer construction season. To mitigate availability issues, Hydro has historically availed of private rental agreements. These accommodations often contain an insufficient number of bedrooms and are inadequate to satisfy the needs of personnel.

Cartwright had hotel accommodations up until 2015 when they were destroyed by a fire. The hotel has not been reconstructed, leaving private rental arrangements as the only viable alternative to address Hydro's accommodation needs. In recent years, the availability of suitable site accommodations in the community has decreased, resulting in crews having to fly to and from the community or make the daily 400-kilometre round trip to Port Hope Simpson.

4.0 Analysis

4.1 Evaluation of Alternatives

A lack of suitable living accommodations in the isolated Labrador communities of Cartwright and Makkovik is affecting Hydro's ability to complete critical maintenance work and is placing maintenance crews in hardship. In consideration of this, the following alternatives were analyzed:

- Deferral;
- Alternative strategies; and
- Purchase and installation of accommodation units

4.1.1 Deferral

Hydro is obligated to provide reliable power generation to the people of Cartwright and Makkovik. The unavailability of suitable site accommodations impacts Hydro's ability to do work, often delaying the completion of critical maintenance and emergency repairs, placing the reliability of the systems at risk.

The shortage of suitable accommodations also affects the health and safety of crews required to complete critical maintenance work in these communities. The lack of suitable accommodations in the communities of Cartwright and Makkovik introduces staff safety risks by extending workdays and creating stress related to unnecessary travel and a potential lack of shelter. Aside from the potential impact that this approach could have on system reliability, it is unacceptable to request that employees travel to a remote location without having reliable accommodations in place. Hydro must ensure the health and safety of its staff. Deferring the construction of Hydro-specific accommodations would result in crews needing to commute excessively and risk travelling to these communities without a guarantee of safe accommodations.

For these reasons, deferral of the proposed accommodation installations is not considered a viable option.

4.1.2 Alternative Strategies

Hydro has considered the option of continuing its reliance on the local hotel to satisfy its lodging requirements in the community of Makkovik; however, as lodging at the sole hotel in Makkovik is limited and not guaranteed, this option fails to address the risks outlined herein, making it not a viable option.

Hydro has also considered the extension of rental accommodations within these communities; however, securing lease agreements has become increasingly challenging due to recent shortages in available rental properties. The volatility of the availability of suitable accommodations places both the health and safety of personnel and the reliability of the system at risk; therefore, it is not a viable option.

4.1.3 Purchase and Installation of Accommodation Units

Given the isolation of the Cartwright and Makkovik Diesel Generating Stations, local accommodations are essential for the completion of critical maintenance activities, capital work, and emergency interventions. The installation of dedicated accommodations in these communities would address Hydro's operational requirements and ensure suitable living arrangements for crews.[2]

4.2 Least-Cost Evaluation

Hydro has not identified any viable alternative strategies to facilitate a least-cost evaluation.

4.3 Recommended Alternative

The proposed purchase and installation of a dedicated accommodations unit in the communities of Cartwright and Makkovik is recommended to mitigate the current risk to system reliability and provide a suitable living arrangement for the crews required to conduct critical work.

4.3.1 Risk of Asset Stranding

The Cartwright and Makkovik Diesel Generating Stations are the sole source of supply power for the communities. While renewable energy alternatives are being considered to offset diesel generation, these generation sources do not provide the firm power requirements necessary to ensure continuity of power supply. Diesel generation will continue to be required to ensure that reliable power generation is available.

Hydro is obligated to provide reliable power generation to the people of Cartwright and Makkovik. To ensure that this requirement is met, it is paramount that Hydro secure reliable accommodation for its employees. The proposed accommodations will serve to satisfy the operational requirements for the entirety of their 40-year service life.

[2] Hydro will continue to solicit long-term leasing options prior to completing the purchase of accommodations. In the event that a leasing option is identified that is more economical than the proposed purchase, Hydro will not proceed with the purchase and will advise the Board of Commissioners of Public Utilities.

For these reasons, the risk of asset stranding is considered low.

4.3.2 Risk Mitigation

Hydro assessed the pre-and-post implementation risk of the scope of work for the 2024–2025 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	4	5	**20**
Post-Execution	1	3	**3**
		Risk Mitigated	**17**
		Risk Mitigated per $1 Million	**11.0**

5.0 Scope of Work

This project involves the purchase and installation of prefabricated accommodation units for the rural Labrador coastal communities of Cartwright and Makkovik. The scope of work includes the following:

- Acquisition of a parcel of land in Makkovik;
- Purchase of two pre-fabricated accommodation units;
- Site installation of accommodation units;
- Connection to existing municipal water/sewer infrastructure; and
- Provision of electrical service hook-ups.

The accommodations in Cartwright will be installed on property that is currently owned by Hydro. Property acquisition will be required for the installation in Makkovik.

5.1 Project Budget

The estimate for the 2024–2025 project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2024	2025	Beyond	Total
Material Supply	2.5	507.8	0.0	**510.3**
Labour	85.4	126.0	0.0	**211.4**
Consultant	23.3	80.0	0.0	**103.3**
Contract Work	0.0	475.6	0.0	**475.6**
Other Direct Costs	2.1	22.4	0.0	**24.5**
Interest and Escalation	6.2	87.2	0.0	**93.4**
Contingency	11.4	121.2	0.0	**132.6**
Total	**130.9**	**1420.2**	**0.0**	**1,551.1**

5.2 Project Schedule

The schedule for the 2024–2025 project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning: Budget review, scope statement, schedule development, and risk assessment.	February 2024	March 2024
Design: Prepare accommodations procurement package and site installation contract.	September 2024	March 2025
Procurement: Finalize land acquisition in Makkovik, procurement of pre-fabricated accommodation units, and tender site installation contract.	February 2024	April 2025
Construction: Complete site installation of accommodations.	June 2025	August 2025
Commissioning: Final commissioning and acceptance.	July 2025	August 2025
Closeout: Final billing, project completion, interest cut-off, and lessons learned.	September 2025	November 2025

6.0 Conclusion

Hydro is obligated to provide reliable power generation to the people of Cartwright and Makkovik. The unavailability of suitable living accommodations is impacting Hydro's ability to complete critical work, placing these isolated systems at risk.

To ensure this obligation is met, it is paramount that Hydro secure safe, reliable accommodations for its employees. The lack of accommodations is placing the maintenance crews in a situation where they could potentially be stranded in the community with no access to appropriate living arrangements.

To address the issue, the purchase and installation of dedicated, four-bedroom, pre-fabricated accommodation units for Cartwright and Makkovik is required.

Project 9

Replace MDR8000 Microwave Radios (2024–2025)

July 2023



Replace MDR8000 Microwave Radios (2024–2025)

Location: Various

Investment Classification: General Plant

Asset Category: Telecontrol

Executive Summary

The microwave radio system is part of Newfoundland and Labrador Hydro's ("Hydro") private telecommunications transport network, which provides critical connectivity to terminal stations and generating facilities and is used for key communications services.

The existing microwave radio platform installed at Hydro's microwave sites in the western and central parts of the Island is obsolete and has been discontinued by the manufacturer. Hydro's existing service contract in place with the manufacturer will expire on December 31, 2025 and cannot be renewed due to obsolescence. After that time, Hydro will be unable to receive support or spare parts to operate these microwave radios.

In the event that a microwave radio was to fail, Hydro's transport network would be impacted. Depending on the location of the failure, this could result in a complete loss of visibility of a terminal station or generating facility by Hydro's Energy Control Centre ("ECC"), disruption of critical transmission line teleprotection circuits, and loss of connectivity to the administrative network at the site.

In consideration of this, the following alternatives were considered:

- Deferral;
- Upgrade life extension; and
- Like-for-like replacement.

There are no viable alternatives to the replacement of these networks due to the general geography of the sites combined with Hydro's technical requirements. As such, Hydro proposes the replacement of these obsolete systems to ensure reliable service is maintained.

There are 10 radio hops[1] connecting 11 sites proposed for replacement as part of this project. Since these assets are part of a connected communications system, these hops require replacement at the same time. It is proposed that 9 of these hops be replaced with the newer version of the microwave radios and the other be replaced with a fibre-optic cable link.

This project has a multi-year approach, with completion planned in 2025 at an estimated cost of $1,453,800.

[1] A hop is a link connecting two sites.

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1.0 Introduction

The microwave radio system is part of Hydro's private telecommunications transport network. This transport network provides critical connectivity to terminal stations and generating facilities and is used for the following communications services:

- Hydro's Supervisory Control and Data Acquisition ("SCADA") network, which provides the Newfoundland and Labrador System Operator's ("NLSO") Energy Control Center ("ECC") with remote visibility[2] and control[3] of the power system;
- Teleprotection[4] systems, which provide high-speed transmission line and breaker failure protection; and
- Hydro's administrative network, which provides voice communications and other related business functions (e.g., email, Internet, etc.).

The existing microwave radio platform installed at Hydro's microwave sites in the western and central parts of the Island is obsolete and has been discontinued by the manufacturer. In the event that a microwave radio was to fail, Hydro's private telecommunications transport network would be impacted.

Hydro proposes the replacement of these obsolete systems to ensure reliable service is maintained.

2.0 Project Description and Justification

This project proposes the replacement of ten obsolete microwave radio hops with two case-specific solutions. Since these assets are part of a connected communications system, these hops require replacement at the same time. Of the hops requiring replacement, one hop—Bay d'Espoir Hill ("BDH") to Bay d'Espoir Plant ("BDP")—will be replaced with fibre optics,[5] while the other nine hops will be replaced with a newer version of the radios due to geographical location, as the distance from existing fibre-optic infrastructure is too great to be a considered a candidate to utilize the technology.

[2] The ECC collects real-time data from remote sites in order to monitor the health of the grid.
[3] The network gives the ECC the ability to control remote devices such as circuit breakers, transformers, reclosers, etc.
[4] Teleprotection is a critical communication service that provides a fast and reliable means to protect the power grid from faults. A high-speed private network, provided by the microwave system, is required to achieve the required latency. Latency (or delay) of the data traffic on this network is of utmost importance.
[5] The infrastructure is already predominately in place in the area.

Hydro's private telecommunications transport network is essential to the reliability of the power grid. In the event that a microwave radio was to fail, Hydro's transport network would be impacted. Depending on the location of the failure, this could result in a range of consequences, including the complete loss of visibility of a terminal station or generating facility by the ECC, disruption of critical transmission line teleprotection circuits, and loss of connectivity to Hydro's on-site administrative network. Electrical system reliability would be compromised and sites would need to be shut down or staffed on a continuous basis until the equipment is repaired or replaced.

The existing microwave radio platform is obsolete and has been discontinued by the manufacturer. As of December 31, 2025, the service contract will expire and cannot be renewed. After that time, Hydro will be unable to receive support or spare parts to operate these microwave radios.

For these reasons, Hydro proposes to replace microwave radios at the following microwave radio hops as part of this project:

- Deer Lake Terminal Station ("DLK") to Blue Grass Hill ("BGH");
- BGH to Mary March Hill ("MMH");
- MMH to Sandy Brook Hill ("SBH");
- SBH to Gull Pond Hill ("GPH");
- GPH to BDH;
- BDH to Godeliech Hill ("GDH");
- BDH to BDP;
- SBH to Stony Brook Terminal Station ("STB");
- GDH to Upper Salmon Plant ("USL"); and
- MMH to Buchans Terminal Station ("BUC").

Figure 1 shows Hydro's microwave network connections. The locations of the radios to be replaced are highlighted in yellow. Those deferred for evaluation are in red boxes. All others have been replaced previously.

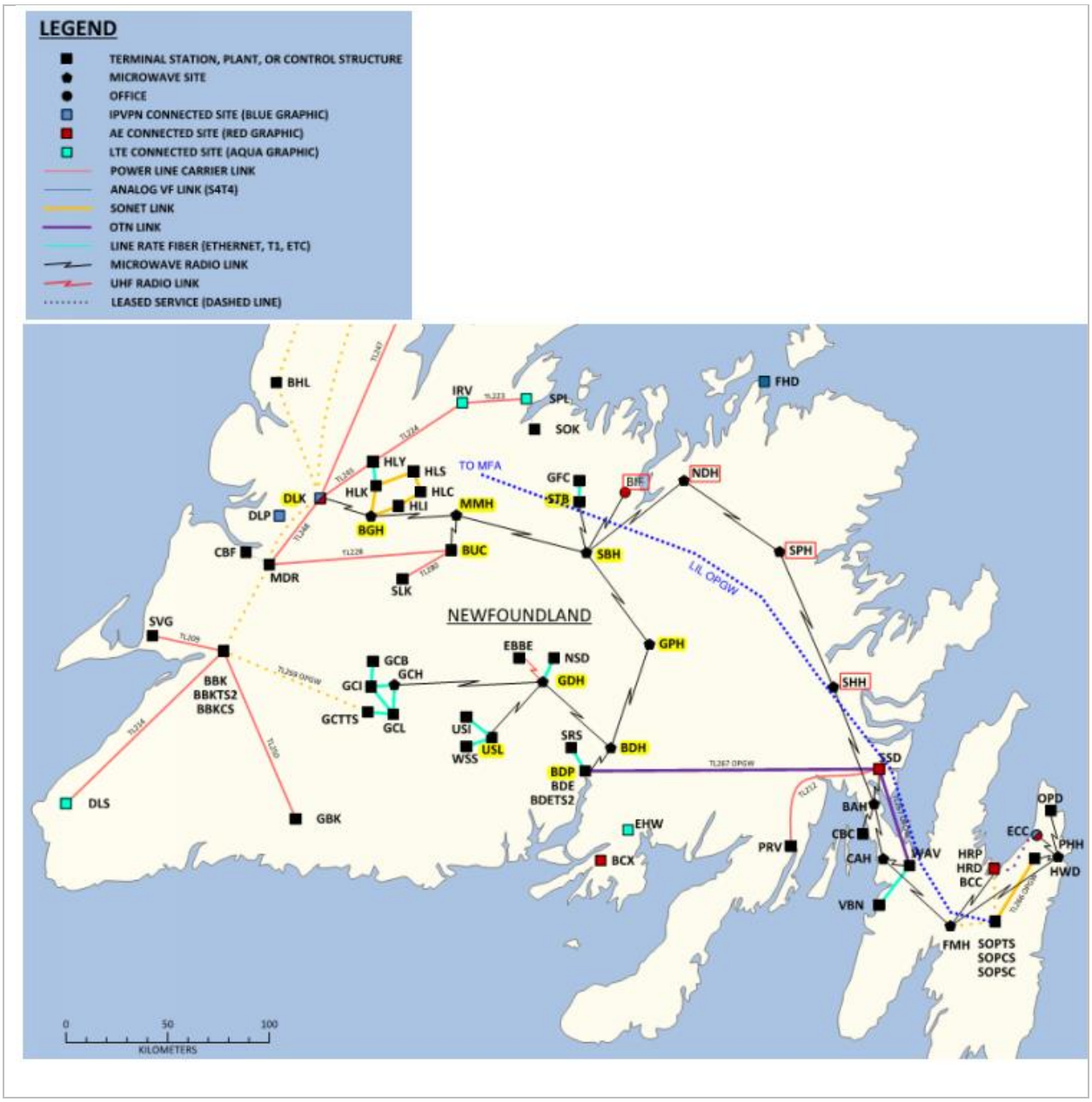


Figure 1: Microwave Network View

3.0 Asset Overview

3.1 Asset Background

Hydro currently has 26 microwave hops in its network. Of these hops, 4 were replaced with the newer version of the microwave radios in 2017 with another 7 replaced in 2019. The remaining 15 hops currently use the obsolete version of the microwave radio, 10 of which are proposed for replacement as part of this project.

