Newfoundland and Labrador Hydro
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P.O. Box 12400. St. John's. NL
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nlhydro.com

July 16, 2024

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Re: 2025 Capital Budget Application

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") 2025 Capital Budget Application ("Application"). Hydro's Application complies with the guidelines and conditions for capital budget proposals outlined by the Board of Commissioners of Public Utilities ("Board") in Order No. P.U. 7(2002–2003), as well as the provisional Capital Budget Application Guidelines issued by the Board.[1]

Through this Application, Hydro is seeking approval of $135.7 million in capital expenditures for 2025. This is comprised of single-year programs and projects for 2025, 2025 expenditures for multi-year proposals commencing in 2025, and 2025 expenditures for programs and projects approved in previous capital budget applications. Hydro notes that the total planned capital spend for 2025 is $195.8 million. This includes expenditures for 2025 previously approved through applications supplemental to the 2024 Capital Budget Application and expenditures related to applications that Hydro anticipates filing subsequent to this Application, once full analysis has been complete. It also includes $1.1 million in specifically assigned customer contributions, applied for within this Application. Further details regarding the total planned capital spend are provided in Section 7 of Schedule 1 to the Application. As four of the projects proposed within Hydro's Application are related to assets that serve only one Hydro customer, Hydro is seeking approval to request contributions from the customers towards the costs of the improvements to the related property. Hydro is also seeking approval of its 2023 Average Rate Base in the amount of $2,329,352,000, as detailed in Schedule 6 to the Application.

The 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.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

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

Encl.

[1] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022.

ecc:

Board of Commissioners of Public Utilities
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Board General

Island Industrial Customer Group
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Denis J. Fleming, Cox & Palmer
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Tacora Resources Inc.
Baseem Saeed

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

Teck Resources Limited
Shawn Kinsella

2025 Capital Budget Application

July 16, 2024

An application to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

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Schedule 7: Capital Programs and Projects

Programs **Program**

Over $5,000,000

- Overhaul Turbine and Valves – Unit 3 (2025) – Holyrood 1
- Upgrade Worst-Performing Distribution Feeders (2025–2027) 2
- Replace Light- and Heavy-Duty Vehicles (2025–2027) 3
- Distribution System In-Service Failures, Miscellaneous Upgrades and Street Lights (2025) 4
- Replace Diesel Gensets (2025–2027) 5

$1,000,000 to $5,000,0000

- Overhaul Hydraulic Units (2025) 6
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Projects **Project**

Over $5,000,000
- Rewind Stator (2025–2026) – Hinds Lake 1

$1,000,000 to $5,000,0000
- Refurbish Intake 2 (2025–2026) – Bay d'Espoir 2
- Refurbish Marine Terminal (2025–2026) – Holyrood 3
- Replace Emergency Diesel Genset (2025–2027) – Cat Arm 4
- Install Mid-Span Structures – TL220 (2025–2026) 5
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$750,000 to $1,000,0000
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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 2025, pursuant to Section 41(1) of the *Act*, (ii) its proposed capital purchases and construction projects for 2025 in excess of $750,000, pursuant to Section 41(3)(a) of the *Act,* (iii) contributions by certain Customers for contributions towards the cost of improvements to certain property, pursuant to Section 41(5) of the Act, and (iv) for an Order, pursuant to Section 78 of the *Act,* fixing and determining its average rate base for 2023.

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*, is a public utility within the meaning of the *Act,* and is subject to the provisions of the *Electrical Power Control Act, 1994.*

B. Application

2. The 2025 Capital Budget Application proposes $135.7 million in 2025 expenditures, comprised of expenditures related to single-year programs and projects proposed for completion in 2025, 2025 expenditures for multi-year programs and projects commencing in 2025, as well as those expenditures in 2025 related to multi-year programs and projects approved in previous capital budget applications.[1] This amount includes $1.1 million in expenditures for which approval to specifically assign the costs to certain customers is requested herein.[2] No new leases with costs in excess of $750,000 over the expected life of the lease are proposed for 2025.

[1] Sch. 1, app. B.

[2] Sch. 1, Table 9.

3. The 2025 Capital Budget Application request for approval does not include the 2025 expenditures related to supplemental applications approved by or currently before the Board, or those anticipated to be filed with the Board in 2025 as supplemental applications once a full analysis of the proposed project is complete.

4. Schedules 1 to 7 to this application are the 2025 Capital Budget Overview, Five-Year Capital Plan (2025–2029), Holyrood Thermal Generating Station Overview – Future Operation and Capital Expenditure Requirements, Bay d'Espoir Hydroelectric Generating Station – Projected Capital Expenditures (2025–2034), 2024 Capital Expenditures Overview, 2023 Average Rate Base, and Capital Programs and Projects.

5. Schedule 1: The 2025 Capital Budget Overview provides:

   a) An overview of Hydro's capital investment strategy and the capital budget proposed for 2025;

   b) A summary of the revenue requirement impact of Hydro's proposed 2025 Capital Budget Application;

   c) Hydro's 2025 Capital Budget financial schedules with projects listed by investment classification, asset category, 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);[3]

   d) The 2024 Update to the Terminal Station Asset Management Strategy (Schedule 1, Appendix F); and

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

6. Schedule 2: Five-Year Capital Plan (2025–2029) provides an overview of Hydro's investment strategy and associated planned capital work for the period 2025–2029, as well as a summary of Hydro's actual and projected capital expenditures for the period 2020–2029 (Schedule 2, Appendix B).

[3] A listing of Hydro's planned 2025 projects and programs under $750,000 is contained within Schedule 7 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: Bay d'Espoir Hydroelectric Generating Station –Projected Capital Expenditures (2025–2034) provides an operational review of the Bay d'Espoir Hydroelectric Generating Station, as well as details of its capital plan for the period 2025–2034.[4]

9. Schedule 5: 2024 Capital Expenditures Overview summarizes 2024 capital expenditures year-to-date May 31, 2024, and provides explanations for reportable variances between the approved budget and the forecasted total budget.

10. Schedule 6: 2023 Average Rate Base sets out Hydro's proposed 2023 rate base of $2,329,352,000.

11. Schedule 7: Capital Programs and Projects contains evidentiary information to support the proposed 2025 construction projects and capital purchases exceeding $750,000, segmented by programs and projects. Also contained in Schedule 7 is a listing of the 2025 proposed programs and projects under $750,000. Capital purchases are included within the programs and projects.

12. There are a number of projects proposed within Hydro's 2025 Capital Budget Application related to assets that serve only one Hydro customer. Hydro's practice regarding assets that serve only one Hydro customer is that the costs of construction and ongoing maintenance of those assets are the responsibility of that customer. Those costs are not borne by other customers through rates or otherwise.

13. The projects are:

    (i) Projects at the Wabush Terminal Station, including the replacement of disconnect B4L34-1 and circuit breaker B4L34, more particularly discussed in Schedule 7, Programs 17 and 18. These assets specifically serve Tacora. The total estimated specifically assigned costs for Tacora in 2025 is $56,400;

[4] This report is provided in compliance with the direction of the Board in Order No. P.U. 35(2023).

(ii) Continuation of a project to install fire protection at the Voisey's Bay Nickel Terminal Station, which was initially proposed in Hydro's 2024 Capital Budget Application as the "Install Fire Protection in 230 kV Stations (2024–2025) – Voisey's Bay' project. The project was initially approved by the Board in Board Order No. P.U. 35(2023). These assets specifically serve Vale Newfoundland and Labrador Limited ("Vale"). The total estimated specifically assigned costs for Vale in 2025 is $599,000;

(iii) A project to refurbish B2L64 in the Buchans Terminal Station, more particularly discussed in Schedule 7, Program 18. These assets specifically serve Teck Resources Limited ("Teck"). The total estimated specifically assigned costs for Teck in 2025 is $10,000; and

(iv) A project to replace the protective relays for Transformer T1 and T2 in the Come By Chance Terminal Station, more particularly discussed in Schedule 7, Program 12. These assets specifically serve Braya Renewable Fuels ("Braya"). The total estimated specifically assigned costs for Braya in 2025 is approximately $387,600.

14. As noted above, the assets solely serve the indicated customer, and the costs allocated to those assets will be specifically assigned for recovery from each customer.

15. Hydro has provided each respective customer with the cost estimates associated with each project and each customer has acknowledged its responsibility for its specific costs.

C. Reason for Approval

16. The proposed capital expenditures for 2025 as set out in the 2025 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

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

a) Approving Hydro's 2025 capital budget of $135.7 million as set out in Appendix A of Schedule 1, pursuant to Section 41(1) of the *Act*;

b) Approving Hydro's 2025 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*;

c) Approving a contribution by those customers noted in paragraph 13 above, of an amount equal to the capital cost of the work described herein related to assets which solely serve the identified customer, pursuant to section 41(5) of the *Act*; and

d) Fixing and determining Hydro's average rate base for 2023 in the amount of $2,329,352,000 as set out in Schedule 6, pursuant to Section 78 of the *Act*.

E. Communications

18. 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 16th day of July 2024.

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 2025, pursuant to Section 41(1) of the *Act*, (ii) its proposed capital purchases and construction projects for 2025 in excess of $750,000, pursuant to Section 41(3)(a) of the *Act*, (iii) contributions by certain Customers for contributions towards the cost of improvements to certain property, pursuant to Section 41(5) of the Act, and (iv) for an Order, pursuant to Section 78 of the *Act*, fixing and determining its average rate base for 2023.

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 Newfoundland and Labrador 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 16th day of July 2024, before me:

Kimberley Duggan
Commissioner for Oaths, Newfoundland and Labrador

R. Collett
Robert Collett

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

Sch 1: 2025 Capital Budget Overview

Schedule 1

2025 Capital Budget Overview



2025 Capital Budget Application

2025 Capital Budget Overview



Executive Summary

Newfoundland and Labrador Hydro's ("Hydro") 2025 Capital Budget Application ("CBA") requests approval for $135.7 million of capital investment. Hydro recognizes that its 2025 Capital Budget represents a material increase in planned capital expenditures compared to recent years, driven primarily by the need for increased investment in asset renewal, and increasing costs associated with a period of sustained high inflation in recent years. The 2025 CBA proposed investment equates to approximately 5.8% of the net book value of Hydro's regulated property, plant and equipment and intangible assets.[1]

As Hydro prepares to enter an era of expansion to reliably meet growing electricity demand, it is imperative that Hydro continue to prudently invest in its existing assets to ensure it continues to provide a level of reliability consistent with customer needs and expectations. Hydro is not alone in facing the challenge of balancing investment in the reliability of existing assets and system expansion to meet growing demand, as all Canadian utilities face aging infrastructure, growing demand, and the need to integrate renewable sources of supply to enable the transition to a green economy. In its 2024 annual report, Electricity Canada ("EC") highlighted the importance of sustained investment in reliability in supporting the energy transition, stating:

> Prioritizing reliability is essential to achieving an orderly transition to a clean energy economy. Reliability is central to achieving sustainability. Without reliable electricity supply, customers will not accept the pace of change, and businesses will not invest. Likewise, reliability and affordability go together, as electricity is integral to homes and businesses, and the loss of power has significant economic consequences. It is in everyone's interest – customers, utilities, regulators, and policymakers – to ensure reliability investments are prioritized. Always On isn't just about keeping the lights on and the EV charged, but it is also applicable to utilities, regulators, and policymakers who must remain vigilant, proactive, and aligned regarding the key role reliability will play in transitioning to *net zero.*[2]

To that end, Hydro's 2025 Capital Budget consists largely of investments related to the renewal of existing core assets, which account for two-thirds of Hydro's planned 2025 capital expenditures. Hydro has carefully considered its capital investment portfolio for 2025, ensuring its proposed programs and projects represent those which are necessary to support the safe, reliable operation of Hydro's system

[1] As of March 31, 2024.
[2] "*Electricity in Canada: Always On,*" Electricity Canada, May 2, 2024. https://issuu.com/canadianelectricityassociation/docs/electricity_in_canada_alwayson_4-24-2024_2_1_

in an environmentally responsible manner. In doing so, Hydro has deferred or cancelled over $18 million in capital investment in the interest of balancing cost and reliability.

Hydro also recognizes the impact of increased capital investment on its customers, including the associated impacts on rates and revenue requirements. While Hydro's expenditures will increase, in part due to the infrastructure required to meet growing electricity needs, the impacts to customers will be limited as a result of the province's rate mitigation plan. Through to and including 2030, the Government of Newfoundland and Labrador ("Government") has committed to target domestic rate increases limited to 2.25% annually. In effect, this means that the capital expenditures required to ensure the delivery of reliable, environmentally responsible power will not create an undue burden on customers. Beyond 2030, the Government has publicly stated that it is committed to rate mitigation.

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Appendix D: 2025 Capital Budget by Materiality – Programs and Projects $1 Million to $5 Million

Appendix E: 2025 Capital Budget by Materiality – Programs and Projects $750,000 to $1 Million

Appendix F: Terminal Station Asset Management Strategy – 2024 Update

Appendix G: Risk Evaluation Matrix

1.0 Introduction

Hydro's 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 service and facilities that are reasonably safe and adequate and just and reasonable[3] and to deliver power to consumers at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.[4]

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 the Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir"), the Holyrood Thermal Generating Station ("Holyrood TGS"), the Stephenville Gas Turbine ("Stephenville GT"), 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. As part of the ongoing *Reliability and Resource Adequacy Study Review* proceeding, Hydro conducted a digital engagement process where it asked customers to share their thoughts on the costs and reliability of the province's electrical grid. As part of that process, four out of five customers told Hydro they believed the system was reliable and 87% said they did not want to pay more for reliability improvements that led to fewer or shorter

[3] *Public Utilities Act,* RSNL 1990, c P-47, s 37(1).
[4] *Electrical Power Control Act, 1994*; SNL 1990, c E-5.1, s 3(b)(iii).

outages.[5] Customers largely prioritize the lowest impact on electricity rates rather than other factors, and Hydro is mindful of this concern as it continues asset management planning.

Hydro has applied these practices, particularly in recent years, to work toward reduced investment to the minimum prudent capital level 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.

Hydro's 2025 CBA requests approval for $135.7 million of capital investment of which $86.7 million consists of newly proposed programs and projects, and $49.0 million related to previously proposed programs and projects, as seen in Figure 1.

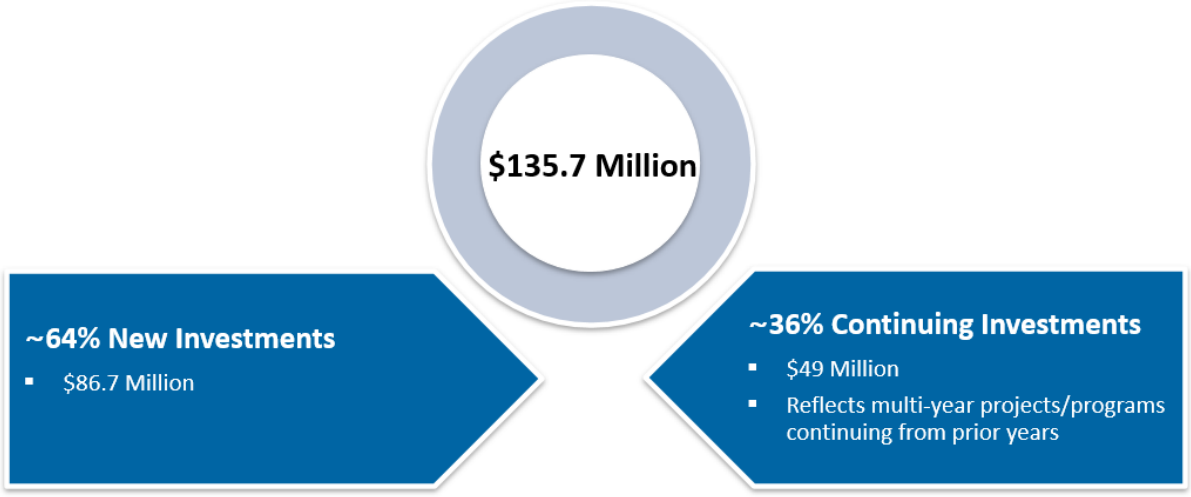


Figure 1: Hydro's 2025 Capital Budget Summary

Hydro's proposals represent an increase in capital expenditures in 2025. The rise primarily reflects ongoing inflation as well as increased renewal-driven expenditures to ensure system reliability, particularly related to aging assets where larger investments are required for major overhaul work, as outlined in Section 6.1. Further detail on Hydro's efforts to manage its 2025 capital spend is included in Section 5.2 of this report.

[5] The outcome of Hydro's Public Engagement Study is available on Hydro's website at https://nlhydro.com/power-the-province/public-engagement/.

As outlined in the Five-Year Capital Plan (2025–2029), the total planned 2025 capital spend is $195.8 million, including $1.1 million in specifically assigned customer contributions. 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 2025 Capital Expenditures is provided in Table 1.

Table 1: Planned 2025 Capital Expenditures

Item	2025 Cost Estimate ($ Millions)
2025 CBA	135.7
Replace Section and Weld Replacement – Bay d'Espoir Penstock 1	35.3[6]
Long-Term Supply for Southern Labrador – Revision 2	19.7[7]
Purchase Spare Generator Step-Up Transformer	4.0[8]
Construction and Installation of Ultra-Fast Electric Vehicle Charging Stations (Fully Contributed)	0.2[9]
Additions for Load Growth – Unit 2065 Replacement and Fuel Storage Upgrades (2024–2027)– Rigolet	0.2[10]
Complete Level 4 Fire Restoration (2024–2025) – Hydro Place	0.3[11]
Additions for Load – Main Brook (2024–2025)	0.3[12]
Additions for Load – Cartwright (2024–2027)	0.0[13]
Total 2025 Planned Capital Spend	**195.7[14]**

[6] As approved by the Board in Order No. P.U. 6(2023).
[7] "Long-Term Supply for Southern Labrador – Revision 2," Newfoundland and Labrador Hydro, rev. October 5, 2023 (originally filed July 16, 2021). The amount of capital expenditures in 2025 is dependent on when or if Hydro receives approval for this project from the Board.
[8] As approved by the Board in Order No. P.U. 28(2023).
[9] As approved by the Board in Order No. P.U. 21(2023).
[10] Supplemental Applications to be filed in 2024, driven by load growth. To be filed as supplemental as approval is required in advance of approval of the 2025 CBA.
[11] Supplemental Application to be filed in 2024, driven by the need for restoration due to a fire in late 2023. To be filed as supplemental as approval is required in advance of approval of the 2025 CBA.
[12] Supplemental Application to be filed in 2024, driven by system growth. To be filed as supplemental as approval is required in advance of approval of the 2025 CBA.
[13] Supplemental Application to be filed in 2024, driven by system growth. To be filed as supplemental as approval is required in advance of approval of the 2025 CBA. The project budget for 2025 is $900.
[14] Includes $1.1 million in specifically assigned expenditures to be recovered directly from specifically assigned customers. This does not include contributions associated with service extensions that are determined during the execution of the project in accordance with the Contributions in Aid of Construction Policy. A breakdown of specifically assigned customer contributions is provided in Section 6.7 of this report.

This 2025 Capital Budget Overview report generally discusses the Capital Plan proposed for 2025, 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;[15]
- Continuation of programs to address in-service failures and miscellaneous upgrades; and
- Legislative compliance (i.e., safety and environmental).

Appendices A through E of this report present Hydro's 2025 Capital Budget of $135.7 million by asset category, 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.[16] Table 2 outlines where Hydro has included the required information within the 2025 CBA as part of Hydro's compliance with each section of the Guidelines.

[15] 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."

[16] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022.

Table 2: Guideline Requirements

Guidelines Section	Content	2025 CBA Location
Application Summary	Activity Drivers per Investment Classification	Schedule 1, Section 6.0
	Determination of Expenditure	Schedule 1, Section 5.0
Reliability Information	Historical SAIDI & SAIFI statistics: Ten Years	Schedule 1, Section 4.0
	Forecast SAIDI & SAIFI statistics: Five Years	Schedule 1, Section 4.0
	Benchmarking against Other Utilities	Schedule 1, Section 4.0
	Worst Performing Feeders	Schedule 1, Section 4.0
Rate Impact Summary	Historical Rates	Schedule 1, Section 6.9
	Project Budget Impact	Schedule 1, Section 6.9
Capital Expenditures Summary	Historical Capital: Ten Years	Schedule 1, Section 2.0
	Current Capital Budget	Schedule 1, Section 2.0
	Forecast Capital Budget: Five Years	Schedule 1, Section 2.0
Five-Year Capital Plan	Capital Plan 2025–2029	Schedule 2
Organization	2025 Capital Budget:	
	By Investment Classification, Major and Minor Asset Category, Materiality, and Programs and Projects	Schedule 1, Appendix A
	By Single- and Multi-Year Programs and Projects	Schedule 1, Appendix B
	By Materiality – Programs and Projects over $5 Million	Schedule 1, Appendix C
	By Materiality – Programs and Projects $1 Million to $5 Million	Schedule 1, Appendix D
	By Materiality – Programs and Projects $750,000 to $1 Million	Schedule 1, Appendix E
Required Information	Programs and Projects over $750,000	Schedule 7
	Programs and Projects under $750,000	Schedule 7
Prioritization	By Risk Mitigated per $1 Million	Schedule 1, Appendix G
	By Risk Mitigated	Schedule 1, Appendix G

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.[17] In most instances, Hydro has fully adhered to the Guidelines. In others, data is presented to the fullest extent practical, along with insight into Hydro's interpretation and application of the Guidelines within its 2025 CBA.

[17] In "Provisional Capital Budget Application Guidelines," Board of Commissioners of Public Utilities, December 20, 2021, the Board noted that full implementation of the Guidelines would be challenging in 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. Hydro has made and will continue to advance amendments to its CBA process to satisfy the Guidelines.

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

Organization – Programs versus Projects

Consistent with the approach that began 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.[18] 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.[19]

Required Information – Asset Data

Hydro has endeavoured 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 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 emphasis on the implementation of processes to improve and expand on asset and maintenance data. Hydro is continuing to mature its information base, with the goal of establishing a technologically-driven maintenance management system, while setting a solid foundation for potential asset management growth. This effort is an important step toward continued improvement of policy, decision-making processes, training and standardization across all areas of asset management.

[18] 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.
[19] 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 a fulsome review of these expenditures.

In 2024, Hydro is focused on progressing a review of its Computerised Maintenance Management System for its Hydraulic Generating Assets. This effort is a significant undertaking which includes, but is not limited to, a review of equipment records and hierarchy, maintenance routines and workflow authorization process optimization, and improved identification of equipment maintenance resource and outage requirements. This review is a crucial step in advancing Hydro's asset management systems, and is foundational, in that it will form the framework for similar reviews of Hydro's other operational areas.

While implementing a common asset management system for both regulated and non-regulated assets can take up to a decade to implement, Hydro is utilizing information learned to further bolster its capital planning efforts. Hydro is committed to continuous improvement in this area, and recognizes the value improved asset management systems and data will add in enabling a fulsome review of Hydro's capital investments by its stakeholders; Hydro believes that the evidence provided in support of this application fully supports the proposed investments.

Prioritization

Hydro recognizes the Board's request that projects be prioritized based on 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 the 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 customers.[20]

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

2.0 Capital Expenditures Summary

Hydro determined its proposed 2025 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 programs for inclusion in its budget, including operational risks, ability to execute, total investment, and cumulative risk associated with balancing aging assets while providing the least-cost, reliable service in an environmentally responsible manner. The focus of the 2025 CBA is to maintain the expected level of reliability while ensuring prudent and reasonable expenditures reflective of Hydro's capital plan considerations.



Figure 2: Hydro's Capital Investment Strategy

Chart 1 demonstrates the trend in capital expenditures from 2014 to 2029.[21]

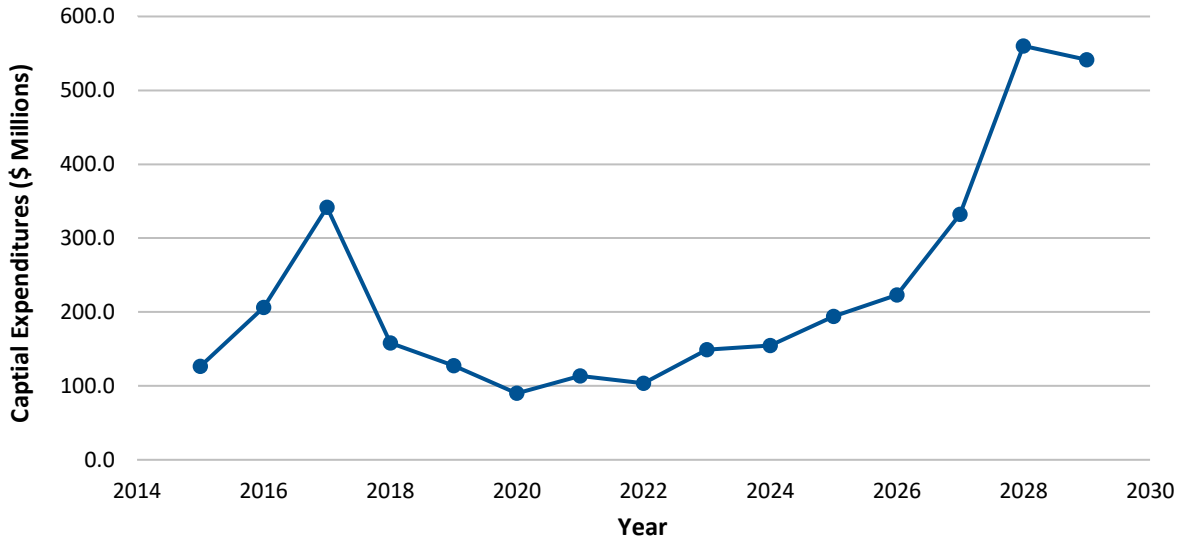


Chart 1: Historical, Budget, and Forecast Capital Expenditures

Hydro's actual and forecast expenditures were higher than average for the period 2016–2018, primarily as a result of expenditures related to the construction of Transmission Line TL267, and remained relatively stable for the period 2019–2022.

Hydro notes that its actual and planned expenditures are forecast to be considerably higher for the period 2023–2029, primarily as a result of Hydro's 2024 Resource Adequacy Plan ("2024 Resource Plan"),[22] increased investment in asset renewal, including refurbishment of the penstocks at Bay d'Espoir, and Hydro's proposed project for long-term supply for southern Labrador. In July 2024, Hydro submitted its recommended Expansion Plan,[23] which includes the installation of a new 150 MW combustion turbine ("CT") with renewable fuel capabilities on the Avalon and Unit 8, a new 154 MW hydroelectric unit in Bay d'Espoir, and up to 400 MW of wind energy. These investments represent the

[21] 2024 Planned Capital Expenditures includes carryover from 2023.
[22] "2024 Resource Adequacy Plan: An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, July 9, 2024.
[23] As discussed in Section 8.0 of Hydro's "2024 Expansion Plans – Development Process and Recommendation" (Appendix C of the 2024 Resource Plan), Hydro's recommended Expansion Plan meets reliability criteria under the Minimum Investment Required scenario while balancing cost and environmental considerations. This plan considers a highly reliable LIL (1% LIL bipole equivalent forced outage rate) and Slow Decarbonization load forecast, resulting in approximately an additional 385 MW and 1.4 TWh added to the Island Interconnected System within the next ten years.

Minimum Investment Required to reliably meet increasing demand associated with electrification and the transition to a green economy and together account for approximately $888 million of Hydro's planned capital expenditures for the period 2025–2029.[24]

Further discussion of Hydro's planned capital expenditures for the period 2025–2029 is provided in Schedule 2 of this application.

3.0 2024 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 impact on Hydro's capital program is anticipated to be manageable. In the event that such disruptions impact Hydro's ability to complete planned work, Hydro utilizes an established internal project change management process to identify the impacts of carryover and to develop temporary mitigation plans to reduce the impact, where possible, until the work can be completed. Hydro is closely monitoring the execution of its 2024 Capital Plan and will continue to prioritize projects to maximize reliability going into the 2024–2025 winter operating season.

Consistent with prior years, capital expenditures approved in Hydro's 2024 CBA but not completed in 2024 will be carried over into 2025. With a large and complex capital program, some degree of carryover is to be expected; the need for carryover is managed through established project management practices that incorporate continual improvement methodologies. This carryover can be strategic, such as deferring projects due to changes in timing requirements, or due to external factors like supply chain disruptions or internal challenges in scheduling resources. Hydro assesses the risk of one-year delays during annual planning and uses project change management to mitigate impacts. Common reasons for under-expenditure include strategic deferral, supply chain issues, and delayed environmental approvals. Hydro continues to refine its planning and execution to reduce future capital expenditure variances and does not anticipate that carryover work will compound annually. Tracking indicates that expenditures generally align with the planned budget, with some variation based on the inherent randomness of risk

[24] Supply additions associated with Hydro's Expansion Plans were not previously included in Hydro's five-year capital plan, as these plans were under development at that time.

events. Any projects or programs with identified carryover will be reflected in Hydro's 2024 Capital Expenditures and Carryover Report.[25]

Schedule 5 of this application contains the 2024 Capital Expenditures Overview Report as of May 31, 2024, which details forecast expenditures and variances.

4.0 Reliability

Hydro is classified as a Region 2 (Urban/Rural) utility by EC. For benchmarking against similar utilities, Hydro has provided EC Region 2 SAIDI[26] and SAIFI[27] averages.[28,29]

4.1 Utility Reliability

Reliability of service is integral to Hydro's mandate, 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 Consumers 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.[30]

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.

[25] Scheduled for filing with the Board on April 1, 2025.
[26] 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.
[27] 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.
[28] EC Region 2 averages are not available prior to 2015.
[29] The annual EC benchmarks for 2023 were not available as of the date this application was submitted.
[30] As Hydro is the only utility serving Labrador, Hydro's Service Continuity metrics are equivalent to its End Consumer metrics in this region.

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 65% of Hydro's proposed 2025 Capital Budget.

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 with and without major events included compared to the EC Region 2 average.

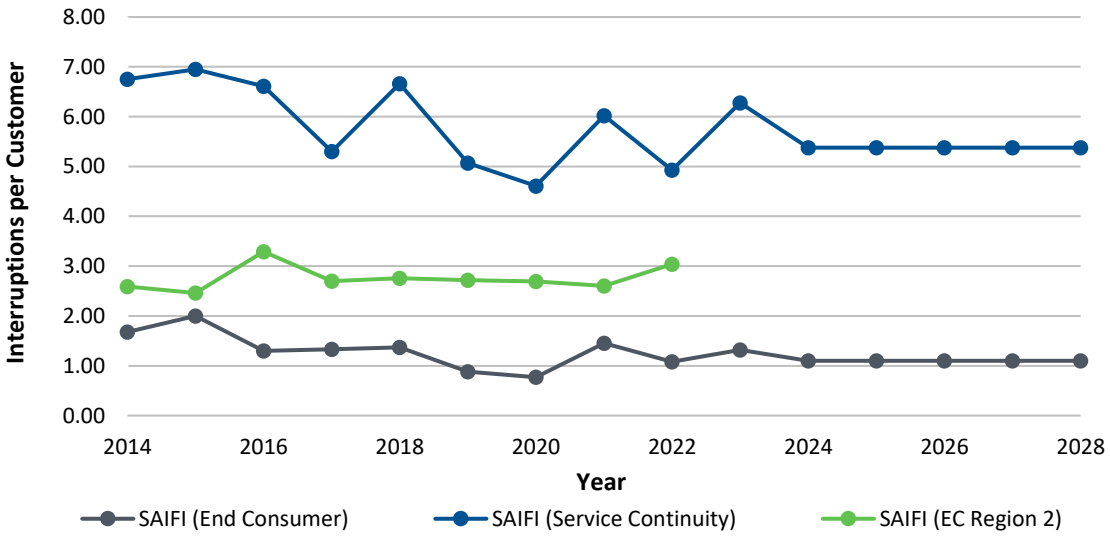


Chart 2: SAIFI Excluding Major Events

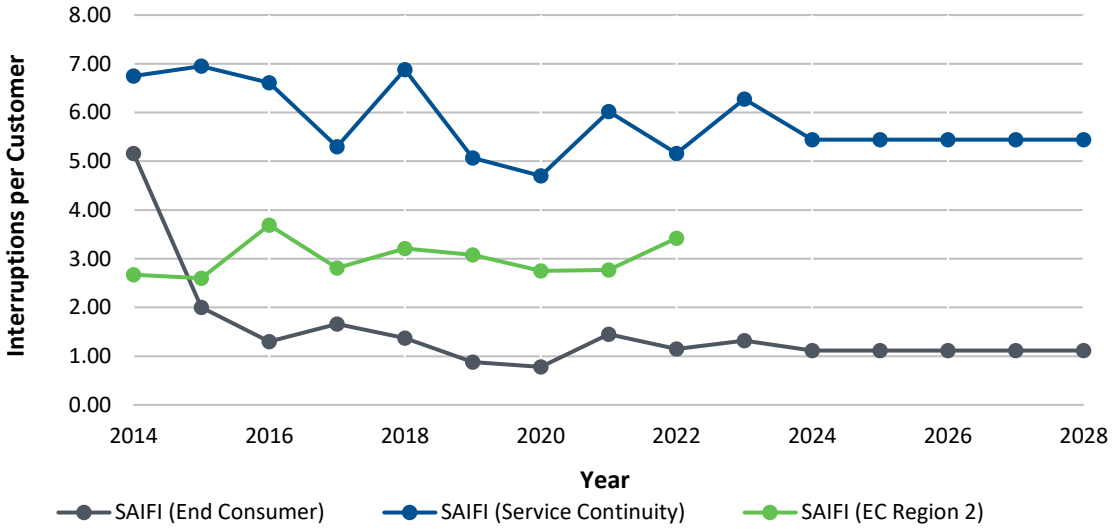


Chart 3: SAIFI Including Major Events

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

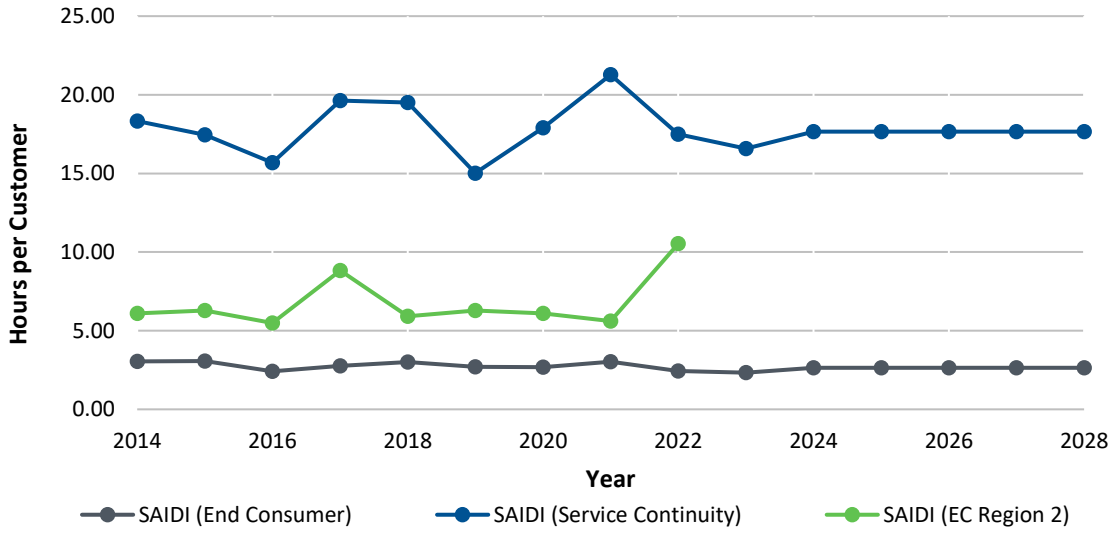


Chart 4: SAIDI Excluding Major Events

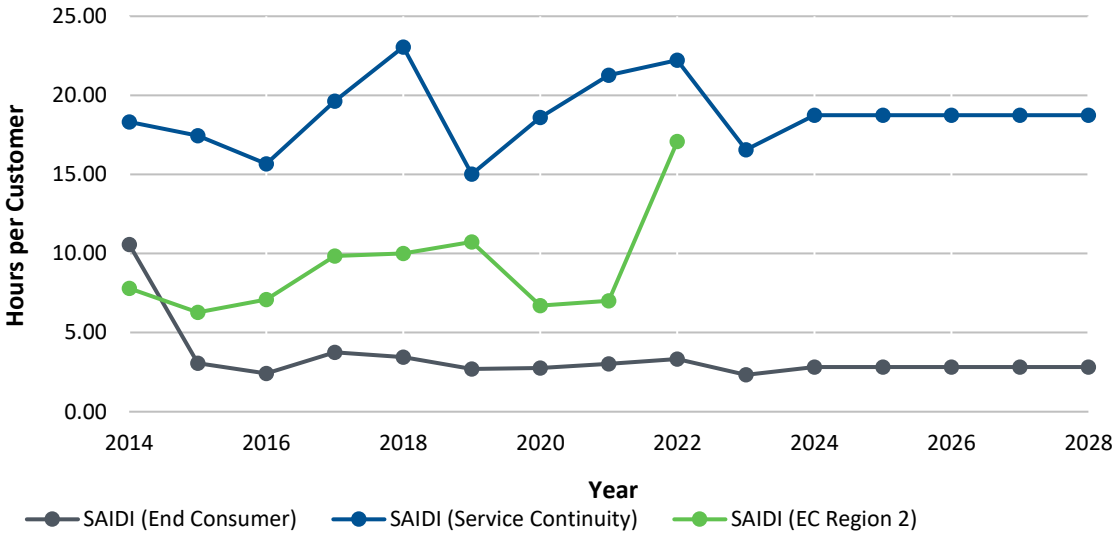


Chart 5: SAIDI Including Major Events

4.1.2 Island

Chart 6 and Chart 7 provide Hydro's Service Continuity SAIFI with and without major events included compared to the EC Region 2 average, for the Island portion of the province.[31]

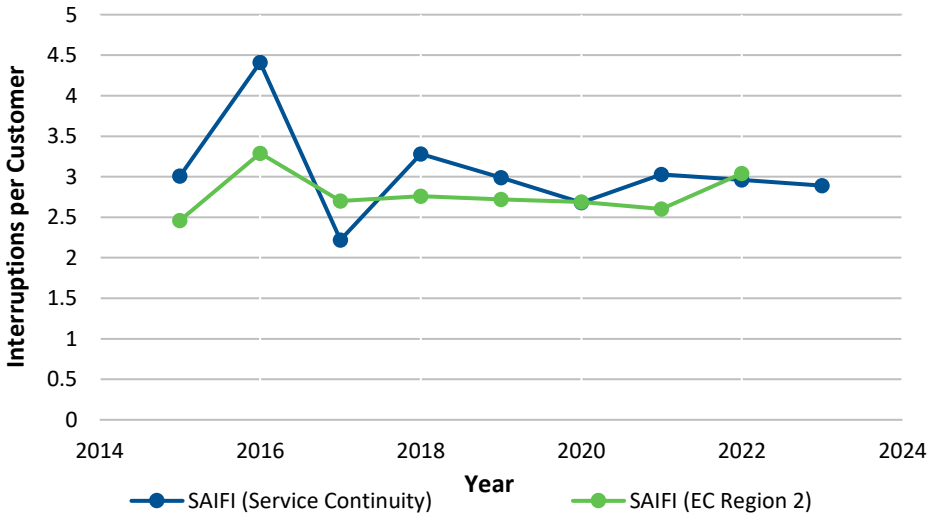


Chart 6: SAIFI Excluding Major Events – Island

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

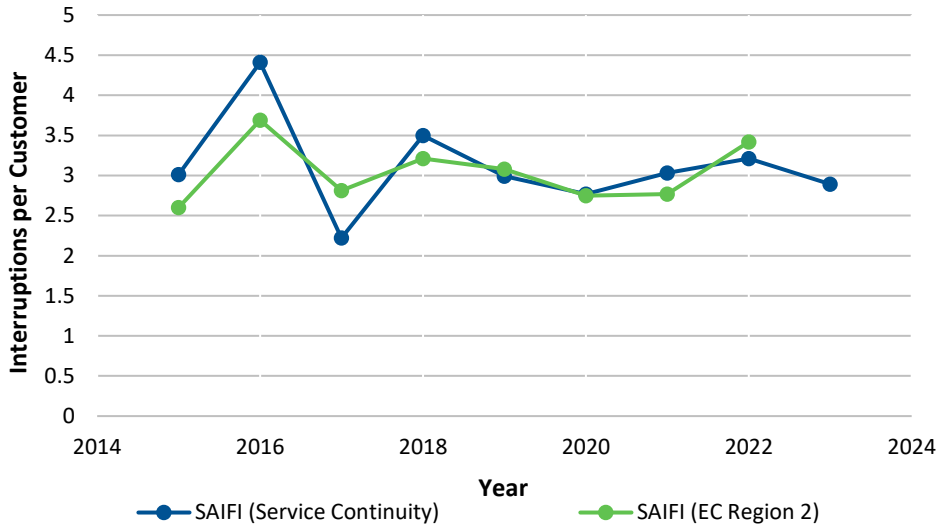


Chart 7: SAIFI Including Major Events – Island

Chart 8 and Chart 9 provide Hydro's Service Continuity SAIDI with and without major events included compared to the EC Region 2 average, for the Island portion of the province.[32]

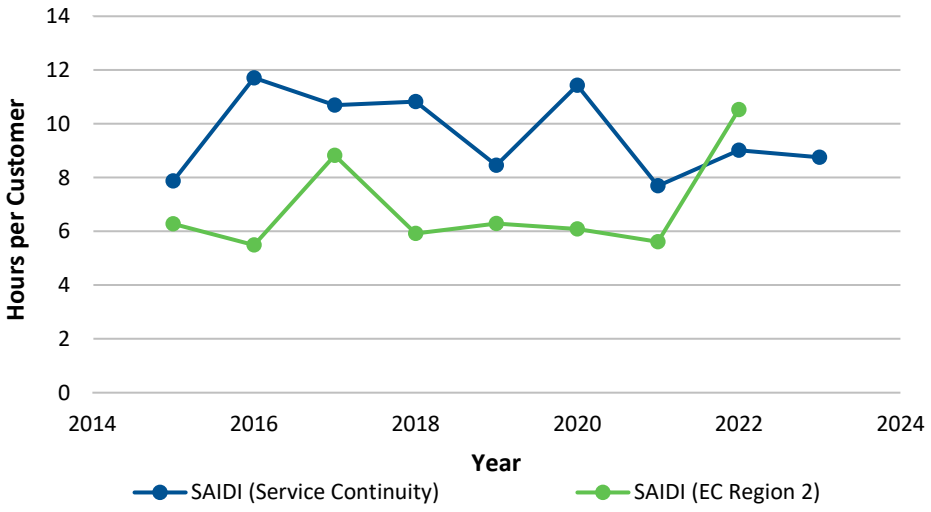


Chart 8: SAIDI Excluding Major Events – Island

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

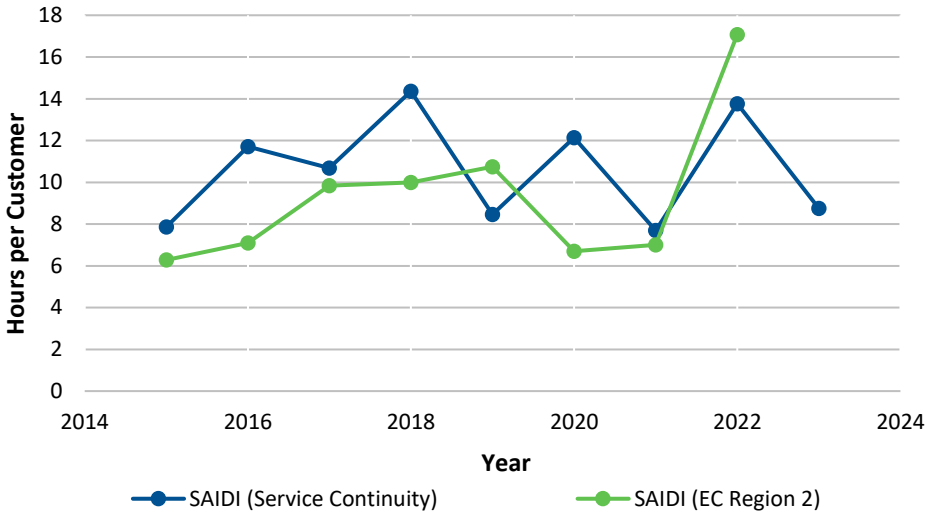


Chart 9: SAIDI Including Major Events – Island

4.1.3 Labrador

Chart 10 and Chart 11 provide Hydro's Service Continuity SAIFI with and without major events included compared to the EC Region 2 average, for Labrador.[33]

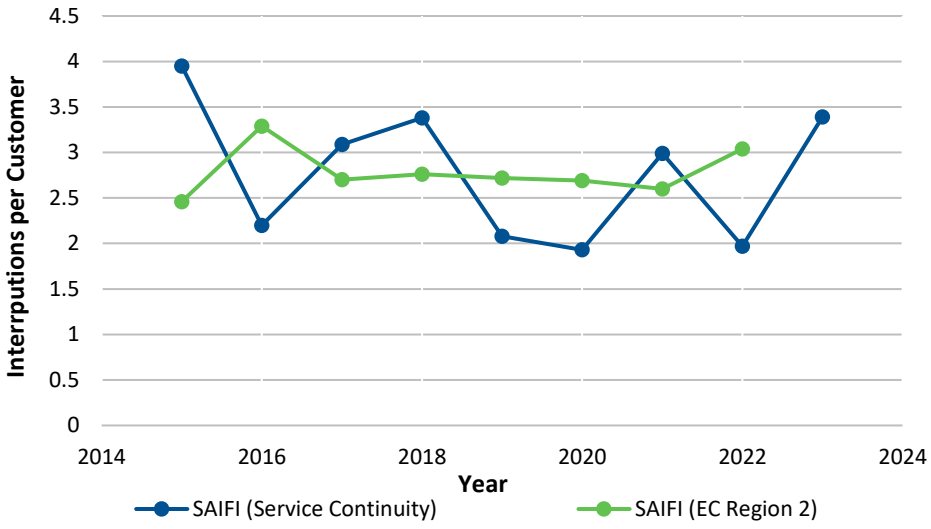


Chart 10: SAIFI Excluding Major Events – Labrador

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

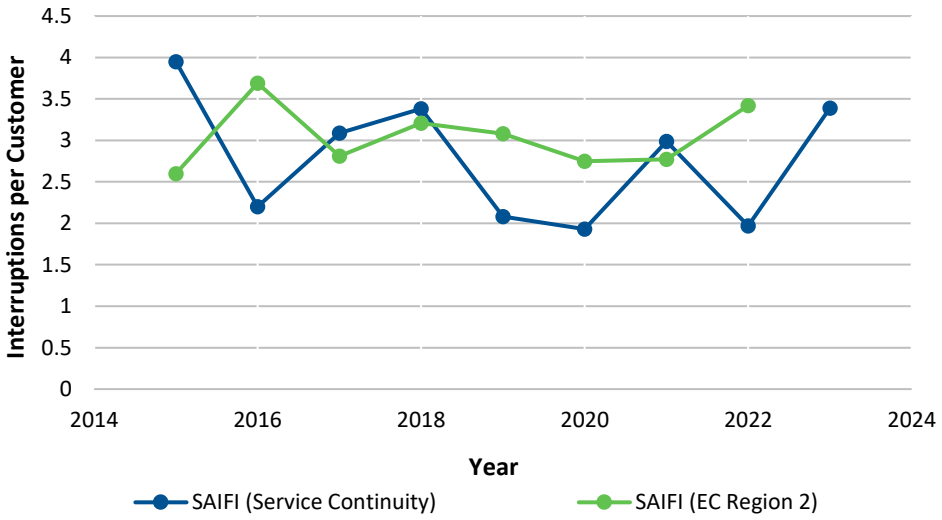


Chart 11: SAIFI Including Major Events – Labrador

Chart 12 and Chart 13 provide Hydro's Service Continuity SAIDI with and without major events compared to the EC Region 2 average, for Labrador.[34]

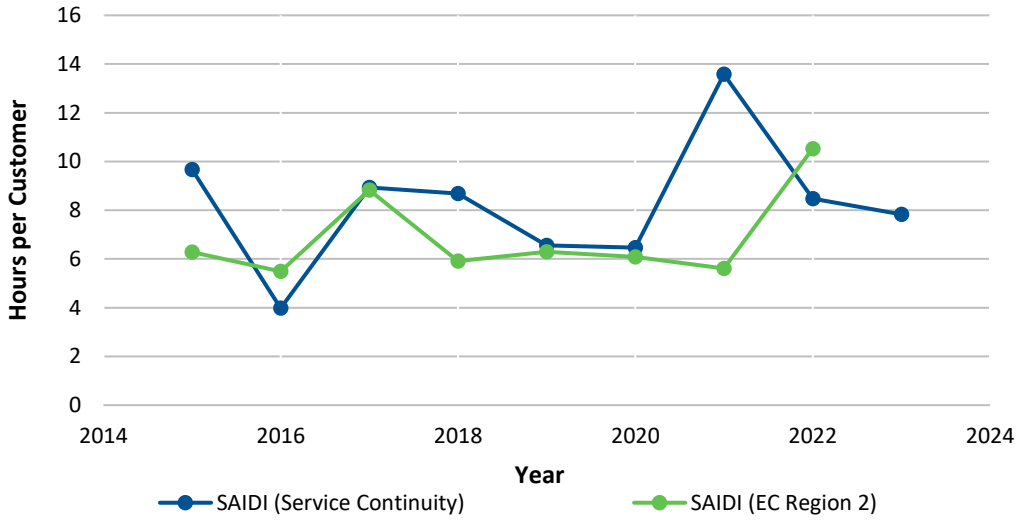


Chart 12: SAIDI Excluding Major Events – Labrador

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

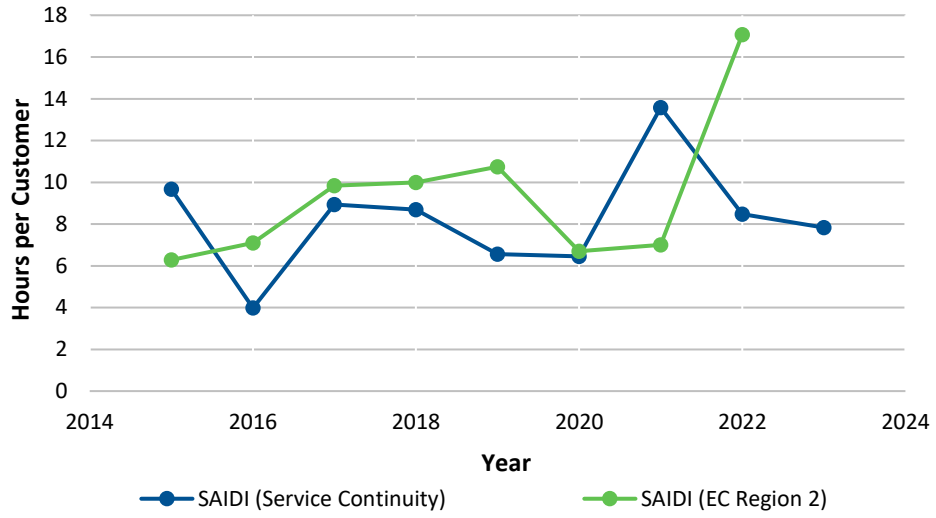


Chart 13: SAIDI Including Major Events – Labrador

4.2 Worst Performing Feeders

Hydro tracks its worst-performing feeders by SAIDI, SAIFI, and CHI[35] 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 2025 CBA, Hydro is proposing a project to improve the reliability performance of English Harbour West Line 1 ("EHW-L1"), based on the feeder's SAIDI, SAIFI, and CHI performance, as well as its condition. 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 EHW-L1. These feeders have been excluded from the

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

selection process for 2025 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 included in Schedule 7 for more detailed information.

In its 2024 CBA, Hydro 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. As the EHW-L1 feeder has also been selected for upgrade under the Renew Distribution Feeders Program; in 2025, Hydro has combined the scope of the two programs for completion under the Upgrade Worst-Performing Distribution Feeders Program (2025–2027). Hydro plans to resume its Renew Distribution Feeders Program in future CBAs.

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

Rank	Feeder	SAIDI
1	Black Tickle, Line 1	21.81
2	Farewell Head, Line 1	15.34
3	Bottom Waters, Line 1	13.50
4	Jackson's Arm, Line 2	13.05
5	Fleur-de-Lys, Line 1	11.36
6	Barachoix, Line 1	10.83
7	English Harbour, Line 1	10.01
8	L'Anse-au-Loup, Line 2	8.84
9	Barachoix, Line 4	8.76
10	St. Anthony, Line 1	8.59
	Hydro Average	3.84

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

Rank	Feeder	SAIFI
1	Happy Valley, Line 15	3.63
2	Bottom Waters, Line 1	3.43
3	L'Anse-au-Loup, Line 2	3.38
4	L'Anse-au-Loup, Line 1	3.18
5	English Harbour, Line 1	3.11
6	Barachoix, Line 4	2.92
7	Happy Valley, Line 7	2.87
8	Barachoix, Line 1	2.71
9	Happy Valley, Line 6	2.66
10	St. Anthony, Line 1	2.58
	Hydro Average	1.55

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

Rank	Feeder	CHI
1	English Harbour, Line 1	8,039
2	Happy Valley, Line 7	7,972
3	Barachoix, Line 4	7,108
4	Barachoix, Line 1	6,106
5	St. Anthony, Line 1	5,617
6	L'Anse-au-Loup, Line 2	5,434
7	Bottom Waters, Line 1	4,878
8	Kings Point, Line 1	4,203
9	Jackson's Arm, Line 2	3,824
10	Farewell Head, Line 1	3,729
	Hydro Average	1,121

5.0 2025 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 the 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.[36] 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 2025 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 2025 is provided in Table 6.[37] 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.

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

Table 6: Deferred 2025 Capital Proposals

Deferred Proposal	2025 Deferred Cost ($000)
Overhaul Fuel Oil Storage Tank 3 (2025) – Holyrood	1,937.2
Rehabilitate Access Roads (2025–2026) – Hinds Lake	1,150.0
Inspect Fuel Storage Tanks (2025) – McCallum	1,000.0
Unit 1 and Unit 2 Major Refurbishment (2025) – Bay d'Espoir	1,000.0
Install Plant Heating System (2025–2026) – Holyrood	901.3
Refurbish Draft Tube Deck - Phase 3 (2025) – Bay d'Espoir	855.0
Replace T1 (2025–2026) – Burgeo	824.9
Replace Rectifier Transformer (2025–2026) – Hinds Lake	510.0
Replace Controllers (2025–2028) – Granite Canal	500.0
Install Barrier Free Improvements – Washrooms (2025–2026)	428.0
Replace Telecontrol Building and Upgrade Equipment (2025–2026) – Daniel's Harbour	408.7
Upgrade Property (2025) – Bishop's Falls, Whitbourne, St. Anthony	370.0
Install Intelligent Electronic Devices Management Software (2025–2026)	350.0
Upgrade Line Depots (2025-2027) – Bay d'Espoir	320.4
Cat Arm Replace Diesel/Office/SF6 Roofs (2025–2026)	275.0
Install Fire Barriers between T10 and T12, T10 and T11 (2025–2026) – Bay d'Espoir	220.4
Overhaul Spherical Valves Unit 1 & 2 (2025) – Cat Arm	200.0
Penstock Level II Condition Assessment (2025) – Granite Canal	200.0
Replace Vibration System (2025) – Stephenville	200.0
Upgrade Cooling (2025–2026) – Hardwoods	200.0
Install Asset Health Monitoring System (2025–2026) – Cat Arm	150.0
Install Remote Fuel Monitoring on Gasoline Fuel Tank (2025–2026) – Granite Canal	150.0
Replace Annunciator Panel (2025–2026) Upper Salmon	150.0
Resurface Parking Lots and Roads (2025) – Bishop's Falls	150.0
Replace Overhead Crane – SC1/SC2 (2025–2026) – Wabush Terminal Station	120.0
Install Secondary Station Service Supply (2025–2027) – Holyrood	103.1
Inspect Fuel Storage Tanks (2025–2026) – Happy Valley	100.0
Install Dynamic Air Gap Monitoring System (2025–2026) – Hinds Lake	100.0
Refurbish Unit Control Panels Unit 2 (2025–2026) – Cat Arm	100.0
Resurface On-Site Roads (2025–2026) – Bay d'Espoir	100.0
Refurbish Office Energy Efficiency and HVAC Systems (2025–2026) – Deer Lake	75.0
Install New Station Service Feed (2025–2027) – Berry Hill	69.3
Upgrade Terminal Station for Mobile Substation (2025–2026) – Daniel's Harbour	60.0
Construct Fire Separation Walls between Transformers (2025–2026) – Happy Valley	54.8
Replace Powerhouse Septic System (2025–2026) – Upper Salmon	50.0
Replace Switchgear (2025–2026) – Grand Falls Terminal Station	50.0
Replace Switchgear Synchronous Condensers 1 and 2 (2025–2026) – Wabush Terminal Station	50.0
Upgrade Transformer Paralleling (2025–2026) – Stoney Brook	36.0
SCADA Additions – Distribution Equipment (2025–2026)	30.0
Total Deferred 2025 Capital Proposals	**13,549.1**

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. Hydro will also occasionally cancel a project, or a portion of a project, following Board approval if the justification, scope, or cost of a project has changed materially and is no longer required or requires additional consideration before re-proposing. A list of projects and programs originally planned for 2025 that have been cancelled is provided in Table 7.

Table 7: Cancelled 2025 Capital Proposals

Cancelled Proposal	2025 Cancelled Cost ($000)
Renew Distribution Feeders (2025–2026)	1,287.3
Replace Diesel Shop Building (2023–2025) – Bishop's Falls	889.9
Additions for Load Growth – Isolated Generation Stations (2025)	650.0
Replace Flow Measuring Devices – Units 1 to 7 (2025–2026) – Bay d'Espoir	350.0
Replace Station Service Transformer 1 (2025-2026) – Bay d'Espoir	200.0
Upgrade Station Access Road (2025) – Buchans, Western Avalon, Sunnyside, Deer Lake	200.0
Replace Unit Annunciator (2025–2026) – Hinds Lake	150.0
Upgrade Terminal Station for Mobile Substation (2025–2026) – Bear Cove	147.7
Construct Storage Building (2025–2026) – Springdale	135.0
Upgrade Outside Property (2025) – Deer Lake	129.0
Refurbish Control Building (2025–2026)	125.1
Site Physical Security Program (2025)	108.0
Level II Condition Assessment Powerhouse Roof (2025) – Hinds Lake	100.0
Refurbish Needle Valve Assembly Unit 2 and Purchase Spare Needle (2025–2026) – Cat Arm	100.0
Telecommunications Tower Condition Management (2025)	93.0
Replace Uninterruptible Power Supply Batteries (2025) – Hydro Place	75.0
Replace Cooling Water Pumps (2025–2026) – Cat Arm	50.0
Total Cancelled 2025 Capital Proposals	**4,790.0**

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. However, Hydro has not advanced any projects or programs for 2025.

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 2025, listed in Table 8, are a result of the extension of the operation of the Stephenville GT as per the 2024 Resource Plan. These assets 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.

Table 8: 2025 Capital Proposal Additions

Added Proposal	2025 Additional Cost ($000)
Inspect Fuel Tanks (2025) – Stephenville	676.9
Power Canal Public Safety Boom (2025–2026) – Upper Salmon	463.8
Upgrade Work Protection Code Application (2025)	452.0
Replace GPS Clocks (2025)	448.3
Replace Roof (2025) – Grey River	390.8
Install Electric Vehicle Chargers (2025–2026) – Hydro Sites	368.0
Purchase Surveying Software and Equipment (2025)	316.4
Upgrade Energy Management System (2025–2026)	284.4
Replace Human Machine Interface (2025) – Stephenville	277.0
Implement SCADA Points Application (2025–2026)	241.9
Update Flame Scanners - Unit 3 (2025) – Holyrood	140.6
Replace 250 Vdc Battery Bank (2025–2026) – Stephenville	73.0
Total 2025 Capital Proposal Additions	**4,133.1**

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 the 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,[38] 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 2025 CBA. Hydro recognizes the magnitude of the 2025 proposed capital expenditures in the sensitive customer environment; there have been 56 projects deferred or cancelled as part of this exercise, resulting in a $18.3 reduction in the overall capital budget. Schedule 5, Section 2.0 of the CBA contains a list of the programs and projects and revised budgets.

[38] "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[39] within its project budgets based on the level of confidence in individual component costs, resulting in project contingencies generally ranging from 10% to 15%.[40]

To determine the accuracy range of Hydro's capital estimates, in 2023, Hydro completed statistical analysis of project variances based on available data for projects proposed and completed since 2014.[41] Hydro's analysis has determined that its average variance is -4%,[42] with a standard deviation of approximately +/-38%. Therefore, Hydro's expected estimated accuracy range is approximately +30%/-40%.

[39] The Association for Advancement of Cost Engineering defines a 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 the aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience."
[40] Prior to the 2019 CBA, Hydro generally included 20% contingency in its capital budget estimates.
[41] Variance is equal to project/program budget minus project/program actual expenditure for projects completed from 2014 to 2022, inclusive.
[42] Programs or projects 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 2025 Capital Budget

The 2025 CBA contains 110 projects and programs,[43] as outlined in Appendix A. The total planned 2025 capital expenditure for which Hydro is seeking approval in its 2025 CBA is $135.7 million.[44] A breakdown and analysis of key drivers are provided in the charts herein.

Chart 14 shows the 2025 Capital Budget summary by major asset category.

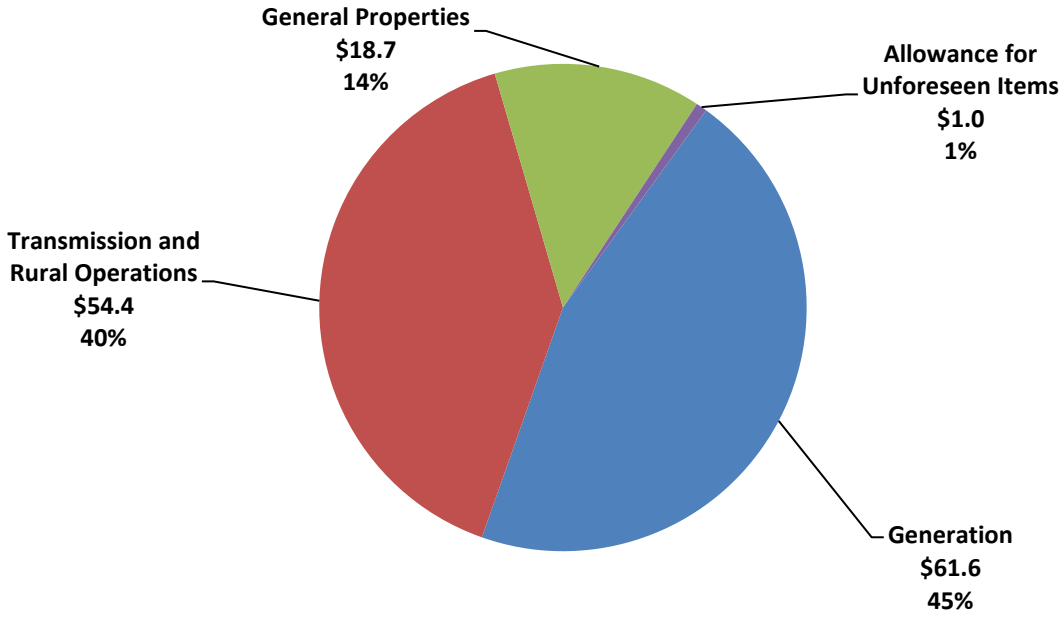


Chart 14: 2025 Capital Budget Summary by Major Asset Category ($ Millions)

The majority of 2025 expenditures are in the areas of Generation and Transmission and Rural Operations. This is primarily a reflection of projects to maintain the reliable operation of the Holyrood TGS, projects to address load growth in Labrador West, and the continuation of Hydro's asset renewal projects and programs.

[43] Including projects less than $750,000.
[44] The 2025 CBA also includes front-end engineering and design expenditures, necessary to support the development of proposals, on a number of projects. Hydro will not capitalize on such costs related to a project if the project does not receive Board approval.

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

Chart 15 shows the 2025 Capital Budget summary by investment classification.

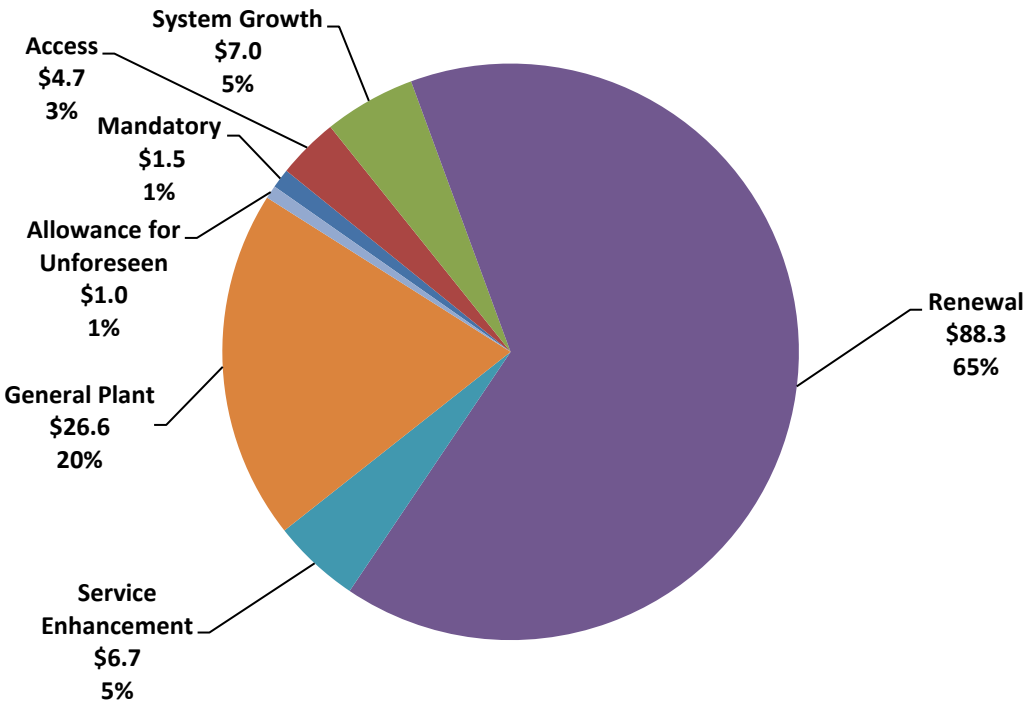


Chart 15: 2025 Capital Budget Summary by Investment Classification ($ Millions)[45]

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, driven primarily by the continuation of Hydro's projects to purchase mobile equipment and for renewal of light- and heavy-duty vehicles.

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

[45] Numbers may not add due to rounding.

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 about two-thirds of Hydro's total proposed 2025 capital investment, totalling $88.3 million. Hydro's proposed 2025 renewal investment by asset category is provided in Chart 16.

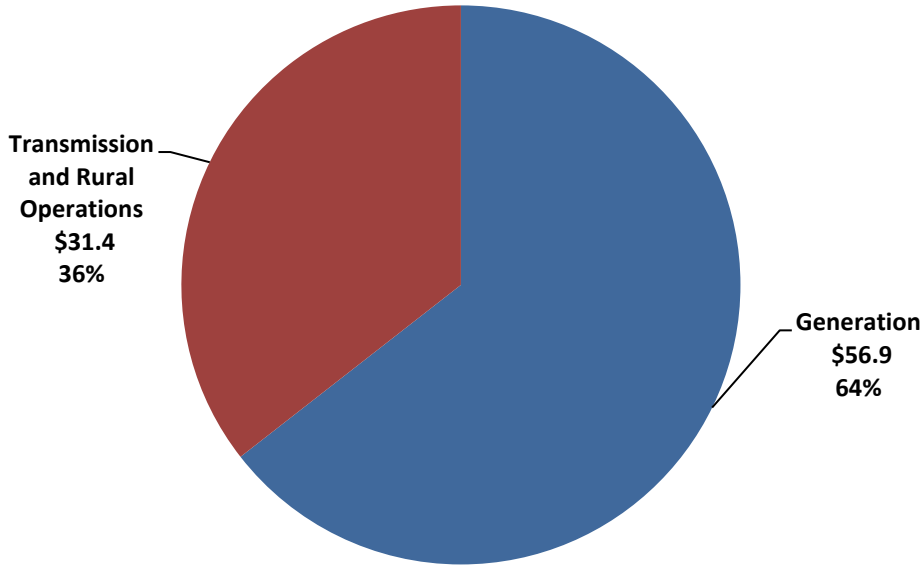


Chart 16: 2025 Renewal Investment by Asset Category ($ Millions)

6.1.1 Generation

Generation renewal investment for 2025 is comprised of investments in Hydro's hydraulic plant, thermal plant, and gas turbine assets. Hydro's proposed generation-related renewal expenditures account for nearly two-thirds of its total proposed 2025 renewal expenditures, totalling $56.9 million.

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 $26.7 million of Hydro's overall proposed capital expenditures for 2025. Key drivers of hydraulic generation renewal investment include the rewind of the generator stator at the

Hinds Lake Hydroelectric Generating Station, the "Overhaul Hydraulic Units Program," and the refurbishment of the control structure at Ebbegunbaeg.

Thermal plant renewal associated with sustaining capital investment at the Holyrood TGS accounts for $28.7 million in 2025, representing half of Hydro's planned spending in generation renewal programs 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 3 turbine and valves and continuation of the "Perform Boiler Condition Assessment and Miscellaneous Upgrades Program" and "Thermal In-Service Failures Program." Further discussion of Hydro's thermal plant investments for 2025 is provided in the Holyrood Thermal Generating Station Overview, included as Schedule 3 of this application.

The remainder of Hydro's generation assets consist of four gas turbines. Gas turbine renewal accounts for $1.5 million in 2025, and includes the inspection of fuel tanks, work associated with the life extension of the Stephenville GT, and continuation of the "Gas Turbine In-Service Failures Program."

6.1.2 Transmission and Rural Operations

Hydro maintains over 4,400 kilometres 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, Transmission and Rural Operations ("TRO") require considerable capital expenditures to maintain these assets. Approximately 36%, or $31.4 million, of Hydro's total proposed 2025 renewal expenditures are allocated to this category.

Hydro's TRO renewal expenditures planned for 2025 are driven primarily by the continuation of programs for the renewal of wood pole line management and "Distribution System In-Service Failures, Miscellaneous Upgrades and Street Lights."

Hydro's 2025 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.

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

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 $26.6 million account for approximately 20% of Hydro's proposed 2025 capital program, a decrease from the 2024 CBA where this investment class accounted for approximately 22% of total expenditures. Key drivers of investment are detailed below, with a breakdown of Hydro's proposed 2025 general plant investment by asset category provided in Chart 17.

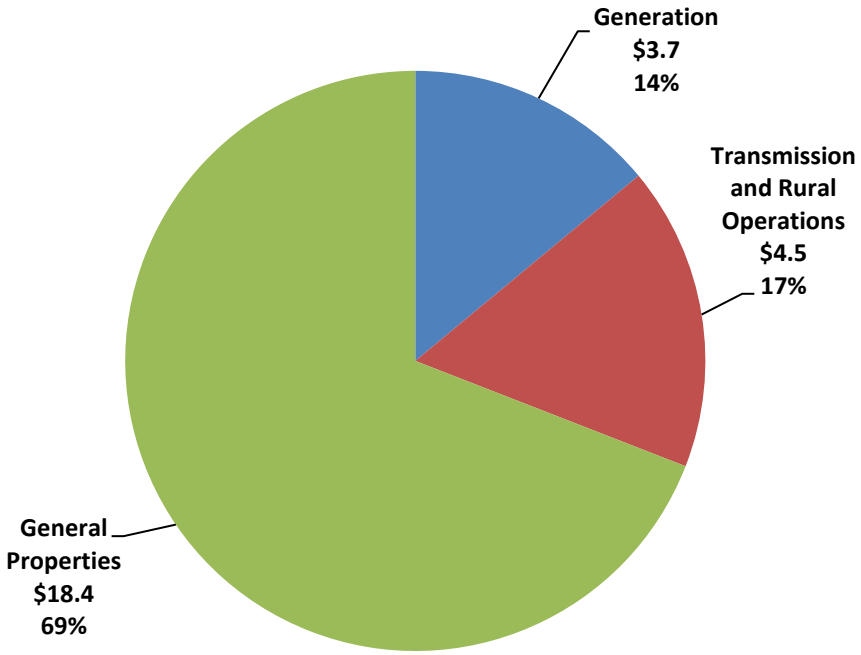


Chart 17: 2025 General Plant Investment by Asset Category ($ Millions)

6.2.1 General Properties

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

Approximately 40% of the planned spend in this area is for the continuation of Hydro's light- and heavy-duty vehicle program, which ensures vehicles are safe and fully operational. Hydro has completed a field verification of the light-duty vehicle fleet and, while reviewing industry standards, has determined that its replacement criteria and the size of its fleet remain appropriate at this time.

The remainder of Hydro's proposed 2025 general properties investment includes Telecontrol and Information System expenditures. Telecontrol expenditures include the replacement of interconnect microwave radios and power line carriers and Hydro's programs to replace battery banks and network communications equipment. 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 of the operation of the electrical system.

6.2.2 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 continuation of the previously approved projects for the refurbishment of the powerhouse and outbuildings at the Holyrood TGS and the replacement of the roof of Powerhouse 1 at Bay d'Espoir.

TRO-related general plant investment includes the continuation of projects such as those previously approved to install fire protection at the Voisey's Bay Terminal Station and the refurbishment of the control buildings at Grandy Brook and Doyles Terminal Stations.

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 5% of Hydro's total proposed 2025 capital investment, totalling $7.0 million in 2025.

6.4 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. In 2025, $6.7 million, or about 5%, of planned capital expenditures are related to service enhancement. Hydro's proposed 2025 service enhancements investment by asset category is provided in Chart 18.

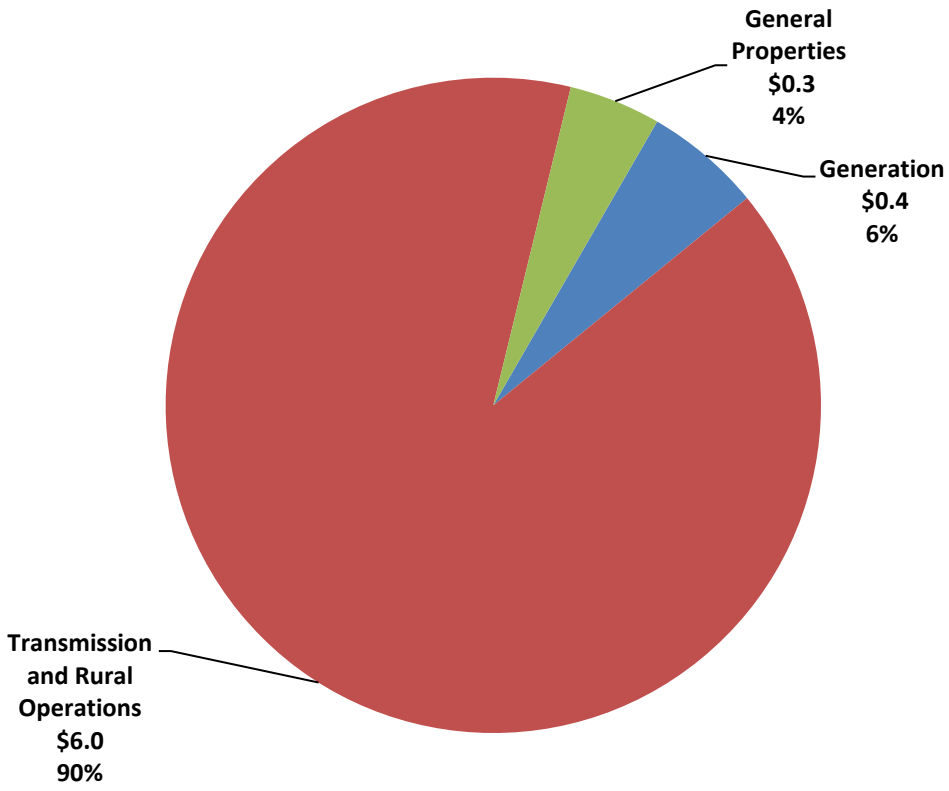


Chart 18: 2025 Service Enhancement Investment by Asset Category ($ Millions)

Primary drivers of service enhancement investment in 2025 include the continuation of Hydro's program to upgrade its worst-performing distribution feeders[46] and the continuation of the previously approved project to replace Hydro's metering system.

6.5 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 2025 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 customer requests to relocate services. Hydro's proposed access capital expenditures account for 3% of Hydro's total proposed 2025 capital investment, totalling $4.7 million in 2025.[47]

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 1% of Hydro's proposed capital investment. In this CBA, mandatory projects include Hydro's project to inspect fuel tanks at the Holyrood CT and the program to purchase meters and metering equipment. Drivers of mandatory investment in 2025 also include the continuation of Hydro's previously approved 2024 terminal station lighting project, required to address components suspected to contain PCBs.[48]

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 2025 CBA includes the following specifically assigned projects:

[46] In 2025, Hydro has combined the scope of the Renew Distribution Feeders Program and the Upgrade Worst-Performing Distribution Feeders Program for completion under the Upgrade Worst-Performing Distribution Feeders (2025–2027) Program, as discussed in Section 4.2.
[47] 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.
[48] Hydro is required under Canadian environmental regulations to remove and dispose of all equipment containing greater than 50 parts per million of PCBs by December 31, 2025.

- Continuation of a project to install fire protection at the Voisey's Bay Nickel Terminal Station, specifically assigned to Vale Newfoundland and Labrador Limited ("Vale"), which was previously approved in Hydro's 2024 CBA. The total estimated specifically assigned costs for Vale in 2025 is approximately $599,000.

- Continuation of Hydro's "Replace Protective Relays Program," with replacement of protective relays for Transformer T1 and T2 in the Come By Chance Terminal Station, specifically assigned to Braya Renewable Fuels ("Braya"). The total estimated specifically assigned costs for Braya in 2025 is approximately $387,600.

- A portion of Hydro's "Renew Circuit Breakers Program" and "Replace Disconnects Program," with assets specifically assigned to Tacora Resources Inc. ("Tacora"), including the replacement of B4L34 and B4L34-1 in the Wabush Terminal Station. The total estimated specifically assigned costs for Tacora in 2025 is $56,400.

- A portion of Hydro's "Renew Circuit Breakers Program" to refurbish B2L64 in the Buchans Terminal Station, specifically assigned to Teck Resources Limited ("Teck"). The total estimated specifically assigned costs for Teck in 2025 is $10,000.

Specifically assigned asset renewals within Hydro's Five-Year Capital Plan (2025–2029) are detailed in Table 9.

Table 9: Specifically Assigned Capital Work

Customer	Specifically Assigned Work	In-Service Year	Program or Project	2025 Specifically Assigned Cost ($000)	Beyond 2025 Specifically Assigned Cost ($000)	Total Remaining Contribution
Vale	VBNTS Fire Suppression System Addition	2025	Install Fire Protection in 230kV Terminal Stations (2024–2025) – Voisey's Bay Nickel	$599.0	-	$599.0
Braya	CBC T1 Protection Relay Replacement	2025	Replace Protective Relays - Various (2024–25)	$193.8	-	$193.8
Braya	CBC T2 Protection Relay Replacement	2025	Replace Protective Relays - Various (2024–25)	$193.8	-	$193.8
Tacora	WABTS B4L34 Replacement	2026	Renew Circuit Breakers (2025–2026)	$47.0	$635.8	$682.8
Teck	BUCTS B2L64 Overhaul	2026	Renew Circuit Breakers (2025–2026)	$10.0	$65.9	$75.9
Tacora	WABTS B4L34-1 Replacement	2026	Replace Disconnects (2025–2026)	$9.4	$71.4	$80.8
Tacora	WABTS B4L35 Replacement	2027	Renew Circuit Breakers (2026–2027)	-	$682.8	$682.8
IOC[49]	WABTS L6 Protection	2027	Replace Protective Relays – Various (2026–27)	-	$150.0	$150.0
IOC	WABTS B4L6 Replacement	2027	Renew Circuit Breakers (2026–2027)	-	$682.8	$682.8

6.8 Leasing Costs

There are no capital leasing costs contained in the 2025 CBA.

6.9 Rate Impact Summary

On a *pro-forma* basis, Hydro's 2025 and 2026 total regulated revenue requirement is estimated to increase by approximately $4.0 million and $15.6 million,[50] respectively, as a result of the capital

[49] Iron Ore Company of Canada ("IOC").
[50] These amounts do not reflect any reduction that may occur as a result of asset retirements.

programs and projects proposed for 2025. Such a revenue requirement increase would represent an increase of 0.6% and 2.4% in 2025 and 2026, respectively, relative to Hydro's 2019 Test Year. This assumes the deferral of $1.9 million of depreciation in the Holyrood TGS Accelerated Depreciation Deferral in 2025[51] whereas, it is assumed that 2026 is a test year that includes $5.6 million accelerated depreciation on Holyrood assets.

The total forecast revenue requirement impact from the 2025 Capital Budget for rural areas is approximately $2.5 million in 2026. Based upon the 2019 Test Year Cost of Service Revenue to Cost ratios, is it estimated that rural customers would contribute $1.1 million towards this increase, with the remainder allocated to the rural deficit and primarily 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[52] street lights where Hydro expects savings to be realized).

Hydro's projected rate impacts as a result of programs and projects proposed in the 2025 CBA, by system, are detailed in Table 10. As a result of the finalization of the Government's rate mitigation plan, announced on May 16, 2024, rate increases at the wholesale level on the Island Interconnected System will be limited to target domestic rate increases of 2.25% annually, attributable to Hydro's costs, up to and including 2030, regardless of the increase in revenue requirement.

Table 10: Projected Wholesale Rate Impact by System (%)

System	2025	2026
Island Interconnected System	0.6	2.5
Labrador Interconnected – Rural	0.5	1.4
Labrador Industrial – Regulated	2.4	6.4
Labrador Industrial – Total Billings	0.2	0.6

[51] Due to the extension of the Holyrood TGS through the Bridging Period, Hydro submitted an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account. The Board approved the extension of the account and related amendments in Board Order No. P.U. 1(2024). Hydro was also directed to file a report on the account in its next general rate application.
[52] Light-emitting diode ("LED").

Hydro's ten-year historical Island Interconnected Wholesale Electricity Rate and Labrador Interconnected Electricity Rate for the years 2014–2023 are presented in Chart 19.

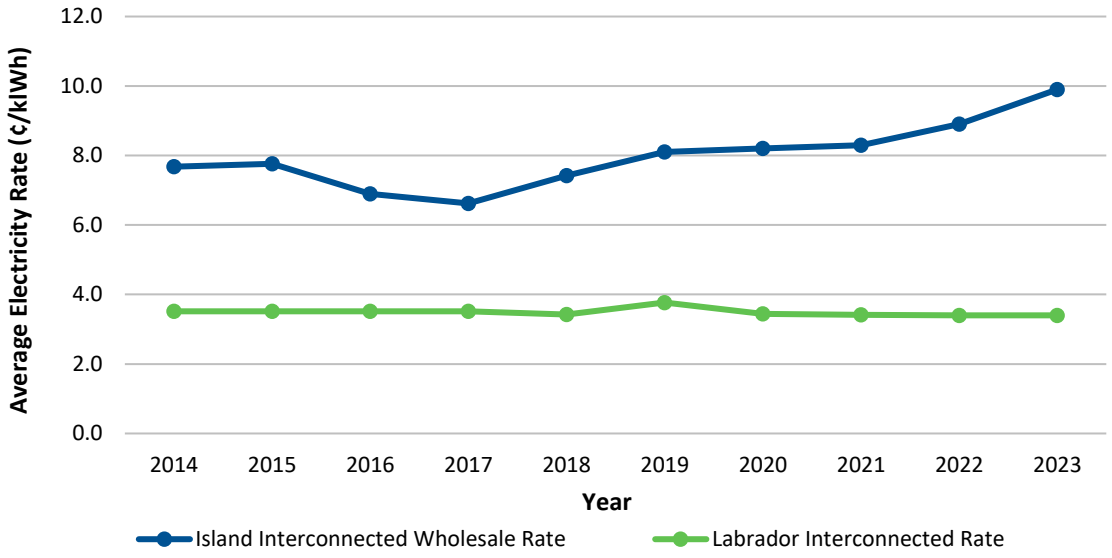


Chart 19: Ten-Year Historical Electricity Rates (¢/kWh)

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.[53] Within the Guidelines, the Board has provided guidance for evaluating risk and mitigation, as well as prioritization.[54] The matrix model scores programs and projects based on reliability, safety, or environmental risk, based on a judgement of the 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 2025 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

[53] 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.
[54] 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.

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. Appendix G provides the prioritization of programs and projects proposed in the 2025 CBA by risk mitigated per $1 million and also includes a prioritization of programs and projects proposed on the basis of risk mitigated.

8.0 Conclusion

Hydro is requesting approval for $135.7 million of capital investment in its 2025 CBA. Hydro recognizes that its 2025 Capital Budget represents a material increase in planned capital expenditure when compared to recent years, driven primarily by the need for increased investment in asset renewal, and increasing costs associated with a period of sustained high inflation in recent years. 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 proposes targeted, service-enhancement investments to address specific issues impacting system-level or localized reliability.