In cases where replacement is necessary, there are two case-specific options—fibre-optic infrastructure or like-for-like replacement with the most recent technology of microwave radios. Fibre-optic technology is preferred, as it tends to result in better reliability and higher bandwidth capabilities; however, the availability of fibre infrastructure or feasibility of installation of fibre infrastructure is a key consideration for his option.

The microwave radio system is comprised of several components including:

- A dedicated equipment shelter (building), unless located at an existing terminal station;
- A microwave tower;
- Microwave antennas and radomes;
- Waveguides and coaxial cables;
- Filters;
- Radio transceivers; and
- Multiplexing equipment.

Generally, only the filters, radio transceivers, and multiplexing equipment located inside the associated equipment shelter will be replaced for this project. This equipment requires replacement, as technological advances and vendor requirements render the previous infrastructure obsolete. Other equipment used outside the equipment shelter, such as towers, antennas/radomes, and waveguides, can be reused, as they are considered universal and can be used with existing and new models.

Table 1 shows the installation date and age of the microwave equipment proposed to be replaced as part of this project.

Table 1: Replacement Microwave Hops Age (Years)

Hop	Year Installed	Age
DLK-BGH	2012	11
BGH-MMH	2012	11
MMH-SBH	2012	11
MMH-BUC	2012	11
SBH-GPH	2014	9
SBH-STB	2014	9
GPH-BDH	2014	9
BDH-GDH	2012	11
BDH-BDP	2011	12
GDH-USL	2009	14

3.2 Historical Reliability

The equipment proposed for replacement is an integral part of the communications network used for continuous monitoring and control of the grid, which requires very high reliability. The path design objective is to achieve 99.9999 % availability, through redundant hardware and multiple frequencies.[6]

Due to regular preventive maintenance, corrective maintenance, and redundant design, the microwave radios have performed reliably since installation. Failed components have been replaced or repaired by the manufacturer, as is required under the aforementioned service contract.

3.3 Asset Condition

The microwave asset conditions are monitored by internal Hydro resources on an ongoing basis using network management systems and regular preventive maintenance procedures.

As a result, the indoor components of the microwave system generally remain in good condition and their replacement is mostly driven by end-of-life product availability and support, which is the case for these proposed replacements.

[6] Availability refers to the minimum percentage of time that the circuit is operational.

4.0 Analysis

4.1 Evaluation of Alternatives

Hydro considered the following alternatives:

- Deferral;
- Upgrade life extension; and
- Like-for-like replacement.

4.1.1 Deferral

The existing microwave radio technology is obsolete and must be replaced by 2025. Hydro has proposed the deferral of 5 of the 15 obsolete microwave radios, as it evaluates the option of fibre-optic implementation. Of the remaining 10 obsolete microwave radios, the majority (9) are not considered candidates for fibre-optic implementation. As these assets are part of a connected communications system, these hops require replacement at the same time.

Further, the deferral of the replacement of the 10 proposed microwave radios beyond 2025 would result in the loss of the service contract with the manufacturer.[7] Without support or available spare parts, the failure of a microwave radio could result in a complete loss of teleprotection, SCADA, and administrative network services at critical operational sites for a prolonged period. The probability of failure is increased due to the age of the assets.

Hydro does maintain a small inventory of critical spare parts to respond quickly to equipment failures but primarily relies on the manufacturer service contract to replenish as parts are used. Procurement of parts from grey market sources is not a viable solution due to quality and/or cybersecurity risks.

Once taken out of service, the existing microwave radios will be added to the critical spares inventory, which can be used to mitigate the risk of spare availability to the remaining five obsolete radios. Therefore, Hydro believes the deferral of the replacement of five hops by one year achieves the appropriate balance of risk. The inclusion of any further deferral presents an unacceptable risk to system reliability and is not considered a viable alternative.

[7] Hydro's existing service contract in place with the manufacturer will expire on December 31, 2025 with no option for renewal. After this time, Hydro will be unable to receive support or spare parts to continue to operate these microwave radios.

4.1.2 Upgrade Life Extension

As spare equipment and manufacturer support are no longer available for Hydro's microwave sites located in the western and central parts of the Island, an upgrade to the existing equipment is not a viable alternative.

4.1.3 Like-for-Like Replacement

The existing microwave radio platform installed at Hydro's microwave sites located in the western and central parts of the Island is obsolete and has been discontinued by the manufacturer. On December 31, 2025, upon the expiry of its existing service contract with the manufacturer, Hydro will be unable to receive support or spare parts to operate these microwave radios. Replacement of the existing system with an up-to-date, comparable product with manufacturer support on ten hops will reduce the risk of failure of this integral part of Hydro's communications network.

Hydro is proposing to complete a like-for-like replacement of the existing microwave radio system with the newer microwave radio version of the product on nine out of ten hops. Hydro will reuse all outdoor and outdoor/indoor components of the system. For one hop, a new fibre-optic link is proposed. An existing distribution line will be utilized to complete the installation of the new cable link. The fibre-optic link will provide enhanced functionality, including higher bandwidth.

4.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

4.3 Recommended Alternative

Hydro recommends the replacement of ten obsolete microwave radio hops installed at its microwave sites located in the western and central parts of the Island with an up-to-date, comparable product with manufacturer support. Of the ten hops proposed for replacement, nine will receive the newer version of the radio, while one will use a fibre-optic link. There are no viable alternatives due to the general geography and technical requirements of the sites.

4.3.1 Risk of Asset Stranding

A microwave system remains the best option for Hydro's transport network for the foreseeable future, with manufacturer support expected for many years. A newer version of the microwave equipment remains early in its production life; therefore, Hydro considers the risk of asset stranding to be low.

4.3.2 Risk Mitigation

Hydro assessed the pre- and-post implementation risk of the scope of work for this 2024–2025 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 2.

Table 2: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	5	4	**20**
Post-Execution	5	1	**5**
		Risk Mitigated	**15**
		Risk Mitigated per $1 Million	**10.3**

5.0 Scope of Work

This project involves the replacement of ten obsolete microwave radio hops. The scope of work will include the following:

- Site visits and front-end engineering design;
- Material procurement, including microwave and fibre-optic materials;
- Tender for fibre-optic cable installation;
- Planning and procurement of microwave engineering, installation, and support services;
- Development of microwave and fibre-optic configurations and final design;
- Upgrade of Hydro's network management software to support new radio equipment;
- Development and implementation of lab staging pre-commissioning plan;
- Contract management of fibre-optic cable installation;
- Development of installation work packages;

- Installation and commissioning of microwave and fibre-optic equipment; and
- Removal of decommissioned microwave equipment.

5.1 Project Budget

The estimate for this 2024–2025 project is shown in Table 3.

Table 3: Project Estimate ($000)

Project Cost	2024	2025	Beyond	Total
Material Supply	734.0	0.0	0.0	**734.0**
Labour	87.2	245.9	0.0	**333.1**
Consultant	0.0	6.0	0.0	**6.0**
Contract Work	39.5	105.8	0.0	**145.3**
Other Direct Costs	5.6	28.8	0.0	**34.4**
Interest and Escalation	37.2	75.1	0.0	**112.3**
Contingency	50	38.7	0.0	**88.7**
Total	**953.5**	**500.3**	**0.0**	**1,453.8**

5.2 Project Schedule

The schedule for this 2024–2025 project is shown in Table 4.

Table 4: Project Schedule

Activity	Start Date	End Date
Planning: Scope, schedule, cost, site visits, and microwave engineering.	January 2024	June 2024
Design: Design, drawings, and work packages.	July 2024	March 2025
Procurement: Bill of materials, material procurement, and fibre-optic tender.	March 2024	March 2025
Construction: Installation of microwave and fibre-optic equipment.	May 2025	September 2025
Commissioning: Software installation, lab staging, and field commissioning.	March 2025	September 2025
Closeout: As-built documentation.	October 2025	December 2025

6.0 Conclusion

The existing microwave radios platform installed at Hydro's microwave sites in the western and central parts of the Island is obsolete and has been discontinued by the manufacturer. Hydro's existing service contract with the manufacturer will expire on December 31, 2025 with no option for renewal. After this time, Hydro will be unable to receive support or spare parts to continue the operation of these microwave radios.

In the event that a microwave radio was to fail, Hydro's transport network will be impacted, compromising the reliability of the electrical system. Depending on the location of the failure, this could result in a complete loss of visibility of a terminal station or generating facility by the ECC, disruption of critical teleprotection circuits, loss of connectivity to Hydro's on-site administrative network, and sites shut down or staffed on a continuous basis until the equipment is repaired or replaced.

There are 10 hops connecting 11 sites as part of this project. As these are part of a connected communications system, these hops require replacement at the same time. It is proposed that 9 of these hops be replaced with the newer version of the microwave radios with the remaining 1 replaced with a fibre-optic cable link.

Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025)

Holyrood

July 2023

newfoundland labrador hydro

Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025)

Location: Holyrood Thermal Generating Station

Investment Classification: General Plant

Asset Category: Thermal Plant

Executive Summary

The Holyrood Thermal Generating Station ("Holyrood TGS") has several buildings that support thermal generation and combustion turbine operations. The buildings directly associated with thermal production include the Main Plant, two pumphouses, and the Wastewater Treatment Plant ("Powerhouse"). The other buildings that indirectly support the Holyrood TGS and combustion turbine operations are commonly referred to as "outbuildings." These buildings undergo regular maintenance to extend the service life of the assets; however, their exterior envelopes have reached the end of their service life.

In 2022, the Flynn Group of Companies ("Flynn") completed a condition assessment of the Powerhouse and outbuilding roofing systems.[1] This assessment identified several facilities for which a roof replacement was recommended. In 2023, an internal assessment of the siding systems identified the need for isolated siding refurbishments and door replacements for several building envelopes.

This project proposes the refurbishment of the exterior building envelope for the Powerhouse and outbuildings identified as requiring immediate refurbishment.

As per the "Reliability and Resource Adequacy Study – 2022 Update,"[2] the Holyrood TGS shall remain available for a "Bridging Period"[3] until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the Labrador-Island Link is proven, and generation reserves

[1] "Roof Condition Report & Proposal – 2 Thermal Plant Rd, Holyrood, NL," Flynn Group of Companies, December 2, 2022, which is included as Attachment 1 to this document.
[2] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[3] Hydro considers the Bridging Period to be from 2023 to 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

are met. These buildings will be required to facilitate operations at the Holyrood TGS through the Bridging Period, as well as to support its continued synchronous condenser operation thereafter.

Delays in the completion of corrective actions will result in the continued deterioration of the building envelope components. This will compromise the integrity and pose a risk of damage to the equipment housed in the buildings, disrupt operations, and result in increased safety concerns during extreme weather events. The integrity of the buildings' exterior envelopes is critical to preventing the ingress of water and wildlife, as well as protecting the interior from the unconditioned environment.

In consideration of this, the following alternatives were considered:

- Deferral;
- Upgrade life extension; and
- Like-for-like replacement.

As the buildings' exterior envelopes have reached the end of their service life, like-for-like replacement was determined to be the only viable alternative to support the operation of the Holyrood TGS. As a result, Hydro is proposing the completion of refurbishments to the Powerhouse and Outbuilding exterior envelopes to ensure their integrity is maintained.

This project has a multi-year approach, with completion planned in 2025 at an estimated cost of $1,195,600.

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List of Attachments

Attachment 1: “Roof Condition Report & Proposal – 2 Thermal Plant Rd, Holyrood, NL,” Flynn Group of Companies, December 2, 2022

1.0 Introduction

The Holyrood TGS has several buildings that support thermal generation and combustion turbine operations. The Powerhouse includes buildings directly associated with thermal production including the Main Plant, two pumphouses, and the Wastewater Treatment Plant. Outbuildings include those that indirectly support the Holyrood TGS and combustion turbine operations, including the Shawmont Building,[4] the Warehouse, the Training Center, and the Pipe Shop. Figure 1 provides the site layout for the Powerhouse and outbuildings.

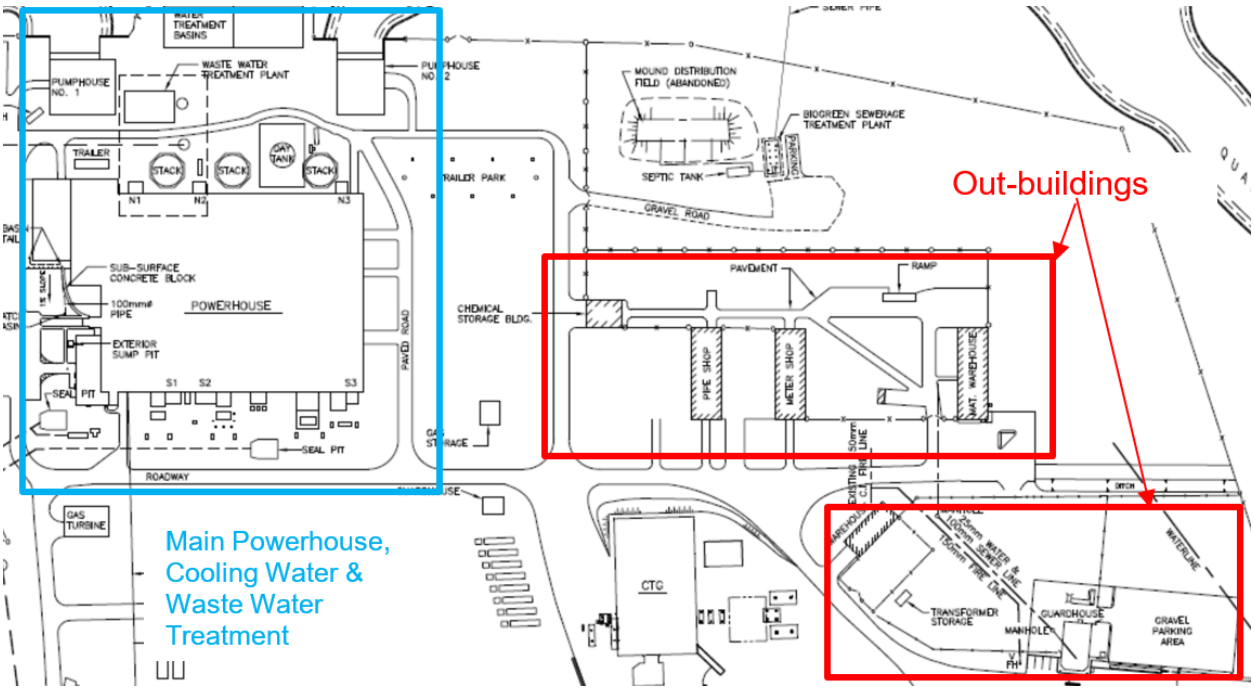


Figure 1: Site Layout for Powerhouse and Outbuildings

The Powerhouse was constructed in 1969, with the outbuildings ranging from the late 1970s to the early 1990s. The metal cladding components of these structures typically carry an anticipated service life of 40 years. The buildings undergo regular maintenance to extend the service life of the assets; however, their exterior envelopes—including roofs, siding, and doors—have reached the end of their service life.

Flynn's 2022 condition assessment of the Powerhouse and Outbuilding roofing systems identified several facilities for which a roof replacement was recommended. In 2023, an internal assessment of the buildings' siding systems and exterior doors identified the need for isolated siding refurbishments and

[4] The Shawmont Building is used as a storage facility.

door replacements. Hydro is proposing the completion of refurbishments to the exterior building envelopes for the Powerhouse and outbuildings to restore their integrity.

2.0 Project Description and Justification

Given the age of the structures, various components of their respective building envelopes have reached the end of their service life.

The Holyrood TGS is located in a coastal environment, with direct exposure to wind off the Atlantic Ocean. When building envelope components such as siding and roofing are compromised, there is an increased risk of damage that comprises the safety and reliability of essential equipment housed inside the buildings. Failure to restore the integrity of the exterior envelope will result in the continued formation of leaks, which disrupt building operations, contribute to the formation of mould and can damage sensitive electrical equipment housed within the facilities. During extreme weather events, compromised components of the envelopes could fail and detach from the structure, potentially resulting in generation outages, and/or risk to the physical safety of personnel.

This project is comprised of the refurbishment of the exterior envelope for the Powerhouse and outbuildings identified as requiring immediate refurbishment. The proposed envelope restoration will extend the service life of the facilities, as these buildings will be required to facilitate operations at the Holyrood TGS through the Bridging Period, as well as to support its continued operation thereafter as a synchronous condenser. As a result, Hydro is proposing refurbishment to restore the envelope's integrity and ensure its ability to shield the interior from the unconditioned environment.

3.0 Asset Overview

3.1 Asset Background

The specific buildings to receive envelope refurbishments under this project include:

- Powerhouse:
  - No. 1 Pumphouse;
  - No. 2 Pumphouse;
  - Main Plant; and
  - Wastewater Treatment Plant.

- Outbuildings:
  - Shawmont Building;
  - Warehouse;
  - Training Center; and
  - Pipe Shop.

The Main Plant and Pumphouses were constructed in 1969 and 1979, respectively, with the Wastewater Treatment Plant constructed in 1992. The associated outbuildings were built in the 1970s to 1990s. All buildings consist of steel frame construction, complete with metal siding. All are equipped with metal roofing systems, except the Main Plant roofing, which consists of a combination of built-up[5] and inverted[6] roofs. The exterior doors are hollow metal insulated with steel frames.[7]

The majority of the exterior envelope components to be replaced under this project are original to the buildings and have reached the end of their service life.

3.2 Historical Reliability

Hydro completes regular maintenance of the building envelope components, including regular inspections, patching, and applications of coating as required. This has served to ensure the reliability of the buildings throughout the course of their service lives. In recent years, an increase in the number of issues has raised concerns that components of the building envelope system have exceeded their service life. These issues include improper operation of doorways, the development of leaks in the roofing systems, and the degradation of siding panels.

3.3 Asset Condition

The buildings to be refurbished under this project were subject to condition assessments in late 2022 and early 2023. During these assessments, several issues were identified, resulting in the proposed exterior envelope refurbishments. The 2022 condition assessment completed by Flynn, included as

[5] Built-up roofing is a roofing system where multiple layers of asphalt are applied between ply sheets (or felts) over the roof deck and insulation.
[6] An inverted roof has the waterproofing layer beneath the insulation rather than above it, requiring insulation to be ballasted to prevent wind uplift.
[7] It could not be confirmed whether the doors were original to the building envelopes; however, the Holyrood TGS does not have maintenance records indicating that any of these doors have been replaced.

Attachment 1 of this proposal, includes pictures depicting the identified issues. A breakdown of the asset condition by structure is outlined in Table 1.

Table 1: Summary of Assessments on Building Envelopes

Building	Year Constructed	Component(s)	Original to Envelope[8]	Issue(s) Identified
Shawmont Building	1979	Metal Roofing System	Yes	• Rusting along ridge capping • Corrosion of roof panels • Deterioration of the coating system • Corroded fasteners
Warehouse	1969	Metal Roofing System	Yes	• Separation of the metal panel seams; • Deteriorated skylights • Loose/missing fasteners • Deterioration of the coating system
Training Centre (Meter Shop)	1984	Metal Roofing System	Yes	• Metal roof panels in poor condition with notable corrosion • Deteriorated coating system • Deteriorated skylights
Pipe Shop	1969	Metal Roofing System	Yes	• Separation of the metal roof panel seams • Corrosion of the metal roof panels • Deteriorated skylights
Wastewater Treatment Plant	1992	Metal siding on the north and south faces of the building and the west exterior door	Yes	• Corrosion is evident on the siding, particularly at the fastener locations and along the bottom edge • Corrosion and deterioration of metal door
No. 1 Pumphouse	1969	South and west exterior doors	Unknown	• Corrosion and deterioration of metal
No. 2 Pumphouse	1979	Metal cladding on the north and west faces of the building and the north exterior door	No	• Corrosion and deterioration of metal door • Scaled coating on cladding • Corrosion of the metal panels • Warping of the panels resulting in improper sealing at the seams • Corroded fasteners
Main Plant	1969	North stairwell exterior door	Unknown	• Corrosion and deterioration of metal

[8] The Holyrood TGS does not have maintenance records indicating that the doors identified have been replaced since construction of their respective buildings.

3.4 Condition-Based Remaining Life

3.4.1 Outbuildings

Roofing systems on the Shawmont Building, Warehouse, Training Centre, and Pipe Shop are original to the building and have been regularly maintained and repaired to ensure reliable operation. However, due to the age of the assets and their exposure to the unconditioned environment, they have all reached the end of their service life.

3.4.2 Powerhouse

Wastewater Treatment Plant

The Wastewater Treatment Plant was constructed in 1992; it is finished with a metal cladding system. The facility lacks a gutter system, resulting in runoff from rain and snowmelt descending the north and south sides of the building. This, in conjunction with being subjected to the prevailing winds and salt spray from Conception Bay, has resulted in the accelerated deterioration of the cladding on these two building faces, as shown in Figure 2. The east and west sides of the building remain in good condition.



Figure 2: Deterioration of Cladding on Wastewater Treatment Plant

No. 2 Pumphouse

Initially constructed in 1979, the No. 2 Pumphouse had its original metal siding replaced in 1995. As Figure 3 shows, the metal cladding has visible signs of corrosion along the upper sections on the north side and much of the blue accent siding on the west side of the building; the remainder of the cladding is deemed to be in good condition.

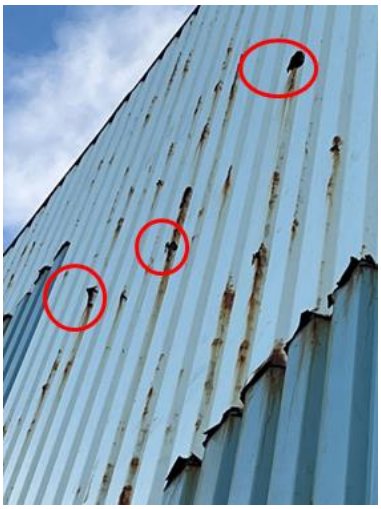


Figure 3: Corrosion to Cladding on No. 2 Pumphouse

Exterior Doors

All exterior doors throughout the site facilities are hollow metal insulated units, completed with metal frames. The doors are no longer latching properly due to significant deterioration and corrosion, as depicted in Figure 4, and fail to provide the intended level of security and weather tightness. The Holyrood TGS maintains exterior doors through regular inspection as part of its preventive maintenance program; however, the six doors identified for refurbishment have reached the end of their service life.



Figure 4: Example of Corrosion and Deterioration of Exterior Door

4.0 Analysis

4.1 Evaluation of Alternatives

The building envelope components slated for refurbishment under this proposal have reached the end of their service life. This has resulted in the formation of leaks and raises concerns regarding the integrity of the building envelope components. As this project is unique to the Holyrood TGS, no pooling or clustering options were identified. In consideration of this, the following alternatives were evaluated:

- Deferral;
- Upgrade life extension; and
- Like-for-like replacement.

4.1.1 Deferral

The exterior building envelope components designated for replacement under this project have exceeded their service life. Their integrity has been compromised and they can no longer be relied upon to provide an adequate level of weather-tightness or protection from wildlife. Previous inspections and repairs have maximized the service life of these assets; however, the deferral of replacement work can no longer be pursued as a viable alternative.

Failure to complete the proposed replacement will result in the continued deterioration of the building envelopes. This may cause the reoccurrence of leaks throughout the facilities and increase the potential for component failure and/or personal injury during extreme weather events; for example, corroded metal cladding has an increased likelihood of detaching from buildings during high wind events. Previous instances of metal siding panels becoming detached from the Powerhouse were noted in 2012 and 2017. During the event in 2012, the detached siding struck a transformer, resulting in a unit outage.

The deteriorated condition of the exterior building envelope components increases the risk of damage to the equipment housed in the buildings, disrupts operations, and increases safety concerns during extreme weather events. For these reasons, deferral of the proposed refurbishment work is not considered a viable alternative.

4.1.2 Upgrade Life Extension

Hydro has completed regular inspections and corrective maintenance on the various envelope components to prolong their service life. These options are now exhausted as recent inspections have

noted that the components have reached the end of their service life. As such, upgrade life extension is no longer a viable option.

4.1.3 Like-for-Like Replacement

The building envelope components to be replaced under this project have reached the end of their service life. Strategic replacement of the existing components, in kind, will restore the integrity of the facilities' exterior envelopes and extend the service life of the buildings.

4.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation.

4.3 Recommended Alternative

As the only viable alternative, the refurbishment of the exterior building envelopes is required to provide weather-tight facilities to support the operation of the Holyrood TGS.

The noted doors, siding, and roofing systems have reached the end of their service life. As these buildings will be required to facilitate operations at the Holyrood TGS through the Bridging Period, as well as to support its continued operation thereafter as a synchronous condenser, the completion of the proposed refurbishments is recommended.

4.3.1 Risk of Asset Stranding

The risk of asset stranding is less imminent as a result of the decision to extend the Holyrood TGS to remain available through the Bridging Period. As Hydro expects continued operation of all three units at the Holyrood TGS through the Bridging Period until its capacity can be replaced to ensure reliable operation for customers, capital expenditures for this facility to operate as a generator continue to be required. Depreciation is required to be calculated on an accelerated basis (i.e., monthly depreciation = capital investment ÷ remaining months of service life).[9]

[9] As a result of the extension of the Holyrood TGS through the Bridging Period, Hydro intends to make an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account in 2023.