Hydro has carefully considered its capital investment portfolio for 2025, ensuring its proposed projects and programs represent those that are necessary to support the safe, reliable operation of Hydro's system in an environmentally responsible manner. In doing so, Hydro has deferred or cancelled over $18 million in capital investment in the interest of balancing cost and reliability.

While Hydro's expenditures will increase, in part, due to the infrastructure required to meet growing electricity needs, the impacts on customers will be limited as a result of the Government's rate mitigation plan; therefore, the increase will not create an undue burden on customers.

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 2025 CBA are prudent and necessary for the safe and reliable operation of the electrical system.

Appendix A

2025 Capital Budget by Investment Classification, Major and Minor Asset Category, Materiality, and Programs and Projects



Newfoundland and Labrador Hydro
2025 Capital Budget Application
Summary by Investment Classification[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Access	-	4,662.5	-	**4,662.5**
Allowance for Unforeseen	-	1,000.0	-	**1,000.0**
General Plant	9,854.5	26,633.3	9,248.9	**45,736.7**
Mandatory	91.6	1,483.2	278.4	**1,853.2**
Renewal	20,781.4	88,268.7	32,997.1	**142,047.1**
Service Enhancement	1,558.3	6,691.0	6,671.8	**14,921.1**
System Growth	10,759.6	6,974.1	789.7	**18,523.4**
Total Capital Budget	**43,045.4**	**135,712.8**	**49,985.9**	**228,744.0**

[1] Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Summary by Major and Minor Asset Category[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
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**
General Properties				
Administration	-	542.6	-	**542.6**
Information Systems	-	3,358.0	781.3	**4,139.3**
Telecontrol	2,302.3	5,182.2	132.4	**7,616.9**
Tools and Equipment	-	1,715.5	-	**1,715.5**
Transportation	5,371.8	7,536.7	4,831.4	**17,739.9**
Properties	-	368.0	288.2	**656.1**
Total General Properties	**7,674.1**	**18,702.9**	**6,033.2**	**32,410.2**
Generation				
Gas Turbines	191.4	2,520.7	296.9	**3,009.0**
Hydraulic Plant	14,103.1	29,378.8	14,099.9	**57,581.9**
Thermal Plant	1,082.7	29,715.5	1,295.6	**32,093.8**
Total Generation	**15,377.2**	**61,615.0**	**15,692.5**	**92,684.7**
Transmission and Rural Operations				
Distribution	2,444.8	17,542.4	6,207.2	**26,194.4**
Generation	1,528.9	4,502.2	9,707.7	**15,738.8**
Metering	302.6	660.6	513.7	**1,476.9**
Terminal Stations	14,054.8	22,927.7	8,921.1	**45,903.6**
Tools and Equipment	240.9	3,415.1	2,681.1	**6,337.1**
Transmission	-	5,346.9	229.3	**5,576.2**
Properties	1,422.1	-	-	**1,422.1**
Total Transmission and Rural Operations	**19,994.1**	**54,394.8**	**28,260.2**	**102,649.1**
Total Capital Budget	**43,045.4**	**135,712.8**	**49,985.9**	**228,744.0**

[1] Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Summary by Materiality[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Over $5 Million				
General Plant	1,479.1	6,863.4	4,831.4	**13,173.9**
Renewal	12,726.8	32,976.5	15,500.9	**61,204.2**
Service Enhancement	-	2,678.9	6,207.2	**8,886.1**
System Growth	10,759.6	6,974.1	789.7	**18,523.4**
Over $5 Million Total	**24,965.5**	**49,492.9**	**27,329.2**	**101,787.6**
$1 Million to $5 Million				
Access	-	4,662.5	-	**4,662.5**
Allowance for Unforeseen	-	1,000.0	-	**1,000.0**
General Plant	7,826.3	8,798.4	2,674.0	**19,298.8**
Renewal	6,104.5	47,673.4	15,114.3	**68,892.2**
Service Enhancement	1,064.3	3,108.7	229.3	**4,402.3**
$1 Million to $5 Million Total	**14,995.1**	**65,243.0**	**18,017.7**	**98,255.8**
$750,000 to $1 Million				
General Plant	328.1	3,369.6	456.5	**4,154.2**
Renewal	154.9	2,406.7	-	**2,561.6**
Service Enhancement	302.6	214.4	235.3	**752.3**
$750,000 to $1 Million Total	**785.6**	**5,990.8**	**691.8**	**7,468.2**
Under $750,000				
General Plant	221.0	7,601.8	1,287.0	**9,109.8**
Mandatory	91.6	1,483.2	278.4	**1,853.2**
Renewal	1,795.2	5,212.1	2,381.8	**9,389.1**
Service Enhancement	191.4	689.0	-	**880.4**
Under $750,000 Total	**2,299.2**	**14,986.1**	**3,947.3**	**21,232.5**
Total Capital Budget	**43,045.4**	**135,712.8**	**49,985.9**	**228,744.0**

[1] Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Summary by Program or Project[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Program				
Access	-	4,662.5	-	**4,662.5**
Allowance for Unforeseen	-	1,000.0	-	**1,000.0**
General Plant	5,588.7	16,345.3	7,982.1	**29,916.1**
Mandatory	-	446.2	278.4	**724.6**
Renewal	5,607.2	63,164.9	16,464.2	**85,236.3**
Service Enhancement	1,064.3	5,209.4	6,207.2	**12,480.9**
Program Total	**12,260.2**	**90,828.4**	**30,931.9**	**134,020.4**
Project				
General Plant	4,265.8	10,288.0	1,266.8	**15,820.5**
Mandatory	91.6	1,037.0	-	**1,128.6**
Renewal	15,174.2	25,103.7	16,532.9	**56,810.8**
Service Enhancement	494.0	1,481.6	464.6	**2,440.2**
System Growth	10,759.6	6,974.1	789.7	**18,523.4**
Project Total	**30,785.2**	**44,884.4**	**19,054.0**	**94,723.6**
Total Capital Budget	**43,045.4**	**135,712.8**	**49,985.9**	**228,744.0**

[1] Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Detailed Breakdown By Investment Classification[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Access				
Provide Service Extensions (2025)	-	4,662.5	-	**4,662.5**
Access Total	**-**	**4,662.5**	**-**	**4,662.5**
Allowance for Unforeseen				
Allowance for Unforeseen Items (2025)	-	1,000.0	-	**1,000.0**
Allowance for Unforeseen Total	**-**	**1,000.0**	**-**	**1,000.0**
General Plant				
Implement SCADA Points Application (2025–2026)	-	241.9	143.4	**385.3**
Install CCTV Systems (2025)	-	440.1	-	**440.1**
Install Electric Vehicle Chargers (2025–2026) - Hydro Sites	-	368.0	288.2	**656.1**
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	53.8	599.0	-	**652.8**
Install Fire Protection in 230 kV Stations (2025–2026) - Come by Chance	-	51.7	534.5	**586.2**
Install Power Canal Public Safety Boom (2025) - Upper Salmon	-	463.8	-	**463.8**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2025)	-	178.5	-	**178.5**
Perform Level 2 Condition Assessment - Powerhouse Slope (2025) - Cat Arm	-	169.4	-	**169.4**
Perform Security Improvements (2025)	-	160.7	-	**160.7**
Perform Software Upgrades and Minor Enhancements (2025)	-	808.7	-	**808.7**
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024–2026) - Happy Valley-Goose Bay	24.0	841.8	7.1	**872.9**
Purchase Mobile Devices (2025)	-	160.2	-	**160.2**
Purchase Personal Computers (2025)	-	575.6	-	**575.6**
Purchase Surveying Software and Equipment (2025)	-	316.4	-	**316.4**
Purchase Tools and Equipment (2025)	-	1,399.1	-	**1,399.1**
Refurbish Control Building (2024–2025) - Grandy Brook and Doyles	109.4	444.7	-	**554.1**
Refurbish Meteorological Stations (2025)	-	167.8	-	**167.8**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025) - Holyrood	156.2	1,039.4	-	**1,195.6**
Replace 48 V Battery Banks and Chargers (2025)	-	559.1	-	**559.1**
Replace Air Conditioning Unit - Powerhouse 1 (2024–2025) - Bay d'Espoir	57.8	231.2	-	**289.0**
Replace Diesel Shop Building (2023–2025) - Bishop's Falls	1,422.1	-	-	**1,422.1**
Replace GPS Clocks (2025–2026)	-	448.3	132.4	**580.7**
Replace Interconnect Microwave Radios (2025)	-	1,103.0	-	**1,103.0**
Replace Light- and Heavy-Duty Vehicles (2023–2025)	3,892.7	673.3	-	**4,566.0**
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 (2025–2027)	-	2,714.6	4,823.0	**7,537.6**
Replace MDR8000 Microwave Radios (2024–2025)	953.5	500.3	-	**1,453.8**
Replace Mobile Equipment (2024–2025)	216.9	599.7	-	**816.6**
Replace Mobile Equipment (2025–2027)	-	1,973.6	2,674.0	**4,647.6**
Replace Network Communications Equipment (2025)	-	413.2	-	**413.2**
Replace Peripheral Infrastructure (2025)	-	205.4	-	**205.4**
Replace Power Line Carrier (2024-2025) - TL247	87.2	667.4	-	**754.6**
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**
Telecommunications In-Service Failures (2025)	-	94.1	-	**94.1**
Update Cyber Security Infrastructure (2025)	-	115.6	-	**115.6**
Upgrade Core OT Infrastructure (2025)	-	674.3	-	**674.3**
Upgrade Energy Management System (2025–2026)	-	284.4	188.5	**472.9**
Upgrade Remote Terminal Units (2025)	-	238.4	-	**238.4**
Upgrade Work Protection Code Application (2025–2026)	-	452.0	449.4	**901.4**
General Plant Total	**9,854.5**	**26,633.3**	**9,248.9**	**45,736.7**

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Detailed Breakdown By Investment Classification[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Mandatory				
Inspect Fuel Tanks (2025) - Holyrood	-	608.0	-	**608.0**
Purchase Meters and Metering Equipment (2025–2026)	-	446.2	278.4	**724.6**
Upgrade Station Lighting (2024–2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon	91.6	429.0	-	**520.6**
Mandatory Total	**91.6**	**1,483.2**	**278.4**	**1,853.2**
Renewal				
Diesel Genset Replacement Program (2023–2025)	993.1	1,415.1	-	**2,408.2**
Diesel In-Service Failures (2025)	-	800.0	-	**800.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2025)	-	6,397.0	-	**6,397.0**
Flatten Downstream Slope (2024–2025) - Hinds Lake	276.1	2,953.4	-	**3,229.5**
Gas Turbine In-Service Failures (2025)	-	500.0	-	**500.0**
Hydraulic In-Service Failures (2025)	-	2,000.0	-	**2,000.0**
Inspect Fuel Tanks (2025) - Stephenville	-	676.9	-	**676.9**
Install Breaker Failure Protection (2025–2027) - Holyrood	-	177.8	487.4	**665.2**
Overhaul Diesel Units (2025)	-	1,000.0	-	**1,000.0**
Overhaul Hydraulic Units (2025)	-	4,972.4	-	**4,972.4**
Overhaul Major Pumps (2025) - Holyrood	-	1,101.9	-	**1,101.9**
Overhaul Turbine and Valves - Unit 3 (2025) - Holyrood	-	15,975.9	-	**15,975.9**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood	-	4,905.8	-	**4,905.8**
Perform Level 2 Condition Assessment - Intake 4 and Unit 7 Draft Tube (2025) - Bay d'Espoir	-	471.5	-	**471.5**
Perform Level 2 Condition Assessment - Stage 1 and 2 Cooling Water Sump Structures (2025) - Holyrood	-	891.9	-	**891.9**
Perform Major Inspection - Synchronous Condenser 2 (2025–2026) - Wabush	-	22.8	572.8	**595.6**
Refurbish Control Structure (2021–2025) - Ebbegunbaeg	12,726.8	4,952.2	-	**17,679.0**
Refurbish Intake 1 (2024–2025) - Bay d'Espoir	272.1	3,071.9	-	**3,344.0**
Refurbish Intake 2 (2025–2026) - Bay d'Espoir	-	284.4	3,069.4	**3,353.8**
Refurbish Marine Terminal (2025–2026) - Holyrood	-	1,190.8	1,295.6	**2,486.5**
Refurbish Surge Tank 1 (2024–2025) - Bay d'Espoir	175.8	2,111.4	-	**2,287.2**
Renew Circuit Breakers (2024–2025)	183.9	2,120.1	-	**2,304.0**
Renew Circuit Breakers (2025–2026)	-	129.7	1,021.7	**1,151.4**
Renew Distribution Feeders (2024–2025)	1,287.3	1,245.1	-	**2,532.4**
Replace 250 Vdc Battery Bank (2025–2026) - Stephenville	-	73.0	296.9	**369.9**
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 Circuit Breaker Reclosing Controllers (2024–2025) - TL247	112.4	215.8	-	**328.2**
Replace Circuit Breaker Reclosing Controllers (2025–2026) - Cow Head and Massey Drive	-	104.6	164.3	**269.0**
Replace Diesel Gensets (2024–2026)	535.8	478.0	3,902.3	**4,916.1**
Replace Diesel Gensets (2025–2027)	-	418.2	5,805.4	**6,223.6**
Replace Disconnects (2024–2025)	127.4	1,358.1	-	**1,485.5**
Replace Disconnects (2025–2026)	-	145.3	1,245.5	**1,390.8**
Replace Emergency Diesel Genset (2025–2027) - Cat Arm	-	266.2	1,335.0	**1,601.3**
Replace Human-Machine Interface (2025) - Stephenville	-	277.0	-	**277.0**
Replace Instrument Transformers (2024–2025)	154.9	714.8	-	**869.7**
Replace Instrument Transformers (2025–2026)	-	112.5	356.4	**468.9**
Replace Protective Relays (2024–2025)	1,388.4	2,050.7	-	**3,439.1**
Replace Protective Relays (2025–2026)	-	668.6	2,070.9	**2,739.5**
Replace Roof (2025) - Grey River	-	390.8	-	**390.8**

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Detailed Breakdown By Investment Classification[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Replace Terminal Station Battery Banks and Chargers (2024–2025)	71.8	120.9	-	**192.7**
Replace Terminal Station Battery Banks and Chargers (2025–2026)	-	123.2	315.3	**438.5**
Rewind Stator (2025–2026) - Hinds Lake	-	5,233.2	9,695.5	**14,928.7**
Terminal Station In-Service Failures (2025)	-	2,500.0	-	**2,500.0**
Thermal In-Service Failures (2025)	-	3,900.0	-	**3,900.0**
Transmission In-Service Failures (2025)	-	184.3	-	**184.3**
Update Flame Scanners - Unit 3 (2025) - Holyrood	-	140.6	-	**140.6**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon	137.0	156.9	-	**293.9**
Upgrade Data Alarm Systems (2025–2026) - Hardwoods	-	184.0	188.7	**372.7**
Upgrade DCS Hardware - Units 1 and 2 (2024–2025) - Holyrood	195.2	277.3	-	**472.5**
Upgrade Distribution - Terminal Station 2 (2024–2025) - Bay d'Espoir	93.2	331.5	-	**424.7**
Upgrade Power Transformers (2024–2025)	864.6	2,711.3	-	**3,575.9**
Upgrade Power Transformers (2025–2026)	-	811.9	1,173.9	**1,985.8**
Upgrade Unit 1 Control System (2024–2025) - Holyrood	468.3	184.3	-	**652.6**
Upgrade UPS 1 and 2 (2024–2025) - Holyrood	263.0	107.6	-	**370.6**
Wood Pole Line Management (2025)	-	4,281.3	-	**4,281.3**
Renewal Total	**20,781.4**	**88,268.7**	**32,997.1**	**142,047.1**
Service Enhancement				
Automate Bulk Metering (2024–2026)	302.6	214.4	235.3	**752.3**
Construct Maintenance Platform (2024–2025) - Holyrood	130.5	228.7	-	**359.2**
Install Mid-Span Structures - TL220 (2025–2026)	-	881.3	229.3	**1,110.6**
Perform Minor Telecommunications Enhancements (2025)	-	99.8	-	**99.8**
Remove Safety Hazards (2025)	-	203.3	-	**203.3**
Upgrade Instrumentation (2024–2025) - Hardwoods	60.9	157.2	-	**218.1**
Upgrade Worst-Performing Distribution Feeders (2024–2025)	1,064.3	2,227.4	-	**3,291.7**
Upgrade Worst-Performing Distribution Feeders (2025–2027)	-	2,678.9	6,207.2	**8,886.1**
Service Enhancement Total	**1,558.3**	**6,691.0**	**6,671.8**	**14,921.1**
System Growth				
Additions for Load - Substation Upgrades - Wabush	10,179.6	514.5	-	**10,694.1**
Additions for Load Growth - Upgrade Transformer Capacity (2023–2024) - Jean Lake	580.0	6,459.6	789.7	**7,829.3**
System Growth Total	**10,759.6**	**6,974.1**	**789.7**	**18,523.4**
Total Capital Budget	**43,045.4**	**135,712.8**	**49,985.9**	**228,744.0**

[1] Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Detailed Breakdown By Major and Minor Asset Category[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Allowance for Unforeseen Items				
Allowance for Unforeseen Items				
Allowance for Unforeseen Items (2025)	-	1,000.0	-	**1,000.0**
Subtotal Allowance for Unforeseen Items	**-**	**1,000.0**	**-**	**1,000.0**
Total Allowance for Unforeseen Items	**-**	**1,000.0**	**-**	**1,000.0**
General Properties				
Administration				
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2025)	-	178.5	-	**178.5**
Perform Security Improvements (2025)	-	160.7	-	**160.7**
Remove Safety Hazards (2025)	-	203.3	-	**203.3**
Subtotal Administration	**-**	**542.6**	**-**	**542.6**
Information Systems				
Implement SCADA Points Application (2025–2026)	-	241.9	143.4	**385.3**
Perform Software Upgrades and Minor Enhancements (2025)	-	808.7	-	**808.7**
Purchase Personal Computers (2025)	-	575.6	-	**575.6**
Replace Peripheral Infrastructure (2025)	-	205.4	-	**205.4**
Update Cyber Security Infrastructure (2025)	-	115.6	-	**115.6**
Upgrade Core OT Infrastructure (2025)	-	674.3	-	**674.3**
Upgrade Energy Management System (2025–2026)	-	284.4	188.5	**472.9**
Upgrade Work Protection Code Application (2025–2026)	-	452.0	449.4	**901.4**
Subtotal Information Systems	**-**	**3,358.0**	**781.3**	**4,139.3**
Properties				
Install Electric Vehicle Chargers (2025–2026) - Hydro Sites	-	368.0	288.2	**656.1**
Subtotal Properties	**-**	**368.0**	**288.2**	**656.1**
Telecontrol				
Install CCTV Systems (2025)	-	440.1	-	**440.1**
Perform Minor Telecommunications Enhancements (2025)	-	99.8	-	**99.8**
Purchase Mobile Devices (2025)	-	160.2	-	**160.2**
Refurbish Meteorological Stations (2025)	-	167.8	-	**167.8**
Replace 48 V Battery Banks and Chargers (2025)	-	559.1	-	**559.1**
Replace GPS Clocks (2025–2026)	-	448.3	132.4	**580.7**
Replace Interconnect Microwave Radios (2025)	-	1,103.0	-	**1,103.0**
Replace MDR8000 Microwave Radios (2024–2025)	953.5	500.3	-	**1,453.8**
Replace Network Communications Equipment (2025)	-	413.2	-	**413.2**
Replace Power Line Carrier (2024-2025) - TL247	87.2	667.4	-	**754.6**
Replace VHF Radio System (2024–2025)	1,261.6	290.6	-	**1,552.2**
Telecommunications In-Service Failures (2025)	-	94.1	-	**94.1**
Upgrade Remote Terminal Units (2025)	-	238.4	-	**238.4**
Subtotal Telecontrol	**2,302.3**	**5,182.2**	**132.4**	**7,616.9**
Tools and Equipment				
Purchase Surveying Software and Equipment (2025)	-	316.4	-	**316.4**
Purchase Tools and Equipment (2025)	-	1,399.1	-	**1,399.1**
Subtotal Tools and Equipment	**-**	**1,715.5**	**-**	**1,715.5**

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Detailed Breakdown By Major and Minor Asset Category[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Transportation				
Replace Light- and Heavy-Duty Vehicles (2023–2025)	3,892.7	673.3	-	**4,566.0**
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 (2025–2027)	-	2,714.6	4,823.0	**7,537.6**
Subtotal Transportation	**5,371.8**	**7,536.7**	**4,831.4**	**17,739.9**
Total General Properties	**7,674.1**	**18,702.9**	**6,033.2**	**32,410.2**
Generation				
Gas Turbines				
Construct Maintenance Platform (2024–2025) - Holyrood	130.5	228.7	-	**359.2**
Gas Turbine In-Service Failures (2025)	-	500.0	-	**500.0**
Inspect Fuel Tanks (2025) - Holyrood	-	608.0	-	**608.0**
Inspect Fuel Tanks (2025) - Stephenville	-	676.9	-	**676.9**
Replace 250 Vdc Battery Bank (2025–2026) - Stephenville	-	73.0	296.9	**369.9**
Replace Human-Machine Interface (2025) - Stephenville	-	277.0	-	**277.0**
Upgrade Instrumentation (2024–2025) - Hardwoods	60.9	157.2	-	**218.1**
Subtotal Gas Turbines	**191.4**	**2,520.7**	**296.9**	**3,009.0**
Hydraulic Plant				
Flatten Downstream Slope (2024–2025) - Hinds Lake	276.1	2,953.4	-	**3,229.5**
Hydraulic In-Service Failures (2025)	-	2,000.0	-	**2,000.0**
Install Power Canal Public Safety Boom (2025) - Upper Salmon	-	463.8	-	**463.8**
Overhaul Hydraulic Units (2025)	-	4,972.4	-	**4,972.4**
Perform Level 2 Condition Assessment - Intake 4 and Unit 7 Draft Tube (2025) - Bay d'Espoir	-	471.5	-	**471.5**
Perform Level 2 Condition Assessment - Powerhouse Slope (2025) - Cat Arm	-	169.4	-	**169.4**
Refurbish Control Structure (2021–2025) - Ebbegunbaeg	12,726.8	4,952.2	-	**17,679.0**
Refurbish Intake 1 (2024–2025) - Bay d'Espoir	272.1	3,071.9	-	**3,344.0**
Refurbish Intake 2 (2025–2026) - Bay d'Espoir	-	284.4	3,069.4	**3,353.8**
Refurbish Surge Tank 1 (2024–2025) - Bay d'Espoir	175.8	2,111.4	-	**2,287.2**
Replace Air Conditioning Unit - Powerhouse 1 (2024–2025) - Bay d'Espoir	57.8	231.2	-	**289.0**
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 Emergency Diesel Genset (2025–2027) - Cat Arm	-	266.2	1,335.0	**1,601.3**
Replace Powerhouse 1 Roof (2024–2025) - Bay d'Espoir	140.2	1,819.2	-	**1,959.4**
Rewind Stator (2025–2026) - Hinds Lake	-	5,233.2	9,695.5	**14,928.7**
Subtotal Hydraulic Plant	**14,103.1**	**29,378.8**	**14,099.9**	**57,581.9**

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Detailed Breakdown By Major and Minor Asset Category[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Thermal Plant				
Overhaul Major Pumps (2025) - Holyrood	-	1,101.9	-	**1,101.9**
Overhaul Turbine and Valves - Unit 3 (2025) - Holyrood	-	15,975.9	-	**15,975.9**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood	-	4,905.8	-	**4,905.8**
Perform Level 2 Condition Assessment - Stage 1 and 2 Cooling Water Sump Structures (2025) - Holyrood	-	891.9	-	**891.9**
Refurbish Marine Terminal (2025–2026) - Holyrood	-	1,190.8	1,295.6	**2,486.5**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025) - Holyrood	156.2	1,039.4	-	**1,195.6**
Thermal In-Service Failures (2025)	-	3,900.0	-	**3,900.0**
Update Flame Scanners - Unit 3 (2025) - Holyrood	-	140.6	-	**140.6**
Upgrade DCS Hardware - Units 1 and 2 (2024–2025) - Holyrood	195.2	277.3	-	**472.5**
Upgrade Unit 1 Control System (2024–2025) - Holyrood	468.3	184.3	-	**652.6**
Upgrade UPS 1 and 2 (2024–2025) - Holyrood	263.0	107.6	-	**370.6**
Subtotal Thermal Plant	**1,082.7**	**29,715.5**	**1,295.6**	**32,093.8**
Total Generation	**15,377.2**	**61,615.0**	**15,692.5**	**92,684.7**
Transmission and Rural Operations				
Distribution				
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2025)	-	6,397.0	-	**6,397.0**
Provide Service Extensions (2025)	-	4,662.5	-	**4,662.5**
Renew Distribution Feeders (2024–2025)	1,287.3	1,245.1	-	**2,532.4**
Upgrade Distribution - Terminal Station 2 (2024–2025) - Bay d'Espoir	93.2	331.5	-	**424.7**
Upgrade Worst-Performing Distribution Feeders (2024–2025)	1,064.3	2,227.4	-	**3,291.7**
Upgrade Worst-Performing Distribution Feeders (2025–2027)	-	2,678.9	6,207.2	**8,886.1**
Subtotal Distribution	**2,444.8**	**17,542.4**	**6,207.2**	**26,194.4**
Generation				
Diesel Genset Replacement Program (2023–2025)	993.1	1,415.1	-	**2,408.2**
Diesel In-Service Failures (2025)	-	800.0	-	**800.0**
Overhaul Diesel Units (2025)	-	1,000.0	-	**1,000.0**
Replace Diesel Gensets (2024–2026)	535.8	478.0	3,902.3	**4,916.1**
Replace Diesel Gensets (2025–2027)	-	418.2	5,805.4	**6,223.6**
Replace Roof (2025) - Grey River	-	390.8	-	**390.8**
Subtotal Generation	**1,528.9**	**4,502.2**	**9,707.7**	**15,738.8**
Metering				
Automate Bulk Metering (2024–2026)	302.6	214.4	235.3	**752.3**
Purchase Meters and Metering Equipment (2025–2026)	-	446.2	278.4	**724.6**
Subtotal Metering	**302.6**	**660.6**	**513.7**	**1,476.9**
Properties				
Replace Diesel Shop Building (2023–2025) - Bishop's Falls	1,422.1	-	-	**1,422.1**
Subtotal Properties	**1,422.1**	**-**	**-**	**1,422.1**

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Detailed Breakdown By Major and Minor Asset Category[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Terminal Stations				
Additions for Load - Substation Upgrades - Wabush	10,179.6	514.5	-	**10,694.1**
Additions for Load Growth - Upgrade Transformer Capacity (2023–2024) - Jean Lake	580.0	6,459.6	789.7	**7,829.3**
Install Breaker Failure Protection (2025–2027) - Holyrood	-	177.8	487.4	**665.2**
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	53.8	599.0	-	**652.8**
Install Fire Protection in 230 kV Stations (2025–2026) - Come by Chance	-	51.7	534.5	**586.2**
Perform Major Inspection - Synchronous Condenser 2 (2025–2026) - Wabush	-	22.8	572.8	**595.6**
Refurbish Control Building (2024–2025) - Grandy Brook and Doyles	109.4	444.7	-	**554.1**
Renew Circuit Breakers (2024–2025)	183.9	2,120.1	-	**2,304.0**
Renew Circuit Breakers (2025–2026)	-	129.7	1,021.7	**1,151.4**
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247	112.4	215.8	-	**328.2**
Replace Circuit Breaker Reclosing Controllers (2025–2026) - Cow Head and Massey Drive	-	104.6	164.3	**269.0**
Replace Disconnects (2024–2025)	127.4	1,358.1	-	**1,485.5**
Replace Disconnects (2025–2026)	-	145.3	1,245.5	**1,390.8**
Replace Instrument Transformers (2024–2025)	154.9	714.8	-	**869.7**
Replace Instrument Transformers (2025–2026)	-	112.5	356.4	**468.9**
Replace Protective Relays (2024–2025)	1,388.4	2,050.7	-	**3,439.1**
Replace Protective Relays (2025–2026)	-	668.6	2,070.9	**2,739.5**
Replace Terminal Station Battery Banks and Chargers (2024–2025)	71.8	120.9	-	**192.7**
Replace Terminal Station Battery Banks and Chargers (2025–2026)	-	123.2	315.3	**438.5**
Terminal Station In-Service Failures (2025)	-	2,500.0	-	**2,500.0**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon	137.0	156.9	-	**293.9**
Upgrade Data Alarm Systems (2025–2026) - Hardwoods	-	184.0	188.7	**372.7**
Upgrade Power Transformers (2024–2025)	864.6	2,711.3	-	**3,575.9**
Upgrade Power Transformers (2025–2026)	-	811.9	1,173.9	**1,985.8**
Upgrade Station Lighting (2024–2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon	91.6	429.0	-	**520.6**
Subtotal Terminal Stations	**14,054.8**	**22,927.7**	**8,921.1**	**45,903.6**
Tools and Equipment				
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 Mobile Equipment (2025–2027)	-	1,973.6	2,674.0	**4,647.6**
Subtotal Tools and Equipment	**240.9**	**3,415.1**	**2,681.1**	**6,337.1**
Transmission				
Install Mid-Span Structures - TL220 (2025–2026)	-	881.3	229.3	**1,110.6**
Transmission In-Service Failures (2025)	-	184.3	-	**184.3**
Wood Pole Line Management (2025)	-	4,281.3	-	**4,281.3**
Subtotal Transmission	**-**	**5,346.9**	**229.3**	**5,576.2**
Total Transmission and Rural Operations	**19,994.1**	**54,394.8**	**28,260.2**	**102,649.1**
Total Capital Budget	**43,045.4**	**135,712.8**	**49,985.9**	**228,744.0**

[1] Numbers may not add due to rounding.

Appendix B

2025 Capital Budget by Single- and Multi-Year Programs and Projects



Newfoundland and Labrador Hydro
2025 Capital Budget Application
Single- and Multi-Year Programs and Projects[1]
($000)

	2025
Single Year	
Access	4,662.5
Allowance for Unforeseen	1,000.0
General Plant	8,243.4
Mandatory	608.0
Renewal	51,367.3
Service Enhancement	303.1
System Growth	-
Single-Year Total	**66,184.3**
Multi-Year (2025 Expenditures)	
Multi-Year Programs and Projects Commencing in 2021	5,466.7
Multi-Year Programs and Projects Commencing in 2022	-
Multi-Year Programs and Projects Commencing in 2023	8,548.0
Multi-Year Programs and Projects Commencing in 2024	35,026.6
Multi-Year Programs and Projects Commencing in 2025	20,487.1
Multi-Year (2025 Expenditures) Total	**69,528.4**
Total 2025 Capital Budget	**135,712.8**

[1] Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Single-Year Programs and Projects[1]
($000)

	2025
Access	
Provide Service Extensions (2025)	4,662.5
Access Total	**4,662.5**
Allowance for Unforeseen	
Allowance for Unforeseen Items (2025)	1,000.0
Allowance for Unforeseen Total	**1,000.0**
General Plant	
Install CCTV Systems (2025)	440.1
Install Power Canal Public Safety Boom (2025) - Upper Salmon	463.8
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2025)	178.5
Perform Level 2 Condition Assessment - Powerhouse Slope (2025) - Cat Arm	169.4
Perform Security Improvements (2025)	160.7
Perform Software Upgrades and Minor Enhancements (2025)	808.7
Purchase Mobile Devices (2025)	160.2
Purchase Personal Computers (2025)	575.6
Purchase Surveying Software and Equipment (2025)	316.4
Purchase Tools and Equipment (2025)	1,399.1
Refurbish Meteorological Stations (2025)	167.8
Replace 48 V Battery Banks and Chargers (2025)	559.1
Replace Interconnect Microwave Radios (2025)	1,103.0
Replace Network Communications Equipment (2025)	413.2
Replace Peripheral Infrastructure (2025)	205.4
Telecommunications In-Service Failures (2025)	94.1
Update Cyber Security Infrastructure (2025)	115.6
Upgrade Core OT Infrastructure (2025)	674.3
Upgrade Remote Terminal Units (2025)	238.4
General Plant Total	**8,243.4**
Mandatory	
Inspect Fuel Tanks (2025) - Holyrood	608.0
Mandatory Total	**608.0**

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Single-Year Programs and Projects[1]
($000)

	2025
Renewal	
Diesel In-Service Failures (2025)	800.0
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2025)	6,397.0
Gas Turbine In-Service Failures (2025)	500.0
Hydraulic In-Service Failures (2025)	2,000.0
Inspect Fuel Tanks (2025) - Stephenville	676.9
Overhaul Diesel Units (2025)	1,000.0
Overhaul Hydraulic Units (2025)	4,972.4
Overhaul Major Pumps (2025) - Holyrood	1,101.9
Overhaul Turbine and Valves - Unit 3 (2025) - Holyrood	15,975.9
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood	4,905.8
Perform Level 2 Condition Assessment - Intake 4 and Unit 7 Draft Tube (2025) - Bay d'Espoir	471.5
Perform Level 2 Condition Assessment - Stage 1 and 2 Cooling Water Sump Structures (2025) - Holyrood	891.9
Replace Human-Machine Interface (2025) - Stephenville	277.0
Replace Roof (2025) - Grey River	390.8
Terminal Station In-Service Failures (2025)	2,500.0
Thermal In-Service Failures (2025)	3,900.0
Transmission In-Service Failures (2025)	184.3
Update Flame Scanners - Unit 3 (2025) - Holyrood	140.6
Wood Pole Line Management (2025)	4,281.3
Renewal Total	**51,367.3**
Service Enhancement	
Perform Minor Telecommunications Enhancements (2025)	99.8
Remove Safety Hazards (2025)	203.3
Service Enhancement Total	**303.1**
Total Single-Year Programs and Projects	**66,184.3**

[1] Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Multi-Year Programs and Projects[1]
($000)

	2024 and Prior Years	2025	2026	2027	2028	2029	Sum of Total With Prior Year
Multi-Year Programs and Projects Commencing in 2021							
Renewal							
Refurbish Control Structure (2021–2025) - Ebbegunbaeg	12,726.8	4,952.2	-	-	-	-	**17,679.0**
Subtotal Renewal	**12,726.8**	**4,952.2**	**-**	**-**	**-**	**-**	**17,679.0**
System Growth							
Additions for Load - Substation Upgrades - Wabush	10,179.6	514.5	-	-	-	-	**10,694.1**
Subtotal System Growth	**10,179.6**	**514.5**	**-**	**-**	**-**	**-**	**10,694.1**
Total Multi-Year Programs and Projects Commencing in 2021	**22,906.4**	**5,466.7**	**-**	**-**	**-**	**-**	**28,373.1**
Multi Year Programs and Projects Commencing in 2023							
General Plant							
Replace Diesel Shop Building (2023–2025) - Bishop's Falls	1,422.1	-	-	-	-	-	**1,422.1**
Replace Light- and Heavy-Duty Vehicles (2023–2025)	3,892.7	673.3	-	-	-	-	**4,566.0**
Subtotal General Plant	**5,314.8**	**673.3**	**-**	**-**	**-**	**-**	**5,988.1**
Renewal							
Diesel Genset Replacement Program (2023–2025)	993.1	1,415.1	-	-	-	-	**2,408.2**
Subtotal Renewal	**993.1**	**1,415.1**	**-**	**-**	**-**	**-**	**2,408.2**
System Growth							
Additions for Load Growth - Upgrade Transformer Capacity (2023–2024) - Jean Lake	580.0	6,459.6	789.7	-	-	-	**7,829.3**
Subtotal System Growth	**580.0**	**6,459.6**	**789.7**	**-**	**-**	**-**	**7,829.3**
Total Multi Year Programs and Projects Commencing in 2023	**6,887.9**	**8,548.0**	**789.7**	**-**	**-**	**-**	**16,225.6**
Multi Year Programs and Projects Commencing in 2024							
General Plant							
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	53.8	599.0	-	-	-	-	**652.8**
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024–2026) - Happy Valley-Goose Bay	24.0	841.8	7.1	-	-	-	**872.9**
Refurbish Control Building (2024–2025) - Grandy Brook and Doyles	109.4	444.7	-	-	-	-	**554.1**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025) - Holyrood	156.2	1,039.4	-	-	-	-	**1,195.6**
Replace Air Conditioning Unit - Powerhouse 1 (2024–2025) - Bay d'Espoir	57.8	231.2	-	-	-	-	**289.0**
Replace Light- and Heavy-Duty Vehicles (2024–2026)	1,479.1	4,148.8	8.4	-	-	-	**5,636.3**
Replace MDR8000 Microwave Radios (2024–2025)	953.5	500.3	-	-	-	-	**1,453.8**
Replace Mobile Equipment (2024–2025)	216.9	599.7	-	-	-	-	**816.6**
Replace Power Line Carrier (2024-2025) - TL247	87.2	667.4	-	-	-	-	**754.6**
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**
Subtotal General Plant	**4,539.7**	**11,182.1**	**15.5**	**-**	**-**	**-**	**15,737.3**
Mandatory							
Upgrade Station Lighting (2024–2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon	91.6	429.0	-	-	-	-	**520.6**
Subtotal Mandatory	**91.6**	**429.0**	**-**	**-**	**-**	**-**	**520.6**
Renewal							
Flatten Downstream Slope (2024–2025) - Hinds Lake	276.1	2,953.4	-	-	-	-	**3,229.5**
Refurbish Intake 1 (2024–2025) - Bay d'Espoir	272.1	3,071.9	-	-	-	-	**3,344.0**
Refurbish Surge Tank 1 (2024–2025) - Bay d'Espoir	175.8	2,111.4	-	-	-	-	**2,287.2**
Renew Circuit Breakers (2024–2025)	183.9	2,120.1	-	-	-	-	**2,304.0**
Renew Distribution Feeders (2024–2025)	1,287.3	1,245.1	-	-	-	-	**2,532.4**
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 Circuit Breaker Reclosing Controllers (2024–2025) - TL247	112.4	215.8	-	-	-	-	**328.2**
Replace Diesel Gensets (2024–2026)	535.8	478.0	3,902.3	-	-	-	**4,916.1**
Replace Disconnects (2024–2025)	127.4	1,358.1	-	-	-	-	**1,485.5**
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 Terminal Station Battery Banks and Chargers (2024–2025)	71.8	120.9	-	-	-	-	**192.7**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon	137.0	156.9	-	-	-	-	**293.9**
Upgrade DCS Hardware - Units 1 and 2 (2024–2025) - Holyrood	195.2	277.3	-	-	-	-	**472.5**
Upgrade Distribution - Terminal Station 2 (2024–2025) - Bay d'Espoir	93.2	331.5	-	-	-	-	**424.7**
Upgrade Power Transformers (2024–2025)	864.6	2,711.3	-	-	-	-	**3,575.9**
Upgrade Unit 1 Control System (2024–2025) - Holyrood	468.3	184.3	-	-	-	-	**652.6**
Upgrade UPS 1 and 2 (2024–2025) - Holyrood	263.0	107.6	-	-	-	-	**370.6**
Subtotal Renewal	**7,061.5**	**20,587.8**	**3,902.3**	**-**	**-**	**-**	**31,551.6**

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Multi-Year Programs and Projects[1]
($000)

	2024 and Prior Years	2025	2026	2027	2028	2029	Sum of Total With Prior Year
Service Enhancement							
Automate Bulk Metering (2024–2026)	302.6	214.4	235.3	-	-	-	**752.3**
Construct Maintenance Platform (2024–2025) - Holyrood	130.5	228.7	-	-	-	-	**359.2**
Upgrade Instrumentation (2024–2025) - Hardwoods	60.9	157.2	-	-	-	-	**218.1**
Upgrade Worst-Performing Distribution Feeders (2024–2025)	1,064.3	2,227.4	-	-	-	-	**3,291.7**
Subtotal Service Enhancement	**1,558.3**	**2,827.7**	**235.3**	**-**	**-**	**-**	**4,621.3**
Total Multi Year Programs and Projects Commencing in 2024	**13,251.1**	**35,026.6**	**4,153.1**	**-**	**-**	**-**	**52,430.8**
Multi-Year Programs and Projects Commencing in 2025							
General Plant							
Implement SCADA Points Application (2025–2026)	-	241.9	143.4	-	-	-	**385.3**
Install Electric Vehicle Chargers (2025–2026) - Hydro Sites	-	368.0	288.2	-	-	-	**656.1**
Install Fire Protection in 230 kV Stations (2025–2026) - Come by Chance	-	51.7	534.5	-	-	-	**586.2**
Replace GPS Clocks (2025–2026)	-	448.3	132.4	-	-	-	**580.7**
Replace Light- and Heavy-Duty Vehicles (2025–2027)	-	2,714.6	1,675.8	3,147.2	-	-	**7,537.6**
Replace Mobile Equipment (2025–2027)	-	1,973.6	54.6	2,619.4	-	-	**4,647.6**
Upgrade Energy Management System (2025–2026)	-	284.4	188.5	-	-	-	**472.9**
Upgrade Work Protection Code Application (2025–2026)	-	452.0	449.4	-	-	-	**901.4**
Subtotal General Plant	**-**	**6,534.4**	**3,466.7**	**5,766.7**	**-**	**-**	**15,767.8**
Mandatory							
Purchase Meters and Metering Equipment (2025–2026)	-	446.2	278.4	-	-	-	**724.6**
Subtotal Mandatory	**-**	**446.2**	**278.4**	**-**	**-**	**-**	**724.6**
Renewal							
Install Breaker Failure Protection (2025–2027) - Holyrood	-	177.8	320.9	166.5	-	-	**665.2**
Perform Major Inspection - Synchronous Condenser 2 (2025–2026) - Wabush	-	22.8	572.8	-	-	-	**595.6**
Refurbish Intake 2 (2025–2026) - Bay d'Espoir	-	284.4	3,069.4	-	-	-	**3,353.8**
Refurbish Marine Terminal (2025–2026) - Holyrood	-	1,190.8	1,295.6	-	-	-	**2,486.5**
Renew Circuit Breakers (2025–2026)	-	129.7	1,021.7	-	-	-	**1,151.4**
Replace 250 Vdc Battery Bank (2025–2026) - Stephenville	-	73.0	296.9	-	-	-	**369.9**
Replace Circuit Breaker Reclosing Controllers (2025–2026) - Cow Head and Massey Drive	-	104.6	164.3	-	-	-	**269.0**
Replace Diesel Gensets (2025–2027)	-	418.2	1,286.6	4,518.7	-	-	**6,223.6**
Replace Disconnects (2025–2026)	-	145.3	1,245.5	-	-	-	**1,390.8**
Replace Emergency Diesel Genset (2025–2027) - Cat Arm	-	266.2	1,221.1	113.9	-	-	**1,601.3**
Replace Instrument Transformers (2025–2026)	-	112.5	356.4	-	-	-	**468.9**
Replace Protective Relays (2025–2026)	-	668.6	2,070.9	-	-	-	**2,739.5**
Replace Terminal Station Battery Banks and Chargers (2025–2026)	-	123.2	315.3	-	-	-	**438.5**
Rewind Stator (2025–2026) - Hinds Lake	-	5,233.2	9,695.5	-	-	-	**14,928.7**
Upgrade Data Alarm Systems (2025–2026) - Hardwoods	-	184.0	188.7	-	-	-	**372.7**
Upgrade Power Transformers (2025–2026)	-	811.9	1,173.9	-	-	-	**1,985.8**
Subtotal Renewal	**-**	**9,946.3**	**24,295.7**	**4,799.1**	**-**	**-**	**39,041.1**
Service Enhancement							
Install Mid-Span Structures - TL220 (2025–2026)	-	881.3	229.3	-	-	-	**1,110.6**
Upgrade Worst-Performing Distribution Feeders (2025–2027)	-	2,678.9	3,677.4	2,529.8	-	-	**8,886.1**
Subtotal Service Enhancement	**-**	**3,560.2**	**3,906.7**	**2,529.8**	**-**	**-**	**9,996.7**
Total Multi-Year Programs and Projects Commencing in 2025	**-**	**20,487.1**	**31,947.5**	**13,095.6**	**-**	**-**	**65,530.2**
Total Multi-Year Programs and Projects	**43,045.4**	**69,528.4**	**36,890.3**	**13,095.6**	**-**	**-**	**162,559.7**

[1] Numbers may not add due to rounding.

Appendix C

2025 Capital Budget by Materiality – Programs and Projects over $5 Million



Newfoundland and Labrador Hydro
2025 Capital Budget Application
By Materiality - Programs and Projects Over $5 Million[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
General Plant				
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 (2025–2027)	-	2,714.6	4,823.0	**7,537.6**
General Plant Total	**1,479.1**	**6,863.4**	**4,831.4**	**13,173.9**
Renewal				
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2025)	-	6,397.0	-	**6,397.0**
Overhaul Turbine and Valves - Unit 3 (2025) - Holyrood	-	15,975.9	-	**15,975.9**
Refurbish Control Structure (2021–2025) - Ebbegunbaeg	12,726.8	4,952.2	-	**17,679.0**
Replace Diesel Gensets (2025–2027)	-	418.2	5,805.4	**6,223.6**
Rewind Stator (2025–2026) - Hinds Lake	-	5,233.2	9,695.5	**14,928.7**
Renewal Total	**12,726.8**	**32,976.5**	**15,500.9**	**61,204.2**
Service Enhancement				
Upgrade Worst-Performing Distribution Feeders (2025–2027)	-	2,678.9	6,207.2	**8,886.1**
Service Enhancement Total	**-**	**2,678.9**	**6,207.2**	**8,886.1**
System Growth				
Additions for Load - Substation Upgrades - Wabush	10,179.6	514.5	-	**10,694.1**
Additions for Load Growth - Upgrade Transformer Capacity (2023–2024) - Jean Lake	580.0	6,459.6	789.7	**7,829.3**
System Growth Total	**10,759.6**	**6,974.1**	**789.7**	**18,523.4**
Total Programs and Projects Over $5 Million	**24,965.5**	**49,492.9**	**27,329.2**	**101,787.6**

[1] Numbers may not add due to rounding.

Appendix D

2025 Capital Budget by Materiality – Programs and Projects $1 Million to $5 Million



Newfoundland and Labrador Hydro
2025 Capital Budget Application
By Materiality - Programs and Projects $1 Million to $5 Million[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
Access				
Provide Service Extensions (2025)	-	4,662.5	-	**4,662.5**
Access Total	**-**	**4,662.5**	**-**	**4,662.5**
Allowance for Unforeseen				
Allowance for Unforeseen Items (2025)	-	1,000.0	-	**1,000.0**
Allowance for Unforeseen Total	**-**	**1,000.0**	**-**	**1,000.0**
General Plant				
Purchase Tools and Equipment (2025)	-	1,399.1	-	**1,399.1**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025) - Holyrood	156.2	1,039.4	-	**1,195.6**
Replace Diesel Shop Building (2023–2025) - Bishop's Falls	1,422.1	-	-	**1,422.1**
Replace Interconnect Microwave Radios (2025)	-	1,103.0	-	**1,103.0**
Replace Light- and Heavy-Duty Vehicles (2023–2025)	3,892.7	673.3	-	**4,566.0**
Replace MDR8000 Microwave Radios (2024–2025)	953.5	500.3	-	**1,453.8**
Replace Mobile Equipment (2025–2027)	-	1,973.6	2,674.0	**4,647.6**
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**
General Plant Total	**7,826.3**	**8,798.4**	**2,674.0**	**19,298.8**
Renewal				
Diesel Genset Replacement Program (2023–2025)	993.1	1,415.1	-	**2,408.2**
Flatten Downstream Slope (2024–2025) - Hinds Lake	276.1	2,953.4	-	**3,229.5**
Hydraulic In-Service Failures (2025)	-	2,000.0	-	**2,000.0**
Overhaul Diesel Units (2025)	-	1,000.0	-	**1,000.0**
Overhaul Hydraulic Units (2025)	-	4,972.4	-	**4,972.4**
Overhaul Major Pumps (2025) - Holyrood	-	1,101.9	-	**1,101.9**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood	-	4,905.8	-	**4,905.8**
Refurbish Intake 1 (2024–2025) - Bay d'Espoir	272.1	3,071.9	-	**3,344.0**
Refurbish Intake 2 (2025–2026) - Bay d'Espoir	-	284.4	3,069.4	**3,353.8**
Refurbish Marine Terminal (2025–2026) - Holyrood	-	1,190.8	1,295.6	**2,486.5**
Refurbish Surge Tank 1 (2024–2025) - Bay d'Espoir	175.8	2,111.4	-	**2,287.2**
Renew Circuit Breakers (2024–2025)	183.9	2,120.1	-	**2,304.0**
Renew Circuit Breakers (2025–2026)	-	129.7	1,021.7	**1,151.4**
Renew Distribution Feeders (2024–2025)	1,287.3	1,245.1	-	**2,532.4**
Replace Diesel Gensets (2024–2026)	535.8	478.0	3,902.3	**4,916.1**
Replace Disconnects (2024–2025)	127.4	1,358.1	-	**1,485.5**
Replace Disconnects (2025–2026)	-	145.3	1,245.5	**1,390.8**
Replace Emergency Diesel Genset (2025–2027) - Cat Arm	-	266.2	1,335.0	**1,601.3**
Replace Protective Relays (2024–2025)	1,388.4	2,050.7	-	**3,439.1**
Replace Protective Relays (2025–2026)	-	668.6	2,070.9	**2,739.5**
Terminal Station In-Service Failures (2025)	-	2,500.0	-	**2,500.0**
Thermal In-Service Failures (2025)	-	3,900.0	-	**3,900.0**
Upgrade Power Transformers (2024–2025)	864.6	2,711.3	-	**3,575.9**
Upgrade Power Transformers (2025–2026)	-	811.9	1,173.9	**1,985.8**
Wood Pole Line Management (2025)	-	4,281.3	-	**4,281.3**
Renewal Total	**6,104.5**	**47,673.4**	**15,114.3**	**68,892.2**
Service Enhancement				
Install Mid-Span Structures - TL220 (2025–2026)	-	881.3	229.3	**1,110.6**
Upgrade Worst-Performing Distribution Feeders (2024–2025)	1,064.3	2,227.4	-	**3,291.7**
Service Enhancement Total	**1,064.3**	**3,108.7**	**229.3**	**4,402.3**
Total Programs and Projects $1 Million to $5 Million	**14,995.1**	**65,243.0**	**18,017.7**	**98,255.8**

[1] Numbers may not add due to rounding.

Appendix E

2025 Capital Budget by Materiality – Programs and Projects $750,000 to $1 Million





Newfoundland and Labrador Hydro
2025 Capital Budget Application
By Materiality - Programs and Projects $750,000 to $1 Million[1]
($000)

	2024 and Prior Years	2025	Future Years	Total
General Plant				
Perform Software Upgrades and Minor Enhancements (2025)	-	808.7	-	**808.7**
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 Power Line Carrier (2024-2025) - TL247	87.2	667.4	-	**754.6**
Upgrade Work Protection Code Application (2025–2026)	-	452.0	449.4	**901.4**
General Plant Total	**328.1**	**3,369.6**	**456.5**	**4,154.2**
Renewal				
Diesel In-Service Failures (2025)	-	800.0	-	**800.0**
Perform Level 2 Condition Assessment - Stage 1 and 2 Cooling Water Sump Structures (2025) - Holyrood	-	891.9	-	**891.9**
Replace Instrument Transformers (2024–2025)	154.9	714.8	-	**869.7**
Renewal Total	**154.9**	**2,406.7**	**-**	**2,561.6**
Service Enhancement				
Automate Bulk Metering (2024–2026)	302.6	214.4	235.3	**752.3**
Service Enhancement Total	**302.6**	**214.4**	**235.3**	**752.3**
Total Programs and Projects $750,000 to $1 Million	**785.6**	**5,990.8**	**691.8**	**7,468.2**

[1] Numbers may not add due to rounding.

Appendix F

Terminal Station Asset Management Strategy – 2024 Update



Terminal Station
Asset Management Strategy

2024 Update



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1.0 Introduction

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

Hydro's Terminal Station Asset Management System governs the life cycle of its terminal station assets. This system monitors, maintains, refurbishes, replaces, and disposes of assets to provide safe, reliable electrical power in an environmentally responsible manner at the lowest possible cost. This system allows the asset managers to establish consistent practices for equipment specifications, placement, maintenance, refurbishment, replacement, and disposal for terminal station assets, such as breakers, transformers, grounding systems, buildings, and sites. These practices ensure consistency in the monitoring, assessments, and action justifications for asset-sustaining projects' capital refurbishment and replacement. Hydro established programs that enact these practices for groupings or sub-groupings of assets (e.g., high-voltage switch replacements).

This report provides information as to the assets involved and an overview of each asset program. It is divided into sections each of which describes an infrastructure asset class, including the high-level function and/or construction of the equipment in that asset class and the associated capital program, including eligibility criteria (a combination of age, usage, condition, and reliability improvement). Hydro will provide an update to its Terminal Station Asset Management Strategy in its annual capital budget applications.

2.0 Background

2.1 Hydro's Terminal Stations

Hydro has 69 terminal stations throughout Newfoundland and Labrador. 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. Terminal stations act as transition points within the transmission system and interface points with the lower voltage distribution and generation systems.

2.2 Terminal Station Infrastructure

Terminal 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;
- 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 Asset Management Programs

3.1 Electrical Equipment

3.1.1 High-Voltage Instrument Transformer Replacements

3.1.1.1 Introduction

Protection, control, and metering devices, such as protective relaying, power quality monitors, and kilowatt-hour 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 and a potential transformer, respectively (Figure 1), known collectively as instrument transformers.

A high-voltage instrument transformer consists of insulated electrical primary and secondary winding, a tank, and bushing components. The insulation system involves the use of insulating oil- or dry-type insulation and a high-voltage porcelain bushing that allows the safe connection of the winding, which is enclosed in a steel tank, to high-voltage conductors. Hydro has approximately 900 individual high-voltage instrument transformers within the Island and Labrador Interconnected Systems.



Figure 1: 69 kV Current Transformer (left) and Potential Transformer (right)

3.1.1.2 Program Description and Justification

Hydro manages its planned budgeted instrument transformer replacements in five categories:

1) Condition;

2) PCB[1] compliance;

3) Age;

4) Additions for protective relay upgrades; and

5) Exclusions

Condition

Deterioration or damage to the various instrument transformer 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 instrument transformer may be forcibly projected, resulting in a safety risk for personnel in the area or damage to other infrastructure.

Damage to an instrument transformer 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 instrument transformer to determine if replacement is required.

Hydro monitors instrument transformers for physical and electrical deterioration by conducting regular visual inspections of the units as part of its Terminal Station Inspection Program as well as regularly scheduled terminal station infrared inspections and electrical insulation testing.

Physical deterioration involves conditions such as oil leaks, rusting, or small chips and cracks in the insulation. An example of rusting on a potential transformer tank is provided as Figure 2.

[1] Polychlorinated biphenyl ("PCB").



Figure 2: Rusting Potential Transformer

Electrical deterioration is identified by conducting power factor testing at intervals that are used to establish the rate and level of insulation degradation. Hydro uses Doble Engineering Company to assist with the assessment of the test results, where required. Hydro's asset management personnel continuously review the unit deterioration information and determine when corrective maintenance or unit replacement is required.

Hydro conducts minor corrective maintenance on its instrument transformers, such as painting and small bushing chip treatment. As external services to economically undertake major corrective maintenance or unit refurbishments are non-existent, units requiring major corrective maintenance or refurbishments are replaced.

PCB Compliance

Environment Canada's *PCB Regulations* require discontinuing the use of all instrument transformers containing PCBs in a concentration greater than or equal to 50 mg/kg by December 31, 2025.[2] Instrument transformers are sealed oil-filled units where the oil, which acts as an electrical insulator, has been known to contain PCBs for equipment manufactured before 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 instrument transformers, Hydro does not sample instrument transformers. Therefore, establishing the actual PCB concentration in an instrument transformer is not possible. In consultation with manufacturers, Hydro has established that units manufactured before 1985 are suspected to

[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.

contain PCBs in concentration levels greater than or equal to 50 mg/kg. As such, Hydro has a program to replace all suspect oil-filled instrument transformers before December 31, 2025.

Age

To reduce the risk of in-service failures and minimize service interruptions, Hydro targets the replacement of instrument transforms at 40 years. According to original equipment manufacturers ("OEM"), the recommended life of an instrument transformer is approximately 30 to 40 years. From 2018–2023, 53% of failed instrument transformers were at least 30 years old at the time of failure.

Additions for Protective Relay Upgrade

Some protective relay upgrades require one or more additional instrument transformers for the upgrade to conform to Hydro's Protection and Control Engineering Standards. The installation of these additional instrument transformers is typically coordinated with the associated protective relay upgrade such that both the protective relay upgrade and the additional instrument transformer(s) are installed at the same time.

Exclusions

Modern-day circuit breaker technology has current transformers embedded in the circuit breaker bushings. As a result, where possible, external current transformers will be displaced by bushing current transformers as circuit breakers are replaced; therefore, current transformers are not included in this program.

3.1.2 High-Voltage Switch Replacements

3.1.2.1 Introduction

High-voltage switches are used to isolate equipment 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 Hydro's "Work Protection Code Book,"[3] as they provide a visible air gap (i.e., visible isolation) for utility

[3] As per "Work Protection Code Book," Newfoundland and Labrador Hydro, 2020, p. 12,
"A Work Protection is a guarantee;
- that an isolated, or isolated and de-energized condition has been established for work, and
- will continue to exist, except for authorized test."

workers. 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. Insulators are made of porcelain and insulate the switch base and operating mechanism from the current-carrying components. The switch base is mounted to a metal frame support structure and supports the insulators. The operating mechanism is operated either 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.

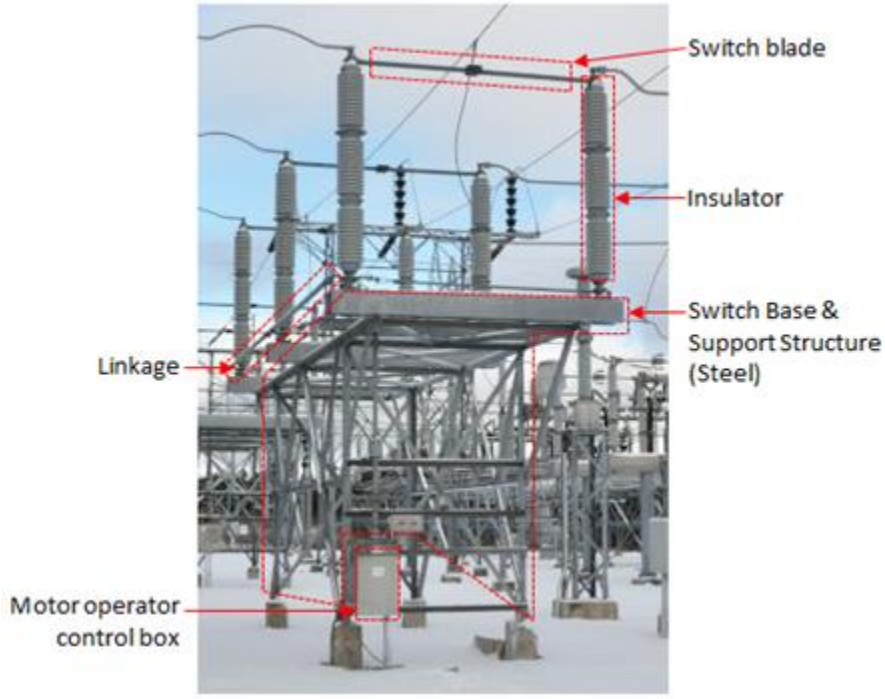


Figure 3: Various Components of a High-Voltage Disconnect Switch

Hydro monitors the condition of its switches by conducting regular visual inspections of the units as part of its Terminal Station and Infrared Inspection Programs and by reviewing reports from the JDE E1 work order system or staff who operate the switch. These reports outline problems such as inoperable mechanical linkages, misalignment of switch blades, broken insulators, and the seizing of moving parts. Asset management personnel determine the timing of corrective maintenance or switch replacement. If

the required parts are available, repairs are undertaken as part of ongoing maintenance. Switches that meet one of the following criteria are planned for replacement:

- Operating deficiencies and reached a service life of 50 years;
- No replacement parts available due to obsolescence, damage beyond repair, or cannot be economically repaired and do not require immediate replacement; or
- Reached a service life of 60 years.

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

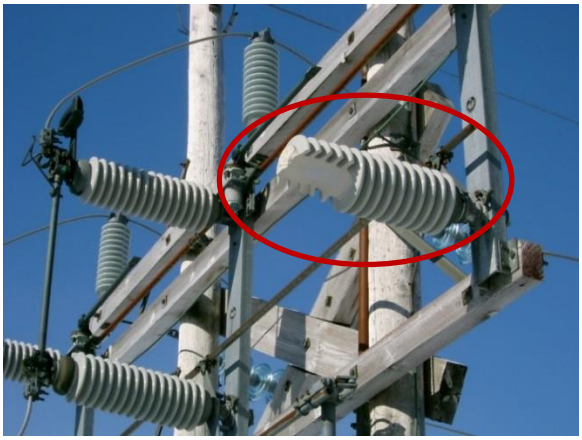


Figure 4: Broken Insulator on 69 kV Disconnect Switch

3.1.3 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-voltage 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. Older arrester designs have a higher incidence of failure than the newer designs.

Hydro's Surge Arrester Asset Management Program replaces surge arresters based on 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 through 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. To reduce the risk of in-service failures and minimize service interruptions, Hydro targets replacement at 40 years of age.

3.1.4 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 outage(s) may occur.

Insulators consist of insulating material, such as glass and porcelain, and metallic 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 type, multi-cone type, and suspension-type insulators.

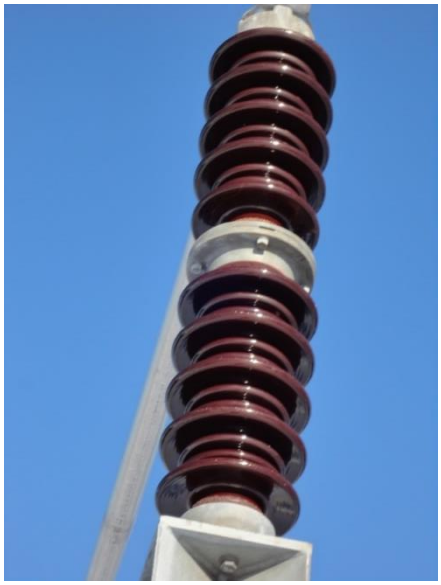


Figure 6: Multi-Cone Type Insulator Prone to Failure due to Cement Growth

For insulators using porcelain, cement is used in mating the porcelain and metallic hardware. Some older insulators have been damaged by a phenomenon known as cement growth, 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 thereby 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, this porcelain may fall, presenting a safety hazard to crews or damaging equipment below. In addition, faults resulting in outages to customers often occur when insulator failure leads to flashover. To eliminate this problem, insulator manufacturers have identified and researched cement growth problems and improved cement quality.

Hydro carries out detailed insulator surveys by geographical area, identifying any known insulator types prone to failure due to cement growth and replacing these insulators as part of this program.

3.1.5 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, an example of which is shown as 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, known as step and touch potentials, may be hazardous to personnel. 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. Step and touch potential analysis involves the gathering of field data and conducting an analysis to determine if ground grid modifications are required to eliminate step and touch potential hazard. This engineering is conducted in accordance with the IEEE Standard 80-2000.[4] 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] Institute of Electrical and Electronics Engineers. (2000). 80-2000, *IEEE Guide for Safety in AC Substation Grounding*.

3.1.6 Power Transformer Upgrades and Refurbishment

3.1.6.1 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 three 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:

- A 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);
- 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.

A 75 MVA, 230/66 kV power transformer at the Hardwoods Terminal Station is provided as Figure 8.



Figure 8: Power Transformer

3.1.6.2 Program Description and Justification

Transformers are expensive components of the electrical system. Similar to many North American utilities, Hydro 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 Program 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 component rusting/corrosion;
- Tap changer component wear or damage;
- Damaged/deteriorated and/or 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 herein.

Transformer Oil Deterioration

The insulating oil in a transformer and its tap changer diverter switch is a critical component of the insulation system. 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 its paper component. Unacceptable levels of deterioration can affect the reliable operation of the transformer. To ensure the oil in a transformer is of an 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 to determine the level of deterioration. If an unacceptable level of deterioration is present, 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. Oil that is PCB-contaminated (i.e., >2 ppm PCB) and 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 high moisture content has a reduced dielectric strength, and therefore its 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. 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 a number of factors, including failed gaskets or severe corrosion of 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 maintenance. Work requiring major refurbishments and replacements (such as radiator or bushing replacements, gasket replacements, and tank rusting refurbishment) are 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 that are subject to wear and damage. Additionally, in older, non-vacuum designed diverter switches, arcing occurs during the movement, leading to deterioration of the insulating oil. This wear and deterioration can lead to 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. 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, immediate removal from service, inspection, and repair. The latter two activities are covered by this project. Another component covered by this project is the correction of 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 bushings that are suspected to have PCB levels not compliant with the latest *PCB Regulations* and those 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 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.

As part of transformer preventive maintenance, Hydro performs power factor testing on bushings every six years. When power factor test 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; they 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 condition 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 before 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 ("Board") on the June 2, 2014.[5] Hydro has identified 46 transformers for installation of online DGA devices between 2019 and 2025.

3.1.7 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

[5] "Report to the Board of Commissioners of Public Utilities Regarding Work to be Performed on Transformers," Newfoundland and Labrador Hydro, June 2, 2014. http://pub.nl.ca/applications/IslandInterconnectedSystem/files/reports/TerminalStationTransformersReport-2014-06-02.pdf

normal or fault conditions. The reliable operation of circuit breakers through its 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 two different types of high-voltage circuit breakers, examples of which are provided in Figure 9.

1) Oil Circuit Breakers ("OCB"): Use oil to interrupt currents and will be at least 36 years old at replacement. In the 2016 Capital Budget Application's ("CBA") Upgrade Circuit Breakers – Various Sites" project, Hydro proposed the replacement of 10 OCBs up to 2020, which were not compliant with *PCB Regulations*.[6,7] The remaining non-compliant breakers will be replaced by December 31, 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. In addition, OCBs rated at 66 kV and above that are compliant with Environment Canada's *PCB Regulations* are planned for replacement after 40 years of service. However, as they come due, a further condition assessment will be completed to determine if life extension can be achieved through refurbishment.

2) Sulphur Hexafluoride ("SF_6") Circuit Breakers: Use SF_6 gas to interrupt current. The installation of these breakers started in 1979 and continue for all new installations.

[6] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol. II, tab 8. http://pub.nl.ca/applications/ARCHIVE/2016/NLH2016Capital/files/application/NLH-2016-Capital-Budget-Application-Volume-I-2015-07-31.pdf

[7] Approved as per *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 9: Oil Circuit Breakers (Left) and SF_6 Circuit Breakers (Right)

As presented in the 2016 CBA, SF_6 circuit breakers rated at 138 kV and above require refurbishment after 20 years of service. In 2018, Hydro added that 66 kV-rated breakers also require refurbishment 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.

3.1.8 Station Service Refurbishment and Upgrades

The power required to operate 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, fed either through a redundant transformer tertiary (supplied from Newfoundland Power Inc.'s 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;[8]

[8] Heating, ventilation, and air-conditioning ("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. If 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 Upgrade Power Transformers project, if required.

3.1.9 Battery Banks and Chargers

3.1.9.1 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. An example of a 125 Vdc terminal station battery bank is provided as Figure 10.

3.1.9.2 Program Description and Justification

Currently, Hydro completes discharge testing on criticality A and B battery banks after 10 years, then every 5 years for flooded cell, and every 2 years for valve regulated. Replacements will be planned if the battery bank's capacity has fallen to 80% or less of its rated capacity. Due to the critical nature of battery banks, flooded cell batteries are replaced after 20 years, valve-regulated lead-acid batteries are replaced after 10 years, and battery chargers are replaced after 20 years.



Figure 10: 125 Vdc Terminal Station Battery Bank

3.1.10 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,[9] this alternate path is accomplished using a bypass switch (see Figure 11). When closed, the bypass switch allows electricity to flow around the breaker, allowing the breaker to be safely de-energized, while maintaining service continuity.

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

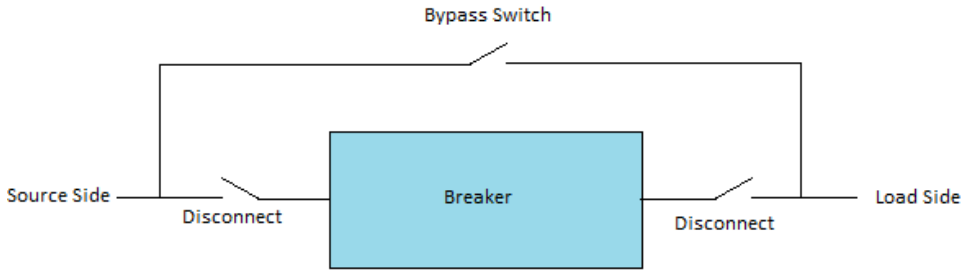


Figure 11: Example of Bypass Switch Installation

Table 1 lists the 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 a breaker bypass for those listed in Table 1.

Table 1: Circuit Breakers without Bypass Switches

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 665 Newfoundland Power Howley area customers
Peter's Barren B1L41	1,900 Great Northern Peninsula customers north of Daniel's Harbor
South Brook L22T1	2340 South Brook area customers

In 2018, Hydro put a hold on this program and is looking at only doing this work when other major terminal station work is planned or if there is a low-cost solution. 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.

3.1.11 Replace Station Lighting

Terminal station lighting is essential to provide adequate illumination for a safe working environment and to deter 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 (See Figure 12 and Figure 13), leading to moisture ingress, which impacts the function of the lighting system. In addition, 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

3.1.12 Synchronous Condensers

Hydro maintains two dedicated synchronous condensers located at the Wabush Terminal Station. Each synchronous condenser undergoes major and minor inspections on a three-year rotating cycle, with minor inspections performed in both year one and year two of the cycle and a major inspection

performed in 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, oil sampling, disassembly and inspection of top half of bearings, clearance checks, electrical tests, visual inspections, 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.

3.2 Civil Works and Buildings

3.2.1 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. Hydro also performs visual inspections of foundations every 120 days during regular terminal station inspections. Foundations identified for repair are addressed under this program.

3.2.2 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. Restoring a terminal station severely damaged by fire to normal operation could take months.

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

In the 2014 CBA project Install Fire Protection Upgrades - Holyrood [10,11] and the 2016 CBA project Install Fire Protection in 230 kV Stations - Bay d'Espoir,[12,13] Hydro received approval to install fire protection in the Holyrood and Bay d'Espoir Terminal Stations, respectively. Due to their criticality, Hydro intends to continue its program to install fire suppression systems in all 230 kV terminal stations.

3.2.3 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 office, breakroom, 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, Hydro must ensure 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 buildings involve the replacement of the roof membrane (Figure 16), siding, and doors (Figure 17) and may also include the 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).

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

[10] "Newfoundland and Labrador Hydro – 2014 Capital Budget Application," Newfoundland and Labrador Hydro, August 5, 2013, vol. I, sch. D, p. D-76.
http://www.pub.nl.ca/applications/ARCHIVE/NLH2014Capital/files/application/NLH2014ApplicationComplete-VolumeI.pdf
[11] Approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 42(2013), Board of Commissioners of Public Utilities, December 20, 2013.
[12] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol. III, tab 26.
http://pub.nl.ca/applications/ARCHIVE/2016/NLH2016Capital/files/application/NLH-2016-Capital-Budget-Application-Volume-III-2015-07-31.pdf
[13] Approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

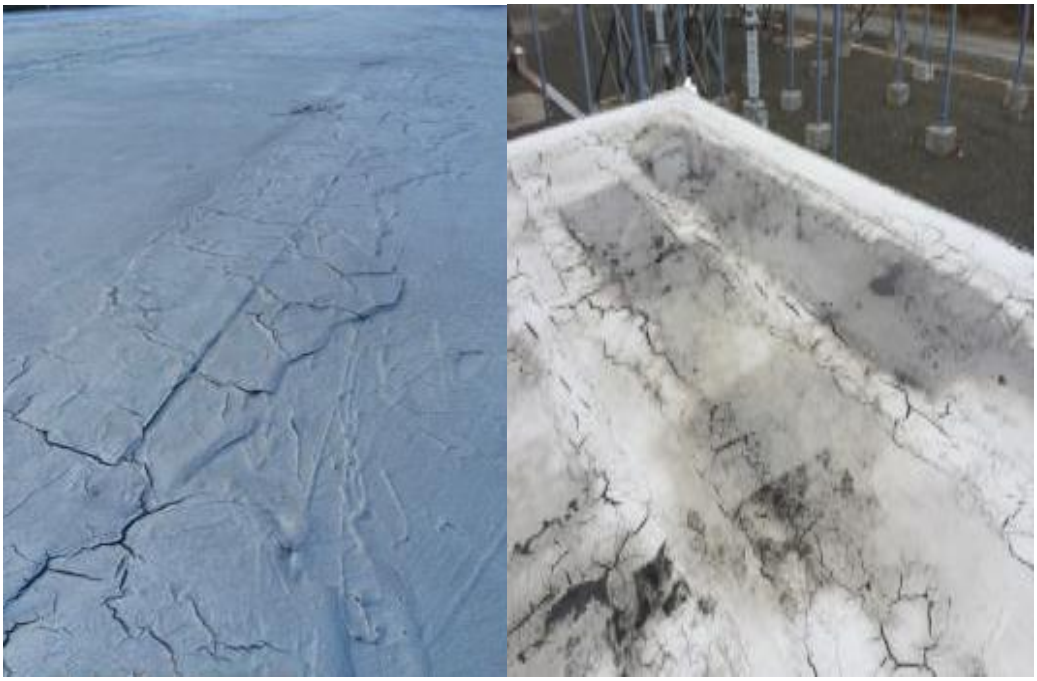


Figure 16: Terminal Station Control Buildings Showing Cracking and Deterioration of the Roof Membrane System



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

3.3 Protection, Control, and Monitoring

3.3.1 Protection and Control Upgrades and Refurbishment

3.3.1.1 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 system operators issue a command. The protection and control system also indicates and allows for the recording of system conditions and alarms 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 ("DFR"); and
- Cables and panels.

3.3.1.2 Program Description and Justification

Electromechanical and Solid State Protective Relay Replacement

Protective relays monitor and analyze the operational 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, which 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 shown in Figure 18.

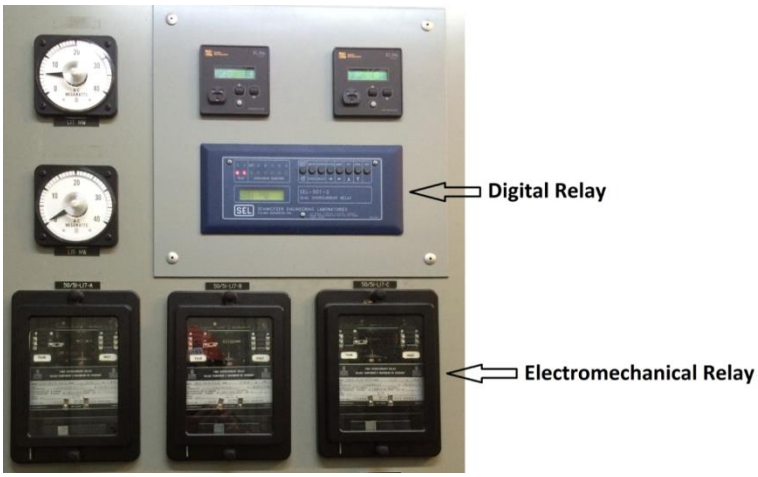


Figure 18: Digital and Electromechanical Relays

It is stated that "Hydro also 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."[14] 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. Priority was given to the 230 kV relay, as Phase 1, with 138 kV and 69 kV to follow.

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 project.[15] Additionally, Hydro installed redundant multifunction transformer protection relays in 2016 for transformers rated above 10 MVA.[16] Under this program, Hydro will continue to install these upgrades.

[14] "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, sec. 3.1, p. 7/26–28. http://pub.nl.ca/applications/IslandInterconnectedSystem/files/reports/AlarmsEventRecordingDevicesandDigitalRelays-2014-08-01.pdf

[15] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol. III, tab 19. http://pub.nl.ca/applications/ARCHIVE/2016/NLH2016Capital/files/application/NLH-2016-Capital-Budget-Application-Volume-III-2015-07-31.pdf

[16] In line with Section 1 of Hydro's "NL Hydro Protection & Control Standard – Transformer Protection," included as Attachment 1 to its response to CA-NLH-037, filed as part of the 2016 CBA proceeding. http://pub.nl.ca/applications/ARCHIVE/2016/NLH2016Capital/files/rfi/CA-NLH-037.PDF

Furthermore, 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 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.[17,18] Hydro will continue its plan to execute the installation of breaker failure protection in the remaining terminal stations. Hydro has also identified concerns with the reliability of legacy breaker failure in 230 kV stations and will be replacing, as necessary, under this program.

Tap Changer Paralleling Control Replacement

Tap changer paralleling controls are designed to:

- Ensure the load bus voltage is regulated, as prescribed by the setting;

[17] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol. I, sch. D, p. D-388. http://pub.nl.ca/applications/ARCHIVE/2016/NLH2016Capital/files/application/NLH-2016-Capital-Budget-Application-Volume-I-2015-07-31.pdf

[18] Approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

- Minimize the current that circulates between the transformers, as would be due to the tap changers operating on inappropriate tap positions; and
- 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. It was recommended the same controller model be applied to all transformers to optimize tap-changing control. The control issues described by the supplier have been seen by Hydro staff at numerous sites.

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

Equipment Alarm Upgrades

Alarms inform the Energy Control Centre ("ECC") and operating personnel that equipment and relaying require attention. These alarms are communicated to the ECC and/or displayed locally on the station annunciator (See 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; as such, Hydro plans to continue installing improved data alarm management in 230 kV terminal stations whose existing data alarm management includes grouped alarms.

Hydro's internal study identified required increases to alarm detail to the ECC for five 230 kV terminal stations assessed—Stony Brook, Holyrood, Sunnyside, Oxen Pond, and Massey Drive. Hydro proposed and received approval to implement the proposed upgrades at the Stony Brook Terminal Station as part of the 2016 CBA Upgrade Data Alarm Systems project.[19,20] Hydro will continue its plan to install improved data alarm management 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, which may negatively affect the safe and reliable operation of the generation and transmission systems. For this reason, Hydro also replaces deteriorated obsolete annunciators.

Digital Fault Recorders

DFR record analog electrical data (such as voltage, frequency, and current) and 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, 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 environment conditions, accidental damage, or the modification/addition of protection and control equipment.

[19] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol. I, sch. D, p. D-374. http://pub.nl.ca/applications/ARCHIVE/2016/NLH2016Capital/files/application/NLH-2016-Capital-Budget-Application-Volume-I-2015-07-31.pdf

[20] Approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

Appendix G

Risk Evaluation Matrix



Impact	Safety	Environment	System Reliability					
			Generation	Transmission and Terminals	Distribution	General Plant and Business Continuity		
						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 a 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 and February on the Island or between October and April in Labrador • Total loss of control of generating units by the Energy Control Centre • Total loss of hydraulic control structure	• Non-redundant equipment serving an industrial customer or Newfoundland Power urban area • Non-redundant equipment interconnecting generation to the Island or Labrador Interconnected Systems • Non-redundant 230 kV or supporting equipment	• Impact to an entire region (e.g., Avalon Peninsula Newfoundland Power customers) • Restoration time >36 hours or rotating outages for >36 hours	• Building unsafe to enter • Damage to equipment inside a 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 the 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 the 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 >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 a 10-km radius from Hydro property	• Loss of generation totaling 75 MW or greater • Loss of a prime power diesel generating unit • Incident occurs between April and November on the Island or between May and September in Labrador • Partial loss of control of a hydraulic control structure • Loss of control of a terminal station or non-staffed generating station by the Energy Control Centre	• Redundant equipment serving industrial customers or Newfoundland Power urban area • Redundant equipment interconnecting generation to the Island or Labrador Interconnected Systems • Redundant 230 kV or supporting equipment	• Impact on remote island community or other Newfoundland Power urban areas (St. John's Metro, Grand Falls, Gander, Corner Brook, >5,000 customers) • Restoration time is 24–36 hours or rotating outages for 24–36 hours	• Damage to equipment inside a 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 24–36 hours, or rotating outages 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 the loss of control/visibility of assets by the Energy Control Centre, impacts to the electricity system, or the inability to perform a critical function of the business • High impact on 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 are impacted
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 500-m radius)	• Loss of generation totaling 50 MW to 75 MW • Incident occurs between November and March on the Island or between September and April in Labrador	• Redundant 138 kV or supporting equipment • Non-redundant 66 kV/69 kV class or supporting equipment	• Impact to 1,000–5,000 customers • Restoration time of 12–24 hours	• Damage to equipment inside a building leading to a business or service interruption of infrastructure/assets (including IT/OT/IS) at multiple non-critical locations or a single critical location causing a disruption in performance levels between 12 and 24 hours, without suspending operations • Access to assets by ground leads to greater than a 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 Energy Control Centre, the electricity system, or a critical business function is compromised • Medium impact on electrical system stability • Cyber security event where the organization can safely perform primary functions at a reduced capacity • Interruption to non-critical service (infrastructure or application) where non-critical functions cannot be performed and between 50 and 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 MW to 50 MW • Incident occurs between May and October on the Island or between June and August in Labrador	• Redundant 138 kV or supporting equipment • Non-redundant 66 kV/69 kV class or supporting equipment	• Impact to 100–1,000 customers • Restoration time <8 hours	• Damage to equipment inside a building leading to a business or service interruption of non-critical infrastructure/assets or of critical infrastructure/assets that is restorable in 4–12 hours without disruption to performance levels • Access to assets by ground leading 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 on the Energy Control Centre or the electricity system but a critical business function is compromised • Low impact on electrical system stability • Cyber security event where the organization can safely perform primary functions • Interruption to non-critical service (Infrastructure or application) with non-critical function compromised for >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 Hydro property or adjacent properties	• Loss of generation up to 25 MW • Incident occurs between June and September on the Island or between July and August in Labrador	• Redundant 66 kV/69 kV class or supporting equipment	• Impact to <100 customers • Restoration time <4 hours	• Damage to equipment inside a building leading to a business or service interruption that is not noticed outside of the operational area monitoring the impacted system • Access to assets by ground leads to a 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 on the Energy Control Centre, the electricity system, or any critical business functions • No impact on 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 on users

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Risk Mitigated

	Risk Mitigated
General Plant	
Upgrade Work Protection Code Application (2025–2026)	15
Replace 48 V Battery Banks and Chargers (2025)	12
Replace Network Communications Equipment (2025)	12
Telecommunications In-Service Failures (2025)	12
Upgrade Remote Terminal Units (2025)	12
Implement SCADA Points Application (2025-2026)	10
Install Power Canal Public Safety Boom (2025) - Upper Salmon	10
Replace Interconnect Microwave Radios (2025)	10
Update Cyber Security Infrastructure (2025)	10
Install Electric Vehicle Chargers (2025–2026) - Hydro Sites	9
Purchase Surveying Software and Equipment (2025)	9
Refurbish Meteorological Stations (2025)	9
Replace Light- and Heavy-Duty Vehicles (2025–2027)	9
Replace Mobile Equipment (2025–2027)	9
Perform Level 2 Condition Assessment - Powerhouse Slope (2025) - Cat Arm	8
Perform Software Upgrades and Minor Enhancements (2025)	8
Purchase Tools and Equipment (2025)	8
Upgrade Core OT Infrastructure (2025)	8
Upgrade Energy Management System (2025–2026)	8
Install CCTV Systems (2025)	6
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2025)	6
Perform Security Improvements (2025)	6
Purchase Mobile Devices (2025)	6
Purchase Personal Computers (2025)	6
Replace GPS Clocks (2025–2026)	6
Replace Peripheral Infrastructure (2025)	6
Install Fire Protection - 230 kV Stations (2025–2026) - Come by Chance	5
Renewal	
Overhaul Turbine and Valves - Unit 3 (2025) - Holyrood	15
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood	15
Perform Level 2 Condition Assessment - Intake 4 and Unit 7 Draft Tube (2025) - Bay d'Espoir	15
Update Flame Scanners - Unit 3 (2025) - Holyrood	15
Diesel In-Service Failures (2025)	12
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2025)	12
Gas Turbine In-Service Failures (2025)	12
Hydraulic In-Service Failures (2025)	12
Inspect Fuel Tanks (2025) - Stephenville	12
Overhaul Hydraulic Units (2025)	12
Overhaul Major Pumps (2025) - Holyrood	12
Replace Human-Machine Interface (2025) - Stephenville	12
Rewind Stator (2025–2026) - Hinds Lake	12
Terminal Station In-Service Failures (2025)	12
Thermal In-Service Failures (2025)	12
Transmission In-Service Failures (2025)	12
Wood Pole Line Management (2025)	12

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Risk Mitigated

	Risk Mitigated
Perform Level 2 Condition Assessment - Stage 1 and 2 Cooling Water Sump Structures (2025) - Holyrood	10
Perform Major Inspection - Synchronous Condenser 2 (2025–2026) - Wabush	10
Refurbish Intake 2 (2025–2026) - Bay d'Espoir	10
Refurbish Marine Terminal (2025–2026) - Holyrood	10
Renew Circuit Breakers (2025–2026)	10
Replace Protective Relays (2025–2026)	10
Replace Terminal Station Battery Banks and Chargers (2025–2026)	10
Overhaul Diesel Units (2025)	8
Replace 250 Vdc Battery Bank (2025–2026) - Stephenville	8
Replace Diesel Gensets (2025–2027)	8
Replace Roof (2025) - Grey River	8
Upgrade Power Transformers (2025–2026)	8
Replace Instrument Transformers (2025–2026)	6
Install Breaker Failure Protection (2025–2027) - Holyrood	5
Replace Disconnects (2025–2026)	5
Replace Circuit Breaker Reclosing Controllers (2025–2026) - Cow Head and Massey Drive	4
Replace Emergency Diesel Genset (2025–2027) - Cat Arm	4
Upgrade Data Alarm Systems (2025–2026) - Hardwoods	4
Service Enhancement	
Perform Minor Telecommunications Enhancements (2025)	12
Remove Safety Hazards (2025)	12
Upgrade Worst-Performing Distribution Feeders (2025–2027)	12
Install Mid-Span Structures - TL220 (2025–2026)	5

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Risk Mitigated per $1 Million

	Risk Mitigated Per $1 Million
General Plant	
Telecommunications In-Service Failures (2025)	127.5
Update Cyber Security Infrastructure (2025)	86.5
Refurbish Meteorological Stations (2025)	53.6
Upgrade Remote Terminal Units (2025)	50.3
Perform Level 2 Condition Assessment - Powerhouse Slope (2025) - Cat Arm	47.2
Purchase Mobile Devices (2025)	37.4
Perform Security Improvements (2025)	37.3
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2025)	33.6
Replace Peripheral Infrastructure (2025)	29.2
Replace Network Communications Equipment (2025)	29.0
Purchase Surveying Software and Equipment (2025)	28.4
Implement SCADA Points Application (2025–2026)	26.0
Install Power Canal Public Safety Boom (2025) - Upper Salmon	21.6
Replace 48 V Battery Banks and Chargers (2025)	21.5
Upgrade Energy Management System (2025–2026)	16.9
Upgrade Work Protection Code Application (2025–2026)	16.6
Install Electric Vehicle Chargers (2025–2026) - Hydro Sites	13.7
Install CCTV Systems (2025)	13.6
Upgrade Core OT Infrastructure (2025)	11.9
Purchase Personal Computers (2025)	10.4
Replace GPS Clocks (2025–2026)	10.3
Perform Software Upgrades and Minor Enhancements (2025)	9.9
Replace Interconnect Microwave Radios (2025)	9.1
Install Fire Protection - 230 kV Stations (2025–2026) - Come by Chance	8.5
Purchase Tools and Equipment (2025)	5.7
Replace Mobile Equipment (2025–2027)	1.9
Replace Light- and Heavy-Duty Vehicles (2025–2027)	1.2
Renewal	
Update Flame Scanners - Unit 3 (2025) - Holyrood	106.7
Transmission In-Service Failures (2025)	65.1
Replace Human Machine Interface (2025) - Stephenville	43.3
Perform Level 2 Condition Assessment - Intake 4 and Unit 7 Draft Tube (2025) - Bay d'Espoir	31.8
Gas Turbine In-Service Failures (2025)	24.0
Replace Terminal Station Battery Banks and Chargers (2025–2026)	22.8
Replace 250 Vdc Battery Bank (2025–2026) - Stephenville	21.6
Replace Roof (2025) - Grey River	20.5
Inspect Fuel Tanks (2025) - Stephenville	17.7
Perform Major Inspection - Synchronous Condenser 2 (2025–2026) - Wabush	16.8
Diesel In-Service Failures (2025)	15.0
Replace Circuit Breaker Reclosing Controllers (2025–2026) - Cow Head and Massey Drive	14.9
Replace Instrument Transformers (2025–2026)	12.8
Perform Level 2 Condition Assessment - Stage 1 and 2 Cooling Water Sump Structures (2025) - Holyrood	11.2
Overhaul Major Pumps (2025) - Holyrood	10.9
Upgrade Data Alarm Systems (2025–2026) - Hardwoods	10.7
Renew Circuit Breakers (2025–2026)	8.7

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Risk Mitigated per $1 Million

	Risk Mitigated Per $1 Million
Overhaul Diesel Units (2025)	8.0
Install Breaker Failure Protection (2025–2027) - Holyrood	7.5
Hydraulic In-Service Failures (2025)	6.0
Terminal Station In-Service Failures (2025)	4.8
Upgrade Power Transformers (2025–2026)	4.0
Refurbish Marine Terminal (2025–2026) - Holyrood	4.0
Replace Protective Relays (2025–2026)	3.7
Replace Disconnects (2025–2026)	3.6
Thermal In-Service Failures (2025)	3.1
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood	3.1
Refurbish Intake 2 (2025–2026) - Bay d'Espoir	3.0
Wood Pole Line Management (2025)	2.8
Replace Emergency Diesel Genset (2025–2027) - Cat Arm	2.5
Overhaul Hydraulic Units (2025)	2.4
Distribution System In-Service Failures, Miscellaneous Upgrades and Street Lights (2025)	1.9
Replace Diesel Gensets (2025–2027)	1.3
Overhaul Turbine and Valves - Unit 3 (2025) - Holyrood	0.9
Rewind Stator (2025–2026) - Hinds Lake	0.8
Service Enhancement	
Perform Minor Telecommunications Enhancements (2025)	120.3
Remove Safety Hazards (2025)	59.0
Install Mid-Span Structures - TL220 (2025–2026)	4.5
Upgrade Worst-Performing Distribution Feeders (2025–2027)	1.4

Sch 2: Five-Year Capital Plan

Schedule 2

Five-Year Capital Plan (2025–2029)



2025 Capital Budget Application

Five-Year Capital Plan (2025–2029)



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Appendix A: Five-Year Capital Plan by Investment Class, and Major and Minor Asset Category (2025–2029)

Appendix B: Capital Expenditures (2020–2029)

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, provided as Appendix A to this Schedule, was developed consistent with its investment philosophy to invest responsibly in the electrical system to the benefit of its customers.[2] 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.[3] 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 2025–2029 Five-Year 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.

Total projected spending each year has increased due to the proposed infrastructure required to increase generation capacity to meet evolving electricity needs. These are made up of major projects required to respond to a rapidly changing energy landscape. As per the findings of the 2024 Resource Plan,[4] these investments include the installation of a combustion turbine with renewable fuel capabilities on the Avalon Peninsula ("Avalon CT"), Unit 8 at the Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir"), and up to 400 MW of wind energy. The 2024 Resource Plan provides further details on the projected utility needs in the province, and Hydro's plans to meet this demand.

[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] Hydro has also provided a ten-year summary of Capital Expenditures from 2020–2029 as Appendix B to this Schedule.
[3] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, December 20, 2021.
[4] "2024 Resource Adequacy Plan: An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, July 9, 2024 ("2024 Resource Plan").

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 $1.86 billion in plant and equipment over the 2025–2029 period; $1.86 billion is related to capital expenditures, including $1.19 billion related to major projects,[5] while $3.34 million is related to investment with up-front contributions (e.g., specifically assigned assets). The average total annual capital expenditure is approximately $372 million when major project additions are included, or $134 million excluding these supply additions. Chart 1 outlines the total planned capital spend per year from 2025–2029.

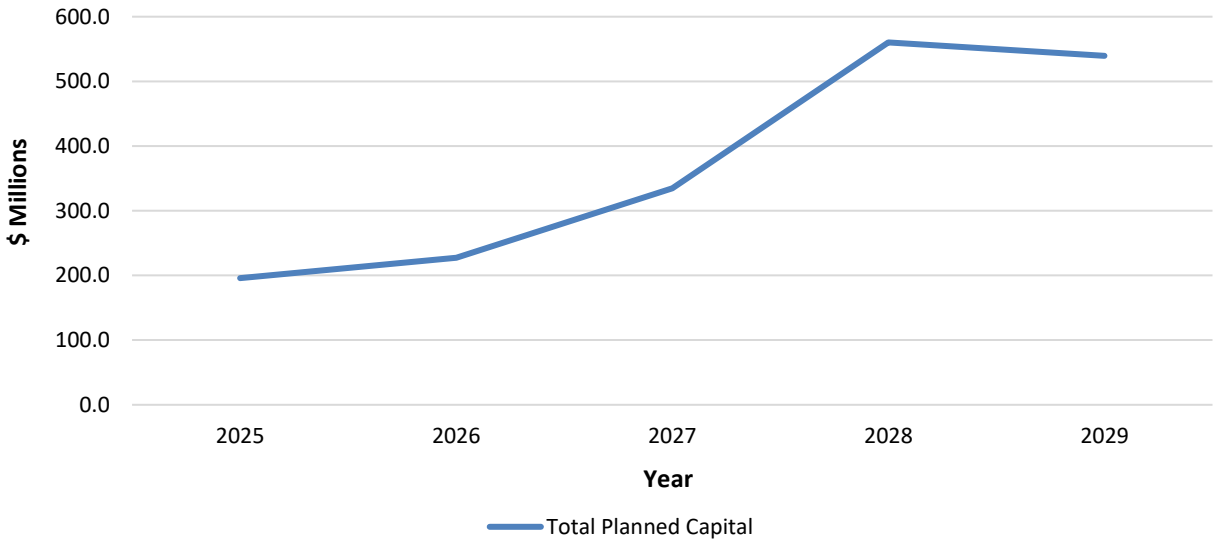


Chart 1: Total Planned Capital Expenditures (2025–2029)
($ Millions)

The projects identified for 2025–2029 are primarily required for system growth and renewal-driven capital.

[5] Major projects currently included in Hydro's five-year plan are as follows: Penstock 1 Life Extension – Phase 1 (2023–2025); Southern Labrador Interconnect; Unit 8 Installation – Bay d'Espoir; Refurbish Penstock 2 and 3 (2026–2028) – Bay d'Espoir; Avalon Combustion Turbine; and Unit 7 Major Refurbishment Turbine and Generator (2026–2029) – Bay d'Espoir.

Hydro filed its 2024 Resource Plan, which included its recommended expansion plan. The Expansion Plan indicates the need for additional generating assets (i) to ensure reliable system operation in the event of an extended outage on the Labrador-Island Link ("LIL") and (ii) to accommodate anticipated load growth on the Island Interconnected System.[6] As a result of this analysis, Hydro has commenced front-end engineering design for two critical additions to its resource supply—a new unit at Bay d'Espoir (Unit 8) and a new 150 MW CT on the Avalon Peninsula and anticipates filing an application for this additional generation in late 2024 or early 2025. Although some uncertainty remains surrounding the timing, cost, and scope of associated projects while design and planning are still ongoing, expenditures associated with these projects are now included in Hydro's 2025–2029 Five-Year Capital Plan.[7] As such, Hydro's planned system growth expenditures trend significantly upward over the 2025–2029 period, primarily as a result of the execution of major projects required for additional generation. Hydro also recognizes that transmission capacity expansion will also be required to address transmission bottlenecks; in support of Hydro's expansion plans, Hydro is exploring the viability of technical options including special protection schemes and dynamic line rating, which would help minimize the transmission investment required. Hydro anticipates that further details regarding these potential investments will be provided in its 2026 CBA.

Renewal expenditures are largely driven by the age of Hydro's assets. 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 ("Stephenville GT"), the Hardwoods Gas Turbine ("Hardwoods GT"), and much of Hydro's transmission and distribution systems, are more than 40–50 years old and require prudent sustaining capital investment to ensure their continued safe and reliable operation. Renewal-driven capital investments include new projects to renew Hydro's steel-tower transmission lines and major projects to refurbish Unit 7 and Penstocks 1, 2, and 3 at Bay d'Espoir. The 2025–2029 Five-Year Capital Plan also reflects system growth investments related to capital upgrades needed to accommodate growth in Labrador West. Other expenditures include service enhancement

[6] *Supra*, f.n. 4.
[7] Hydro's five-year capital plan may be updated as more details become available. Currently, Hydro forecasts the installation of the new Avalon CT and construction of Unit 8 at Bay d'Espoir, with the majority of these costs expected in 2028 and 2029.

projects, such as the interconnection of the communities of southern Labrador, and renewal of assets specifically assigned to Industrial customers ($3.34 million).[8]

Hydro has recommended that all three Holyrood TGS units and the Hardwoods GT and Stephenville GT are to remain available through the Bridging Period while Hydro seeks to develop new long-term sources of supply. In 2021, Hydro engaged Hatch Ltd. ("Hatch") 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.[9] Hydro's planned thermal generation capital expenditures for the period 2025–2029 reflect the findings of this study and includes projects for the renewal of assets at the Holyrood TGS. A refresh of this study to evaluate the continued extension of the Holyrood TGS beyond the current retirement period will be completed by Hatch in late 2024 and will help inform Hydro's 2026–2035 capital plans.

Hydro is cognizant of the significant investment required to implement additional generation and therefore, will continue to 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,[10] and continuing its approach initially presented in the 2023 CBA, Hydro has provided a discussion of significant expenditures within each investment classification. This approach allows Hydro to focus 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.

Hydro's five-year planned expenditures for the period 2025–2029, segmented by investment classification, are presented in Chart 2.

[8] Excluding federal government contributions for ultra-fast direct current fast chargers.
[9] "*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.
[10] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, December 20, 2021.

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

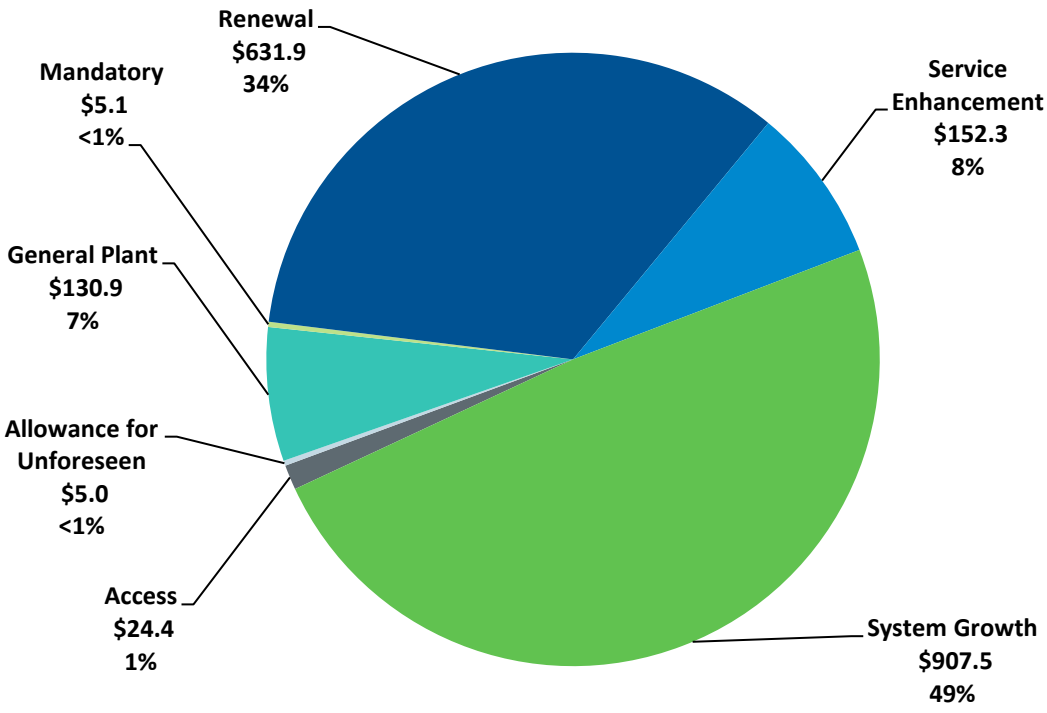


Chart 2: Five-Year Planned Capital Expenditures by Investment Classification (2025–2029) ($ Millions)

3.1 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 $908 million, or 49%, of Hydro's planned capital expenditures for the next five years. Hydro's planned system growth expenditures for the period 2025–2029 are provided in Chart 3.

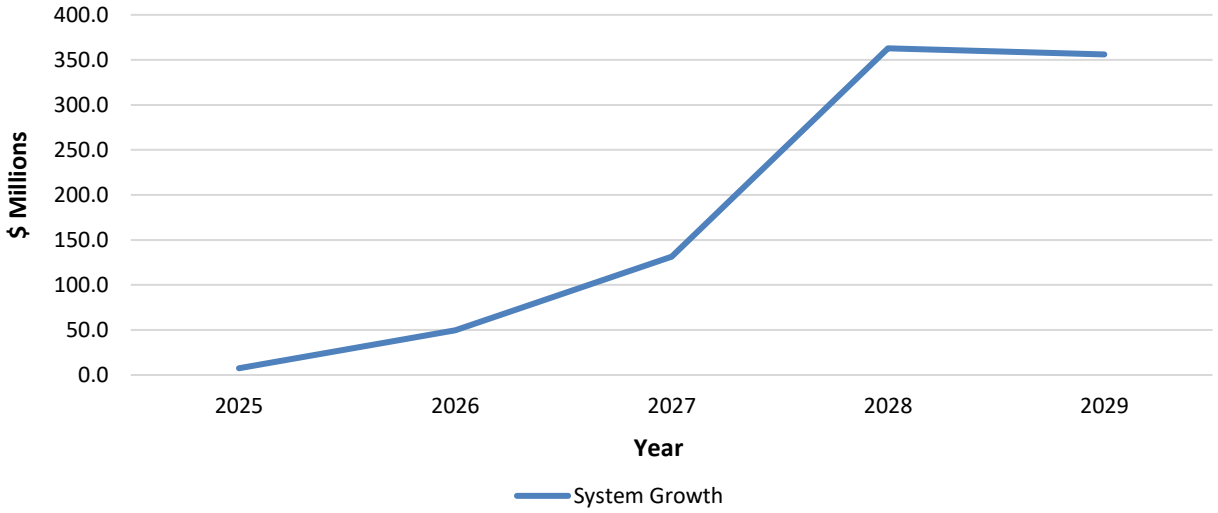


Chart 3: Planned System Growth Capital Expenditures (2025–2029)
($ Millions)

As forecast, Hydro's planned system growth expenditures trend significantly upward over the 2025–2029 period, primarily as a result of the execution of major projects required for additional generation on the Island Interconnected System to respond to a rapidly changing energy landscape. As per the findings of the 2024 Resource Plan, these investments include the installation of a new 150 MW Avalon CT with renewable fuel capabilities and Unit 8 – a new 154 MW hydroelectric unit in Bay d'Espoir, as detailed below. Hydro's planned system growth investments in the five-year plan consist of:

- Installation of the new Avalon CT and construction of Unit 8 at Bay d'Espoir, which are required as per the 2024 Resource Plan to provide additional generation on the Island Interconnected System;
- Continuation of Hydro's Additions For Load Growth Program 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.

3.2 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 $632 million, or 34%, of Hydro's planned capital expenditures for the next five years. Hydro's planned renewal expenditures for the period 2025–2029 are provided in Chart 4.

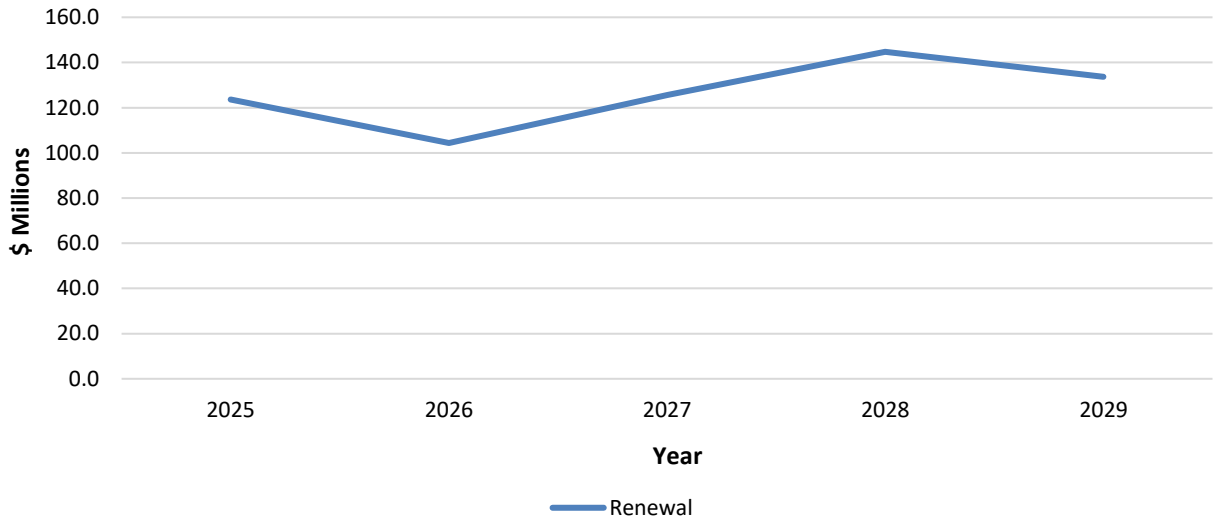


Chart 4: Planned Renewal Capital Expenditures (2025–2029)
($ Millions)

Hydro's planned renewal expenditures remain relatively consistent for the period, aside from increased expenditures in 2028. The increase in 2028 is primarily due to planned expenditures associated with the refurbishment of the Bay d'Espoir Penstocks and Unit 7 Turbine and Generator, as detailed below.

Generation renewal-driven investment is forecast to total $463 million over the next five years. The requirement to invest sustaining capital in generation facilities has been increasing 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 investment in projects required

for the renewal of Holyrood TGS assets. Hydro's planned renewal expenditures related to Holyrood TGS assets peaks in 2025, primarily due to planned expenditures associated with the Unit 3 turbine and valve overhaul, and decreases thereafter, as expected. 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 capital plan are as follows:

- 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. In particular, major refurbishment of the Unit 7 turbine and generator at the Bay d'Espoir, planned to commence in 2026.[11]
- Penstock Life Extension—Hydro received approval for Phase 1 of this initiative, which involves the refurbishment of Penstock 1 at the Bay d'Espoir in 2023, planned for completion in 2025. Phase 2, which will see the refurbishment of Penstocks 2 and 3, is planned to commence in 2026. An update on the execution of Phase 1 of this initiative is provided in Hydro's 2024 Capital Expenditure Overview, included as Schedule 5.
- 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. In particular, overhaul of the Unit 3 turbine and valves, planned to occur in 2025.
- Renewal of Gas Turbine Assets – In particular, major inspection of the Holyrood Gas Turbine required on the basis of turbine operating hours, planned to commence in 2028.

Renewal-driven investments also include the In-Service Failures Program in all years, which is an allotment of funds to be used in the event that immediate refurbishment or replacement must be

[11] Further discussion of Hydro's planned expenditures for Bay d'Espoir is provided in the Bay d'Espoir Hydroelectric Generating Station – Projected Capital Expenditures (2025–2034) report, which is provided as Schedule 4 to this application.

completed due to the occurrence of an actual failure, the identification of an incipient failure, or determination of faster-than-anticipated equipment deterioration.[12]

Transmission and Rural Operations ("TRO") renewal-driven investment is forecast to be $169 million over the next five years. TRO renewal investment is largely driven by Hydro's asset renewal programs, such as its Terminal Station 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;
- Hydro's Wood Pole Line Management Program, required for renewal of wood pole transmission lines;
- Hydro's Diesel Unit Replacement and Overhaul programs, required to maintain the reliable operation of Hydro's diesel generating stations and maintain customer demand;
- Renewal of distribution feeders through Hydro's Renew Distribution Feeders programs; and
- Renewal of steel-tower transmission lines, required to address deficiencies identified by inspection with two transmission lines currently planned for renewal over the next five years.

3.3 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 approximately $152 million, or 8%, of Hydro's planned capital expenditures for the next five years. Hydro's planned service enhancement expenditures for the period 2025–2029 are provided in Chart 5.

[12] 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.

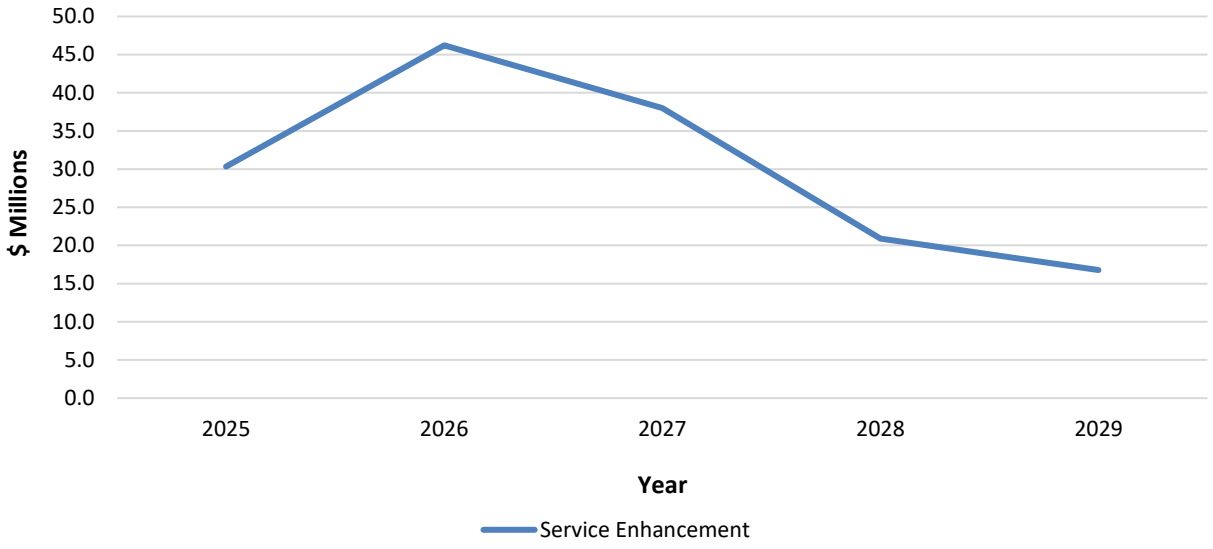


Chart 5: Planned Service Enhancement Capital Expenditures (2025–2029)
($ Millions)

Hydro's planned service enhancement expenditures peak is in 2026, and trend downwards for the remainder of the period; this is primarily due to expenditures associated with Hydro's proposed long-term plan for supply for southern Labrador.

Hydro's total planned service enhancement expenditures for the period 2025–2029 organized by major asset category are provided in Chart 6.

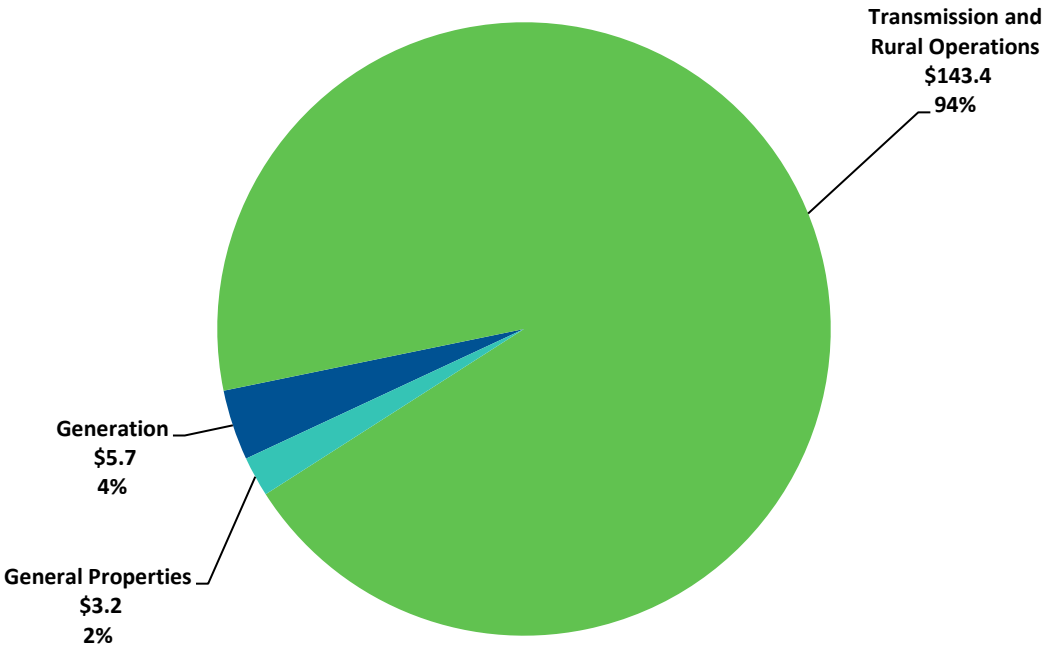


**Chart 6: Five-Year Planned Service Enhancement Expenditures by Asset Category (2025–2029)
($ Millions)**

The primary drivers of planned service enhancement investment in Hydro's five-year capital plan are related to TRO, and 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;[13]
- Hydro's Upgrade of Worst-Performing Distribution Feeders Program, 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

[13] "Long-Term Supply for Southern Labrador – Revision 2," Newfoundland and Labrador Hydro, rev. October 5, 2023 (originally filed July 16, 2021). Regulatory review of Hydro's application is ongoing.

- Replacement of the diesel plant in Rigolet, planned to commence in 2028, due to the facility having reached the end of its useful life and maximum spatial capacity.

3.4 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 totals approximately $131 million, or 7% of Hydro's planned capital expenditures for the next five years. Hydro's planned general plant expenditures for the period 2025–2029 are provided in Chart 7.

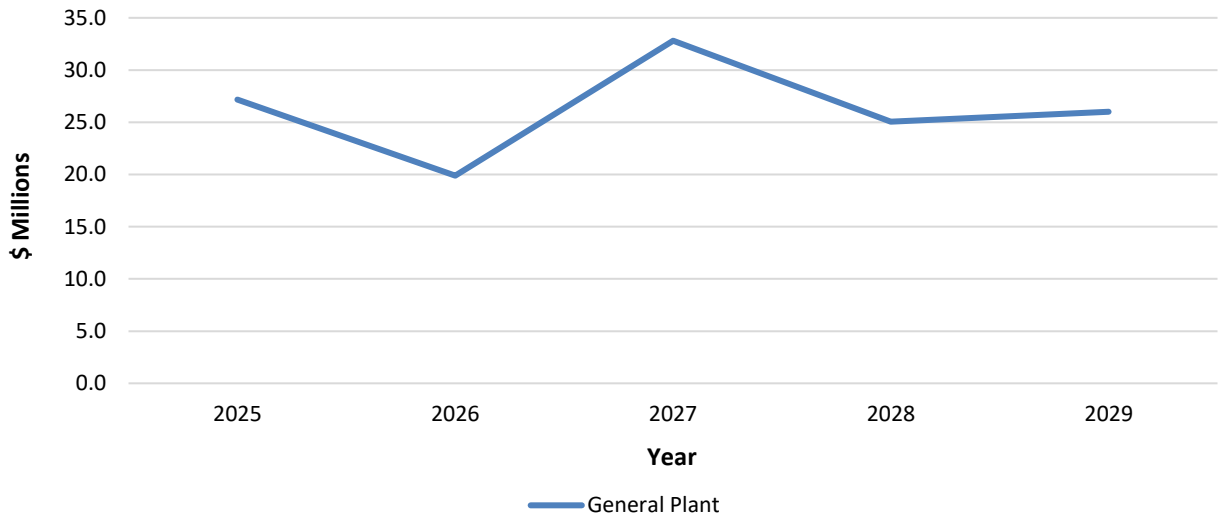


Chart 7: Planned General Plant Capital Expenditures (2025–2029)
($ Millions)

Hydro's planned general plant expenditures remain relatively steady over the period, aside from a peak in 2027. Rising expenditures in 2027 are primarily associated with the installation of a plant heating system at the Holyrood TGS which is planned to commence in 2026, and is detailed below.

Hydro's total planned general plant expenditures for the period 2025–2029 organized by major asset category is provided in Chart 8.

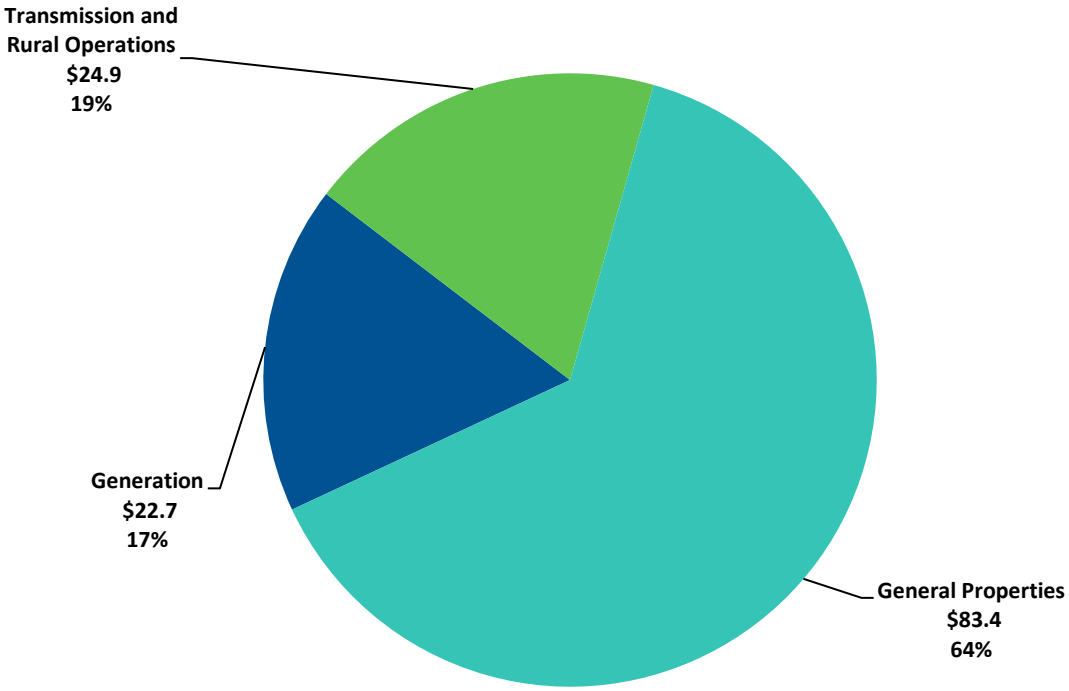


Chart 8: Five-Year Planned General Plant Expenditures by Asset Category (2025–2029)
($ Millions)

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 continues to experience higher than average vehicle expenditures resulting from global supply chain challenges and increased inflation, and is required to renew Hydro's fleet of light- and heavy-duty vehicles that support the operation and maintenance of its assets;
- Projects and programs to renew information systems infrastructure, such as software, cybersecurity, and operations technology infrastructure, personal computers, and mobile devices;
- Projects and programs to renew telecontrol infrastructure, including microwave radio systems, fibre-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. In particular, refurbishment of the windows at Hydro Place which have reached the end of their useful life, with work planned to commence in 2026.

3.5 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 approximately $24 million, or 1%, of Hydro's planned capital expenditures for the next five years. Hydro's planned access expenditures for the period 2025–2029 are provided in Chart 9.

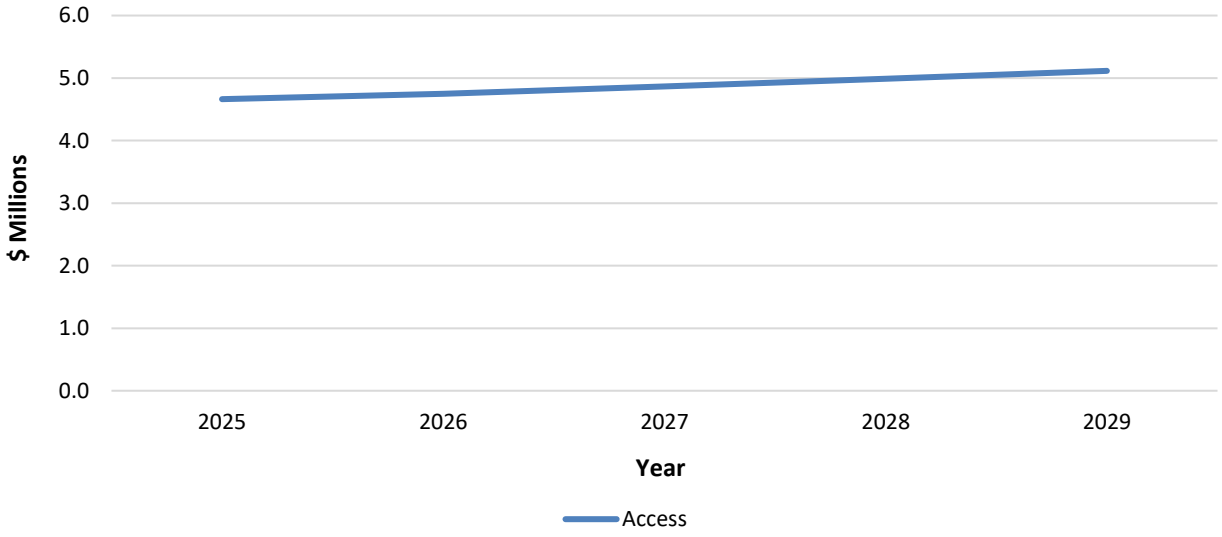


Chart 9: Planned Access Capital Expenditures (2025–2029)
($ Millions)

Hydro's planned access-driven expenditures remain consistent for the period 2025–2029. Hydro's five-year plan and relate to the continuation of the Provide Service Extensions Program, which is required to provide service extensions to accommodate customers' requests for service.

4.0 Conclusion

Hydro's five-year plan reflects an investment of approximately $1.86 billion in plant and equipment over the 2025–2029 period; $1.86 billion is related to capital expenditures, including $1.19 billion related to major projects, while $3.34 million is related to investment assets with up-front contributions.

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

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 by Investment Class, and Major and Minor Asset Category (2025–2029)



Newfoundland and Labrador Hydro
2025 Capital Budget Application
Five-Year Capital Plan Summary By Investment Class [1]
($000)

	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Access	-	4,662.5	4,749.0	4,868.0	4,990.0	5,115.0	**24,384.5**
Allowance for Unforeseen	-	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	**5,000.0**
General Plant	11,011.1	27,182.3	19,887.8	32,809.0	25,056.0	26,007.9	**141,954.0**
Mandatory	91.6	1,483.2	1,228.4	945.0	720.0	745.0	**5,213.2**
Renewal	36,059.0	123,597.8	104,364.1	125,540.1	144,725.7	133,673.7	**667,960.3**
Service Enhancement	2,896.8	30,351.5	46,215.3	38,014.8	20,904.3	16,781.4	**155,164.0**
System Growth	10,842.3	7,540.3	49,742.9	131,456.9	362,827.3	355,949.2	**918,358.9**
Total Capital Plan	**60,900.8**	**195,817.6**	**227,187.5**	**334,633.7**	**560,223.2**	**539,272.1**	**1,918,035.0**

[1] Numbers may not add due to rounding.

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Five-Year Capital Plan Detailed Breakdown By Investment Classification [1]
($000)

	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Access							
Provide Service Extensions (2025)	-	4,662.5	-	-	-	-	**4,662.5**
Provide Service Extensions (2026)	-	-	4,749.0	-	-	-	**4,749.0**
Provide Service Extensions (2027)	-	-	-	4,868.0	-	-	**4,868.0**
Provide Service Extensions (2028)	-	-	-	-	4,990.0	-	**4,990.0**
Provide Service Extensions (2029)	-	-	-	-	-	5,115.0	**5,115.0**
Access Total	**-**	**4,662.5**	**4,749.0**	**4,868.0**	**4,990.0**	**5,115.0**	**24,384.5**
Allowance for Unforeseen							
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 Items (2029)	-	-	-	-	-	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 (2023–2025)	3,892.7	673.3	-	-	-	-	**4,566.0**
Install Ultra-Fast DC Electric Vehicle Chargers	1,828.5	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 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**
Complete Level 4 Fire Restoration (2024–2025) - Hydro Place	750.2	317.7	-	-	-	-	**1,067.9**
Replace Mobile Equipment (2024–2025)	216.9	599.7	-	-	-	-	**816.6**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025) - Holyrood	156.2	1,039.4	-	-	-	-	**1,195.6**
Replace Powerhouse 1 Roof (2024–2025) - Bay d'Espoir	140.2	1,819.2	-	-	-	-	**1,959.4**
Refurbish Control Building (2024–2025) - Grandy Brook and Doyles	109.4	444.7	-	-	-	-	**554.1**
Replace Power Line Carrier (2024-2025) - TL247	87.2	667.4	-	-	-	-	**754.6**
Replace Air Conditioning Unit - Powerhouse 1 (2024–2025) - Bay d'Espoir	57.8	231.2	-	-	-	-	**289.0**
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	53.8	599.0	-	-	-	-	**652.8**
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024–2026) - Happy Valley-Goose Bay	24.0	841.8	7.1	-	-	-	**872.9**
Replace Light- and Heavy-Duty Vehicles (2025–2027)	-	2,714.6	1,675.8	3,147.2	-	-	**7,537.6**
Replace Mobile Equipment (2025–2027)	-	1,973.6	54.6	2,619.4	-	-	**4,647.6**
Purchase Tools and Equipment (2025)	-	1,399.1	-	-	-	-	**1,399.1**
Replace Interconnect Microwave Radios (2025)	-	1,103.0	-	-	-	-	**1,103.0**
Perform Software Upgrades and Minor Enhancements (2025)	-	808.7	-	-	-	-	**808.7**
Upgrade Core OT Infrastructure (2025)	-	674.3	-	-	-	-	**674.3**
Purchase Personal Computers (2025)	-	575.6	-	-	-	-	**575.6**
Replace 48 V Battery Banks and Chargers (2025)	-	559.1	-	-	-	-	**559.1**
Install Power Canal Public Safety Boom (2025) - Upper Salmon	-	463.8	-	-	-	-	**463.8**
Upgrade Work Protection Code Application (2025–2026)	-	452.0	449.4	-	-	-	**901.4**
Replace GPS Clocks (2025–2026)	-	448.3	132.4	-	-	-	**580.7**
Install CCTV Systems (2025)	-	440.1	-	-	-	-	**440.1**
Replace Network Communications Equipment (2025)	-	413.2	-	-	-	-	**413.2**
Install Electric Vehicle Chargers (2025–2026) - Hydro Sites	-	368.0	288.2	-	-	-	**656.1**
Purchase Surveying Software and Equipment (2025)	-	316.4	-	-	-	-	**316.4**
Upgrade Energy Management System (2025–2026)	-	284.4	188.5	-	-	-	**472.9**
Implement SCADA Points Application (2025–2026)	-	241.9	143.4	-	-	-	**385.3**
Upgrade Remote Terminal Units (2025)	-	238.4	-	-	-	-	**238.4**
Replace Peripheral Infrastructure (2025)	-	205.4	-	-	-	-	**205.4**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2025)	-	178.5	-	-	-	-	**178.5**
Perform Level 2 Condition Assessment - Powerhouse Slope (2025) - Cat Arm	-	169.4	-	-	-	-	**169.4**
Refurbish Meteorological Stations (2025)	-	167.8	-	-	-	-	**167.8**
Perform Security Improvements (2025)	-	160.7	-	-	-	-	**160.7**
Purchase Mobile Devices (2025)	-	160.2	-	-	-	-	**160.2**
Update Cyber Security Infrastructure (2025)	-	115.6	-	-	-	-	**115.6**
Telecommunications In-Service Failures (2025)	-	94.1	-	-	-	-	**94.1**
Install Fire Protection in 230 kV Stations (2025–2026) - Come by Chance	-	51.7	534.5	-	-	-	**586.2**

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Five-Year Capital Plan Detailed Breakdown By Investment Classification [1]
($000)

	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Replace Light- and Heavy-Duty Vehicles (2026–2028)	-	-	2,800.0	125.0	3,800.0	-	**6,725.0**
Replace Diesel Shop Building (2026–2027) - Bishop's Falls	-	-	1,422.0	889.9	-	-	**2,311.9**
Purchase Tools and Equipment (2026)	-	-	1,413.7	-	-	-	**1,413.7**
Replace Mobile Equipment (2026–2028)	-	-	1,350.0	90.0	2,950.0	-	**4,390.0**
Refurbish Windows (2026–2029) - Hydro Place	-	-	1,279.3	1,267.2	1,289.8	1,312.8	**5,149.1**
Purchase Personal Computers (2026)	-	-	912.8	-	-	-	**912.8**
Install Plant Heating System (2026–2027) - Holyrood	-	-	901.3	9,594.0	-	-	**10,495.3**
Perform Building Refurbishments (2026–2027)	-	-	750.0	400.0	-	-	**1,150.0**
Refurbish Building Envelopes (2026–2027) - Holyrood	-	-	750.0	500.0	-	-	**1,250.0**
Perform Software Upgrades and Minor Enhancements (2026)	-	-	625.0	-	-	-	**625.0**
Perform Accessibility Improvements (2026–2029)	-	-	450.0	350.0	175.0	160.0	**1,135.0**
Replace 48 V Battery Banks and Chargers (2026)	-	-	441.1	-	-	-	**441.1**
Replace Walkway to Toe of Dam (2026) - Paradise River	-	-	391.0	-	-	-	**391.0**
Upgrade Core OT Infrastructure (2026)	-	-	375.0	-	-	-	**375.0**
Update Cyber Security Infrastructure (2026)	-	-	322.0	-	-	-	**322.0**
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**
Refurbish Meteorological Stations - Phase 2 (2026)	-	-	200.0	-	-	-	**200.0**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2026)	-	-	194.2	-	-	-	**194.2**
Upgrade Remote Terminal Units (2026)	-	-	173.0	-	-	-	**173.0**
Replace Peripheral Infrastructure (2026)	-	-	164.5	-	-	-	**164.5**
Upgrade Spherical Valve Controls (2026–2029) - Bay d'Espoir	-	-	150.0	210.2	213.8	217.5	**791.5**
Replace UPS System - Backup Control Center (2026) - Holyrood	-	-	150.0	-	-	-	**150.0**
Replace Teleprotection Equipment (2026–2027)	-	-	100.0	250.0	-	-	**350.0**
Replace Backup Generators at Microwave Repeater Sites (2026–2027)	-	-	100.0	100.0	-	-	**200.0**
Refurbish Office - Energy Efficiency and HVAC (2026–2027) - Deer Lake	-	-	100.0	100.0	-	-	**200.0**
Telecommunications In-Service Failures (2026)	-	-	96.0	-	-	-	**96.0**
Install Fire Protection in 230 kV Stations (2026–2027) - Bottom Brook	-	-	68.4	616.5	-	-	**684.9**
Install Electric Vehicle Chargers (2026–2027) - Hydro Sites	-	-	51.6	367.9	-	-	**419.5**
Replace Radio Links to Hydraulic Control Structures (2026–2027)	-	-	50.0	100.0	-	-	**150.0**
Replace Network Communications Equipment (2029)	-	-	-	-	-	243.0	**243.0**
Replace Light- and Heavy-Duty Vehicles (2027–2029)	-	-	-	2,900.0	815.0	3,500.0	**7,215.0**
Purchase Tools and Equipment (2027)	-	-	-	1,417.5	-	-	**1,417.5**
Replace Mobile Equipment (2027–2029)	-	-	-	1,300.0	100.0	2,950.0	**4,350.0**
Purchase Personal Computers (2027)	-	-	-	957.9	-	-	**957.9**
Perform Building Refurbishments (2027–2028)	-	-	-	650.0	550.0	-	**1,200.0**
Perform Software Upgrades and Minor Enhancements (2027)	-	-	-	625.0	-	-	**625.0**
Resurface Parking Lots and Roads (2027) - Bishop's Falls	-	-	-	500.0	400.0	-	**900.0**
Replace 48 V Battery Banks and Chargers (2027)	-	-	-	454.4	-	-	**454.4**
Upgrade Core OT Infrastructure (2027)	-	-	-	375.0	-	-	**375.0**
Update Cyber Security Infrastructure (2027)	-	-	-	350.0	-	-	**350.0**
Upgrade Fire System (2027) - Holyrood	-	-	-	350.0	-	-	**350.0**
Upgrade Energy Management System (2027–2028)	-	-	-	283.0	184.2	-	**467.2**
Replace Peripheral Infrastructure (2027)	-	-	-	261.2	-	-	**261.2**
Replace Network Communications Equipment (2027)	-	-	-	229.0	-	-	**229.0**
Install CCTV Systems (2027)	-	-	-	212.2	-	-	**212.2**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2027)	-	-	-	197.6	-	-	**197.6**
Upgrade Fire Panel and Devices (2027) - Hydro Place	-	-	-	197.0	-	-	**197.0**
Purchase Mobile Devices (2027)	-	-	-	183.4	-	-	**183.4**
Upgrade Remote Terminal Units (2027)	-	-	-	179.0	-	-	**179.0**
Replace Cisco Call Manager Appliances (2027)	-	-	-	130.0	-	-	**130.0**
Telecommunications In-Service Failures (2027)	-	-	-	99.0	-	-	**99.0**
Replace Power Line Carrier (2027–2028) - TL212	-	-	-	93.6	681.4	-	**775.0**
Replace Powerhouse Roofs (2027–2028) - Hinds Lake	-	-	-	84.3	735.8	-	**820.1**
Install Electric Vehicle Chargers (2027–2028) - Hydro Sites	-	-	-	52.6	374.2	-	**426.8**
Replace Mobile Equipment (2028–2030)	-	-	-	-	1,800.0	100.0	**1,900.0**
Replace Light- and Heavy-Duty Vehicles (2028–2030)	-	-	-	-	1,700.0	1,900.0	**3,600.0**

Newfoundland and Labrador Hydro
2025 Capital Budget Application
Five-Year Capital Plan Detailed Breakdown By Investment Classification [1]
($000)

	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Purchase Tools and Equipment (2028)	-	-	-	-	1,421.4	-	**1,421.4**
Replace Powerhouse 2 Roof (2028) - Bay d'Espoir	-	-	-	-	960.0	-	**960.0**
Perform Software Upgrades and Minor Enhancements (2028)	-	-	-	-	725.0	-	**725.0**
Perform Building Refurbishments (2028–2029)	-	-	-	-	550.0	750.0	**1,300.0**
Replace/Upgrade Fire Suppression System (2028) - Hydro Place	-	-	-	-	528.5	-	**528.5**
Replace Controllers (2028–2031) - Granite Canal	-	-	-	-	500.0	500.0	**1,000.0**
Replace Generators and Associated Switchgear (2028) - Hydro Place	-	-	-	-	500.0	544.0	**1,044.0**
Replace 48 V Battery Banks and Chargers (2028)	-	-	-	-	468.0	-	**468.0**
Purchase Personal Computers (2028)	-	-	-	-	465.5	-	**465.5**
Upgrade Core OT Infrastructure (2028)	-	-	-	-	425.0	-	**425.0**
Update Cyber Security Infrastructure (2028)	-	-	-	-	375.0	-	**375.0**
Upgrade Drainage to Stop Frost Heaving (2028) - Stoney Brook, Springdale, Holyrood, Jackson's Arm, and Buchans	-	-	-	-	250.0	-	**250.0**
Replace HVAC Equipment (2028–2029) - Hydro Place	-	-	-	-	240.0	200.0	**440.0**
Replace Network Communications Equipment (2028)	-	-	-	-	236.0	-	**236.0**
Install CCTV Systems (2028)	-	-	-	-	218.5	-	**218.5**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2028)	-	-	-	-	201.0	-	**201.0**
Stabilize Powerhouse Slope (2028) - Cat Arm	-	-	-	-	200.0	-	**200.0**
Upgrade Remote Terminal Units (2028)	-	-	-	-	184.0	-	**184.0**
Replace Sewage System (2028) - Bishop's Falls	-	-	-	-	156.1	-	**156.1**
Purchase Mobile Devices (2028)	-	-	-	-	144.0	-	**144.0**
Replace Peripheral Infrastructure (2028)	-	-	-	-	133.3	-	**133.3**
Telecommunications In-Service Failures (2028)	-	-	-	-	102.0	-	**102.0**
Replace Fuel Tank, Lines, Pumps, and Associated Hardware (2028) - Hydro Place	-	-	-	-	100.0	-	**100.0**
Refurbish Rip Rap - CD4 (2028–2029) - Cat Arm	-	-	-	-	100.0	450.0	**550.0**
Install Electric Vehicle Chargers (2028–2029) - Hydro Sites	-	-	-	-	53.5	380.7	**434.1**
Replace Septic System - Burnt Dam (2028–2029) - Bay d'Espoir	-	-	-	-	50.0	125.0	**175.0**
Replace Light- and Heavy-Duty Vehicles (2029–2031)	-	-	-	-	-	2,800.0	**2,800.0**
Replace Mobile Equipment (2029–2031)	-	-	-	-	-	1,800.0	**1,800.0**
Replace Powerhouse Roof (2029) - Cat Arm	-	-	-	-	-	1,500.0	**1,500.0**
Purchase Tools and Equipment (2029)	-	-	-	-	-	1,425.5	**1,425.5**
Perform Software Upgrades and Minor Enhancements (2029)	-	-	-	-	-	650.0	**650.0**
Perform Building Refurbishments (2029–2030)	-	-	-	-	-	500.0	**500.0**
Replace 48 V Battery Banks and Chargers (2029)	-	-	-	-	-	482.0	**482.0**
Renew Property, Grounds, and Infrastructure (2029) - St. Anthony, Bishop's Falls, Stephenville, and Whitbourne	-	-	-	-	-	445.3	**445.3**
Purchase Personal Computers (2029)	-	-	-	-	-	441.5	**441.5**
Upgrade Core OT Infrastructure (2029)	-	-	-	-	-	425.0	**425.0**
Update Cyber Security Infrastructure (2029)	-	-	-	-	-	392.0	**392.0**
Upgrade Energy Management System (2029–2030)	-	-	-	-	-	302.8	**302.8**
Replace Emergency Diesel Genset - North Salmon Spillway (2029–2030) - Upper Salmon	-	-	-	-	-	250.0	**250.0**
Purchase Mobile Devices (2029)	-	-	-	-	-	221.0	**221.0**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2029)	-	-	-	-	-	204.5	**204.5**
Upgrade Remote Terminal Units (2029)	-	-	-	-	-	190.0	**190.0**
Replace Peripheral Infrastructure (2029)	-	-	-	-	-	164.0	**164.0**
Perform Level 2 Condition Assessment - Site Buildings (2029) - Holyrood	-	-	-	-	-	120.0	**120.0**
Telecommunications In-Service Failures (2029)	-	-	-	-	-	105.0	**105.0**
Install CCTV Systems (2029)	-	-	-	-	-	102.0	**102.0**
Refurbish Rip Rap - SD-2 - West Salmon Dam (2029–2030) - Upper Salmon	-	-	-	-	-	100.0	**100.0**
Install Electric Vehicle Chargers (2029–2030) - Hydro Sites	-	-	-	-	-	54.4	**54.4**
General Plant Total	**11,011.1**	**27,182.3**	**19,887.8**	**32,809.0**	**25,056.0**	**26,007.9**	**141,954.0**

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	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Mandatory							
Upgrade Station Lighting (2024–2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon	91.6	429.0	-	-	-	-	**520.6**
Inspect Fuel Tanks (2025) - Holyrood	-	608.0	-	-	-	-	**608.0**
Purchase Meters and Metering Equipment (2025–2026)	-	446.2	278.4	-	-	-	**724.6**
Purchase Meters and Metering Equipment (2026)	-	-	950.0	-	-	-	**950.0**
Purchase Meters and Metering Equipment (2027)	-	-	-	945.0	-	-	**945.0**
Purchase Meters and Metering Equipment (2028)	-	-	-	-	720.0	-	**720.0**
Purchase Meters and Metering Equipment (2029)	-	-	-	-	-	745.0	**745.0**
Mandatory Total	**91.6**	**1,483.2**	**1,228.4**	**945.0**	**720.0**	**745.0**	**5,213.2**
Renewal							
Refurbish Control Structure (2021–2025) - Ebbegunbaeg	12,726.8	4,952.2	-	-	-	-	**17,679.0**
Penstock 1 Life Extension - Phase 1 (2023–2025)	15,277.6	35,329.1	-	-	-	-	**50,606.7**
Diesel Genset Replacement Program (2023–2025)	993.1	1,415.1	-	-	-	-	**2,408.2**
Replace Protective Relays (2024–2025)	1,388.4	2,050.7	-	-	-	-	**3,439.1**
Renew Distribution Feeders (2024–2025)	1,287.3	1,245.1	-	-	-	-	**2,532.4**
Upgrade Power Transformers (2024–2025)	864.6	2,711.3	-	-	-	-	**3,575.9**
Replace Diesel Gensets (2024–2026)	535.8	478.0	3,902.3	-	-	-	**4,916.1**
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**
Flatten Downstream Slope (2024–2025) - Hinds Lake	276.1	2,953.4	-	-	-	-	**3,229.5**
Refurbish Intake 1 (2024–2025) - Bay d'Espoir	272.1	3,071.9	-	-	-	-	**3,344.0**
Upgrade UPS 1 and 2 (2024–2025) - Holyrood	263.0	107.6	-	-	-	-	**370.6**
Upgrade DCS Hardware - Units 1 and 2 (2024–2025) - Holyrood	195.2	277.3	-	-	-	-	**472.5**
Renew Circuit Breakers (2024–2025)	183.9	2,120.1	-	-	-	-	**2,304.0**
Refurbish Surge Tank 1 (2024–2025) - Bay d'Espoir	175.8	2,111.4	-	-	-	-	**2,287.2**
Replace Annunciator Panels (2024–2025) - Cat Arm	160.2	191.2	-	-	-	-	**351.4**
Replace Instrument Transformers (2024–2025)	154.9	714.8	-	-	-	-	**869.7**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon	137.0	156.9	-	-	-	-	**293.9**
Replace Disconnects (2024–2025)	127.4	1,358.1	-	-	-	-	**1,485.5**
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247	112.4	215.8	-	-	-	-	**328.2**
Upgrade Distribution - Terminal Station 2 (2024–2025) - Bay d'Espoir	93.2	331.5	-	-	-	-	**424.7**
Replace Terminal Station Battery Banks and Chargers (2024–2025)	71.8	120.9	-	-	-	-	**192.7**
Overhaul Turbine and Valves - Unit 3 (2025) - Holyrood	-	15,975.9	-	-	-	-	**15,975.9**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2025)	-	6,397.0	-	-	-	-	**6,397.0**
Rewind Stator (2025–2026) - Hinds Lake	-	5,233.2	9,695.5	-	-	-	**14,928.7**
Overhaul Hydraulic Units (2025)	-	4,972.4	-	-	-	-	**4,972.4**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood	-	4,905.8	-	-	-	-	**4,905.8**
Wood Pole Line Management (2025)	-	4,281.3	-	-	-	-	**4,281.3**
Thermal In-Service Failures (2025)	-	3,900.0	-	-	-	-	**3,900.0**
Terminal Station In-Service Failures (2025)	-	2,500.0	-	-	-	-	**2,500.0**
Hydraulic In-Service Failures (2025)	-	2,000.0	-	-	-	-	**2,000.0**
Refurbish Marine Terminal (2025–2026) - Holyrood	-	1,190.8	1,295.6	-	-	-	**2,486.5**
Overhaul Major Pumps (2025) - Holyrood	-	1,101.9	-	-	-	-	**1,101.9**
Overhaul Diesel Units (2025)	-	1,000.0	-	-	-	-	**1,000.0**
Perform Level 2 Condition Assessment - Stage 1 and 2 Cooling Water Sump Structures (2025) - Holyrood	-	891.9	-	-	-	-	**891.9**
Upgrade Power Transformers (2025–2026)	-	811.9	1,173.9	-	-	-	**1,985.8**
Diesel In-Service Failures (2025)	-	800.0	-	-	-	-	**800.0**
Inspect Fuel Tanks (2025) - Stephenville	-	676.9	-	-	-	-	**676.9**
Replace Protective Relays (2025–2026)	-	668.6	2,070.9	-	-	-	**2,739.5**
Gas Turbine In-Service Failures (2025)	-	500.0	-	-	-	-	**500.0**
Perform Level 2 Condition Assessment - Intake 4 and Unit 7 Draft Tube (2025) - Bay d'Espoir	-	471.5	-	-	-	-	**471.5**
Replace Diesel Gensets (2025–2027)	-	418.2	1,286.6	4,518.7	-	-	**6,223.6**
Replace Roof (2025) - Grey River	-	390.8	-	-	-	-	**390.8**
Refurbish Intake 2 (2025–2026) - Bay d'Espoir	-	284.4	3,069.4	-	-	-	**3,353.8**

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Replace Human-Machine Interface (2025) - Stephenville	-	277.0	-	-	-	-	**277.0**
Replace Emergency Diesel Genset (2025–2027) - Cat Arm	-	266.2	1,221.1	113.9	-	-	**1,601.3**
Transmission In-Service Failures (2025)	-	184.3	-	-	-	-	**184.3**
Upgrade Data Alarm Systems (2025–2026) - Hardwoods	-	184.0	188.7	-	-	-	**372.7**
Install Breaker Failure Protection (2025–2027) - Holyrood	-	177.8	320.9	166.5	-	-	**665.2**
Replace Disconnects (2025–2026)	-	145.3	1,245.5	-	-	-	**1,390.8**
Update Flame Scanners - Unit 3 (2025) - Holyrood	-	140.6	-	-	-	-	**140.6**
Renew Circuit Breakers (2025–2026)	-	129.7	1,021.7	-	-	-	**1,151.4**
Replace Terminal Station Battery Banks and Chargers (2025–2026)	-	123.2	315.3	-	-	-	**438.5**
Replace Instrument Transformers (2025–2026)	-	112.5	356.4	-	-	-	**468.9**
Replace Circuit Breaker Reclosing Controllers (2025–2026) - Cow Head and Massey Drive	-	104.6	164.3	-	-	-	**269.0**
Replace 250 Vdc Battery Bank (2025–2026) - Stephenville	-	73.0	296.9	-	-	-	**369.9**
Perform Major Inspection - Synchronous Condenser 2 (2025–2026) - Wabush	-	22.8	572.8	-	-	-	**595.6**
Refurbish Penstock 2 and 3 (2026–2028) - Bay d'Espoir	-	-	20,000.0	45,000.0	65,000.0	-	**130,000.0**
Wood Pole Line Management (2026)	-	-	5,714.3	-	-	-	**5,714.3**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2026)	-	-	5,489.0	-	-	-	**5,489.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2026) - Holyrood	-	-	5,217.7	-	-	-	**5,217.7**
Thermal In-Service Failures (2026)	-	-	4,069.8	-	-	-	**4,069.8**
Overhaul Turbine Valves - Unit 2 (2026) - Holyrood	-	-	3,873.0	-	-	-	**3,873.0**
Refurbish Stage 1 and 2 Cooling Water Sump Structures (2026-2027) - Holyrood	-	-	3,507.9	3,549.3	-	-	**7,057.2**
Terminal Station In-Service Failures (2026)	-	-	2,565.0	-	-	-	**2,565.0**
Overhaul Hydraulic Units (2026)	-	-	2,169.9	-	-	-	**2,169.9**
Hydraulic In-Service Failures (2026)	-	-	2,036.0	-	-	-	**2,036.0**
Overhaul Generator and Install Online Monitoring Equipment - Unit 2 (2026) - Holyrood	-	-	1,989.0	-	-	-	**1,989.0**
Overhaul Major Pumps (2026) - Holyrood	-	-	1,625.0	-	-	-	**1,625.0**
Overhaul Diesel Units (2026)	-	-	1,565.3	-	-	-	**1,565.3**
Renew Distribution Feeders (2026–2027)	-	-	1,361.6	1,356.1	-	-	**2,717.7**
Renew Steel Tower Transmission Line (2026–2029) - L23/24	-	-	1,000.0	1,000.0	1,000.0	1,000.0	**4,000.0**
Inspect Fuel Storage Tank and Replace Wharf (2026–2028) - McCallum	-	-	1,000.0	2,000.0	2,000.0	-	**5,000.0**
Replace Protective Relays (2026–2027)	-	-	850.0	1,350.0	-	-	**2,200.0**
Diesel In-Service Failures (2026)	-	-	834.8	-	-	-	**834.8**
Replace T1 (2026–2027) - Burgeo	-	-	824.9	433.0	-	-	**1,257.9**
Replace Parts of Stage 1: 129 Vdc Battery Chargers, Batteries, Panels, and Breakers (2026) - Holyrood	-	-	750.0	-	-	-	**750.0**
Inspect Fuel Storage Tanks (2026) - Rigolet	-	-	650.0	-	-	-	**650.0**
Inspect Fuel Tanks (2026) - Happy Valley	-	-	600.0	-	-	-	**600.0**
Perform Level 2 Condition Assessment - North Salmon Spillway (2026) - Upper Salmon	-	-	540.9	-	-	-	**540.9**
Gas Turbine In-Service Failures (2026)	-	-	521.8	-	-	-	**521.8**
Upgrade Water Treatment and Wastewater Treatment Assets (2026–2027) - Holyrood	-	-	500.0	500.0	-	-	**1,000.0**
Replace Tank Farm Steam Piping and Complete Level 2 Condition Assessment of Fuel Piping (2026) - Holyrood	-	-	473.0	-	-	-	**473.0**
Upgrade Cooling Water for Air Compressor 1 and 2 and Purchase Air-Cooled Compressor (2026) - Holyrood	-	-	440.0	-	-	-	**440.0**
Perform Level 2 Condition Assessment - Condenser and Condenser Tubes (2026) - Holyrood	-	-	400.0	-	-	-	**400.0**
Replace Disconnects (2026–2027)	-	-	393.3	730.5	-	-	**1,123.8**
Inspect Stack Liners and Replace Aviation Lights (2026) - Holyrood	-	-	360.0	-	-	-	**360.0**
Replace 125 Vdc Battery Bank (2026) - Hardwoods	-	-	350.0	-	-	-	**350.0**
Complete Major Refurbishment Turbine and Generator - Unit 7 (2026–2029) - Bay d'Espoir	-	-	350.0	3,428.7	5,715.0	38,063.2	**47,556.9**
Refurbish Spillway Gate - Salmon River Spillway (2026–2029) - Upper Salmon	-	-	349.3	5,757.6	6,112.1	6,362.1	**18,581.1**
Renew Circuit Breakers (2026–2027)	-	-	302.4	961.5	-	-	**1,263.9**
Overhaul Major Feedwater Valves and Actuators - Unit 2 (2026) - Holyrood	-	-	300.0	-	-	-	**300.0**

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Backup Critical Data (DCS, BMS, Turbine Controls) through ExaGrid (2026) - Holyrood	-	-	275.0	-	-	-	**275.0**
Construct Pole Storage Ramps (2026–2030) - Labrador	-	-	250.0	250.0	250.0	250.0	**1,000.0**
Perform Level 2 Condition Assessment - Penstock 4 (2026) - Bay d'Espoir	-	-	206.2	-	-	-	**206.2**
Replace Instrument Transformers (2026–2027)	-	-	204.3	136.2	-	-	**340.5**
Replace Roof (2026) - Hopedale	-	-	200.0	600.0	-	-	**800.0**
Upgrade DCS Obsolete Components (2026–2027) - Holyrood	-	-	200.0	200.0	-	-	**400.0**
Replace Vibration System (2026) - Stephenville	-	-	200.0	-	-	-	**200.0**
Upgrade Cranes and Hoists (2026–2027) - Holyrood	-	-	200.0	300.0	-	-	**500.0**
Transmission In-Service Failures (2026)	-	-	188.9	-	-	-	**188.9**
Replace Terminal Station Battery Banks and Chargers (2026–2027)	-	-	180.8	120.5	-	-	**301.3**
Replace Annunciator Panel (2026–2027) - Upper Salmon	-	-	150.0	200.0	-	-	**350.0**
Perform Level 2 Condition Assessment - Penstock (2026) - Hinds Lake	-	-	130.0	-	-	-	**130.0**
Install Breaker Failure Protection (2026–2027) - Western Avalon	-	-	116.0	234.0	-	-	**350.0**
Replace Battery Bank (2026–2027) - Granite Canal	-	-	100.0	150.0	-	-	**250.0**
Replace Circuit Breaker Reclosing Controllers (2026–2027) - Holyrood	-	-	100.0	150.0	-	-	**250.0**
Perform Major Inspection - Synchronous Condenser 1 (2026–2027) - Wabush	-	-	86.0	484.0	-	-	**570.0**
Upgrade Power Transformers (2026–2027)	-	-	66.0	1,270.0	-	-	**1,336.0**
Rehabilitate Intake Decks 1–3 (2026–2028) - Bay d'Espoir	-	-	55.0	161.5	169.5	-	**386.0**
Replace Switchgear - Synchronous Condensers 1 and 2 (2026–2027) - Wabush	-	-	50.0	700.0	-	-	**750.0**
Replace Air Dryer (2026) - Hardwoods	-	-	50.0	-	-	-	**50.0**
Replace DC Fuel Pump (2026) - Hardwoods	-	-	50.0	-	-	-	**50.0**
Repair Self-Supporting Foundation (2026–2027) - TL212	-	-	50.0	250.0	-	-	**300.0**
Replace Switchgear (2026–2027) - Grand Falls	-	-	50.0	300.0	-	-	**350.0**
Upgrade Data Alarm Systems (2026–2027) - Springdale and Indian River	-	-	34.0	62.0	-	-	**96.0**
Overhaul Hydraulic Units (2027)	-	-	-	5,665.0	-	-	**5,665.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2027)	-	-	-	5,626.0	-	-	**5,626.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2027) - Holyrood	-	-	-	5,337.1	-	-	**5,337.1**
Wood Pole Line Management (2027)	-	-	-	4,721.1	-	-	**4,721.1**
Thermal In-Service Failures (2027)	-	-	-	4,163.0	-	-	**4,163.0**
Overhaul Turbine Valves - Unit 1 (2027) - Holyrood	-	-	-	4,000.0	-	-	**4,000.0**
Terminal Station In-Service Failures (2027)	-	-	-	2,631.7	-	-	**2,631.7**
Hydraulic In-Service Failures (2027)	-	-	-	2,077.0	-	-	**2,077.0**
Overhaul Generator and Upgrade Online Monitoring - Unit 3 (2027) - Holyrood	-	-	-	1,930.9	-	-	**1,930.9**
Overhaul Diesel Units (2027)	-	-	-	1,601.1	-	-	**1,601.1**
Overhaul Major Pumps (2027) - Holyrood	-	-	-	1,440.0	-	-	**1,440.0**
Renew Distribution Feeders (2027–2028)	-	-	-	1,402.1	1,396.1	-	**2,798.2**
Renew Circuit Breakers (2027–2028)	-	-	-	945.4	1,238.7	-	**2,184.1**
Diesel In-Service Failures (2027)	-	-	-	853.9	-	-	**853.9**
Replace Protective Relays (2027–2028)	-	-	-	800.0	1,300.0	-	**2,100.0**
Inspect Fuel Storage Tanks (2027) - Makkovik	-	-	-	700.0	-	-	**700.0**
Overhaul Marine Terminal Loading Arms (2027) - Holyrood	-	-	-	550.0	-	-	**550.0**
Replace Disconnects (2027–2028)	-	-	-	538.8	1,000.6	-	**1,539.4**
Gas Turbine In-Service Failures (2027)	-	-	-	533.7	-	-	**533.7**
Refurbish MD1 (2027–2028) - Ebbegunbaeg	-	-	-	500.0	3,700.0	-	**4,200.0**
Perform Level 2 Condition Assessment - West Salmon Spillway (2027) - Upper Salmon	-	-	-	474.6	-	-	**474.6**
Replace Diesel Gensets (2027)	-	-	-	400.0	100.0	-	**500.0**
Refurbish Draft Tube Deck - Phase 3 (2027–2029) - Bay d'Espoir	-	-	-	365.5	728.6	6,994.8	**8,088.9**
Inspect Light Oil System (2027) - Holyrood	-	-	-	200.0	-	-	**200.0**
Replace Roof (2027) - Cartwright	-	-	-	200.0	500.0	-	**700.0**
Transmission In-Service Failures (2027)	-	-	-	193.6	-	-	**193.6**
Upgrade Data Alarm Systems (2027–2028) - Grand Falls	-	-	-	183.0	190.0	-	**373.0**
Replace Instrument Transformers (2027–2028)	-	-	-	173.4	115.6	-	**289.0**
Replace Rip Rap - LD5 - Salmon River Spillway (2027) - Upper Salmon	-	-	-	152.2	-	-	**152.2**

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Install Breaker Failure Protection (2027–2028) - Hardwoods	-	-	-	133.0	267.0	-	**400.0**
Perform Level 2 Condition Assessment - Penstock Steel Section (2027) - Paradise River	-	-	-	130.0	-	-	**130.0**
Overhaul Quarry Brook Dam (2027–2028) - Holyrood	-	-	-	100.0	150.0	-	**250.0**
Replace Fuel Pumps (2027–2028) - Hardwoods	-	-	-	100.0	100.0	-	**200.0**
Replace Black Start Diesel (2027–2028) - Hardwoods	-	-	-	100.0	150.0	-	**250.0**
Replace Terminal Station Battery Banks and Chargers (2027–2028)	-	-	-	88.8	59.2	-	**148.0**
Replace Circuit Breaker Reclosing Controllers (2027–2028) - Deer Lake	-	-	-	50.0	75.0	-	**125.0**
Upgrade Power Transformers (2027–2028)	-	-	-	45.0	880.0	-	**925.0**
Perform Major Inspection (2028) - Holyrood	-	-	-	-	7,500.0	7,500.0	**15,000.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2028)	-	-	-	-	5,767.0	-	**5,767.0**
Overhaul Hydraulic Units (2028)	-	-	-	-	5,500.0	-	**5,500.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2028) - Holyrood	-	-	-	-	5,457.4	-	**5,457.4**
Overhaul Turbine Valves - Unit 3 (2028) - Holyrood	-	-	-	-	4,270.0	-	**4,270.0**
Thermal In-Service Failures (2028)	-	-	-	-	4,256.8	-	**4,256.8**
Wood Pole Line Management (2028)	-	-	-	-	3,739.7	-	**3,739.7**
Terminal Station In-service Failures (2028)	-	-	-	-	2,700.1	-	**2,700.1**
Hydraulic In-Service Failures (2028)	-	-	-	-	2,116.0	-	**2,116.0**
Overhaul Diesel Units (2028)	-	-	-	-	1,637.2	-	**1,637.2**
Renew Distribution Feeders (2028–2029)	-	-	-	-	1,443.4	1,437.2	**2,880.5**
Diesel In-Service Failures (2028)	-	-	-	-	873.2	-	**873.2**
Replace Protective Relays (2028–2029)	-	-	-	-	800.0	1,100.0	**1,900.0**
Inspect Fuel Storage Tanks (2028) - Black Tickle	-	-	-	-	800.0	-	**800.0**
Gas Turbine In-Service Failures (2028)	-	-	-	-	545.7	-	**545.7**
Perform Major Refurbishment Turbine and Generator (2028–2029) - Upper Salmon	-	-	-	-	500.0	15,000.0	**15,500.0**
Refurbish North Salmon Spillway (2028–2029) - Upper Salmon	-	-	-	-	500.0	1,500.0	**2,000.0**
Replace Diesel Shop (2028–2029) - Goose Bay	-	-	-	-	500.0	1,500.0	**2,000.0**
Renew Circuit Breakers (2028–2029)	-	-	-	-	489.4	943.1	**1,432.5**
Overhaul Major Pumps (2028) - Holyrood	-	-	-	-	450.0	-	**450.0**
Replace Diesel Gensets (2028)	-	-	-	-	400.0	100.0	**500.0**
Replace Disconnects (2028–2029)	-	-	-	-	340.8	632.9	**973.7**
Replace Equipment Foundations (2028)	-	-	-	-	280.0	-	**280.0**
Replace Instrument Transformers (2028–2029)	-	-	-	-	254.4	169.6	**424.0**
Replace Battery Banks 1 and 2 (2028–2029) - Hinds Lake	-	-	-	-	200.0	300.0	**500.0**
Replace Battery Banks 1 and 2 - Powerhouse 1 (2028–2029) - Bay d'Espoir	-	-	-	-	200.0	300.0	**500.0**
Transmission In-Service Failures (2028)	-	-	-	-	198.4	-	**198.4**
Upgrade Data Alarm Systems (2028–2029) - Happy Valley	-	-	-	-	183.0	190.0	**373.0**
Install Breaker Failure Protection (2028–2029) - Wabush	-	-	-	-	175.0	355.0	**530.0**
Replace Terminal Station Battery Banks and Chargers (2028–2029)	-	-	-	-	154.8	103.2	**258.0**
Refurbish Unit Control Panels - Unit 2 (2028–2029) - Cat Arm	-	-	-	-	100.0	570.0	**670.0**
Perform Major Inspection - Synchronous Condenser 2 (2028–2029) - Wabush	-	-	-	-	86.0	484.0	**570.0**
Upgrade Power Transformers (2028–2029)	-	-	-	-	60.0	1,080.0	**1,140.0**
Upgrade Reclosing Circuit Breakers (2028–2029) - Indian River	-	-	-	-	50.0	75.0	**125.0**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2029)	-	-	-	-	-	5,911.0	**5,911.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2029) - Holyrood	-	-	-	-	-	5,580.4	**5,580.4**
Overhaul Turbine Valves - Unit 2 (2029) - Holyrood	-	-	-	-	-	4,500.0	**4,500.0**
Thermal In-Service Failures (2029)	-	-	-	-	-	4,352.7	**4,352.7**
Upgrade Exciter and Transformer - Unit 3 (2029) - Holyrood	-	-	-	-	-	4,000.0	**4,000.0**
Wood Pole Line Management (2029)	-	-	-	-	-	3,987.1	**3,987.1**
Terminal Station In-service Failures (2029)	-	-	-	-	-	2,770.3	**2,770.3**
Hydraulic In-Service Failures (2029)	-	-	-	-	-	2,156.0	**2,156.0**
Renew Circuit Breakers (2029–2030)	-	-	-	-	-	1,738.0	**1,738.0**
Overhaul Diesel Units (2029)	-	-	-	-	-	1,674.1	**1,674.1**
Renew Distribution Feeders (2029–2030)	-	-	-	-	-	1,485.9	**1,485.9**
Overhaul Hydraulic Units (2029)	-	-	-	-	-	1,350.0	**1,350.0**
Replace Protective Relays (2029–2030)	-	-	-	-	-	1,000.0	**1,000.0**

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	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Replace Diesel Gensets (2029)	-	-	-	-	-	1,000.0	**1,000.0**
Overhaul Major Pumps (2029) - Holyrood	-	-	-	-	-	900.0	**900.0**
Diesel In-Service Failures (2029)	-	-	-	-	-	892.9	**892.9**
Gas Turbine In-Service Failures (2029)	-	-	-	-	-	558.0	**558.0**
Refurbish West Salmon Spillway (2029–2030) - Upper Salmon	-	-	-	-	-	500.0	**500.0**
Perform Level 2 Condition Assessment - Spillway (2029) - Hinds Lake	-	-	-	-	-	450.0	**450.0**
Replace Disconnects (2029–2030)	-	-	-	-	-	360.5	**360.5**
Replace Instrument Transformers (2029–2030)	-	-	-	-	-	307.7	**307.7**
Replace Fuel Oil Water injection Pumps (2029) - Holyrood	-	-	-	-	-	300.0	**300.0**
Inspect Fuel Storage Tanks (2029) - Cartwright and Norman's Bay	-	-	-	-	-	300.0	**300.0**
Perform Level 2 Condition Assessment - Turbine and Generator (2029) - Cat Arm	-	-	-	-	-	300.0	**300.0**
Overhaul Fuel Oil Storage Tank 3 (2029–2030) - Holyrood	-	-	-	-	-	300.0	**300.0**
Transmission In-Service Failures (2029)	-	-	-	-	-	203.4	**203.4**
Perform Level 2 Condition Assessment - Penstock (2029) - Upper Salmon	-	-	-	-	-	200.0	**200.0**
Perform Level 2 Condition Assessment - Stacks (2029) - Holyrood	-	-	-	-	-	200.0	**200.0**
Replace Terminal Station Battery Banks and Chargers (2029–2030)	-	-	-	-	-	98.6	**98.6**
Perform Modified Major Inspection - Synchronous Condenser 1 (2029–2030) - Wabush	-	-	-	-	-	77.0	**77.0**
Upgrade Power Transformers (2029–2030)	-	-	-	-	-	60.0	**60.0**
Perform Level 2 Condition Assessment - Stage 1 North Air Receiver (2029) - Holyrood	-	-	-	-	-	50.0	**50.0**
Replace Cooling Water Pumps 3 and 5 - Powerhouse 1 (2029–2030) - Bay d'Espoir	-	-	-	-	-	50.0	**50.0**
Upgrade Reclosing Circuit Breakers (2029–2030) - Bear Cove	-	-	-	-	-	50.0	**50.0**
Renewal Total	**36,059.0**	**123,597.8**	**104,364.1**	**125,540.1**	**144,725.7**	**133,673.7**	**667,960.3**
Service Enhancement							
Purchase Spare Generator Step-Up Transformer	1,338.5	3,966.7	2,161.7	-	-	-	**7,466.9**
Upgrade Worst-Performing Distribution Feeders (2024–2025)	1,064.3	2,227.4	-	-	-	-	**3,291.7**
Automate Bulk Metering (2024–2026)	302.6	214.4	235.3	-	-	-	**752.3**
Construct Maintenance Platform (2024–2025) - Holyrood	130.5	228.7	-	-	-	-	**359.2**
Upgrade Instrumentation (2024–2025) - Hardwoods	60.9	157.2	-	-	-	-	**218.1**
Southern Labrador Interconnection	-	19,693.8	37,432.4	24,615.3	6,203.5	-	**87,945.0**
Upgrade Worst-Performing Distribution Feeders (2025–2027)	-	2,678.9	3,677.4	2,529.8	-	-	**8,886.1**
Install Mid-Span Structures - TL220 (2025–2026)	-	881.3	229.3	-	-	-	**1,110.6**
Remove Safety Hazards (2025)	-	203.3	-	-	-	-	**203.3**
Perform Minor Telecommunications Enhancements (2025)	-	99.8	-	-	-	-	**99.8**
Install Intelligent Electronic Device Management Software (2026–2027)	-	-	572.1	269.9	-	-	**842.0**
Upgrade Worst-Performing Distribution Feeders (2026–2027)	-	-	508.0	2,962.6	-	-	**3,470.6**
Install Fire Barriers between T10 and T12, T10 and T11 (2026–2027) - Bay d'Espoir	-	-	220.4	1,108.6	-	-	**1,329.0**
Remove Safety Hazards (2026)	-	-	204.9	-	-	-	**204.9**
Upgrade Cooling (2026–2027) - Hardwoods	-	-	200.0	800.0	-	-	**1,000.0**
Replace Black Start Gas Turbine Instrumentation (2027–2028) - Holyrood	-	-		150.0	150.0	-	**300.0**
Replace Expansion Joint and Rock Scaling (2026–2027) - Paradise River	-	-	135.2	1,600.0	-	-	**1,735.2**
Upgrade Excitation System (2026–2027) - Paradise River	-	-	103.3	84.5	-	-	**187.8**
Install Secondary Station Service Supply (2026-2028) - Holyrood	-	-	103.1	97.8	952.0	-	**1,153.0**
Perform Minor Telecommunications Enhancements (2026)	-	-	101.7	-	-	-	**101.7**
Relocate Section of Line (2026–2028) - TL220	-	-	89.3	1,292.3	2,318.0	-	**3,699.6**
Upgrade Terminal Station for Mobile Substation (2026–2027) - St. Anthony	-	-	76.1	431.0	-	-	**507.1**
Install New Station Service Feed (2026–2028) - Berry Hill	-	-	69.3	60.8	585.0	-	**715.1**
Upgrade Transformer Paralleling (2026–2027) - Stony Brook and Sunnyside	-	-	64.0	120.0	-	-	**184.0**

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	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Perform Distribution Equipment SCADA Additions (2026–2027)	-	-	31.7	294.1	-	-	**325.8**
Upgrade Worst-Performing Distribution Feeders (2027–2028)	-	-	-	1,089.2	2,467.0	-	**3,556.1**
Remove Safety Hazards (2027)	-	-	-	208.5	-	-	**208.5**
Perform Minor Telecommunications Enhancements (2027)	-	-	-	104.8	-	-	**104.8**
Upgrade Terminal Station for Mobile Substation (2027–2028) - Glenburnie	-	-	-	76.1	431.0	-	**507.1**
Construct Fire Separation Walls between Transformers (2027–2028) - Happy Valley	-	-	-	54.8	773.9	-	**828.7**
Perform Distribution Equipment SCADA Additions (2027–2028)	-	-	-	32.7	302.7	-	**335.4**
Upgrade Transformer Paralleling (2027–2028) - Bottom Brook	-	-	-	32.0	60.0	-	**92.0**
Replace Diesel Plant (2028–2031) - Rigolet	-	-	-	-	5,000.0	10,000.0	**15,000.0**
Upgrade Worst-Performing Distribution Feeders (2028–2029)	-	-	-	-	538.5	3,139.6	**3,678.1**
Install Intelligent Electronic Device Management Software (2028)	-	-	-	-	396.8	-	**396.8**
Remove Safety Hazards (2028)	-	-	-	-	212.1	-	**212.1**
Install Asset Health Monitoring System (2028–2029) - Cat Arm	-	-	-	-	150.0	150.0	**300.0**
Perform Minor Telecommunications Enhancements (2028)	-	-	-	-	107.9	-	**107.9**
Upgrade Terminal Station for Mobile Substation (2028–2029) - Roddickton	-	-	-	-	76.1	431.0	**507.1**
Install Low Pressure Compressor, Piping, and Controls (2028–2029) - Hinds Lake	-	-	-	-	75.0	525.0	**600.0**
Install Fire Barriers between Substation and T1, T2, and T3 (2028–2029) - Massey Drive	-	-	-	-	39.1	731.5	**770.6**
Perform Distribution Equipment SCADA Additions (2028–2029)	-	-	-	-	33.6	311.6	**345.3**
Upgrade Transformer Paralleling - Terminal Station 2 (2028–2029) - Bay d'Espoir	-	-	-	-	32.0	60.0	**92.0**
Upgrade Worst-Performing Distribution Feeders (2029–2030)	-	-	-	-	-	554.4	**554.4**
Install Intelligent Electronic Device Management Software (2029)	-	-	-	-	-	408.7	**408.7**
Remove Safety Hazards (2029)	-	-	-	-	-	215.8	**215.8**
Perform Minor Telecommunications Enhancements (2029)	-	-	-	-	-	111.1	**111.1**
Upgrade Terminal Station for Mobile Substation (2029–2030) - Grandy Brook	-	-	-	-	-	76.1	**76.1**
Distribution Equipment SCADA Additions (2029–2030)	-	-	-	-	-	34.6	**34.6**
Upgrade Transformer Paralleling - T5 and T10 (2029–2030) - Holyrood	-	-	-	-	-	32.0	**32.0**
Service Enhancement Total	**2,896.8**	**30,351.5**	**46,215.3**	**38,014.8**	**20,904.3**	**16,781.4**	**155,164.0**
System Growth							
Additions for Load - Substation Upgrades - Wabush	10,179.6	514.5	-	-	-	-	**10,694.1**
Additions for Load Growth - Upgrade Transformer Capacity (2023–2024) - Jean Lake	580.0	6,459.6	789.7	-	-	-	**7,829.3**
Additions for Load - Unit 2065 Replacement and Fuel Storage Upgrades (2024–2027) - Rigolet	50.1	226.4	1,604.8	1,457.2	-	-	**3,338.4**
Additions for Load - Cartwright (2024–2027)	18.9	0.9	0.9	487.2	-	-	**507.8**
Additions for Load - Main Brook (2024–2025)	13.8	339.0	-	-	-	-	**352.8**
Install Unit 8 - Bay d'Espoir	-	-	26,450.0	21,000.0	158,000.0	167,000.0	**372,450.0**
Avalon Combustion Turbine	-	-	19,165.0	106,735.0	203,004.0	187,079.0	**515,983.0**
Additions for Load Growth - Isolated Generation Stations (2026)	-	-	939.2	-	-	-	**939.2**
Additions for Load - Distribution System (2026)	-	-	793.3	-	-	-	**793.3**
Additions for Load Growth - Isolated Generation Stations (2027)	-	-	-	960.7	-	-	**960.7**
Additions for Load - Distribution System (2027)	-	-	-	816.9	-	-	**816.9**
Additions for Load Growth - Isolated Generation Stations (2028)	-	-	-	-	982.3	-	**982.3**
Additions for Load - Distribution System (2028)	-	-	-	-	840.9	-	**840.9**
Additions for Load Growth - Isolated Generation Stations (2029)	-	-	-	-	-	1,004.5	**1,004.5**
Additions for Load - Distribution System (2029)	-	-	-	-	-	865.7	**865.7**
System Growth Total	**10,842.3**	**7,540.3**	**49,742.9**	**131,456.9**	**362,827.3**	**355,949.2**	**918,358.9**
Total Capital Plan	**60,900.8**	**195,817.6**	**227,187.5**	**334,633.7**	**560,223.2**	**539,272.1**	**1,918,035.0**

[1] Numbers may not add due to rounding.