4.3.2 Risk Mitigation

Hydro assessed the pre-and-post implementation risk of the scope of work for the 2024–2025 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 2.

Table 2: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	3	**12**
Post-Execution	2	1	**2**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**8.4**

5.0 Scope of Work

The scope of this project is to refurbish the building envelopes for various facilities at the Holyrood TGS. Envelope refurbishments consist of roof replacement, siding replacement, and exterior door replacement. The following is a breakdown of the proposed scope of work by structure:

- Powerhouse:
  - Main Plant: Replace the north stairwell access door;
  - Wastewater Treatment Plant: Replace the west access door as well as the siding on the north and south faces;
  - No. 1 Pumphouse: Replace the south and west access doors; and
  - No. 2 Pumphouse: Replace the north access door as well as sections of siding on the north and west faces.
- Outbuildings:
  - Shawmont Building: Replace metal roofing system;
  - Warehouse: Replace metal roofing system;
  - Training Center: Replace metal roofing system; and
  - Pipe Shop: Replace metal roofing system.

5.1 Project Budget

The estimate for the 2024–2025 project is shown in Table 3.

Table 3: Project Estimate ($000)

Project Cost	2024	2025	Beyond	Total
Material Supply	19.6	0.0	0.0	**19.6**
Labour	76.1	78.9	0.0	**155.0**
Consultant	33.0	25.0	0.0	**58.0**
Contract Work	0.0	781.4	0.0	**781.4**
Other Direct Costs	6.8	0.5	0.0	**7.3**
Interest and Escalation	7.1	65.0	0.0	**72.1**
Contingency	13.6	88.6	0.0	**102.2**
Total	**156.2**	**1,039.4**	**0.0**	**1,195.6**

5.2 Project Schedule

The schedule for the 2024–2025 project is shown in Table 4.

Table 4: Project Schedule

Activity	Start Date	End Date
Planning: Budget review, scope statement, schedule, and risk assessment.	February 2024	March 2024
Design: Engage consultant, complete detailed engineering, and prepare the tender package.	May 2024	December 2024
Procurement: Tender and award contract for building envelope refurbishment.	February 2025	March 2025
Construction: Complete building envelope refurbishments.	June 2025	August 2025
Closeout: Project completion, interest cut-off, and complete lessons learned	September 2025	October 2025

6.0 Conclusion

The Powerhouse and associated outbuildings were subject to a condition assessment in 2022 and 2023. The assessments highlighted several issues and advised that various components of the respective exterior building envelopes had reached the end of their service life.

The Holyrood TGS is located in a coastal environment, with direct exposure to the wind off the Atlantic Ocean. When building envelope components such as siding and roofing are compromised, the risk to safety and reliability as well as the risk of damaging essential equipment housed inside the buildings increases.

The proposed refurbishments are required to restore the integrity of the building envelopes, thus ensuring their reliability and safety, and extending the service life of the facilities.

Attachment 1

Roof Condition Report & Proposal – 2 Thermal Plant Rd, Holyrood, NL

Flynn Group of Companies

December 2, 2022

FLYNN GROUP OF COMPANIES

ROOF CONDITION REPORT & PROPOSAL

2 Thermal Plant Rd.
Holyrood, NL

Disclaimer:

Flynn Group of Companies has conducted and performed a roof audit at this site. The results and findings from this report are based solely and exclusively on the observations of the inspector at the specific time of the inspection and are intended exclusively for the above noted client. Nonetheless, there may have been hidden issues and unforeseen deficiencies and defects, including those which may not have been visible at the time due to various conditions (ie. weather; mechanical; other contractor work; etc) . Performing this roof audit does not guarantee that the observations noted have and/or will remain identical beyond the time that they were made, nor does it provide a warranty or promise of the roof being in the same condition beyond such time. Changes on roof structure and conditions can and do occur over time. The indication of the age of a roof is just an approximation based solely from visual observations. To verify the age of a roof, the owner/buyer should review all records and permits on file for the site in question with the local building department to determine when the roof was installed and the dates of any prior approved repairs.

Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022

Address Line1: 2 Thermal Plant Rd.

Building Name/Address Line2:

City: Holyrood **Province/State:** NL **Postal/Zip Code:** A0A 2R0

Roof Composition

Shawmont Building

Deck:	Metal;	**Membrane:**	Metal;
Insulation:	Fiberglass;	**Surfacing:**	None;
Vapor Retarder:	Not known;	**Was cut test performed:**	N/A
Resaturated:	N/A	**Roof Height:**	20
Caulking:	Poor(cracking)	**Approximate Age:**	43
Masonry Adjoining:	N/A	**Life Remaining:**	1-2
Walls Adjoining:	N/A	**Cleanliness:**	Clean
Penetration Flashing:	N/A	**Leaking:**	Not Known
Fasteners:	Corroded	**Exposed Areas:**	No
Drainage & Drains:	N/A	**Roof Drain Strainers Control Weirs:**	N/A
Blisters/Ridges:	No	**Mastic Pans:**	N/A
Splits:	N/A	**Skylights:**	N/A
Membrane Flashing:	N/A	**Roof Mounted Units:**	N/A
Metal Flashing:	N/A	**Curbs/Sleepers:**	N/A
Approximate Area:	2400		

Work Done and Comments

Roof Audit / Roof Condition Report
Roof is in poor condition due to rusted areas , corroded fasteners & deteriorated sealant in areas

Further Work Recommended

Maintenance required immediately - 1-2 year life space at current condition

Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022

Address Line1: 2 Thermal Plant Rd.

Building Name/Address Line2:

City: Holyrood **Province/State:** NL **Postal/Zip Code:** A0A 2R0

Roof Composition

Stores / Warehouse

Deck:	Metal;	**Membrane:**	Metal;
Insulation:	Fiberglass;	**Surfacing:**	None;
Vapor Retarder:	Not known;	**Was cut test performed:**	No
Resaturated:	No	**Roof Height:**	20
Caulking:	Fair	**Approximate Age:**	53
Masonry Adjoining:	N/A	**Life Remaining:**	1
Walls Adjoining:	N/A	**Cleanliness:**	Clean
Penetration Flashing:	Poor	**Leaking:**	Yes
Fasteners:	Fair	**Exposed Areas:**	
Drainage & Drains:	N/A	**Roof Drain Strainers Control Weirs:**	N/A
Blisters/Ridges:	No	**Mastic Pans:**	N/A
Splits:	No	**Skylights:**	Poor
Membrane Flashing:	Damaged	**Roof Mounted Units:**	N/A
Metal Flashing:	Poor	**Curbs/Sleepers:**	N/A
Approximate Area:	4920		

Work Done and Comments

Visual inspection from man lift
Areas of fiberglass skylights to be replaced with metal panels and maintenance on all open seams to be sealed with seam sealer

Further Work Recommended

Replacement required in 1-2 years.

Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022

Address Line1: 2 Thermal Plant Rd.

Building Name/Address Line2:

City: Holyrood **Province/State:** NL **Postal/Zip Code:** A0A 2R0

Roof Composition

Training Center

Deck:	Metal;	**Membrane:**	Metal;
Insulation:	Fiberglass;	**Surfacing:**	None;
Vapor Retarder:	Not known;	**Was cut test performed:**	No
Resaturated:	No	**Roof Height:**	20
Caulking:	Poor(cracking)	**Approximate Age:**	38
Masonry Adjoining:	N/A	**Life Remaining:**	1-2
Walls Adjoining:	N/A	**Cleanliness:**	Clean
Penetration Flashing:	Poor	**Leaking:**	Not Known
Fasteners:	Missing	**Exposed Areas:**	N/A
Drainage & Drains:	N/A	**Roof Drain Strainers Control Weirs:**	N/A
Blisters/Ridges:	No	**Mastic Pans:**	N/A
Splits:	N/A	**Skylights:**	Poor
Membrane Flashing:	N/A	**Roof Mounted Units:**	N/A
Metal Flashing:	Fair	**Curbs/Sleepers:**	N/A
Approximate Area:	4920		

Work Done and Comments

visual inspection of roof area from man lift
areas of fiberglass skylights to be replaced with new metal panels

Further Work Recommended

Immediate preventative maintenance required. Replacement possible 1-2 years

Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022

Address Line1: 2 Thermal Plant Rd.

Building Name/Address Line2:

City: Holyrood **Province/State:** NL **Postal/Zip Code:** A0A 2R0

Roof Composition

Pipe Shop

Deck:	Metal;	**Membrane:**	Metal;
Insulation:	Fiberglass;	**Surfacing:**	None;
Vapor Retarder:	Not known;	**Was cut test performed:**	No
Resaturated:	No	**Roof Height:**	20
Caulking:	Poor(cracking)	**Approximate Age:**	53
Masonry Adjoining:	N/A	**Life Remaining:**	1-2
Walls Adjoining:	N/A	**Cleanliness:**	Fair
Penetration Flashing:	Poor	**Leaking:**	No
Fasteners:	Missing	**Exposed Areas:**	N/A
Drainage & Drains:	N/A	**Roof Drain Strainers Control Weirs:**	N/A
Blisters/Ridges:	No	**Mastic Pans:**	N/A
Splits:	No	**Skylights:**	Poor
Membrane Flashing:	Damaged	**Roof Mounted Units:**	N/A
Metal Flashing:	Missing	**Curbs/Sleepers:**	Required Reflashing
Approximate Area:	4920		

Work Done and Comments

visual inspection of roof area from man lift
areas of metal roofing panels deteriorated and in need of replacement

Further Work Recommended

Immediate preventative maintenance required. Replacement in 1-2 years.

Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022

Address Line1: 2 Thermal Plant Rd.

Building Name/Address Line2:

City: Holyrood **Province/State:** NL **Postal/Zip Code:** A0A 2R0

Roof Composition

security office

Deck:	Metal;	**Membrane:**	Metal;
Insulation:	Fiberglass; underneath metal roofing ;	**Surfacing:**	None;
Vapor Retarder:	Not known;	**Was cut test performed:**	No
Resaturated:	No	**Roof Height:**	15
Caulking:	Good	**Approximate Age:**	15
Masonry Adjoining:	N/A	**Life Remaining:**	20
Walls Adjoining:	N/A	**Cleanliness:**	Clean
Penetration Flashing:	Good	**Leaking:**	No
Fasteners:	Good	**Exposed Areas:**	N/A
Drainage & Drains:	N/A	**Roof Drain Strainers Control Weirs:**	N/A
Blisters/Ridges:	No	**Mastic Pans:**	N/A
Splits:	No	**Skylights:**	N/A
Membrane Flashing:	Good	**Roof Mounted Units:**	N/A
Metal Flashing:	Good	**Curbs/Sleepers:**	N/A
Approximate Area:	2040		

Work Done and Comments

visual inspection of roof area
area of roof in good condition no repairs needed

Further Work Recommended

Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022

Address Line1: 2 Thermal Plant Rd.

Building Name/Address Line2:

City: Holyrood **Province/State:** NL **Postal/Zip Code:** A0A 2R0

Roof Composition

chemical storage

Deck:	Metal;	**Membrane:**	Metal;
Insulation:	None; Thickness: 0;	**Surfacing:**	None;
Vapor Retarder:	Not known;	**Was cut test performed:**	No
Resaturated:	No	**Roof Height:**	20
Caulking:	Fair	**Approximate Age:**	27
Masonry Adjoining:	N/A	**Life Remaining:**	5
Walls Adjoining:	N/A	**Cleanliness:**	Clean
Penetration Flashing:	Fair	**Leaking:**	No
Fasteners:	Good	**Exposed Areas:**	No
Drainage & Drains:	N/A	**Roof Drain Strainers Control Weirs:**	N/A
Blisters/Ridges:	No	**Mastic Pans:**	N/A
Splits:	No	**Skylights:**	N/A
Membrane Flashing:	Good	**Roof Mounted Units:**	N/A
Metal Flashing:	Good	**Curbs/Sleepers:**	Damaged
Approximate Area:	1440		

Work Done and Comments

visual inspection of roof area
area around one gooseneck flange in need of repairs due to deteriorated metal roofing panel

Further Work Recommended

Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022



Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022



Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022



Roof Condition Report

Name: NL Hydro - Roof Inspections **Job Number:** 028-455568-310 **Inspection Date:** 12/2/2022



Purchase 50’ Material Handler Aerial Device on Tracked Unit (2024–2026)

Happy Valley-Goose Bay

July 2023

newfoundland labrador hydro

Purchase 50' Material Handler Aerial Device on Tracked Unit (2024–2026)

Location: Happy Valley-Goose Bay

Investment Classification: General Plant

Asset Category: Tools and Equipment

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") uses aerial devices wherever possible to perform maintenance and upgrade work on its distribution and transmission assets efficiently. Hydro must have access to functional and reliable equipment to maintain its system safely and efficiently.

To replace equipment that is due for retirement, Hydro plans to purchase new equipment that will increase work efficiency and improve the application of live line techniques.

This project proposes the purchase of an 8-ton tracked unit equipped with a 50' Category B[1] material handler aerial device outfitted with a Power Line Technician ("PLT") bucket, jib, and winch. This equipment will allow for the performance of required live line work and preventive maintenance on Hydro's distribution structures and lines, which can only be reached with off-road equipment. Hydro does not have a 50' aerial device tracked unit stationed in Labrador. Hydro currently has one 160' device on larger tracked units; however, due to their physical size, these units cannot always be used in areas with restricted right-of-way access, which are common in distribution applications. This unit will allow crews to perform structure and line maintenance more efficiently.

With the addition of this tracked unit, Hydro plans to retire a 17-year-old, 10-ton tracked unit equipped with a hydraulic dump body and knuckle boom. This unit is at the end of its useful life and is obsolete.