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	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Allowance for Unforeseen Items							
Allowance for Unforeseen Items							
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 Items (2029)	-	-	-	-	-	1,000.0	**1,000.0**
Subtotal Allowance for Unforeseen Items	**-**	**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**
General Properties							
Administration							
Complete Level 4 Fire Restoration (2024–2025) - Hydro Place	750.2	317.7	-	-	-	-	**1,067.9**
Remove Safety Hazards (2025)	-	203.3	-	-	-	-	**203.3**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2025)	-	178.5	-	-	-	-	**178.5**
Perform Security Improvements (2025)	-	160.7	-	-	-	-	**160.7**
Refurbish Windows (2026–2029) - Hydro Place	-	-	1,279.3	1,267.2	1,289.8	1,312.8	**5,149.1**
Perform Accessibility Improvements (2026–2029)	-	-	450.0	350.0	175.0	160.0	**1,135.0**
Remove Safety Hazards (2026)	-	-	204.9	-	-	-	**204.9**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2026)	-	-	194.2	-	-	-	**194.2**
Remove Safety Hazards (2027)	-	-	-	208.5	-	-	**208.5**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2027)	-	-	-	197.6	-	-	**197.6**
Upgrade Fire Panel and Devices (2027) - Hydro Place	-	-	-	197.0	-	-	**197.0**
Replace/Upgrade Fire Suppression System (2028) - Hydro Place	-	-	-	-	528.5	-	**528.5**
Replace Generators and Associated Switchgear (2028) - Hydro Place	-	-	-	-	500.0	544.0	**1,044.0**
Replace HVAC Equipment (2028–2029) - Hydro Place	-	-	-	-	240.0	200.0	**440.0**
Remove Safety Hazards (2028)	-	-	-	-	212.1	-	**212.1**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2028)	-	-	-	-	201.0	-	**201.0**
Replace Fuel Tank, Lines, Pumps, and Associated Hardware (2028) - Hydro Place	-	-	-	-	100.0	-	**100.0**
Remove Safety Hazards (2029)	-	-	-	-	-	215.8	**215.8**
Modify Office Buildings and Procure Furniture, Fixtures, and Equipment (2029)	-	-	-	-	-	204.5	**204.5**
Subtotal Administration	**750.2**	**860.3**	**2,128.4**	**2,220.3**	**3,246.5**	**2,637.1**	**11,842.7**
Information Systems							
Perform Software Upgrades and Minor Enhancements (2025)	-	808.7	-	-	-	-	**808.7**
Upgrade Core OT Infrastructure (2025)	-	674.3	-	-	-	-	**674.3**
Purchase Personal Computers (2025)	-	575.6	-	-	-	-	**575.6**
Upgrade Work Protection Code Application (2025–2026)	-	452.0	449.4	-	-	-	**901.4**
Upgrade Energy Management System (2025–2026)	-	284.4	188.5	-	-	-	**472.9**
Implement SCADA Points Application (2025–2026)	-	241.9	143.4	-	-	-	**385.3**
Replace Peripheral Infrastructure (2025)	-	205.4	-	-	-	-	**205.4**
Update Cyber Security Infrastructure (2025)	-	115.6	-	-	-	-	**115.6**
Purchase Personal Computers (2026)	-	-	912.8	-	-	-	**912.8**
Perform Software Upgrades and Minor Enhancements (2026)	-	-	625.0	-	-	-	**625.0**
Upgrade Core OT Infrastructure (2026)	-	-	375.0	-	-	-	**375.0**
Update Cyber Security Infrastructure (2026)	-	-	322.0	-	-	-	**322.0**
Replace Peripheral Infrastructure (2026)	-	-	164.5	-	-	-	**164.5**
Purchase Personal Computers (2027)	-	-	-	957.9	-	-	**957.9**
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**
Upgrade Energy Management System (2027–2028)	-	-	-	283.0	184.2	-	**467.2**
Replace Peripheral Infrastructure (2027)	-	-	-	261.2	-	-	**261.2**
Perform Software Upgrades and Minor Enhancements (2028)	-	-	-	-	725.0	-	**725.0**
Purchase Personal Computers (2028)	-	-	-	-	465.5	-	**465.5**
Upgrade Core OT Infrastructure (2028)	-	-	-	-	425.0	-	**425.0**
Update Cyber Security Infrastructure (2028)	-	-	-	-	375.0	-	**375.0**

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	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Replace Peripheral Infrastructure (2028)	-	-	-	-	133.3	-	**133.3**
Perform Software Upgrades and Minor Enhancements (2029)	-	-	-	-	-	650.0	**650.0**
Purchase Personal Computers (2029)	-	-	-	-	-	441.5	**441.5**
Upgrade Core OT Infrastructure (2029)	-	-	-	-	-	425.0	**425.0**
Update Cyber Security Infrastructure (2029)	-	-	-	-	-	392.0	**392.0**
Upgrade Energy Management System (2029–2030)	-	-	-	-	-	302.8	**302.8**
Replace Peripheral Infrastructure (2029)	-	-	-	-	-	164.0	**164.0**
Subtotal Information Systems	**-**	**3,358.0**	**3,180.6**	**2,852.1**	**2,308.0**	**2,375.3**	**14,074.0**
Properties							
Install Electric Vehicle Chargers (2025–2026) - Hydro Sites	-	368.0	288.2	-	-	-	**656.1**
Perform Building Refurbishments (2026–2027)	-	-	750.0	400.0	-	-	**1,150.0**
Install Electric Vehicle Chargers (2026–2027) - Hydro Sites	-	-	51.6	367.9	-	-	**419.5**
Perform Building Refurbishments (2027–2028)	-	-	-	650.0	550.0	-	**1,200.0**
Install Electric Vehicle Chargers (2027–2028) - Hydro Sites	-	-	-	52.6	374.2	-	**426.8**
Perform Building Refurbishments (2028–2029)	-	-	-	-	550.0	750.0	**1,300.0**
Install Electric Vehicle Chargers (2028–2029) - Hydro Sites	-	-	-	-	53.5	380.7	**434.1**
Perform Building Refurbishments (2029–2030)	-	-	-	-	-	500.0	**500.0**
Install Electric Vehicle Chargers (2029–2030) - Hydro Sites	-	-	-	-	-	54.4	**54.4**
Subtotal Properties	**-**	**368.0**	**1,089.8**	**1,470.4**	**1,527.7**	**1,685.1**	**6,140.9**
Tools and Equipment							
Purchase Tools and Equipment (2025)	-	1,399.1	-	-	-	-	**1,399.1**
Purchase Surveying Software and Equipment (2025)	-	316.4	-	-	-	-	**316.4**
Purchase Tools and Equipment (2026)	-	-	1,413.7	-	-	-	**1,413.7**
Purchase Tools and Equipment (2027)	-	-	-	1,417.5	-	-	**1,417.5**
Purchase Tools and Equipment (2028)	-	-	-	-	1,421.4	-	**1,421.4**
Purchase Tools and Equipment (2029)	-	-	-	-	-	1,425.5	**1,425.5**
Subtotal Tools and Equipment	**-**	**1,715.5**	**1,413.7**	**1,417.5**	**1,421.4**	**1,425.5**	**7,393.6**
Transportation							
Replace Light- and Heavy-Duty Vehicles (2023–2025)	3,892.7	673.3	-	-	-	-	**4,566.0**
Install Ultra-Fast DC Electric Vehicle Chargers	1,828.5	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 (2025–2027)	-	2,714.6	1,675.8	3,147.2	-	-	**7,537.6**
Replace Light- and Heavy-Duty Vehicles (2026–2028)	-	-	2,800.0	125.0	3,800.0	-	**6,725.0**
Replace Light- and Heavy-Duty Vehicles (2027–2029)	-	-	-	2,900.0	815.0	3,500.0	**7,215.0**
Replace Light- and Heavy-Duty Vehicles (2028–2030)	-	-	-	-	1,700.0	1,900.0	**3,600.0**
Replace Light- and Heavy-Duty Vehicles (2029–2031)	-	-	-	-	-	2,800.0	**2,800.0**
Subtotal Transportation	**7,200.3**	**7,768.0**	**4,484.2**	**6,172.2**	**6,315.0**	**8,200.0**	**40,139.7**
Telecontrol							
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 Interconnect Microwave Radios (2025)	-	1,103.0	-	-	-	-	**1,103.0**
Replace 48 V Battery Banks and Chargers (2025)	-	559.1	-	-	-	-	**559.1**
Replace GPS Clocks (2025–2026)	-	448.3	132.4	-	-	-	**580.7**
Install CCTV Systems (2025)	-	440.1	-	-	-	-	**440.1**
Replace Network Communications Equipment (2025)	-	413.2	-	-	-	-	**413.2**
Upgrade Remote Terminal Units (2025)	-	238.4	-	-	-	-	**238.4**
Refurbish Meteorological Stations (2025)	-	167.8	-	-	-	-	**167.8**
Purchase Mobile Devices (2025)	-	160.2	-	-	-	-	**160.2**
Perform Minor Telecommunications Enhancements (2025)	-	99.8	-	-	-	-	**99.8**
Telecommunications In-Service Failures (2025)	-	94.1	-	-	-	-	**94.1**
Install Intelligent Electronic Device Management Software (2026–2027)	-	-	572.1	269.9	-	-	**842.0**
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**
Refurbish Meteorological Stations - Phase 2 (2026)	-	-	200.0	-	-	-	**200.0**
Upgrade Remote Terminal Units (2026)	-	-	173.0	-	-	-	**173.0**
Replace UPS System - Backup Control Center (2026) - Holyrood	-	-	150.0	-	-	-	**150.0**
Perform Minor Telecommunications Enhancements (2026)	-	-	101.7	-	-	-	**101.7**

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	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Replace Teleprotection Equipment (2026–2027)	-	-	100.0	250.0	-	-	**350.0**
Replace Backup Generators at Microwave Repeater Sites (2026–2027)	-	-	100.0	100.0	-	-	**200.0**
Refurbish Office - Energy Efficiency and HVAC (2026–2027) - Deer Lake	-	-	100.0	100.0	-	-	**200.0**
Telecommunications In-Service Failures (2026)	-	-	96.0	-	-	-	**96.0**
Replace Radio Links to Hydraulic Control Structures (2026–2027)	-	-	50.0	100.0	-	-	**150.0**
Replace Network Communications Equipment (2029)	-	-	-	-	-	243.0	**243.0**
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**
Upgrade Remote Terminal Units (2027)	-	-	-	179.0	-	-	**179.0**
Replace Cisco Call Manager Appliances (2027)	-	-	-	130.0	-	-	**130.0**
Perform Minor Telecommunications Enhancements (2027)	-	-	-	104.8	-	-	**104.8**
Telecommunications In-Service Failures (2027)	-	-	-	99.0	-	-	**99.0**
Replace Power Line Carrier (2027–2028) - TL212	-	-	-	93.6	681.4	-	**775.0**
Replace 48 V Battery Banks and Chargers (2028)	-	-	-	-	468.0	-	**468.0**
Install Intelligent Electronic Device Management Software (2028)	-	-	-	-	396.8	-	**396.8**
Replace Network Communications Equipment (2028)	-	-	-	-	236.0	-	**236.0**
Install CCTV Systems (2028)	-	-	-	-	218.5	-	**218.5**
Upgrade Remote Terminal Units (2028)	-	-	-	-	184.0	-	**184.0**
Purchase Mobile Devices (2028)	-	-	-	-	144.0	-	**144.0**
Perform Minor Telecommunications Enhancements (2028)	-	-	-	-	107.9	-	**107.9**
Telecommunications In-Service Failures (2028)	-	-	-	-	102.0	-	**102.0**
Replace 48 V Battery Banks and Chargers (2029)	-	-	-	-	-	482.0	**482.0**
Install Intelligent Electronic Device Management Software (2029)	-	-	-	-	-	408.7	**408.7**
Purchase Mobile Devices (2029)	-	-	-	-	-	221.0	**221.0**
Upgrade Remote Terminal Units (2029)	-	-	-	-	-	190.0	**190.0**
Perform Minor Telecommunications Enhancements (2029)	-	-	-	-	-	111.1	**111.1**
Telecommunications In-Service Failures (2029)	-	-	-	-	-	105.0	**105.0**
Install CCTV Systems (2029)	-	-	-	-	-	102.0	**102.0**
Subtotal Telecontrol	**2,302.3**	**5,182.2**	**2,840.9**	**2,505.3**	**2,538.6**	**1,862.8**	**17,232.1**
Total General Properties	**10,252.8**	**19,251.9**	**15,137.5**	**16,637.9**	**17,357.1**	**18,185.7**	**96,823.0**
Generation							
Gas Turbines							
Construct Maintenance Platform (2024–2025) - Holyrood	130.5	228.7	-	-	-	-	**359.2**
Upgrade Instrumentation (2024–2025) - Hardwoods	60.9	157.2	-	-	-	-	**218.1**
Inspect Fuel Tanks (2025) - Stephenville	-	676.9	-	-	-	-	**676.9**
Inspect Fuel Tanks (2025) - Holyrood	-	608.0	-	-	-	-	**608.0**
Gas Turbine In-Service Failures (2025)	-	500.0	-	-	-	-	**500.0**
Replace Human-Machine Interface (2025) - Stephenville	-	277.0	-	-	-	-	**277.0**
Replace 250 Vdc Battery Bank (2025–2026) - Stephenville	-	73.0	296.9	-	-	-	**369.9**
Avalon Combustion Turbine	-	-	19,165.0	106,735.0	203,004.0	187,079.0	**515,983.0**
Inspect Fuel Tanks (2026) - Happy Valley	-	-	600.0	-	-	-	**600.0**
Gas Turbine In-Service Failures (2026)	-	-	521.8	-	-	-	**521.8**
Replace 125 Vdc Battery Bank (2026) - Hardwoods	-	-	350.0	-	-	-	**350.0**
Upgrade Cooling (2026–2027) - Hardwoods	-	-	200.0	800.0	-	-	**1,000.0**
Replace Vibration System (2026) - Stephenville	-	-	200.0	-	-	-	**200.0**
Replace Black Start Gas Turbine Instrumentation (2027–2028) - Holyrood	-	-		150.0	150.0	-	**300.0**
Install Secondary Station Service Supply (2026-2028) - Holyrood	-	-	103.1	97.8	952.0	-	**1,153.0**
Replace Air Dryer (2026) - Hardwoods	-	-	50.0	-	-	-	**50.0**
Replace DC Fuel Pump (2026) - Hardwoods	-	-	50.0	-	-	-	**50.0**
Gas Turbine In-Service Failures (2027)	-	-	-	533.7	-	-	**533.7**
Replace Fuel Pumps (2027–2028) - Hardwoods	-	-	-	100.0	100.0	-	**200.0**
Replace Black Start Diesel (2027–2028) - Hardwoods	-	-	-	100.0	150.0	-	**250.0**
Perform Major Inspection (2028) - Holyrood	-	-	-	-	7,500.0	7,500.0	**15,000.0**
Gas Turbine In-Service Failures (2028)	-	-	-	-	545.7	-	**545.7**
Gas Turbine In-Service Failures (2029)	-	-	-	-	-	558.0	**558.0**
Replace Fuel Oil Water injection Pumps (2029) - Holyrood	-	-	-	-	-	300.0	**300.0**
Subtotal Gas Turbines	**191.4**	**2,520.7**	**21,536.8**	**108,516.5**	**212,401.8**	**195,437.0**	**540,604.3**

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	2024 and Prior Years	2025	2026	2027	2028	2029	Total
Hydraulic Plant							
Refurbish Control Structure (2021–2025) - Ebbegunbaeg	12,726.8	4,952.2	-	-	-	-	**17,679.0**
Penstock 1 Life Extension - Phase 1 (2023–2025)	15,277.6	35,329.1	-	-	-	-	**50,606.7**
Replace Annunciator - Phase 2 (2024–2025) - Bay d'Espoir	294.1	187.5	-	-	-	-	**481.6**
Flatten Downstream Slope (2024–2025) - Hinds Lake	276.1	2,953.4	-	-	-	-	**3,229.5**
Refurbish Intake 1 (2024–2025) - Bay d'Espoir	272.1	3,071.9	-	-	-	-	**3,344.0**
Refurbish Surge Tank 1 (2024–2025) - Bay d'Espoir	175.8	2,111.4	-	-	-	-	**2,287.2**
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**
Replace Air Conditioning Unit - Powerhouse 1 (2024–2025) - Bay d'Espoir	57.8	231.2	-	-	-	-	**289.0**
Rewind Stator (2025–2026) - Hinds Lake	-	5,233.2	9,695.5	-	-	-	**14,928.7**
Overhaul Hydraulic Units (2025)	-	4,972.4	-	-	-	-	**4,972.4**
Hydraulic In-Service Failures (2025)	-	2,000.0	-	-	-	-	**2,000.0**
Perform Level 2 Condition Assessment - Intake 4 and Unit 7 Draft Tube (2025) - Bay d'Espoir	-	471.5	-	-	-	-	**471.5**
Install Power Canal Public Safety Boom (2025) - Upper Salmon	-	463.8	-	-	-	-	**463.8**
Refurbish Intake 2 (2025–2026) - Bay d'Espoir	-	284.4	3,069.4	-	-	-	**3,353.8**
Replace Emergency Diesel Genset (2025–2027) - Cat Arm	-	266.2	1,221.1	113.9	-	-	**1,601.3**
Perform Level 2 Condition Assessment - Powerhouse Slope (2025) - Cat Arm	-	169.4	-	-	-	-	**169.4**
Install Unit 8 - Bay d'Espoir	-	-	26,450.0	21,000.0	158,000.0	167,000.0	**372,450.0**
Refurbish Penstock 2 and 3 (2026–2028) - Bay d'Espoir	-	-	20,000.0	45,000.0	65,000.0	-	**130,000.0**
Overhaul Hydraulic Units (2026)	-	-	2,169.9	-	-	-	**2,169.9**
Hydraulic In-Service Failures (2026)	-	-	2,036.0	-	-	-	**2,036.0**
Perform Level 2 Condition Assessment - North Salmon Spillway (2026) - Upper Salmon	-	-	540.9	-	-	-	**540.9**
Replace Walkway to Toe of Dam (2026) - Paradise River	-	-	391.0	-	-	-	**391.0**
Complete Major Refurbishment Turbine and Generator - Unit 7 (2026–2029) - Bay d'Espoir	-	-	350.0	3,428.7	5,715.0	38,063.2	**47,556.9**
Refurbish Spillway Gate - Salmon River Spillway (2026–2029) - Upper Salmon	-	-	349.3	5,757.6	6,112.1	6,362.1	**18,581.1**
Perform Level 2 Condition Assessment - Penstock 4 (2026) - Bay d'Espoir	-	-	206.2	-	-	-	**206.2**
Upgrade Spherical Valve Controls (2026–2029) - Bay d'Espoir	-	-	150.0	210.2	213.8	217.5	**791.5**
Replace Annunciator Panel (2026–2027) - Upper Salmon	-	-	150.0	200.0	-	-	**350.0**
Replace Expansion Joint and Rock Scaling (2026–2027) - Paradise River	-	-	135.2	1,600.0	-	-	**1,735.2**
Perform Level 2 Condition Assessment - Penstock (2026) - Hinds Lake	-	-	130.0	-	-	-	**130.0**
Upgrade Excitation System (2026–2027) - Paradise River	-	-	103.3	84.5	-	-	**187.8**
Replace Battery Bank (2026–2027) - Granite Canal	-	-	100.0	150.0	-	-	**250.0**
Rehabilitate Intake Decks 1–3 (2026–2028) - Bay d'Espoir	-	-	55.0	161.5	169.5	-	**386.0**
Overhaul Hydraulic Units (2027)	-	-	-	5,665.0	-	-	**5,665.0**
Hydraulic In-Service Failures (2027)	-	-	-	2,077.0	-	-	**2,077.0**
Refurbish MD1 (2027–2028) - Ebbegunbaeg	-	-	-	500.0	3,700.0	-	**4,200.0**
Perform Level 2 Condition Assessment - West Salmon Spillway (2027) - Upper Salmon	-	-	-	474.6	-	-	**474.6**
Refurbish Draft Tube Deck - Phase 3 (2027–2029) - Bay d'Espoir	-	-	-	365.5	728.6	6,994.8	**8,088.9**
Replace Rip Rap - LD5 - Salmon River Spillway (2027) - Upper Salmon	-	-	-	152.2	-	-	**152.2**
Perform Level 2 Condition Assessment - Penstock Steel Section (2027) - Paradise River	-	-	-	130.0	-	-	**130.0**
Replace Powerhouse Roofs (2027–2028) - Hinds Lake	-	-	-	84.3	735.8	-	**820.1**
Overhaul Hydraulic Units (2028)	-	-	-	-	5,500.0	-	**5,500.0**
Hydraulic In-Service Failures (2028)	-	-	-	-	2,116.0	-	**2,116.0**
Replace Powerhouse 2 Roof (2028) - Bay d'Espoir	-	-	-	-	960.0	-	**960.0**
Perform Major Refurbishment Turbine and Generator (2028–2029) - Upper Salmon	-	-	-	-	500.0	15,000.0	**15,500.0**
Replace Controllers (2028–2031) - Granite Canal	-	-	-	-	500.0	500.0	**1,000.0**
Refurbish North Salmon Spillway (2028–2029) - Upper Salmon	-	-	-	-	500.0	1,500.0	**2,000.0**
Replace Battery Banks 1 and 2 (2028–2029) - Hinds Lake	-	-	-	-	200.0	300.0	**500.0**
Stabilize Powerhouse Slope (2028) - Cat Arm	-	-	-	-	200.0	-	**200.0**
Replace Battery Banks 1 and 2 - Powerhouse 1 (2028–2029) - Bay d'Espoir	-	-	-	-	200.0	300.0	**500.0**

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Install Asset Health Monitoring System (2028–2029) - Cat Arm	-	-	-	-	150.0	150.0	**300.0**
Refurbish Rip Rap - CD4 (2028–2029) - Cat Arm	-	-	-	-	100.0	450.0	**550.0**
Refurbish Unit Control Panels - Unit 2 (2028–2029) - Cat Arm	-	-	-	-	100.0	570.0	**670.0**
Install Low Pressure Compressor, Piping, and Controls (2028–2029) - Hinds Lake	-	-	-	-	75.0	525.0	**600.0**
Replace Septic System - Burnt Dam (2028–2029) - Bay d'Espoir	-	-	-	-	50.0	125.0	**175.0**
Hydraulic In-Service Failures (2029)	-	-	-	-	-	2,156.0	**2,156.0**
Replace Powerhouse Roof (2029) - Cat Arm	-	-	-	-	-	1,500.0	**1,500.0**
Overhaul Hydraulic Units (2029)	-	-	-	-	-	1,350.0	**1,350.0**
Refurbish West Salmon Spillway (2029–2030) - Upper Salmon	-	-	-	-	-	500.0	**500.0**
Perform Level 2 Condition Assessment - Spillway (2029) - Hinds Lake	-	-	-	-	-	450.0	**450.0**
Perform Level 2 Condition Assessment - Turbine and Generator (2029) - Cat Arm	-	-	-	-	-	300.0	**300.0**
Replace Emergency Diesel Genset - North Salmon Spillway (2029–2030) - Upper Salmon	-	-	-	-	-	250.0	**250.0**
Perform Level 2 Condition Assessment - Penstock (2029) - Upper Salmon	-	-	-	-	-	200.0	**200.0**
Refurbish Rip Rap - SD-2 - West Salmon Dam (2029–2030) - Upper Salmon	-	-	-	-	-	100.0	**100.0**
Replace Cooling Water Pumps 3 and 5 - Powerhouse 1 (2029–2030) - Bay d'Espoir	-	-	-	-	-	50.0	**50.0**
Subtotal Hydraulic Plant	**29,380.7**	**64,707.9**	**67,302.9**	**87,155.0**	**251,525.8**	**244,913.6**	**744,985.8**
Thermal Plant							
Upgrade Unit 1 Control System (2024–2025) - Holyrood	468.3	184.3	-	-	-	-	**652.6**
Upgrade UPS 1 and 2 (2024–2025) - Holyrood	263.0	107.6	-	-	-	-	**370.6**
Upgrade DCS Hardware - Units 1 and 2 (2024–2025) - Holyrood	195.2	277.3	-	-	-	-	**472.5**
Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025) - Holyrood	156.2	1,039.4	-	-	-	-	**1,195.6**
Overhaul Turbine and Valves - Unit 3 (2025) - Holyrood	-	15,975.9	-	-	-	-	**15,975.9**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood	-	4,905.8	-	-	-	-	**4,905.8**
Thermal In-Service Failures (2025)	-	3,900.0	-	-	-	-	**3,900.0**
Refurbish Marine Terminal (2025–2026) - Holyrood	-	1,190.8	1,295.6	-	-	-	**2,486.5**
Overhaul Major Pumps (2025) - Holyrood	-	1,101.9	-	-	-	-	**1,101.9**
Perform Level 2 Condition Assessment - Stage 1 and 2 Cooling Water Sump Structures (2025) - Holyrood	-	891.9	-	-	-	-	**891.9**
Update Flame Scanners - Unit 3 (2025) - Holyrood	-	140.6	-	-	-	-	**140.6**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2026) - Holyrood	-	-	5,217.7	-	-	-	**5,217.7**
Thermal In-Service Failures (2026)	-	-	4,069.8	-	-	-	**4,069.8**
Overhaul Turbine Valves - Unit 2 (2026) - Holyrood	-	-	3,873.0	-	-	-	**3,873.0**
Refurbish Stage 1 and 2 Cooling Water Sump Structures (2026-2027) - Holyrood	-	-	3,507.9	3,549.3	-	-	**7,057.2**
Overhaul Generator and Install Online Monitoring Equipment - Unit 2 (2026) - Holyrood	-	-	1,989.0	-	-	-	**1,989.0**
Overhaul Major Pumps (2026) - Holyrood	-	-	1,625.0	-	-	-	**1,625.0**
Install Plant Heating System (2026–2027) - Holyrood	-	-	901.3	9,594.0	-	-	**10,495.3**
Refurbish Building Envelopes (2026–2027) - Holyrood	-	-	750.0	500.0	-	-	**1,250.0**
Replace Parts of Stage 1: 129 Vdc Battery Chargers, Batteries, Panels, and Breakers (2026) - Holyrood	-	-	750.0	-	-	-	**750.0**
Upgrade Water Treatment and Wastewater Treatment Assets (2026–2027) - Holyrood	-	-	500.0	500.0	-	-	**1,000.0**
Replace Tank Farm Steam Piping and Complete Level 2 Condition Assessment of Fuel Piping (2026) - Holyrood	-	-	473.0	-	-	-	**473.0**
Upgrade Cooling Water for Air Compressor 1 and 2 and Purchase Air-Cooled Compressor (2026) - Holyrood	-	-	440.0	-	-	-	**440.0**
Perform Level 2 Condition Assessment - Condenser and Condenser Tubes (2026) - Holyrood	-	-	400.0	-	-	-	**400.0**
Inspect Stack Liners and Replace Aviation Lights (2026) - Holyrood	-	-	360.0	-	-	-	**360.0**
Overhaul Major Feedwater Valves and Actuators - Unit 2 (2026) - Holyrood	-	-	300.0	-	-	-	**300.0**
Backup Critical Data (DCS, BMS, Turbine Controls) through ExaGrid (2026) - Holyrood	-	-	275.0	-	-	-	**275.0**

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Upgrade Cranes and Hoists (2026–2027) - Holyrood	-	-	200.0	300.0	-	-	**500.0**
Upgrade DCS Obsolete Components (2026–2027) - Holyrood	-	-	200.0	200.0	-	-	**400.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2027) - Holyrood	-	-	-	5,337.1	-	-	**5,337.1**
Thermal In-Service Failures (2027)	-	-	-	4,163.0	-	-	**4,163.0**
Overhaul Turbine Valves - Unit 1 (2027) - Holyrood	-	-	-	4,000.0	-	-	**4,000.0**
Overhaul Generator and Upgrade Online Monitoring - Unit 3 (2027) - Holyrood	-	-	-	1,930.9	-	-	**1,930.9**
Overhaul Major Pumps (2027) - Holyrood	-	-	-	1,440.0	-	-	**1,440.0**
Overhaul Marine Terminal Loading Arms (2027) - Holyrood	-	-	-	550.0	-	-	**550.0**
Upgrade Fire System (2027) - Holyrood	-	-	-	350.0	-	-	**350.0**
Inspect Light Oil System (2027) - Holyrood	-	-	-	200.0	-	-	**200.0**
Overhaul Quarry Brook Dam (2027–2028) - Holyrood	-	-	-	100.0	150.0	-	**250.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2028) - Holyrood	-	-	-	-	5,457.4	-	**5,457.4**
Overhaul Turbine Valves - Unit 3 (2028) - Holyrood	-	-	-	-	4,270.0	-	**4,270.0**
Thermal In-Service Failures (2028)	-	-	-	-	4,256.8	-	**4,256.8**
Overhaul Major Pumps (2028) - Holyrood	-	-	-	-	450.0	-	**450.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2029) - Holyrood	-	-	-	-	-	5,580.4	**5,580.4**
Overhaul Turbine Valves - Unit 2 (2029) - Holyrood	-	-	-	-	-	4,500.0	**4,500.0**
Thermal In-Service Failures (2029)	-	-	-	-	-	4,352.7	**4,352.7**
Upgrade Exciter and Transformer - Unit 3 (2029) - Holyrood	-	-	-	-	-	4,000.0	**4,000.0**
Overhaul Major Pumps (2029) - Holyrood	-	-	-	-	-	900.0	**900.0**
Overhaul Fuel Oil Storage Tank 3 (2029–2030) - Holyrood	-	-	-	-	-	300.0	**300.0**
Perform Level 2 Condition Assessment - Stacks (2029) - Holyrood	-	-	-	-	-	200.0	**200.0**
Perform Level 2 Condition Assessment - Site Buildings (2029) - Holyrood	-	-	-	-	-	120.0	**120.0**
Perform Level 2 Condition Assessment - Stage 1 North Air Receiver (2029) - Holyrood	-	-	-	-	-	50.0	**50.0**
Subtotal Thermal Plant	**1,082.7**	**29,715.5**	**27,127.4**	**32,714.3**	**14,584.2**	**20,003.1**	**125,227.3**
Total Generation	**30,654.8**	**96,944.1**	**115,967.1**	**228,385.9**	**478,511.8**	**460,353.8**	**1,410,817.4**
Transmission and Rural Operations							
Distribution							
Renew Distribution Feeders (2024–2025)	1,287.3	1,245.1	-	-	-	-	**2,532.4**
Upgrade Worst-Performing Distribution Feeders (2024–2025)	1,064.3	2,227.4	-	-	-	-	**3,291.7**
Upgrade Distribution - Terminal Station 2 (2024–2025) - Bay d'Espoir	93.2	331.5	-	-	-	-	**424.7**
Additions for Load - Cartwright (2024–2027)	18.9	0.9	0.9	487.2	-	-	**507.8**
Additions for Load - Main Brook (2024–2025)	13.8	339.0	-	-	-	-	**352.8**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2025)	-	6,397.0	-	-	-	-	**6,397.0**
Provide Service Extensions (2025)	-	4,662.5	-	-	-	-	**4,662.5**
Upgrade Worst-Performing Distribution Feeders (2025–2027)	-	2,678.9	3,677.4	2,529.8	-	-	**8,886.1**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2026)	-	-	5,489.0	-	-	-	**5,489.0**
Provide Service Extensions (2026)	-	-	4,749.0	-	-	-	**4,749.0**
Renew Distribution Feeders (2026–2027)	-	-	1,361.6	1,356.1	-	-	**2,717.7**
Replace T1 (2026–2027) - Burgeo	-	-	824.9	433.0	-	-	**1,257.9**
Additions for Load - Distribution System (2026)	-	-	793.3	-	-	-	**793.3**
Upgrade Worst-Performing Distribution Feeders (2026–2027)	-	-	508.0	2,962.6	-	-	**3,470.6**
Construct Pole Storage Ramps (2026–2030) - Labrador	-	-	250.0	250.0	250.0	250.0	**1,000.0**
Perform Distribution Equipment SCADA Additions (2026–2027)	-	-	31.7	294.1	-	-	**325.8**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2027)	-	-	-	5,626.0	-	-	**5,626.0**
Provide Service Extensions (2027)	-	-	-	4,868.0	-	-	**4,868.0**
Renew Distribution Feeders (2027–2028)	-	-	-	1,402.1	1,396.1	-	**2,798.2**
Upgrade Worst-Performing Distribution Feeders (2027–2028)	-	-	-	1,089.2	2,467.0	-	**3,556.1**
Additions for Load - Distribution System (2027)	-	-	-	816.9	-	-	**816.9**
Perform Distribution Equipment SCADA Additions (2027–2028)	-	-	-	32.7	302.7	-	**335.4**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2028)	-	-	-	-	5,767.0	-	**5,767.0**
Provide Service Extensions (2028)	-	-	-	-	4,990.0	-	**4,990.0**

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Renew Distribution Feeders (2028–2029)	-	-	-	-	1,443.4	1,437.2	**2,880.5**
Additions for Load - Distribution System (2028)	-	-	-	-	840.9	-	**840.9**
Upgrade Worst-Performing Distribution Feeders (2028–2029)	-	-	-	-	538.5	3,139.6	**3,678.1**
Perform Distribution Equipment SCADA Additions (2028–2029)	-	-	-	-	33.6	311.6	**345.3**
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2029)	-	-	-	-	-	5,911.0	**5,911.0**
Provide Service Extensions (2029)	-	-	-	-	-	5,115.0	**5,115.0**
Renew Distribution Feeders (2029–2030)	-	-	-	-	-	1,485.9	**1,485.9**
Additions for Load - Distribution System (2029)	-	-	-	-	-	865.7	**865.7**
Upgrade Worst-Performing Distribution Feeders (2029–2030)	-	-	-	-	-	554.4	**554.4**
Distribution Equipment SCADA Additions (2029–2030)	-	-	-	-	-	34.6	**34.6**
Subtotal Distribution	**2,477.5**	**17,882.3**	**17,685.8**	**22,147.6**	**18,029.2**	**19,104.9**	**97,327.3**
Generation							
Diesel Genset Replacement Program (2023–2025)	993.1	1,415.1	-	-	-	-	**2,408.2**
Replace Diesel Gensets (2024–2026)	535.8	478.0	3,902.3	-	-	-	**4,916.1**
Additions for Load - Unit 2065 Replacement and Fuel Storage Upgrades (2024–2027) - Rigolet	50.1	226.4	1,604.8	1,457.2	-	-	**3,338.4**
Southern Labrador Interconnection	-	19,693.8	37,432.4	24,615.3	6,203.5	-	**87,945.0**
Overhaul Diesel Units (2025)	-	1,000.0	-	-	-	-	**1,000.0**
Diesel In-Service Failures (2025)	-	800.0	-	-	-	-	**800.0**
Replace Diesel Gensets (2025–2027)	-	418.2	1,286.6	4,518.7	-	-	**6,223.6**
Replace Roof (2025) - Grey River	-	390.8	-	-	-	-	**390.8**
Overhaul Diesel Units (2026)	-	-	1,565.3	-	-	-	**1,565.3**
Inspect Fuel Storage Tank and Replace Wharf (2026–2028) - McCallum	-	-	1,000.0	2,000.0	2,000.0	-	**5,000.0**
Additions for Load Growth - Isolated Generation Stations (2026)	-	-	939.2	-	-	-	**939.2**
Diesel In-Service Failures (2026)	-	-	834.8	-	-	-	**834.8**
Inspect Fuel Storage Tanks (2026) - Rigolet	-	-	650.0	-	-	-	**650.0**
Replace Roof (2026) - Hopedale	-	-	200.0	600.0	-	-	**800.0**
Overhaul Diesel Units (2027)	-	-	-	1,601.1	-	-	**1,601.1**
Additions for Load Growth - Isolated Generation Stations (2027)	-	-	-	960.7	-	-	**960.7**
Diesel In-Service Failures (2027)	-	-	-	853.9	-	-	**853.9**
Inspect Fuel Storage Tanks (2027) - Makkovik	-	-	-	700.0	-	-	**700.0**
Replace Diesel Gensets (2027)	-	-	-	400.0	100.0	-	**500.0**
Replace Roof (2027) - Cartwright	-	-	-	200.0	500.0	-	**700.0**
Replace Diesel Plant (2028–2031) - Rigolet	-	-	-	-	5,000.0	10,000.0	**15,000.0**
Overhaul Diesel Units (2028)	-	-	-	-	1,637.2	-	**1,637.2**
Additions for Load Growth - Isolated Generation Stations (2028)	-	-	-	-	982.3	-	**982.3**
Diesel In-Service Failures (2028)	-	-	-	-	873.2	-	**873.2**
Inspect Fuel Storage Tanks (2028) - Black Tickle	-	-	-	-	800.0	-	**800.0**
Replace Diesel Shop (2028–2029) - Goose Bay	-	-	-	-	500.0	1,500.0	**2,000.0**
Replace Diesel Gensets (2028)	-	-	-	-	400.0	100.0	**500.0**
Overhaul Diesel Units (2029)	-	-	-	-	-	1,674.1	**1,674.1**
Additions for Load Growth - Isolated Generation Stations (2029)	-	-	-	-	-	1,004.5	**1,004.5**
Replace Diesel Gensets (2029)	-	-	-	-	-	1,000.0	**1,000.0**
Diesel In-Service Failures (2029)	-	-	-	-	-	892.9	**892.9**
Inspect Fuel Storage Tanks (2029) - Cartwright and Norman's Bay	-	-	-	-	-	300.0	**300.0**
Subtotal Generation	**1,579.0**	**24,422.3**	**49,415.5**	**37,907.0**	**18,996.2**	**16,471.5**	**148,791.5**
Metering							
Automate Bulk Metering (2024–2026)	302.6	214.4	235.3	-	-	-	**752.3**
Purchase Meters and Metering Equipment (2025–2026)	-	446.2	278.4	-	-	-	**724.6**
Purchase Meters and Metering Equipment (2026)	-	-	950.0	-	-	-	**950.0**
Purchase Meters and Metering Equipment (2027)	-	-	-	945.0	-	-	**945.0**
Purchase Meters and Metering Equipment (2028)	-	-	-	-	720.0	-	**720.0**
Purchase Meters and Metering Equipment (2029)	-	-	-	-	-	745.0	**745.0**
Subtotal Metering	**302.6**	**660.6**	**1,463.7**	**945.0**	**720.0**	**745.0**	**4,836.9**
Properties							
Replace Diesel Shop Building (2026–2027) - Bishop's Falls	-	-	1,422.0	889.9	-	-	**2,311.9**
Resurface Parking Lots and Roads (2027) - Bishop's Falls	-	-	-	500.0	400.0	-	**900.0**
Replace Sewage System (2028) - Bishop's Falls	-	-	-	-	156.1	-	**156.1**
Renew Property, Grounds, and Infrastructure (2029) - St. Anthony, Bishop's Falls, Stephenville, and Whitbourne	-	-	-	-	-	445.3	**445.3**

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Subtotal Properties	**-**	**-**	**1,422.0**	**1,389.9**	**556.1**	**445.3**	**3,813.3**
Tools and Equipment							
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	841.8	7.1	-	-	-	**872.9**
Replace Mobile Equipment (2025–2027)	-	1,973.6	54.6	2,619.4	-	-	**4,647.6**
Replace Mobile Equipment (2026–2028)	-	-	1,350.0	90.0	2,950.0	-	**4,390.0**
Replace Mobile Equipment (2027–2029)	-	-	-	1,300.0	100.0	2,950.0	**4,350.0**
Replace Mobile Equipment (2028–2030)	-	-	-	-	1,800.0	100.0	**1,900.0**
Replace Mobile Equipment (2029–2031)	-	-	-	-	-	1,800.0	**1,800.0**
Subtotal Tools and Equipment	**240.9**	**3,415.1**	**1,411.7**	**4,009.4**	**4,850.0**	**4,850.0**	**18,777.1**
Terminal Stations							
Additions for Load - Substation Upgrades - Wabush	10,179.6	514.5	-	-	-	-	**10,694.1**
Purchase Spare Generator Step-Up Transformer	1,338.5	3,966.7	2,161.7	-	-	-	**7,466.9**
Additions for Load Growth - Upgrade Transformer Capacity (2023–2024) - Jean Lake	580.0	6,459.6	789.7	-	-	-	**7,829.3**
Replace Protective Relays (2024–2025)	1,388.4	2,050.7	-	-	-	-	**3,439.1**
Upgrade Power Transformers (2024–2025)	864.6	2,711.3	-	-	-	-	**3,575.9**
Renew Circuit Breakers (2024–2025)	183.9	2,120.1	-	-	-	-	**2,304.0**
Replace Instrument Transformers (2024–2025)	154.9	714.8	-	-	-	-	**869.7**
Upgrade Data Alarm Systems (2024–2025) - Western Avalon	137.0	156.9	-	-	-	-	**293.9**
Replace Disconnects (2024–2025)	127.4	1,358.1	-	-	-	-	**1,485.5**
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247	112.4	215.8	-	-	-	-	**328.2**
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	91.6	429.0	-	-	-	-	**520.6**
Replace Terminal Station Battery Banks and Chargers (2024–2025)	71.8	120.9	-	-	-	-	**192.7**
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	53.8	599.0	-	-	-	-	**652.8**
Terminal Station In-Service Failures (2025)	-	2,500.0	-	-	-	-	**2,500.0**
Upgrade Power Transformers (2025–2026)	-	811.9	1,173.9	-	-	-	**1,985.8**
Replace Protective Relays (2025–2026)	-	668.6	2,070.9	-	-	-	**2,739.5**
Upgrade Data Alarm Systems (2025–2026) - Hardwoods	-	184.0	188.7	-	-	-	**372.7**
Install Breaker Failure Protection (2025–2027) - Holyrood	-	177.8	320.9	166.5	-	-	**665.2**
Replace Disconnects (2025–2026)	-	145.3	1,245.5	-	-	-	**1,390.8**
Renew Circuit Breakers (2025–2026)	-	129.7	1,021.7	-	-	-	**1,151.4**
Replace Terminal Station Battery Banks and Chargers (2025–2026)	-	123.2	315.3	-	-	-	**438.5**
Replace Instrument Transformers (2025–2026)	-	112.5	356.4	-	-	-	**468.9**
Replace Circuit Breaker Reclosing Controllers (2025–2026) - Cow Head and Massey Drive	-	104.6	164.3	-	-	-	**269.0**
Install Fire Protection in 230 kV Stations (2025–2026) - Come by Chance	-	51.7	534.5	-	-	-	**586.2**
Perform Major Inspection - Synchronous Condenser 2 (2025–2026) - Wabush	-	22.8	572.8	-	-	-	**595.6**
Terminal Station In-Service Failures (2026)	-	-	2,565.0	-	-	-	**2,565.0**
Replace Protective Relays (2026–2027)	-	-	850.0	1,350.0	-	-	**2,200.0**
Replace Disconnects (2026–2027)	-	-	393.3	730.5	-	-	**1,123.8**
Renew Circuit Breakers (2026–2027)	-	-	302.4	961.5	-	-	**1,263.9**
Install Fire Barriers between T10 and T12, T10 and T11 (2026–2027) - Bay d'Espoir	-	-	220.4	1,108.6	-	-	**1,329.0**
Replace Instrument Transformers (2026–2027)	-	-	204.3	136.2	-	-	**340.5**
Replace Terminal Station Battery Banks and Chargers (2026–2027)	-	-	180.8	120.5	-	-	**301.3**
Install Breaker Failure Protection (2026–2027) - Western Avalon	-	-	116.0	234.0	-	-	**350.0**
Replace Circuit Breaker Reclosing Controllers (2026–2027) - Holyrood	-	-	100.0	150.0	-	-	**250.0**
Perform Major Inspection - Synchronous Condenser 1 (2026–2027) - Wabush	-	-	86.0	484.0	-	-	**570.0**
Upgrade Terminal Station for Mobile Substation (2026–2027) - St. Anthony	-	-	76.1	431.0	-	-	**507.1**
Install New Station Service Feed (2026–2028) - Berry Hill	-	-	69.3	60.8	585.0	-	**715.1**
Install Fire Protection in 230 kV Stations (2026–2027) - Bottom Brook	-	-	68.4	616.5	-	-	**684.9**
Upgrade Power Transformers (2026–2027)	-	-	66.0	1,270.0	-	-	**1,336.0**

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Upgrade Transformer Paralleling (2026–2027) - Stony Brook and Sunnyside	-	-	64.0	120.0	-	-	**184.0**
Replace Switchgear - Synchronous Condensers 1 and 2 (2026–2027) - Wabush	-	-	50.0	700.0	-	-	**750.0**
Replace Switchgear (2026–2027) - Grand Falls	-	-	50.0	300.0	-	-	**350.0**
Upgrade Data Alarm Systems (2026–2027) - Springdale and Indian River	-	-	34.0	62.0	-	-	**96.0**
Terminal Station In-Service Failures (2027)	-	-	-	2,631.7	-	-	**2,631.7**
Renew Circuit Breakers (2027–2028)	-	-	-	945.4	1,238.7	-	**2,184.1**
Replace Protective Relays (2027–2028)	-	-	-	800.0	1,300.0	-	**2,100.0**
Replace Disconnects (2027–2028)	-	-	-	538.8	1,000.6	-	**1,539.4**
Upgrade Data Alarm Systems (2027–2028) - Grand Falls	-	-	-	183.0	190.0	-	**373.0**
Replace Instrument Transformers (2027–2028)	-	-	-	173.4	115.6	-	**289.0**
Install Breaker Failure Protection (2027–2028) - Hardwoods	-	-	-	133.0	267.0	-	**400.0**
Replace Terminal Station Battery Banks and Chargers (2027–2028)	-	-	-	88.8	59.2	-	**148.0**
Upgrade Terminal Station for Mobile Substation (2027–2028) - Glenburnie	-	-	-	76.1	431.0	-	**507.1**
Construct Fire Separation Walls between Transformers (2027–2028) - Happy Valley	-	-	-	54.8	773.9	-	**828.7**
Replace Circuit Breaker Reclosing Controllers (2027–2028) - Deer Lake	-	-	-	50.0	75.0	-	**125.0**
Upgrade Power Transformers (2027–2028)	-	-	-	45.0	880.0	-	**925.0**
Upgrade Transformer Paralleling (2027–2028) - Bottom Brook	-	-	-	32.0	60.0	-	**92.0**
Terminal Station In-service Failures (2028)	-	-	-	-	2,700.1	-	**2,700.1**
Replace Protective Relays (2028–2029)	-	-	-	-	800.0	1,100.0	**1,900.0**
Renew Circuit Breakers (2028–2029)	-	-	-	-	489.4	943.1	**1,432.5**
Replace Disconnects (2028–2029)	-	-	-	-	340.8	632.9	**973.7**
Replace Equipment Foundations (2028)	-	-	-	-	280.0	-	**280.0**
Replace Instrument Transformers (2028–2029)	-	-	-	-	254.4	169.6	**424.0**
Upgrade Drainage to Stop Frost Heaving (2028) - Stoney Brook, Springdale, Holyrood, Jackson's Arm, and Buchans	-	-	-	-	250.0	-	**250.0**
Upgrade Data Alarm Systems (2028–2029) - Happy Valley	-	-	-	-	183.0	190.0	**373.0**
Install Breaker Failure Protection (2028–2029) - Wabush	-	-	-	-	175.0	355.0	**530.0**
Replace Terminal Station Battery Banks and Chargers (2028–2029)	-	-	-	-	154.8	103.2	**258.0**
Perform Major Inspection - Synchronous Condenser 2 (2028–2029) - Wabush	-	-	-	-	86.0	484.0	**570.0**
Upgrade Terminal Station for Mobile Substation (2028–2029) - Roddickton	-	-	-	-	76.1	431.0	**507.1**
Upgrade Power Transformers (2028–2029)	-	-	-	-	60.0	1,080.0	**1,140.0**
Upgrade Reclosing Circuit Breakers (2028–2029) - Indian River	-	-	-	-	50.0	75.0	**125.0**
Install Fire Barriers between Substation and T1, T2, and T3 (2028–2029) - Massey Drive	-	-	-	-	39.1	731.5	**770.6**
Upgrade Transformer Paralleling - Terminal Station 2 (2028–2029) - Bay d'Espoir	-	-	-	-	32.0	60.0	**92.0**
Terminal Station In-service Failures (2029)	-	-	-	-	-	2,770.3	**2,770.3**
Renew Circuit Breakers (2029–2030)	-	-	-	-	-	1,738.0	**1,738.0**
Replace Protective Relays (2029–2030)	-	-	-	-	-	1,000.0	**1,000.0**
Replace Disconnects (2029–2030)	-	-	-	-	-	360.5	**360.5**
Replace Instrument Transformers (2029–2030)	-	-	-	-	-	307.7	**307.7**
Replace Terminal Station Battery Banks and Chargers (2029–2030)	-	-	-	-	-	98.6	**98.6**
Perform Modified Major Inspection - Synchronous Condenser 1 (2029–2030) - Wabush	-	-	-	-	-	77.0	**77.0**
Upgrade Terminal Station for Mobile Substation (2029–2030) - Grandy Brook	-	-	-	-	-	76.1	**76.1**
Upgrade Power Transformers (2029–2030)	-	-	-	-	-	60.0	**60.0**
Upgrade Reclosing Circuit Breakers (2029–2030) - Bear Cove	-	-	-	-	-	50.0	**50.0**
Upgrade Transformer Paralleling - T5 and T10 (2029–2030) - Holyrood	-	-	-	-	-	32.0	**32.0**
Subtotal Terminal Stations	**15,393.3**	**26,894.4**	**16,412.3**	**14,754.1**	**12,946.7**	**12,925.5**	**99,326.3**

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Transmission							
Wood Pole Line Management (2025)	-	4,281.3	-	-	-	-	**4,281.3**
Install Mid-Span Structures - TL220 (2025–2026)	-	881.3	229.3	-	-	-	**1,110.6**
Transmission In-Service Failures (2025)	-	184.3	-	-	-	-	**184.3**
Wood Pole Line Management (2026)	-	-	5,714.3	-	-	-	**5,714.3**
Renew Steel Tower Transmission Line (2026–2029) - L23/24	-	-	1,000.0	1,000.0	1,000.0	1,000.0	**4,000.0**
Transmission In-Service Failures (2026)	-	-	188.9	-	-	-	**188.9**
Relocate Section of Line (2026–2028) - TL220	-	-	89.3	1,292.3	2,318.0	-	**3,699.6**
Repair Self-Supporting Foundation (2026–2027) - TL212	-	-	50.0	250.0	-	-	**300.0**
Wood Pole Line Management (2027)	-	-	-	4,721.1	-	-	**4,721.1**
Transmission In-Service Failures (2027)	-	-	-	193.6	-	-	**193.6**
Wood Pole Line Management (2028)	-	-	-	-	3,739.7	-	**3,739.7**
Transmission In-Service Failures (2028)	-	-	-	-	198.4	-	**198.4**
Wood Pole Line Management (2029)	-	-	-	-	-	3,987.1	**3,987.1**
Transmission In-Service Failures (2029)	-	-	-	-	-	203.4	**203.4**
Subtotal Transmission	**-**	**5,346.9**	**7,271.8**	**7,457.0**	**7,256.1**	**5,190.5**	**32,522.3**
Total Transmission and Rural Operations	**19,993.2**	**78,621.6**	**95,082.8**	**88,610.0**	**63,354.3**	**59,732.7**	**405,394.7**
Total Capital Plan	**60,900.8**	**195,817.6**	**227,187.5**	**334,633.7**	**560,223.2**	**539,272.1**	**1,918,035.0**

[1] Numbers may not add due to rounding.

Appendix B

Capital Expenditures (2020–2029)





Newfoundland and Labrador Hydro
2025 Capital Budget Application
Capital Expenditures 2020–2029[1]
($000)

	Actuals				Budget					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Access	3,962.5	5,169.6	16,308.9	13,846.8	5,014.9	4,662.5	4,749.0	4,868.0	4,990.0	5,115.0
Allowance for Unforeseen	-	-	1,000.0	-	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
General Plant	9,374.0	8,221.7	7,414.6	13,183.3	27,497.4	27,182.3	19,887.8	32,809.0	25,056.0	26,007.9
Mandatory	-	-	-	388.7	2,540.3	1,483.2	1,228.4	945.0	720.0	745.0
Renewal	72,476.2	96,225.3	58,147.7	96,149.9	102,401.1	123,597.8	104,364.1	125,540.1	144,725.7	133,673.7
Service Enhancement	2,344.0	1,268.2	7,214.0	12,839.9	9,003.0	30,351.5	46,215.3	38,014.8	20,904.3	16,781.4
System Growth	1,517.8	2,607.3	11,496.3	12,467.4	7,285.0	7,540.3	49,742.9	131,456.9	362,827.3	355,949.2
Total	**89,674.5**	**113,492.1**	**101,581.5**	**148,876.1**	**154,741.7**	**195,817.6**	**227,187.5**	**334,633.7**	**560,223.2**	**539,272.1**

[1] Numbers may not add due to rounding.

Sch 3: Holyrood TGS
Overview

Schedule 3

Holyrood Thermal Generating Station Overview

Future Operation and Capital Expenditure Requirements



2025 Capital Budget Application

Holyrood Thermal Generating Station Overview

Future Operation and Capital Expenditure Requirements



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1.0 Background

In Order No P.U. 5(2012), 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:

- 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 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), 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. In Order No. P.U. 35(2023), the Board subsequently requested Hydro file an updated report to this effect in its 2025 CBA. This report outlines Hydro's operational outlook, maintenance strategy, and capital plan for 2025–2030.

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 can generate up to 40% of

the Island's annual energy needs if necessary. 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 TGS

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.[1]

[1] 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.

In 2021, Hatch Ltd. ("Hatch") completed its Life Extension Condition Assessment ("LECA") Study,[2] including a capital plan to support standby operation of the Holyrood TGS to 2030. Hydro's capital plan for 2025–2030 largely reflects the capital plan provided by Hatch, with modifications to reflect the operating scenario outlook contained in Section 3.0. Hydro's planned capital expenditures for the Holyrood TGS for the period 2025–2030, segmented by generation-related and synchronous condenser-related expenditures, are provided in Chart 1.

3.0 Current Operational Outlook and Schedule

Hydro has recommended that all three Holyrood TGS units and the Hardwoods and Stephenville Gas Turbines are to remain available through the "Bridging Period" while Hydro seeks to develop new long-term sources of supply.[3] This is in accordance with capacity requirements as specified by Hydro in 2024 Resource Adequacy Plan ("2024 Resource Plan")[4] as part of the *Reliability and Resource Adequacy Study Review* proceeding ("*RRA Study Review*").

The results of the Holyrood TGS LECA 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. Based on the information provided, Hydro can expect the reasonable operation of the facility through the Bridging Period, with required human, capital, and maintenance investments. In 2024, Hydro is completing a refresh of the capital plan presented in this condition assessment. The purpose of this refresh is to assess the cost and viability of the operation of Holyrood TGS beyond 2030,[5] to inform supply options in the event that some supply from Holyrood TGS is needed in advance of new generation. This refresh will consider the required capital investments for the continued operation of the Holyrood TGS to 2030 and beyond as necessary to aid future analysis.

[2] "*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.
[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, Stephenville Gas Turbine and the Hardwoods Gas Turbine until their capacities can be adequately replaced.
[4] "2024 Resource Adequacy Plan: An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, July 9, 2024.
[5] As noted in correspondence "*Reliability and Resource Adequacy Study Review* – Planned Reports, Studies and Analyses – Response to Further Comments and Directions," Newfoundland and Labrador Hydro, January 19, 2024, Hatch has been requested to assess life extension up to 2035; however, Hydro does not intend to keep Holyrood TGS in operation for this full period.

4.0 Maintenance Strategy through to Decommissioning

Scheduled overhauls of plant equipment are ongoing 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; an extension beyond more typical timeframes may be achieved in some instances, allowing Hydro to reduce costs while maintaining safety and reliability. Advancement of refurbishment intervals may be required in some instances, as necessitated by asset condition.

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 2025 Capital Plan Summary

Planned 2025 capital expenditures for the Holyrood TGS include both generation-related and non-generation-related (i.e., synchronous condenser mode) investments. The 2025 capital project proposals, as outlined in Table 1 and Table 2 were identified considering safety, environment, asset condition, equipment obsolescence, forecast production requirements, and Hydro's commitment to have the Holyrood TGS fully available through the Bridging Period. The projects outlined herein reflect the necessary refurbishment and replacement projects to support the reliability of the Holyrood TGS and the provision of service to customers. In the event of unforeseen failure or unexpected as-found conditions, adjustments or additions may be required beyond the current plan.

Hydro's proposed projects and programs in the 2025 CBA are informed by the LECA, supplemented by Hydro's operational experience and updated asset condition information.

Table 1 provides a summary description of the proposed 2025 capital programs and projects for the Holyrood TGS. Table 2 provides a summary description of programs and projects which were previously approved, with planned expenditures in 2025.

Table 1: Holyrood TGS Programs and Projects Proposed in the 2025 CBA

	Program/Project (Totals)	Scope Summary	Proposal Location
Generation	Overhaul Turbine and Valves – Unit 3 (2025) ($16.0 million)	This program is required to complete an overhaul on a nine-year cycle for the turbines and a three-year cycle for the turbine valves and is appropriate based on the observations made during previous overhauls. The scope of the 2025 work includes an overhaul of the turbine and valves for Unit 3 and remediation of the crack in the lower steam chest of the turbine. The turbine overhaul will include the removal of the top half HP, IP and LP[6] casings, the turbine rotor, and the diaphragms. A visual inspection will be completed to identify cracks or other concerns that could lead to turbine failure. Replacement or refurbishment will be completed as required. The turbine valve overhaul will consist of dismantling all the control valves, main stop valve, combined reheat stop and intercept valves, extraction non-return valves, and blowdown valve for inspection and detailed measurements. The valves will be refurbished as required through the replacement of damaged parts. Overhaul of the valves is required for safe control and operation of the steam turbine. In the 2025 program, the Unit 3 steam check crack will be remediated while the turbine is disassembled to provide access. This requires some additional disassembly beyond the normal turbine overhaul scope.	Schedule 7, Program 1
Generation	Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) ($4.9 million)	This program is required to complete identified Level 2 Condition Assessments and detailed inspections of HP 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 the safe and reliable operation of the boilers. The 2025 scope includes work that was identified through prior assessments. Replacements and refurbishments identified through the completion of the boiler work, such as the replacement of expansion joints, which are deemed capital in nature will be included in the scope.	Schedule 7, Program 7
Generation	Thermal In-Service Failures (2025)[7] ($3.9 million)	The purpose of this program is to allow the 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 7, Program 11

[6] High Pressure ("HP"), Intermediate Pressure ("IP") and Low Pressure ("LP").
[7] 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
Generation	Refurbish Marine Terminal (2025–2026) ($1.2 million in 2025; $2.5 million total)	This two-year project is to complete a refurbishment of the Marine Terminal at the Holyrood TGS. The refurbishments include a section of the shoreline boardwalk, gravity fender bumpers, and capstan gearboxes. The Level 2 Condition Assessments will be completed on the jetty steel piles, bollards, and gravity fender mechanical linkage arms. The 2025 scope of work includes the refurbishment of the shoreline boardwalk and the gravity fender bumpers, overhauling two Capstan gearboxes, procuring mechanical linkage for fender #2, and a Level 2 Condition Assessment of the jetty.	Schedule 7, Project 3
Generation	Overhaul Major Pumps (2025) ($1.1 million)	This program is required to complete the identified inspection and overhaul of the Unit 3 West Boiler Feed Pump and the replacement of the Unit 3 North Vacuum Pump. The 2025 scope of work for the Unit 3 West Boiler Feed Pump includes the disassembly, inspection, refurbishment and replacement of parts, as required, and reassembly and commissioning. The 2025 scope of work for the Unit 3 North Vacuum Pump includes replacing the original pump.	Schedule 7, Program 19
Generation	Perform Level 2 Condition Assessment Stage 1 and 2 Cooling Water Sump Structures (2025) ($0.9 million)	This project is required to complete a Level 2 Condition Assessment of the reinforced concrete support beams for the floor structure in the Stage 1 and 2 cooling water sumps located in Pumphouse 1 & 2 at the Holyrood TGS. Deterioration of the reinforced concrete beams, which support the floor slab for each pump house, has compromised their integrity resulting in a restriction of floor loading to foot traffic only. The scope of work for 2025 includes the procurement of stop logs, dewatering and cleaning the sumps, erection of scaffold, and the condition assessment of the reinforced concrete support beams.[8]	Schedule 7, Project 8
Generation	Update Flame Scanners – Unit 3 (2025) ($0.1 million)	This project proposes to complete a replacement of flame scanners on Unit 3. The current flame scanner system is obsolete and a lack of replacement parts and service options is a risk to reliable operation. Flame scanners are instruments that are used to detect the presence of flame on a burner inside of the boiler, and send that information back to the Burner Management System. The importance of this is that if a burner goes out, the flame scanner will detect the absence of flame, and the system will cut fuel to that burner to avoid the buildup of non-combusted fuel that could create a dangerous explosive environment inside the boiler.	Schedule 7, Programs and Projects under $750,000

[8] Should the assessment findings support the urgency, Hydro will file a supplemental application to commence the execution of the refurbishment scope ahead of the next capital budget application.

Table 2: Previously Approved Holyrood TGS Programs and Projects with Expenditures in the 2025 CBA[9]

	Program/Project (Totals)	Scope Summary
Synchronous Condenser	Refurbish Outbuilding and Powerhouse Building Envelopes (2024–2025) ($1.0 million in 2025; $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 one to two 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.
Generation	Upgrade Unit 1 Turbine Control System (2024–2025) ($0.2 million in 2025; $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 was replaced in 2023 under a previously approved project. The control system controls the turbine valves and adjusts the steam intake into the turbine, maintaining the desired generation at the required rotational speed of 3,600 rpm. The upgrade will replace control cards that have been obsolete since 2014 with currently supported system controls. Continuing to use the current system maintains an increased risk of a unit shut down due to an in-service failure, with a long duration due to the unavailability of trained service technicians and parts. Unit 3 does not have this type of control system.
Generation	Upgrade DCS Hardware – Units 1 and 2 (2024–2025) ($0.3 million in 2025; $0.5 million total)	This two-year project proposes to replace obsolete components of the 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, in 2023, completed this upgrade on components required for post-steam operation of Unit 3 as a synchronous condenser. This current project will replace obsolete components required to support the 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 cyberattack.
Generation	Upgrade UPS 1 & 2 (2024–2025) ($0.1 million in 2025; $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 continually for approximately 25 years. They provide uninterrupted power to critical systems on Unit 1 and Unit 2 respectively during blackouts and other system disruptions. They have been at “end of life” status since 2010, with limited parts and no technical support from the original equipment manufacturer (“OEM”). Replacement is needed for the continued reliable operation of the Holyrood TGS.

[9] Approved in Board Order No. P.U. 2(2024).

Hydro is managing several deteriorating pieces of infrastructure, notably fuel oil storage tanks, to reach 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 3.

Table 3: Fuel Oil Storage Tank Status

Tank	Status
Fuel Oil Storage Tank 1	Removed from service in 2021 in preparation for retirement but was restored in 2023 as it was in generally better condition than Tank 2. After restoration and during return to service in September 2023, an oil leak was discovered, requiring further work on Tank 1, which was completed in Spring 2024. The tank is now back in service.
Fuel Oil Storage Tank 2	Kept in service for the winter of 2023–2024 to maintain three-tank operation because of the Tank 1 leak that was discovered in September 2023. Tank 2 will be kept available for service as a contingency until the Tank 4 overhaul is complete in 2024 and that tank is returned to service. Tank 2 will be removed from service and retired towards the end of 2024.
Fuel Oil Storage Tank 3	Discussions with the regulator resulted in an extension of this tank from 2025 to 2031. The project to refurbish this tank has been included in the Holyrood Capital Plan as a two-year project in 2029–2030. This could be deferred by one year or cancelled pending generation requirements from Holyrood at that time.
Fuel Oil Storage Tank 4	Expiry in 2024. The approved project is underway to complete the overhaul in 2024.
Day Tank	Project to refurbish was completed in 2023. Expires in 2033.

Based on current operating assumptions, Hydro has determined that the increased risks related to operating with three tanks are acceptable through the Bridging Period.

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

Table 4 outlines programs and projects proposed in the 2025 CBA by major system or subsystem and the necessity for generation or synchronous condenser operation.

Table 4: 2025 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	N/A	Required	N/A
Feedwater and Condensate	Overhaul Major Pumps	Required	N/A
Boiler	Perform Boiler Condition Assessment and Miscellaneous Upgrades Update Flame Scanners	Required	N/A
Turbine Generator	Overhaul Turbine and Valves – Unit 3	Required	N/A
Cooling Water Systems	Perform Level 2 Condition Assessment - Stage 1 & 2 Cooling Water Sump Structures	Required	N/A
Buildings and Grounds	N/A	Required	Required
Common Systems	Refurbish Marine Terminal	Required	N/A
	Thermal In-Service Failures[10]	Required	Required

6.0 Holyrood TGS 2025–2030 Capital Expenditures Outlook

As shown in Chart 1, capital investment will be necessary from 2025 to 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.

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

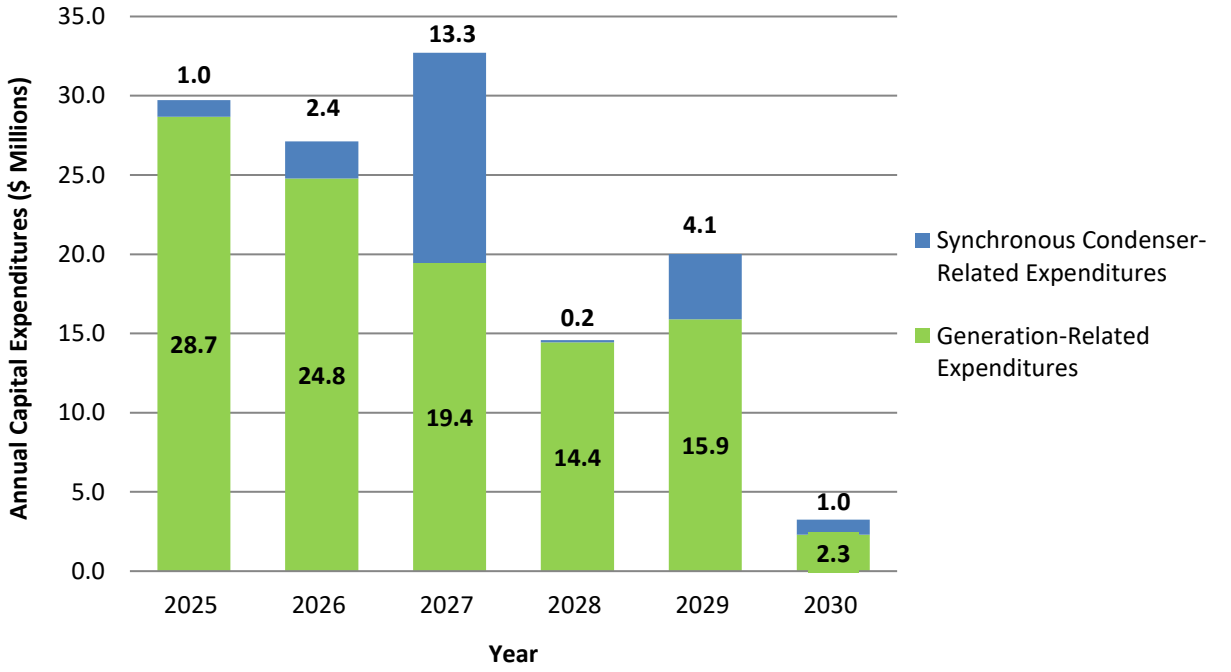


Chart 1: Holyrood TGS Capital Expenditures 2025–2030[11,12]

Planned expenditures for the 2025–2030 capital plan period total $127.5 million, of which, $105.5 million is related to generation and $22.2 million is related to synchronous condenser operation. Approximately $90 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 the 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. A source of plant heat is also required in the near term to prevent the possibility of plant freeze-up and severe damage to critical generation equipment, should a circumstance arise where all three boilers at Holyrood TGS are not available simultaneously during cold weather. Hydro is assessing

[11] Numbers may not add due to rounding.
[12] Included in the 2025–2029 generation-related expenditures category is an annual average of $4.1 million for thermal in-service failures. Depending on the failure type, a portion of the $4.1 million could be attributed to synchronous condenser-related expenditures. In 2030, the entire thermal in-service failure expenditure of $0.7 million is considered to be synchronous condenser-related.

options for plant heating and will submit a project as early as practical to address the near-term and long-term needs. The project timing is subject to change but currently planned for submission in the 2026 CBA as a two-year project.

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

Several assumptions have been made in the creation of the capital plan for the Holyrood TGS. This includes projected scenarios of timelines for the transition of generation capability from the Holyrood TGS to new generation assets, the expected retirement sequence and retirement dates of the thermal generating units at the Holyrood TGS, and other key operational assumptions. These assumptions and the associated capital plan reflect the 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 the Holyrood TGS, the site will continue to operate Unit 3 as a synchronous condenser. The Holyrood Combustion 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's annual operation schedule is assumed to remain consistent with recent operations, with the critical winter period 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 winter 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 regularly. 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 2024–2030:

Holyrood TGS units will typically be online and staged to meet load requirements, as needed, from the mid-October through March timeframe.[13]

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 the 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 the second unit. No capital investment will be made to facilitate faster start times or improve standby operation.

4) An alternate source of heat is required to prevent freeze-up of the plant and consequential severe damage to critical generation equipment should all three boilers at Holyrood TGS be unavailable for operation simultaneously during cold weather. This requirement will result in advancing the plant heating project to before 2030.

5) Current reliability targets; derated adjusted forced outage rate ("DAFOR"),[14] and derated adjusted utilization forced outage probabilities ("DAUFOP")[15] – 20% (as noted in the *RRA Study Review*)[16] 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.

[13] The operation of the Holyrood TGS will be determined in advance of each winter operating season, depending on system conditions at that time.
[14] 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.
[15] DAUFOP is a metric that measures the percentage of time that a unit or group of units will encounter a forced outage and not be available when required. DAUFOP is a measure primarily used for gas turbines; however, this measure will be applicable to the thermal generating units.
[16] Hydro's resource planning model does not differentiate between DAFOR and DAUFOP; rather, it requires the selection of a forced outage rate percentage.

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.[17]

8) The Unit 3 turbine steam chest crack is managed with support from the turbine service provider, General Electric ("GE"). GE has completed an engineering study that defines acceptable conditions for continued operation until the crack is remediated. Hydro is also working with Mitsubishi (Hitachi), the OEM for Unit 3, to plan remediation of this crack during the 2025 planned major overhaul.

9) 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 updated in 2023 to provide updated estimates.

10) The proposed capital projects from the LECA Study and the planned refresh to be completed in 2024, will be considered in detail relative to the transition scenarios and assumptions. Changing assumptions and asset conditions 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.

11) 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 the 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.

[17] 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.

6.1 Depreciation Impacts of Holyrood TGS Life Extension

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).[18]

7.0 Holyrood TGS 2025–2033 Operating Expenses

In Order No. P.U. 14(2004), 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 identified and expected system equipment maintenance ("SEM") expenditures for the years 2025–2033, inclusive, are provided in Appendix C.

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 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.[19]

[18] Due to the extension of the Holyrood TGS through the Bridging Period, Hydro submitted an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account. The Board approved the extension of the account and related amendments in Board Order No. P.U. 1(2024). Hydro was also directed to file a report on the account in its next general rate application.
[19] In the maintenance plan, 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.

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 Study Review*,[20] the Holyrood TGS shall remain available for a "Bridging Period" until 2030, or until such time that the units are not required for the provision of reliable service to customers. In July 2024, Hydro filed its 2024 Resource Plan, which indicated additional generating assets are required to be brought online (i) to accommodate anticipated load growth on the island interconnected; and (ii) to ensure reliable system operation in the event of an extended outage on the Labrador-Island Link. Hydro has commenced front-end engineering design for new supply additions, and anticipates filing an application for additional generation in late 2024 or early 2025. While Hydro is committed to transitioning from Holyrood as a generating facility as soon as reasonably possible, there are no reasonable alternatives that would allow Hydro to transition from generation at Holyrood until new sources of supply are available. Please refer to Section 5.2.3 of Hydro's 2024 Resource Plan for further discussion of short-term supply options.

[20] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.

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
2025 Capital Budget Application
Planned Capital Expenditures
($000)

	2024 and Prior Years	2025	2026	2027	2028	2029	2030	Total
Generator								
Upgrade Unit 1 Control System (2024-2025) - Holyrood	468.3	184.3						**652.6**
Upgrade UPS 1 & 2 (2024-2025) - Holyrood	263.0	107.6						**370.6**
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood	195.2	277.3						**472.5**
Thermal In-Service Failures (2025)		3,900.0						**3,900.0**
Overhaul Major Pumps (2025) - Holyrood		1,101.9						**1,101.9**
Overhaul Turbine and Valves - Unit 3 (2025) - Holyrood		15,975.9						**15,975.9**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) - Holyrood		4,905.8						**4,905.8**
Perform Level 2 Condition Assessment Stage 1 and 2 Cooling Water Sump Structures (2025) - Holyrood		891.9						**891.9**
Refurbish Marine Terminal (2025-2026) - Holyrood		1,190.8	1,295.6					**2,486.5**
Update Flame Scanners - Unit 3 (2025) - Holyrood		140.6						**140.6**
Thermal In-Service Failures (2026)			4,069.8					**4,069.8**
Overhaul Generator and Install On-line Monitoring Equipment - Unit 2 (2026) - Holyrood			1,989.0					**1,989.0**
Overhaul Major Pumps (2026) - Holyrood			1,625.0					**1,625.0**
Overhaul Turbine Valves - Unit 2 (2026) - Holyrood			3,873.0					**3,873.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2026) - Holyrood			5,217.7					**5,217.7**
Backup Critical Data (DCS, BMS, Turbine Controls) through ExaGrid (2026) - Holyrood			275.0					**275.0**
Inspect Stack Liners and Replace Aviation Lights (2026) - Holyrood			360.0					**360.0**
Overhaul Major Feedwater Valves and Actuators - Unit 2 (2026) - Holyrood			300.0					**300.0**
Perform Level 2 Condition Assessment - Condenser and Condenser Tubes (2026) - Holyrood			400.0					**400.0**
Replace Parts of Stage 1: 129 Vdc Battery Chargers, Batteries, Panels, and Breakers (2026) - Holyrood			750.0					**750.0**
Replace Tank Farm Steam Piping and Complete Level 2 Condition Assessment of Fuel Piping (2026) - Holyrood			473.0					**473.0**
Upgrade Cooling Water for Air Compressor #1 and #2 and Purchase Air Cooled Compressor (2026) - Holyrood			440.0					**440.0**
Upgrade DCS Obsolete Components (2026-2027) - Holyrood			200.0	200.0				**400.0**
Refurbish Stage 1 and 2 Cooling Water Sump Structures (2026-2027) - Holyrood			3,507.9	3,549.3				**7,057.2**
Thermal In-Service Failures (2027)				4,163.0				**4,163.0**
Overhaul Major Pumps (2027) - Holyrood				1,440.0				**1,440.0**
Overhaul Turbine Valves - Unit 1 (2027) - Holyrood				4,000.0				**4,000.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2027) - Holyrood				5,337.1				**5,337.1**
Inspect Light Oil System (2027) - Holyrood				200.0				**200.0**
Overhaul Marine Terminal Loading Arms (2027) - Holyrood				550.0				**550.0**
Thermal In-Service Failures (2028)					4,256.8			**4,256.8**
Overhaul Major Pumps (2028) - Holyrood					450.0			**450.0**
Overhaul Turbine Valves - Unit 3 (2028) - Holyrood					4,270.0			**4,270.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2028) - Holyrood					5,457.4			**5,457.4**
Overhaul Major Pumps (2029) - Holyrood						900.0		**900.0**
Overhaul Turbine Valves - Unit 2 (2029) - Holyrood						4,500.0		**4,500.0**
Perform Boiler Condition Assessment and Miscellaneous Upgrades (2029) - Holyrood						5,580.4		**5,580.4**
Thermal In-Service Failures (2029)						4352.7		**4,352.7**
Overhaul Fuel Oil Storage Tank 3 (2029-2030) - Holyrood						300.0	2,300.0	**2,600.0**
Perform Level 2 Condition Assessment - Stacks (2029) - Holyrood						200.0		**200.0**
Perform Level 2 Condition Assessment - Stage 1 North Air Receiver (2029) - Holyrood						50.0		**50.0**
Generator Total	**926.5**	**28,676.1**	**24,776.1**	**19,439.4**	**14,434.2**	**15,883.1**	**2,300.0**	**106,435.4**
Synchronous Condenser								
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood	156.2	1,039.4						**1,195.6**
Upgrade Cranes and Hoists (2026-2027) - Holyrood			200.0	300.0				**500.0**
Install Plant Heating System (2026-2027) - Holyrood			901.3	9,594.0				**10,495.3**
Refurbish Building Envelopes (2026-2027) - Holyrood			750.0	500.0				**1,250.0**
Upgrade Water Treatment and Waste Water Treatment Assets (2026-2027) - Holyrood			500.0	500.0				**1,000.0**
Overhaul Generator and Upgrade Online Monitoring - Unit 3 (2027) - Holyrood				1,930.9				**1,930.9**
Overhaul Quarry Brook Dam (2027-2028) - Holyrood				100.0	150.0			**250.0**
Upgrade Fire System (2027) - Holyrood				350.0				**350.0**
Perform Level 2 Condition Assessment - Site Buildings (2029) - Holyrood						120.0		**120.0**
Upgrade Exciter and Transformer - Unit 3 (2029) - Holyrood						4,000.0		**4,000.0**
Thermal In-Service Failures (2030) - Holyrood							700.0	**700.0**
Replace Batteries/Chargers - Holyrood							250.0	**400.0**
Synchronous Condenser Total	**156.2**	**1,039.4**	**2,351.3**	**13,274.9**	**150.0**	**4,120.0**	**950.0**	**22,191.8**
Grand Total	**1,082.7**	**29,715.5**	**27,127.4**	**32,714.3**	**14,584.2**	**20,003.1**	**3,250.0**	**128,627.3**

Appendix C

Ten-Year System Equipment Maintenance Expenditures





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

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generating Units										
Materials (inc. Boiler Overhauls)	1,200	1,015	1,026	1,037	1,048	1,060	81	82	83	83
Lubes, Chems, Gases	24	16	16	16	17	17	-	-	-	-
Contract Labour (inc. Boiler Overhauls)	4,196	4,405	4,453	4,502	4,552	4,602	189	191	193	195
Generating Units Total	**5,420**	**5,436**	**5,496**	**5,556**	**5,617**	**5,679**	**270**	**273**	**276**	**279**
Common Equipment										
Materials	541	544	550	556	562	568	285	288	292	295
Tools and Operating Supplies	29	24	24	24	24	25	14	14	15	15
Lubes, Chems, Gases	68	42	42	43	43	44	8	8	8	9
Contract Labour (Service Contracts)	1,195	1,843	1,864	1,884	1,905	1,926	476	481	486	491
Common Equipment Total	**1,833**	**2,453**	**2,480**	**2,507**	**2,534**	**2,562**	**783**	**792**	**801**	**810**
Environmental										
Materials	240	326	330	334	337	341	79	79	80	81
Tools and Operating Supplies	15	10	10	10	10	10	7	7	7	7
Lubes, Chems, Gases	381	369	374	378	382	386	172	174	176	178
Contract Labour (Service Contracts)	96	102	253	104	105	106	277	108	110	111
Environmental Total	**731**	**807**	**966**	**825**	**834**	**844**	**535**	**369**	**373**	**378**
Grand Total	**7,984**	**8,696**	**8,941**	**8,888**	**8,986**	**9,085**	**1,589**	**1,434**	**1,450**	**1,466**

[1] Numbers may not add due to rounding.

Sch 4: BDE Projected Capital Expenditures

Schedule 4

Bay d’Espoir Hydroelectric Generating Station

Projected Capital Expenditures (2025–2034)



2025 Capital Budget Application

Bay d'Espoir Hydroelectric Generating Station

Projected Capital Expenditures (2025–2034)



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Appendix A: Full Asset Description

1.0 Background

In Order No P.U. 35(2023), the Board of Commissioners of Public Utilities ("Board") directed Newfoundland and Labrador Hydro ("Hydro") to file, in conjunction with its 2025 Capital Budget Application ("CBA"), a report about the Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir" or "BDE"). In this Order, the Board noted that:

> …the Bay d'Espoir Facility is a critical hydraulic generating asset. Significant capital expenditures are proposed for this facility in 2024 and significant additional expenditures are planned for future years. In addition, Hydro is currently investigating the potential expansion of this facility and this will be addressed as a part of the Board's ongoing Reliability and Resource Adequacy Review. The Board also notes that Hydro is conducting an asset management review which will address all of its assets including Bay d'Espoir. It may be some time before these reviews are completed and a new approach to asset management for Bay d'Espoir is developed. As a result the Board believes it is premature to direct Hydro to develop an asset management plan for the refurbishment of the Bay d'Espoir Facility. The Board does believe, however, that it would be helpful for Hydro to include in its next capital budget application a report setting out its capital plan for the Bay d'Espoir Facility addressing anticipated and potential work and expenditures over the 2025-2034 period.[1]

This report provides an operational overview of Bay d'Espoir and its capital plan for the 2025–2034 period.

2.0 Introduction

Bay d'Espoir, shown in Figure 1, is a critical generating asset on the Island Interconnected System ("IIS"), with seven generating units in two powerhouses, providing an installed capacity of 613.4 MW and producing an average of 2,672 GWh[2] of energy each year.

[1] *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 35(2023), Board of Commissioners of Public Utilities, pp. 14–15/40–9.
[2] Using the most recently available five-year average (2019–2023).



Figure 1: Bay d'Espoir

The location, total rated generating capacity, and in-service dates for each turbine generating unit are provided below in Table 1.

Table 1: Installed Units at Bay d'Espoir

Unit Location	Unit Name	Rating (MW)	In-Service Date
Bay d'Espoir Powerhouse 1	BDE Unit 1	76.5	March 1967
	BDE Unit 2	76.5	June 1967
	BDE Unit 3	76.5	October 1967
	BDE Unit 4	76.5	September 1968
	BDE Unit 5	76.5	February 1970
	BDE Unit 6	76.5	March 1970
Bay d'Espoir Powerhouse 2	BDE Unit 7	154.4	December 1977

Hydro has an Asset Management Program, which governs the life cycle of its hydraulic generation assets, including those located at Bay d'Espoir. This program monitors, maintains, refurbishes, replaces and disposes of assets to provide safe, reliable electrical power in an environmentally responsible

manner at the least cost. Within this program, assets are grouped by five asset classifications, including hydraulic generating units, hydraulic structures, reservoirs, site buildings and services, and auxiliary equipment.

For this report, four of the noted asset classifications are to be discussed: Hydro's hydraulic generating units, hydraulic structures, site buildings and services, and auxiliary equipment. As this scope is intended to address Bay d'Espoir itself, the fifth asset classification, reservoirs, is considered to be outside the scope of this report.

The Generating Unit asset class, which pertains to the seven units located at Bay d'Espoir, consists of:

- Generators;
- Governors;
- Isolated Phase Buses;
- Spherical Valves;[3]
- Turbines;
- Exciters; and
- Metering, Monitoring, SCADA,[4] Protection and Control Equipment.

It is noted that assets such as generator step-up transformers and generator circuit breakers are considered external to the generating station, and are classified as terminal station assets. As such, details of Hydro's Terminal Station Asset Management System and the life cycle strategy for these assets can be found in Appendix F to Schedule 1 of this Application.

In addition to the components included in the hydraulic generating unit asset class listed above, the following components from Hydro's hydraulic structures asset classification are considered essential to

[3] Spherical valves are mainly employed in power plants where more than one generating unit share a penstock, as is the case in Bay d'Espoir Powerhouse 1, with two units per penstock. As Bay d'Espoir Unit 7 is the single unit in Powerhouse 2, it does not have a spherical valve installed.
[4] Supervisory Control and Data Acquisition ("SCADA").

the operation of generating unit assets at Bay d'Espoir, as they are responsible for conveying water from the reservoir into the generating unit:

- Gates;
- Penstocks; and
- Surge Tanks.

Finally, the reliable operation of Bay d'Espoir cannot be maintained without ensuring the appropriate capital investments are planned and executed on the site buildings and services and auxiliary equipment contained within the station. These asset classifications are comprised of components including, but not limited to, powerhouse buildings, site access roads, station service, ancillary AC/DC electrical systems, and service/cooling water systems.

A functional description and further sub-classification of the infrastructure, equipment and systems within each asset classification is provided in Appendix A.

In recent years, as assets are aging, significant expenditures have been proposed for Bay d'Espoir and it is expected that continued investment in these assets is required to ensure the provision of reliable electrical service. This report will set out the capital plan for Bay d'Espoir, addressing anticipated and potential life extension activities, along with estimated expenditures for the 2025–2034 period. In addition, this report will provide operational context and summarize major refurbishment and replacement work which has already been completed at Bay d'Espoir.

3.0 Operational Overview

With an installed capacity of 613.4 MW, Bay d'Espoir is the largest hydroelectric generating site on the Island. The facility generates an average of 2,672 GWh of energy each year, which represents approximately 41% of Hydro's average annual Island energy sales.

The generating units are operated according to system conditions to balance the system load requirements while maintaining efficient water management strategies and respecting necessary operating conditions as outlined by the asset owners. As such, Bay d'Espoir provides both continuous

base-load generation, as well as unit dispatch to meet the higher demand required at system peaks. In addition to providing generation supply, Unit 7, the largest capacity unit at Bay d'Espoir, also provides synchronous condensing capability to provide the necessary voltage support to the IIS during periods when power generation from this unit is not required.

The continued reliable operation of assets located at Bay d'Espoir is critical to meet both current customer demand and future system energy requirements. To ensure these assets continue to be managed efficiently, Hydro plans and schedules capital investments to minimize impacts to generation availability while maximizing the useful life of the assets, where practical.

4.0 Asset Management Approach

Hydro has an Asset Management Program which governs its hydraulic assets throughout their lifecycle and aims to anticipate future failures so that refurbishment or replacement can be incorporated into the proposed capital plan at an appropriate time as outlined in this report. However, there are situations where immediate refurbishment or replacement, which has not been included in a given year in the identified capital plan, has to be undertaken due to the occurrence of an unanticipated failure or the recognition of an incipient failure, to maintain the delivery of safe, reliable electricity at least cost, in an environmentally responsible manner. Situations such as these will be included in Hydraulic Generation In-Service Failures projects through the 2025–2034 period and reported in the current year's application for the previous year's work. Hydro notes that, although projects are set forth in a given year, there may be unforeseen circumstances, such as outage availability, that necessitate a change in scheduled completion. These changes will continue to be monitored and reported internally via established Management of Change processes.

4.1 Condition Assessment Practices

Condition information of hydraulic generation assets is primarily obtained through operating-expensed time-based activities, or through capital-expensed overhauls and refurbishments, which require lengthy planned outages and a greater level of disassembly, with specialized inspections and testing of equipment as well as the detailed inspection of components that may not normally be accessible during operation, as detailed in Appendix A. The information obtained during these inspections is reviewed by Long-Term Asset Planning and Engineering personnel who determine what, if any, corrective action is

required and leverage industry professionals, either through the original equipment manufacturer ("OEM") or consultant services to supplement expertise, when required.

In addition to the routine inspections noted, Long-Term Asset Planning and Engineering personnel may initiate condition assessments of existing equipment as the end of design life is approaching, or asset degradation has become apparent, to determine whether corrective action is necessary, or whether additional information is required to determine what is typically obtained through routine inspections. These condition assessments often involve the engagement of industry professionals who execute the assessment under the direction of Hydro employees to ensure all necessary information is collected and analyzed to form the basis of future capital project scopes and justifications.

Based on the outcomes of routine inspections, overhauls, and condition assessments, corrective actions may be required immediately or may be executed at a future time. The timing of the corrective actions is determined after considering various factors including, but not limited to, reliability, safety, frequency of operation, asset criticality, operating constraints and geographic location.

5.0 Historical Investments

Bay d'Espoir has been providing safe, reliable, and environmentally responsible electricity consistent with the least cost to the people of the province for more than 50 years. Hydro notes that although significant future expenditures are planned, there have been refurbishment and replacement activities ongoing at Bay d'Espoir throughout the life of the assets to ensure continued reliable operation. Overviews outlining major work and upgrades completed on Bay d'Espoir Units 1 to 7 over the past 30 years are provided in Table 2 to Table 8.

Table 2: Major Work and Upgrades[5] for Bay d'Espoir Unit 1

Year	Major Work/Upgrade
2021	Excitation Controls Replaced
2020	Unit Overhaul (PM9) Completed
2019	Slip Ring Replaced
2015	Excitation Transformer Replaced
2015	Auto-Grease System Replaced
2015	Thrust/Guide Bearing Coolers Replaced
2013	Air Gap Monitoring and Continuous Partial Discharge Monitoring Installed
2013	Upgraded Unit Protection
2013	Generator Rotor Poles Refurbished
2013	Stator Rewind
2013	Unit Overhaul (PM9) Completed
2008	Cooling Water Piping Replaced
2003	Spherical Valve Controls Upgrade Unit 1
2000	Generator Bearing Cooling Coil Installation
1999	Turbine Bearing Cooling Coil Installation
1998	Exciter Replacement
1996	Runner Replacement

Table 3: Major Work and Upgrades for Bay d'Espoir Unit 2

Year	Major Work/Upgrade
2021	Excitation Controls Replaced
2019	Slip Ring Replaced
2018	Discharge Ring Machining Completed
2018	Unit Overhaul (PM9) Completed
2015	Excitation Transformer Replaced
2014	Thrust/Guide Bearing Coolers Replaced
2013	Auto-Grease System Replaced
2010	Air Gap Monitoring and Continuous Partial Discharge Monitoring Installed
2010	Upgraded Unit Protection
2010	Rotor Pole Refurbishment
2010	Stator Rewind
2008	Cooling Water Piping Replaced
2002	Spherical Valve Controls Upgrade Unit 2
2000	Generator Bearing Cooling Coil Installation
2000	Turbine Bearing Cooling Coil Installation
1997	Exciter Replacement
1993	Runner Replacement

[5] Major work and upgrades include replacements, material upgrades, or work which resulted in asset life extension.

Table 4: Major Work and Upgrades for Bay d'Espoir Unit 3

Year	Major Work/Upgrade
2023	Unit Overhaul (PM9) Completed
2021	Excitation Controls Replaced
2019	Slip Ring Replaced
2017	Discharge Ring Machining Completed
2015	Excitation Transformer Replaced
2015	Thrust/Guide Bearing Coolers Replaced
2014	Air Gap Monitoring and Continuous Partial Discharge Monitoring Installed
2014	Upgraded Unit Protection
2014	Rotor Pole Refurbishment
2014	Stator Rewind
2014	Unit Overhaul (PM9) Completed
2013	Auto-Grease System Replaced
2009	Unit Overhaul (PM9) Completed
2009	Cooling Water Piping Replaced
2004	Spherical Valve Controls Upgrade Unit 3
1999	Generator Bearing Cooling Coil Installation
1999	Turbine Bearing Cooling Coil Installation
1997	Exciter Replacement
1994	Runner Replacement

Table 5: Major Work and Upgrades for Bay d'Espoir Unit 4

Year	Major Work/Upgrade
2022	Unit Overhaul (PM9) Completed
2021	Excitation Controls Replaced
2019	Slip Ring Replaced
2016	Discharge Ring Machining Completed
2016	Unit Overhaul (PM9) Completed
2015	Excitation Transformer Replaced
2015	Auto-Grease System Replaced
2014	Thrust/Guide Bearing Coolers Replaced
2012	Air Gap Monitoring and Continuous Partial Discharge Monitoring Installed
2012	Upgraded Unit Protection
2012	Generator Rotor Poles Refurbished
2012	Stator Rewind
2011	Unit Overhaul (PM9) Completed
2009	Cooling Water Piping Replaced
2001	Spherical Valve Controls Upgrade Unit 4
1998	Exciter Replacement
1994	Runner Replacement

Table 6: Major Work and Upgrades for Bay d'Espoir Unit 5

Year	Major Work/Upgrade
2021	Excitation Controls Replaced
2021	Air Gap Monitoring and Continuous Partial Discharge Monitoring Installed
2021	Stator Rewind
2021	Unit Overhaul (PM9) Completed
2020	Upgraded Unit Protection
2019	Slip Ring Replaced
2015	Spherical Valve Bypass Valve Replaced
2015	Unit Overhaul (PM9) Completed
2015	Excitation Transformer Replaced
2014	Auto-Grease System Replaced
2010	Cooling Water Piping Replaced
2009	Unit Overhaul (PM9) Completed
2005	Spherical Valve Controls Upgrade Unit 5
2000	Turbine Bearing Cooling Coil Installation
2000	Generator Bearing Cooling Coil Installation
1995	Exciter Replacement
1994	Runner Replacement

Table 7: Major Work and Upgrades for Bay d'Espoir Unit 6

Year	Major Work/Upgrade
2022	Air Gap Monitoring and Continuous Partial Discharge Monitoring Installed
2022	Stator Rewind
2022	Unit Overhaul (PM9) Completed
2021	Excitation Controls Replaced
2019	Slip Ring Replaced
2018	Upgraded Unit Protection
2016	Unit Overhaul (PM9) Completed
2015	Spare Excitation Transformer Replaced
2014	Auto-Grease System Replaced
2014	Excitation Transformer Replaced
2014	Refurbished Turbine Bearing
2010	Cooling Water Piping Replaced
2010	Unit Overhaul (PM9) Completed
2000	Generator Bearing Cooling Coil Installation
1999	Replace Cooling Water Pump #6
1998	Turbine Bearing Cooling Coil Installation
1995	Exciter Replacement
1995	Runner Replacement

Table 8: Major Work and Upgrades for Bay d'Espoir Unit 7

Year	Major Work/Upgrade
2020	Upgraded Unit Protection
2019	Discharge Ring Machining Completed
2019	Unit Overhaul (PM9) Completed
2016	Vibration Monitoring System Installed
2016	Unit Overhaul (PM9) Completed
2015	Excitation Transformer Replacement
2010	Unit Overhaul (PM9) Completed
2004	Exciter Replacement

In addition to ensuring the continued reliable operation of the generating units at Bay d'Espoir, Hydro has also planned and executed projects to renew and replace assets classified as either hydraulic structures, site buildings and services, or common auxiliary equipment, which are critical to the operation of generating unit assets at Bay d'Espoir. Major work and upgrades for these assets are provided in Table 9.

Table 9: Major Work and Upgrades for Hydraulic Structures, Site Buildings and Services, and Common Auxiliary Equipment

Year	Major Work/Upgrade
2024 – Ongoing	Powerhouse 1 Draft Tube Desk Refurbishment – Phase 2 (Condition Assessment)
2021	Intake 3 Refurbishment Completed
2019	Powerhouse 1 Stop Log Refurbishment
2019	Powerhouse 1 Draft Tube Deck Refurbished – Phase 1
2019	Surge Tank 1 Exterior Coating Refurbishment
2019	Site Facilities Building Constructed
2018 – Present[6]	Penstock 3 Weld Refurbishment
2017 – Present	Penstock 2 Weld Refurbishment
2016 – Present	Penstock 1 Weld Refurbishment
2016	Surge Tank 2 Interior and Exterior Coating Refurbishment
2015	Surge Tank 3 Interior Coating Refurbishment
2015	Powerhouse 2 Battery Bank 2 Replaced
2014	Surge Tank 3 Exterior Coating Refurbishment
2014	Intakes 1, 2, & 3 Control System Upgrade
2012	Powerhouse 2 Battery Bank 1 Replaced
2009	Powerhouse 1 Battery Bank 1 Replaced
2009	Powerhouse 1 Battery Bank 2 Replaced

[6] Hydro conducts annual penstock inspections and completes weld repairs as required.

6.0 Bay d'Espoir Capital Expenditure Outlook Overview

As presented in the previous section, significant life extension work has been completed at Bay d'Espoir to date, with a large portion of the generating unit and supporting assets already being in a refurbished or renewed operating condition. However, ongoing capital investment is necessary throughout the future life of Bay d'Espoir to ensure the continued reliable operation of all assets. It is anticipated that various classifications of investments and expenditures will be required, including refurbishment, upgrade or replacement of failed or obsolete equipment, and general plant infrastructure work. Planned and anticipated capital expenditures for the 2025–2034 period can be separated into two categories, those on the current five-year plan and those residing on Hydro's longer-term capital plan project list.

6.1 Capital Expenditure Outlook 2025–2029

Hydro's five-year capital plan for Bay d'Espoir has been developed consistent with its investment philosophy and includes details on the costs and timing of forecast asset replacements and refurbishments. The five-year plan is revised annually, considering evolving asset management practices, asset condition information, operational and system requirements, as well as operating environment factors. The anticipated five-year plan for assets associated with Bay d'Espoir is provided in Table 10, which includes projects approved in previous years with costs planned for 2025.

Table 10: 2025–2029 Planned Capital Work for Bay d'Espoir ($000)

Project Title	2025	2026	2027	2028	2029
Complete Major Refurbishment Turbine and Generator - Unit 7 (2026-2029) – BDE		350.0	3,428.7	5,715.0	38,063.2
Install Unit 8 – BDE		26,450.0	21,000.0	158,000.0	167,000.0
Perform Level 2 Condition Assessment – Intake 4 and Unit 7 Draft Tube (2025) – BDE	471.5				
Overhaul BDE Unit 1 (2025) –Include Spherical Valve Refurbishment[7,8]	2,382.6				
Overhaul BDE Unit 2 (2025) –Include Spherical Valve Refurbishment[7,8]	2,589.8				
Overhaul BDE Unit 3 (2028) –Include Spherical Valve Refurbishment[7,8]				2,708.6	
Overhaul BDE Unit 4 (2028) –Include Spherical Valve Refurbishment[7,8]				2,708.6	
Overhaul BDE Unit 5 (2027) –Include Spherical Valve Refurbishment[7,8]			2,656.8		
Overhaul BDE Unit 6 (2027) –Include Spherical Valve Refurbishment[7,8]			2,656.8		
Overhaul BDE Unit 7 (2026)[7,8]		600.0			
Penstock 1 Life Extension – Phase 1 (2023-2025) – BDE	35,329.1				
Perform Level 2 Condition Assessment - Penstock 4 (2026) – BDE		206.2			
Rehabilitate Intake Decks 1–3 (2026-2028) – BDE		55.0	161.5	169.5	
Refurbish Draft Tube Deck - Phase 3 (2027–2029) – BDE			365.5	728.6	6,994.8
Refurbish Intake 1 (2024-2025) – BDE	3,071.9				
Refurbish Intake 2 (2025-2026) – BDE	284.4	3,069.4			
Refurbish Penstock 2 and 3 (2026–2028) – BDE		20,000.0	45,000.0	65,000.0	
Refurbish Surge Tank 1 (2024-2025) – BDE	2,111.4				
Replace Annunciator – Phase 2 (2024-2025) – BDE	187.5				
Replace Battery Bank 1 and 2 – Powerhouse 1 (2028–2029) – BDE				200.0	300.0
Replace Cooling Water Pumps 3 and 5 – Powerhouse 1 (2029–2030) – BDE[9]					50.0
Replace Air Conditioning Unit – Powerhouse 1 (2024-2025) – BDE	231.2				
Replace Powerhouse 1 Roof (2024-2025) – BDE	1,819.2				
Replace Powerhouse 2 Roof (2028) – BDE				960.0	
Upgrade Spherical Valve Controls (2026-2029) – BDE		150.0	210.2	213.8	217.5
Total – Including Major Projects	**48,478.6**	**50,880.6**	**75,479.5**	**236,404.1**	**212,625.5**
Total – Excluding Major Projects[10]	**13,149.5**	**4,080.6**	**6,050.8**	**7,689.1**	**7,562.30**

[7] Included in the Overhaul Hydraulic Units Program.
[8] The overhauls for Units 1–7 listed in this chart is not an exhaustive list of the work included in the five-year capital plan for the Hydraulic Overhaul Units program, which is the program this work is captured under. The combined expenditures for these seven units is thus lower than the annual and combined totals in the five-year plan for that program.
[9] This includes an additional $350,000 in 2030.
[10] This total excludes anticipated major project expenditures associated with Unit 8 Installation, Penstock 1 Life Extension, Unit 7 Major Refurbishment, and Refurbishment of Penstocks 2 and 3.

Projects identified for 2025 form part of the 2025 CBA and information about each scope and estimate are provided in the proposal relevant to each identified project or the Capital Projects Under $750,000 table.

Projects proposed for the 2025–2029 period are primarily required for renewal-driven capital, which is largely driven by the age and condition of Bay d'Espoir, resulting in end-of-service life for equipment and deterioration in the condition causing reduced performance or reliability. This plan reflects investments of approximately $623.8 million over the 2025–2029 period, which includes $42.8 million of previously approved capital. The average annual capital expenditure for Bay d'Espoir in that period is $124.8 million. Primary drivers of the significant increase to planned investment at the facility include the installation of Unit 8 as recommended in Hydro's 2024 Resource Plan;[11] the proposal of future phases of Penstock Life Extension activities, which will see Penstocks 2 and 3 refurbished similar to the work approved for Penstock 1;[12] as well as the proposal to complete major refurbishment activities on Unit 7, which is the remaining unit at Bay d'Espoir to undergo significant investment.

As outlined in Section 5.0, with the exception of Unit 7, the generating unit assets at Bay d'Espoir have previously undergone significant life extension activities, thus the planned expenditures through the 2025-2029 period consist of regularly scheduled overhauls that, for the first time, have expanded scopes to include necessary spherical valve overhauls and turbine small component replacements[13] required to ensure continued safe, reliable and environmentally responsible operation given the age of the generation assets.

Considering hydraulic structure assets, planned investments include the continuation of Hydro's efforts to refurbish upstream and downstream assets associated with the intakes and draft tubes, as well as the necessary Level 2 condition assessments to form the basis of future capital expenditures.

[11] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, July 9, 2024 ("2024 Resource Plan").
[12] "Penstock 1 Section Replacement and Weld Refurbishment – Bay d'Espoir Hydroelectric Generating Facility," Newfoundland and Labrador Hydro, December 7, 2022. 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.
[13] Small component replacements include but not limited to wicket gate greased bushing replacement with greaseless, wicket gate linkage refurbishment and servomotor overhauls.

6.2 Capital Expenditure Outlook 2030–2034

In addition to a detailed five-year capital plan, Hydro also maintains longer-term asset management plans for Bay d'Espoir. These plans contain both recurring time-based capital interventions, such as six-year unit overhauls, in addition to various stand-alone projects which are forecast to occur in a future year. As these projects are beyond the detailed five-year planning cycle, the exact timing of the proposal to the Board and associated execution schedule is not yet determined. During the annual capital planning cycle, as the five-year plan is updated and adjusted, identified scopes from the longer-term plan are scrutinized and added to the five-year plan, as appropriate. At present, the projects identified for the period of 2030–2034 are outlined in Table 11.

Table 11: 2030–2034 Planned Capital Work for Bay d'Espoir ($000)[14]

Project Title	Estimated Project Costs
Battery Bank 1 Replacement PH2 – BDE	250.0
Install Unit 8 – BDE	155.0
Overhaul BDE Unit 1	350.0
Overhaul BDE Unit 2	350.0
Overhaul BDE Unit 3	50.0
Overhaul BDE Unit 4	350.0
Overhaul BDE Unit 5	350.0
Overhaul BDE Unit 6	350.0
Penstock 1 Level 2 Condition Assessment – BDE	130.0
Penstock 2 Level 2 Condition Assessment – BDE	130.0
Penstock 2 Level 2 Condition Assessment – BDE	130.0
Refurbish PH2 Service and Cooling Water Systems – BDE	600.0
Replace Battery Bank 2 PH2 – BDE	250.0
Replace PH2 Oil/Water Separator – BDE	200.0
Replace Station Service Switchboard PLC – BDE	1,200.0
Rewind Rotor Unit 5 – BDE	5,500.0
Rewind Rotor Unit 6 – BDE	5,500.0

[14] Costs in Table 11 are presented in 2024 dollars. Costs will be escalated to appropriate years when the timeline of execution is determined.

The identified projects primarily represent time-based capital interventions on the assets, with the addition of the rotor rewinds for Units 5 and 6 as well as refurbishment and replacement activities for auxiliary assets which are identified as approaching end-of-service life in the 2030–2034 period. The plan currently reflects an investment of approximately $15.8 million over the 2030–2034 period, with an average annual capital expenditure for Bay d'Espoir of approximately $3.1 million.

Hydro notes that, as cost estimates are refined for future years of the plan, projected expenditures are subject to change. In addition, following the completion of planned and future condition assessments, as well as through ongoing routine maintenance and inspection activities, additional projects may be identified and included in the above-proposed project lists, where appropriate. Such additions will result in increases to the proposed expenditures noted above. Hydro will incorporate any necessary changes to the plan using internally established Management of Change processes.

7.0 Conclusion

Bay d'Espoir is a critical generating asset on the IIS that has been providing safe, reliable, environmentally responsible energy consistent with the least cost to the people of the province for over 50 years. To ensure the continued reliable operation of Bay d'Espoir, Hydro has historically planned and executed major work on assets, as required, and continues to utilize its Asset Management Program to complete necessary inspections and assessments to ensure refurbishment or replacement activities can be incorporated into the proposed capital plan at an appropriate time. In the first 50 years of the life of the facility, significant investment has been made to ensure generating assets are maintained and refurbished according to good utility practice; including but not limited to, ongoing six-year turbine and generator overhauls, the completion of turbine runner replacements, generator rewinds and excitation upgrades as well as various other necessary investments.

Looking ahead to the 2025–2034 period, significant investment requirements remain for Bay d'Espoir, with the most significant expenditures being Penstock 1–3 refurbishments, a major refurbishment of the Unit 7 turbine and generator assemblies, and rewinds of Units 5 and 6 rotors. The continuation of ongoing time-based sustaining activities, and refurbishment and replacement of end-of-life assets will also be required through 2034 and beyond. Hydro remains committed to completing regular routine

inspections, overhauls, and condition assessments to ensure that the most accurate asset information is available for consideration in the management of the province's power grid.

Appendix A

Full Asset Description



Hydraulic Generating Units

Generator

A generator is an electric rotating machine that transforms mechanical power from a hydraulic turbine into electric power.

Stator Assembly

A stator consists of a core and a frame; it is the stationary part of a machine that serves as both a magnetic circuit and a supporting member. The core is made up of sheets of electrical steel; the sheets, which are 0.35–0.5 mm thick and insulated with varnish, are formed into stacks and fastened in the cast or welded frame. Stator windings fit into slots made in the core. The stator is cooled with surface air coolers, which are heat exchangers that have cooling water flowing through which cool the hot air blown around the stator.

Rotor Assembly

The rotor consists of a fabricated spider, laminated rim, field poles and windings, a brake ring and collector rings.

Thrust and Guide Bearing

The thrust and guide bearing combination on the generator sustains axial and lateral loading and prevents axial and lateral movement. The bearing consists of a segmented guide bearing, thrust block, rotating ring, segmented spring-supported thrust bearing, base ring, oil reservoir, cooling coils, alarm devises, and a high pressure oil injection system for start-up (if equipped).

Cooling Water System

The cooling water system supplies water to the thrust and guide bearing cooling coil to cool the oil reservoir. The cooling water also supplies the surface air coolers in the generator to cool the stator and rotor by air circulation within the generator.

Governor

The governor serves to keep the speed of the hydro unit constant in order to maintain the systems frequency of 60 hertz. Any change in load or other operational disturbances will cause the governor to

open or close the wicket gates to allow more or less water to maintain the constant speed of the Hydro Unit.

Governor Speed Generators

Speed control is one of the primary functions of a governor. On mechanical governors, a set of rotating flyballs, opposed by a spring, controls the position of a valve. The valve controls the flow of oil to a servomotor that controls the wicket gates. Any change in speed will cause the valve to be moved off its centered position, making the gates open or close, and changing the unit's speed. Modern electronic governors control the gates by monitoring electronic signals from speed sensors.

Governor Pump

The pump used by the governor to port oil through the governing system.

Governor Piping System

The network of pipes required to deliver the governor oil to the desired location.

Accumulator Tank

An accumulator tank stores oil for the governor system and is pressurized by air.

Servomotor Assembly

The servomotors are hydraulically actuated pistons, controlled by the governor, that move the linkages connected to the wicket gates to allow water regulation to the hydraulic generating unit to maintain a constant speed.

Isolated Phase Bus

Isolated phase bus is the current carrying conductors used to transmit large currents. For Hydro's generation sites, it is the means used to carry the current from the generators to the step-up transformers. The conductors are individually contained within housings to provide electrical and physical protection and to minimize the possibility of faults.

Disconnect Switch

Disconnect switches are used to electrically isolate the isolated phase bus either for maintenance activities or troubleshooting. Proper operation of these switches is essential for the establishment of a safe work environment and for reliable and secure system operation.

Grounding Switch

Grounding switches are used to provide a safe and secure electrical connection between a piece of equipment and ground. Proper grounding of equipment is essential for the establishment of a safe work environment.

Buswork

Buswork is the current carrying conductors which provide connections for the electrical circuits.

Main Inlet Valve

Main Inlet Valves are mainly employed in power plants with more than one generating unit sharing a common penstock. When one penstock is used to supply two or more generating units these valves are installed on each unit to provide isolation from the penstock water supply. This allows the operation of one unit while the other unit is down for maintenance or in stand-by. Most of Hydro's Main Inlet Valves are of the spherical valve type.

Turbine

A turbine is a rotary machine that converts kinetic energy and potential energy of water into mechanical work. Components of the turbine include:

Runner

Flowing water is directed on to the blades of a turbine runner, creating a force on the blades. Since the runner is spinning, the force acts through a distance, which is the definition of work. In this way, energy is transferred from the water flow to the turbine.

Draft Tube

In power turbines a diffuser tube is installed at the exit of the runner, known as draft tube.

Guide Bearing

The guide bearing on the turbine sustains lateral loading and prevents lateral movement. The bearing consists of a segmented guide bearing, oil reservoir, cooling coils, and instrumentation to monitor bearing temperature and oil levels within acceptable ranges.

Auto-greasing System

The auto-greasing system delivers controlled amounts of lubricant to multiple locations on a hydraulic generating unit while the machine is in operation.

Turbine Shaft and Coupling

The turbine shaft is the portion of the hydraulic units' shaft that is connected to the turbine. The shaft coupling joins the generator shaft to the turbine shaft.

Scroll Case

A spiral-shaped steel intake guiding the flow into the wicket gates located just prior to the turbine.

Headcover Assembly

The headcover is the top stationary part of a hydraulic turbine that encloses the system.

Wicket Gates and Linkages

Adjustable elements that control the flow of water from the scroll case into the turbine passage by the linkages connected to the servomotors.

Excitation

Excitation Transformer

The excitation transformer is a part of the excitation system. It is used to convert the generator terminal voltage to a lower voltage which supplies the rectifier. The excitation system creates the DC energy for the rotating magnetic field in the generator to enable conversion of mechanical energy into electrical energy. Without an excitation transformer, a generating unit is not able to produce electricity.

Field Breaker

The field breaker is a circuit breaker used to isolate the power supply between the excitation system and the generator rotor. The field breaker performs switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of the field breaker through its fast response and complete interruption of current flow is essential for the protection of the excitation system.

Metering, Monitoring, Protection, SCADA and Control

Ground Cubicle

Minimizes fault damage incurred by generators, and maintains sufficient fault detection to improve power system reliability.

Auto Control Panel

The auto control panels are where control or monitoring instruments are displayed. This is where operators interface with the generating unit.

Synchronizing Panel

Synchronization panels are mainly designed and used to meet power system requirements. These panels function both manually and with an automatic synchronizing function for one or more generators or breakers. They are widely used in synchronizing generators.

Temperature and Frequency Control Panel

This panel displays the temperature and frequency of the hydro unit.

Time and Frequency Clock

Highly sensitive equipment used to measure the time and frequency of the unit.

Oscillogragh

An Oscillogragh is a device for recording oscillations, especially those of an electric current.

Voltage and Megawatt Panel

This panel displays the voltage and megawatt output from the hydro unit.

Recorder

The recorder records the voltage and megawatt readings of the unit.

Control Cables and Junction Boxes

Control cables connect various circuits for the operation of each generator. Junction boxes are also located along cable paths where it is practical to terminate cables from various sources.

Vibration Monitoring System

Hydro Unit systems

For Hydro Units vibration sensors are mounted on the critical bearings and wired to the plants computer system or to a dedicated vibration monitoring system. Two alarm levels (soft and trip) are then set to alert the operator that maintenance attention is needed or in the case of a Trip Alarm to shut the machine down to prevent failure.

Handheld Units

Handheld vibration units use magnetic vibration sensors that are directly connected to the equipment to monitor vibration and record data. This data can then be downloaded to a computer for analysis.

Data Acquisition System

This system measures an electrical or physical phenomenon such as voltage, current, temperature, pressure, or sound with a computer. The system consists of sensors, measurement hardware, and a computer with programmable software.

Hydraulic Structure

Substructure

The substructure is the underlying or supporting structure, such as the concrete foundation.

Superstructure

The superstructure is the components of a hydraulic structure that are on top of the substructure. This includes components such as the structural steel, hoists and motors for the gates.

Gates

The structure gates are designed to hold back water. In a spillway the water is on one side and the other side is typically dry when the gates are closed. Depending on the function of the particular structure, the

gates are opened to move water from one reservoir to another, or to spill water from the reservoir when the water level exceeds the maximum safe level.

Stoplogs/Master logs

The stoplogs are a set of wooden or steel logs that are put in place by a crane or hoist with the help of a lifting device called the master log. The stop logs act as a temporary measure to isolate the water side of the gate for maintenance.

Gate Hoist

A gate hoist is a device used for lifting or lowering a gate by means of a drum or lift-wheel around which a wire rope or chain wraps.

Gate Rollers, seals, and embedded parts

The gate rollers are attached to the gate and roll along the embedded steel in the gains.

Heating Systems

There are three heating systems that can be used in a structure; the first is a gain heater that heats the roller path on the side of the structure and ensures the roller path is free of ice during the winter. Sill heaters heat the bottom of the gate where it sits on the concrete substructure so that the gate does not freeze to the bottom during winter. The other heating system is on the gate itself and is called gate heaters. Gate heaters are used to ensure that ice does not form inside the gate and that water side of the gate is free of ice during the winter.

Control Systems

Control systems are typically computer systems designed to control gate systems remotely. Some older technology electronic controllers are used for specific simple control features.

De-icing Systems

In conjunction with the heating systems other systems are strategically employed to combat ice around gates. Water uplifters are used to agitate the water close to the surface of the gate to inhibit the formation of ice. Bubbler systems use compressed air to lift warmer water at lower levels in the reservoir to prevent the formation of ice cover or to remove ice build-up on trash racks.

Penstock

A penstock is a channel for conveying water to a turbine, commonly constructed of steel, wood, or rock.

Surge Tank

A surge tank is a tank connected to a penstock carrying reservoir water. It is intended to neutralize sudden changes of pressure in the flow by filling when the pressure increases and emptying when it drops to minimize the effects of water hammer in a penstock.

Heating Systems

The surge tank heating system prevents the stagnant water in the surge tank from freezing in the winter. If surge tank water freezes, water can't flow freely to avoid water hammer.

Relief Valves

Relief values are an alternative to Surge Tanks to minimize the effects of water hammer in a penstock. The use of a Surge Tank or a relief valve is determined during the design stage of a new unit and it is typically not possible to change the design after initial construction.

Coating Systems

Metal penstocks are coated to protect the steel and welds from corrosion due to the water inside and the elements outside of the penstock or surge tank.

Drainage Systems

Drain pipes are installed under the penstocks in the bedding material to collect any leakage from the penstocks as well as surface water and any leakage from the intakes/dams.

Water Level Systems

Water level systems are located at hydraulic structures to provide information to operations to make informed decisions about water management and other operating conditions.

Reservoirs

Dams and Dykes

Hydro currently operates more than 100 dams, dykes and hydraulic structures on the island of Newfoundland. Hydro dams are constructed to hold back water and raise its level in order to contain water for electricity generation. The majority of Hydro's dams are embankment type structures with our highest structure being 63m high.

Power Canals

Power canals are typically a dyke lined canal developed to convey water from one reservoir to another or a reservoir to an intake structure.

Passive Overflow Spillways

Passive overflow spillways are dams which are built to spill water from a reservoir at a specific elevation. Overflow spillways in our Hydro system are constructed of rock fill with steel sheet pile cores, concrete or timber crib.

Control Weirs

Control weirs are low head concrete overflow spillways which maintain the water elevation upstream of the weir to within a specified range.

Fuse Plugs

Fuse plugs are sections of dams that are constructed of earth materials and designed to fail in a controlled manner without damaging adjacent larger more critical dams.

Power Tunnels

Power tunnels convey water, through rock, from an intake structure to a generating station.

Diversion Tunnels

Diversion tunnels divert water around the work site.

Dam Instrumentation

This instrumentation monitors the dam design criteria. Examples of dam instrumentation include piezometers, inclinometers, survey monuments and anemometers. This condition monitoring instrumentation is used to measure movement of the dam structure and water content in the dam.

Public Safety Around Dams Control Measures

Public safety risks are determined by completing risk assessment in accordance with Canadian Dam Association ("CDA") guidelines for Public Safety Around Dams. Control measures are then recommended to reduce the risk to the public. These measures include such items as signage, fencing, audible or visual alarms, booms, buoys, operational changes and public education.

Site Buildings and Services

Water Distribution System

A water distribution system is a system for the collection, transmission, treatment, storage and distribution of water from source to site locations.

Piping

The network of pipes required to deliver the site water to the site facilities.

Pumps

The driver of the water from the source is by pumps.

Storage Tanks

Storage tanks hold water to provide a consistent water pressure at site facilities and a volume of water that can be used for firefighting.

Filters

To remove sediment and fine particles from the water filtration systems are used.

Fuel Storage and Distribution System

Fuel Storage and Distribution System are site specific systems to have fuel and distribution methods on site.

Diesel Fuel Tank

Tanks that house diesel fuel only.

Gasoline Fuel Tank

Tanks that house gasoline fuel only.

Jet Fuel Tank

Tanks that house jet fuel only.

Fuel Dispenser and Pumps

Apparatus used to dispense and meter the fuel.

Powerhouse Building

Buildings used to house hydraulic generating units and the auxiliary mechanical and electrical equipment required for the generation of electricity.

Vertical Lift Equipment Doors

Vertical lift doors are large doors that allow access to the powerhouse building for large material and equipment. The doors are operated manually or electrically by a counter weight arrangement.

Roof

The roof is the structure forming the upper covering of a powerhouse building.

Substructure

The substructure is the underlying concrete support of the powerhouse.

Superstructure

The superstructure is the building that is placed upon the substructure. This includes the concrete and steel that make up the walls of the building.

Service Buildings

Service buildings are any other building on site that supports Hydro's generation of electricity. This includes warehouses, maintenance buildings, training facilities, site accommodations, and security facilities.

Substructure

The substructure is the underlying concrete support of the service building.

Superstructure

The superstructure is the building that is placed upon the substructure.

Septic System

A septic system stores and distributes sewage. This includes a septic tank, septic field and all associated distribution piping.

Garage Doors

A garage doors is a large door on a service building that opens either manually or by an electric motor. These are typically overhead doors similar to automotive garages or residential attached garages.

Exhaust Systems (Welding)

Wielding exhaust systems are ventilation systems, in maintenance buildings, that specifically circulate fresh air using ducts and fans in the area to ensure worker safety.

Ventilation Systems

Ventilation systems circulate fresh air using ducts and fans.

Security Systems

A security system detects and issues an alarm due to an intrusion or unauthorized entry. Security systems are also used to prevent unauthorized access to Hydro facilities.

Helicopter Pad ("Helipad")

A helipad is a landing area or platform for helicopters and powered lift aircraft. While helicopters and powered lift aircraft are able to operate on a variety of relatively flat surfaces, a fabricated helipad provides a clearly marked hard surface away from obstacles where such aircraft can land safely.

Site Fencing and Gate Controls

All sites have fencing and or gates with control to maintain site security and public safety.

Parking Lots and Stairways

The parking lots and stairways are areas for staff, contractors and the general public to park vehicles for safe access to Hydro's facilities.

Site and Access Roads

Site and Access Roads are used to allow access to specific locations, such as generating stations, terminal station, hydroelectric dam, and all Hydro locations.

Drainage

Drainage is the sloping of land to divert water away from a specific area.

Culverts

Culverts allow the passage of water through/under a road.

Bridge

Bridges are structures used to span sections of site roads over a stream, river, valley, canal, or any obstacle preventing access to the site location.

Common Auxiliary Equipment

Station Service

A station service switchboard is an electrical panel used to supply low voltage power to the critical and auxiliary electrical equipment necessary for the operation of the generating units. The protective devices included within the station service switchboards are required to monitor the flow of electricity and to interrupt this flow, in a selective and timely manner, in the event of an electrical fault.

Station Service Transformers

Station Service Transformers convert electricity from higher voltages to voltages used in the ancillary AC/DC Electrical system.

Circuit Breakers

Circuit breakers perform switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of circuit breakers is essential for the protection of the critical and auxiliary equipment supplied by the station service switchboard.

Disconnects and Switches

Disconnects and switches are used to electrically isolate equipment for maintenance activities or troubleshooting. Proper operation of these switches is essential for the establishment of a safe work environment and for reliable and secure system operation. Faulty and/or malfunctioning disconnects or switches that do not operate properly create a safety hazard.

Grounding Transformers

Grounding transformers are used to provide a ground path for the station service systems. This ground path ensures that the system's neutral is at or near ground potential. The establishment of a suitable ground enables safe operation of a grounded electrical system, and allows protective devices (like relays or low voltage circuit breakers) to detect and isolate line-to-ground faults.

Instrumentation Transformers

Instrument transformers are used to provide inputs to protection, control and metering equipment required for protection of the electrical equipment supplied from the station service system.

Surge Arrestors

Surge arresters provide overvoltage protection of electrical equipment from lightning and switching surges.

Power Cables and Junction Boxes

Cables to connect station service to switchgear and electrical panels and ancillary equipment. Junction boxes are also located along cable paths where it is practical to terminate cables from various sources.

Ancillary AC/DC electrical system

Switchgear and Panels

Switchgear and Panels are devices which are used to distribute electricity to cables. This equipment protects the cables and equipment from overload and short circuits.

Power Cables and Junction Boxes

Distributes electricity to equipment

Battery Banks and Chargers

Provides DC electricity for DC powered equipment.

Diesel Standby Generator

A diesel generator is the combination of a diesel engine with an electric to generate electrical energy. Prime-power diesels provide power to sites that are not connected to an interconnected distribution system. Emergency diesels are on stand-by at various locations within Hydro's system to ensure system reliability.

Engine

This is the diesel engine used to drive the genset.

Generator

The generator converts mechanical energy from the engine to electricity.

Enclosure

Some diesels are located outside and require an enclosure to house the unit away from the weather.

Cranes

Cranes are machines used for moving heavy objects, typically by suspending them from a projecting arm or beam.

Overhead

An overhead crane consists of parallel runways with a traveling bridge spanning the gap. A hoist, the lifting component of a crane, travels along the bridge.

Monorail

A traveling crane suspended from a single rail.

Gantry

Gantry cranes are a type of crane built atop a gantry, which is a structure used to straddle an object or workspace

Wire Rope

Wire rope is a length of rope made from wires twisted together as strands.

Fire Protection and Detection System

A fire alarm system has a number of devices working together to detect and warn people through visual and audio devices when smoke, fire, carbon monoxide or other emergencies are present.

Transformer Deluge System

A transformer deluge fire sprinkler system is an automated water spray system where the water distribution piping is equipped with open spray nozzles for discharging over a transformer. Deluge systems are connected to a water supply through a deluge valve that is opened by the operation of a smoke or heat detection system.

Fire Panels

A Fire Alarm Control Panel, or Fire Alarm Control Unit, is the controlling component of a Fire Alarm System.

Generator Deluge System

A generator deluge fire sprinkler system is an automated water spray system where the water distribution piping is equipped with open spray nozzles for discharging within the generator. Deluge systems are connected to a water supply through a deluge valve that is opened by the operation of a smoke or heat detection system.

Inergen System

Inergen agent is a mixture of three naturally occurring gases: nitrogen, argon, and carbon dioxide. This system releases the Inergen agent when the system is activated and floods the contained room with the

agent to extinguish the fire by decreasing the oxygen concentration below levels required to sustain combustion.

Office Sprinkler System

An office space sprinkler system is a system for protecting a building against fire by means of overhead pipes which convey water to heat-activated outlets.

Passive Fire Protection

Passive fire protection is an integral component of the three components of structural fire protection and fire safety in a building. This protection is used to contain fires or slow the spread of fires.

Powerhouse Public Address System

A public address system is an electronic sound amplification and distribution system with a microphone, amplifier and loudspeakers, used to allow a communication within a loud powerhouse.

Compressed Air System

Compressed air is air kept under a pressure that is greater than atmospheric pressure.

Air Receiver Tank

This is the tank where the pressurized air is stored until it is required.

Air Dryer

An air dryer is used for removing water vapor from compressed air. The process of air compression concentrates atmospheric contaminants, including water vapor. This raises the dew point of the compressed air relative to free atmospheric air and leads to condensation within pipes as the compressed air cools downstream of the compressor.

Excessive water in compressed air, in either the liquid or vapor phase, can cause a variety of operational problems for equipment using the compressed air. These include freezing of outdoor air lines, corrosion in piping and equipment, malfunctioning of pneumatic process control instruments, fouling of processes and products, and more.

Compressors

A machine used to supply air at increased pressure.

Service/Cooling Water System

Service or Cooling water is the water removing heat from a machine or system.

Pumps

Cooling water pumps distribute the water from the source to the system.

Basket Strainers

Cooling water is sourced from the tailrace or other unfiltered sources and the basket strainer is a closed vessel with cleanable screen element designed to remove and retain foreign particles down to 0.001 inch diameter from various flowing fluids

Piping, valves, and controls

The piping, valves and controls are required components of the cooling water system.

Domestic Water System

Domestic water use is water used for indoor and outdoor site purposes such as washrooms, and kitchens.

Drainage/Unwatering System

This system handles the removal of water from the hydraulic generating unit draft tube for maintenance.

Sump Pumps

The pumping system required to remove the water.

Water Level System

Water level or gauge height or stage is the elevation water in a reservoir.

Air Conditioners

Air conditioners control the temperature in many locations for personnel and equipment. The units also provide humidity control in rooms with sensitive electrical equipment like communication rooms.

Ventilation System

Ventilation systems circulate fresh air using ducts and fans.

PCB Waste Oil and Waste Oil Tanks

These are specifically marked oil tanks that only contain waste oil, once the tanks are full a waste disposal company will come to site to empty the tank. Polychlorinated biphenyl ("PCB") waste oil has to be disposed of properly outside of the province this is why there are two types of waste oil storage.

Lube Oil Storage

Lubrication oil storage includes laydown areas for the 200 litre drums that are located at most generating stations, carrying devices for these drums, and smaller storage containers that are used for top-ups when required. The proper storage for lube oil is important to equipment health because a proper container will limit any air borne particulates or any moisture from contaminating the oil.

Sch 5: 2024 Capital Expenditures Overview

Schedule 5

2024 Capital Expenditures Overview



2025 Capital Budget Application

2024 Capital Expenditures Overview



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Appendix A: Capital Programs and Projects Variance Summary

Appendix B: Capital Expenditures and Carryover Report for the Year Ended December 31, 2023

1.0 Variance Explanations

Explanations are provided herein for projects and programs that, as of May 31, 2024, are:

- Budgeted over $750,000 and are forecast to have a variance of more than $100,000 and 10% from the budgeted amount, on a total project/program basis;
- Budgeted under $750,000 and are forecast to exceed $750,000, on a total project/program basis; or
- Cancelled.

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.[1] Actual variances at the completion of each project and program will be discussed in the 2024 Capital Expenditures and Carryover Report[2] when annual expenditures are final. As requested by the Board of Commissioners of Public Utilities ("Board"), a copy of the 2023 Capital Expenditures and Carryover Report[3] is provided as Appendix B to this report.

[1] The 2024 Capital Projects and Programs Variance Summary on all 2024 programs and projects is provided as Appendix A.
[2] As per "Annual Capital Expenditures Reports – Filing Schedule," Board of Commissioners of Public Utilities, February 13, 2023; *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 35(2023), Board of Commissioners of Public Utilities, January 26, 2023, p. 2/36–37; and *Public Utilities Act*, RSNL 1990, c P-47, s. 41(4), Hydro's 2024 Capital Expenditures and Carryover Report is to be filed by April 1, 2025.
[3] "Capital Expenditures and Carryover Report for the Year Ended December 31, 2023," Newfoundland and Labrador Hydro, April 1, 2024.

1.1 Renewal

1.1.1 In-Service Failures (2024)[4]

Table 1: Program Variance – In-Service Failures (2024) ($000)

Program	Budget	Expenditures and Forecast	Forecasted Variance
Gas Turbine	358.0	7,000.7	6,642.7
Distribution	4,345.4	4,345.4	-
Terminal Station	1,300.0	3,614.5	2,314.5
Thermal	3,508.7	3,508.7	-
Hydraulic	1,500.0	2,500.0	1,000.0
Diesel	488.3	488.3	-
Transmission	158.5	158.5	-
Telecommunications	91.4	91.4	-
Total	**11,750.3**	**21,707.5**	**9,957.2**

In-Service Failures programs are one-year programs that include refurbishment and replacement work due to actual failures, the identification of incipient failures, or the determination of faster-than-anticipated equipment deterioration for Hydro's assets. The procurement of capital spares required to support such work is included under the In-Service Failure programs.[5] Budget estimates for In-Service Failure programs are based on historical averages, along with Hydro's experience and engineering judgement. As many of these programs are new or have been introduced in recent years, they have limited historical data; Hydro expects that it may take several years of implementation to determine an appropriate baseline estimate for annual in-service failure expenditures. The forecasted variances for the Gas Turbine, Hydraulic, and Terminal Station In-Service Failures programs are primarily attributed to more scopes of work required in 2024 than anticipated at the time of the original budget estimates and the nature of failures requiring more material expenditure to address.

[4] While some individual In-Service Failure programs did not meet the threshold for reportable variance, all 2024 In-Service Failures programs are listed herein for completeness.
[5] The Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights program also includes distribution system upgrades and the installation of LED street lights.

Hydro experienced a number of failures necessitating material investment in 2024, including the following scopes that have exceeded $750,000:

- The continuation of the refurbishment of the Stephenville Gas Turbine generator stator and rotor from 2023;[6] and
- The continuation of the refurbishment of a spare generation transformer from 2023.[7]

Further detail on material expenditures for In-Service Failure programs will be provided in the 2024 Capital Expenditures and Carryover Report.

1.1.2 Overhaul Pumps (2024) – Holyrood

Table 2: Program Variance – Overhaul Pumps (2024) – Holyrood ($000)

Budget	Expenditures and Forecast	Forecasted Variance
661.0	837.2	176.2

This is a one-year program (2024) to overhaul the Unit 1 South Vacuum Pump, the Unit 2 North Vacuum Pump, and the Unit 2 East Boiler Feed Pump at the Holyrood Thermal Generating Station ("Holyrood TGS"). The forecasted variance in overall program expenditures is attributed to contract pricing for the pump overhauls, which is higher than the original budget estimate. There are no viable alternatives for this program and Hydro is proceeding with execution.

1.1.3 Boiler Condition Assessment and Miscellaneous Upgrades (2024) – Holyrood

Table 3: Program Variance – Boiler Condition Assessment and Miscellaneous Upgrades (2024) – Holyrood ($000)

Budget	Expenditures and Forecast	Forecasted Variance
3,957.8	6,057.8	2,100.0

[6] In August 2023, generator rotor blades were damaged, which also caused secondary damage to the stator end windings. Additional information can be found in "Capital Expenditures and Carryover Report for the Year Ended December 31, 2023," Newfoundland and Labrador Hydro, April 1, 2024, app. B, p. B-5, Table C-5, which is included as Appendix B to this report.
[7] In July 2023, one of the bushings on Bay d'Espoir power transformer T6 failed catastrophically. The failed transformer was replaced with an available spare in 2023. The failed transformer was then refurbished in 2023 and 2024 to restore the availability of a capital spare generation transformer. The 2024 forecast expenditures for this scope of work are $1.6 million.

This is a one-year program (2024) to perform a Level 2 Condition Assessment on the internal components of the boilers and associated high-energy piping and to complete refurbishment and replacement work required before the 2024–2025 winter operating season. The forecasted variance in the overall program expenditures is primarily attributed to the extent of the required boiler condition assessment and refurbishment work. Upon disassembly and assessment of the boilers in 2023, the level of necessary work identified for execution in 2024 was greater than anticipated at the time of the original budget estimate. Material scopes of work that were not included in the original estimate are:

- Additional non-destructive examinations of the boiler waterwall, primary superheater, secondary superheater, and reheater sections for Units 1, 2, and 3;
- Boiler economizer hopper and piping replacement for Unit 3;
- Boiler high-pressure feedwater heater inspection and overhaul for Units 1, 2, and 3 (one heater inspection/overhaul per unit); and
- Boiler burner windbox floor refurbishment for Unit 1.

There are no viable alternatives for this program and Hydro is proceeding with execution.

1.1.4 Replace Powerhouse Station Service Panel (2023–2024) – Upper Salmon

Table 4: Project Variance – Replace Powerhouse Station Service Panel (2023–2024) – Upper Salmon ($000)

Budget	Expenditures and Forecast	Forecasted Variance
1,568.5	2,111.5	543.0

This two-year project (2023–2024) commenced in 2023. Due to obsolescence, the project scope includes replacing the 600 V station service panel at the Upper Salmon Hydroelectric Generating Station ("Upper Salmon"). The forecasted variance in overall project expenditures is attributed to contract pricing to procure the replacement station service panel that was higher than the original budget estimate. There are no viable alternatives for this project and Hydro is proceeding with execution.

1.1.5 Overhaul Unit 2 Turbine and Valves (2023) – Holyrood

Table 5: Program Variance – Overhaul Unit 2 Turbine and Valves (2023) – Holyrood ($000)

Budget	Expenditures and Forecast	Forecasted Variance
9,701.8	11,368.4	1,666.6

This one-year program (2023) has carried over into 2024. The program scope is to overhaul the Unit 2 turbine and valves and complete electrical testing on the generator. The forecasted variance in overall program expenditures is attributed to the extent of the turbine rotor refurbishment work that was required following unit disassembly and inspection of the rotor at the original equipment manufacturer's ("OEM") facility. The inspection revealed cracks on the low-pressure turbine blades, which required the purchase and installation of a new set of blades. The original program budget was based on historical turbine and valve overhaul expenditures. The extent of the turbine and valve overhaul costs can only be determined after the unit is removed from service and disassembled for inspection, during the program execution. In this case, the extent of the required refurbishment was greater than originally estimated. The turbine rotor was overhauled at the OEM facility and returned to the Holyrood TGS in 2023. The remainder of the program scope is expected to be completed in 2024. There are no viable alternatives for this program and Hydro is proceeding with execution.

1.1.6 Holyrood Fuel Tank 1 Inspection and Refurbishment (Supplemental)

Table 6: Project Variance – Holyrood Fuel Tank 1 Inspection and Refurbishment (Supplemental) ($000)

Budget	Expenditures and Forecast	Forecasted Variance
2,052.1	5,000.0	2,947.9

This two-year supplemental project (2022–2023) has carried over into 2024. The project scope is to clean, inspect, and refurbish a fuel oil storage tank (Tank 1) at the Holyrood TGS. The forecasted variance in overall project expenditures is attributed to more cleaning, inspection, and refurbishment work required than was anticipated at the time of the original budget estimate. A leak was identified in Tank 1 during the initial filling following the planned cleaning, inspection, and refurbishment work. This required the removal of fuel from the tank and additional cleaning, inspection, and refurbishment

work. Soil remediation was also required as a result of the leak. The additional tank inspections and refurbishment work were completed in 2024. There are no viable alternatives for this project and Hydro proceeded with execution.

1.1.7 Replace Transformer T7 (2020) – Holyrood Terminal Station

Table 7: Project Variance – Replace Transformer T7 (2020) – Holyrood Terminal Station ($000)

Budget	Expenditures and Forecast	Forecasted Variance
2,678.1	4,450.7	1,772.6

This is a one-year project (2020) that extended into 2024. The project scope was to replace a transformer at the Holyrood Terminal Station (T7) with a transformer removed from the Churchill Falls Switchyard (T31) and complete associated civil and protection and control upgrades. The removal of the old T7 transformer and its foundation and the installation of a new concrete pad and oil containment system were completed in 2020.

As a result of Hydro's decision to maintain L1301 as a backup for the Muskrat Falls to Happy Valley Interconnection for the winter of 2020–2021, T31 was not available in 2020 to replace 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 to Happy Valley Interconnection, T31 again was not available to replace T7. As Hydro intended to continue to maintain L1301 as a backup supply for the 2021–2022 winter 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. After investigating several other options for transporting the transformer in the fall of 2022, it was decided to delay to a more favourable time of year in 2023 and allow further investigation of more economical options. The transportation route was finalized and transport of T31 to Holyrood was completed in 2023.

As a result of a tragic incident at the Holyrood Terminal Station in August 2023, resulting in a workplace fatality, some remaining construction and commissioning activities at the Holyrood Terminal Station carried over into 2024. The remaining work was completed in 2024.

The forecasted variance in overall project expenditures is attributed to higher-than-originally estimated transformer transportation costs. Hydro proceeded with the project as originally planned.

1.2 General Plant

1.2.1 Upgrade Energy Management System (2024)

Table 8: Program Variance – Upgrade Energy Management System (2024) ($000)

Budget	Expenditures and Forecast	Forecasted Variance
366.4	-	(366.4)

This one-year program (2024) has been cancelled. The program scope was to upgrade the Energy Management System ("EMS") software to mitigate security vulnerabilities, implement bug fixes, and introduce enhanced functionality on a two-year cycle. The software vendor advised Hydro that it is unable to support this work in 2024. Hydro's attempts to escalate with the vendor did not lead to change. The scope originally planned for 2024 is now included within the Upgrade Energy Management System (2025–2026) program in the 2025 Capital Budget Application ("CBA").

1.2.2 Replace Building Exterior (2023–2024) – Postville

Table 9: Project Variance – Replace Building Exterior (2023–2024) – Postville ($000)

Budget	Expenditures and Forecast	Forecasted Variance
683.3	1,300.9	617.6

This two-year project (2023–2024) is expected to be completed in 2024. The project scope is to refurbish the powerhouse building exterior envelope for the Postville Diesel Generating Station. The forecasted variance in overall project expenditures is attributed to contract pricing that was higher than the original budget estimate. There are no viable alternatives for this project and Hydro is proceeding with execution.

1.2.3 Upgrade Water and Fire Suppression Systems (2023–2024) - Bishop's Falls

Table 10: Project Variance – Upgrade Water and Fire Suppression Systems (2023–2024) – Bishop's Falls ($000)

Budget	Expenditures and Forecast	Forecasted Variance
3,240.0	4,810.0	1,570.0

This two-year project (2023–2024) is expected to carry over into 2025. The project scope is to:

- Install a new water supply line from the town near the Botwood Highway close to the Bishop's Falls Complex;
- Install dedicated domestic water and firewater distribution lines; and
- Upgrade the fire suppression system in the main building of the Bishop's Falls Complex.

The forecasted variance in overall project expenditures is attributed to procurement and construction costs that are higher than the original budget estimate. In particular, it was determined during the engineering design that a new pumphouse building and a backup fire pump generator are required. There are no viable alternatives for this project and Hydro is proceeding with execution. The project is expected to carry over into 2025 due to a longer-than-originally-planned design phase and longer-than-originally-expected lead times for some of the new components.

1.2.4 Replace Diesel Shop Building (2023–2025) – Bishop's Falls

Table 11: Project Variance – Replace Diesel Shop Building (2023–2025) – Bishop's Falls ($000)

Budget	Expenditures and Forecast	Forecasted Variance
2,312.2	248.0	(2,064.2)

This project budget has been updated as part of the 2025 CBA. Please refer to Section 2.4 for further discussion.

1.2.5 Replace Underground Firewater Distribution System (2022–2023) – Holyrood

Table 12: Project Variance – Replace Underground Firewater Distribution System (2022–2023) – Holyrood ($000)

Budget	Expenditures and Forecast	Forecasted Variance
1,706.3	3,066.8	1,360.5

This two-year project (2022–2023) has carried over into 2024. The project scope is to replace the underground firewater distribution system that protects the buildings and terminal station at the Holyrood TGS. The forecasted variance in the overall project expenditures is attributed to construction contract pricing that is higher than the original budget estimate. There are no viable alternatives for this project and Hydro is proceeding with execution. The project carried over into 2024 due to a longer than originally planned design phase.

1.3 System Growth

1.3.1 Additions for Load Growth – Upgrade Transformer Capacity (2023–2024) – Jean Lake

Table 13: Project Variance - Additions for Load Growth - Upgrade Transformer Capacity (2023–2024) – Jean Lake ($000)

Budget	Expenditures and Forecast	Forecasted Variance
6,016.1	7,829.3	1,813.2

This project budget has been updated as part of the 2025 CBA; please refer to Section 2.2 for further discussion.

1.4 Access

There are no forecasted reportable variances for projects and programs in the Access Investment Classification.

1.5 Service Enhancement

1.5.1 Replace Metering System (2022–2024)

Table 14: Project Variance – Replace Metering System (2022–2024) ($000)

Budget	Expenditures and Forecast	Forecasted Variance
5,875.8	8,095.8	2,220.0

This three-year project (2022–2024) is expected to carry over into 2025. The project scope is to replace manually-read meters and TS1 meters with a drive-by automatic meter reading system. The forecasted variance in overall project expenditures is primarily attributed to contract labour costs necessary to complete the project. The original project plan was to utilize internal resources to complete the installation of the meters; however, the pace of meter replacements is slower than anticipated due to resource constraints. To bring the project to completion in a reasonable timeframe, Hydro is planning to hire internal temporary resources to support the project and utilize contractors to install approximately 16,000 meters. Also contributing to the project forecasted variance, project management and implementation of the associated information systems require additional funding to complete the planned scope of work. Hydro reviewed the cost-benefit analysis of alternatives and confirmed that the solution being implemented remains the least cost alternative. Hydro is proceeding with execution. The project is expected to carry over into 2025 due to the pace of meter installations.

1.5.2 Winterize Unit 2102 and Install Mobile – Charlottetown (Supplemental)

Table 15: Project Variance – Winterize Unit 2102 and Install Mobile – Charlottetown (Supplemental) ($000)

Budget	Expenditures and Forecast	Forecasted Variance
1,314.7	1,639.7	325.0

This supplemental project commenced in 2022 and has carried over to 2024. The project scope is to perform upgrades to improve the reliability of service for the communities of Charlottetown and Pinsent's Arm in Labrador. The forecasted variance in overall project expenditures is primarily attributed to more extensive refurbishment work required than originally anticipated and additional environmental permitting requirements.

Construction was completed in 2023 except for the replacement of the transformer for Unit 2108. Delivery of the new transformer was delayed and its installation is now planned for 2024. The change will not impact the reliability of service, as the rental transformer installed on-site will remain until the new transformer is installed and placed in service. A review of project alternatives confirmed that the project remains the least cost alternative and Hydro is proceeding with execution.

1.5.3 Upgrades for Future Retirement of Stephenville Gas Turbine (2021–2022)

Table 16: Project Variance – Upgrades for Future Retirement of Stephenville Gas Turbine (2021–2022) ($000)

Budget	Expenditures and Forecast	Forecasted Variance
6,874.8	5,000.0	(1,874.8)

This two-year project (2021–2022) commenced in 2021; it has carried over and will be closed in 2024. The project scope includes several 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 decommissioning of Stephenville Gas Turbine. A portion of the project scope is complete and in service. In 2024, Hydro decided to cancel most of the remaining scope of this project as a result of the decision to keep Stephenville Gas Turbine available for the 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.[8] Hydro intends to submit a future capital budget proposal for a new project to complete the remaining upgrades, timed to coincide with the retirement of Stephenville Gas Turbine.

No scope of work has been completed at the Stephenville Terminal Station. Completed project scope at the Bottom Brook Terminal Station includes:

- Concrete pads and oil containment systems for two transformers;
- A new disconnect switch;
- Foundations and structures for 230 kV and 69 kV buses;

[8] "2024 Resource Adequacy Plan: An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, July 9, 2024.

- A portion of the lighting upgrades; and
- A portion of the grounding system upgrades.

Transformer and transmission line protection upgrades are partially complete and these scopes are being transferred to the Replace Protective Relays program, for completion as part of that program. These upgrades will provide immediate benefits by reducing customer impact from any unplanned outages.

All other remaining scope is cancelled and will be completed as part of the future capital project. For new equipment purchased but not yet installed, Hydro is exploring opportunities to utilize that equipment on other projects, keep it as capital spares, or add it to inventory. All other expenditures incurred on this project will be treated financially as work in progress. If the expenditures are deemed used and useful with regard to the new project scope, the expenditures will be assigned to the new assets if and when the new project is approved, constructed and placed in service.

1.6 Mandatory

There are no forecasted reportable variances for projects and programs in the Mandatory Investment Classification.

1.7 Allowance for Unforeseen

Hydro did not identify any work to the end of May 2024 that necessitated the use of the Allowance for Unforeseen Items Account.

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 2025 that were approved as part of the 2024 CBA. Hydro identified five previously approved projects and programs where the overall forecast expenditure is higher or lower than the estimate approved as part of the 2024 CBA and/or the forecasted expenditures are expected to shift beyond 2025. The 2025 portion of the budget for each of these projects and programs is now different than originally presented in the 2024 CBA. A summary of the original and updated cost estimates as of May 2024 for these projects and programs is provided herein.

2.1 Renew Circuit Breakers (2024–2025)

This two-year program (2024–2025) commenced in 2024. 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 this program as a result of the deferral of a portion of the scope to future years based on updated asset condition information. One less breaker replacement and one less breaker refurbishment are now planned compared to the number included in the original budget estimate. The budget estimate in Table 17 has been revised to reflect the forecast cost decrease.

Table 17: Budget Update – Renew Circuit Breakers (2024–2025) ($000)

Program Cost	Approved 2024	Estimated 2025	Total
Budget Estimate in 2024 CBA	183.9	2,779.3	**2,963.2**
Revised Budget Estimate in 2025 CBA[9]	183.9	2,120.1	**2,304.0**
Actual Expenditure and Forecast	63.1	2,240.9	**2,304.0**

2.2 Additions for Load Growth – Upgrade Transformer Capacity (2023–2024) – Jean Lake

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 of the largest transformer, T1. The project schedule was extended into 2025 as part of the 2024 CBA and is now extended into 2026 due to the long lead time for the new transformer, which can not be delivered in time for installation in 2025. The project schedule has been updated to install and commission the transformer in 2026. Hydro is forecasting an increase in cost for the supply of the new transformer, based upon tendered pricing. There are no viable alternatives for this project and Hydro is proceeding with execution. The budget estimate in Table 18 has been revised to reflect the cost increase and schedule extension into 2026.

[9] The revised budget estimate for 2025 is the estimated expenditures less the forecasted carryover of budget previously approved.

Table 18: Budget Update – Additions for Load Growth – Upgrade Transformer Capacity (2023–2024) – Jean Lake ($000)[10]

	Approved		Estimated		
Project Cost	**2023**	**2024**	**2025**	**2026**	**Total**
Budget Estimate in 2023 CBA	580.0	5,436.1	-	-	**6,016.1**
Revised Budget Estimate in 2024 CBA	580.0	-	5,436.1	-	**6,016.1**
Revised Budget Estimate in 2025 CBA[11]	580.0	-	6,459.6	789.7	**7,829.3**
Actual Expenditure and Forecast[12]	52.0	811.0	6,176.6	789.7	**7,829.3**

2.3 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.

The work at St. Brendan's was completed in 2023. As reflected in a budget update in the 2024 CBA, Hydro changed the scope for Hopedale to a lower-cost alternative and extended the project schedule into 2026. 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 kW and 850 kW at 1,800 rpm is now the least-cost alternative by a significant margin. Hydro proceeded to re-tender for the procurement of this smaller genset. The program schedule was extended into 2026 as a result of the additional time required to re-evaluate alternatives and the anticipated long lead time for the genset.

Since the budget update in the 2024 CBA, Hydro has been able to make improvements to the schedule and budget. The expected delivery of the genset is shorter than previously anticipated, which will allow construction to commence in 2024 and be completed in 2025. Engineering and construction are

[10] Numbers may not add due to rounding.
[11] The revised budget estimates for 2025 and 2026 are the estimated expenditures less the forecasted carryover of budget previously approved.
[12] Hydro intends to advance a portion of the 2025 revised budget into 2024.

forecast to be completed for less than the previous budget estimate. The budget estimate in Table 19 has been revised to reflect the forecast cost decrease and schedule advancement.

Table 19: Budget Update – Diesel Genset Replacement Program (2023–2025) ($000)[13]

	Approved		Estimated		
Program Cost	**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	819.1	174.0	1,883.1	250.0	**3,126.1**
Revised Budget Estimate in 2025 CBA[14]	819.1	174.0	1,415.1	-	**2,408.2**
Actual Expenditure and Forecast	683.6	1,449.6	275.0	-	**2,408.2**

2.4 Replace Diesel Shop Building (2023–2025) – Bishop's Falls

This three-year project (2023–2025) closed in 2024 before commencement of construction. The project scope is to replace the existing diesel shop building at the Bishop's Falls Complex. As the engineering design approached 33% completion, the estimate to complete the project increased from $2.3 million to approximately $5.7 million. Hydro then decided to halt project activity and close the project, to allow for further review of the scope, estimate, and justification. Hydro intends to submit a new project proposal for review by the Board as part of its 2026 CBA. The engineering and planning expenditures incurred on this project will be treated financially as work in progress. If the expenditures are deemed used and useful with regard to the new project scope, the expenditures will be assigned to the new asset if and when the new project is approved, constructed, and placed in service. The budget estimate in Table 20 has been revised to reflect the closure of the project.

Table 20: Budget Update – Replace Diesel Shop Building (2023–2025) – Bishop's Falls ($000)

	Approved		Estimated	
Project Cost	**2023**	**2024**	**2025**	**Total**
Budget Estimate in 2023 CBA	168.0	1,254.1	890.1	**2,312.2**
Actual Expenditure and Forecast[15]	198.7	49.3	-	**248.0**

[13] Numbers may not add due to rounding.
[14] The revised budget estimate for 2025 is the estimated expenditures less the forecasted carryover of budget previously approved.
[15] As this project has been cancelled, there is no revised 2025 budget.

2.5 Replace Light- and Heavy-Duty Vehicles (2023–2025)

This is a three-year program (2023–2025). The program scope is to procure 39 light-duty vehicles and 6 heavy-duty vehicles. In 2023, a need was identified to procure an additional 7 light-duty vehicles, due to unforeseen in-service failures. The vehicles did not merit repair costs, given their age, high usage, and/or condition. As well, Hydro is experiencing higher than estimated tendered pricing for vehicles. There are no viable alternatives for this program. The budget estimate in Table 21 has been revised to reflect the forecast cost increase.

Table 21: Budget Update – Replace Light- and Heavy-Duty Vehicles (2023–2025) ($000)

	Approved		Estimated	
Project Cost	**2023**	**2024**	**2025**	**Total**
Budget Estimate in 2023 CBA	1,308.1	2,584.6	473.3	**4,366.0**
Revised Budget Estimate in 2025 CBA[16]	1,308.1	2,584.6	673.3	**4,566.0**
Actual Expenditure and Forecast[17]	2,573.2	1,519.5	473.3	**4,566.0**

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."[18] While Hydro recognizes that more substantial reporting may be required as planning progresses on Penstock 2 and 3, Hydro has included its second update herein concerning the current status of the Penstock 1 refurbishment project, which is currently in the execution phase, completing detailed design and procurement, with the engineering, procurement and construction management ("EPCM") contract awarded.

Since the approval of the Penstock 1 refurbishment project, a project team has been assigned; the award of the EPCM contract occurred in November 2023. This critical work commenced the detailed

[16] The revised budget estimate for 2025 is the estimated expenditures less the forecasted carryover of budget previously approved.
[17] Hydro intends to advance a portion of the 2025 revised budget into 2024.
[18] 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.

design, procurement support, construction contract administration, and construction management for the project.

Hydro has progressed several major milestones since that time—early steel material was awarded in April 2024 and a Request for Proposals was issued in June 2024 for the major civil construction contract, which Hydro anticipates to close in August 2024. Major detailed engineering has been completed for this work in advance of the construction season in 2025. The project's overall budget and schedule for completion remain consistent with Hydro's approved application at this time. Project annual cash flow varies from the originally planned projection due to the timing of steel supply, steel prices, and engineering design work timing. Hydro anticipates it will be better positioned to update project costs and schedule once the major civil construction contract has been awarded, which is slated to be awarded in the third quarter of 2024.

In May 2023, inspections were completed on Penstocks 2 and 3 at Bay d'Espoir. Inspections revealed three indications[19] on Penstock 2, and nine indications on Penstock 3, ranging from several inches to several feet. All indications were discovered in areas that were not previously repaired. As a result of these findings, the inspection depth was increased to the same level as that of Penstock 1, to elevate the chances of capturing as many indications as possible. All indications were repaired and the penstocks were returned to service. Kleinschmidt is undertaking a review of new findings from the inspection and will provide recommendations for future life extension work, which will be considered in the project planning for the refurbishment projects for Penstocks 2 and 3. Hydro recommended continuing the increased scope of inspections on Penstock 3 until such time that a long-term solution is implemented.

The 2024 inspection of Penstock 3 was completed in May 2024. In total, nine indications ranging from a few inches to full can[20] length were discovered in areas that were not previously repaired. These welds were repaired and the Penstock was returned to service. Penstock 2 is scheduled for inspection beginning on July 30, 2024.

[19] Indications are the areas where repairs are required as determined by (an) inspection(s).
[20] Each penstock is constructed of many cans, each of which were constructed individually by welding two halves together horizontally along the longitudinal axis of the can, then welded end-on-end using a circumferential weld.

Appendix A

Capital Programs and Projects Variance Summary





2024 Capital Expenditures By Investment Classification
($000)

	Capital Budget									Actual Expenditure and Forecast								Variance			
	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	
Investment Classification	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	2024 Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
Access	-	3,479.25	12,281.70	586.36	272.23	4,742.70	5,014.93	-	**21,090.01**	(0.00)	826.07	6,178.94	9,070.17	2,098.65	2,916.29	-	**21,090.11**	0.10	0.00%	-	0.00%
General Plant	-	-	738.10	7,164.80	3,371.95	24,501.91	27,873.85	12,324.95	**44,729.76**	-	-	276.32	5,785.13	4,121.33	23,376.09	12,544.91	**46,103.79**	1,374.03	3.07%	(376.43)	-1.35%
Mandatory	-	-	-	323.30	(65.38)	2,605.70	2,540.32	429.00	**3,358.00**	-	-	-	388.68	378.64	2,161.67	429.00	**3,358.00**	-	0.00%	-	0.00%
Renewal	3,224.28	21,246.11	28,233.90	40,630.00	14,391.36	71,339.70	85,731.06	68,231.10	**232,905.09**	695.61	11,553.08	28,823.23	40,875.35	27,858.00	74,543.07	63,897.16	**248,245.50**	15,340.40	6.59%	16,670.00	19.44%
Service Enhancement	-	1,530.35	7,248.82	6,917.72	3,455.04	6,419.88	9,874.93	9,191.70	**31,308.47**	-	151.77	3,609.67	9,084.52	2,515.76	6,487.22	9,622.30	**31,471.24**	162.76	0.52%	(871.95)	-8.83%
System Growth	-	3,488.42	11,496.30	2,264.20	454.09	6,547.90	7,001.99	5,950.60	**29,747.42**	-	1,094.61	4,265.54	12,467.43	2,460.13	4,824.85	7,480.76	**32,593.34**	2,845.92	9.57%	283.00	4.04%
Allowance for Unforeseen[1]	-	-	-	-	(0.00)	1,000.00	1,000.00	-	**1,000.00**	-	-	-	-	-	1,000.00	-	**1,000.00**	(0.00)	0.00%	-	0.00%
Total	**3,224.28**	**29,744.12**	**59,998.82**	**57,886.38**	**21,879.29**	**117,157.79**	**139,037.08**	**96,127.35**	**364,138.75**	**695.61**	**13,625.53**	**43,153.69**	**77,671.28**	**39,432.52**	**115,309.19**	**93,974.14**	**383,861.96**	**19,723.22**		**15,704.63**	

[1] As there have been no Allowance for Unforeseen expeditures as of May 31, 2024, a separate summary has not been provided.