This project has a multi-year approach, with completion planned in 2026 due to supply chain-related delays in delivery times. This estimated project cost is $872,900.

[1] American National Standards Institute. (2009). ANSI/SIA A92.2 *Vehicle-Mounted Elevating and Rotating Aerial Devices.*

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1.0 Introduction

Hydro uses aerial devices wherever possible to efficiently perform maintenance and upgrade work on its distribution and transmission assets. With some existing off-road equipment due for replacement, Hydro plans to purchase new equipment with improved off-road capabilities. This will allow Hydro to work more efficiently and increase its application of live line techniques in remote areas.

At present, Hydro does not have a unit in Labrador outfitted with a PLT bucket, jib, and winch to perform live line work at the distribution level. Hydro proposes the purchase of a 50' Category B material handler aerial device on an 8-ton off-road tracked unit that will provide the necessary equipment for live line work. To manage fleet size and composition, Hydro plans to retire and not replace unit V7066/V6106, a 2006 PowerTraxx 10-ton tracked unit equipped with a hydraulic dump body and knuckle boom that has reached the end of its service life.

2.0 Project Description and Justification

This project proposes the purchase of an 8-ton tracked unit equipped with a 50' Category B material handler aerial device outfitted with a PLT bucket, jib, and winch to more efficiently perform required live line work and preventive maintenance on Hydro's distribution structures and lines, which can only be reached with off-road equipment. The existing fleet of equipment used for off-road work is not always effective for completing live line work, particularly in remote locations. This project will also retire unit V7066/V6106, which is at the end of its useful life.

Performing work with aerial devices is safe, efficient, and reduces customer impacts; however, in off-road locations, work sites cannot always be accessed with an aerial device. Hydro currently has in its fleet a larger 160' off-road tracked unit; however, it is often too large to safely and effectively navigate distribution system right-of-ways. As such, distribution live line work is generally limited to areas accessible to wheeled line trucks. The proposed off-road unit will be a more compact design than the current unit, which will allow Hydro to perform live line work in remote/off-road areas.

3.0 Asset Background

Hydro does not currently have an off-road tracked unit with a 50' Category B aerial device. With the addition of this tracked unit, Hydro plans to retire and not replace unit V7066/V6106—a 2006 PowerTraxx 10-ton tracked unit equipped with a hydraulic dump body and knuckle boom. Unit V7066 is

currently 17 years old and has reached the end of its service life; it is not outfitted with a PLT bucket, jib, and winch to perform live line work. Due to changing work methods (i.e., live line work), this piece of equipment no longer meets Hydro's needs.

4.0 Analysis

4.1 Recommended Alternative

It is recommended to purchase an 8-ton tracked unit equipped with a 50' Category B material handler aerial device outfitted with a PLT bucket, jib, and winch. This unit is required to complete critical live line work and preventive maintenance on Hydro's distribution structures and lines that can only be reached with off-road equipment.

Hydro's implementation of the live line work initiative, which reduces customer outage length and allows PLTs to work safely and effectively, requires an off-road tracked unit with a 50' Category B aerial device. Failure to purchase this unit will negatively impact response time during trouble calls, outage time for customers, and the safety of PLTs.

4.1.1 Risk of Asset Stranding

This unit is a critical piece of equipment, necessary to maintain a safe and reliable fleet to perform required live line work and preventive maintenance on Hydro's distribution structures and lines. Hydro is not anticipating a change in requirements for this unit in Happy Valley-Goose Bay; however, the unit can also be redeployed as required; therefore, the risk of asset stranding is low.

4.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for this 2024–2026 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	4	**12**
Post-Execution	3	1	**3**
		Risk Mitigated	**9**
		Risk Mitigated per $1 Million	**10.3**

5.0 Scope of Work

This project proposes the purchase of an 8-ton tracked unit equipped with a 50' Category B material handler aerial device outfitted with a PLT bucket, jib, and winch. This scope includes the procurement of the vehicle and accessorizing as required based on the purpose of the vehicle.

5.1 Project Budget

The estimate for the 2024–2026 project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2024	2025	Beyond	Total
Material Supply	0.0	0.5	0.0	**0.5**
Labour	22.3	3.7	6.3	**32.3**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	725.0	0.0	**725.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	0.5	39.8	0.4	**40.7**
Contingency	1.2	72.8	0.4	**74.4**
Total	**24.0**	**841.8**	**7.1**	**872.9**

5.2 Project Schedule

The schedule for the 2024–2026 project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning: Open work orders and plan and develop detailed schedules.	January 2024	February 2024
Procurement: Tender and award for an 8-ton tracked unit equipped with a 50' Category B material handler aerial device.	February 2024	March 2024
Commissioning: Receive and commission unit.	November 2025	December 2025
Closeout: Close work order, complete all documentation, and complete lessons learned.	June 2026	June 2026

6.0 Conclusion

Hydro's continuation of live line work requires an off-road tracked unit with a 50' Category B aerial device. Hydro currently has no such device. The purchase of this unit–outfitted with a PLT bucket, jib, and winch–to perform required live line work and preventive maintenance on Hydro's distribution structures and lines will replace one existing unit at the end of its useful life and allow Hydro better access to off-road work sites and increased application of efficient live line techniques.

Project 12

Replace Grader Unit V9829 (2024)

Bay d'Espoir

July 2023



Replace Grader Unit V9829 (2024)

Location: Bay d'Espoir

Investment Classification: General Plant

Asset Category: Tools and Equipment

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") uses motor graders for road grading and snow plowing to maintain road access to complete critical maintenance and upgrade work on its distribution, transmission, and generation assets. To maintain its system safely and efficiently, Hydro must have access to functional and reliable equipment. To replace equipment that is due for retirement, Hydro plans to purchase new equipment that will reduce safety and reliability risks.

This project proposes the replacement of grader Unit V9829, located in Bay d'Espoir, with a similar model, as it has reached the end of its service life. The existing grader is currently utilized in the Bay d'Espoir area, including critical sites such as the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir Facility"), West Salmon Spillway, North Salmon Spillway, Upper Salmon Hydroelectric Generating Station ("Upper Salmon Station"), and associated access roads. Should these roads not be suitable for travel, there is a risk of increased maintenance costs, delays in scheduled and unscheduled work, and safety concerns for Hydro employees and members of the public that utilize these roads.

The estimated cost for work executed under this project is $836,700.

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1.0 Introduction

To maintain its system safely and efficiently, Hydro uses motor graders for road grading and snow plowing to maintain access to its distribution, transmission, and generation assets. Hydro must have access to functional and reliable equipment to enable the completion of critical maintenance and upgrade work in areas accessible by access roads.

Hydro's existing grader unit located in Bay d'Espoir, Unit V9829, is due for retirement and must be replaced to reduce safety and reliability risks. Unit V9829 is a 2008 John Deere 722D motor grader, which was purchased in 2008. In addition to the standard moldboard,[1] this vehicle is equipped with a scarifier[2], wing blade, and a V-plow blade, which are necessary to facilitate road grading and snow plowing in and around the Bay d'Espoir area. This vehicle is used regularly at critical sites including the Bay d'Espoir Facility, West Salmon Spillway, North Salmon Spillway, Upper Salmon Station, and the many access roads interconnecting these sites.

2.0 Project Description and Justification

The scope of this work is to replace Unit V9829, a 15-year-old motor grader, with a similar model equipped with the same components.

This grader is a critical piece of equipment used for road maintenance and snow removal in and around the Bay d'Espoir area. As it has aged, it has become less reliable and requires corrective maintenance more frequently. The roadways cleared and maintained with this grader are required to access the Upper Salmon Powerhouse, West Salmon Spillway, North Salmon Spillway, and their associated dams and dam-related-instrumentation. Lack of access to these sites would negatively impact scheduled maintenance activities, as well as emergency response times.

Unit V9829 has reached the end of its service life; therefore, to continue providing safe and reliable operation, it must be replaced.

[1] A moldboard is a blade on a machine that pushes material to one side as the machine advances.
[2] A scarifier is designed to break up compacted material to facilitate grading.

3.0 Asset Background

Unit V9829 is 15 years old and has been used for 6,469 engine hours. By the time it is replaced in 2024, it is estimated that the grader will have approximately 8,000 engine hours. According to the equipment manufacturer, this type of vehicle has an average useful life of 6,000 to 7,000 engine hours.

Due to age, the equipment manufacturer has discontinued the fabrication of spare parts; as such, replacement parts can no longer be reliably sourced. As stated herein, the vehicle has become less reliable, with repairs becoming more frequent due to age. Recent issues include problems with the fuel gauge and exhaust manifold, various fuel and coolant leaks, and a faulty transmission. Hydro has performed maintenance and repairs on this vehicle to keep it in safe working condition; however, it has reached the end of its service life.

4.0 Analysis

4.1 Recommended Alternative

Unit V9829, a 2008 John Deere 722D motor grader, has reached the end of its service life. Hydro's recommendation is to purchase a like-for-like replacement, which is similar to the existing model and equipped with the same components.

By owning a grader within its fleet of equipment, Hydro ensures timely snow clearing and grading, which prevents operational disruptions. Without this grader, it would be difficult to perform road maintenance and snow removal, as is required of a 24-hour operation. Access roads leading to critical infrastructure could subsequently deteriorate, creating safety hazards and potential inaccessibility during emergencies. Deteriorated roads may also increase maintenance costs associated with Hydro's fleet vehicles, due to travel in unnecessarily rough conditions.

For these reasons, replacing Unit V9829 is the only viable alternative for this project.

4.1.1 Risk of Asset Stranding

This grader is a critical piece of equipment used for road maintenance and snow removal in and around the Bay d'Espoir area, including access roads to Upper Salmon, West Salmon Spillway, North Salmon Spillway, and their associated dams and dam-related instrumentation. There are no plans to retire any of these assets and Hydro does not foresee any changes in its requirements for this grader; therefore, Hydro considers the risk of asset stranding to be low.

4.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for this 2024 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	3	4	**12**
Post-Execution	3	1	**3**
		Risk Mitigated	**9**
		Risk Mitigated per $1 Million	**10.8**

5.0 Scope of Work

The scope of this work is to replace grader Unit V9829 in the Bay d'Espoir area with a similar model that is equipped with a scarifier, wing blade, and V-plow blade. This scope includes the procurement of the grader and accessorizing as required based on the purpose of the vehicle.

5.1 Project Budget

The estimate for the 2024 project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	**2024**	**2025**	**Beyond**	**Total**
Material Supply	0.5	0.0	0.0	**0.5**
Labour	29.9	0.0	0.0	**29.9**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	710.0	0.0	0.0	**710.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	23.7	0.0	0.0	**23.7**
Contingency	72.6	0.0	0.0	**72.6**
Total	**836.7**	**0.0**	**0.0**	**836.7**

5.2 Project Schedule

The schedule for the 2024 project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning: Open work order and plan and develop detailed schedules.	January 2024	February 2024
Procurement: Tender and award for grader unit that is equipped with a scarifier, wing blade, and V-plow blade.	February 2024	March 2024
Commissioning: Receive and commission grader unit.	October 2024	October 2024
Closeout: Close work order, complete all documentation, and complete lessons learned.	December 2024	December 2024

6.0 Conclusion

Grader Unit V9829 is a critical piece of equipment used for road maintenance and snow removal in and around the Bay d'Espoir area. Without this vehicle, it would be difficult to maintain the access roads leading to critical infrastructure and to remove snow on roadways, as is required of a 24-hour operation. The deterioration of these roadways creates the risk of safety hazards for employees and members of the public. Hydro's current grader has reached the end of its service life, becoming less reliable over the years, and requiring more frequent corrective maintenance. To continue providing safe, reliable operation, Hydro proposes to replace this grader.

Project 13

Replace Power Line Carrier (2024–2025)

TL247

July 2023



Replace Power Line Carrier (2024–2025)

Location: TL247

Investment Classification: Renewal

Asset Category: Telecontrol

Executive Summary

Power line carrier ("PLC") is a technology that uses the conductors of an ac transmission line as the medium to provide communications services to some of Newfoundland and Labrador Hydro's ("Hydro") terminal stations and generating stations.

At Hydro's terminal stations and generating stations, PLC equipment facilitates the following communications services:

- Teleprotection: For high-speed, automatic transmission line and breaker fail protection;
- Supervisory Control and Data Acquisition ("SCADA"): For remote monitoring and control of terminal station and generating facility equipment from the Energy Control Centre ("ECC"); and
- Voice (Telephone).

This project proposes the replacement of the PLC system installed between Deer Lake Terminal Station and Cat Arm Hydroelectric Generating Station ("Cat Arm Station"), located on the western portion of the Island. This PLC system has been in service for approximately 20 years and is therefore more likely to fail unexpectedly. The equipment has been discontinued; as such, no support or spare parts are available from the manufacturer. Continued utilization of this equipment poses the risk of failure and resultant loss of communications required for the protection and control of the power system; therefore, Hydro believes replacement of the PLC system is prudent and necessary to ensure reliable service.

Hydro recommends the like-for-like replacement of the proposed PLC system. There are no viable alternatives for communications in the affected service area and the increasing risk of failure associated with deferral is not acceptable once the useful service life has been exceeded.

This project has a multi-year approach, with completion planned in 2025 at an estimated cost of $754,600.

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1.0 Introduction

PLC is a technology that uses the conductors of an ac transmission line as the medium to provide communications services between high-voltage terminal stations and/or generating facilities. PLC systems are generally installed to serve sites where higher bandwidth systems, such as microwave or fibre optic communications, are not technically or financially viable.