2024 Capital Expenditures Summary by Asset Category
($000)

	Capital Budget									Actual Expenditure and Forecast								Variance			
	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	
Asset Category	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	2024 Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
Hydraulic Plant	-	9,806.36	11,214.50	10,743.10	1,433.43	24,477.40	25,910.83	50,847.10	**107,088.46**	-	5,836.64	13,533.58	11,097.61	2,712.52	26,775.48	48,269.90	**108,225.74**	1,137.28	1.06%	3,577.17	13.81%
Thermal Plant	-	-	1,559.20	16,223.50	5,852.38	20,216.06	26,068.44	1,608.60	**39,607.36**	-	-	1,296.48	15,458.81	11,156.76	18,337.92	1,608.60	**47,858.57**	8,251.21	20.83%	3,426.24	13.14%
Gas Turbines	546.14	2,500.00	2,427.40	277.10	2,990.24	1,536.58	4,526.82	385.90	**7,673.13**	35.03	39.28	2,367.51	334.98	1,713.17	8,816.56	1,025.70	**14,332.23**	6,659.10	86.78%	6,002.91	132.61%
Terminal Stations	2,678.14	11,090.21	26,173.40	11,663.90	3,194.11	24,164.20	27,358.31	23,659.80	**99,429.65**	660.58	5,370.71	15,183.89	28,508.41	8,793.30	18,641.80	24,651.52	**101,810.21**	2,380.56	2.39%	76.79	0.28%
Transmission	-	3,479.25	12,281.70	586.36	272.23	4,393.60	4,665.84	-	**20,740.91**	-	826.07	6,178.94	9,070.17	1,186.03	3,479.81	-	**20,741.01**	0.10	0.00%	-	0.00%
Distribution	-	-	486.80	1,077.80	612.43	12,434.80	13,047.23	3,804.00	**17,803.40**	(0.00)	0.00	99.11	853.06	5,387.86	7,659.37	3,804.00	**17,803.40**	-	0.00%	-	0.00%
Generation	-	2,868.31	4,702.20	7,621.72	5,499.85	3,389.90	8,889.75	6,513.40	**25,095.53**	-	1,552.83	2,066.73	5,783.79	3,989.97	6,725.94	4,655.30	**24,774.56**	(320.97)	-1.28%	1,826.15	20.54%
Properties	-	-	-	565.10	(12.98)	4,269.20	4,256.22	890.15	**5,724.45**	-	-	-	578.08	331.61	2,544.50	1,909.81	**5,364.00**	(360.45)	-6.30%	(1,380.11)	-32.43%
Metering	-	-	515.60	4,365.60	623.41	1,767.90	2,391.31	449.70	**7,098.80**	-	-	2,264.44	1,993.35	549.09	3,631.62	880.30	**9,318.80**	2,220.00	31.27%	1,789.40	74.83%
Tools and Equipment	-	-	40.80	2,505.70	1,752.32	2,171.90	3,924.22	1,448.60	**6,167.00**	-	-	35.58	758.59	372.22	4,151.71	848.90	**6,167.00**	0.00	0.00%	599.70	15.28%
Information Systems	-	-	-	187.40	42.78	2,519.30	2,562.08	-	**2,706.70**	-	-	-	114.62	582.92	1,486.79	-	**2,184.33**	(522.37)	-19.30%	(492.37)	-19.22%
Telecontrol	-	-	28.22	105.30	73.99	5,463.30	5,537.29	1,458.30	**7,055.12**	-	-	1.87	57.66	1,591.72	4,224.33	1,458.30	**7,333.88**	278.76	3.95%	278.76	5.03%
Transportation	-	-	569.00	1,963.80	(454.90)	8,471.93	8,017.03	5,061.80	**16,066.53**	-	-	125.56	3,062.14	931.61	7,085.42	5,061.80	**16,266.53**	200.00	1.24%	-	0.00%
Administration	-	-	-	-	-	881.71	881.71	-	**881.71**	-	-	-	-	133.74	747.97	-	**881.71**	-	0.00%	-	0.00%
Allowance for Unforeseen Items	-	-	-	-	(0.00)	1,000.00	1,000.00	-	**1,000.00**	-	-	-	-	-	1,000.00	-	**1,000.00**	(0.00)	0.00%	-	0.00%
Total	**3,224.28**	**29,744.12**	**59,998.82**	**57,886.38**	**21,879.29**	**117,157.79**	**139,037.08**	**96,127.35**	**364,138.75**	**695.61**	**13,625.53**	**43,153.69**	**77,671.28**	**39,432.52**	**115,309.19**	**94,174.14**	**384,061.96**	**19,923.22**		**15,704.63**	

2024 Capital Expenditures Summary By Year
($000)

	Capital Budget									Actual Expenditure and Forecast									Variance			
	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	
Year	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	2024 Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
2024	-	-	-	-	(0.00)	53,588.89	53,588.89	39,838.90	**93,427.79**	(0.00)	0.00	(0.00)	(0.00)	16,455.49	48,992.37	39,340.56	**104,788.42**	11,360.63	12.16%	11,858.96	22.13%
2023	-	-	-	25,295.92	4,172.98	50,608.40	54,781.38	50,821.75	**126,726.07**	(0.00)	0.00	(0.00)	23,834.22	13,745.87	42,025.95	51,513.48	**131,119.51**	4,393.44	3.47%	990.44	1.81%
2022	-	-	11,687.32	26,782.80	11,042.69	3,631.00	14,673.69	-	**42,101.12**	-	-	9,470.76	20,119.32	5,206.34	12,406.75	430.60	**47,633.77**	5,532.65	13.14%	2,939.40	20.03%
2021	-	23,764.87	33,602.40	5,221.30	3,552.84	9,329.50	12,882.34	5,466.70	**77,384.77**	-	12,509.98	24,578.62	21,472.33	3,495.72	9,302.45	2,889.50	**74,248.59**	(3,136.18)	-4.05%	(84.17)	-0.65%
2020	3,224.28	5,979.25	14,709.10	586.36	3,110.79	-	3,110.79	-	**24,498.99**	695.61	1,115.55	9,104.31	12,245.41	529.11	2,581.68	-	**26,271.67**	1,772.68	7.24%	-	0.00%
Total	**3,224.28**	**29,744.12**	**59,998.82**	**57,886.38**	**21,879.29**	**117,157.79**	**139,037.08**	**96,127.35**	**364,138.75**	**695.61**	**13,625.53**	**43,153.69**	**77,671.28**	**39,432.52**	**115,309.19**	**94,174.14**	**384,061.96**	**19,923.22**		**15,704.63**	

2024 Capital Expenditures By Investment Classification
Access
($000)

	Capital Budget									Actual Expenditure and Forecast								Variance			
	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	
Program/Project	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	2024 Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
Purchase Meters and Metering Equipment (2024)	-	-	-	-	-	470.70	470.70	-	**470.70**	-	-	-	-	39.59	431.11	-	**470.70**	-	0.00%	-	0.00%
Provide Service Extensions (2024)	-	-	-	-	-	4,272.00	4,272.00	-	**4,272.00**	(0.00)	0.00	(0.00)	(0.00)	1,880.29	2,391.71	-	**4,272.00**	-	0.00%	-	0.00%
Valentine Gold Interconnection - Supplemental	-	3,479.25	12,281.70	586.36	272.23	-	272.23	-	**16,347.31**	-	826.07	6,178.94	9,070.17	178.77	93.47	-	**16,347.41**	0.10	0.00%	-	0.00%
Total	**-**	**3,479.25**	**12,281.70**	**586.36**	**272.23**	**4,742.70**	**5,014.93**	**-**	**21,090.01**	**(0.00)**	**826.07**	**6,178.94**	**9,070.17**	**2,098.65**	**2,916.29**	**-**	**21,090.11**	**0.10**		**-**	

2024 Capital Expenditures By Investment Classification
General Plant
($000)

	Capital Budget									Actual Expenditure and Forecast								Variance			
	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	
Program/Project	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	2024 Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
Replace Network Communications Equipment (2024)	-	-	-	-	-	180.70	180.70	-	**180.70**	-	-	-	-	95.37	85.33	-	**180.70**	-	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2024) - Telecontrol	-	-	-	-	-	45.60	45.60	-	**45.60**	-	-	-	-	39.88	5.72	-	**45.60**	-	0.00%	-	0.00%
Upgrade SCADA Network (2024)	-	-	-	-	-	402.30	402.30	-	**402.30**	-	-	-	-	387.69	293.37	-	**681.06**	278.76	69.29%	278.76	69.29%
Minor Telecommunications Enhancements (2024)	-	-	-	-	-	96.90	96.90	-	**96.90**	-	-	-	-	42.55	54.35	-	**96.90**	-	0.00%	-	0.00%
Replace MDR8000 Microwave Radios (2024-2025)	-	-	-	-	-	953.50	953.50	500.30	**1,453.80**	-	-	-	-	22.51	930.99	500.30	**1,453.80**	-	0.00%	-	0.00%
Replace CCTV Cameras (2024)	-	-	-	-	-	317.60	317.60	-	**317.60**	-	-	-	-	169.22	148.38	-	**317.60**	-	0.00%	-	0.00%
Replace SONET Multiplexors (2024)	-	-	-	-	-	430.40	430.40	-	**430.40**	-	-	-	-	61.35	369.05	-	**430.40**	-	0.00%	-	0.00%
Replace VHF Radio System (2024-2025)	-	-	-	-	-	1,261.60	1,261.60	290.60	**1,552.20**	-	-	-	-	49.24	1,212.36	290.60	**1,552.20**	-	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2024) - Hydraulic Plants	-	-	-	-	-	209.40	209.40	-	**209.40**	-	-	-	-	35.62	173.78	-	**209.40**	-	0.00%	-	0.00%
Replace Powerhouse 1 Roof (2024-2025) - Bay d'Espoir	-	-	-	-	-	140.20	140.20	1,819.20	**1,959.40**	-	-	-	-	17.42	122.78	1,819.20	**1,959.40**	-	0.00%	-	0.00%
Replace Powerhouse 1 Air Conditioning Unit (2024-2025) - Bay d'Espoir	-	-	-	-	-	57.80	57.80	231.20	**289.00**	-	-	-	-	20.64	37.16	231.20	**289.00**	-	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2024) - Thermal Plants	-	-	-	-	-	167.10	167.10	-	**167.10**	-	-	-	-	50.83	116.27	-	**167.10**	-	0.00%	-	0.00%
Refurbish Outbuilding and Powerhouse Building Envelopes (2024-2025) - Holyrood	-	-	-	-	-	156.20	156.20	1,039.40	**1,195.60**	-	-	-	-	26.52	129.68	1,039.40	**1,195.60**	-	0.00%	-	0.00%
Install Fire Protection in 230 kV Stations (2024–2025) - Voisey's Bay	-	-	-	-	-	53.80	53.80	599.00	**652.80**	-	-	-	-	7.34	46.46	599.00	**652.80**	-	0.00%	-	0.00%
Refurbish Control Building (2024-2025) - Grandy Brook and Doyles	-	-	-	-	-	109.40	109.40	444.70	**554.10**	-	-	-	-	23.82	85.58	444.70	**554.10**	-	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2024) - Gas Turbine	-	-	-	-	-	18.60	18.60	-	**18.60**	-	-	-	-	19.42	(0.82)	-	**18.60**	-	0.00%	-	0.00%
Replace Mobile Equipment (2024-2025)	-	-	-	-	-	216.90	216.90	599.70	**816.60**	-	-	-	-	13.44	803.16	-	**816.60**	-	0.00%	599.70	276.49%
Replace Light- and Heavy-Duty Vehicles (2024-2026)	-	-	-	-	-	1,479.10	1,479.10	4,157.20	**5,636.30**	-	-	-	-	507.86	971.24	4,157.20	**5,636.30**	-	0.00%	-	0.00%
Replace Grader Unit V9829 (2024) - Bay d'Espoir	-	-	-	-	-	836.70	836.70	-	**836.70**	-	-	-	-	21.49	815.21	-	**836.70**	-	0.00%	-	0.00%
Purchase 50' Material Handler Aerial Device on Tracked Unit (2024-2026) - Happy Valley Goose Bay	-	-	-	-	-	24.00	24.00	848.90	**872.90**	-	-	-	-	10.10	13.90	848.90	**872.90**	-	0.00%	-	0.00%
Purchase Office Equipment Less Than $50,000 (2024)	-	-	-	-	-	50.00	50.00	-	**50.00**	-	-	-	-	12.46	37.54	-	**50.00**	-	0.00%	-	0.00%
General Property Rehabilitation (2024) - Hydro Place	-	-	-	-	-	234.00	234.00	-	**234.00**	-	-	-	-	9.81	224.19	-	**234.00**	-	0.00%	-	0.00%
Upgrade HVAC Supervisory Controllers (2024) - Hydro Place	-	-	-	-	-	149.60	149.60	-	**149.60**	-	-	-	-	9.67	139.93	-	**149.60**	-	0.00%	-	0.00%
Purchase Personal Computers (2024)	-	-	-	-	-	555.90	555.90	-	**555.90**	-	-	-	-	290.13	265.77	-	**555.90**	-	0.00%	-	0.00%
Replace Peripheral Infrastructure (2024)	-	-	-	-	-	276.80	276.80	-	**276.80**	-	-	-	-	3.84	272.97	-	**276.80**	-	0.00%	-	0.00%
Upgrade Core OT Infrastructure (2024)	-	-	-	-	-	174.70	174.70	-	**174.70**	-	-	-	-	119.91	54.79	-	**174.70**	-	0.00%	-	0.00%
Update Cyber Security Infrastructure (2024)	-	-	-	-	-	281.30	281.30	-	**281.30**	-	-	-	-	58.86	489.49	-	**548.35**	267.05	94.93%	267.05	94.93%
Perform Software Upgrades and Minor Enhancements (2024)	-	-	-	-	-	864.20	864.20	-	**864.20**	-	-	-	-	70.79	400.38	-	**471.18**	(393.02)	-45.48%	(393.02)	-45.48%
Upgrade Energy Management System (2024)	-	-	-	-	-	366.40	366.40	-	**366.40**	-	-	-	-	4.61	(4.61)	-	**-**	(366.40)	-100.00%	(366.40)	-100.00%
Upgrade Fleet Infrastructure Program - Install L2 EV Chargers (2024) - Hydro Place	-	-	-	-	-	322.63	322.63	-	**322.63**	-	-	-	-	16.41	306.23	-	**322.63**	-	0.00%	-	0.00%
Perform Office Modifications (2024) - Hydro Place	-	-	-	-	-	249.81	249.81	-	**249.81**	-	-	-	-	15.38	234.43	-	**249.81**	-	0.00%	-	0.00%
Install L-1 Blades Unit 1 (2024) Holyrood	-	-	-	-	-	581.26	581.26	-	**581.26**	-	-	-	-	128.12	453.14	-	**581.26**	-	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2023) - Central Region	-	-	-	-	-	188.20	188.20	-	**188.20**	-	-	-	-	64.16	124.04	-	**188.20**	-	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2023) - Labrador Region	-	-	-	-	0.00	120.10	120.10	-	**120.10**	-	-	-	-	23.65	96.45	-	**120.10**	0.00	0.00%	-	0.00%
Purchase Tools and Equipment Less than $50,000 (2023) - Northern Region	-	-	-	-	(0.00)	97.00	97.00	-	**97.00**	-	-	-	-	26.37	70.63	-	**97.00**	(0.00)	0.00%	-	0.00%
Replace Peripheral Infrastructure (2023)	-	-	-	187.40	42.78	-	42.78	-	**187.40**	-	-	-	114.62	34.77	8.01	-	**157.40**	(30.00)	-16.01%	-	0.00%
Replace Light- and Heavy-Duty Vehicles (2023-2025)	-	-	-	1,308.10	(1,065.10)	2,584.60	1,519.50	673.30	**4,566.00**	-	-	-	2,573.20	340.92	1,178.59	473.30	**4,566.00**	-	0.00%	-	0.00%
Water System Condition Assessment and Upgrades (2023) - Bay d'Espoir	-	-	-	161.00	69.84	504.90	574.74	-	**665.90**	-	-	-	91.16	94.38	480.36	-	**665.90**	-	0.00%	-	0.00%
Replace Building Exterior (2023-2024) - Postville	-	-	-	124.60	(4.45)	558.70	554.25	-	**683.30**	-	-	-	129.05	42.18	1,129.67	-	**1,300.90**	617.60	90.38%	617.60	111.43%
Upgrade Water and Fire Suppression Systems (2023-2024) - Bishop's Falls	-	-	-	353.70	37.51	2,886.30	2,923.81	-	**3,240.00**	-	-	-	316.19	258.36	2,325.64	1,909.81	**4,810.00**	1,570.00	48.46%	(339.81)	-11.62%
Replace Diesel Shop Building (2023-2025) - Bishop's Falls	-	-	-	168.00	(30.65)	1,254.10	1,223.45	890.15	**2,312.25**	-	-	-	198.65	43.07	6.28	-	**248.00**	(2,064.25)	-89.27%	(1,174.10)	-95.97%
Replace HVAC System (2023-2024) - Bishop's Falls	-	-	-	43.40	(19.84)	128.80	108.96	-	**172.20**	-	-	-	63.24	30.18	212.58	-	**306.00**	133.80	77.70%	133.80	122.80%
Install Fire Protection in 230 kV Stations (2023-2024) - Deer Lake	-	-	-	79.20	45.73	535.30	581.03	-	**614.50**	-	-	-	33.47	99.60	481.43	-	**614.50**	-	0.00%	-	0.00%
Replace Mobile Equipment (2023-2024)	-	-	-	541.20	(147.31)	187.30	39.99	-	**728.50**	-	-	-	688.51	67.03	(27.04)	-	**728.50**	-	0.00%	-	0.00%
Install Ultra-Fast DC Electric Vehicle Chargers - Supplemental	-	-	-	62.50	51.26	1,766.00	1,817.26	231.30	**2,059.80**	-	-	-	11.24	33.72	1,783.54	231.30	**2,059.80**	-	0.00%	-	0.00%
Replace Light- and Heavy-Duty Vehicles (2022-2024)	-	-	569.00	593.20	558.93	2,319.60	2,878.53	-	**3,481.80**	-	-	125.56	477.70	32.71	2,845.83	-	**3,481.80**	-	0.00%	-	0.00%
Replace Underground Fire Water Distribution System (2022-2023) - Holyrood	-	-	128.30	1,578.00	1,933.60	-	1,933.60	-	**1,706.30**	-	-	115.17	1,018.02	527.82	1,405.79	-	**3,066.80**	1,360.50	79.73%	-	0.00%
Purchase 46' Material Handler Aerial Device on Track Unit	-	-	20.40	698.80	669.50	38.80	708.30	-	**758.00**	-	-	13.19	36.52	15.26	693.03	-	**758.00**	-	0.00%	-	0.00%
Purchase 85' Material Handler Aerial Device on Track Unit	-	-	20.40	1,265.70	1,230.14	67.80	1,297.94	-	**1,353.90**	-	-	22.40	33.56	24.84	1,273.10	-	**1,353.90**	-	0.00%	-	0.00%
Total	**-**	**-**	**738.10**	**7,164.80**	**3,371.95**	**24,501.91**	**27,873.85**	**12,324.95**	**44,729.76**	**-**	**-**	**276.32**	**5,785.13**	**4,121.33**	**23,376.09**	**12,544.91**	**46,103.79**	**1,374.03**		**(376.43)**	

2024 Capital Expenditures By Investment Classification
Mandatory
($000)

	Capital Budget									Actual Expenditure and Forecast								Variance			
	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	
Program/Project	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
Refurbish Fuel Oil Storage Tank 4 (2024) - Holyrood	-	-	-	-	-	1,920.00	1,920.00	-	**1,920.00**	-	-	-	-	51.47	1,868.53	-	**1,920.00**	-	0.00%	-	0.00%
Upgrade Station Lighting (2024-2025) - Bottom Waters, Deer Lake, Doyles, Indian River, and Western Avalon Terminal Stations	-	-	-	-	-	91.60	91.60	429.00	**520.60**	-	-	-	-	31.96	59.64	429.00	**520.60**	-	0.00%	-	0.00%
Replace Terminal Station Lighting (2023-2024)	-	-	-	323.30	(65.38)	594.10	528.72	-	**917.40**	-	-	-	388.68	295.22	233.50	-	**917.40**	-	0.00%	-	0.00%
Total	**-**	**-**	**-**	**323.30**	**(65.38)**	**2,605.70**	**2,540.32**	**429.00**	**3,358.00**	**-**	**-**	**-**	**388.68**	**378.64**	**2,161.67**	**429.00**	**3,358.00**	**-**		**-**	

2024 Capital Expenditures By Investment Classification
Renewal
($000)

	Capital Budget									Actual Expenditure and Forecast									Variance			
	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	
Program/Project	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	2024 Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
Telecommunications In-Service Failure (2024)	-	-	-	-	-	91.40	91.40	-	**91.40**	-	-	-	-	27.97	63.43	-	**91.40**	-	0.00%	-	0.00%
Purchase Mobile Devices (2024)	-	-	-	-	-	155.60	155.60	-	**155.60**	-	-	-	-	80.18	75.42	-	**155.60**	-	0.00%	-	0.00%
Replace 48 V Battery Banks and Chargers (2024)	-	-	-	-	-	422.20	422.20	-	**422.20**	-	-	-	-	21.19	401.01	-	**422.20**	-	0.00%	-	0.00%
Replace Power Line Carrier (2024-2025) - TL247	-	-	-	-	-	87.20	87.20	667.40	**754.60**	-	-	-	-	13.46	73.74	667.40	**754.60**	-	0.00%	-	0.00%
Upgrade Remote Terminal Units (2024)	-	-	-	-	-	165.90	165.90	-	**165.90**	-	-	-	-	21.96	143.94	-	**165.90**	-	0.00%	-	0.00%
Flatten Downstream Slope (2024-2025) - Hinds Lake	-	-	-	-	-	276.10	276.10	2,953.40	**3,229.50**	-	-	-	-	23.14	252.96	2,953.40	**3,229.50**	-	0.00%	-	0.00%
Penstock Level II Condition Assessment (2024) - Upper Salmon	-	-	-	-	-	382.80	382.80	-	**382.80**	-	-	-	-	15.50	367.30	-	**382.80**	-	0.00%	-	0.00%
Replace Annunciator Panels (2024-2025) - Cat Arm	-	-	-	-	-	160.20	160.20	191.20	**351.40**	-	-	-	-	113.96	46.24	191.20	**351.40**	-	0.00%	-	0.00%
Refurbish Surge Tank 1 (2024-2025) - Bay d'Espoir	-	-	-	-	-	175.80	175.80	2,111.40	**2,287.20**	-	-	-	-	17.58	158.22	2,111.40	**2,287.20**	-	0.00%	-	0.00%
Replace Timber Crib and Insulation (2024) - Burnt Dam Spillway	-	-	-	-	-	161.80	161.80	-	**161.80**	-	-	-	-	20.28	141.52	-	**161.80**	-	0.00%	-	0.00%
Hydraulic In-Service Failures (2024)	-	-	-	-	-	1,500.00	1,500.00	-	**1,500.00**	-	-	-	-	211.59	2,288.41	-	**2,500.00**	1,000.00	66.67%	1,000.00	66.67%
Replace Annunciator - Phase 2 (2024-2025) - Bay d'Espoir	-	-	-	-	-	294.10	294.10	187.50	**481.60**	-	-	-	-	52.57	241.53	187.50	**481.60**	-	0.00%	-	0.00%
Refurbish Intake 1 (2024-2025) - Bay d'Espoir	-	-	-	-	-	272.10	272.10	3,071.90	**3,344.00**	-	-	-	-	104.19	167.91	3,071.90	**3,344.00**	-	0.00%	-	0.00%
Overhaul Hydraulic Units (2024)	-	-	-	-	-	323.80	323.80	-	**323.80**	-	-	-	-	18.78	305.02	-	**323.80**	-	0.00%	-	0.00%
Thermal In-Service Failures (2024)	-	-	-	-	-	3,508.70	3,508.70	-	**3,508.70**	-	-	-	-	2,021.67	1,487.03	-	**3,508.70**	-	0.00%	-	0.00%
Upgrade DCS Hardware - Units 1 and 2 (2024-2025) - Holyrood	-	-	-	-	-	195.20	195.20	277.30	**472.50**	-	-	-	-	23.68	171.52	277.30	**472.50**	-	0.00%	-	0.00%
Upgrade Unit 1 Control System (2024-2025) - Holyrood	-	-	-	-	-	468.30	468.30	184.30	**652.60**	-	-	-	-	106.60	361.70	184.30	**652.60**	-	0.00%	-	0.00%
Overhaul Pumps (2024) - Holyrood	-	-	-	-	-	661.00	661.00	-	**661.00**	-	-	-	-	35.71	801.53	-	**837.24**	176.24	26.66%	176.24	26.66%
Overhaul Unit 1 Turbine Valves and Generator (2024) - Holyrood	-	-	-	-	-	5,181.40	5,181.40	-	**5,181.40**	-	-	-	-	138.36	5,043.04	-	**5,181.40**	-	0.00%	-	0.00%
Upgrade UPS 1 & 2 (2024-2025) - Holyrood	-	-	-	-	-	263.00	263.00	107.60	**370.60**	-	-	-	-	20.88	242.12	107.60	**370.60**	-	0.00%	-	0.00%
Boiler Condition Assessment and Miscellaneous Upgrades (2024) - Holyrood	-	-	-	-	-	3,957.80	3,957.80	-	**3,957.80**	-	-	-	-	1,095.89	4,961.91	-	**6,057.80**	2,100.00	53.06%	2,100.00	53.06%
Overhaul Marine Terminal Loading Arms (2024) - Holyrood	-	-	-	-	-	511.00	511.00	-	**511.00**	-	-	-	-	31.27	479.73	-	**511.00**	-	0.00%	-	0.00%
Renew Circuit Breakers (2024–2025)	-	-	-	-	-	183.90	183.90	2,779.30	**2,963.20**	-	-	-	-	22.44	40.70	2,240.86	**2,304.00**	(659.20)	-22.25%	(120.76)	-65.67%
Terminal Station In-Service Failures (2024)	-	-	-	-	(0.00)	1,300.00	1,300.00	-	**1,300.00**	-	-	-	-	1,812.33	1,802.16	-	**3,614.49**	2,314.49	178.04%	2,314.49	178.04%
Upgrade Power Transformers (2024-2025)	-	-	-	-	-	864.60	864.60	2,711.30	**3,575.90**	-	-	-	-	207.44	657.16	2,711.30	**3,575.90**	-	0.00%	-	0.00%
Replace Terminal Station Battery Banks and Chargers (2024–2025)	-	-	-	-	-	71.80	71.80	120.90	**192.70**	-	-	-	-	21.33	50.47	120.90	**192.70**	-	0.00%	-	0.00%
Replace Instrument Transformers (2024–2025)	-	-	-	-	-	154.90	154.90	714.80	**869.70**	-	-	-	-	27.51	127.39	714.80	**869.70**	-	0.00%	-	0.00%
Replace Protective Relays (2024–2025)	-	-	-	-	-	1,388.40	1,388.40	2,050.70	**3,439.10**	-	-	-	-	128.21	1,260.19	2,050.70	**3,439.10**	-	0.00%	-	0.00%
Replace Disconnects (2024–2025)	-	-	-	-	-	127.40	127.40	1,358.10	**1,485.50**	-	-	-	-	51.83	75.57	1,358.10	**1,485.50**	-	0.00%	-	0.00%
Upgrade Data Alarm Systems (2024–2025) - Western Avalon Terminal Station	-	-	-	-	-	137.00	137.00	156.90	**293.90**	-	-	-	-	22.89	114.11	156.90	**293.90**	-	0.00%	-	0.00%
Replace Circuit Breaker Reclosing Controllers (2024–2025) - TL247	-	-	-	-	-	112.40	112.40	215.80	**328.20**	-	-	-	-	8.58	103.82	215.80	**328.20**	-	0.00%	-	0.00%
Diesel In-Service Failures (2024)	-	-	-	-	-	488.30	488.30	-	**488.30**	-	-	-	-	1,451.38	(963.08)	-	**488.30**	-	0.00%	-	0.00%
Overhaul Diesel Units (2024)	-	-	-	-	-	829.20	829.20	-	**829.20**	-	-	-	-	336.38	492.82	-	**829.20**	-	0.00%	-	0.00%
Wood Pole Line Management (2024)	-	-	-	-	-	3,765.20	3,765.20	-	**3,765.20**	-	-	-	-	482.51	3,282.69	-	**3,765.20**	-	0.00%	-	0.00%
Transmission In-Service Failures (2024)	-	-	-	-	-	158.50	158.50	-	**158.50**	-	-	-	-	69.95	88.55	-	**158.50**	-	0.00%	-	0.00%
Upgrade Distribution (2024-2025) - Bay d'Espoir Terminal Station 2	-	-	-	-	-	93.20	93.20	331.50	**424.70**	-	-	-	-	29.18	64.02	331.50	**424.70**	-	0.00%	-	0.00%
Renew Distribution Feeders (2024-2025)	-	-	-	-	-	1,287.30	1,287.30	1,245.10	**2,532.40**	-	-	-	-	14.89	1,272.41	1,245.10	**2,532.40**	-	0.00%	-	0.00%
Replace Diesel Gensets (2024-2026)	-	-	-	-	-	535.80	535.80	4,380.30	**4,916.10**	-	-	-	-	83.06	452.74	4,380.30	**4,916.10**	-	0.00%	-	0.00%
Gas Turbine In-Service Failures (2024)	-	-	-	-	-	358.00	358.00	-	**358.00**	-	-	-	-	1,440.22	5,560.49	-	**7,000.71**	6,642.71	1855.51%	6,642.71	1855.51%
Inspect Fuel Tanks (2024) - Hardwoods Gas Turbines	-	-	-	-	-	692.90	692.90	-	**692.90**	-	-	-	-	52.62	0.48	639.80	**692.90**	-	0.00%	(639.80)	-92.34%
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2024)	-	-	-	-	-	4,345.40	4,345.40	-	**4,345.40**	-	-	-	(0.00)	2,685.61	1,659.79	-	**4,345.40**	-	0.00%	-	0.00%
Replace Power Line Carrier (2023–2024) - TL223 and TL224	-	-	-	105.30	49.52	852.40	901.92	-	**957.70**	-	-	-	55.78	547.41	354.51	-	**957.70**	-	0.00%	-	0.00%
Replace Human Machine Interface (2023) - Happy Valley Gas Turbine	-	-	-	138.60	17.31	-	17.31	-	**138.60**	-	-	-	137.69	27.49	(10.18)	-	**155.00**	16.40	11.83%	-	0.00%
Replace Oil Mist Separator (2023-2024) - Happy Valley Gas Turbine	-	-	-	138.50	99.94	262.10	362.04	-	**400.60**	-	-	-	38.56	48.40	313.64	-	**400.60**	-	0.00%	-	0.00%
Replace Powerhouse Station Service Panel (2023-2024) - Upper Salmon	-	-	-	591.80	251.52	976.70	1,228.22	-	**1,568.50**	-	-	-	883.28	128.02	1,100.20	-	**2,111.50**	543.00	34.62%	-	0.00%
Replace Diesel Genset 1 (2023-2024) - Ebbegunbaeg	-	-	-	298.00	165.45	728.30	893.75	-	**1,026.30**	-	-	-	132.55	343.07	550.68	-	**1,026.30**	-	0.00%	-	0.00%
Refurbish Superstructure (2023-2024) - Salmon River Spillway	-	-	-	328.30	149.30	2,500.00	2,649.30	-	**2,828.30**	-	-	-	179.00	129.19	2,520.10	-	**2,828.30**	-	0.00%	-	0.00%
Overhaul Unit 2 Turbine and Valves (2023) - Holyrood	-	-	-	9,701.80	2,092.02	-	2,092.02	-	**9,701.80**	-	-	-	9,276.35	3,306.40	(1,214.38)	-	**11,368.37**	1,666.57	17.18%	-	0.00%
Replace Intermediate Fuel Storage Tanks (2023-2024) - Nain	-	-	-	127.40	55.57	593.70	649.27	-	**721.10**	-	-	-	71.83	305.20	344.07	-	**721.10**	-	0.00%	-	0.00%
Circuit Breakers Renewal Program (2023-2024)	-	-	-	216.90	(416.88)	3,595.10	3,178.22	-	**3,812.00**	-	-	-	633.78	559.27	2,618.95	-	**3,812.00**	0.00	0.00%	-	0.00%
Install Breaker Failure Protection (2023-2024) - Sunnyside	-	-	-	73.50	(9.96)	216.20	206.24	-	**289.70**	-	-	-	467.17	112.84	93.39	-	**673.40**	383.70	132.45%	-	0.00%
Replace Data Alarm System Annunciators (2023) - Buchans	-	-	-	61.20	(16.65)	104.80	88.15	-	**166.00**	-	-	-	77.85	35.88	52.27	-	**166.00**	-	0.00%	-	0.00%
Replace Circuit Breaker Reclosing Controllers (2023-2024) - Hardwoods	-	-	-	81.60	37.76	149.60	187.36	-	**231.20**	-	-	-	43.84	26.96	160.39	-	**231.20**	-	0.00%	-	0.00%
Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) - Wabush Terminal Station	-	-	-	577.20	(115.13)	516.10	400.97	-	**1,093.30**	-	-	-	692.33	178.60	222.36	-	**1,093.30**	-	0.00%	-	0.00%
Penstock Life Extension - Phase 1 (2023-2025)	-	-	-	2,105.00	972.64	13,172.60	14,145.24	35,329.10	**50,606.70**	-	-	-	1,132.36	994.72	13,150.53	35,329.10	**50,606.70**	-	0.00%	-	0.00%
Holyrood Thermal Generating Station Unit 1 and Unit 2 Turbine Last Stage Blades	-	-	-	3,596.50	1,567.26	2,812.20	4,379.46	-	**6,408.70**	-	-	-	2,029.24	1,320.09	3,059.37	-	**6,408.70**	-	0.00%	-	0.00%
Diesel Genset Replacement Program (2023-2025)	-	-	-	819.10	67.08	174.00	241.08	2,133.10	**3,126.20**	-	-	-	683.62	80.15	1,369.48	275.00	**2,408.25**	(717.95)	-22.97%	1,208.55	501.32%
Terminal Station Renewal Program (2023-2024)	-	-	-	1,733.70	299.11	5,584.50	5,883.61	-	**7,318.20**	-	-	-	1,434.59	1,872.06	4,272.95	-	**7,579.60**	261.40	3.57%	261.40	4.44%
Labrador City L22 Voltage Conversion (2022-2023)	-	-	486.80	1,004.40	1,210.71	-	1,210.71	-	**1,491.20**	-	-	99.11	181.39	477.04	733.67	-	**1,491.20**	-	0.00%	-	0.00%
Diesel Genset Replacement Unit 2039 - St. Lewis	-	-	397.00	1,583.80	1,365.25	-	1,365.25	-	**1,980.80**	-	-	238.70	361.75	516.64	848.61	-	**1,965.70**	(15.10)	-0.76%	-	0.00%
Diesel Genset Replacement Unit 2012 - L'Anse-Au-Loup	-	-	339.90	2,513.20	2,468.15	210.20	2,678.35	-	**3,063.30**	-	-	170.26	214.69	111.62	2,566.72	-	**3,063.30**	-	0.00%	-	0.00%
Holyrood Upgrade Turbine Control System Unit 2 - Supplemental	-	-	235.90	490.10	68.71	-	68.71	-	**726.00**	-	-	150.68	506.61	148.24	(79.53)	-	**726.00**	-	0.00%	-	0.00%
Holyrood Fuel Tank 1 Fuel Inspection And Refurbishment - Supplemental	-	-	1,195.00	857.10	190.79	0.00	190.79	-	**2,052.10**	-	-	1,030.63	2,628.58	2,174.04	(833.25)	-	**5,000.00**	2,947.90	143.65%	1,150.00	602.76%
Hydraulic Generation R&M	-	6,569.54	7,976.20	3,788.90	300.93	-	300.93	-	**18,334.64**	-	3,640.20	9,232.04	4,755.67	184.28	116.64	-	**17,928.84**	(405.80)	-2.21%	-	0.00%
Terminal Station R&M	-	6,071.45	9,640.40	6,109.70	33.78	-	33.78	-	**21,821.55**	-	3,874.12	9,422.58	5,679.46	83.70	(49.92)	-	**19,009.95**	(2,811.60)	-12.88%	-	0.00%
Refurbish Ebbegunbaeg Control Structure	-	3,236.82	3,238.30	3,470.10	(476.25)	2,781.60	2,305.35	4,952.20	**17,679.02**	-	2,196.44	4,301.54	3,923.59	182.73	4,699.80	2,375.00	**17,679.11**	0.08	0.00%	2,577.17	111.79%
Replace Unit 2047 - Ramea	-	307.71	2,010.80	118.30	1,075.39	-	1,075.39	-	**2,436.81**	-	49.04	216.05	1,096.33	350.46	724.93	-	**2,436.81**	-	0.00%	-	0.00%
Diesel Genset Replacements (2021-2022)	-	2,560.60	286.20	-	49.53	-	49.53	-	**2,846.80**	-	1,503.79	1,036.26	382.20	98.40	(48.87)	-	**2,971.77**	124.97	4.39%	-	0.00%
Perform Combustor Inspection - Holyrood Gas Turbine	546.14	2,500.00	2,427.40	-	2,872.98	-	2,872.98	-	**5,473.54**	35.03	39.28	2,367.51	158.73	98.37	2,774.61	-	**5,473.53**	(0.01)	0.00%	-	0.00%
Replace Transformer T7 (2020) - Holyrood Terminal Station	2,678.14	-	-	-	(34.42)	-	(34.42)	-	**2,678.14**	660.58	250.21	557.86	3,016.51	251.97	(286.40)	-	**4,450.73**	1,772.59	66.19%	-	0.00%
Total	**3,224.28**	**21,246.11**	**28,233.90**	**40,630.00**	**14,391.36**	**71,339.70**	**85,731.06**	**68,231.10**	**232,905.09**	**695.61**	**11,553.08**	**28,823.23**	**40,875.35**	**27,858.00**	**74,543.07**	**63,897.16**	**248,245.50**	**15,340.40**		**16,670.00**	

2024 Capital Expenditures By Investment Classification
Service Enhancement
($000)

	Capital Budget									Actual Expenditure and Forecast								Variance			
	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	
Program/Project	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	2024 Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
Install Anemometer (2024) - Cat Arm	-	-	-	-	-	68.60	68.60	-	**68.60**	-	-	-	-	40.47	28.13	-	**68.60**	-	0.00%	-	0.00%
Remove Safety Hazards (2024)	-	-	-	-	-	198.30	198.30	-	**198.30**	-	-	-	-	86.42	111.88	-	**198.30**	-	0.00%	-	0.00%
Automate Bulk Metering (2024-2026)	-	-	-	-	-	302.60	302.60	449.70	**752.30**	-	-	-	-	19.29	283.31	449.70	**752.30**	-	0.00%	-	0.00%
Construct Maintenance Platform (2024-2025) - Holyrood Gas Turbine	-	-	-	-	-	130.50	130.50	228.70	**359.20**	-	-	-	-	5.52	124.98	228.70	**359.20**	-	0.00%	-	0.00%
Upgrade Worst-Performing Distribution Feeders (2024-2025)	-	-	-	-	-	1,064.30	1,064.30	2,227.40	**3,291.70**	-	-	-	-	44.12	1,020.18	2,227.40	**3,291.70**	-	0.00%	-	0.00%
Upgrade Instrumentation (2024-2025) - Hardwoods Gas Turbine	-	-	-	-	-	60.90	60.90	157.20	**218.10**	-	-	-	-	13.67	47.23	157.20	**218.10**	-	0.00%	-	0.00%
Install Line Monitoring System (2024) - TL201	-	-	-	-	-	469.90	469.90	-	**469.90**	-	-	-	-	454.81	15.10	-	**469.90**	-	0.00%	-	0.00%
Upgrade Exhaust Stack Expansion Joints (2024) - Hardwoods and Stephenville	-	-	-	-	-	32.18	32.18	-	**32.18**	-	-	-	-	26.88	5.30	-	**32.18**	-	0.00%	-	0.00%
Upgrade of Worst-Performing Distribution Feeders (2023-2024)	-	-	-	73.40	(598.28)	1,372.60	774.32	-	**1,446.00**	-	-	-	671.68	256.73	517.59	-	**1,446.00**	-	0.00%	-	0.00%
Install Oil Spill Containment Transformer T1S (2023-2024) - Cat Arm	-	-	-	155.10	54.71	426.50	481.21	-	**581.60**	-	-	-	100.39	140.21	341.00	-	**581.60**	-	0.00%	-	0.00%
Purchase Spare Generator Step-Up Transformer - Supplemental	-	-	-	39.60	22.07	1,298.90	1,320.97	6,128.70	**7,467.20**	-	-	-	17.53	17.90	1,303.07	6,128.70	**7,467.20**	-	0.00%	-	0.00%
Replace Unit 2090/2044 - Charlottetown and Mary's Harbour	-	-	-	401.02	(13.73)	-	(13.73)	-	**401.02**	-	-	-	414.75	46.43	(60.16)	-	**401.02**	-	0.00%	-	0.00%
IOC SCADA Data Link	-	-	28.22	-	24.47	-	24.47	-	**28.22**	-	-	1.87	1.88	11.73	12.74	-	**28.22**	-	0.00%	-	0.00%
Install Fire Protection in Diesel Plants (2022-2023) - Ramea	-	-	90.70	1,838.10	343.57	-	343.57	-	**1,928.80**	-	-	76.87	1,000.97	409.27	(65.70)	-	**1,421.41**	(507.39)	-26.31%	-	0.00%
Replace Metering System (2022-2024)	-	-	515.60	4,365.60	623.41	994.60	1,618.01	-	**5,875.80**	-	-	2,264.44	1,993.35	490.21	2,917.20	430.60	**8,095.80**	2,220.00	37.78%	1,789.40	110.59%
Winterize Unit 2102 and Install Mobile - Charlottetown (Supplemental)	-	-	1,269.80	44.90	44.10	0.00	44.10	-	**1,314.70**	-	-	205.62	1,389.98	155.59	(111.49)	-	**1,639.70**	325.00	24.72%	-	0.00%
Upgrades for Future Retirement of Stephenville Gas Turbine (2021-2022)	-	1,530.35	5,344.50	-	2,954.72	-	2,954.72	-	**6,874.85**	-	151.77	1,060.87	3,493.98	296.49	(3.12)	-	**5,000.00**	(1,874.85)	-27.27%	(2,661.35)	-90.07%
Total	**-**	**1,530.35**	**7,248.82**	**6,917.72**	**3,455.04**	**6,419.88**	**9,874.93**	**9,191.70**	**31,308.47**	**-**	**151.77**	**3,609.67**	**9,084.52**	**2,515.76**	**6,487.22**	**9,622.30**	**31,471.24**	**162.76**		**(871.95)**	

2024 Capital Expenditures By Investment Classification
System Growth
($000)

	Capital Budget									Actual Expenditure and Forecast								Variance			
	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	
Program/Project	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	2024 Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
Additions for Load Growth - Upgrade Transformer Capacity (2023-2024) - Jean Lake Terminal Station	-	-	-	580.00	527.98	-	527.98	5,436.10	**6,016.10**	-	-	-	52.02	49.14	761.84	6,966.26	**7,829.26**	1,813.16	30.14%	283.00	53.60%
Additions for Load (2022) - Mary's Harbour Service Conductor	-	-	307.80	51.30	49.41	-	49.41	-	**359.10**	-	-	122.97	38.62	3.21	46.19	-	**211.00**	(148.10)	-41.24%	-	0.00%
Additions for Load - Wabush Substation Upgrades	-	1,186.70	6,253.00	-	455.29	2,739.90	3,195.19	514.50	**10,694.10**	-	300.60	2,299.38	4,384.48	475.84	2,719.34	514.50	**10,694.14**	0.04	0.00%	-	0.00%
Wabush Terminal Station Upgrades	-	2,301.72	4,935.50	1,632.90	(578.58)	3,808.00	3,229.42	-	**12,678.12**	-	794.01	1,843.19	7,992.32	1,931.94	1,297.48	-	**13,858.93**	1,180.81	9.31%	-	0.00%
Total	**-**	**3,488.42**	**11,496.30**	**2,264.20**	**454.09**	**6,547.90**	**7,001.99**	**5,950.60**	**29,747.42**	**-**	**1,094.61**	**4,265.54**	**12,467.43**	**2,460.13**	**4,824.85**	**7,480.76**	**32,593.34**	**2,845.92**		**283.00**	

2024 Capital Expenditures By Investment Classification
Contribution in Aid of Construction ("CIAC")
($000)

	Capital Budget									Actual Expenditure and Forecast								Variance			
	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	
Program/Project	2020	2021	2022	2023	Carryover to 2024	Original 2024	Revised 2024	2025 and Beyond	Total	2020	2021	2022	2023	Original 2024	2024 Forecast Remaining Jun to Dec	2025 and Beyond	Total	Project		Annual	
Braya Renewable 2024 (CIAC)	-	-	-	-	-	(41.00)	(41.00)	(387.60)	**(428.60)**	-	-	-	-	-	(41.00)	(387.60)	**(428.60)**	-	0.00%	-	0.00%
Vale Voisey's Bay (CIAC)	-	-	-	-	-	(53.80)	(53.80)	(599.00)	**(652.80)**	-	-	-	-	-	(53.80)	(599.00)	**(652.80)**	-	0.00%	-	
IOC - Refurb WAB Circcuit Breakers 2024 (CIAC)	-	-	-	-	-	(1,210.20)	(1,210.20)	-	**(1,210.20)**	-	-	-	-	-	(1,210.20)	-	**(1,210.20)**	-	0.00%	-	
Braya Renewable 2023 (CIAC)	-	-	-	(28.00)	(28.00)	(391.60)	(419.60)	-	**(419.60)**	-	-	-	-	(419.60)	-	-	**(419.60)**	-	0.00%	-	
IOC - Refurb WAB Circcuit Breakers 2023 (CIAC)	-	-	-	(770.00)	-	(30.40)	(30.40)	-	**(800.40)**	-	-	-	(624.34)	-	(30.40)	-	**(654.74)**	145.66	-18.20%	-	0.00%
Ultra-Fast DC EV Chargers (CIAC)	-	-	-	-	-	(2,000.00)	(2,000.00)	-	**(2,000.00)**	-	-	-	-	(2,000.00)	-	-	**(2,000.00)**	-	0.00%	-	
IOC SCADA Data Link (CIAC)	-	-	(28.22)	-	(28.22)	-	(28.22)	-	**(28.22)**	-	-	-	-	-	(28.22)	-	**(28.22)**	-	0.00%	-	0.00%
Valentine Gold Interconnection (CIAC)	-	(3,730.00)	(12,085.00)	-	(498.27)	-	(498.27)	-	**(15,815.00)**	-	(3,730.00)	(9,015.73)	(2,571.00)	-	(498.27)	-	**(15,815.00)**	(0.00)	0.00%	-	0.00%
Provide Service Extenstions - All Areas (CIAC)	-	-	-	-	-	-	-	-	**-**	-	-	-	-	(770.98)	-	-	**(770.98)**	(770.98)	-	(770.98)	-
Upgrade Disribution Systems - All Areas (CIAC)	-	-	-	-	-	-	-	-	**-**	-	-	-	-	(0.87)	-	-	**(0.87)**	(0.87)	-	(0.87)	-
Total	**-**	**(3,730.00)**	**(12,113.22)**	**(798.00)**	**(554.49)**	**(3,727.00)**	**(4,281.49)**	**(986.60)**	**(21,354.82)**	**-**	**(3,730.00)**	**(9,015.73)**	**(3,195.34)**	**(3,191.45)**	**(1,861.89)**	**(986.60)**	**(21,981.00)**	**(626.19)**		**(771.85)**	

Appendix B

Capital Expenditures and Carryover Report for the Year Ended December 31, 2023



Newfoundland and Labrador Hydro
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P.O. Box 12400. St. John's. NL
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April 1, 2024

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

Attention: Jo-Anne Galarneau
Executive Director & Board Secretary

Re: Capital Expenditures and Carryover Report for the Year Ended December 31, 2023

Enclosed please find Newfoundland and Labrador Hydro's ("Hydro") "Capital Expenditures and Carryover Report for the Year Ended December 31, 2023," filed pursuant to correspondence from the Board of Commissioners of Public Utilities on February 13, 2023,[1] Board Order No. P.U. 35(2023),[2] and in compliance with Section 41(4) of the *Public Utilities Act.*[3]

This report provides information on Hydro's capital expenditures for all programs and projects proposed and approved as part of its "2023 Capital Budget Application"[4] and additional supplemental capital budgets approved by the Board. As per the "Capital Budget Application Guidelines (Provisional),"[5] this report provides key performance indicator data as well as details and explanations regarding the reportable variances between budgeted and actual expenditures for programs and projects with expenditures in the 2023 calendar year. This report also provides a listing of budget carried over to future years and specific details regarding the execution of the Remove Safety Hazards (2023) – Various program, the Perform Software Upgrades and Minor Enhancements (2023) program, various In-Service Failures (2023) programs, the Boiler Condition Assessment and Miscellaneous Upgrades (2023) – Holyrood program, and the Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) – Wabush Terminal Station program.

[1] "Annual Capital Expenditures Reports – Filing Schedule," Board of Commissioners of Public Utilities, February 13, 2023.
[2] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 35(2023), Board of Commissioners of Public Utilities, December 21, 2023.
[3] *Public Utilities Act*, RSNL 1990, c P-47, s 41(4).
[4] "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022. http://pub.nl.ca/applications/NLH2023Capital/index.php
[5] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022.

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Should you have any questions, please contact the undersigned.

Yours truly,

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Capital Expenditures and Carryover Report

For the Year Ended December 31, 2023

April 1, 2024

A report to the Board of Commissioners of Public Utilities



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1.0 Overview

This report is filed pursuant to correspondence from the Board of Commissioners of Public Utilities ("Board") on February 13, 2023,[1] Board Order No. P.U. 35(2023),[2] and in compliance with Section 41(4) of the *Public Utilities Act;*[3] it provides information on Newfoundland and Labrador Hydro's ("Hydro") capital expenditures for all programs and projects proposed and approved as part of the "2023 Capital Budget Application."[4] As noted within this report, information is also provided on capital expenditures related to additional supplemental capital budgets approved by the Board. As per the "Capital Budget Application Guidelines (Provisional)" ("Provisional Guidelines"),[5] this report provides key performance indicator ("KPI") data as well as details and explanations regarding the reportable variances between budgeted and actual expenditures for programs and projects with expenditures in the 2023 calendar year. Appendix A provides the variances by investment classification and Appendix B provides specific details regarding the execution of the following programs:

- Remove Safety Hazards (2023);
- Perform Software Upgrades and Minor Enhancements (2023);
- In-Service Failures (2023) for various asset categories;
- Boiler Condition Assessment and Miscellaneous Upgrades (2023) – Holyrood; and
- Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condensers 1 and 2 (2023-2024) – Wabush Terminal Station.

1.1 Expenditures

Hydro's 2023 capital expenditures totalled $148.9 million. Renewal of existing assets was the largest driver of investment in 2023, accounting for $96.1 million in 2023. Access and General Plant investments

[1] "Annual Capital Expenditures Reports – Filing Schedule," Board of Commissioners of Public Utilities, February 13, 2023.
[2] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 35(2023), Board of Commissioners of Public Utilities, December 21, 2023.
[3] *Public Utilities Act*, RSNL 1990, c P-47, s 41(4).
[4] "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022. http://pub.nl.ca/applications/NLH2023Capital/index.php
[5] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022.

accounted for $13.8 million and $13.2 million, respectively, followed by Service Enhancement ($12.8 million), System Growth ($12.5 million), and Mandatory investments ($0.4 million).[6]

Invested capital for terminal station infrastructure was $38.0 million, including $9.1 million towards the interconnection of Valentine Gold,[7] $8.0 million in upgrades at the Wabush Terminal Station, $6.9 million for the circuit breaker upgrade and renewal programs, and $4.4 million to upgrade the Wabush Substation. The thermal generation equipment and infrastructure at the Holyrood Thermal Generating Station ("Holyrood TGS") required 2023 expenditures totalling $29.2 million, including $9.3 million for the overhaul of the Unit 2 turbine and valves, which will continue into 2024, and $4.4 million for the condition assessment and upgrades of the three boilers. Expenditures to maintain Hydro's hydraulic generation equipment and infrastructure across the province totalled $26.3 million and included $8.4 million to refurbish the generator at the Upper Salmon Hydroelectric Generating Station ("Upper Salmon"). $14.4 million was invested in Hydro's transmission lines,[8] including $5.1 million for the Wood Pole Line Management Program, and $13.8 million in distribution systems in 2023.

Hydro's total capital expenditures of $148.9 million included unplanned additional work totalling approximately $21.9 million. Expenditures included $3.6 million completed under the scope of supplemental projects approved in 2023 and a net $18.3 million increase in work to address in-service failures and unforeseen levels of required refurbishment identified during planned condition assessments in 2023.[9]

1.2 Expenditures Compared to Approved Budget

Actual expenditures in Hydro's overall capital campaign for 2023 were over budget by $2.5 million (1.7%). Projects and programs that exceeded their individual 2023 approved budgets ($32.5 million cumulatively) were mostly offset by projects and programs that underspent their individual 2023 approved budgets ($30.0 million cumulatively). Hydro completed an analysis of 2023 capital expenditures to determine the categories and main drivers of under- and over-expenditure variances

[6] Numbers may not add due to rounding.
[7] This project includes expenditures associated with an expansion of Star Lake Terminal Station and construction of TL271.
[8] This does not include expenditures related to the construction of TL271, which were part of the Valentine Gold interconnection and reported under the Terminal Stations asset category.
[9] Includes expenditures completed under the Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2023) program.

from the approved capital budget. Overexpenditures were primarily associated with a greater-than-estimated volume of work required to address failures and condition assessments as well as work completed for higher cost than the original budget estimates. Underexpenditures were primarily a result of supply chain challenges and strategic carryover of work to future years. Sections 2.0 and 5.0 of this report provide more details on under- and over-expenditures.

1.3 Carryover

In 2023, Hydro carried over $21.9 million of budget to future years; this includes a carryover of $13.5 million associated with scopes deferred from 2023 to a future year and $8.4 million associated with the reallocation of cost flow within the years of approved projects and programs. Hydro's 2023 carryover was lower than the average for the previous nine-year period ($28.2 million) and was primarily driven by supply chain challenges and strategic carryover of work to future years. Section 7.0 provides the overall carryover amount for the ten years 2014–2023.

1.4 Key Performance Indicators

As set out in the Provisional Guidelines approved by the Board, Hydro has introduced a summary of KPIs for capital expenditures specific to projects and programs in Section 4.0 of this report. The Provisional Guidelines require the inclusion of ten years of data for each KPI. The Provisional Guidelines introduced a new definition for programs and, as Hydro did not track the required metrics for each indicator prior to the approval of the Provisional Guidelines, Hydro has provided this data beginning in 2023 and will continue to add to the same with each subsequent report.

2.0 Capital Budget versus Actual Expenditures 2014–2023

Appendix A provides a summary of capital expenditures related to programs and projects that were active in 2023, with associated expenditures broken out annually for the periods 2020–2023 (actual) and 2024 and beyond (forecast). Table 1 and Chart 1 provide a summary of Hydro's capital budget variances for the years 2014–2023.

Table 1: Capital Budget vs. Actual Expenditures 2014–2023

Year	Approved Budget ($000)	Actual Expenditures ($000)	Variance ($000)	Variance (%)
2023	146,403	148,876	2,473	1.7
2022	138,136	103,408	(34,728)	(25.1)
2021	136,304	113,492	(22,812)	(16.7)
2020	134,752	87,555	(47,197)	(35.0)
2019	164,194	126,575	(37,619)	(22.9)
2018	213,050	156,985	(56,065)	(26.3)
2017	340,501	340,741	240	0.1
2016	350,601	203,941	(146,660)	(41.8)
2015	311,177	125,119	(186,058)	(59.8)
2014	280,601	204,728	(75,873)	(27.0)

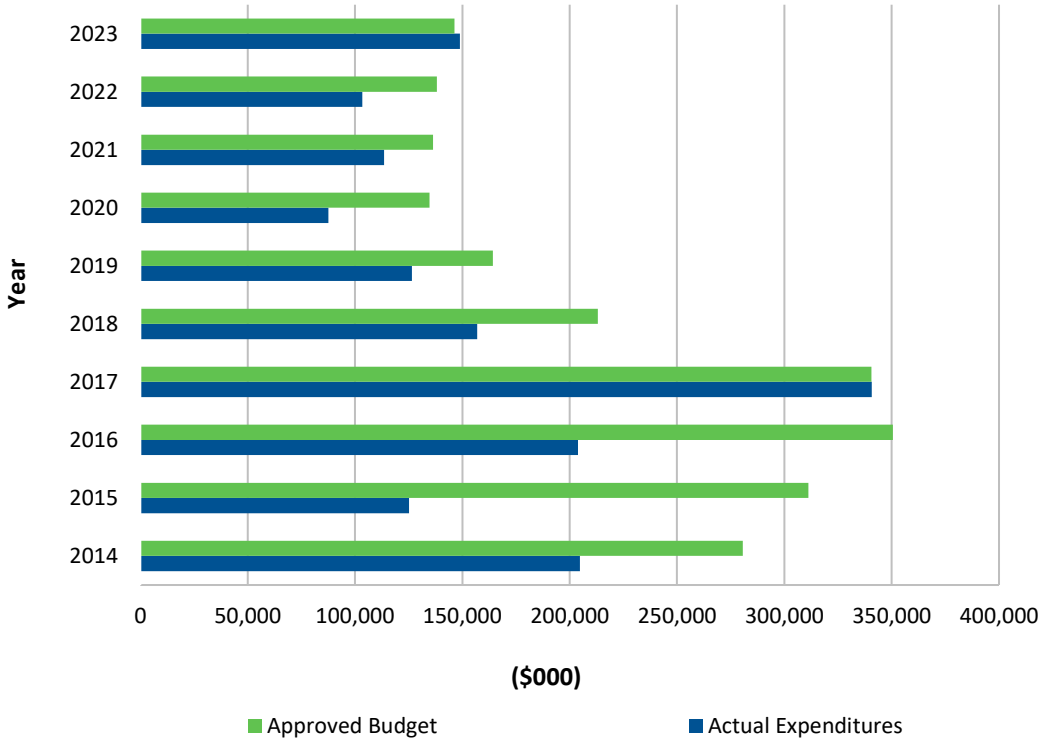


Chart 1: Capital Budgets vs. Actual Expenditures 2014–2023

In 2023, actual expenditures were above budget in Hydro's overall capital campaign by $2.5 million (1.7%), as shown in Table 1 and Chart 1. Projects and programs that exceeded their individual 2023 approved budgets ($32.5 million cumulatively) were mostly offset by projects and programs that

underspent their individual 2023 approved budgets ($30.0 million cumulatively). Hydro completed an analysis of 2023 capital campaign and project expenditures to determine the categories of variances from the approved capital budget.

Two main drivers of 2023 program and project over-expenditures were identified.

1) Greater-than-estimated volume of work required to address failures and condition assessments; and

2) Work completed for a higher cost than the original budget estimates.

Two main drivers of 2023 program and project under-expenditures were identified.

1) Supply chain challenges; and

2) Strategic carryover of work to future years.

The results of Hydro's analysis are summarized in Chart 2 and discussed in more detail herein.[10]

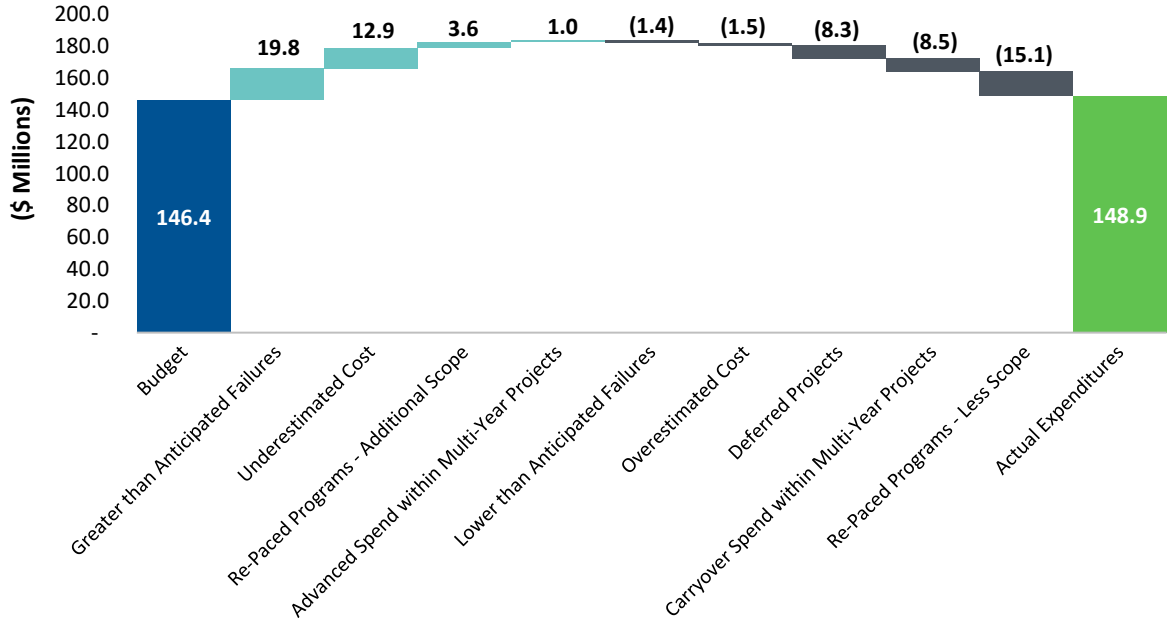


Chart 2: Analysis of 2023 Budget to Actual Capital Expenditures

[10] Projects and programs with a material variance (at least $100,000 and 10%) are listed within their respective sections herein. For projects and programs with a material overspend variance, detailed discussion is provided in Section 5.0 and referenced herein. Per the Provisional Guidelines, variance explanations for underspent projects and programs are not required; however, underspent projects and programs are listed and a brief description of the factors contributing to underspend are provided within this section.

2.1 Work Required to Address Failures and Condition Assessments

Some programs and projects had undefined scopes of work at the time of budget estimate preparation, including:

- In-Service Failures programs for various asset classifications;
- Programs and projects that involve taking assets out-of-service for condition assessment to determine the extent of refurbishment required; and
- Projects that utilize the Allowance for Unforeseen Items Account.[11]

For these programs and projects, estimates are typically based on historical expenditures and engineering judgment. In 2023, as shown in Chart 2, programs and projects required to address failures and condition assessments with expenditures in excess of the estimates accounted for $19.8 million in over-expenditures and programs and projects of this nature with fewer expenditures than estimated accounted for $1.4 million in under-expenditures, for a net over-expenditure of $18.3 million.[12] The most material programs and projects in this category with over-expenditures were:

- Upper Salmon Hydroelectric Generating Station Rotor Rim Shrinking and Stator Recentering (Supplemental);
- Gas Turbine In-Service Failures (2023);
- Hydraulic In-Service Failures (2023);
- Wood Pole Line Management Program (2023);
- Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2023);

[11] Hydro did not undertake any work under the Allowance for Unforeseen Items Account in 2023.
[12] Numbers may not add due to rounding.

- Holyrood Fuel Tank 1 Inspection and Refurbishment (Supplemental);[13]
- Overhaul Unit 2 Turbine and Valves (2023) – Holyrood;
- Terminal Station In-Service Failures (2023);
- Boiler Condition Assessment and Miscellaneous Upgrades (2023) – Holyrood; and
- Overhaul Pumps (2023) – Holyrood.

2.2 Re-Pacing of Programs

The pace of work within programs impacted Hydro's 2023 capital expenditures. As shown in Chart 2, programs with less work completed in 2023 compared to the budget estimate accounted for an under-expenditure of $15.1 million while programs with more work completed in 2023 compared to the budget estimate accounted for an over-expenditure of $3.6 million, for a net under-expenditure of $11.6 million.[14] Three main drivers of the re-pacing of program work to future years have been identified.

1) **Supply Chain Challenges:** Supply chain challenges resulted in the delayed delivery of some new equipment, which prevented Hydro from completing capital work for some programs in 2023. In particular, Hydro is experiencing long lead times for diesel gensets, heavy-duty vehicles, and

[13] In its application, "Application for Approval of Various Supplemental Capital Projects at the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, June 6, 2022, Hydro requested approval for, among other capital works, the refurbishment of Tank 2.
http://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
These projects were approved as per *Public Utilities Act*, RSNL 1990, c p-47, Board Order No. P.U. 24(2022), Board of Commissioners of Public Utilities, August 18, 2022. However, in "Request for Change or Modification to Board Order No. P.U. 24(2022) – Approval of Various Supplemental Capital Projects at the Holyrood Thermal Generation Station," Newfoundland and Labrador Hydro, September 26, 2022, Hydro advised it had determined refurbishment and reinstatement of Tank 1 could be completed for substantially less than the amount estimated for the refurbishment of Tank 2.
http://pub.nl.ca/applications/NLH2023RequestChangePU24/app/From%20NLH%20-%20Request%20for%20Change%20or%20Modification%20to%20Board%20Order%20No.%20P.U.%2024(2022)%20-%202022-09-26.PDF
As per *Public Utilities Act*, RSNL 1990, c p-47, Board Order No. P.U. 30(2022), Board of Commissioners of Public Utilities, October 7, 2022, the Board approved Hydro's request to modify Order No. P.U. 24(2022) to approve the refurbishment of Tank 1 rather than Tank 2.

[14] Numbers may not add due to rounding.

transformer components, impacting program pacing. The programs with the most material under-expenditures due to delayed delivery of equipment were:

- **Diesel Genset Replacement Unit 2012 – L'Anse-Au-Loup:** Delayed delivery of the new genset;
- **Replace Light- and Heavy-Duty Vehicles (2021–2022):** Delayed delivery of the new heavy-duty vehicles;
- **Diesel Genset Replacement Unit 2039 – St. Lewis:** Delayed delivery of the new genset;
- **Terminal Station Refurbishment and Modernization (2022–2023):** Delayed delivery of various transformer components; and
- **Replace Light- and Heavy-Duty Vehicles (2022–2024)**: Delayed delivery of the new heavy-duty vehicles.

2) **Strategic Re-Pacing of Work:** When appropriate, Hydro makes strategic decisions to delay work to future years based on updated asset condition information, updated electrical system planning requirements, or improved execution plans. The programs with the most material under-expenditures due to strategic delays were:

- **Perform Combustor Inspection – Holyrood Gas Turbine**: Delayed as the unit had not reached the number of equivalent unit starts that would necessitate the inspection; and
- **Upgrade Circuit Breakers (2022-2023) – Various**: A circuit breaker replacement associated with Unit 1 at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir") was delayed due to the unavailability of a generation outage for this unit, as other generation outages were required for more urgent work.

3) **Expanded Scope:** At times, it is necessary to complete more refurbishment work than originally planned and this may result in the delay of some work to future years. This was the case for one program with a material impact on under-expenditures:

- **Overhaul Unit 2 Turbine and Valves (2023) – Holyrood**: While the turbine was at the original equipment manufacturer's ("OEM") facility for inspection and refurbishment in 2023, cracks were discovered on the low-pressure turbine blades

that required the purchase and installation of a new set of blades, delaying completion of the work to 2024.

2.3 Actual Expenditure Variance from Estimates

As shown in Chart 2, capital program and project work completed in 2023 for more than the original budget estimate accounted for approximately $12.9 million of over-expenditure and work completed in 2023 for less than the original budget estimate accounted for $1.5 million in underexpenditure, for a net overexpenditure of $11.4 million associated with estimates. The most material programs and projects with over-expenditures were:

- Upper Salmon Hydroelectric Generating Station Rotor Rim Shrinking and Stator Recentering (Supplemental);
- Wood Pole Line Management (2023);
- Replace Transformer T7 – Holyrood;
- Wabush Terminal Station Upgrades;
- Replace Underground Firewater Distribution System – Holyrood;
- Upgrades for Future Retirement of Stephenville Gas Turbine; and
- Replace Powerhouse Station Service Panel (2023–2024) – Upper Salmon.

Most of these over-expenditures associated with estimates are attributed to materials and construction contracts that exceeded the budget estimates, which may be indicative of a general shift in market pricing. There were also environmental mitigation costs incurred on the Wood Pole Line Management Program (2023) that were not identified during the budget estimate phase.[15]

[15] Refer to variance explanation 5.1.8.

2.4 Deferred Projects

As shown in Chart 2, several projects planned for completion in 2023 have carried over to 2024, resulting in 2023 under-expenditures of $8.3 million. Two main themes related to these deferrals were identified.

1) **Strategic Deferral of Work**: When appropriate, Hydro makes strategic decisions to defer project completion to future years, based on updated asset condition information, updated electrical system planning requirements, or improved project execution plans. Hydro deferred a project to 2024 that resulted in a material under-expenditure.

    - **Upgrades for Future Retirement of the Stephenville Gas Turbine**: The required timing for this project scope has changed as the planned retirement of the Stephenville Gas Turbine has been deferred to a future year.[16]

2) **Supply Chain Challenges:** Supply chain challenges resulted in delayed delivery of some new equipment that prevented Hydro from completing some capital projects in 2023. In particular, Hydro is experiencing long lead times for diesel gensets and transformers. The projects with the most material under-expenditures due to delayed delivery of equipment were:

    - **Labrador City L22 Voltage Conversion (2022-2023)**: Delayed delivery of the pad-mount transformers; and
    - **Replace Unit 2047 Ramea**:[17] Delayed delivery of the new genset.

2.5 Changes within Continuing Multi-Year Projects

For some multi-year projects, changes are made to the project schedule without affecting the project completion date but impacting the annual cost flow. As shown in Chart 2, expenditures that are now forecast to occur in future years within multi-year contracts accounted for $8.5 million in 2023

[16] As reported in "2023 Near-Term Reliability Report – November Report," Newfoundland and Labrador Hydro, November 15, 2023, sec. 3.3.2, p. 24/1–3, Hydro is continuing operation of the Stephenville Gas Turbine beyond 2024. At this time, a recommended revised retirement date has not been concluded.
http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/reports/From%20NLH%20-%20Near-Term%20Reliability%20Report%20-%20November%20%202023%20-%202023-11-15.PDF

[17] "Application for Purchase of a Diesel Generating Unit – Ramea," Newfoundland and Labrador Hydro, July 28, 2021.
http://pub.nl.ca/applications/NLH2021Capital/NLH2021Capital_SUPP_Ramea/app/Approval%20of%20the%20Purchase%20of%20a%20Diesel%20Generating%20Unit%20for%20Use%20in%20Ramea%20-%202021-07-28.pdf

underexpenditures while costs advanced from future years into 2023 accounted for $1.0 million in overexpenditures, for a net underexpenditure of $7.4 million.[18]

Three main drivers of changes within continuing multi-year projects have been identified.

1) **Supply Chain Challenges:** Supply chain challenges resulted in delayed delivery of some new equipment that resulted in expenditures moving to future years within multi-year projects. In particular, Hydro is experiencing long lead times for material handlers and power transformers impacting annual cost flow within projects. The projects with the most material under-expenditures due to delayed delivery of equipment were:

    - **Purchase 85' Material Handler Aerial Device on Track Unit:** Delivery of the unit is delayed from 2023 to 2024;
    - **Purchase 46' Material Handler Aerial Device on Track Unit:** Delivery of the unit is delayed from 2023 to 2024; and
    - **Additions for Load Growth - Upgrade Transformer Capacity (2023–2024)** – **Jean Lake Terminal Station**: Delivery of a power transformer has been delayed from 2024 to 2025, with initial progress payment delayed from 2023 to 2024.[19]

2) **Strategic Schedule Change:** When appropriate, Hydro makes strategic decisions to reschedule work to future years within continuing multi-year projects, based on updated asset condition information, updated electrical system planning requirements, or improved project execution plans. Hydro changed the project execution plan for a continuing multi-year project in 2023, which resulted in a material under-expenditure:

    - **Purchase and Replace Last Stage Blades for Units 1 and 2 – Holyrood Thermal Generating Station:**[20] The original project plan included the installation of last stage blades on Unit 1 in 2023 and on Unit 2 in 2024. After completing an *in situ*

[18] Numbers may not add due to rounding.
[19] Hydro reforecasted this project within its "2024 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 21, 2023, resulting in a change in project completion from 2024 to 2025. http://pub.nl.ca/applications/NLH2024Capital/index.php
[20] "Purchase and Replace Last Stage Blades for Units 1 and 2 – Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 29, 2023. http://pub.nl.ca/applications/NLH2023Capital_SUPP_LastStageBlades/app/Approval%20of%20the%20Purchase%20and%20Replacement%20of%20Last%20Stage%20Blades%20for%20Units%201%20and%202%20at%20the%20Holyrood%20Thermal%20Generating%20Station%20-%202023-03-29.pdf

inspection on both units before the 2023 maintenance outages, it was determined that Unit 2 was in worse condition than Unit 1; it was decided to replace the last stage blades for Unit 2 in 2023 and Unit 1 in 2024. The Unit 1 disassembly costs were included in the 2023 budget but are not required until 2024. The Unit 2 disassembly costs in 2023 were already included in the separate Overhaul Unit 2 Turbine and Valves (2023) program, so disassembly costs were not incurred for this project.

3) **Later-than-Anticipated Project Approval:** The approval and commencement of a project in 2023 was later than anticipated when the initial budget estimate was prepared, resulting in some first-year activities carrying over into the subsequent year:

- **Penstock 1 Section Replacement and Weld Refurbishment – Bay d'Espoir (2023–2025):**[21] The initial project budget estimate and associated original cost flow assumed project approval and commencement in January 2023. However, the project was approved in April 2023, resulting in the shifting of some expenditures into 2024. The planned project completion year of 2025 is not impacted by this later start date.

2.6 Cancelled Scopes of Work

Upon approval by the Board, projects may be cancelled in whole, or in part, when new information or conditions impact the original project justification. There were no cancelled scopes of work in 2023.

2.7 Modified Scopes of Work

Upon approval of the Board, projects may be modified if new information or conditions impact the selection of the preferred project alternatives. There were no modified scopes of work in 2023.

[21] "Penstock 1 Section Replacement and Weld Refurbishment – Bay d'Espoir Hydroelectric Generating Facility," Newfoundland and Labrador Hydro, December 7, 2022. http://pub.nl.ca/applications/NLH2022WeldRefurbishment/apps/From%20NLH%20-%20Approval%20of%20Section%20Replacement%20and%20Weld%20Refurbishment%20of%20Penstock%201%20at%20the%20Bay%20d%E2%80%99Espoir%20Hydroelectric%20Generating%20Facility%20-%202022-12-07.pdf

3.0 Capital Expenditures by Investment Classification

Appendix A presents Hydro's capital expenditures by Investment Classification, including:

- Access;
- General Plant;
- Mandatory;
- Renewal;
- Service Enhancement;
- System Growth;
- Allowance for Unforeseen; and
- Contribution in Aid of Construction.

4.0 Key Performance Indicators

As set out in the Provisional Guidelines, this report will now include a summary of KPIs for capital expenditures specific to projects and programs for the last ten years.

The KPIs for projects are:

- The number of projects planned and completed by materiality threshold; and
- The original budget value of projects completed and the final cost of projects completed by materiality threshold.[22]

The KPIs for programs are:

- The number of units planned and completed by materiality threshold; and
- The estimated average unit cost and actual average unit cost.

[22] Does not include ongoing projects.

4.1 Project Key Performance Indicators

4.1.1 Planned versus Completed Projects by Year and Materiality Threshold

In this section, Hydro will provide table and graphical representations, both in aggregate and for each Investment Classification, of the planned versus completed projects by materiality threshold.[23] Hydro completed 35 of 51 projects planned for completion in 2023. The primary contributing factors for projects planned for completion but not completed in 2023 were internal resource challenges, changes in the required timing of some projects, and delayed material delivery. Hydro has assessed the risks associated with delayed completion of these projects and, where necessary, has applied appropriate mitigations. As such, none of the projects carried over into 2024 represent a significant risk to the supply of electricity to customers.

Table 2: Planned vs. Completed Projects – Aggregate

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Projects	Completed Projects	Planned Projects	Completed Projects	Planned Projects	Completed Projects
2023	37	29	12	6	2	0

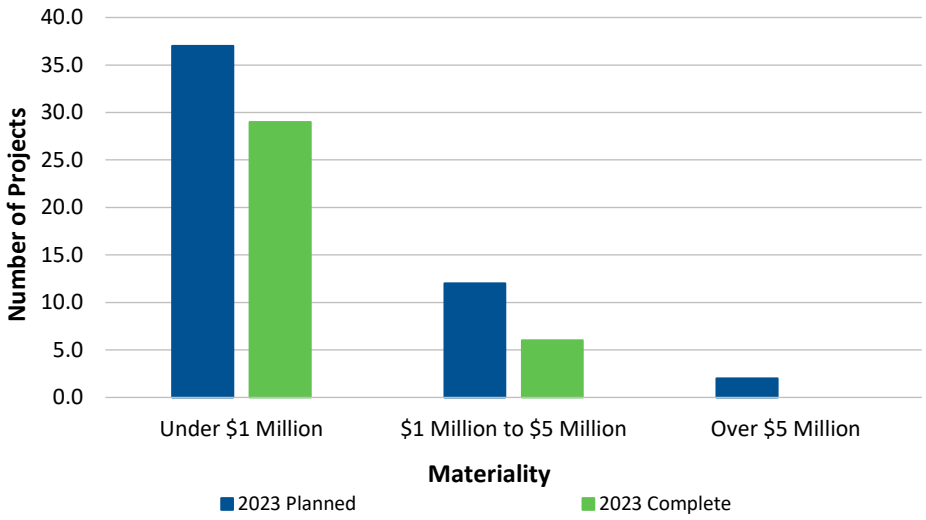


Chart 3: Planned vs. Completed Projects – Aggregate[24]

[23] For the purposes of this metric, a project is deemed complete when the full project scope is complete, all assets are in service, and the project is closed. For projects that have multiple assets planned to go in service, some assets may be in service when planned while others may have carried over. In 2023, there were two projects counted as incomplete in this metric, but had over 90% of the assets placed in service in 2023—Winterize Unit 2102 and Install Mobile – Charlottetown (approved budget of $1,314,700) and Replace Unit 2090/2044 – Charlottetown and Mary's Harbour (approved budget of $401,020).
[24] Does not include projects that were advanced and completed in 2022.

Renewal

Table 3: Planned vs. Completed Projects – Renewal

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Projects	Completed Projects	Planned Projects	Completed Projects	Planned Projects	Completed Projects
2023	23	18	8	5	0	0

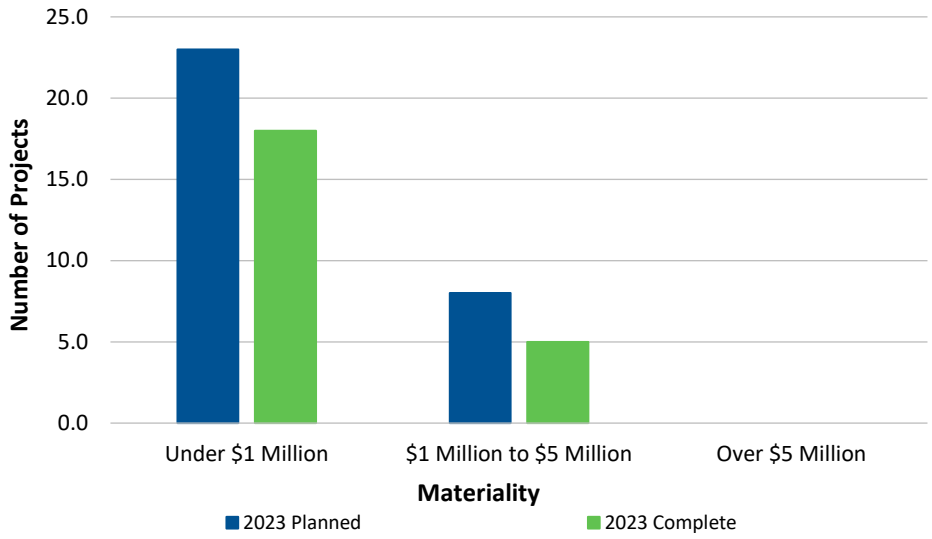


Chart 4: Planned vs. Completed Projects – Renewal

General Plant

Table 4: Planned vs. Completed Projects – General Plant

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Projects	Completed Projects	Planned Projects	Completed Projects	Planned Projects	Completed Projects
2023	5	5	2	1	0	0

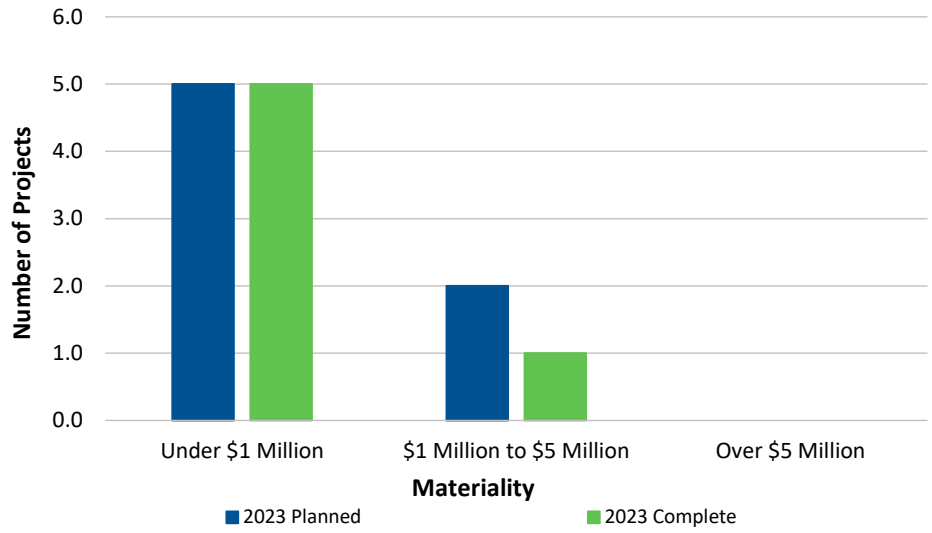


Chart 5: Planned vs. Completed Projects – General Plant

System Growth

Table 5: Planned vs. Completed Projects – System Growth

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Projects	Completed Projects	Planned Projects	Completed Projects	Planned Projects	Completed Projects
2023	1	0	0	0	0	0

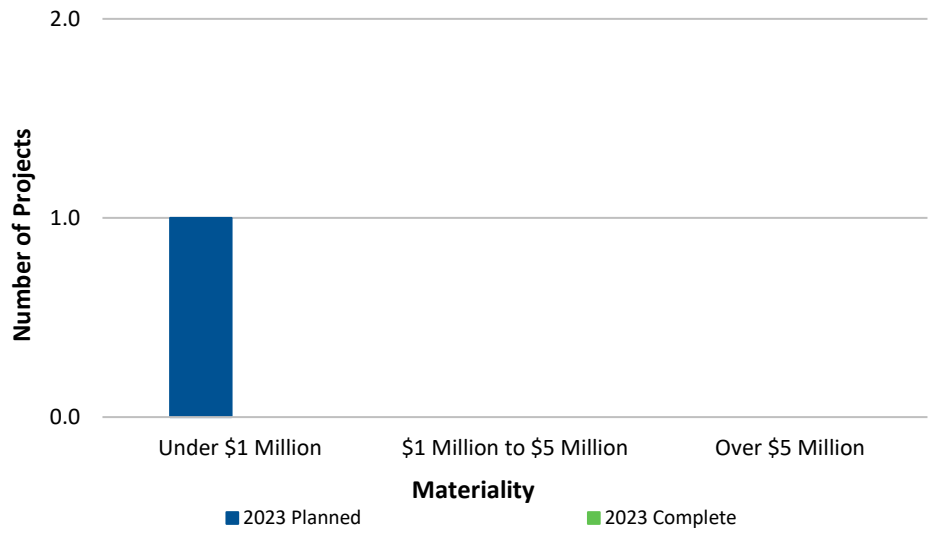


Chart 6: Planned vs. Completed Projects – System Growth

Access

Table 6: Planned vs. Completed Projects – Access

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Projects	Completed Projects	Planned Projects	Completed Projects	Planned Projects	Completed Projects
2023	1	1	0	0	1	0

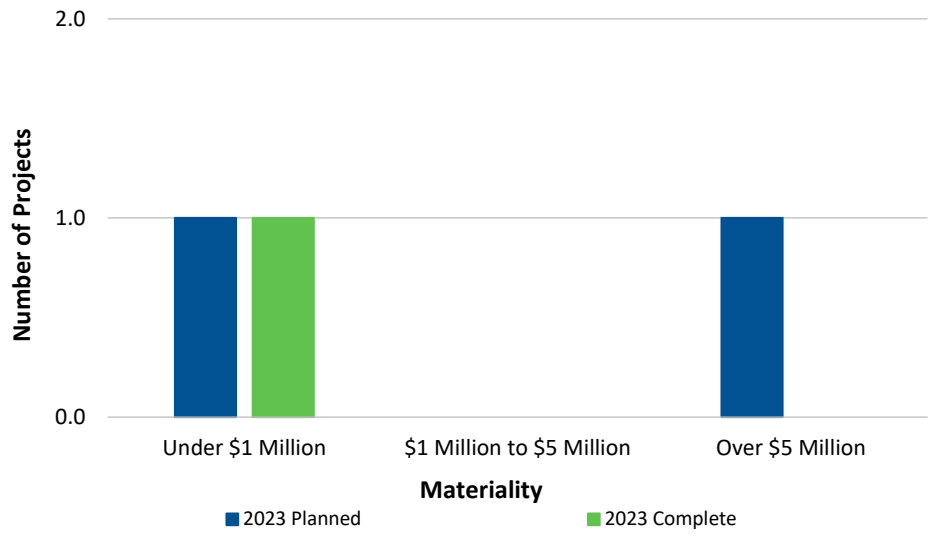


Chart 7: Planned vs. Completed Projects – Access

Service Enhancements

Table 7: Planned vs. Completed Projects – Service Enhancements

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Projects	Completed Projects	Planned Projects	Completed Projects	Planned Projects	Completed Projects
2023	7	5	2	0	1	0

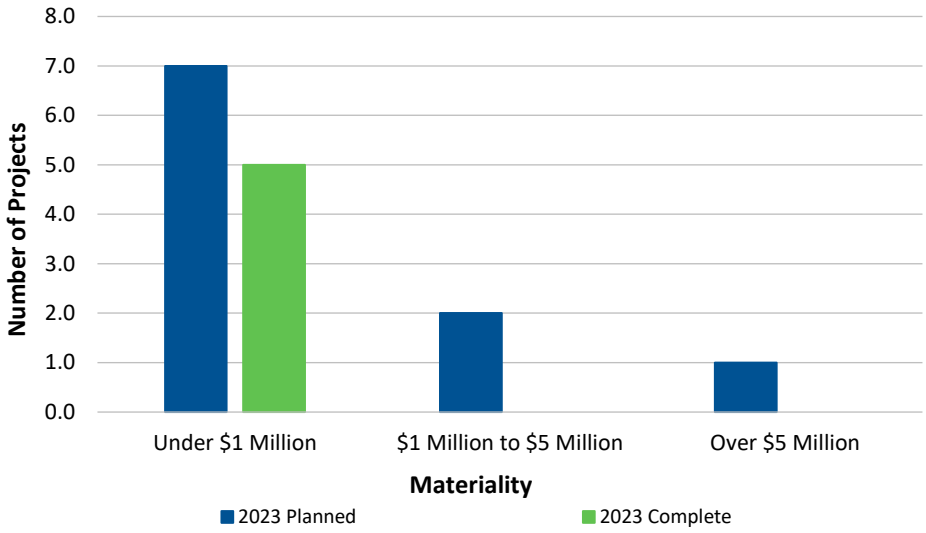


Chart 8: Planned vs. Completed Projects – Service Enhancements

Mandatory

Table 8: Planned vs. Completed Projects – Mandatory[25]

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Projects	Completed Projects	Planned Projects	Completed Projects	Planned Projects	Completed Projects
2023	0	0	0	0	0	0

[25] As there were no projects in the Mandatory Investment Classification for 2023, no corresponding chart has been provided.

4.1.2 Budget versus Actual Expenditures by Year and Materiality Threshold

In this section, Hydro will provide tables and graphical representations, both in aggregate and for each Investment Classification, of the planned budget versus actual expenditure for completed projects by materiality threshold. The actual expenditures for projects in these tables include total expenditures across all years of the projects. Major drivers of project variances are discussed in Section 2.0 and detailed discussion of variances exceeding $100,000 and 10% are provided in Section 5.0.

Table 9: Budget vs. Actual Expenditures – Completed Projects – Aggregate ($000)[26]

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures
2023	9,406	10,470	12,816	17,834	0	0

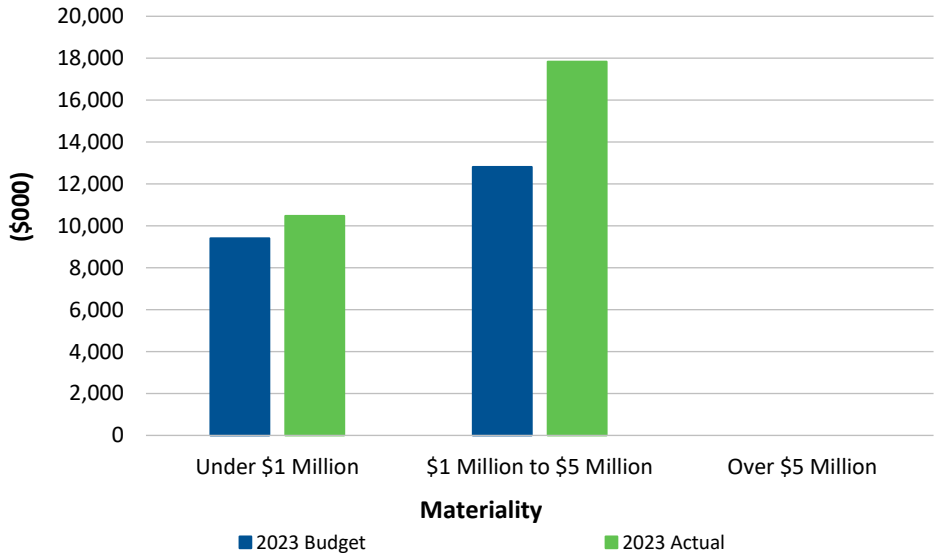


Chart 9: Budget vs. Actual Expenditures – Completed Projects – Aggregate

[26] Numbers may not add due to rounding.

Renewal

Table 10: Budget vs. Actual Expenditures – Completed Projects – Renewal

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures
2023	6,875	7,480	11,680	16,349	0	0

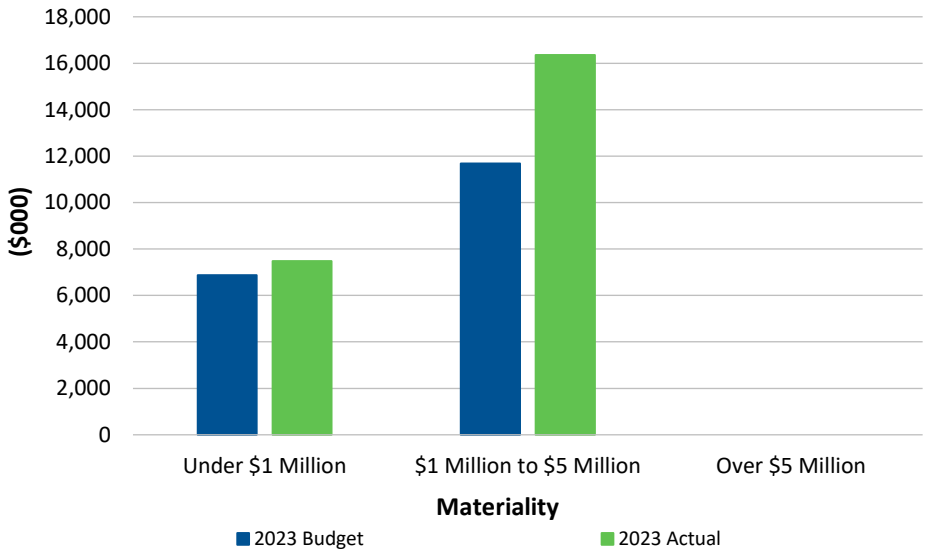


Chart 10: Budget vs. Actual Expenditures – Completed Projects – Renewal

General Plant

Table 11: Budget vs. Actual Expenditures – Completed Projects – General Plant

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures
2023	857	1,166	1,136	1,485	0	0

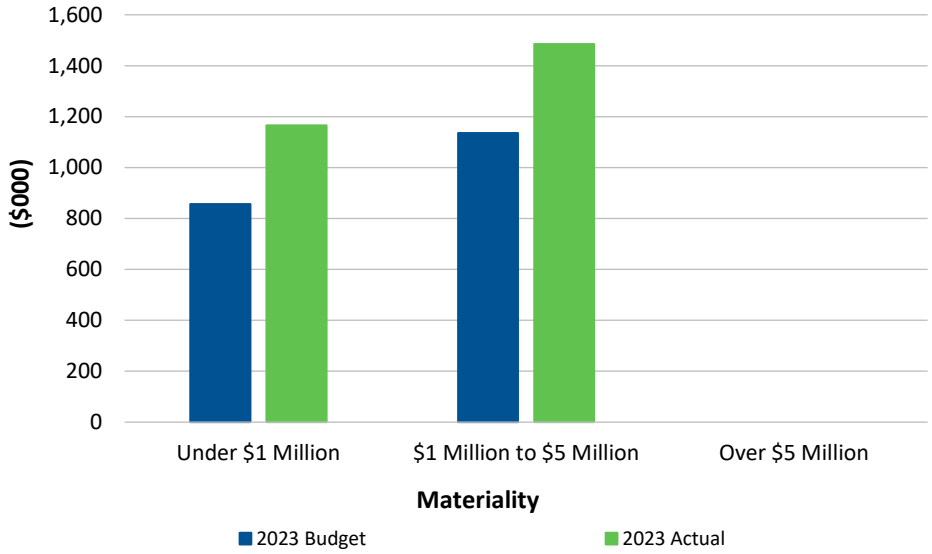


Chart 11: Budget vs. Actual Expenditures – Completed Projects – General Plant

System Growth

Table 12: Budget vs. Actual Expenditures – Completed Projects – System Growth[27]

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures
2023	0	0	0	0	0	0

Access

Table 13: Budget vs. Actual Expenditures – Completed Projects – Access

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures
2023	227	203	0	0	0	0

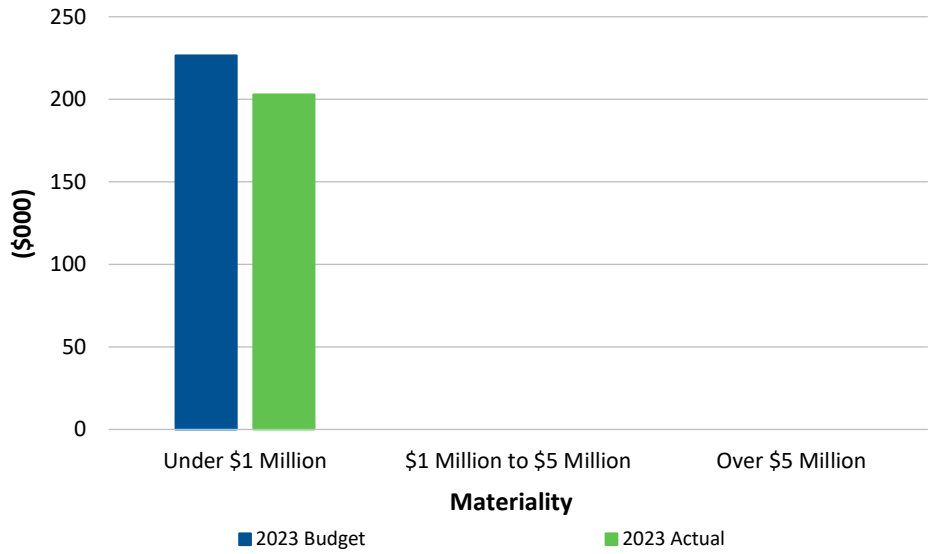


Chart 12: Budgets vs. Actual Expenditures – Completed Projects – Access

[27] As there were no projects completed in 2023 in the System Growth Investment Classification, no corresponding chart has been provided.

Service Enhancements

Table 14: Budget vs. Actual Expenditures – Completed Projects – Service Enhancements

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures
2023	1,448	1,620	0	0	0	0

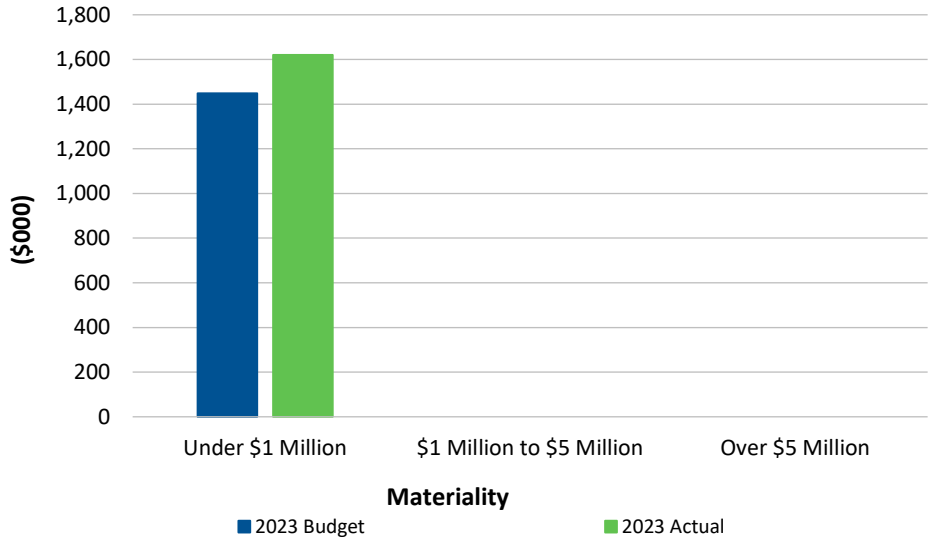


Chart 13: Budget vs. Actual Expenditures – Completed Projects – Service Enhancements

Mandatory

Table 15: Budget vs. Actual Expenditures – Completed Projects – Mandatory[28]

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures	Total Budget	Actual Expenditures
2023	0	0	0	0	0	0

[28] As there were no projects in 2023 in the Mandatory Investment Classification, no corresponding chart has been provided.

4.2 Program Key Performance Indicators

Planned versus completed units and budget versus actual weighted average unit costs for programs beginning in 2023 are presented in Sections 4.2.1 and 4.2.2, respectively.[29] Some programs do not lend themselves to unitization,[30] despite otherwise meeting the definition of a program; therefore they are excluded from the program KPIs herein. These programs are:

- Perform Software Upgrades and Minor Enhancements (2023);
- Upgrade Core OT Infrastructure (2023);
- Update Cyber Security Infrastructure (2023);
- Overhaul Unit 2 Turbine and Valves (2023) – Holyrood;
- Diesel In-Service Failures (2023);
- Gas Turbine In-Service Failures (2023);
- Transmission In-Service Failures (2023);
- Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2023);
- Boiler Condition Assessment and Miscellaneous Upgrades (2023) – Holyrood;
- Wood Pole Line Management Program (2023);
- Thermal In-Service Failures (2023);
- Hydraulic In-Service Failures (2023);
- Terminal Station In-Service Failures (2023);
- Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condensers 1 and 2 (2023–2024) – Wabush Terminal Station;
- Provide Service Extensions (2023);
- Remove Safety Hazards (2023); and
- Upgrade Worst-Performing Distribution Feeders (2023–2024).

[29] KPI data is not available for programs that were proposed prior to the implementation of the Provisional Guidelines.
[30] Programs that do not lend themselves to unitization include those with undefined scopes, scopes that change materially year to year, or scopes that are not made up of discrete components.

In total, Hydro completed the installation or refurbishment of 503 units, compared to 394 planned units in 2023. The additional units completed are attributed primarily to greater than anticipated replacements for mobile devices and personal computers.

4.2.1 Planned versus Completed Units by Year and Materiality Threshold

In this section, Hydro will provide table and graphical representations, both in aggregate and for each Investment Classification,[31] of the planned number of units versus the actual number of units completed by year and materiality threshold.

Table 16: Planned vs. Completed Program Units – Aggregate

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Units	Completed Units	Planned Units	Completed Units	Planned Units	Completed Units
2023	341	450	53	53	0	0

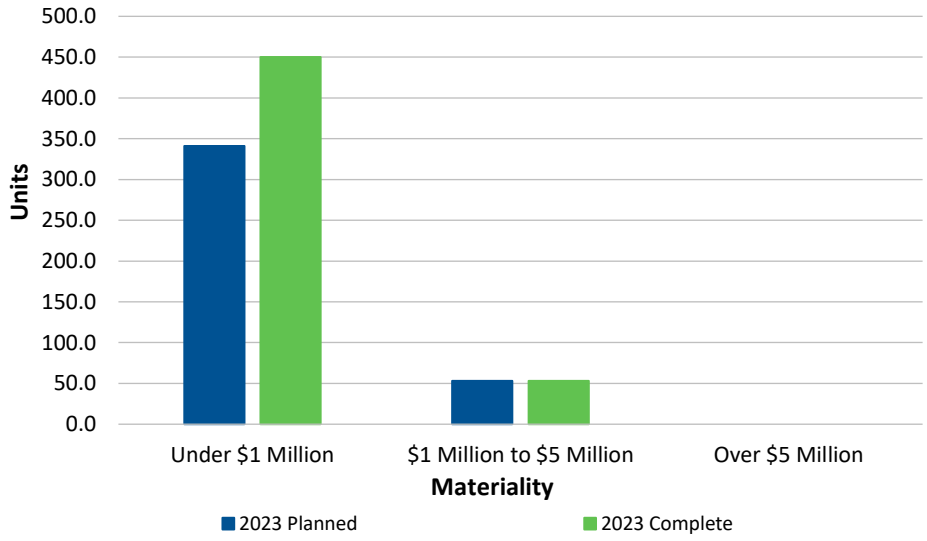


Chart 14: Planned vs. Completed Program Units – Aggregate

[31] As detailed in Section 4.2, some programs do not lend themselves to unitization and have been excluded from the program KPIs herein; as such, no data was available for the System Growth, Access, Service Enhancement, and Mandatory Investment Classifications.

Renewal

Table 17: Planned vs. Completed Program Units – Renewal

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Units	Completed Units	Planned Units	Completed Units	Planned Units	Completed Units
2023	31	34	14	15	0	0

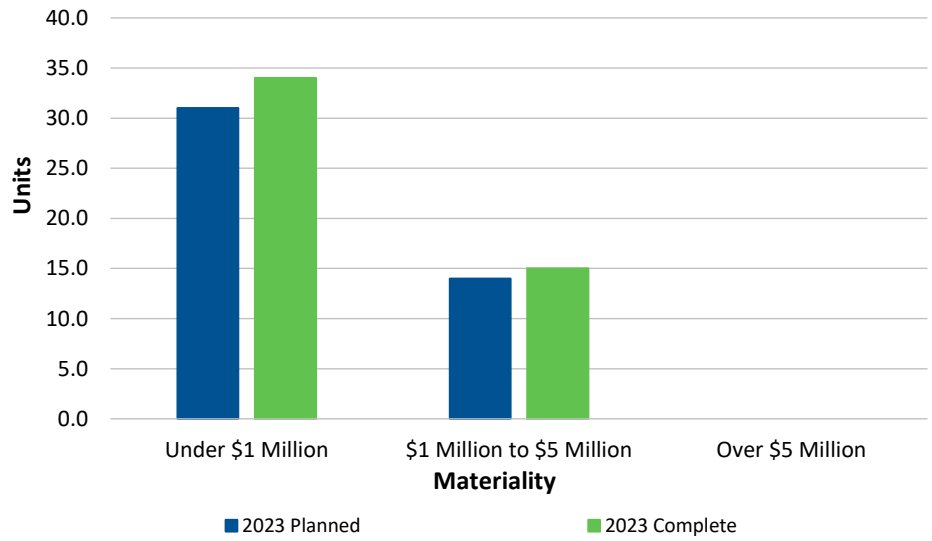


Chart 15: Planned vs. Completed Program Units – Renewal

General Plant

Table 18: Planned vs. Completed Program Units – General Plant

	Under $1 Million		$1 Million to $5 Million		Over $5 Million	
Year	Planned Units	Completed Units	Planned Units	Completed Units	Planned Units	Completed Units
2023	310	416	39	38	0	0

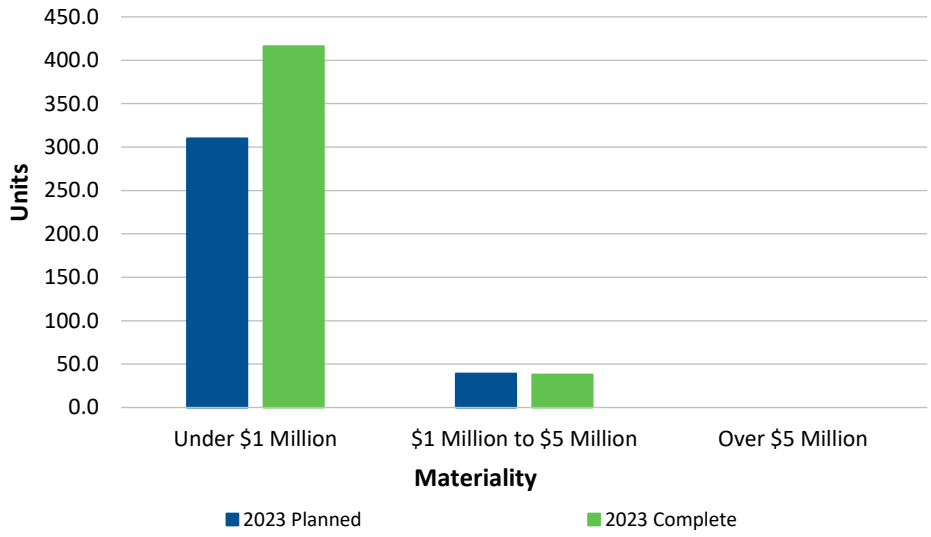


Chart 16: Planned vs. Completed Program Units – General Plant

4.2.2 Estimated versus Actual Weighted Average Unit Cost

In this section, Hydro will provide table and graphical representations, both in aggregate and for each Investment Classification,[32] of the estimated weighted average unit cost versus the actual weighted average unit cost by year. The primary drivers of lower weighted average unit costs were lower than anticipated unit costs for personal computers, peripheral infrastructure, and instrument transformers.

Table 19: Estimated vs. Actual Weighted Average Unit Cost – Aggregate ($000)

Year	Estimated Weighted Average Unit Cost	Actual Weighted Average Unit Cost
2023	24.1	21.0

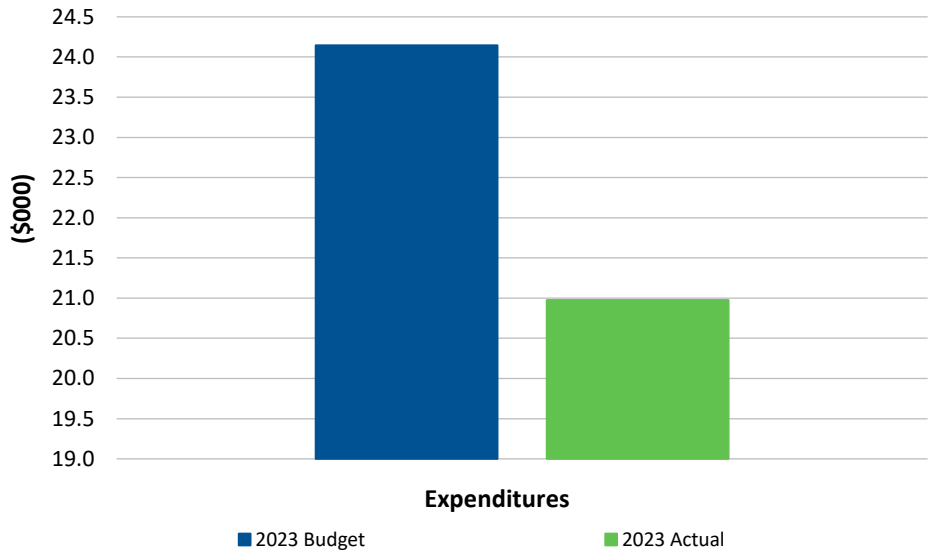


Chart 17: Estimated vs. Actual Weighted Average Unit Cost – Aggregate

[32] As detailed in Section 4.2, some programs do not lend themselves to unitization and have been excluded from the program KPIs herein; as such, no data was available for System Growth, Access, Service Enhancement, and Mandatory Investment Classifications.

Renewal

Table 20: Estimated vs. Actual Weighted Average Unit Cost – Renewal ($000)

Year	Estimated Weighted Average Unit Cost	Actual Weighted Average Unit Cost
2023	123.3	134.5

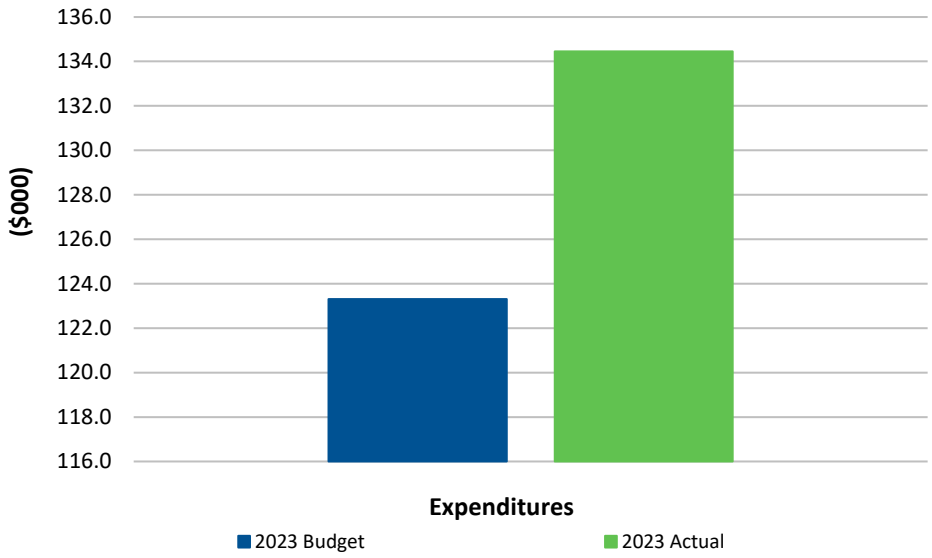


Chart 18: Estimated vs. Actual Weighted Average Unit Cost – Renewal

General Plant

Table 21: Estimated vs. Actual Weighted Average Unit Cost – General Plant ($000)

Year	Estimated Weighted Average Unit Cost	Actual Weighted Average Unit Cost
2023	11.4	8.7

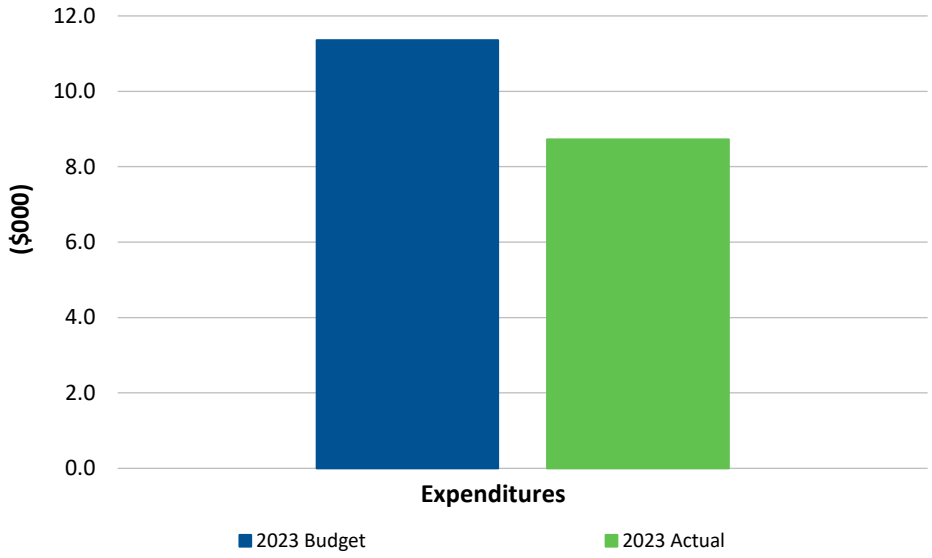


Chart 19: Estimated vs. Actual Weighted Average Unit Cost – General Plant

5.0 Variance Explanations

As per the Provisional Guidelines set forth by the Board, Hydro is required to report on actual capital expenditure variances that exceed the approved total program or project budget by more than 10% and $100,000. Hydro has also included variance explanations for projects or programs continuing beyond 2023 with forecast variances exceeding the threshold, and for 2023 programs or projects where expenditures exceeded the approved 2023 budget by more than 10% and $100,000. For multi-year projects and programs, annual and overall variances are reported.[33] For programs and projects budgeted under $750,000, Hydro has included variance explanations if the actual expenditures

[33] In cases where actual expenditures of only one of the annual and overall project/program budgets meets the reporting thresholds (exceeding the budget by 10% and 100,000), only the applicable variance includes an explanation. Numbers may not add due to rounding.

exceeded $750,000. The programs and projects are ordered in the sections below based on the order they appear in the tables found in Appendix A.

5.1 Renewal

5.1.1 In-Service Failures (2023)[34]

Program	Budget ($000)	Expenditures ($000)	Variance ($000)
Gas Turbine	344.2	3,606.8	3,262.6
Hydraulic	1,500.0	4,081.1	2,581.1
Thermal	3,300.0	2,887.8	(412.2)
Diesel	480.4	727.2	246.8
Terminal Station	1,300.0	2,846.7	1,546.7
Distribution	3,986.0	6,029.1	2,043.1
Transmission	151.7	193.6	41.9
Total	**11,062.3**	**20,372.3**	**9,310.0**

In-Service Failures are one-year programs (2023) that closed in 2023. The scope of these programs includes 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 assets, and included the procurement of capital spares required to support such work.[35] Budget estimates for In-Service Failure programs are based on historical averages, along with Hydro's experience and engineering judgement. As many of these programs are new or have been introduced in recent years and have limited historical data, Hydro expects that it may take several years of implementation to determine an appropriate baseline estimate for annual in-service failure expenditures. The variances in 2023 and expenditures are primarily attributed to more scopes of work required in 2023 than anticipated at the time of the original budget estimates and the nature of failures in 2023 requiring more material expenditure to address. Hydro experienced a number of failures necessitating material investment in 2023; further detail on material expenditures for In-Service Failure programs is provided in Appendix B.

[34] While some individual In-Service Failure programs did not meet the threshold for reportable variance, all 2023 In-Service Failures programs are listed herein for completeness.
[35] The Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights program also includes distribution system upgrades and the installation of LED street lights in addition to in-service failures.

5.1.2 Replace Powerhouse Station Service Panel (2023–2024) – Upper Salmon

Variance Type	Budget ($000)	Expenditures and Forecast ($000)	Variance ($000)
Annual	591.8	883.3	291.5
Project	1,568.5	2,111.5	543.0

This is a two-year project (2023–2024) that commenced in 2023. The project scope includes the replacement of the Upper Salmon 600 V station service panel due to obsolescence. The variance in 2023 and overall project expenditures is attributed to contract pricing to procure the replacement station service panel that was higher than the original budget estimate.

5.1.3 Overhaul Pumps (2023) – Holyrood

Variance Type	Budget ($000)	Expenditures ($000)	Variance ($000)
Annual	742.4	1,429.9	687.5
Program	742.4	1,429.9	687.5

This was a one-year program (2023) that closed in 2023. The program scope was to overhaul the Unit 2 West Cooling Water Pump and the Unit 2 West Boiler Feed Pump. The variance in 2023 and overall program expenditures is attributed to the extent of the required pump refurbishment work. The original program budget was based on historical pump overhaul expenditures. The extent of the pump overhauls can only be determined after the pumps are removed from service and disassembled for inspection during the program execution. In this case, the extent of refurbishment following the disassembly of the pumps was greater than originally estimated.

5.1.4 Overhaul Unit 2 Turbine and Valves (2023) – Holyrood

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Program	9,701.8	11,368.4	1,666.6

This is a one-year program (2023) that has carried over into 2024. The program scope is to overhaul the Unit 2 turbine and valves and complete electrical testing on the generator. The variance in the overall program forecast is attributed to the extent of the turbine rotor refurbishment work that was required

following unit disassembly and inspection of the rotor at the OEM's facility. The inspection revealed cracks on the low-pressure turbine blades that required the purchase and installation of a new set of blades. The original program budget was based on historical turbine and valve overhaul expenditures. The extent of the turbine and valve overhaul costs can only be determined after the unit is removed from service and disassembled for inspection, during the program execution. In this case, the extent of the required refurbishment was greater than originally estimated. The turbine rotor was overhauled at the OEM facility and returned to the Holyrood TGS in 2023. The remainder of the program scope is expected to be completed in the second quarter of 2024.

5.1.5 Boiler Condition Assessment and Miscellaneous Upgrades (2023) – Holyrood

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	2,926.6	4,336.4	1,409.8
Program	2,926.6	4,336.4	1,409.8

This was a one-year program (2023) that closed in 2023. The program scope was to perform a Level 2 Condition Assessment on the internal components of the boilers and associated high-energy piping and to complete refurbishment and replacement work required prior to the 2023–2024 winter operating season. The variance in 2023 and overall program expenditures is attributed to the extent of the required boiler refurbishment work. Upon disassembly and assessment of the boilers, the level of necessary refurbishment was greater than anticipated at the time of the original budget estimate.[36]

5.1.6 Circuit Breakers Renewal Program (2023–2024)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	216.9	633.8	416.9

[36] A summary of work executed that was not originally anticipated in the program scope is included in Appendix B.

This is a two-year program (2023–2024) that commenced in 2023. The program scope includes circuit breaker replacements and refurbishments at a number of terminal stations. The variance in 2023 expenditures is attributed to:

- An unplanned circuit breaker refurbishment that was required to be completed at the Howley Terminal Station, due to its deteriorated condition; and
- Early procurement of one of the circuit breakers required for Bay d'Espoir, which was originally planned to be received in 2024.

5.1.7 Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023–2024) – Wabush Terminal Station

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	577.2	692.3	115.1

This is a two-year program (2023–2024) that commenced in 2023. The program scope is to complete a level II condition assessment on the internal components of Synchronous Condensers 1 and 2 at the Wabush Terminal Station and to complete refurbishment activities identified from the condition assessments that are deemed necessary to support continued safe and reliable operation. The variance in 2023 expenditures is attributed to additional refurbishment activities that were recommended by the OEM and completed in 2023.[37]

5.1.8 Wood Pole Line Management Program (2023)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	2,824.4	5,085.8	2,261.4
Program	2,824.4	5,085.8	2,261.4

This was a one-year program (2023) that closed in 2023; it is part of the annual program for the inspection, refurbishment, or replacement of wood pole transmission line components, including poles, structures, hardware, and conductors. The variance in 2023 and overall program expenditures is

[37] A summary of work executed that was not originally anticipated in the program scope is included in Appendix B.

primarily attributed to environmental mitigation activities that were required for access to TL234 and TL233 to complete the planned scope of work. The amount and depth of bog and wetlands requiring mitigation were significantly higher than originally anticipated. Also contributing to the variance, more components on TL201 and L1303 required immediate replacement than anticipated at the time of the original budget estimate.

5.1.9 Upper Salmon Hydroelectric Generating Station Rotor Rim Shrinking and Stator Recentering (Supplemental)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	3,276.9	8,423.8	5,146.8
Project	3,999.8	9,146.6	5,146.8

This is a two-year supplemental project (2022–2023) that was completed in 2023. The project scope was to complete a rotor rim shrinking and stator recentering of the Upper Salmon unit generator stator and rotor assemblies. The variance in 2023 and overall project expenditures 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;[38]
- 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 recertification of the powerhouse crane and lifting device, required for the 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;[39] and

[38] Further discussion of this issue was provided in Hydro's response to request for information PUB-NLH-026, as part of the "2024 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 21, 2023. http://pub.nl.ca/applications/NLH2024Capital/responses/PUB-NLH-026.PDF

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

- Additional scopes of work that were identified following disassembly and inspection of the unit, including rotor refurbishment, rotor pole removal and cleaning, stator refurbishment, and generating unit re-alignment.

5.1.10 Holyrood Inspect and Refurbish Day Tank (Supplemental)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	757.4	902.3	144.9
Program	797.2	942.1	144.9

This was a two-year supplemental program (2022–2023) that closed in 2023. The program scope was to clean, inspect, and refurbish the fuel oil day tank at the Holyrood TGS. The variance in 2023 and overall program expenditures is attributed to additional inspections that were completed on the day tank prior to returning the tank to service. The additional inspections were undertaken to further mitigate risk, following lessons learned from a leak that occurred in 2023 on a different fuel oil storage tank.

5.1.11 Holyrood Fuel Tank 1 Inspection and Refurbishment (Supplemental)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	1,021.5	2,628.6	1,607.1
Program	2,052.1	3,850.0	1,797.9

This is a two-year supplemental program (2022–2023) that has carried over into 2024. The program scope is to clean, inspect, and refurbish a fuel oil storage, Tank 1, at the Holyrood TGS. The variance in 2023 and the overall program forecast is attributed to more cleaning, inspection, and refurbishment work required than was anticipated at the time of the original budget estimate. A leak was identified in Tank 1 during the initial filling following the planned cleaning, inspection, and refurbishment work. This required the removal of fuel from the tank and additional cleaning, inspection, and refurbishment work. Soil remediation was also required as a result of the leak. Additional tank inspections have been completed and refurbishment work is expected to be completed in the second quarter of 2024.

5.1.12 Refurbish Ebbegunbaeg Control Structure

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	3,447.2	3,923.6	476.4

This is a four-year project (2021–2024) that commenced in 2021. The project scope is to refurbish the three water control gates and associated equipment at the Ebbegunbaeg Control Structure. The variance in 2023 expenditures is attributed to higher-than-originally-estimated contractor pricing for construction work completed in 2023 for one of the three gates and associated equipment.

5.1.13 Upgrade Distributed Control System Hardware – Holyrood

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	205.2	340.2	135.0
Project	728.6	863.6	135.0

This was a two-year project (2021–2022) that carried over and was completed in 2023. The project scope was to replace the distributed control system hardware, including processors, servers, computer stations, and network communications equipment for the Unit 3 Synchronous Condenser, Station Service, and the Wastewater Treatment Plant systems at the Holyrood TGS. The variance in 2023 and overall project expenditures is attributed to the additional engineering and construction effort required to replace the network communications equipment for the upgrades of the Unit 3 Synchronous Condenser and Station Service systems. The original estimate assumed that the network communications equipment could be replaced *in situ* but an alternative centralized location was required to ensure accessibility of the equipment for future maintenance.

5.1.14 Diesel Genset Replacements (2021–2022)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	131.7	382.2	250.5

This is a two-year program (2021–2022) that has carried over into 2024. The program scope is to replace a diesel genset and upgrade associated mechanical, electrical, and protection and control equipment at the Nain Diesel Generating Station. The program is substantially complete with most planned assets in service. A portion of the plant automation work carried over to 2024 due to internal protection and control resources in 2022 and 2023 being dedicated to higher-priority work. The variance in 2023 expenditures is attributed to the costs associated with carrying the program an additional year and delays associated with resource constraints and program team turnover.

5.1.15 Upgrade Circuit Breakers (2021–2023) – Various[40]

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	280.7	777.0	496.3

This was a three-year program (2021–2023) that closed in 2023. The program scope included circuit breaker replacements and refurbishments at a number of terminal stations. The variance in 2023 expenditures is attributed to an engineering and construction effort that was greater than anticipated to complete the remaining program scope. Although 2023 expenditures were greater than the 2023 budget, the overall program was completed for less than the approved budget.

5.1.16 Replace Elevator Motors and Control Equipment – Hydro Place

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Project	736.7	964.6	227.9

[40] This program was originally proposed as a two-year program (2021–2022) as part of the "2021 Capital Budget Application," Newfoundland and Labrador Hydro, rev. November 2, 2020 (originally filed August 2, 2020), vol. II, Tab 10. http://pub.nl.ca/applications/NLH2021Capital/applications/From%20NLH%20-%202021%20Capital%20Budget%20Application%20-%20Volume%20II%20-%20Revision%202%20-%202020-11-02.PDF
The schedule was then updated as a three-year program (2021–2023) as part of the "2022 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 17, 2021, vol. II, Tab 18. http://pub.nl.ca/applications/NLH2022Capital/applications/From%20NLH%20-%202022%20Capital%20Budget%20Application%20-%20Volume%20II%20-%20Revision%201%20-%202021-09-17.PDF
The three-year program was approved as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 37(2021), Board of Commissioners of Public Utilities, December 20, 2021.

This was a two-year project (2021–2022) that carried over and was completed in 2023. The project scope was to replace motors and control equipment for the two elevators at Hydro Place. The variance in overall project expenditures is attributed to additional required upgrades to the elevator equipment, necessitated by updated building code requirements.

5.1.17 Hydraulic Unit Overhauls Program (2023)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	975.7	1,289.4	313.7
Program	975.7	1,289.4	313.7

This is a one-year program (2023) that closed in 2023. The scope of this program was to partially dismantle Bay d'Espoir Unit 3 and Unit 1 at the Cat Arm Hydroelectric Generating Station ("Cat Arm") to inspect, test, clean, refurbish, and replace defective components of the generating units, as required based on information from the maintenance records for the units. The variance in 2023 and overall program expenditures is attributed to:

- Higher–than-budgeted internal labour costs to complete the overhaul activities on Unit 3 at the Bay d'Espoir Hydroelectric Generating Facility; and,
- A requirement to replace the Cat Arm Unit 1 draft tube access platform, which was not identified at the time of the original budget estimate.

5.1.18 Replace Transformer T7 – Holyrood

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	2,244.0	3,016.5	772.5
Project	2,678.1	4,450.7	1,772.6

This is a one-year project (2020) that has extended into 2024. The project scope is to replace a transformer at the Holyrood TGS, T7, with a transformer to be removed from the Churchill Falls Switchyard, T31, and complete associated civil and protection and control upgrades. The removal of the

old T7 and its foundation and the installation of a new concrete pad and oil containment system were completed in 2020.

As a result of Hydro's decision to maintain L1301 as a backup for the Muskrat Falls to Happy Valley Interconnection for the winter of 2020–2021, T31 was not available in 2020 to replace 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 to Happy Valley Interconnection, T31 again was not available to replace T7. As Hydro intended to continue to maintain L1301 as a backup supply for the 2021–2022 winter 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. After investigating several other options for transporting the transformer in the fall of 2022, it was decided to delay to a more favourable time of year in 2023 and allow further investigation of more economical options. The transportation route was finalized and transport of T31 to Holyrood was completed in 2023.

Hydro suffered a tragic incident at the Holyrood Terminal Station in August 2023, resulting in a workplace fatality; as a result, some remaining construction and commissioning activities at the Holyrood TGS have carried over into 2024.

The variances in 2023 and overall project expenditures are attributed to higher-than-originally estimated transformer transportation costs.

5.2 General Plant

5.2.1 Replace Light- and Heavy-Duty Vehicles (2023-2025)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	1,308.1	2,573.2	1,265.1

This is a three-year program (2023–2025) that commenced in 2023. The program scope is to procure 39 light-duty vehicles and 6 heavy-duty vehicles. The variance in 2023 annual expenditures is attributed to the unexpected early receipt of light-duty vehicles, which were originally expected in 2024.

5.2.2 Replace Underground Firewater Distribution System – Holyrood

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Project	1,706.3	3,066.8	1,360.5

This is a two-year project (2022–2023) that has carried over into 2024. The project scope is to replace the underground firewater distribution system that protects the buildings and terminal station at the Holyrood TGS. The variance in the overall project forecast is attributed to higher-than-originally-estimated contract pricing to replace the system. As there are no viable alternatives for this project, Hydro is proceeding with execution. The project carried over into 2024, as the design took longer than originally anticipated.

5.2.3 Replace Transfer Switches and Associated Hardware – Hydro Place

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	1,099.0	1,298.5	199.5
Project	1,135.9	1,485.3	349.5

This was a two-year project (2021–2022) that carried over and was completed in 2023. The project scope was to replace automatic transfer switches and associated hardware required for the provision of backup power to the Energy Control Centre and other critical loads within Hydro Place. The variances in 2023 and overall project expenditures are attributed to project management, engineering, procurement, and construction costs that exceeded the original budget estimate, primarily due to unforeseen complexities of the project scope and schedule. Specifically, the following contributed to additional expenditures:

- An arc-flash energy review of the detailed design identified a requirement to upgrade four circuit breakers, that was not anticipated at the time of the original budget estimate;
- Construction and commissioning were scheduled over several weekend and evening outages, to minimize disruption and risk to critical information and operational technology systems; and
- A price escalation of industrial goods due to global supply chain challenges since the preparation of the original budget estimate.

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

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Program	3,208.9	4,055.1	846.2

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

5.3 System Growth

5.3.1 Wabush Terminal Station Upgrades

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	6,232.9	7,992.3	1,759.4

This is a four-year project (2021–2024)[41] that commenced in 2021. The project scope includes the replacement of Transformers T4 and T5 and the addition of a new capacitor bank to support Hydro's ability to provide firm supply for customers in accordance with the criteria established for the transmission system in Western Labrador. The variance in 2023 expenditures is attributed to the civil and electrical construction contract and the T5 replacement construction contract costs exceeding the original budget estimate.

5.4 Access

5.4.1 Provide Service Extensions (2023)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	3,964.0	4,573.7	609.7
Program	3,964.0	4,573.7	609.7

[41] This project was originally proposed as a three-year project (2021–2023) as part of the 2021 Capital Budget Application. The project schedule was then updated and approved as a four-year project (2021–2024) as part of the 2022 Capital Budget Application.

This is an annual project to provide service extensions to customers. The budget is based on historical data from each region. The variance in 2023 was primarily the result of higher market pricing for materials, per service extension completed.

5.5 Service Enhancement

5.5.1 Upgrade Public Safety Around Dams and Waterways (2023)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	482.1	795.5	313.4
Program	482.1	795.5	313.4

This was a one-year program (2023) that closed in 2023. The variance in the 2023 and overall program expenditures is attributed to increased contractor costs associated with installing safety boom anchors at the Granite Canal Hydroelectric Generating Station ("Granite Canal"). The original budget estimate assumed that boom anchors could be installed in bedrock. During the detailed engineering design, it was determined that there was inadequate bedrock and that concrete block anchors were required. The increased cost was primarily associated with the placement of the concrete anchors, which included the cost of a crane rental and road upgrades that were necessary for the crane to gain site access.

5.5.2 Upgrade of Worst-Performing Distribution Feeders (2023–2024)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	73.4	671.7	598.3

This is a two-year program (2023–2024) that commenced in 2023. The program scope is to upgrade a distribution feeder and relocate a section of distribution line in the Farewell Head Distribution System. The variance in 2023 expenditures is attributed to a change in the program execution strategy. Installation of the poles and anchors was advanced from 2024 to 2023 and was completed by a contractor. By executing this work in 2023, Hydro has more schedule flexibility to complete the remaining scope in 2024 with internal forces.

5.5.3 Upgrade of Worst-Performing Distribution Feeders (2022–2023)

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	1,911.1	2,190.7	279.6
Program	2,772.9	3,052.5	279.6

This was a two-year program (2022–2023) that closed in 2023. The program scope was to upgrade distribution feeders and widen right-of-ways located in the Bottom Waters Distribution System. The variance in 2023 and overall program expenditures is attributed to more poles and crossarms requiring replacement than anticipated at the time of the original budget estimate.

5.5.4 Winterize Unit 2102 and Install Mobile – Charlottetown (Supplemental)[42]

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Annual	1,109.1	1,390.0	280.9
Project	1,314.7	1,639.7	325.0

This is a supplemental project that commenced in 2022 and has carried over to 2024. The project scope is to perform upgrades to improve reliability of service for the communities of Charlottetown and Pinsent's Arm in Labrador. The variances in 2023 and the overall project forecast are attributed to:

- More extensive refurbishment is required than originally anticipated for the mobile genset purchased from the Lower Churchill Project (Unit 2108);
- A requirement to purchase and install a new silencer for Unit 2108, to ensure that the unit operates properly with the required exhaust stack height, was not anticipated at the time of the budget estimate;
- Unanticipated environmental assessment costs, which included multiple iterations of emissions modelling to meet environmental permitting requirements;

[42] "Application for Approval of Capital Expenditures Necessary to Address Supply in Charlottetown and Pinsent's Arm, Labrador," Newfoundland and Labrador Hydro, October 7, 2022. http://pub.nl.ca/applications/NLH2022Capital/NLH2022Capital_SUPP_SupplyCharlottetown/app/From%20NLH%20-%20Approval%20of%20Capital%20Expenditures%20Necessary%20to%20Address%20Supply%20in%20Charlottetown%20and%20Pinsent%E2%80%99s%20Arm,%20Labrador%20-%202022-10-07.PDF

- Additional engineering and project management costs are required to source a suitable new transformer for Unit 2108; and
- Inefficiencies related to multiple unit failures on site and requirements to change project plans to accommodate repairs and response work.

The project construction was completed in 2023 with the exception of the replacement of the transformer for Unit 2108. Delivery of the new transformer was delayed and its installation is now planned for 2024. The change will not impact reliability of service, as a rental transformer installed on site will remain until the new transformer is installed and placed in service.

5.5.5 Upgrades for Future Retirement of Stephenville Gas Turbine

Variance Type	Budget ($000)	Actual Expenditures ($000)	Variance ($000)
Project	6,874.9	7,661.4	786.5

This is a two-year project (2021–2022) that commenced in 2021 and has carried 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 decommissioning of Stephenville Gas Turbine. The variance in the overall project forecast is attributed to higher-than-originally budgeted costs for the civil and electrical construction contracts. However, Hydro is expecting to finalize a decision in 2024 to cancel most of the remaining scope of this project, as the planned retirement of Stephenville Gas Turbine has been deferred beyond 2024. If any of the cancelled scope is deemed to be required in future years, it will be included in a future capital budget application.

5.6 Mandatory

There are no reportable variances for projects and programs in the Mandatory Investment Classification.

5.7 Allowance for Unforeseen

Hydro did not identify any work in 2023 that necessitated the use of the Allowance for Unforeseen Items Account.

6.0 Lease/Purchase Approval Approach

Hydro did not execute any capital leases in 2023.

7.0 Carryover Report

In 2023, Hydro carried over $21.9 million of budget to future years; this includes a carryover of $13.5 million associated with the deferred completion of scopes planned for completion in 2023 to a future year and $8.4 million associated with reallocation of cost-flow within the years of approved projects and programs. Chart 20 shows Hydro's capital carryover for the years 2014–2023. For comparison, the average carryover amount for the previous nine years 2014–2022 was $28.2 million.

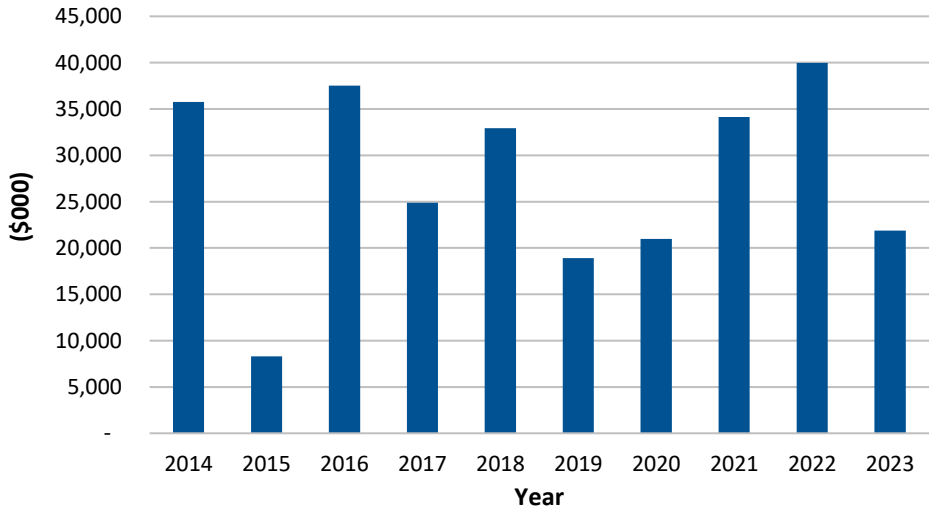


Chart 20: Carryover by Year (2014–2023)

Hydro's 2023 carryover was primarily driven by deferral of project scopes and re-pacing of programs, which were primarily driven by supply chain challenges and strategic carryover of work to future years, as detailed in Section 2.0.

8.0 Conclusion

Hydro's 2023 capital expenditures totalled $148.9 million. Actual expenditures in Hydro's overall capital campaign for 2023 were over budget by 1.7%, or $2.5 million. Projects and programs that exceeded their individual 2023 approved budgets were largely offset by projects and programs that underspent

their individual 2023 approved budgets. The primary driver of over-expenditure in 2023 was replacement or refurbishment associated with a greater-than-anticipated asset failure.

Hydro proposes projects and programs required to maintain safe, reliable, least-cost service to its customers, in an environmentally responsible manner. Hydro strives to execute all approved scopes of work when they are required and inevitably experiences some carryover of work each year. Hydro utilizes established project management practices and procedures to monitor, control, and manage this carryover. These practices and procedures incorporate continual improvement methodologies to ensure that lessons learned are captured and leveraged.

In 2023, Hydro carried over $21.9 million of budget to future years, 22% lower than the previous nine-year carryover average of $28.2 million. As detailed in this report, Hydro completed an analysis of 2023 capital expenditures and concluded that the carryover of work to future years was the primary driver of 2023 under-expenditure. Two main themes related to carryover were identified:

1) Strategic deferral of work; and

2) Supply chain challenges resulting in delays in receiving equipment.

As part of its annual work planning cycle, in the early part of the calendar year, Hydro determines the risk associated with a one-year delay in completing each capital program and project work scope. This allows Hydro to minimize the risk of carryover if constraints prevent Hydro from executing all planned work. Hydro utilizes an established project change management process to identify the impacts of carryover and to develop temporary mitigation plans to reduce the impact where possible until the work can be completed. As such, none of the projects or programs carried over into 2024 represent a significant risk to the supply of electricity to customers. Hydro continues to review its capital budget planning and execution methodologies and use its expenditures analysis to identify opportunities that may contribute to reduced capital expenditure variances in future years.

Appendix A

Financial Schedules



2023 Capital Expenditures By Year
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Year	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	2024 and Beyond	Project Carryover	Multi-Year Cash Flow Reallocation	Total	Project		Annual	
2023	-	-	-	(0.00)	51,941.82	51,941.82	96,958.42	**148,900.24**	(0.00)	0.00	(0.00)	57,770.44	96,958.42	2,138.38	2,034.60	**158,901.84**	10,001.60	6.72%	5,828.62	11.22%
2022	-	-	17,805.11	2,403.15	47,842.24	50,245.39	3,631.00	**69,278.35**	(0.00)	0.00	12,788.77	52,367.80	3,631.00	4,127.31	6,915.38	**79,830.26**	10,551.90	15.23%	2,122.41	4.22%
2021	-	31,462.31	40,966.60	21,908.84	6,041.60	27,950.44	14,796.20	**93,266.71**	-	15,691.73	31,260.21	24,871.03	14,796.20	4,152.38	(599.54)	**90,172.01**	(3,094.71)	-3.32%	(3,079.40)	-11.02%
2020	5,064.18	9,406.15	14,709.10	15,678.79	586.36	16,265.15	-	**29,765.78**	885.50	2,475.75	12,288.37	13,866.88	-	3,110.79	-	**32,627.28**	2,861.50	9.61%	(2,398.27)	-14.74%
Total	**5,064.18**	**40,868.46**	**73,480.81**	**39,990.78**	**106,412.02**	**146,402.80**	**115,385.62**	**341,211.09**	**885.50**	**18,167.48**	**56,337.34**	**148,876.15**	**115,385.62**	**13,528.86**	**8,350.43**	**361,531.38**	**20,320.29**		**2,473.35**	

2023 Capital Expenditures By Asset Category
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Asset Category	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	2024 and Beyond	Project Carryover	Multi-Year Cash Flow Reallocation	Total	Project		Annual	
Hydraulic Plant	-	9,806.36	12,173.90	1,405.86	17,533.50	18,939.36	60,945.40	**100,459.16**	-	5,836.64	14,256.45	26,307.47	60,945.40	300.93	1,132.50	**108,779.40**	8,320.24	8.28%	7,368.11	38.90%
Thermal Plant	-	360.40	2,271.56	357.11	27,685.64	28,042.75	2,812.20	**33,129.80**	-	171.64	2,090.39	29,225.74	2,812.20	4,285.12	1,567.26	**40,152.34**	7,022.54	21.20%	1,182.98	4.22%
Gas Turbines	546.14	2,500.00	2,613.00	3,129.24	706.20	3,835.44	262.10	**6,627.44**	35.03	39.28	2,455.58	4,115.66	262.10	2,890.29	99.94	**9,897.89**	3,270.44	49.35%	280.22	7.31%
Terminal Stations	2,678.14	16,609.12	33,017.70	18,482.39	21,146.00	39,628.39	31,648.40	**105,099.36**	660.58	7,997.62	20,298.33	37,973.92	31,648.40	2,954.07	240.04	**101,772.96**	(3,326.39)	-3.16%	(1,654.47)	-4.17%
Transmission	-	3,479.25	12,281.70	8,756.04	3,610.16	12,366.20	-	**19,371.11**	-	826.07	6,178.94	14,384.21	-	272.23	-	**21,661.46**	2,290.35	11.82%	2,018.01	16.32%
Distribution	-	-	1,511.40	412.68	11,099.80	11,512.48	1,372.60	**13,983.80**	(0.00)	0.00	998.72	13,822.53	1,372.60	1,210.71	(598.28)	**16,806.28**	2,822.48	20.18%	2,310.05	20.07%
Generation	125.35	4,064.11	4,879.02	3,666.34	10,199.02	13,865.37	3,669.70	**22,937.20**	121.63	1,658.59	3,125.43	8,766.58	3,669.70	1,548.26	3,951.59	**22,841.78**	(95.42)	-0.42%	(5,098.78)	-36.77%
Properties	-	-	-	-	565.10	565.10	5,159.35	**5,724.45**	-	-	-	578.08	5,159.35	-	(12.98)	**5,724.45**	-	0.00%	12.98	2.30%
Metering	-	-	515.60	(1,748.84)	4,592.20	2,843.36	994.60	**6,102.40**	-	-	2,264.44	2,196.31	994.60	-	623.41	**6,078.76**	(23.64)	-0.39%	(647.05)	-22.76%
Tools and Equipment	-	-	735.80	85.50	3,514.60	3,600.10	293.90	**4,544.30**	-	-	650.30	1,761.45	293.90	-	1,752.32	**4,457.98**	(86.32)	-1.90%	(1,838.65)	-51.07%
Information Systems	-	-	369.00	104.92	1,264.00	1,368.92	-	**1,633.00**	-	-	264.08	1,432.21	-	42.78	-	**1,739.07**	106.07	6.50%	63.29	4.62%
Telecontrol	-	-	221.22	145.95	1,258.20	1,404.15	852.40	**2,331.82**	-	-	75.27	1,500.52	852.40	24.47	49.52	**2,502.18**	170.36	7.31%	96.37	6.86%
Transportation	1,625.40	3,204.25	1,952.41	4,050.11	1,963.80	6,013.91	7,374.97	**16,120.83**	4.01	934.24	3,343.91	5,201.89	7,374.97	-	(454.90)	**16,404.12**	283.29	1.76%	(812.03)	-13.50%
Administration	89.14	844.97	938.50	1,143.47	273.80	1,417.27	-	**2,146.42**	64.24	703.40	335.50	1,609.57	-	-	-	**2,712.72**	566.30	26.38%	192.30	13.57%
Allowance for Unforeseen Items	-	-	-	-	1,000.00	1,000.00	-	**1,000.00**	-	-	-	-	-	-	-	-	(1,000.00)	-100.00%	(1,000.00)	-100.00%
Total	**5,064.18**	**40,868.46**	**73,480.81**	**39,990.78**	**106,412.02**	**146,402.80**	**115,385.62**	**341,211.09**	**885.50**	**18,167.48**	**56,337.34**	**148,876.15**	**115,385.62**	**13,528.86**	**8,350.43**	**361,531.38**	**20,320.29**		**2,473.35**	

2023 Capital Expenditures By Investment Classification
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Investment Classification	**2020**	**2021**	**2022**	**Carryover to 2023**	**Original 2023**	**Revised 2023**	**2024 and Beyond**	**Total**	**2020**	**2021**	**2022**	**2023**	**2024 and Beyond**	**Project Carryover**	**Multi-Year Cash Flow Reallocation**	**Total**	**Project**		**Annual**	
Access	-	3,479.25	12,281.70	8,756.04	4,776.96	13,533.00	-	**20,537.91**	(0.00)	826.07	6,178.94	13,846.83	-	272.23	-	**21,124.07**	586.16	2.85%	313.83	2.32%
General Plant	1,625.40	3,401.63	4,317.01	5,472.27	10,334.30	15,806.57	14,427.12	**34,105.46**	4.01	1,041.90	4,526.06	13,183.33	14,427.12	1,976.38	1,395.56	**36,554.37**	2,448.92	7.18%	(2,623.24)	-16.60%
Mandatory	-	-	-	-	323.30	323.30	594.10	**917.40**	-	-	-	388.68	594.10	-	(65.38)	**917.40**	-	0.00%	65.38	20.22%
Renewal	3,438.78	28,868.67	36,643.98	9,889.18	77,969.94	87,859.12	77,644.50	**224,565.87**	881.48	15,023.93	36,661.81	96,149.93	77,644.50	7,877.71	6,513.66	**240,753.03**	16,187.16	7.21%	8,290.81	9.44%
Service Enhancement	-	1,630.50	8,741.82	5,036.48	9,743.32	14,779.80	10,221.40	**30,337.04**	-	180.97	4,704.99	12,839.94	10,221.40	3,353.13	101.91	**31,402.34**	1,065.30	3.51%	(1,939.86)	-13.13%
System Growth	-	3,488.42	11,496.30	10,836.81	2,264.20	13,101.01	12,498.50	**29,747.42**	-	1,094.61	4,265.54	12,467.43	12,498.50	49.41	404.68	**30,780.17**	1,032.75	3.47%	(633.57)	-4.84%
Allowance for Unforeseen	-	-	-	(0.00)	1,000.00	1,000.00	-	**1,000.00**	-	-	-	-	-	-	-	-	(1,000.00)	-100.00%	(1,000.00)	-100.00%
Total	**5,064.18**	**40,868.46**	**73,480.81**	**39,990.78**	**106,412.02**	**146,402.80**	**115,385.62**	**341,211.09**	**885.50**	**18,167.48**	**56,337.34**	**148,876.15**	**115,385.62**	**13,528.86**	**8,350.43**	**361,531.38**	**20,320.29**		**2,473.35**	

2023 Capital Expenditures By Investment Classification
Renewal
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Project	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	2024 and Beyond	Project Carryover	Multi-Year Cash Flow Reallocation	Total	Project		Annual	
Replace Remote Terminal Units (2023)	-	-	-	-	179.70	179.70	-	**179.70**	-	-	-	234.43	-	-	-	**234.43**	54.73	30.46%	54.73	30.46%
Replace Power Line Carrier (2023–2024) - TL223 and TL224	-	-	-	-	105.30	105.30	852.40	**957.70**	-	-	-	55.78	852.40	-	49.52	**957.70**	-	0.00%	(49.52)	-47.03%
Replace 48 V Battery Banks and Chargers (2023)	-	-	-	-	439.70	439.70	-	**439.70**	-	-	-	418.96	-	-	-	**418.96**	(20.74)	-4.72%	(20.74)	-4.72%
Replace Human Machine Interface (2023) - Happy Valley Gas Turbine	-	-	-	-	138.60	138.60	-	**138.60**	-	-	-	137.69	-	17.31	-	**155.00**	16.40	11.83%	(0.91)	-0.66%
Replace Oil Mist Separator (2023-2024) - Happy Valley Gas Turbine	-	-	-	-	138.50	138.50	262.10	**400.60**	-	-	-	38.56	262.10	-	99.94	**400.60**	-	0.00%	(99.94)	-72.16%
Gas Turbine In-Service Failures (2023)	-	-	-	-	344.20	344.20	-	**344.20**	-	-	-	3,606.75	-	-	-	**3,606.75**	3,262.55	947.86%	3,262.55	947.86%
Penstock Life Extension - Phase 1 (2023-2025) - Supplemental	-	-	-	-	2,105.00	2,105.00	48,501.70	**50,606.70**	-	-	-	1,132.36	48,501.70	-	972.64	**50,606.70**	-	0.00%	(972.64)	-46.21%
Replace Powerhouse Station Service Panel (2023-2024) - Upper Salmon	-	-	-	-	591.80	591.80	976.70	**1,568.50**	-	-	-	883.28	976.70	-	251.52	**2,111.50**	543.00	34.62%	291.48	49.25%
Replace Emergency Lift (2023) - Salmon River Spillway	-	-	-	-	49.80	49.80	-	**49.80**	-	-	-	90.74	-	-	-	**90.74**	40.94	82.21%	40.94	82.21%
Replace Diesel Genset 1 (2023-2024) - Ebbegunbaeg	-	-	-	-	298.00	298.00	728.30	**1,026.30**	-	-	-	132.55	728.30	-	165.45	**1,026.30**	-	0.00%	(165.45)	-55.52%
Hydraulic In-Service Failures (2023)	-	-	-	-	1,500.00	1,500.00	-	**1,500.00**	-	-	-	4,081.09	-	-	-	**4,081.09**	2,581.09	172.07%	2,581.09	172.07%
Refurbish Superstructure (2023-2024) - Salmon River Spillway	-	-	-	-	328.30	328.30	2,500.00	**2,828.30**	-	-	-	179.00	2,500.00	-	149.30	**2,828.30**	-	0.00%	(149.30)	-45.48%
Unit 7 Condition Assessment (2023) - Bay d'Espoir	-	-	-	-	597.50	597.50	-	**597.50**	-	-	-	379.41	-	-	-	**379.41**	(218.09)	-36.50%	(218.09)	-36.50%
Holyrood Thermal Generating Station Unit 1 and Unit 2 Turbine Last Stage Blades	-	-	-	-	3,596.50	3,596.50	2,812.20	**6,408.70**	-	-	-	2,029.24	2,812.20	-	1,567.26	**6,408.70**	-	0.00%	(1,567.26)	-43.58%
Thermal In-Service Failures (2023)	-	-	-	-	3,300.00	3,300.00	-	**3,300.00**	-	-	-	2,887.83	-	-	-	**2,887.83**	(412.17)	-12.49%	(412.17)	-12.49%
Overhaul Pumps (2023) - Holyrood	-	-	-	-	742.40	742.40	-	**742.40**	-	-	-	1,429.89	-	-	-	**1,429.89**	687.49	92.60%	687.49	92.60%
Overhaul Unit 2 Turbine and Valves (2023) - Holyrood	-	-	-	-	9,701.80	9,701.80	-	**9,701.80**	-	-	-	9,276.35	-	2,092.02	-	**11,368.37**	1,666.57	17.18%	(425.45)	-4.39%
Refurbish Workshop Roof (2023) - Holyrood	-	-	-	-	243.70	243.70	-	**243.70**	-	-	-	237.75	-	-	-	**237.75**	(5.95)	-2.44%	(5.95)	-2.44%
Boiler Condition Assessment and Miscellaneous Upgrades (2023) - Holyrood	-	-	-	-	2,926.60	2,926.60	-	**2,926.60**	-	-	-	4,336.36	-	-	-	**4,336.36**	1,409.76	48.17%	1,409.76	48.17%
Diesel In-Service Failures (2023)	-	-	-	-	480.40	480.40	-	**480.40**	-	-	-	727.18	-	-	-	**727.18**	246.78	51.37%	246.78	51.37%
Overhaul Diesel Units (2023)	-	-	-	-	1,502.00	1,502.00	-	**1,502.00**	-	-	-	1,347.26	-	-	-	**1,347.26**	(154.74)	-10.30%	(154.74)	-10.30%
Replace Intermediate Fuel Storage Tanks (2023-2024) - Nain	-	-	-	-	127.40	127.40	593.70	**721.10**	-	-	-	71.83	593.70	-	55.57	**721.10**	-	0.00%	(55.57)	-43.62%
Terminal Station In-Service Failures (2023)	-	-	-	-	1,300.00	1,300.00	-	**1,300.00**	-	-	-	2,846.69	-	-	-	**2,846.69**	1,546.69	118.98%	1,546.69	118.98%
Circuit Breakers Renewal Program (2023-2024)	-	-	-	-	216.90	216.90	3,595.10	**3,812.00**	-	-	-	633.78	3,595.10	-	(416.88)	**3,812.00**	-	0.00%	416.88	192.20%
Install Breaker Failure Protection (2023-2024) - Sunnyside	-	-	-	-	73.50	73.50	216.20	**289.70**	-	-	-	467.17	216.20	-	(9.96)	**673.40**	383.70	132.45%	393.67	535.60%
Replace Data Alarm System Annunciators (2023) - Buchans	-	-	-	-	61.20	61.20	104.80	**166.00**	-	-	-	77.85	104.80	-	(16.65)	**166.00**	-	0.00%	16.65	27.21%
Replace Circuit Breaker Reclosing Controllers (2023-2024) - Hardwoods	-	-	-	-	81.60	81.60	149.60	**231.20**	-	-	-	43.84	149.60	-	37.76	**231.20**	-	0.00%	(37.76)	-46.27%
Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) - Wabush Terminal Station	-	-	-	-	577.20	577.20	516.10	**1,093.30**	-	-	-	692.33	516.10	-	(115.13)	**1,093.30**	-	0.00%	115.13	19.95%
Wood Pole Line Management Program (2023)	-	-	-	-	2,824.40	2,824.40	-	**2,824.40**	-	-	-	5,085.84	-	-	-	**5,085.84**	2,261.44	80.07%	2,261.44	80.07%
Transmission In-Service Failures (2023)	-	-	-	-	151.70	151.70	-	**151.70**	-	-	-	193.59	-	-	-	**193.59**	41.89	27.61%	41.89	27.61%
Control System Replacement - Holyrood Gas Turbine	-	-	146.00	75.17	41.00	116.17	-	**187.00**	-	-	70.83	121.48	-	-	-	**192.31**	5.31	2.84%	5.31	4.57%
Upper Salmon Hydroelectric Generating Station Rotor Rim Shrink and Stator Recentering - Supplemental	-	-	959.40	236.53	3,040.40	3,276.93	-	**3,999.80**	-	-	722.87	8,423.77	-	-	-	**9,146.64**	5,146.84	128.68%	5,146.84	157.06%
Purchase Turbine Last Stage Blades - Holyrood	-	-	18.26	(146.28)	1,560.64	1,414.36	-	**1,578.90**	-	-	164.54	1,435.04	-	-	-	**1,599.57**	20.67	1.31%	20.67	1.46%
Holyrood Upgrade Turbine Control System Unit 2	-	-	235.90	85.22	490.10	575.32	-	**726.00**	-	-	150.68	506.61	-	68.71	-	**726.00**	-	0.00%	(68.71)	-11.94%
Holyrood Tank Farm Underground Firewater System Replacement	-	-	83.50	55.63	1,330.50	1,386.13	-	**1,414.00**	-	-	27.87	1,235.04	-	-	-	**1,262.91**	(151.09)	-10.69%	(151.09)	-10.90%
Holyrood Inspect and Refurbish Day Tank	-	-	89.40	49.57	707.80	757.37	-	**797.20**	-	-	39.83	902.32	-	-	-	**942.14**	144.94	18.18%	144.94	19.14%
Holyrood Fuel Tank #1 Fuel Inspection And Refurbishment	-	-	1,195.00	164.37	857.10	1,021.47	-	**2,052.10**	-	-	1,030.63	2,628.58	-	190.79	-	**3,850.00**	1,797.90	87.61%	1,607.11	157.33%
Unit 3 Generator Components Condition Assessment and Miscellaneous Upgrades	-	-	153.00	(69.78)	338.80	269.02	-	**491.80**	-	-	209.95	334.74	-	-	-	**544.70**	52.90	10.76%	65.72	24.43%
Labrador City L22 Voltage Conversion (2022-2023)	-	-	486.80	387.69	1,004.40	1,392.09	-	**1,491.20**	-	-	99.11	181.39	-	1,210.71	-	**1,491.20**	-	0.00%	(1,210.71)	-86.97%
Makkovik Diesel Generating Station Roof Replacement	-	-	176.82	257.60	457.20	714.80	-	**634.02**	-	-	95.68	638.21	-	-	-	**733.89**	99.87	15.75%	(76.59)	-10.71%
Mary's Harbour Diesel Engine Replacement	-	-	-	-	137.70	137.70	-	**137.70**	-	-	-	124.64	-	-	-	**124.64**	(13.06)	-9.48%	(13.06)	-9.48%
Diesel Genset Replacement Unit 2039 - St. Lewis	-	-	397.00	158.30	1,583.80	1,742.10	-	**1,980.80**	-	-	238.70	361.75	-	-	1,365.25	**1,965.70**	(15.10)	-0.76%	(1,380.35)	-79.24%
Diesel Genset Replacement Unit 2012 - L'Anse-Au-Loup	-	-	339.90	169.64	2,513.20	2,682.84	210.20	**3,063.30**	-	-	170.26	214.69	210.20	-	2,468.15	**3,063.30**	-	0.00%	(2,468.15)	-92.00%
Upgrade Circuit Breakers (2022-2023) - Various	-	-	2,121.90	(1,081.18)	7,361.80	6,280.62	-	**9,483.70**	-	-	117.38	5,525.97	-	-	-	**5,643.35**	(3,840.35)	-40.49%	(754.65)	-12.02%
Refurbish Ebbegunbaeg Control Structure	-	3,236.82	3,238.30	(22.86)	3,470.10	3,447.24	7,733.80	**17,679.02**	-	2,196.44	4,301.54	3,923.59	7,733.80	-	(476.25)	**17,679.13**	0.11	0.00%	476.36	13.82%
Upgrade Distributed Control System Hardware - Holyrood	-	360.40	368.20	205.25	-	205.25	-	**728.60**	-	171.64	351.72	340.24	-	-	-	**863.59**	134.99	18.53%	134.99	65.77%
Replace Unit 2047 - Ramea	-	307.71	2,010.80	2,053.42	118.30	2,171.72	-	**2,436.81**	-	49.04	216.05	1,096.33	-	1,075.39	-	**2,436.81**	-	0.00%	(1,075.39)	-49.52%
Diesel Genset Replacements (2021-2022)	-	2,560.60	286.20	131.73	-	131.73	-	**2,846.80**	-	1,503.79	1,036.26	382.20	-	49.53	-	**2,971.77**	124.97	4.39%	250.47	190.15%
Upgrade Circuit Breakers (2021-2022) - Various	-	5,418.76	4,293.60	(539.64)	820.30	280.66	-	**10,532.66**	-	2,597.72	4,818.60	777.00	-	-	-	**8,193.32**	(2,339.34)	-22.21%	496.34	176.85%
Replace Elevator Motors and Controls Equipment - Hydro Place	89.14	647.60	-	44.45	-	44.45	-	**736.74**	64.24	595.74	256.31	48.36	-	-	-	**964.65**	227.91	30.94%	3.91	8.80%
Perform Combustor Inspection - Holyrood Gas Turbine	546.14	2,500.00	2,427.40	3,031.71	-	3,031.71	-	**5,473.54**	35.03	39.28	2,367.51	158.73	-	2,872.98	-	**5,473.53**	(0.01)	0.00%	(2,872.98)	-94.76%
Replace Diesel Plant Roof - L'anse Aux Loup and St. Anthony	125.35	1,195.80	-	130.93	-	130.93	-	**1,321.15**	121.63	105.76	963.02	145.49	-	-	-	**1,335.90**	14.75	1.12%	14.57	11.13%
Diesel Genset Replacement Program (2023-2025)	-	-	-	-	819.10	819.10	2,307.10	**3,126.20**	-	-	-	683.62	2,307.10	-	67.08	**3,057.80**	(68.40)	-2.19%	(135.48)	-16.54%
Hydraulic Unit Overhauls Program (2023)	-	-	-	-	975.70	975.70	-	**975.70**	-	-	-	1,289.41	-	-	-	**1,289.41**	313.71	32.15%	313.71	32.15%
Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights (2023)	-	-	-	-	3,986.00	3,986.00	-	**3,986.00**	(0.00)	0.00	(0.00)	6,029.09	-	-	-	**6,029.09**	2,043.09	51.26%	2,043.09	51.26%
Hydraulic Generation R&M	-	6,569.54	7,976.20	1,192.20	3,788.90	4,981.10	-	**18,334.64**	-	3,640.20	9,232.04	4,755.67	-	300.93	-	**17,928.84**	(405.80)	-2.21%	(225.43)	-4.53%
Terminal Station R&M	-	6,071.45	9,640.40	1,075.52	6,109.70	7,185.22	-	**21,821.55**	-	3,874.12	9,422.58	5,679.46	-	33.78	-	**19,009.95**	(2,811.60)	-12.88%	(1,505.76)	-20.96%
Terminal Station Renewal Program (2023-2024)	-	-	-	-	1,733.70	1,733.70	5,584.50	**7,318.20**	-	-	-	1,434.59	5,584.50	-	299.11	**7,318.20**	-	0.00%	(299.11)	-17.25%
Replace Transformer T7 - Holyrood	2,678.14	-	-	2,243.99	-	2,243.99	-	**2,678.14**	660.58	250.21	557.86	3,016.51	-	(34.42)	-	**4,450.73**	1,772.59	66.19%	772.51	34.43%
Total	**3,438.78**	**28,868.67**	**36,643.98**	**9,889.18**	**77,969.94**	**87,859.12**	**77,644.50**	**224,565.87**	**881.48**	**15,023.93**	**36,661.81**	**96,149.93**	**77,644.50**	**7,877.71**	**6,513.66**	**240,753.03**	**16,187.16**		**8,290.81**	

2023 Capital Expenditures By Investment Classification
General Plant
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Project	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	2024 and Beyond	Project Carryover	Multi-Year Cash Flow Reallocation	Total	Project		Annual	
Purchase Office Equipment Less Than $50,000 (2023)	-	-	-	-	75.60	75.60	-	**75.60**	-	-	-	55.69	-	-	-	**55.69**	(19.91)	-26.33%	(19.91)	-26%
Purchase Personal Computers (2023)	-	-	-	-	221.60	221.60	-	**221.60**	-	-	-	239.11	-	-	-	**239.11**	17.51	7.90%	17.51	8%
Replace Peripheral Infrastructure (2023)	-	-	-	-	187.40	187.40	-	**187.40**	-	-	-	114.62	-	42.78	-	**157.40**	(30.00)	-16.01%	(72.78)	-39%
Upgrade Core OT Infrastructure (2023)	-	-	-	-	171.70	171.70	-	**171.70**	-	-	-	255.26	-	-	-	**255.26**	83.56	48.67%	83.56	49%
Update Cyber Security Infrastructure (2023)	-	-	-	-	232.10	232.10	-	**232.10**	-	-	-	230.53	-	-	-	**230.53**	(1.57)	-0.68%	(1.57)	-1%
Perform Software Upgrades and Minor Enhancements (2023)	-	-	-	-	451.20	451.20	-	**451.20**	-	-	-	357.32	-	-	-	**357.32**	(93.88)	-20.81%	(93.88)	-21%
Replace Network Communications Equipment (2023)	-	-	-	-	189.00	189.00	-	**189.00**	-	-	-	238.69	-	-	-	**238.69**	49.69	26.29%	49.69	26%
Upgrade Site Facilities (2023)	-	-	-	-	45.20	45.20	-	**45.20**	-	-	-	47.11	-	-	-	**47.11**	1.91	4.23%	1.91	4%
Purchase Tools and Equipment Less than $50,000 (2023) - Telecontrol	-	-	-	-	40.40	40.40	-	**40.40**	-	-	-	47.40	-	-	-	**47.40**	7.00	17.33%	7.00	17%
Replace Standalone PBX Phone Systems (2023)	-	-	-	-	175.50	175.50	-	**175.50**	-	-	-	208.97	-	-	-	**208.97**	33.47	19.07%	33.47	19%
Purchase Mobile Devices (2023)	-	-	-	-	83.40	83.40	-	**83.40**	-	-	-	116.35	-	-	-	**116.35**	32.95	39.51%	32.95	40%
Replace Light- and Heavy-Duty Vehicles (2023-2025)	-	-	-	-	1,308.10	1,308.10	3,058.07	**4,366.17**	-	-	-	2,573.20	3,058.07	-	(1,065.10)	**4,566.17**	200.00	4.58%	1,265.10	97%
Water System Condition Assessment and Upgrades (2023) - Bay d'Espoir	-	-	-	-	161.00	161.00	504.90	**665.90**	-	-	-	91.16	504.90	-	69.84	**665.90**	-	0.00%	(69.84)	-43%
Refurbish BioGreen Sewage System (2023) - Holyrood	-	-	-	-	256.60	256.60	-	**256.60**	-	-	-	504.94	-	-	-	**504.94**	248.34	96.78%	248.34	97%
Purchase Tools and Equipment Less than $50,000 (2023) - Hydraulic Plants	-	-	-	-	144.90	144.90	-	**144.90**	-	-	-	149.98	-	-	-	**149.98**	5.08	3.51%	5.08	4%
Purchase Tools and Equipment Less than $50,000 (2023) - Thermal Plants	-	-	-	-	55.10	55.10	-	**55.10**	-	-	-	122.78	-	-	-	**122.78**	67.68	122.83%	67.68	123%
Purchase Tools and Equipment Less than $50,000 (2023) - Gas Turbine	-	-	-	-	18.30	18.30	-	**18.30**	-	-	-	16.66	-	-	-	**16.66**	(1.64)	-8.97%	(1.64)	-9%
Replace Building Exterior (2023-2024) - Postville	-	-	-	-	124.60	124.60	558.70	**683.30**	-	-	-	129.05	558.70	-	(4.45)	**683.30**	-	0.00%	4.45	4%
Upgrade Water and Fire Suppression Systems (2023-2024) - Bishop's Falls	-	-	-	-	353.70	353.70	2,886.30	**3,240.00**	-	-	-	316.19	2,886.30	-	37.51	**3,240.00**	-	0.00%	(37.51)	-11%
Replace Diesel Shop Building (2023-2025) - Bishop's Falls	-	-	-	-	168.00	168.00	2,144.25	**2,312.25**	-	-	-	198.65	2,144.25	-	(30.65)	**2,312.25**	-	0.00%	30.65	18%
Replace HVAC System (2023-2024) - Bishop's Falls	-	-	-	-	43.40	43.40	128.80	**172.20**	-	-	-	63.24	128.80	-	(19.84)	**172.20**	-	0.00%	19.84	46%
Install Fire Protection in 230 kV Stations (2023-2024) - Deer Lake	-	-	-	-	79.20	79.20	535.30	**614.50**	-	-	-	33.47	535.30	-	45.73	**614.50**	-	0.00%	(45.73)	-58%
Replace Mobile Equipment (2023-2024)	-	-	-	-	541.20	541.20	187.30	**728.50**	-	-	-	688.51	187.30	-	(147.31)	**728.50**	-	0.00%	147.31	27%
Upgrade Energy Management System (2022) - Hydro Place	-	-	292.60	42.97	-	42.97	-	**292.60**	-	-	249.63	199.69	-	-	-	**449.33**	156.73	53.56%	156.73	365%
Hydro Command Centre Upgrade (2022) - Hydro Place	-	-	76.40	61.95	-	61.95	-	**76.40**	-	-	14.45	35.67	-	-	-	**50.12**	(26.28)	-34.39%	(26.28)	-42%
Replace Network Communications Equipment (2022)	-	-	193.00	119.60	-	119.60	-	**193.00**	-	-	73.40	130.94	-	-	-	**204.34**	11.34	5.88%	11.34	9%
Replace Tracks - V7271 - Supplemental	-	-	48.31	48.31	-	48.31	-	**48.31**	-	-	-	45.00	-	-	-	**45.00**	(3.31)	-6.85%	(3.31)	-7%
Replace Light- and Heavy-Duty Vehicles (2022-2024)	-	-	569.00	443.44	593.20	1,036.64	2,319.60	**3,481.80**	-	-	125.56	477.70	2,319.60	-	558.93	**3,481.80**	-	0.00%	(558.93)	-54%
Replace Underground Fire Water Distribution System - Holyrood	-	-	128.30	13.13	1,578.00	1,591.13	-	**1,706.30**	-	-	115.17	1,018.02	-	1,933.60	-	**3,066.80**	1,360.50	79.73%	(573.11)	-36%
Purchase 46' Material Handler Aerial Device on Track Unit	-	-	20.40	7.21	698.80	706.01	38.80	**758.00**	-	-	13.19	36.52	38.80	-	669.50	**758.00**	-	0.00%	(669.50)	-95%
Purchase 85' Material Handler Aerial Device on Track Unit	-	-	20.40	(2.00)	1,265.70	1,263.70	67.80	**1,353.90**	-	-	22.40	33.56	67.80	-	1,230.14	**1,353.90**	-	0.00%	(1,230.14)	-97%
Replace Light-Duty Mobile Equipment (2022) - Various	-	-	695.00	80.29	-	80.29	-	**695.00**	-	-	614.71	90.69	-	-	-	**705.41**	10.41	1.50%	10.41	13%
Replace Transfer Switches and Associated Hardware - Hydro Place	-	197.38	938.50	1,099.02	-	1,099.02	-	**1,135.88**	-	107.67	79.19	1,298.48	-	-	-	**1,485.34**	349.46	30.77%	199.46	18%
Replace Light- and Heavy-Duty Vehicles (2021-2022)	-	1,320.95	1,335.10	2,014.17	-	2,014.17	-	**2,656.05**	-	81.42	1,220.47	537.11	-	-	-	**1,839.00**	(817.05)	-30.76%	(1,477.05)	-73%
Purchase Tools and Equipment Less than $50,000 (2023) - Central Region	-	-	-	-	281.40	281.40	-	**281.40**	-	-	-	333.86	-	-	-	**333.86**	52.46	18.64%	52.46	19%
Purchase Tools and Equipment Less than $50,000 (2023) - Labrador Region	-	-	-	-	372.30	372.30	-	**372.30**	-	-	-	298.99	-	-	-	**298.99**	(73.31)	-19.69%	(73.31)	-20%
Purchase Tools and Equipment Less than $50,000 (2023) - Northern Region	-	-	-	-	355.20	355.20	-	**355.20**	-	-	-	279.31	-	-	-	**279.31**	(75.89)	-21.37%	(75.89)	-21%
Install Ultra-Fast DC Electric Vehicle Chargers - Supplemental	-	-	-	-	62.50	62.50	1,997.30	**2,059.80**	-	-	-	11.24	1,997.30	-	51.26	**2,059.80**	-	0.00%	(51.26)	-82%
Level 2 Chargers for Electric Vehicles	-	299.80	-	72.53	-	72.53	-	**299.80**	-	194.13	33.14	130.02	-	-	-	**357.29**	57.49	19.18%	57.49	79%
Replace Light and Heavy Duty Vehicles (2020-2021) - Various	1,625.40	1,583.50	-	1,471.67	-	1,471.67	-	**3,208.90**	4.01	658.70	1,964.73	1,427.61	-	-	-	**4,055.06**	846.16	26.37%	(44.06)	-3%
Total	**1,625.40**	**3,401.63**	**4,317.01**	**5,472.27**	**10,334.30**	**15,806.57**	**14,427.12**	**34,105.46**	**4.01**	**1,041.90**	**4,526.06**	**13,183.33**	**14,427.12**	**1,976.38**	**1,395.56**	**36,554.37**	**2,448.92**		**(2,623.24)**	

2023 Capital Expenditures By Investment Classification
System Growth
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Project	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	2024 and Beyond	Project Carryover	Multi-Year Cash Flow Reallocation	Total	Project		Annual	
Additions for Load Growth - Upgrade Transformer Capacity (2023-2024) - Jean Lake Terminal Station	-	-	-	-	580.00	580.00	5,436.10	**6,016.10**	-	-	-	52.02	5,436.10	-	527.98	**6,016.10**	-	0.00%	(527.98)	-91.03%
Additions for Load (2022) - Mary's Harbour Service Conductor	-	-	307.80	36.73	51.30	88.03	-	**359.10**	-	-	122.97	38.62	-	49.41	-	**211.00**	(148.10)	-41.24%	(49.41)	-56.13%
Additions for Load - Wabush Substation Upgrades	-	1,186.70	6,253.00	6,200.06	-	6,200.06	3,254.40	**10,694.10**	-	300.60	2,299.38	4,384.48	3,254.40	-	455.29	**10,694.14**	0.04	0.00%	(1,815.59)	-29.28%
Wabush Terminal Station Upgrades	-	2,301.72	4,935.50	4,600.02	1,632.90	6,232.92	3,808.00	**12,678.12**	-	794.01	1,843.19	7,992.32	3,808.00	-	(578.58)	**13,858.93**	1,180.81	9.31%	1,759.40	28.23%
Total	**-**	**3,488.42**	**11,496.30**	**10,836.81**	**2,264.20**	**13,101.01**	**12,498.50**	**29,747.42**	**-**	**1,094.61**	**4,265.54**	**12,467.43**	**12,498.50**	**49.41**	**404.68**	**30,780.17**	**1,032.75**		**(633.57)**	

2023 Capital Expenditures By Investment Classification
Access
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Project	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	2024 and Beyond	Project Carryover	Multi-Year Cash Flow Reallocation	Total	Project		Annual	
Purchase Meters and Metering Equipment (2023)	-	-	-	-	226.60	226.60	-	**226.60**	-	-	-	202.96	-	-	-	**202.96**	(23.64)	-10.43%	(23.64)	-10.43%
Valentine Gold Interconnection - Supplemental	-	3,479.25	12,281.70	8,756.04	586.36	9,342.40	-	**16,347.31**	-	826.07	6,178.94	9,070.17	-	272.23	-	**16,347.41**	0.10	0.00%	(272.23)	-2.91%
Provide Service Extensions (2023)	-	-	-	-	3,964.00	3,964.00	-	**3,964.00**	(0.00)	0.00	(0.00)	4,573.71	-	-	-	**4,573.71**	609.71	15.38%	609.71	15.38%
Total	**-**	**3,479.25**	**12,281.70**	**8,756.04**	**4,776.96**	**13,533.00**	**-**	**20,537.91**	**(0.00)**	**826.07**	**6,178.94**	**13,846.83**	**-**	**272.23**	**-**	**21,124.07**	**586.16**		**313.83**	

2023 Capital Expenditures By Investment Classification
Service Enhancement
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Project	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	2024 and Beyond	Project Carryover	Multi-Year Cash Flow Reallocation	Total	Project		Annual	
Remove Safety Hazards (2023)	-	-	-	-	198.20	198.20	-	**198.20**	-	-	-	207.03	-	-	-	**207.03**	8.83	4.46%	8.83	4.46%
Upgrade Public Safety Around Dams and Waterways (2023)	-	-	-	-	482.10	482.10	-	**482.10**	-	-	-	795.46	-	-	-	**795.46**	313.36	65.00%	313.36	65.00%
Upgrade of Worst-Performing Distribution Feeders (2023-2024)	-	-	-	-	73.40	73.40	1,372.60	**1,446.00**	-	-	-	671.68	1,372.60	-	(598.28)	**1,446.00**	-	0.00%	598.28	815.09%
Replace Unit 2090/2044 - Charlottetown and Mary's Harbour	-	-	-	-	401.02	401.02	-	**401.02**	-	-	-	414.75	-	(13.73)	-	**401.02**	-	0.00%	13.73	3.42%
Purchase Spare Generator Step-Up Transformer	-	-	-	-	39.60	39.60	7,427.70	**7,467.30**	-	-	-	17.53	7,427.70	-	22.07	**7,467.30**	-	0.00%	(22.07)	-55.73%
Install Oil Spill Containment Transformer T1S (2023-2024) - Cat Arm	-	-	-	-	155.10	155.10	426.50	**581.60**	-	-	-	100.39	426.50	-	54.71	**581.60**	-	0.00%	(54.71)	-35.28%
TL215 Guying Upgrades	-	-	-	-	47.70	47.70	-	**47.70**	-	-	-	34.62	-	-	-	**34.62**	(13.08)	-27.42%	(13.08)	-27.42%
IOC SCADA Data Link	-	-	28.22	26.35	-	26.35	-	**28.22**	-	-	1.87	1.88	-	24.47	-	**28.22**	-	0.00%	(24.47)	-92.87%
Install Infrared Scanning Ports - Happy Valley Gas Turbine	-	-	39.60	22.36	25.60	47.96	-	**65.20**	-	-	17.24	35.80	-	-	-	**53.04**	(12.16)	-18.65%	(12.16)	-25.35%
Install Recloser Remote Control (2021-2022) - Various	-	-	174.60	36.78	149.10	185.88	-	**323.70**	-	-	37.82	175.95	-	-	-	**213.76**	(109.94)	-33.96%	(9.94)	-5.35%
Upgrade of Worst-Performing Distribution Feeders (2022-2023)	-	-	850.00	(11.80)	1,922.90	1,911.10	-	**2,772.90**	-	-	861.80	2,190.72	-	-	-	**3,052.52**	279.62	10.08%	279.62	14.63%
CHT Winterize Unit 2102 and Install Mobile - Supplemental	-	-	1,269.80	1,064.18	44.90	1,109.08	-	**1,314.70**	-	-	205.62	1,389.98	-	44.10	-	**1,639.70**	325.00	24.72%	280.90	25.33%
Install Fire Protection in Diesel Plants (2022-2023) - Ramea	-	-	90.70	(336.17)	1,838.10	1,501.93	-	**1,928.80**	-	-	76.87	1,000.97	-	343.57	-	**1,421.41**	(507.39)	-26.31%	(500.96)	-33.35%
Replace Metering System	-	-	515.60	(1,748.84)	4,365.60	2,616.76	994.60	**5,875.80**	-	-	2,264.44	1,993.35	994.60	-	623.41	**5,875.80**	0.00	0.00%	(623.41)	-23.82%
Upgrades for Future Retirement of Stephenville Gas Turbine	-	1,530.35	5,344.50	5,662.17	-	5,662.17	-	**6,874.85**	-	151.77	1,060.87	3,493.98	-	2,954.72	-	**7,661.35**	786.50	11.44%	(2,168.19)	-38.29%
Install Fire Protection in 230 kV Stations - Massey Drive	-	100.15	428.80	321.44	-	321.44	-	**528.95**	-	29.20	178.46	315.85	-	-	-	**523.50**	(5.45)	-1.03%	(5.60)	-1.74%
Total	**-**	**1,630.50**	**8,741.82**	**5,036.48**	**9,743.32**	**14,779.80**	**10,221.40**	**30,337.04**	**-**	**180.97**	**4,704.99**	**12,839.94**	**10,221.40**	**3,353.13**	**101.91**	**31,402.34**	**1,065.30**		**(1,939.86)**	

2023 Capital Expenditures By Investment Classification
Mandatory
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Project	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	2024 and Beyond	Project Carryover	Multi-Year Cash Flow Reallocation	Total	Project		Annual	
Replace Terminal Station Lighting (2023-2024)	-	-	-	-	323.30	323.30	594.10	**917.40**	-	-	-	388.68	594.10	-	(65.38)	**917.40**	-	0.00%	65.38	20.22%
Total	-	-	-	-	**323.30**	**323.30**	**594.10**	**917.40**	**-**	**-**	**-**	**388.68**	**594.10**	-	**(65.38)**	**917.40**	**-**		**65.38**	

2023 Capital Expenditures By Investment Classification
Contribution in Aid of Construction ("CIAC")
($000)

	Capital Budget								Actual Expenditure and Forecast								Variance			
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J		K (G+H+I+J)	K-F		H-D	
														Carryover to 2024 and Beyond						
Project	2020	2021	2022	Carryover to 2023	Original 2023	Revised 2023	2024 and Beyond	Total	2020	2021	2022	2023	2024 and Beyond	Project Carryover	Multi-Year Cash Flow Reallocation	Total	Project		Annual	
Braya Renewable (CIAC)	-	-	-	-	(28.00)	(28.00)	(391.60)	**(419.60)**	-	-	-	-	(391.60)	-	(28.00)	**(419.60)**	-	0.00%	28.00	-100.00%
IOC - 13252202 Refurb WAB Circ	-	-	-	-	(770.00)	(770.00)	(30.40)	**(800.40)**	-	-	-	(624.34)	(30.40)	-	-	**(654.74)**	145.66	-18.20%	145.66	-18.92%
WAB Airport Upstream Cap (CIAC)	-	-	-	-	(290.63)	(290.63)	-	**(290.63)**	-	-	-	(290.63)	-	-	-	**(290.63)**	-	0.00%	-	0.00%
IOC SCADA Data Link (CIAC)	-	-	(28.22)	(28.22)	-	(28.22)	-	**(28.22)**	-	-	-	-	-	-	(28.22)	**(28.22)**	-	0.00%	28.22	-100.00%
Valentine Gold Interconnection (CIAC)	-	(3,730.00)	(12,085.00)	(3,069.27)	-	(3,069.27)	-	**(15,815.00)**	-	(3,730.00)	(9,015.73)	(2,571.00)	-	-	(498.27)	**(15,815.00)**	(0.00)	0.00%	498.27	-16.23%
Provide Service Extenstions - All Areas (CIAC)	-	-	-	-	-	-	-	-	-	-	-	(78.50)	-	-	-	**(78.50)**	(78.50)	N/A	(78.50)	N/A
Upgrade Disribution Systems - All Areas (CIAC)	-	-	-	-	-	-	-	-	-	-	-	(4.72)	-	-	-	**(4.72)**	(4.72)	N/A	(4.72)	N/A
Total	**-**	**(3,730.00)**	**(12,113.22)**	**(3,097.49)**	**(1,088.63)**	**(4,186.11)**	**(422.00)**	**(17,353.84)**	**-**	**(3,730.00)**	**(9,015.73)**	**(3,569.19)**	**(422.00)**	**-**	**(554.49)**	**(17,291.41)**	**62.44**		**700.15**	

Appendix B

Program Scope Details 2023



Remove Safety Hazards

In Board Order No. P.U. 38(2010) related to Hydro's 2011 Capital Budget Application, the Board directed Hydro to include in its annual report on capital expenditures an explanation of each scope of work that was undertaken for the Remove Safety Hazards program, setting out the safety hazard that was identified, the location, the steps taken to address the issue, and the amount of the expenditure. Table C-1 outlines the work scopes undertaken in 2023.