At Hydro's terminal stations and generating facilities, PLC equipment facilitates the following communications services, each of which is essential to the safe and reliable operation of the electrical power grid:

- Teleprotection: For high-speed, automatic transmission line and breaker fail protection;
- SCADA: For remote monitoring and control of terminal station equipment from the ECC; and
- Voice (Telephone).

This project proposes the replacement of one of Hydro's PLC systems that has been in service for approximately 20 years, which is now obsolete and no longer supported by the manufacturer. The PLC system planned for replacement is installed on Transmission Line 247 ("TL247") and provides communications to the Cat Arm Station from the Deer Lake Terminal Station.

2.0 Project Description and Justification

This project proposes the replacement of the PLC system for TL247 with the latest version of the same equipment. Figure 1 shows the location of TL247, which is a 230 kV transmission line.

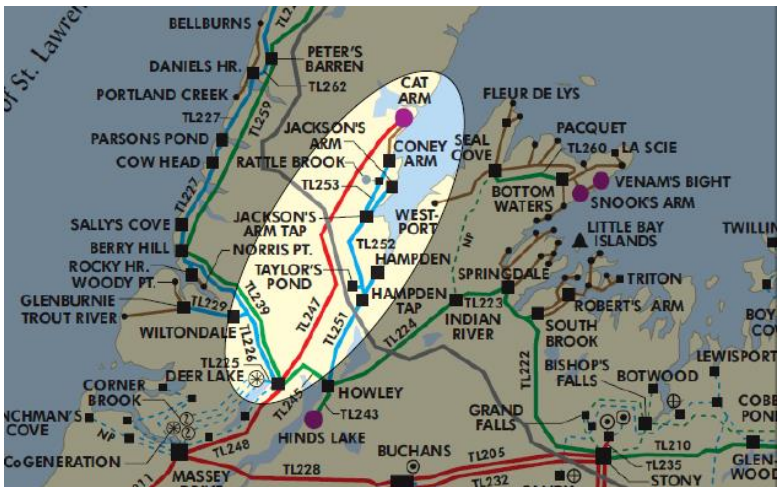


Figure 1: Location of TL247

This project is required to replace obsolete infrastructure such that Hydro can ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner. The PLC equipment for TL247 has been in service for approximately 20 years and is now obsolete. The currently installed model of PLC for TL247 has been discontinued by the manufacturer since 2012. The manufacturer has indicated that, due to the unavailability of electronic components that are now obsolete, repair of discontinued products is becoming increasingly difficult. As such, continued utilization of this equipment poses the risk of loss of communications required for the protection and control of the power system. Failure of the PLC equipment for TL247 would result in a loss of teleprotection and SCADA services at the Cat Arm Station. Electrical system reliability would be compromised and the Cat Arm Station would need to be shut down or staffed on a continuous basis until the PLC equipment is repaired or replaced.

3.0 Asset Overview

3.1 Asset Background

Hydro currently has 14 PLC systems in operation throughout its electrical system. Like other communications equipment, PLC manufacturers do not continue support for older technology iterations. As a result, Hydro has implemented a 20-year useful life on all PLC systems to ensure all installed equipment can be fully supported and repaired when required. These installed PLC systems are all manufactured by ABB; however, versions of the technology can differ based on their respective initial installation date and end-of-life replacement schedules.

3.2 Historical Reliability

The PLC system for TL247 has operated reliably with no major outages occurring over its lifetime, with only regular preventive and minor corrective maintenance being required.

3.3 Asset Condition

The PLC system for TL247 was installed in 2004 and is currently in good working order; however, it will have been in service for 20 years at the time of replacement. Based on Hydro's experience and the environment in which the PLC equipment operates, Hydro considers 20 years to be the serviceable life of the PLC equipment. The equipment has also been discontinued by the manufacturer and, as a result, no replacement parts or support is available should a failure occur. Hydro does carry a small number of spare parts for its installed PLC systems for emergency repairs; however, these spares do not constitute

a full PLC replacement and would not be available in sufficient quantity if multiple sites had the same fault.

4.0 Analysis

4.1 Recommended Alternative

Hydro's recommendation is to replace the PLC communications for TL247 with the latest version of the same equipment. This is because there are no other viable solutions for the replacement of the TL247 PLC equipment. PLC equipment at the end of its useful service life is more likely to fail unexpectedly. Deferral is not a viable option for this PLC system, as its failure would result in the loss of teleprotection and SCADA for the Cat Arm Station. Electrical system reliability would be compromised and the Cat Arm Station would need to be shut down or staffed on a continuous basis until the PLC equipment is repaired or replaced.

4.1.1 Risk of Asset Stranding

The risk of asset stranding is low as there is a requirement for communications of some form for the life of Cat Arm Station. Hydro does not currently anticipate the retirement of this station at any point in the foreseeable future. PLC is currently the most efficient and cost-effective solution for this station.

4.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for this 2024–2025 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	4	4	**16**
Post-Execution	4	1	**4**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**15.9**

5.0 Scope of Work

This is a two-year project to replace the TL247 PLC system. The work will take place at the Deer Lake Terminal Station and the Cat Arm Station. The replacement process consists of the following major activities:

- PLC procurement;
- PLC design modifications, including drawing creation and/or modification;
- PLC manufacturer factory acceptance testing;
- Removal of existing PLC equipment; and
- Installation, commissioning, and testing of new PLC equipment.

5.1 Project Budget

The cost estimate for the 2024–2025 project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2024	2025	Beyond	Total
Material Supply	0.0	371.8	0.0	**371.8**
Labour	72.9	147.8	0.0	**220.7**
Consultant	0.0	20.0	0.0	**20.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	2.4	24.5	0.0	**26.9**
Interest and Escalation	4.3	46.9	0.0	**51.2**
Contingency	7.6	56.4	0.0	**64.0**
Total	**87.2**	**667.4**	**0.0**	**754.6**

5.2 Project Schedule

The schedule for the 2024–2025 project is provided in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning: Generate initial project schedule.	February 2024	March 2024
Design: Verify PLC design and configuration.	February 2024	March 2024
Procurement: Issue tender, order PLC equipment, and schedule factory acceptance testing.	March 2024	April 2024
Factory Acceptance Testing: Complete factory acceptance testing and verification.	October 2024	December 2024
Equipment Delivery: Receive all PLC equipment.	January 2025	February 2025
Construction/Commissioning: Removal of old and installation and commissioning of new PLC for TL247 (Exact timing dependant on outage availability).	July 2025	October 2025
Closeout: Drawing finalization and project closeout.	November 2025	December 2025

6.0 Conclusion

The PLC equipment for TL247 is at the end of its useful service life of 20 years and is more likely to fail unexpectedly. Furthermore, this model has been discontinued and, as a result, no support or spare parts are available from the manufacturer. Failure of the PLC equipment for TL247 would result in a loss of teleprotection and SCADA services at the Cat Arm Station. Electrical system reliability would be compromised and the Cat Arm Station would need to be shut down or staffed on a continuous basis until the PLC equipment is repaired or replaced.

To maintain reliable communications associated with the protection and control of the electrical power grid, Hydro recommends the replacement of this PLC system with the latest version of this equipment.

Automate Bulk Metering (2024–2026)

July 2023

newfoundland labrador hydro

Automate Bulk Metering (2024–2026)

Location: Various

Investment Classification: Service Enhancement

Asset Category: Metering

Executive Summary

Metering is a core function of Newfoundland and Labrador Hydro's ("Hydro") service obligation; accurate metering of electricity usage is necessary to provide quality service to customers. Hydro is mandated by Measurement Canada and required under the *Electricity and Gas Inspection Act*[1] and *Electricity and Gas Inspection Regulations*[2] to ensure that in-service meters are accurate, in good working condition, and removed from service before the meter expiry date.

This project proposes the replacement of 44 obsolete electromechanical kWh meters and associated test switches with industrial meters that have demand, load profile, and remote communication capabilities.

Hydro currently has electromechanical kWh meters installed at generating stations—including gas turbines and remote generating stations—for plant output and station service readings. These readings are required for financial reporting and planning where they are often a key component of various calculations, including regulatory reporting. The currently installed meters are over 40 years old and are manually read, as they cannot be used with remote communications that are required to automate readings. Such manual processes have the potential for errors, risks, and delays from both a controls and operations perspective. As these meters require replacement, Hydro believes it to be the appropriate time to propose a transition away from the use of manual meter reading in determining demand and energy usage.

Hydro recommends replacing obsolete electromechanical kWh meters with industrial meters with demand, load profile, and remote communication capabilities. These meters will be given a network connection to facilitate remote reading, which will improve the accuracy of meter readings and provide potential cost savings by enabling Hydro to improve its business processes. This is the only viable option

[1] *Electricity and Gas Inspection Act*, RSC, 1985, c E-4.
[2] SOR/86-131.

for the replacement of these meters, as they are obsolete and remote communications, demand, and load profile readings are increasingly important to meeting Hydro's service obligation.

This project has a multi-year approach, with completion planned in 2026 at an estimated cost of $752,300.

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1.0 Introduction

Hydro currently collects plant output and station service demand data from electromechanical kWh meters installed at generating stations. These readings are a necessary input to financial reporting, planning, load forecasting, and regulatory reporting such as monthly energy supply reports.

The currently installed meters are over 40 years old and are obsolete. These meters are not equipped with remote communications that would enable readings to be automated. These meters also cannot provide 15-minute interval data along with kWh and peak demand data, which has become essential for Hydro to forecast demand and supply requirements. Implementation of a modern metering solution will address the current obsolescence, improve accuracy, and enable cost savings through greater efficiency in meter reading and the reduction of administrative effort.

2.0 Project Description and Justification

This project proposes the replacement of 44 obsolete electromechanical kWh meters and their associated test switches with industrial meters that have a remote connection, demand, and load profile capabilities. This project also includes the purchase of equipment to supply communications to each of these meters. The proposed generating stations to be upgraded with new meters and communications equipment are provided in Table 1.

Table 1: Location and Number of New Meters

Location	Number of Meters
Bay d'Espoir Hydroelectric Generating Facility	15
Cat Arm Hydroelectric Generating Station	6
Hinds Lake Hydroelectric Generating Station	3
Granite Canal Hydroelectric Generating Station	4
Upper Salmon Hydroelectric Generating Station	3
Paradise River Hydroelectric Generating Station	3
Roddickton Mini Hydro	2
Hawke's Bay Diesel Generating Station	2
St. Anthony Diesel Generating Station	2
Hardwoods Gas Turbine[3]	2
Holyrood Gas Turbine	2

[3] As per the "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, the Hardwoods Gas Turbine shall remain for a "Bridging Period" or until such time that sufficient alternative generation is commissioned, adequate performance of the Labrador-Island Link is proven, and generation reserves are met. Hydro considers the Bridging Period to be from 2023 to 2030. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability while new generation capacity is being built. The primary, readily available supply options in this period are extending the retirements of the Holyrood TGS and the Hardwoods Gas Turbine until their capacities can be adequately replaced.

This project is required to ensure that month-end generation production reports are accurate, timely, and are not subject to errors due to manual reading and input. Errors in these readings can result in understatement or overstatement of energy output by the units. In addition, the kWh meters that are currently installed cannot provide detailed metering data (e.g., interval readings, peak demand/generation, power factor) that has become paramount for both planning and financial purposes. Remote stations are not continuously staffed; as such, there are occasions when priority work or weather conditions create a delay in meter readings. The automated process will provide 15-minute interval data, peak demand, and load profile quantities to ensure timely and accurate reporting consistently for all applicable stakeholders.

3.0 Asset Background

The currently installed meters are obsolete at more than 40 years of age.

Currently, the generation kWh readings on Hydro's plant output and station service meters are subject to manual reading. The data collected is manually recorded and is then transmitted to the Industrial Billing department for processing and report generation. Dial meters, as shown in Figure 1, typically use multipliers[4] to determine the amount of energy utilized within a reading period, which can make manual readings more difficult to ascertain. For example, when units are operated for short durations, dial meters do not always show sufficient progress, resulting in a visible, measurable increase in manual meter readings. As a result, manual meter reads are at high risk for inaccuracy. Accuracy in meter readings is critical to Hydro providing quality service to its customers and meeting its legislative obligations.



Figure 1: Dial Meter Example

[4] For example, the units at the Bay d'Espoir Hydroelectric Generating Facility use a 96,000 kWh multiplier to determine the energy output on a dial meter.

4.0 Analysis

4.1 Recommended Alternative

Hydro recommends replacing obsolete electromechanical kWh meters with industrial meters with demand, load profile, and remote communication capabilities. As these meters require replacement, Hydro believes this is the appropriate time to propose a transition away from the use of manual meter reading in determining demand and energy usage.

This is the only viable option for the replacement of these meters, as they are obsolete, and remote communications, demand, and load profile readings have become increasingly important to meeting Hydro's service obligation.

4.1.1 Risk of Asset Stranding

The meters are required for the life of the stations identified within this project but can be redeployed to another location if required; therefore, the risk of asset stranding is low.[5]

4.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2024–2026 project in accordance with Hydro's Capital Risk Assessment process as outlined in Section 7.0 of Schedule 1. The outcome of this assessment is provided in Table 2.

Table 2: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Execution	4	4	**16**
Post-Execution	4	2	**8**
		Risk Mitigated	**8**
		Risk Mitigated per $1 Million	**10.6**

[5] The risk of asset stranding is less imminent as a result of the decision to extend the Hardwoods Gas Turbine to remain available through the Bridging Period. As Hydro expects continued generation of the Hardwoods Gas Turbine until its capacity can be adequately replaced to ensure reliability for customers, capital expenditures for this facility to operate as a generator continue to be required.

5.0 Scope of Work

This is a three-year project to replace 44 industrial meters at various Hydro facilities. The test switches associated with each meter will also be replaced to bring them to current Hydro standards. As well, network cabling and accessories will be required for each meter to connect them for remote reading. The meter replacement process consists of the following major activities:

- Procurement of meters, test switches, and networking equipment;
- Meter design modifications, including drawing creation and/or modification;
- Removal of existing metering equipment and test switches; and
- Installation, commissioning, and testing of new meters, test switches and network connection.

5.1 Project Budget

The estimate for the 2024–2026 project is shown in Table 3.

Table 3: Project Estimate ($000)

Project Cost	2024	2025	Beyond	Total
Material Supply	166.4	7.7	11.3	**185.4**
Labour	89.2	142.3	160.9	**392.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	6.7	20.6	7.3	**34.6**
Interest and Escalation	14.0	26.7	37.8	**78.5**
Contingency	26.3	17.1	18.0	**61.4**
Total	**302.6**	**214.4**	**235.3**	**752.3**

5.2 Project Schedule

The schedule for the 2024–2025 project is shown in Table 4.

Table 4: Project Schedule

Activity	Start Date	End Date
Planning: Open project and generate initial project plan.	February 2024	March 2024
Design: Confirm meters, test switches, and communications equipment to order.	February 2024	March 2026
Procurement: Order meters and test switches and communications equipment.	March 2024	April 2026
Construction: Installation of meters and test switches and communications equipment.	June 2024	October 2026
Commissioning: Test installed meter function and meter communications.	June 2024	October 2026
Closeout: Project closeout.	October 2026	November 2026

6.0 Conclusion

The electromechanical kWh meters at various Hydro generating stations are over 40 years old, obsolete, and must be replaced. Hydro's standards for metering have changed over time. As these meters must now be capable of remote reading, 15-minute interval data, and kWh and peak demand readings. Implementation of a modern metering solution will address the current obsolescence, improve accuracy, and enable cost savings through greater efficiency in meter reading and the reduction of administrative effort.

Proposals under $750,000

Proposals under $750,000



Description of Newfoundland and Labrador Hydro ("Hydro") Proposed Programs and Projects Under $750,000 by Investment Class ($000)

Access			
Title	**Total Spend**	**Project/Program**	**Description**
Purchase Meters and Metering Equipment (2024)	470.7	Program	Hydro is required under legislation to provide reliable and accurate revenue metering to its customers and maintain compliance with the Government of Canada's *Electricity and Gas Inspection Act and Regulations*. This program will enable Hydro to purchase new meters for its residential, commercial, and industrial customer base to ensure meter availability for new service applications and replacements as required. The program mitigates the risk associated with meeting regulatory requirements and inaccurate readings and maintains the integrity of the metering installations.
General Plant			
Title	**Total Spend**	**Project/Program**	**Description**
Install Fire Protection in 230 kV Stations (2024–2025) – Voisey's Bay	652.8	Project	The Voisey's Bay Terminal Station, serving an industrial customer, has no automatic fire protection system to permit early intervention in the event of a fire. As a continuation of Hydro's plan to install automatic fire protection systems in its 230 kV terminal stations, this project will install an automatic fire protection system in the control building at the Voisey's Bay Terminal Station. As terminal stations are critical to the reliable supply of power to customers, Hydro is installing fire suppression systems to protect the control cabinets, wiring, cables, sensitive electronic equipment, and any other critical equipment in the event of a fire. As the terminal station is a specifically assigned asset, project costs will be recovered directly from the customer.
Purchase Personal Computers (2024)	555.9	Program	This program is proposed to replace personal computing devices and accessories approaching end-of-life following Hydro's established replacement criteria. Under this program, computers identified as being deployed and in service for over five years (for mobile laptop computers) and over six years (for desktop/workstation/thin-client computers) will be replaced throughout 2024 to maintain adequate service levels for business continuity and ensure electronic business data is secure.

General Plant (Cont')			
Title	**Total Spend**	**Project/Program**	**Description**
Refurbish Control Building (2024–2025)– Grandy Brook and Doyles	554.1	Project	This project includes the interior and exterior refurbishment of the Grandy Brook and Doyles Control Buildings to address deficiencies identified by a condition assessment. These control buildings are 34 and 56 years old, respectively, and have not undergone any significant refurbishments since their original construction. These buildings house critical electrical equipment that, if not adequately protected, could result in damage that would impact reliability within the regions.
Replace SONET Multiplexors (2024)	430.4	Project	The Synchronous Optical Network ("SONET") multiplexor ("MUX") system is part of Hydro's private telecommunications transport network. This transport network provides critical connectivity to terminal stations and generating facilities through several communications services. Twelve SONET MUXs in Hydro's telecommunications system are obsolete and manufacturer support will be unavailable after the first quarter of 2024. The replacement of these obsolete MUXs will mitigate the risk of failure, which could result in the complete loss of visibility of a station or plant by the Newfoundland and Labrador System Operator and disruption of critical teleprotection circuits, in addition to the loss of connectivity to Hydro's administrative network at the site.
Upgrade SCADA Network (2024)	402.3	Project	Hydro's supervisory control and data acquisition ("SCADA") network provides connectivity from the Energy Control Centre ("ECC") to the remote terminal units at terminal stations, generating facilities, and hydraulic control structures. The current SCADA network, a key component of the overall SCADA system, no longer meets current and future business requirements. As a result, the current SCADA network must be updated, with the key drivers being: the digitization of Hydro equipment and assets, the need for increased bandwidth and flexibility to access operational data, and improved cybersecurity.
Upgrade Energy Management System (2024)	366.4	Program	This program proposes an Energy Management System ("EMS") software upgrade to mitigate security vulnerabilities, implement bug fixes, and introduce enhanced functionality on a two-year cycle. The EMS is a critical application used to monitor and control the electrical grid and is necessary to support the reliable operation of the Newfoundland and Labrador Interconnected System. Failure to keep this software current will place Hydro at risk of unplanned system outages that could affect the monitoring and control of the transmission grid and generation facilities.

General Plant (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Replace CCTV Cameras (2024)	317.6	Project	This project proposes the purchase and installation of an appropriate video solution to replace the current closed circuit television ("CCTV") systems at ten of Hydro's terminal stations to address physical security concerns at critical operating sites. The current CCTV systems have been discontinued by the manufacturer and can no longer be serviced. The project is required to improve physical security at Hydro's sites and enable the ability to detect and/or deter unauthorized access and theft, mitigating safety risks to the public and personnel as well as financial risks to Hydro and its customers.
Replace Powerhouse 1 Air Conditioning Unit (2024 – 2025) – Bay d'Espoir	289.0	Project	This project is for the replacement of the air conditioning ("AC") unit for the offices located in Powerhouse 1 of the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir Facility"). The current AC unit is at the end of its service life and contains an ozone-depleting gas, R22 refrigerant. The production and import of R22 refrigerant has been prohibited by the Government of Canada since 2020, due to its environmental impact if released into the air. Recent increases in maintenance activity due to its age places the unit at increased risk of accidental release. Hydro is proposing to replace the AC unit with one of similar capacity, which will ensure the reliable operation of the office area AC system and mitigate environmental risk due to refrigerant leakage.
Update Cyber Security Infrastructure (2024)	281.3	Program	Hydro's computer systems and network infrastructure require continuous protection from cyber threats. In 2024, this program will upgrade or replace specific cyber security infrastructure components necessary to maintain the required level of service and risk mitigation. Hydro proposes this program to ensure it has adequate cyber security tools to mitigate security threats to Operating Technology ("OT") infrastructure and software. A serious incident involving the loss of corporate data or access to critical business, plant, or energy control systems could result in significant unplanned costs and negatively affect financial results, reputation, customers (i.e., reliability), and the province's electricity grid.

General Plant (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Replace Peripheral Infrastructure (2024)	276.8	Program	Hydro maintains peripheral equipment to support and conduct business processes such as printing, scanning, and presentations. The current peripheral hardware replacement life cycle ranges from six to ten years based on equipment type and support arrangements. Devices to be replaced under this project have been in service for a period beyond the expected service life and have exceeded their expected useful life. Replacement parts may not be available as maintenance agreements and warranties have expired. Failure of, and technological issues with, this equipment could result in loss of productivity and interrupt key activities. In 2024, the program will replace approximately 29 printing devices, 2 plotters, 1 projector, and 2 boardroom displays with a small boardroom upgrade.
General Property Rehabilitation (2024) – Hydro Place	234.0	Project	This project proposes the completion of general property rehabilitation work at Hydro Place, including the replacement of the exterior stairway handrail and main entrance walkway. Original to the building's construction, these assets are at an age in which they are no longer performing per their design intent. Rehabilitation of these assets will return them to their required service level, including eliminating safety concerns like sharp edges, pinch points, tripping hazards, and slippery surfaces. This project mitigates risk to personnel and members of the public that utilize these assets.
Replace Network Communications Equipment (2024)	180.7	Program	This program is required to replace networking devices on Hydro's administrative network as they near manufacturers' end-of-support or to ensure maximum operability due to changes in technology. Lack of manufacturer support can result in unplanned network outages as well as security vulnerabilities. To mitigate risks associated with hardware and software vulnerabilities for devices that are at or near manufacturers' end-of-support, Hydro recommends the replacement of 28 networking devices, including switches, routers, and wireless devices, with functionally-equivalent devices based on their criticality and operational impact.
Upgrade Core OT Infrastructure (2024)	174.7	Program	To ensure the reliability of critical applications and services used to monitor and control the electrical grid, Hydro proposes the upgrade of hardware components related to the EMS servers and storage infrastructure to ensure Hydro has a reliable and secure environment to support EMS operations. These upgrades to core OT infrastructure components will prevent data loss and ensure new data can be obtained for factors critical to grid management, such as system events, alarms, weather, and load forecasts.

General Plant (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Upgrade HVAC Supervisory Controllers (2024) – Hydro Place	149.6	Project	Hydro Place is equipped with a building automation system ("BAS") to manage and control its heating, ventilation, and air conditioning ("HVAC") equipment. The supervisory controllers in Hydro's HVAC system, which are responsible for network management, system-wide control coordination, and the related BAS software, are obsolete. This project will replace the supervisory controllers and software, mitigating risk to critical server and control room infrastructure. A planned approach will maintain the reliability and security of the system as the original equipment manufacturer ("OEM") will guarantee replacement parts and support for the foreseeable future.
Minor Telecommunications Enhancements (2024)	96.9	Program	Hydro's communications network provides connectivity for users to access critical business systems that enable day-to-day operations. Requests for immediate business needs are made of Network Services for minor capital expenditures to respond to business needs, improve service delivery, or reduce reoccurring operating expenditures (i.e., monthly service fees). Examples of requests include expansion of network coverage to unserved facilities, increases to bandwidth, additional telecommunications equipment, and enhancements to remote monitoring capability and communication site facilities. Hydro proposes to bundle such requests under this program to mitigate risks associated with failing to respond to business requirements, network connectivity to field locations, and the ability to achieve cost savings.
Purchase Tools & Equipment (Less than $50,000) – Transmission & Rural Operations (2024)	405.3	Program	This program includes the purchase of required tools and equipment for Hydro's Transmission and Rural Operations including the northern, central, and Labrador regions. The program mitigates safety risks associated with failing to provide proper tools and equipment for personnel.
Purchase Tools & Equipment (Less than $50,000) – Generation (2024)	395.1	Program	This program includes the purchase of required tools and equipment for Hydro's generation facilities, including hydraulic plants, thermal plants, and gas turbines. The program mitigates safety risks associated with failing to provide proper tools and equipment for personnel.
Purchase Office Equipment (Less than $50,000)	50.0	Program	This program includes the purchase of office equipment required for various locations. The program mitigates safety risks associated with failing to provide proper tools and equipment for personnel.
Purchase Tools & Equipment (Less than $50,000) – Telecontrol (2024)	45.6	Program	This program includes the purchase of required tools and equipment for Hydro's Network Services Department. The program mitigates safety risks associated with failing to provide proper tools and equipment for personnel.

Mandatory			
Title	**Total Spend**	**Project/Program**	**Description**
Upgrade Station Lighting (2024–2025) – Bottom Waters, Deer Lake, Doyles, Indian River and Western Avalon Terminal Stations	520.6	Project	This project will replace station lighting systems in five terminal stations in various locations within Hydro's system, which are nearing the end of service life and are suspected of polychlorinated biphenyl ("PCB") contamination. Station lighting is necessary to provide a safe working environment and to act as a deterrent for theft and vandalism, and replacement is required to ensure compliance with federal environmental PCB Regulations related to removing equipment containing PCBs by December 31, 2025.
Renewal			
Title	**Total Spend**	**Project/Program**	**Description**
Inspect Fuel Tanks – Hardwoods Gas Turbines	692.9	Project	Inspection of the fuel storage tank at the Hardwoods Terminal Station is required to ensure compliance with regulatory requirements, identify necessary maintenance and repair items, and maximize forecasted remaining asset service life. Hydro is proposing to complete this required inspection a year early in consideration of major capital works previously approved or forecast for the hydraulic generation portfolio. The completion of repairs identified during the inspection will confirm that the tanks are structurally sound, suitable for operation, and not at risk of releasing fuel into the environment. This project mitigates the risks associated with undetected deterioration resulting in fuel leaking from the tank.
Overhaul Pumps (2024) – Holyrood	661.0	Program	Hydro proposes to overhaul the Unit 2 East Boiler Feed Pump, Unit 1 South Vacuum Pump, and Unit 2 North Vacuum Pump at the Holyrood Thermal Generating Station ("Holyrood TGS"), as they are due for overhaul in 2024 based on the OEM's recommended overhaul cycle for these pumps. The program is required to maintain the acceptable operating condition of the pumps, which contribute to the reliable operation and availability of Units 1 and 2 at the Holyrood TGS at full generation capacity.
Upgrade Unit 1 Control System (2024–2025) – Holyrood	652.6	Project	This project proposes the replacement of the obsolete turbine control system ("TCS") hardware on Unit 1 at the Holyrood TGS including integration with the upgraded Unit 2 system. This project is required to support the operation of the Holyrood TGS and the increased risk of in-service failure as the equipment continues to age, coupled with a lack of reliable spare parts and OEM support. Hydro recommends upgrading the Unit 1 TCS, to minimize the risk of an extended unplanned outage at the Holyrood TGS due to TCS hardware issues.

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Overhaul Marine Terminal Loading Arms (2024) – Holyrood	511.0	Project	The Holyrood TGS has two marine terminal loading arms that provide a moveable, adjustable link between the piping on the tanker and the piping onshore that leads to the fuel oil storage tanks. The marine terminal loading arms experience corrosion and wear due to operating and loading conditions, as well as exposure to inclement weather and the saltwater of Conception Bay. An overhaul has been completed regularly based on OEM recommendations and Hydro's operational experience, with the next scheduled overhaul due in 2024. Completing this overhaul will ensure the continued reliable operation of the marine terminal loading arms and reduce environmental risks due to a fuel oil leak.
Diesel In-Service Failures (2024)	488.3	Program	The Diesel In-Service Failures program allows Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable operations. This program will also allow Hydro to continue to proactively manage the pool of capital spare equipment to support diesel generation operations. Failure to perform work that is justified under this program could result in a detrimental impact to customer power supply or an unacceptable risk to workers or public safety. In most cases, diesel generating stations are the sole source of power for the community served and equipment failures must be addressed promptly.
Replace Annunciator – Phase 2 (2024–2025) – Bay d'Espoir	481.6	Project	The existing unit annunciators at the Bay d'Espoir Facility are obsolete and manufacturer parts for failed annunciator components are no longer available. This impacts the ability to effectively respond to equipment issues as the annunciators are becoming increasingly unreliable. An upgrade of the unit annunciators is necessary to increase the reliability of alarm notifications. Upgrades to the Bay d'Espoir Facility's annunciator system were planned in two phases, with Phase 1 anticipated for completion in 2023. This project addresses Phase 2 and includes the replacement of the six local unit annunciator systems. To support the continued reliable operation of the Bay d'Espoir Facility, Hydro recommends upgrading the annunciator systems for Units 1–6.

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Upgrade DCS Hardware – Units 1 and 2 (2024–2025) – Holyrood	472.5	Project	A significant number of components of the existing distributed control system ("DCS") hardware at the Holyrood TGS are no longer supported by the OEM, which impacts Unit 1, Unit 2, and the burner management system for Unit 3. Hydro has limited spare inventory to mitigate potential issues with these components; however, existing computer stations and network switches for Units 1 and 2 must be replaced as they are obsolete and beyond their expected useful life. This project will mitigate the risk of an extended unplanned outage at the Holyrood TGS due to DCS hardware issues.
Upgrade Distribution (2024–2025) – Bay d'Espoir Terminal Station 2	424.7	Project	Bay d'Espoir Terminal Station 2 has several 25 kV assets that require replacement or relocation due to age, safety considerations, and/or have reached the end of their useful life. The terminal station includes multiple gang-operated switches and reclosers that supply three feeders. Spare parts are becoming difficult to source due to obsolescence, as the OEM is no longer in business. The assets needing replacement include one disconnect switch, two recloser bypass switches, and six current transformers, which require both replacement and relocation onto the steel structure. These components are integral to the safe and reliable operation of the terminal station and replacement will decrease the risk of in-service failures.
Replace 48 V Battery Banks and Chargers (2024)	422.2	Program	This program is proposed to replace the battery banks and chargers to support the reliable operation of the 48 Vdc[1] power system that is critical for the operation of Hydro's communications equipment. Systems will be proposed for replacement based on performance issues, including reaching the end of their useful life, reliability, and physical condition criteria, as well as the availability of support from the manufacturer. The program mitigates the risk of loss of communications to sites, which can result in loss of monitoring and control, loss of teleprotection, and loss of administrative voice and data communications. Loss of communications can also lead to extended and widespread customer outages as well as damage to equipment.

[1] Direct current ("dc").

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Penstock Level II Condition Assessment (2024) – Upper Salmon	382.8	Program	Hydro is proposing to introduce this program of external inspections and Level 2 Condition Assessments to support the reliable operation of its hydraulic generation fleet and is recommending the penstock at the Upper Salmon Hydroelectric Generating Station for review in 2024. Since 2018, Hydro has set up a framework to carry out external inspections and internal Level 2 Condition Assessments of the penstocks on a six-year frequency. This allows Hydro to assess the current condition and degradation rate of the penstocks to help develop a plan to ensure long-term reliability. Completing this work during a planned outage in 2024 will allow Hydro to perform critical trending on the condition of the penstock, facilitating informed decisions on any future maintenance.
Upgrade UPS 1 & 2 (2024–2025) – Holyrood	370.6	Project	There are four independent uninterruptable power supply ("UPS") units installed at the Holyrood TGS. These UPS units are used to provide uninterruptable power to various systems during system disruptions. UPS 1 and 2 are planned to be replaced in 2024–2025, as they have been at an end-of-life status since 2010. Through frequent incremental extensions of steam operation, Hydro deferred replacement of these units until post-steam operation, when they could be retired. Reliable UPS 1 and 2 capability is required to maintain the reliable operation of the Holyrood TGS until the end of steam generation. The continued deferral will result in an increased risk of failure, potentially resulting in a full unit trip or damage to equipment. This replacement is required to support the safe and reliable operation of the Holyrood TGS through the Bridging Period.
Gas Turbine In-Service Failures (2024)	358.0	Program	The Gas Turbine In-Service Failures program will allow Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable operations. This program will also allow Hydro to continue to proactively manage the pool of capital spare equipment to support gas turbine generation operations. Failure to continue this program could result in a detrimental impact to customer power supply or an unacceptable risk to workers or public safety.

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Replace Annunciator Panels (2024–2025) – Cat Arm	351.4	Project	Hydro recommends replacing the station annunciation system at the Cat Arm Hydroelectric Generating Station, as the existing annunciation system is obsolete and has exceeded its useful life. The OEM is unable to provide direct replacement parts and there have been several failures to annunciator components in recent years. The annunciation system provides alarm notifications based on plant auxiliary equipment and abnormalities associated with the two generating units. An improperly functioning annunciation system can lead to increased generation equipment outage time, as field staff are unable to respond to equipment issues efficiently.
Replace Circuit Breaker Reclosing Controllers (2024–2025) – TL247	328.2	Project	Three reclosing controllers for the 230 kV circuit breakers at the Cat Arm and Deer Lake Terminal Stations need to be upgraded, as they have reached the end of their useful life, have condition concerns, and/or do not comply with Hydro's current protection and control standard. This project proposes to upgrade these three controllers with modern microprocessor-based reclosing controllers. Failure to replace the three reclosing controllers challenges the dependability, security, and service continuity of power transmission of the 230 kV line (TL247) in the event of an abnormal condition experienced by this line.
Overhaul Hydraulic Units (2024)	323.8	Program	Hydro performs time-based preventive maintenance annually on all major hydraulic units on the Island Interconnected System, including PM9 inspections every six years. The PM9 inspections are required to identify refurbishments and recommendations to be conducted to increase the lifespan of the unit(s). The unit at the Granite Canal Hydroelectric Generating Station has been selected for PM9 inspection a year early and will be overhauled according to the results of the inspection. Early inspection of this unit will help mitigate the effects of anticipated extended outages of other hydraulic units within Hydro's fleet in 2025, limiting the risk of power loss to customers.

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Upgrade Data Alarm Systems (2024 – 2025) – Western Avalon Terminal Station	293.9	Project	To support the continued reliable operation of the Western Avalon Terminal Station, which is of critical importance to Hydro operations, Hydro proposes replacing the station's data alarm system. The main annunciator of the data alarm system has exceeded its useful life with limited spare part availability, and module failure could lead to long-term deficiencies with the annunciator operation. This impacts the ability to effectively respond to equipment issues at the Western Avalon Terminal Station as the level of alarm granularity is reduced. Issues with the annunciator can lead to increased outage time, as field staff must manually inspect equipment to identify the source of equipment issues.
Replace Terminal Station Battery Banks and Chargers (2024–2025)	192.7	Program	Battery banks and chargers are used to supply direct current power to critical terminal station components (such as circuit breakers, protection and control relays, and disconnect switch motor operators) and provide ac[2] power in the event of a loss of the normal supply. This program reviews battery banks and chargers and recommends replacement based on age and condition following Hydro's established practices. For this year's program scope, three battery chargers have been identified for replacement at two sites. Failure to replace these assets could result in station service outages at the affected operational sites and additional costs associated with emergency replacements.
Upgrade Remote Terminal Units (2024)	165.9	Program	This program is required to replace obsolete remote terminal units ("RTU") processor cards. Hydro uses RTUs to remotely control equipment and to transmit real-time grid performance information from the equipment site to the ECC, helping to maintain reliability and respond to issues as they arise. Obsolete processor failures will lead to forced and unscheduled upgrades of the RTU, resulting in SCADA outages and continual staffing to maintain operations and prevent prolonged customer outages. In 2024, Hydro anticipates the upgrade of six RTUs with new processors, selected for upgrade based on criticality or impact on the system as well as other planned capital/operations work occurring in the same year. New processors also have enhanced monitoring, control, and security functionality.

[2] Alternating current ("ac").

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Replace Timber Crib and Insulation (2024) – Burnt Dam Spillway	161.8	Project	This project proposes the replacement of the current timber crib structure at the Burnt Dam Spillway, which is 32 years old and in a deteriorated state. It is no longer capable of protecting the fuse plug at the Burnt Dam Spillway from wave action and ice damage, which is a critical component of flood handling capabilities at Burnt Pond and the Bay d'Espoir System. The proposed replacement of the rock-filled timber crib structure will mitigate the risk of an unintentional failure of the fuse plug, which would spill water from the Bay d'Espoir Reservoir System and result in lost electrical generation for an extended period.
Transmission In-Service Failures (2024)	158.5	Program	The Transmission In-Service Failures program allows Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable operations. This program mitigates the risk of detrimental impacts of failures to customer power supply or unacceptable risks to worker or public safety. This program will also allow Hydro to continue to proactively manage the pool of capital spare equipment to support its transmission system. Hydro's transmission assets deliver the majority of customer power needs throughout the province.
Purchase Mobile Devices (2024)	155.6	Program	Using mobile devices that are beyond their end-of-life could impede Hydro's ability to communicate effectively and securely. This program is proposed to replace mobile devices at the end of the life cycle following Hydro's established replacement criteria, mitigating the risk of device malfunction, lost productivity, and unplanned replacement expenses. An allowance for net new devices and unplanned replacements is also included in the budget.
Telecommunications In-Service Failures (2024)	91.4	Program	The introduction of the Telecommunications In-Service Failures program will allow Hydro to undertake timely refurbishment and replacement work that is not included in its preventive maintenance program, supporting Hydro's effort to maintain safe and reliable operations. Hydro operates a telecommunication network that serves more than 150 operational and administrative sites province-wide and provides critical services to the real-time operation and reliability of the electrical system. Due to the quantity, geographic spread, and variety of telecommunications assets, unanticipated failures and deterioration are likely to occur. This program mitigates the risk of detrimental impacts of failures to customer power supply, threats to the reliability of the network, or unacceptable risks to worker or public safety. This program will also allow Hydro to continue to proactively manage the pool of critical spare parts to meet its telecommunications requirements.

Service Enhancement			
Title	**Total Spend**	**Project/Program**	**Description**
Construct Maintenance Platform (2024–2025) – Holyrood Gas Turbine	359.2	Project	Hydro is proposing a project to install a permanent access platform for the Holyrood Gas Turbine to complete critical maintenance. The current temporary scaffold system on the south side of the turbine chamber impedes floor-level egress and has been identified as a safety concern. A permanent access platform designed and constructed to eliminate the egress constraints imposed by the scaffold will provide for the safety of personnel during the completion of unit maintenance activities.
Upgrade Instrumentation (2024–2025) – Hardwoods Gas Turbine	218.1	Project	The project proposes the replacement of auxiliary systems instrumentation and vibration monitoring components at the Hardwoods Gas Turbine to support its continued safe and reliable operation. The existing instrumentation associated with the auxiliary systems consists of gauges and switches located inside various enclosures that must be accessed locally. This project will mitigate safety risks to Hydro personnel due to high temperatures and noise levels, as well as potential exposure to high-pressure fuel, lube oil, and air systems. Additionally, improvements to the vibration monitoring system will improve asset monitoring and address obsolescence.
Remove Safety Hazards (2024)	198.3	Program	The Remove Safety Hazard program ensures Hydro can remove potential hazards in situations where immediate refurbishment or replacement must be completed due to safety hazards imposed on customers, employees, contractors, and the public. The program is required as part of Hydro's obligation to provide a safe work environment for its employees in compliance with the *Newfoundland and Labrador Occupational Health and Safety Regulations*.
Install Anemometer (2024) – Cat Arm	68.6	Project	The project proposes the purchase and installation of a new remote meteorological station at the Cat Arm CD-4 dam site. Data from the site is required to facilitate accurate engineering analysis to repair damage on the upstream slope of the dam site, first identified by Hydro in 2019, which has since experienced further deterioration. Failure to complete this project would result in the use of inaccurate data for the repair design, increasing the risk of inadequate repair, which could lead to more extensive rehabilitation requirements in future or a potential dam breach. The meteorological station installed at the Cat Arm CD-4 dam site will continue to be used in Hydro's dam safety surveillance program for local wind monitoring.