Total Approved Budget: **$198,200**

Total Expenditure: **$207,034**

Table C-1: Remove Safety Hazards[1]

Program Work Scope	Expenditure[2] ($000)	Safety Hazard Identified	Work Scope Detail
Replace Parking Lot Lights and Poles – Hydro Place	131.0	A condition assessment of the parking lot poles and lighting identified that 18 poles and their associated lighting systems should be replaced due to corrosion and wear on the poles and defective lighting systems.	New poles and LED lighting systems were purchased in 2023. Construction is planned as part of the Remove Safety Hazards (2024) program.
Upgrade Ventilation Systems for Chemical Storage Areas – Holyrood TGS	45.0[3]	The ventilation systems for chemical storage areas in the Chemical Storage Building and Pipe Shop Building were determined to be inadequate for reliable expulsion of airborne contaminants, which can irritate mucus membranes and the respiratory tract.	New ventilation systems were designed and materials were ordered as part of the Remove Safety Hazards Program (2022). Construction was completed in 2023.
Work Scopes Under $50,000	31.0		

[1] Details are provided for program scopes greater than $50,000.
[2] Numbers may not add due to rounding.
[3] This work scope incurred $38.0 in 2022 for a total 2022–2023 cost of $83.0 ($000).

Perform Software Upgrades and Minor Enhancements

In its 2023 Capital Budget Application, Hydro committed to providing a summary of unforeseen work executed under the Perform Software Upgrades and Minor Enhancements (2023) program in this report. Table C-2 provides a summary of such work.

Total Approved Budget: **$451,200**

Total Expenditure: **$357,316**

Table C-2: Unforeseen Software Upgrades and Minor Enhancement Scope

Program Work Scope	Expenditure ($000)	Scope Detail and Justification[4]
Upgrade Server Operating Systems	51.2	The operating systems for 16 servers were required to be upgraded, as vendor support ended in the fourth quarter of 2023. The upgrades ensured that these products could continue to receive security updates, non-security updates, bug fixes, technical support, and online technical content updates. The upgrades were completed in 2023.
Work Scopes Under $50,000	29.0	

Terminal Station In-Service Failures

Hydro will provide a summary of scopes of work undertaken under the Terminal Station In-Service Failures program that exceed $750,000. Table C-3 outlines 2023 expenditures under this program.

Total Approved Budget: **$1,300,000**

Total Expenditure: **$2,846,695**

[4] Details are provided for program scopes greater than $50,000.

Table C-3: Terminal Station In-Service Failures

Program Work Scope	Expenditure[5] ($000)	Failure Identified	Scope Description
Bay d'Espoir Transformer T6 Replacement – Bay d'Espoir Terminal Station 1	1,218.4	One of the bushings on Bay d'Espoir Power Transformer T6 failed catastrophically on July 25, 2023. This failure removed Generating Unit 6 (85 MVA of generation capability) from Hydro's electrical system. This loss of generation capacity was an unacceptable reliability risk to customers on the Island Interconnected System and immediate replacement of Bay d'Espoir T6 was required.	Bay d'Espoir T6 was replaced with the available on-site spare power transformer.
Restore Power Transformer Capital Spare for Hydraulic Generating Unit Transformers – Bay d'Espoir Terminal Station 1	613.7[6]	The spare transformer used to replace Bay d'Espoir Transformer T6 in 2023[7] was serving as a spare for nine power transformers—Bay d'Espoir T1 to T7, Granite Canal T1, and Upper Salmon T1. Two alternatives were considered to restore availability of a spare—procurement of a new transformer; and refurbishment of the failed Bay d'Espoir T6. The alternative to procure a new transformer was rejected as the risk of being without a spare while waiting for fabrication and delivery of a new transformer (24 to 30 months) was deemed unacceptable. Refurbishment of the failed Transformer T6 was established as the best solution to restore the availability of a spare.	The failed Bay d'Espoir Transformer T6 was refurbished, to restore the availability of a capital spare generation transformer. This work commenced in 2023 and was completed as part of the Terminals In-Service Failure (2024) program.
Work Scopes Under $750,000	1,014.6		

[5] Numbers may not add due to rounding.
[6] This work scope is expected to exceed $750,000 when 2023 and 2024 expenditures are final.
[7] Refer to the first entry in this table.

Hydraulic In-Service Failures

Hydro will provide a summary of scopes of work undertaken under the Hydraulic Generation In-Service Failures program that exceed $750,000. Table C-4 outlines 2023 expenditures under this program.

Total Approved Budget: **$1,500,000**

Total Expenditure: **$4,081,091**

Table C-4: Hydraulic In-Service Failures

Program Work Scope	Expenditure[8] ($000)	Failure Identified	Scope Description
Refurbish Penstock 1 Defects – Bay d'Espoir	1,432.1	Penstock 1 supplies water from Intake 1 to Bay d'Espoir Units 1 and 2, and is approximately 1,000 metres in length and is a steel fabrication. Inspection and testing of Penstock 1 during the planned outage in 2023 revealed a higher-than-normal percentage of defects in the longitudinal weld seams. A more extensive test and refurbishment program was recommended, to reduce the risk of penstock failure during operation.	Non-destructive testing of the Penstock 1 longitudinal seam welds was completed. Identified defects were refurbished and the penstock was returned to service.
Work Scopes Under $750,000	2,649.0		

Thermal In-Service Failures

Hydro will provide a summary of scopes of work undertaken under the Thermal Generation In-Service Failures program that exceed $750,000. All program scopes of work undertaken in the 2023 program were under $750,000.

Total Approved Budget: **$3,300,000**

Total Expenditure: **$2,887,828**

[8] Numbers may not add due to rounding.

Gas Turbine In-Service Failures

Hydro will provide a summary of scopes of work undertaken under the Gas Turbine Generation In-Service Failures program that exceed $750,000. Table C-5 outlines 2023 expenditures under this program.

Total Approved Budget: **$344,200**

Total Expenditure: **$3,606,746**

Table C-5: Gas Turbine Generation In-Service Failures

Program Work Scope	Expenditure ($000)	Failure Identified	Scope Description
Generator Refurbishment – Stephenville Gas Turbine	3,436.1	In August 2023, generator rotor blades were damaged, which also caused secondary damage to the stator end windings.	The generator stator and rotor were removed for refurbishment. The stator was refurbished on site in 2023. The rotor was shipped to Hydro's service provider for refurbishment, which commenced in November 2023. The remaining work is expected to be completed in the second quarter of 2024, as part of the 2024 Gas Turbine In-Service Failures Program.
Overhaul Engine 202205 – Hardwoods Gas Turbine	77.0[9]	During a borescope inspection of Engine 202205, material loss was discovered on a nozzle guide vane. Hydro's service provider recommended that the engine be removed and overhauled.	Engine 202205 was removed from service and sent for overhaul to the service provider's facility in 2023. An available spare engine was installed and placed in service in 2023 to restore full generation capacity for the Hardwoods Gas Turbine. The engine being overhauled is expected to be returned to Hydro in the Second Quarter of 2024, as part of the 2024 Gas Turbine In-Service Failures Program.
Work Scopes Under $750,000	93.6		

[9] This work scope is expected to exceed $750,000 when 2023 and 2024 expenditures are final.

Diesel In-Service Failures

Hydro will provide a summary of scopes of work undertaken under the Diesel In-Service Failures program that exceed $750,000. All program scopes of work undertaken in the 2023 program were under $750,000.

Total Approved Budget: **$480,400**

Total Expenditure: **$727,177**

Transmission In-Service Failures

Hydro will provide a summary of scopes of work undertaken under the Transmission In-Service Failures program that exceed $750,000. All program scopes of work undertaken in the 2023 program were under $750,000.

Total Approved Budget: **$151,700**

Total Expenditure: **$193,589**

Distribution System In-Service Failures and Miscellaneous Upgrades, and Street Lights

Hydro will provide a summary of scopes of work undertaken under the Distribution System In-Service Failures, Miscellaneous Upgrades, and Street Lights program that exceed $750,000. All program scopes of work undertaken in the 2023 program were under $750,000.

Total Approved Budget: **$3,986,000**

Total Expenditure: **$6,029,094**

Boiler Condition Assessment and Miscellaneous Upgrades (2023) – Holyrood

In the capital budget application for the Holyrood Boiler Condition Assessment and Miscellaneous Upgrades (2023) program, Hydro listed all known components requiring replacement or refurbishment prior to the 2023–2024 winter operating season and indicated that it was possible that additional components may be identified as requiring replacement or refurbishment during the 2022 and 2023 condition assessment. For those additional components that were material in dollar value and met

capitalization criteria, Hydro proposed to communicate these items to the Board in this report. The condition assessments were completed on Units 1, 2, and 3 in 2023. Table C-6 provides a summary of the additional components that required replacement or refurbishment prior to the 2023–2024 winter operating season.

Total Approved Budget: **$2,926,600**

Total Expenditure: **$4,336,361**

Table C-6: Boiler Condition Assessment and Miscellaneous Upgrades (2023) – Holyrood

Scope Title	Expenditure ($000)	Scope of Work and Justification[10]
Units 1 and 2 Economizer Inlet/Outlet Header Attachment Inspection and Refurbishment	619.2	In 2022, the boiler service contractor recommended an inspection of the Units 1 and 2 economizer inlet and outlet header attachments during the scheduled unit outages in 2023. In 2023, the headers were cleaned on both units and inspected for leaking boiler tubes and any other issues present. The inspections on the Unit 1 inlet and outlet headers identified deterioration on: • Two boiler tubes that were then replaced; • Header supports that were then refurbished; and • Boiler tube-to-header welds that were then refurbished. The Unit 2 economizer inlet and outlet header attachments were also cleaned and inspected but no issues were identified.
Unit 3 Air Heater Cold End Basket Replacement	550.2	In 2022, the boiler service contractor recommended replacement of the Unit 3 air heater cold end baskets. The cold end baskets in boiler air heaters help improve the overall boiler efficiency by preheating the combustion air before it enters the furnace. Preheating the air reduces the energy required to bring it up to combustion temperature, leading to fuel savings and increased efficiency. The existing cold end baskets and support structure had extensive corrosion and were replaced in 2023 during the annual unit outage.

[10] Details are provided for program scopes greater than $50,000.

Scope Title	Expenditure ($000)	Scope of Work and Justification[10]
Unit 3 Lower Waterwall Slope Tube Inspection and Refurbishment	258.5	In 2022, the boiler service contractor recommended an inspection of the Unit 3 lower water wall slope tubes to check for tube thinning. Boiler tube thinning leads to inadequate thickness for pressure requirements and can result in a forced outage. Work in 2023 included boiler cleaning, thickness measurements on the lower water wall slope tubing, and a visual inspection for any signs of damage. Following the inspection, welding repairs were completed on tubes that were measured to be below the minimum wall thickness.
Unit 3 Gas Outlet Duct Plate Inspection and Refurbishment	147.3	The Unit 3 gas outlet duct conveys flue gas from the boiler to the breeching and stack. In 2023, scaffolding was erected, the ducting was cleaned internally, and plate thickness measurements were completed to determine the areas of the gas outlet duct that required refurbishment. Duct plate refurbishment was then completed and internal insulation was replaced where required to prevent condensation on the steel plate where corrosion would occur.
Unit 2 Front Wall Downcomer/ Header Expansion Joint Refurbishment	139.1	Boiler downcomers and headers are subjected to significant temperature differentials, causing them to expand and contract during operation. Expansion joints accommodate this thermal movement and prevent stress buildup in the downcomers, boiler headers, and associated piping. Expansion joints help maintain a seal between sections of the downcomers/headers and the boiler, preventing leakage of boiler gas. Proper sealing is essential for the efficient operation of the boiler and to prevent energy loss. Three expansion joints were cleaned and inspected in 2023; one expansion joint was replaced, one was refurbished, and all exposed expansion joints were refurbished on the boiler casing to ensure a proper seal between the internals of the boiler and the powerhouse.
Unit 3 Lower Vestibule Casing Replacement	89.3	Boiler casing inspection and refurbishment is necessary for maintaining the structural integrity, thermal efficiency, safety, and environmental compliance of boiler systems. The boiler casing and insulation was replaced in 2023 due to end-of-life condition of the cladding and insulation system.
Work Scopes Under $50,000	1.8	

Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condensers 1 and 2 (2023–2024) - Wabush Terminal Station

The primary scope of work for this program is to perform a Level 2 Condition Assessment on the internal components of Synchronous Condenser 1 ("SC1") and Synchronous Condenser 2 ("SC2") at the Wabush Terminal Station and complete refurbishment activities identified from the condition assessments that are deemed necessary to support the continued safe and reliable operation of SC1 and SC2. For those refurbishments that are material in dollar value and meet capitalization criteria, Hydro proposed in its 2023 Capital Budget Application to complete these activities within this program and communicate these items to the Board in its 2023 and 2024 Capital Expenditures and Carryover Reports. The condition assessment was completed for SC2 in 2023. Table C-7 provides a summary of the additional components that required replacement or refurbishment.

Total Approved Budget: **$1,093,300**

2023 Approved Budget: **$577,200**

2023 Expenditure: **$692,335**

Table C-7: Major Condition Assessment and Miscellaneous Refurbishments Synchronous Condenser 1 and 2 (2023-2024) - Wabush Terminal Station

Scope Title	Expenditure ($000)	Scope of Work and Justification[11]
SC1 and SC2 Oil Rings Procurement	138.5	As part of an inspection in 2022, the OEM recommended that the oil rings be replaced as they are worn and causing secondary oil contamination. New sets of oil rings were procured for both SC1 and SC2, with installation planned for the outages in 2024.
SC2 Stator and Rotor Cleaning and Painting	56.8	As part of an inspection in 2022, the OEM recommended that the SC2 rotor be removed, cleaned, and painted. In 2023, the SC2 rotor was removed. The rotor and stator were found to be coated in an oily residue and both were cleaned with carbon dioxide and painted.
Work Scopes Under $50,000	0	

[11] Details are provided for program scopes greater than $50,000.

Sch 6: 2023 Average Rate Base

Schedule 6

2023 Average Rate Base



2025 Capital Budget Application

2023 Average Rate Base



Table 1: Computation of Average Rate Base for the Year Ended December 31, 2023 ($000)[1,2]

	2023
Capital Assets – Return 4	2,972,380
Work in Progress[3]	59,596
	3,031,976
Deduct:	
Accumulated Depreciation – Return 6[4]	(713,461)
Contributions in Aid of Construction – Return 7[3]	(50,154)
Total Capital Assets	2,268,361
Deduct Items Excluded from Rate Base:	
Work in Progress[3]	(59,596)
Asset Retirement Obligations (Net of Amortization)	(11,237)
Electric Vehicle Charger Elimination[5]	(639)
Net Capital Assets	2,196,889
Net Capital Assets, Previous Year	2,161,118
Unadjusted Average Capital Assets	2,179,004
Deduct:	
Average Net Capital Assets Excluded from Rate Base	(7,811)
Average Capital Assets	**2,171,193**
Working Capital Allowance – Return 8	**702**
Fuel Inventory – Return 10	**57,802**
Supplies Inventory – Return 10	**41,349**
Average Deferred Charges for Rate Base – Return 11	**58,306**
Average Rate Base at Year End – Return 12	**2,329,352**

[1] The 2023 Average Rate Base is an excerpt of Return 3. For further information, please refer to "2023 Annual Return," Newfoundland and Labrador Hydro, April 2, 2024, Return 3.
[2] Numbers may not add due to rounding.
[3] Contributions of $16.3 million related to Capital Assets not in service have been net in Work in Progress. In addition, insurance proceeds of $1.0 million related to Capital Assets not in service have been net in Work in Progress.
[4] Accumulated Depreciation is net of the Retirement Asset Pool and Removal Provision. For further details, please refer to "2023 Annual Return," Newfoundland and Labrador Hydro, April 2, 2024, Return 6.
[5] As per Board Order No. P.U. 33(2023), electric vehicle chargers were excluded from Capital Assets and included in Regulatory Assets. The total is comprised of $0.9 million Capital Assets and $(0.3) million related to Deferred Contributions.

Sch 7: Capital
Programs and Projects

Schedule 7

Capital Programs and Projects



Programs

Programs

Over $750,000



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Schedule 7: Capital Programs and Projects

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Over $5,000,000	
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• Upgrade Worst-Performing Distribution Feeders (2025–2027)	2
• Replace Light- and Heavy-Duty Vehicles (2025–2027)	3
• Distribution System In-Service Failures, Miscellaneous Upgrades and Street Lights (2025)	4
• Replace Diesel Gensets (2025–2027)	5
$1,000,000 to $5,000,0000	
• Overhaul Hydraulic Units (2025)	6
• Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025) – Holyrood	7
• Provide Service Extensions (2025)	8
• Replace Mobile Equipment (2025–2027)	9
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• Replace Protective Relays (2025–2026)	12
• Terminal Station In-Service Failures (2025)	13
• Hydraulic In-Service Failures (2025)	14
• Upgrade Power Transformers (2025–2026)	15
• Purchase Tools and Equipment (2025)	16
• Replace Disconnects (2025–2026)	17
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Over $5,000,000

Program 1

Overhaul Turbine and Valves

Unit 3

2025

Holyrood

newfoundland labrador hydro

Overhaul Turbine and Valve – Unit 3 (2025)

Location: Holyrood

Investment Classification: Renewal

Asset Category: Thermal Plant

Cost: $15,975,913

Executive Summary

To support the continued safe and reliable operation of the Holyrood Thermal Generating Station ("Holyrood TGS") at rated output, 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 3 turbine and turbine valves in 2025.

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 overhaul of the Unit 3 turbine was last performed in 2016. The Unit 3 turbine valves overhaul was last performed in 2022. As such, the Unit 3 turbine and turbine valves are due for overhaul in 2025 according to the established overhaul cycles.

If an overhaul is not completed in 2025, the Unit 3 turbine and valves could fail while in operation. Such failure could result in forced unit outages resulting in the loss of up to 150 MW for several weeks to several months in duration, depending on the magnitude of the failure. 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. Due to the large diameter and weight of the rotor, an overspeed failure has the potential to be catastrophic and can severely impact safe and reliable operations.

As per the "Reliability and Resource Adequacy Study – 2022 Update ("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. At this time, capital investment related to the generation function of the Holyrood TGS, such as the overhaul of the turbine and turbine valves, 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 2025 program is $15,975,900.

[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.

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List of Attachments

Attachment 1: Holyrood 3: Fracture Mechanics Assessment of HP Valve Chest.

1.0 Introduction

Holyrood TGS is a critical part of the Island Interconnected System and is required to provide safe and reliable electricity. It has three generating units; Units 1, 2, and 3 with a total generation capacity of 490 MW. As per the 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.

The Unit 3 turbine is a critical asset required for the generation of 150 MW of power from Unit 3 at the Holyrood TGS. The turbine is equipped with valves critical to the unit's safe and reliable operation. The turbine and valves are exposed to several high degradation mechanisms including erosion, wear, fatigue, and cracking due to high temperature, high pressure ("HP"), and high flow velocity. To ensure these assets remain in reliable operating condition, it is prudent that regular preventive maintenance is performed. Under this program, Hydro performs turbine overhauls on a nine-year cycle and turbine valve overhauls on a three-year cycle at the Holyrood TGS.

2.0 Program Description and Justification

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 at the Holyrood TGS. 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, and refurbish or overhaul as required.

The scope of work under this program in 2025 will involve the overhaul of the Unit 3 turbine and turbine valves. As the generator overhaul is not due to be performed until 2027, it is not included in this year of the program. This work is required to ensure the continued reliable and safe operation of Unit 3 and the overall reliability of the Island Interconnected System through a reduction in forced outages or deratings, as well as confirmation of the operational accuracy of critical safety valves.

For the 2025 program, a welding repair must also be completed to the Unit 3 steam chest.[3] Weld cracking was first observed in 1998, and initiated along the interior surface of a weld joining the lower part of the steam chest with the lower half of the Unit 3 turbine casing. In 2022, an assessment of the

[3] A turbine steam chest is a valve casing for the turbine control valves.

steam chest weld crack was completed by the turbine service contractor, General Electric ("GE"), which concluded that the steam chest should only continue to be operated for a limited time; with a set number of start-stop cycles of the turbine until the steam chest has been repaired or replaced. While an annual inspection is performed on the steam chest crack, the risk to safety and reliability is unacceptable due to the increased growth rate of this crack which is approaching a critical size to failure. If the steam chest is not repaired, the weld crack could continue to propagate to a critical length where safe operation of the unit is no longer achievable, or complete failure of the steam chest weld could occur and create a serious safety and operational hazard.

3.0 Asset Overview

3.1 Asset Background

The assets covered under this program for 2025 are the Unit 3 turbine and turbine values, required for generation from Unit 3 at the Holyrood TGS.

The Unit 3 turbine was manufactured by Hitachi in 1978. The turbine consists of a HP section, an Intermediate Pressure ("IP") section and a parallel flow Low Pressure ("LP") section. Each section contains stages of blades, which are attached to the rotor, and diaphragms, which are stationary. The passage of steam through these blades and diaphragms converts the energy of the steam into rotational energy in the turbine. The turbine rotor sits on three journal bearings. A lube oil system consisting of a storage tank, oil coolers, and pumps, provides lube oil to the bearings. The Unit 3 turbine rotor is coupled to the generator rotor using a clutch that can be disengaged to allow using the Unit 3 generator in synchronous operation mode. If the turbine is not disassembled for internal inspection and overhaul every nine years, there is an elevated risk of a component failure that could lead to a catastrophic failure.

The Unit 3 turbine is equipped with 17 major turbine valves with functions summarized as follows:

- Four control valves for flow regulation, turbine speed control, and over-speed protection;
- Two main stop valves and two reheat stop/intercept valves for isolation, shut down, and emergency shut down;
- One blowdown valve for emergency pressure release; and

- Eight extraction steam non-return valves to prevent return of cool water from the feedwater preheater and to provide over-speed protection.

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 over-speed condition or other damage to the turbine components. If the turbine valves are not overhauled every three years, they are at an elevated risk of not functioning as designed. 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; because of the complexity and magnitude of the components, significant outages would be expected if repairs were required.

The overhaul of the Unit 3 turbine and turbine valves was last performed in 2016 and 2022, respectively. As such, according to the established overhaul cycles, the Unit 3 turbine and turbine valves are due for overhaul in 2025.

3.2 Asset Condition

As the turbine and turbine valves are exposed to degradation mechanisms such as high temperatures, HP, corrosive fluids, and erosive flows, regular maintenance and overhauls ensure the components continue to function as expected. The Unit 3 turbine was last overhauled in 2016 and the valves were last overhauled in 2022. Since that time, the unit has operated at a similar capacity and is expected to be available to operate at full capacity throughout the 2025–2026 winter season. In addition to routine turbine and valve overhaul activities, a crack in the Unit 3 steam chest requires remediation under this program.

A crack was discovered in 1998 in the lower part of the Unit 3 turbine steam chest. In 2001, Hydro performed a reinforcement repair for the steam chest crack as recommended by GE, and beginning in 2013, inspections to monitor the steam chest crack size were conducted every three years by a specialized inspection contractor. In 2022, an assessment of the steam chest crack was completed by the turbine service contractor, GE,[4] as recommended in the Hatch Ltd. Life Extension Condition

[4] Please refer to Attachment 1 of this report.

Assessment study of the Holyrood TGS.[5] Based on crack size measurements observed in previous inspections, GE determined in this assessment that the maximum allowable crack depth is 19.5 mm; in 2022, the maximum measured crack depth was 13 mm.

Cracking in the turbine steam chest, as observed on Unit 3, is typically due to fatigue alone or in combination with high-temperature creep. Crack growth rate is a function of stress ranges, which in the case of the turbine steam chest, result from the changes in the pressure and temperature due to the start-stop cycles of the turbine. Considering the uncertainties of the crack behaviour and the safety risk posed by a release of steam from the turbine, an assessment completed by GE determined that the turbine can currently sustain a maximum of eight start-stop cycles between formal inspections. Eight cycles are typical of one year's operation. If further crack growth is observed during planned inspections, it would lead to a reduction in permissible cycles (i.e., less than a year's operation), or potentially that the unit is unsafe to operate any further. The impact of a steam chest rupture cannot be understated.

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. The turbines, turbine valves, and generators were placed in service in 1970 for Units 1 and 2 and in 1979 for Unit 3. Chart 1 to Chart 3 provide the age for all assets covered under the program.

[5] "HTGS Condition Assessment and Life Extension Study," Hatch Ltd., March 31, 2022, vol. I and vol. II.



Chart 1: Asset Counts by Asset Age – Turbine



Chart 2: Asset Counts by Asset Age – Turbine Valves

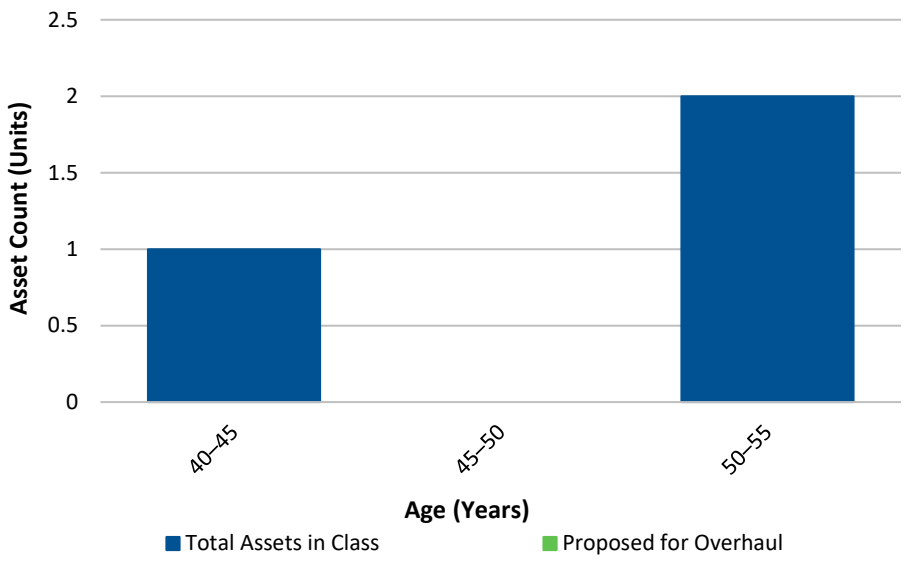


Chart 3: Asset Counts by Asset Age – Generator

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 Overhauled

Chart 4 to Chart 6 provide the five-year historical, current, and five-year forecast number of assets overhauled per year.[6]

[6] 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 the operating regime.

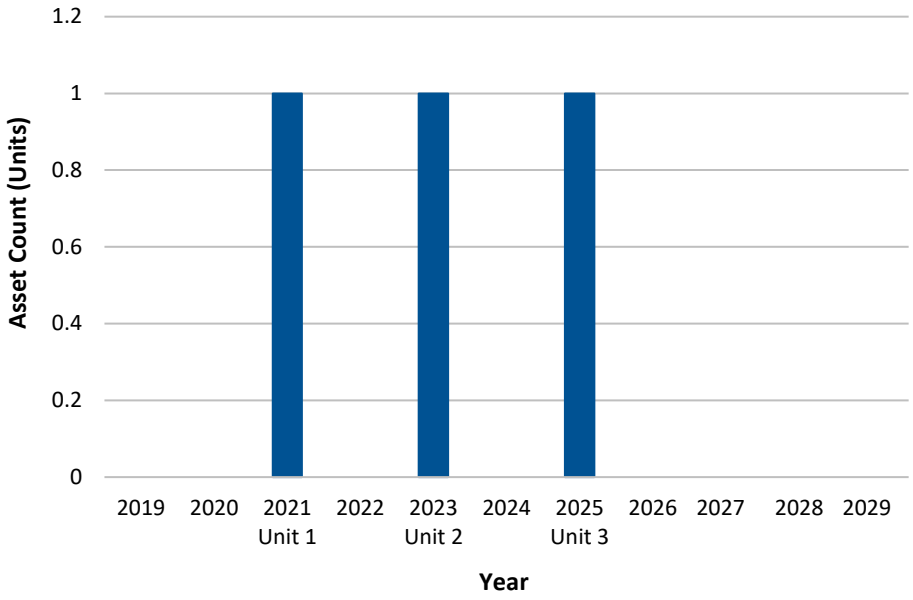


Chart 4: Historical and Forecast Assets Overhauled Count – Turbine

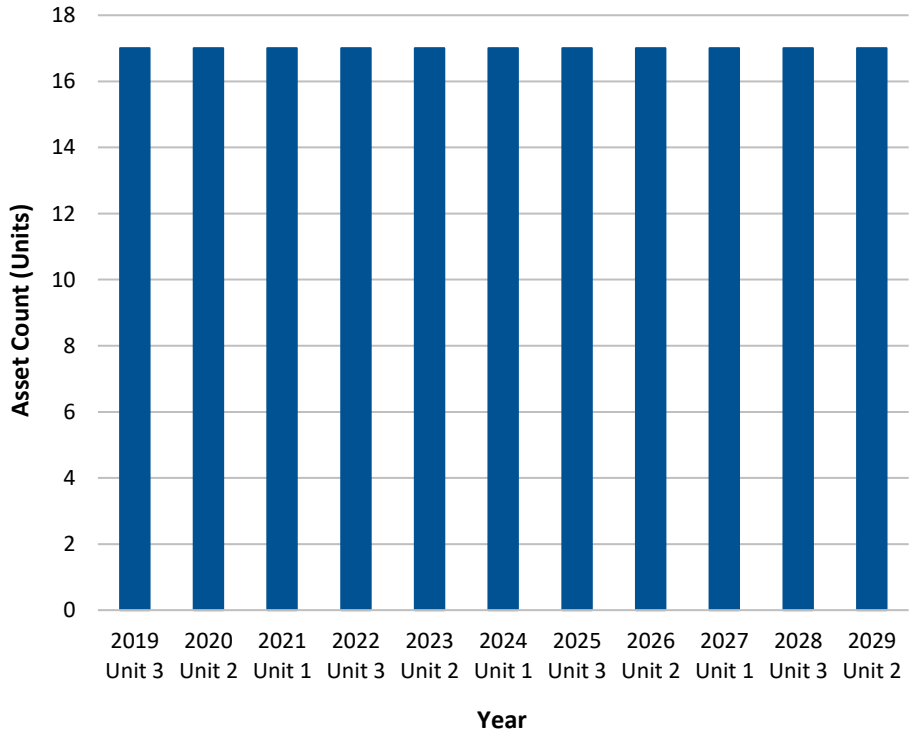


Chart 5: Historical and Forecast Assets Overhauled – Turbine Valves

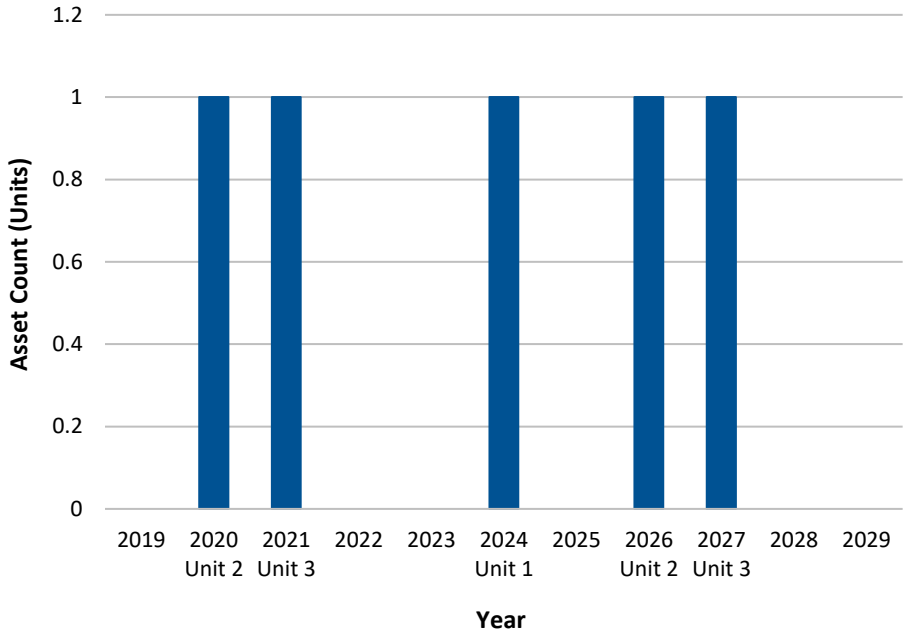


Chart 6: Historical and Forecast Assets Overhauled – Generator

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.

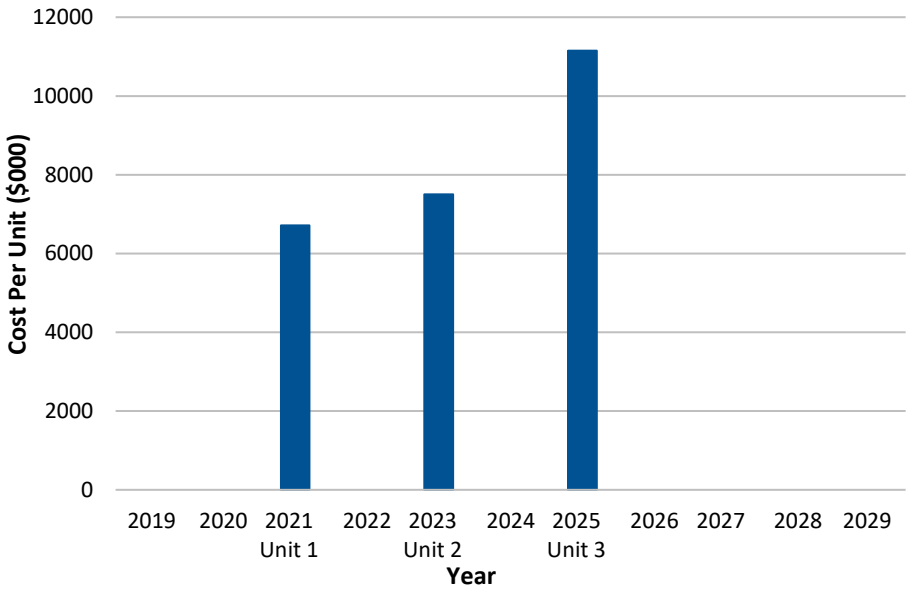


Chart 7: Average Unit Costs of Assets Overhauled – Turbine[7]

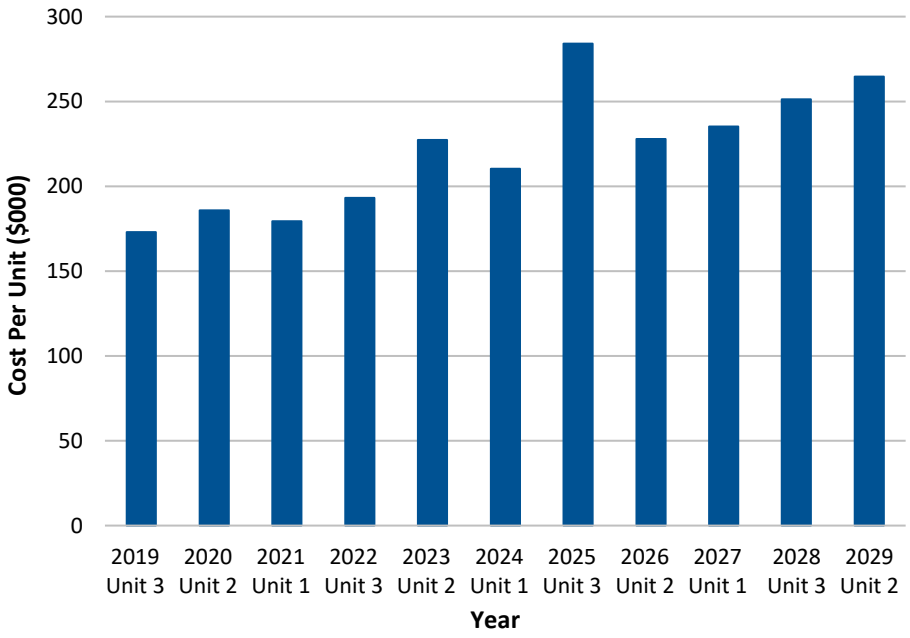


Chart 8: Average Unit Costs of Assets Overhauled – Turbine Valves

[7] The 2025 budget includes the cost of turbine overhaul scope as per previous overhauls, in addition to the cost of $4 million for the steam chest welding crack repair.

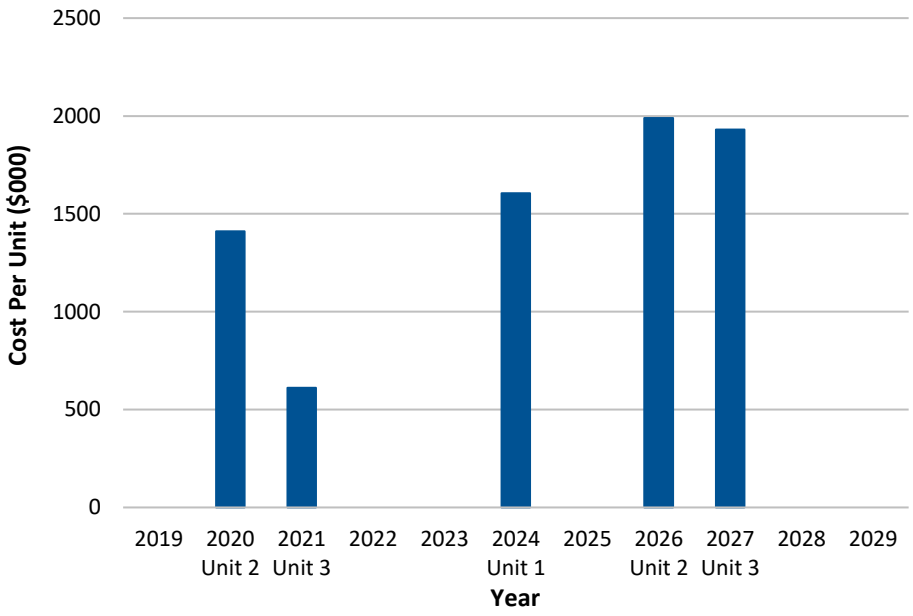


Chart 9: Average Unit Costs of Assets Overhauled – Generator

4.3 Historical Reliability

Hydro tracks performance data for its thermal generation units using the Derated Adjusted Forced Outage Rate ("DAFOR").[8,9] 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.

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro evaluated the following alternatives:

- Pace reduction;
- Pace advancement;
- Condition-based refurbishment;
- Continuation of overhaul program; and

[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.
[9] Filed quarterly with the Board, most recently "Quarterly Report on Performance of Generating Units for the Twelve Months Ended March 31, 2024," Newfoundland and Labrador Hydro, April 30, 2024.

- Overhaul.

5.1.1 Pace Reduction

A pace reduction of this program increases the failure risk of Unit 3 turbine and valves while in operation, which could result in collateral damage and loss of 150 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 is not disassembled for internal inspection after nine years of operation, there is an elevated risk of a component failure that could lead to a catastrophic failure. Turbine rotor blades must be inspected using NDE[10] techniques to identify any cracking that could result in a serious failure. Failure of stationary components within the turbine could liberate parts that could pass through the turbine causing extensive damage. Such failures would result in forced outages of many weeks or months. Bearings must be disassembled and inspected using NDE techniques to ensure they are acceptable for continued operation and clearance measurements must be confirmed to ensure proper operation without oil leaks. Auxiliary components including the lube oil system must be cleaned, inspected and overhauled to ensure a continuous reliable supply of lube oil to each bearing.

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

[10] Non-Destructive Evaluation ("NDE").

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.

All turbines at the Holyrood TGS are currently on a nine-year overhaul cycle and turbine valves are on a three-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.

5.1.2 Pace Advancement

Hydro's historical experience with this program has not demonstrated a need to accelerate turbine and valve overhauls.

5.1.3 Condition-Based Refurbishment

The condition of the turbine and valves cannot be adequately determined through external inspection or monitoring instrumentation. To assess the condition of internal components, disassembly of the turbine and valves is required. As such, condition-based refurbishment of the turbine and valves is not a viable option.

5.1.4 Continuation of Overhaul Program

This alternative consists of planned disassembly, detailed internal inspection, refurbishment and reassembly of all major internal components of the Unit 3 turbine and valves. 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.

5.2 Least-Cost Evaluation

Hydro has not identified any viable alternatives to facilitate a least-cost evaluation for the overhaul program; however, Hydro did seek engagement from GE and the turbine OEM to determine the best path forward for remediation of the Unit 3 steam chest crack.

In 2024, GE was engaged to study repair and replacement options for the Unit 3 steam chest crack. Upon completion of their analysis, GE recommended replacing the entire upper and lower half of the turbine casing, including the steam chest, with an anticipated manufacturing cost of approximately

$18 million. This replacement work would also require 24 months for fabrication, and a 4-month outage to Unit 3.

After consultation with the Unit 3 turbine OEM, it was determined that a welding repair could be completed onsite during the 2025 Unit 3 planned outage for the turbine overhaul at an estimated cost of approximately $4 million. As the 2025 turbine overhaul is the most cost-effective opportunity to complete the welding repair and to support the continued safe and reliable operation of the Unit 3 turbine at least cost, Hydro has proposed to complete the welding repair as proposed by the Unit 3 turbine OEM instead of replacement.

5.3 Recommended Alternative

Hydro recommends overhauling the Holyrood TGS Unit 3 turbine and turbine valves in 2025. Overhauling the Unit 3 turbine and turbine valves 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 3. Without regular overhauls, these components are at an elevated risk of malfunctioning.

5.3.1 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).[11]

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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 .

[11] Due to the extension of the Holyrood TGS through the Bridging Period, Hydro submitted an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account. The Board approved the extension of the account and related amendments in Board Order No. P.U. 1(2024). Hydro also was directed to file a report on the account in its next general rate application.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	5	4	**20**
Post-Implementation	5	1	**5**
		Risk Mitigated	**15**
		Risk Mitigated per $1 Million	**0.9**

6.0 Scope of Work

6.1 Unit 3 Turbine Overhaul

The turbine overhaul will include the removal of the top half of HP, IP, and LP casings, the turbine rotor, and the diaphragms. The rotor and diaphragms will be grit blasted to remove all scale buildup and then NDE and visual inspection will be completed to identify cracks or other concerns that could lead to turbine failure. Replacement or refurbishment will be completed as required. The bearings will be disassembled for detailed inspection and overhauled or replaced with spare bearings as required. All bolts, studs and nuts will be inspected using NDE techniques to ensure they are in good condition for continued safe operation. Parts will be replaced as required. Auxiliary equipment including the lube oil system will be overhauled to ensure all components are in good operational condition before returning to service. The turbine will be reassembled ensuring correct alignment and clearances. Balancing of the rotor will be completed upon unit start-up if required. While onsite, the turbine contractor will revisit the erosion damage at the steam inlet elbow to the upper control valves. Any recommended refurbishment to ensure extended safe operation will be completed by the contractor.

6.2 Unit 3 Turbine Valves Overhaul

The turbine valve overhaul will consist of dismantling all the control valves, main stop valve, combined reheat stop and intercept valves, extraction non-return valves, and blowdown valve 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.

6.3 Unit 3 Steam Chest Crack Repair

The Unit 3 turbine overhaul in 2025 will also include the steam chest crack repair to be completed by the Unit 3 turbine OEM. The proposed welding repair will remove the area of the steam chest where the

crack was initiated. The repair will require the removal of the lower half of the turbine casing, including the lower portion of the steam chest, for welding repair.[12]

6.4 Program Budget

The estimate for the 2025 program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	900.0	0.0	0.0	**900.0**
Labour	993.4	0.0	0.0	**993.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	12,050.0	0.0	0.0	**12,050.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	638.2	0.0	0.0	**638.2**
Contingency	1,394.3	0.0	0.0	**1,394.3**
Total	**15,975.9**	**0.0**	**0.0**	**15,975.9**

Chart 10 to Chart 13 provide the historical expenditures since 2019, the forecast 2024 expenditures, the proposed 2025 budget, and the forecast costs through 2029.[13]

[12] Budget for repair has been included within the turbine scope as shown in Charts 7, 10, and 13.
[13] *Supra,* f.n. 6.

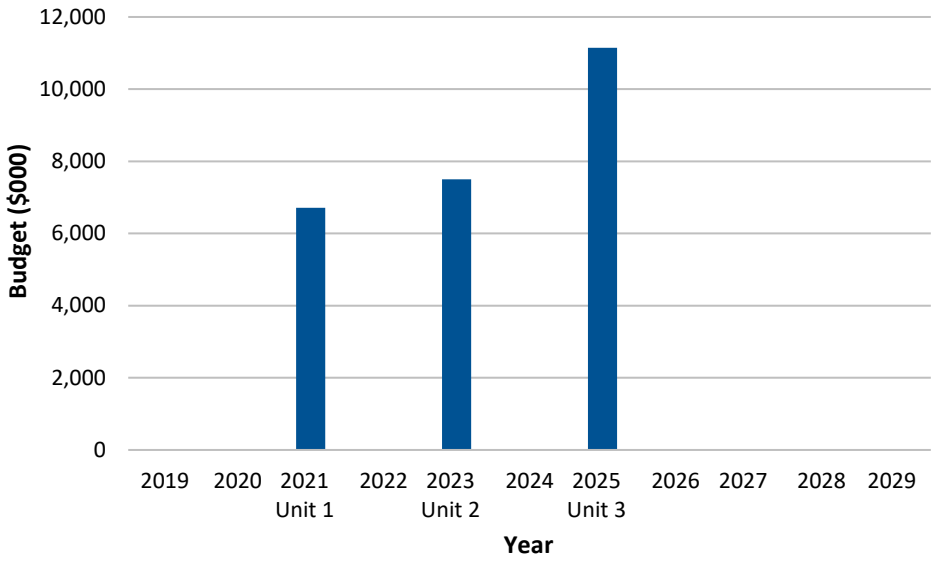


Chart 10: Historical and Forecast Program Budget – Turbine[14]

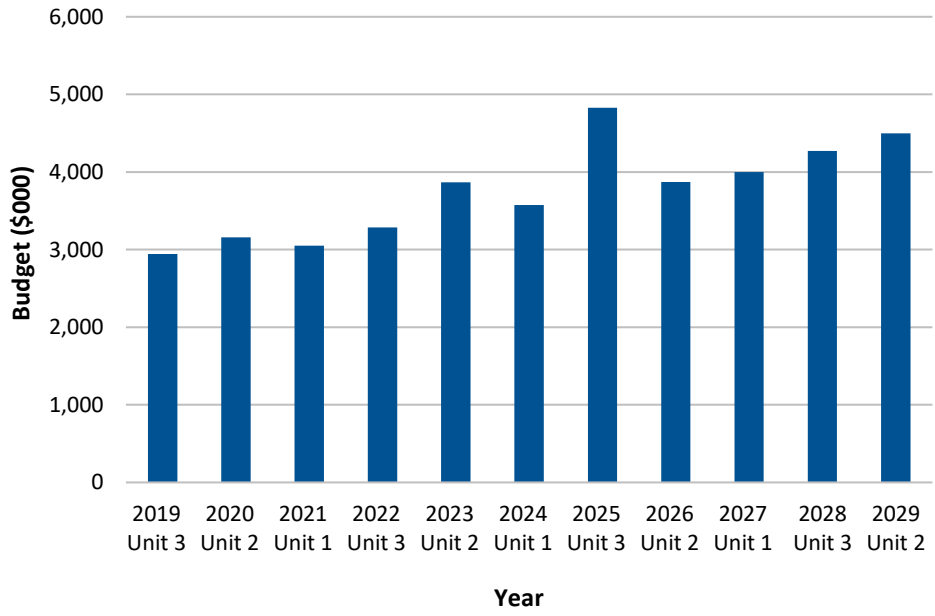


Chart 11: Historical and Forecast Program Budget – Turbine Valves

[14] The 2025 budget includes the cost of turbine overhaul scope as per previous overhauls, in addition to the cost of $4 million for the steam chest welding crack repair.

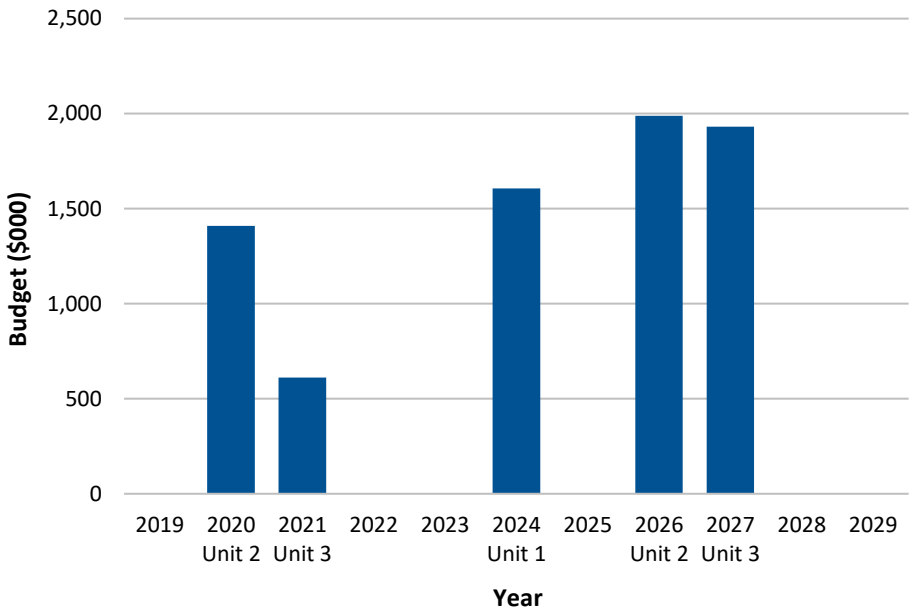


Chart 12: Historical and Forecast Program Budget – Generator

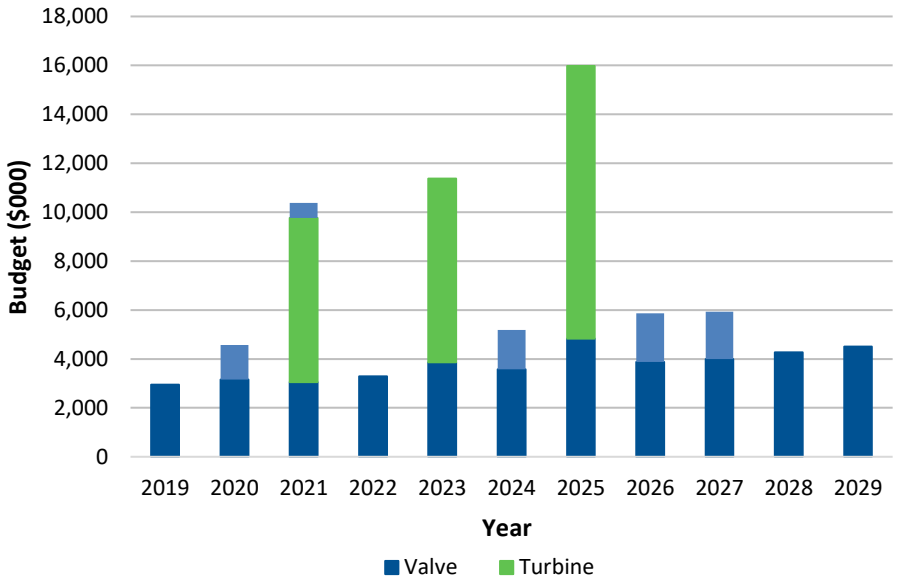


Chart 13: Historical and Forecast Program Budget – Total[15]

[15] The 2025 budget includes the cost of turbine overhaul scope as per previous overhauls, in addition to the cost of $4 million for the steam chest welding crack repair.

6.5 Program Schedule

The schedule for the program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Prepare planning documents.	January 2025	January 2025
Design:		
Prepare technical specifications for overhaul contract.	February 2025	February 2025
Procurement:		
Prepare overhaul contract documents; and award contract.	February 2025	March 2025
Construction:		
Review materials inventory and supply construction materials.	March 2025	November 2025
Perform turbine and valve overhauls.	June 2025	November 2025
Closeout:		
Prepare closeout documents.	November 2025	December 2025

7.0 Conclusion

The overhaul of the Holyrood TGS Unit 3 turbine was last performed in 2016 and the overhaul of the Unit 3 turbine values was last performed in 2022. To support the continued safe and reliable operation of the Holyrood TGS Unit 3, Hydro proposes the overhaul of the Unit 3 turbine and turbine valves in 2025, which will also include the repair of the Unit 3 steam chest crack. 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 3.

Attachment 1:

Holyrood 3: Fracture Mechanics Assessment of HP Valve Chest

GE Power



	GE Power	Document No.: GMD2022988

Revision:	Doc. Type:	Language:	Total Pages:	Function responsible:	Security Level:	Derived from:	Replaces:
A	DB	de	60				

Prepared by:	Checked by:	Approved by:
Dr. Frank Biesinger		

Holyrood 3: Fracture Mechanics Assessment of HP Valve Chest

Cross-Checked by:

Cross-Checked by:

General Data

System Name	Holyrood 3
System ID	SY0019258
Power	150 MW
Speed	3600 rpm
Country	Canada

1 Summary

This document summarizes the fracture mechanics assessment study performed on the HP-Valve chest for Holyrood Unit 3 Turbine.

The Holyrood power plant is a Bunker C fuel unit that is operated with sub-critical steam parameters. It is located in the province of Newfoundland and Labrador in Canada. The unit, originally build by Hitachi, was commissioned in 1979 and is operated by Newfoundland & Labrador Hydro. The specified steam parameters at HP inlet are 538°C and 125 bar.

It is assumed that the HP-Valve chest is made of steel cast material of the type 1.25 CrMoV. This is based on Positive Material Identification (PMI) performed on the valve chest in Aug. 2022. The measured chemical composition and the hardness values correspond quite well with the GE material designated STG50T. The GE internal material data for this material has been used to perform the assessments.

Phased Array Ultrasonic Testing (PAUT) were conducted to determine the crack depth by Acuren Group Inc. PAUT tests were performed in 2013, 2016, 2019, 2021 and 2022 (Slide 17 and 18 in slide deck). The results from the PAUT tests showed extensive cracking on the inside of the weld chest at the joining weld. From the PAUT inspection in May 2019 up to July 2021 the maximum crack depth increase was 6 mm. Between the two dates 14 starts are conducted.

A fracture mechanics assessment study was performed based on Phased Array Ultrasonic Testing (PAUT) results from Acuren Group Inc. The fracture mechanics assessment was performed acc. to BS7910:2005. The calculated crack growth behavior was adjusted to the crack extension between May 2019 up to July 2021. After another 8 start-stop cycles the assessment line in the Failure Assessment Diagram (FAD) will be reached

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(slide 36 in slide deck). The maximum allowable crack depth is 19.5 mm. In July 2022 the maximum measured crack depth was 13 mm.

It is strongly recommended to perform a repair or replacement latest reaching this point. To reduce future crack propagation in a limited operation the recommendations are to lower life steam temperature by approx. 50 K, the life steam pressure by approx. 25 bara, pre-heat the valve chest to at least 175°C prior to applying the full pressure and reduce the number of starts and load changes as much as possible.

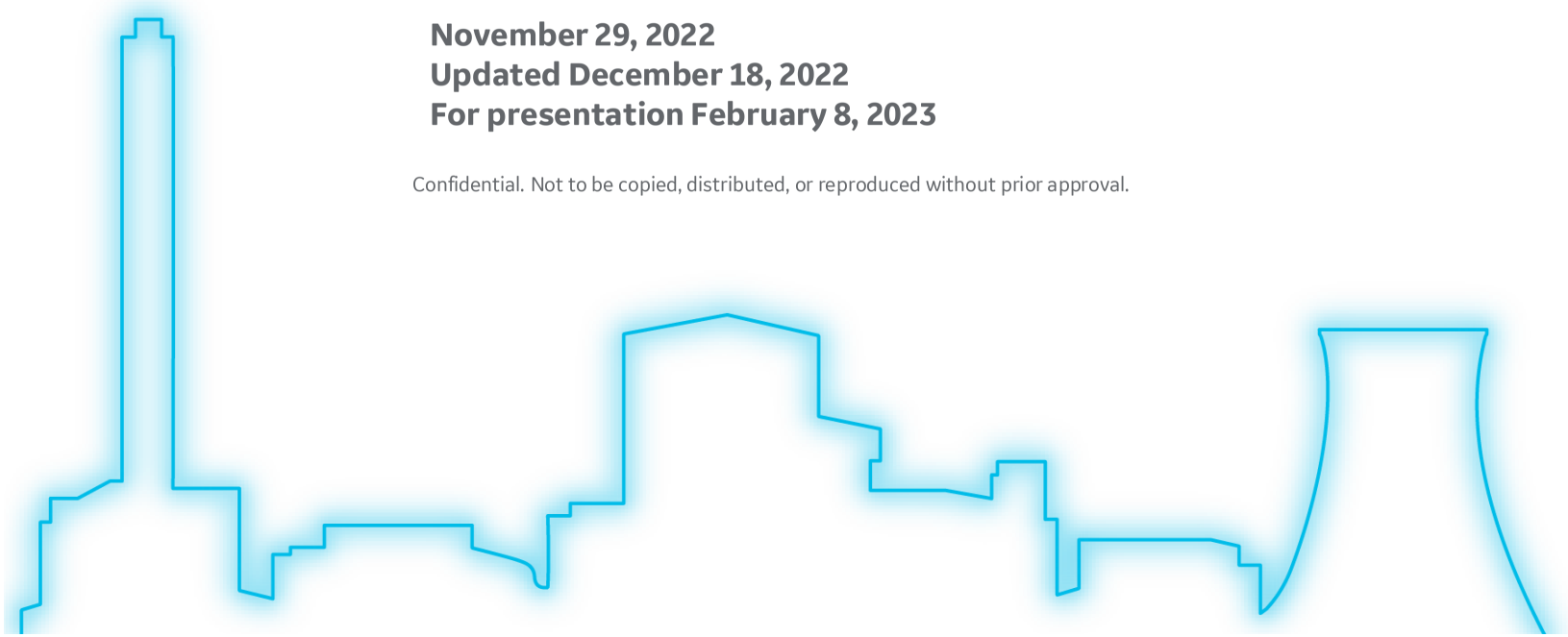
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FULL Steam AHEAD

Holyrood 3 – HP Valve Casing Weld Fracture Mechanics Assessment

November 29, 2022
Updated December 18, 2022
For presentation February 8, 2023

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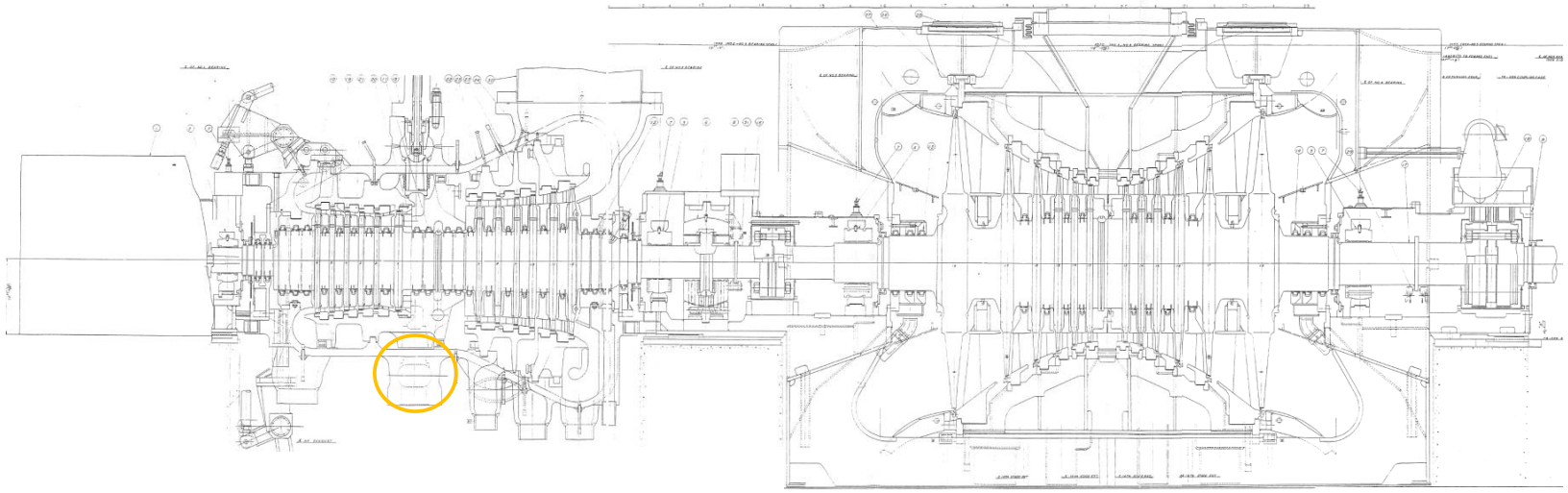
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Holyrood 3 (SY0019258)



HP-IP+LP
HP valve chest: Assumption: similar to GE designation STG50T (1.25 CrMoV) based on PMI conducted
OEM: Hitachi

spec. data of turbine		Operating data Plant overall view	Jan 1993 - March 2022
Power Output / MW	150	Operating hours [OH]	119'510
LS- / HRH-Temperature / °C Temperature originally specified	538 / 538 (1000°F)	Starts in total [-]	276
LS- / HRH-Pressure / bar	125 / (1813psi)	Cold start [-]	
LS- / HRH-Mass flow [kg/s]	135 /	Warm start [-]	
Commissioning	Jan 1979	Hot start [-]	

t/cycle = 433 h/cycle: steady state operation per start-stop in average

Source: GFSK 2022/10/25
HRD 3 Operational Data - Starts and Stops.xlsx

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Material of Valve Chest



Material of Valve Chest Update 2023/02/02

PMI on Surface of Valve Chest and Weld Overlay

TEAM Industrial Services
TISI Canada Inc.

Report No: U3-LCV-02 JW

POSITIVE MATERIAL IDENTIFICATION INSPECTION REPORT

Job Number: 5082-0051	Client Specifications : QA/QC
Client Name: **APM/NL HYDRO**	Acceptance: CLIENT INFORMATION
Date of Examination: AUGUST.2.2022	Procedure: PMI CAN 1 Rev 0
Work Location: HOLYROOD, NL	**Technique:** PMI CAN 1 Rev 0
Unit No. 3	Requisition No: N/A
Items Examined 1	Project Name: Lower Control Valve – LH ONLY

PMI	Cr	Ni	Mo								DISPLAY
Min %											TS-S5
Max %											TS-A6

DESCRIPTION		CR	CU	MO	MN	LEC	FE	V	DISPLAY	ACC	REJ
UNIT No. 3	Above Weld	1.3	0.06	1.05	0.59	0.95	95.13	0.13	TS-A6		
										✓	
LOWER LEFT CONTROL VALVE	On Weld	0.13	0.03	0.89	0.89	2.57	95.21	0.08	TS-S5	✓	
	Below Weld	0.51	0.03	1.17	0.66	2.57	94.75	0.11	TS-S5	✓	

GE-Designation	DIN-Designation	Cr [wt.-%] min	Cr [wt.-%] max	Cu [wt.-%] min	Cu [wt.-%] max	Mo [wt.-%] min	Mo [wt.-%] max	Mn [wt.-%] min	Mn [wt.-%] max	V [wt.-%] min	V [wt.-%] max	Delivery Instruction GE
STG50T	GS-17CrMoV5-10	1.2	1.5	-	0.3	0.9	1.1	0.5	0.9	0.2	0.3	NB 00069

Based on the conducted measurements STG50T is the nearest equivalent to the valve material.

Source: PMI-U3-LCV-02-02.08.2022 (4).pdf
NB 00069

Hardness Measurement on Surface of Valve Chest and Weld Overlay

Above Weld	On Weld	Below Weld
219 HB	233 HB	216 HB
221 HB	234 HB	218 HB
217 HB	229 HB	221 HB

GE-Designation	DIN-Designation	Brinell Harndess [HB] min	max	Delivery Instruction GE
STG50T	G17CrMoV5-10	176	233	NB 00069

- PMI of the valve chest
  - "Above weld": matches quite well with the chemical specification for the GE material designated STG50T
  - "On weld" and "Below weld": deviations of PMI results compared to "Above weld" results
- Hardness Measurement of valve chest
  - Given the accuracy of the hardness measurement, all values measured meet the GE material specification designated STG50T.

Source: Hardness Report AUGUST. 02.2022 (4).pdf
NB 00069

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Fracture Mechanics



Fracture Mechanics Assessment

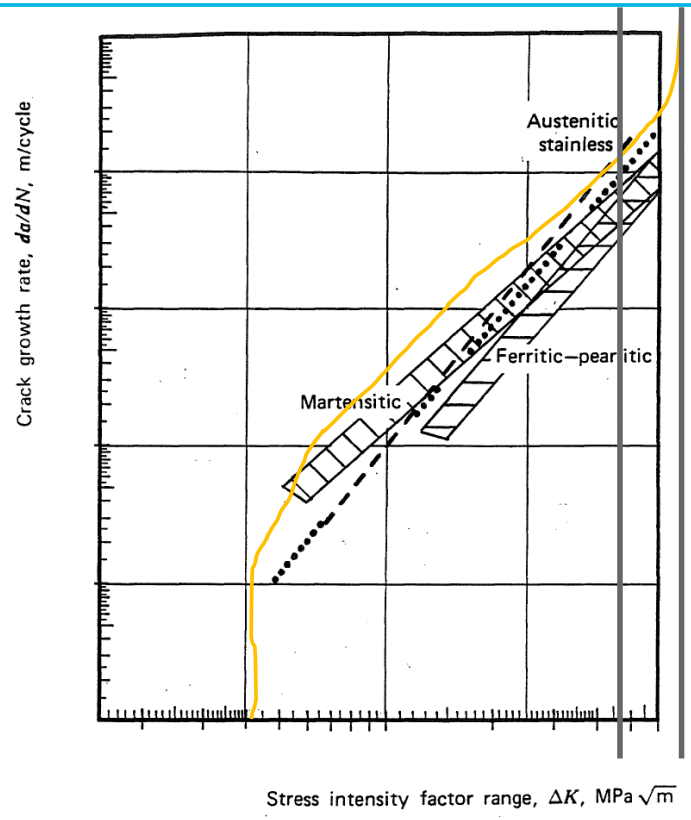
Fatigue Crack Growth (FCG)

- Fatigue crack growth: Paris-Law based on GE-internal document HTGE-ST-0082 for Stg50T and weld connection was used to complete calculations with the following;
  - Temperature correction based on Youngs-Modulus
  - Coefficients for **upper bound** crack growth used

Paris-Law:

$$\frac{da}{dN} = C \cdot \left(\frac{E(20°C)}{E(T)} \cdot \Delta K_{\mathrm{Ieff}} \right)^{m}$$

Crack Growth as Function of Stress Intensity Factor



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Fracture Mechanics Assessment

Fracture Toughness K_{IC} ; K_{mat}

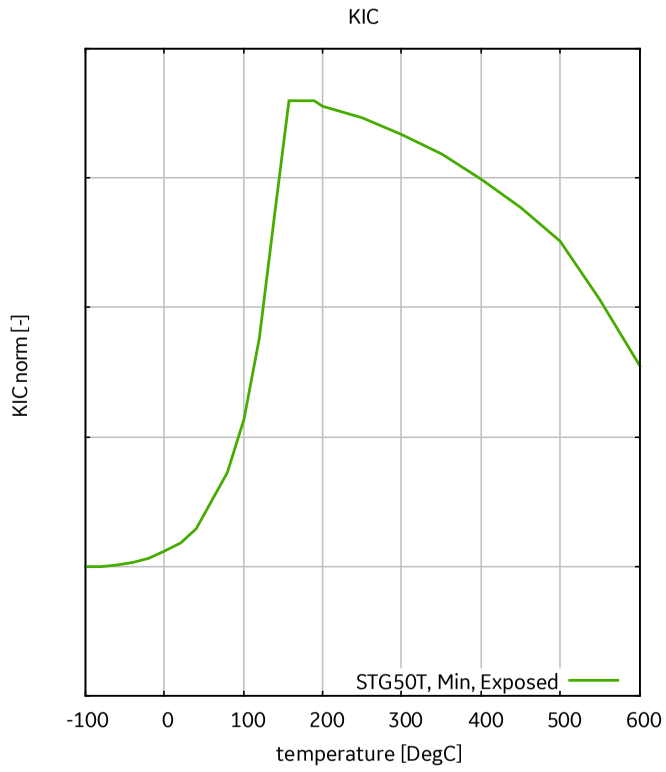
- According to GE internal guideline TN12/1076 **exposed minimum** fracture toughness for Stg50T has been used
- Exposure condition for material tests:

Material	Exposure Temperature [°C]	Exposure Time [hours]
STG50T	475	30 000

- Fracture toughness K_{IC} ; K_{mat}:
  - to allow for end of Paris-Law: limit to √0.5
    $\rightarrow K_{mat} = 0.707 * K_{IC} = KIC / \sqrt{2}$
  - $K_{\mathrm{mat}} = \sigma \cdot Y \cdot \sqrt{\pi \cdot 2 \cdot a} \triangleq \frac{K_{\mathrm{IC}}}{\sqrt{2}} = \sigma \cdot Y \cdot \sqrt{\pi \cdot a_{\mathrm{c}}}$

  $\rightarrow$ this corresponds to a safety factor of 2 on the critical crack length

Normalized Fracture Toughness for Stg50T



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Fracture Mechanics Assessment

Creep Crack Growth (CCG)

Creep Crack Growth

- Based on a K-type formula from BS7910:2005
- Material properties Ccr and q from BS7910:2005 for 1CrMo, **upper bound** (nearest equivalent to STG50T).

Creep crack propagation rate

- acc. BS7910:2005 eq. (T.4)

$$\frac{da}{dt} = C_{\mathrm{cr}} \cdot \left(C^*\right)^q$$

- acc. AVIF-Nr. A 178

$$C^* = \sigma_{\mathrm{ref}} \cdot \dot{\varepsilon}_{\mathrm{ref}} \cdot \left(\frac{K_I}{\sigma_{\mathrm{ref}}}\right)^2$$

Source: BS7910:2005
AVIF-Nr. A 178, Abschlussbericht: Langzeitkriechermüdungsrissverhalten (Vorhaben Nr. 255) IfW Darmstadt und MPA Stuttgart, 2005

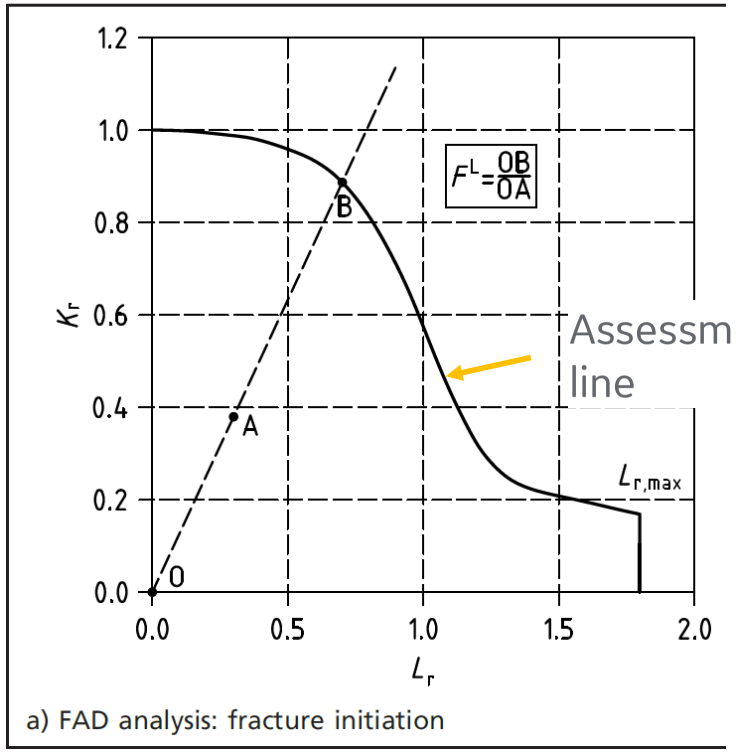
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Fracture Mechanics Assessment

Failure Assessment Diagram (FAD)

- The Failure Assessment Diagram (FAD) enables an assessment to be made of the resistance to fracture and plastic collapse of a flawed component.
  - Load ratio L_r = reference stress σ_{ref} / yield strength σ_Y
  - Fracture ratio K_r = stress intensity factor K_I / fracture toughness K_{mat}
- Assessment of fracture initiation of particular indication under consideration of the respective loading.
- All assessment points below the Assessment Line are acceptable.
- Associated with an assessment are **reserve factors** $F^L = \frac{OB}{OA}$ which indicate the proximity to the limiting conditions (Assessment Line) or show the margin for future operation.

Figure N.3 **FAD analysis for (a) fracture initiation**



a) FAD analysis: fracture initiation

Source: BS7910:2019

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Fracture Mechanics Assessment Update 2022/12/18

Methodology / Technology

- Fracture Mechanics Assessment:
  - Based on BS7910 Level 2
    - Fatigue Crack Growth (FCG)
    - Creep Crack Growth (CCG)
    - Failure Assessment Diagram (FAD)
    - Chapter M.3.3 Long surface flaws in plates
  - Input generated with the help of
    - Finite Element Analysis (ANSYS)
    - Material:
      - GE-internal material database for material properties like UTS, yield strength, Youngs modulus, Poisson ratio, creep strain evolution law, material properties for FCG (Paris Law)
      - BS7910 for material properties of CCG
    - BS7910:2005

Methodology / Technology

- Finite Element Analysis (ANSYS)
  - Steady-state and transient start-stop calculation
    - based on limited operational data provided by customer
    - thermo-mechanical stresses of the undisturbed geometry determined as input for the analytical fracture mechanics assessment
      - Over-elastic behavior considered by applying the Neuber method using Ramberg-Osgood material law
  - Limit-Load calculation
    - to assess the amplification factor of the nominal internal pressure
    - cracked valve body with a modeled crack of 13 mm depth along the entire internal surface including pressure on the crack faces
    - at steady-state temperature

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Fracture Mechanics Assessment Update 2022/12/18

Assumptions

- Material
  - It has been assumed (c.f. slide 5) that the valve chest has been produced out of a material which is similar to the type 1.25CrMoV (GS-17CrMoV5-10, Mat. No. 1.7706) and that the crack growth at the joining weld can be calculated with base material properties.
  - GE-internal material designation: STG50T
  - All material properties derived from GE-internal material database except properties for CCG
  - Fracture toughness
    - Minimum scatter band values
    - in an exposed state (after exposure to 475°C over 30 000 hours)
    - End of Paris-Law limited to $K_{mat} = \sqrt{0.5} \cdot K_{IC}$ to prevent accelerated crack growth in the region of the fracture toughness.

Assumption

- Fracture Mechanics Assessment
  - Structural model
    - Based on the PAUT results it has been assumed that the crack should be modeled as a long surface crack
    - Crack configuration is covered by the model in Chapter M.3.3 Long surface flaws in plates from BS7910:2005
    - Crack depth is constant along the length of the plate
  - Loading type
    - Stress distribution along the crack depth converted into membrane and bending stress based on FEM stress distribution
    - As the crack depth increases, the membrane and bending stresses are re-calculated
- Valve Geometry
  - The valve geometry has been scanned in and modeled in 3D

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Fracture Mechanics Assessment Update 2022/12/18

Assumptions

- PAUT
  - Crack elongation based on the PAUT reports from Acuren Group Inc.
  - No statement is made about the quality and accuracy of the PAUT inspections.
  - The results are used as stated in the respective reports from Acuren Group Inc.

Assumption

- Crack growth
  - It is assumed that the inspection results from May 2019 (crack depth 6 mm) and July 2021 (crack depth 12 mm) lead to a maximum crack growth at the location marked with “12”.
  - The reason for this maximum crack growth can only be determined by fractographic investigation of the crack faces. A potential explanation could be that due to ordinary crack growth the crack picked up indications in the ligament and therefore the crack growth was accelerated. This scenario is possible for future crack growth as well and has been partially confirmed by the PAUT measurement in July 2022. → the measured crack extension between May 2019 and July 2021 is the basis for the adjusted crack growth calculation
  - In 2001 GE stated: “the bottom half sees more severe service due to condensate flashing on start-up and shut down.”

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Fracture Mechanics Assessment Update 2022/12/18

Assumptions

- Leak-before-break behavior
  - Has not been performed because as the crack depth is quite similar along the entire internal surface it might be assumed that the crack growth along the entire crack front is homogenous. A breakthrough would then potentially lead to an opening along the entire length of the valve chest (c.f. slide 40).
  - Since the structural model of a Long surface flaw in plates is used for the crack growth calculation only the breakthrough along the entire plate would be predicted.

Assumption

- "Critical crack depth before a repair must be made"
  - Any crack configuration in the FAD is allowable which is below the assessment line (c.f. page 35)
  - This configuration is reached at a crack depth of about 19.5 mm.
  - A repair or other remedy measures are strongly recommended latest at this point. To reduce future crack propagation in a limited operation the recommendation from page 48 need to be implemented.
  - Based on the results of the crack growth calculation adjusted to the PAUT results (05/2019 – 07/2021) after 8 cycles, starting in 07/2021, it is recommended to conduct any repair or remedy measures.

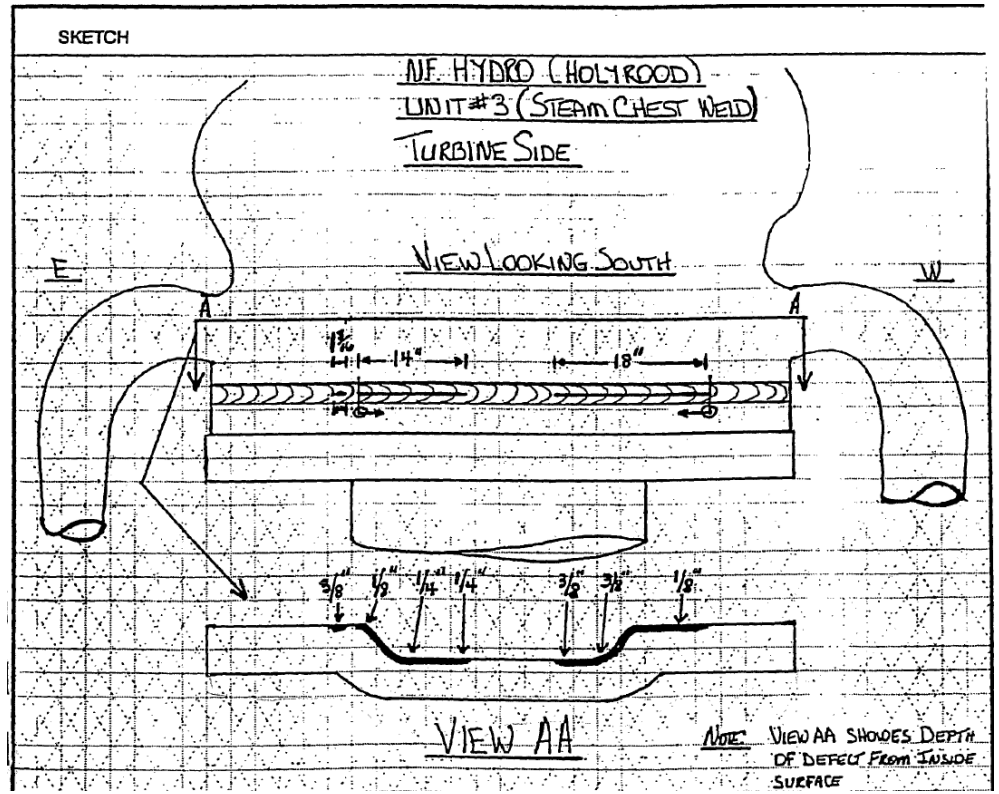
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Findings
HP-Valve Casing Weld



Findings

Findings and UT Results



Source: 2000 U3 steam chest crack - repair application - Christians file.pdf

Reinforcement Weld

- On the outside of the joining weld a reinforcement weld was completed in 2001 by GE.
- Any weldment will lead to residual stresses which will be balanced across the wall thickness
  - Potential compressive residual stresses from reinforcement welding could give rise to tensile residual stresses on the inside at the crack location.
  - Any residual stress configuration is not covered in the FEM simulation, since no substantial information is available.
    → Consideration of the measured crack extension covers any potential effect of residual stresses or inferior material properties.

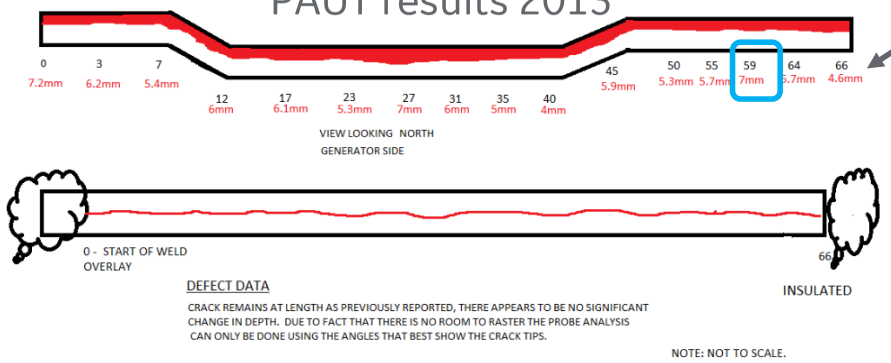
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Findings

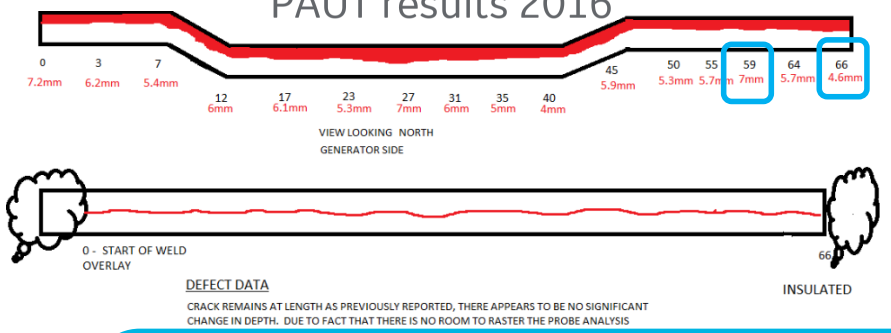
PAUT Results

66inch → 1676 mm

PAUT results 2013



PAUT results 2016

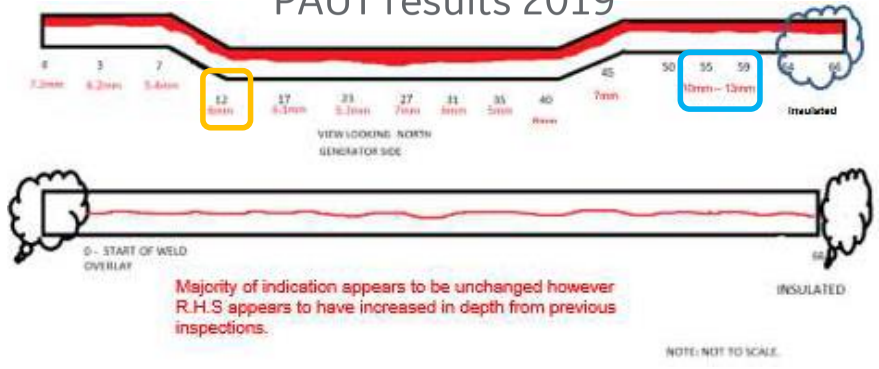


Source: Phased Array Report 2019.pdf

PAUT Results

05/2019

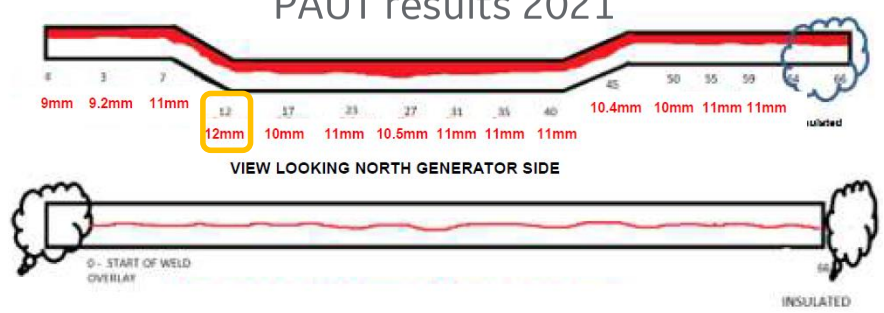
PAUT results 2019



14 Starts

07/2021

PAUT results 2021

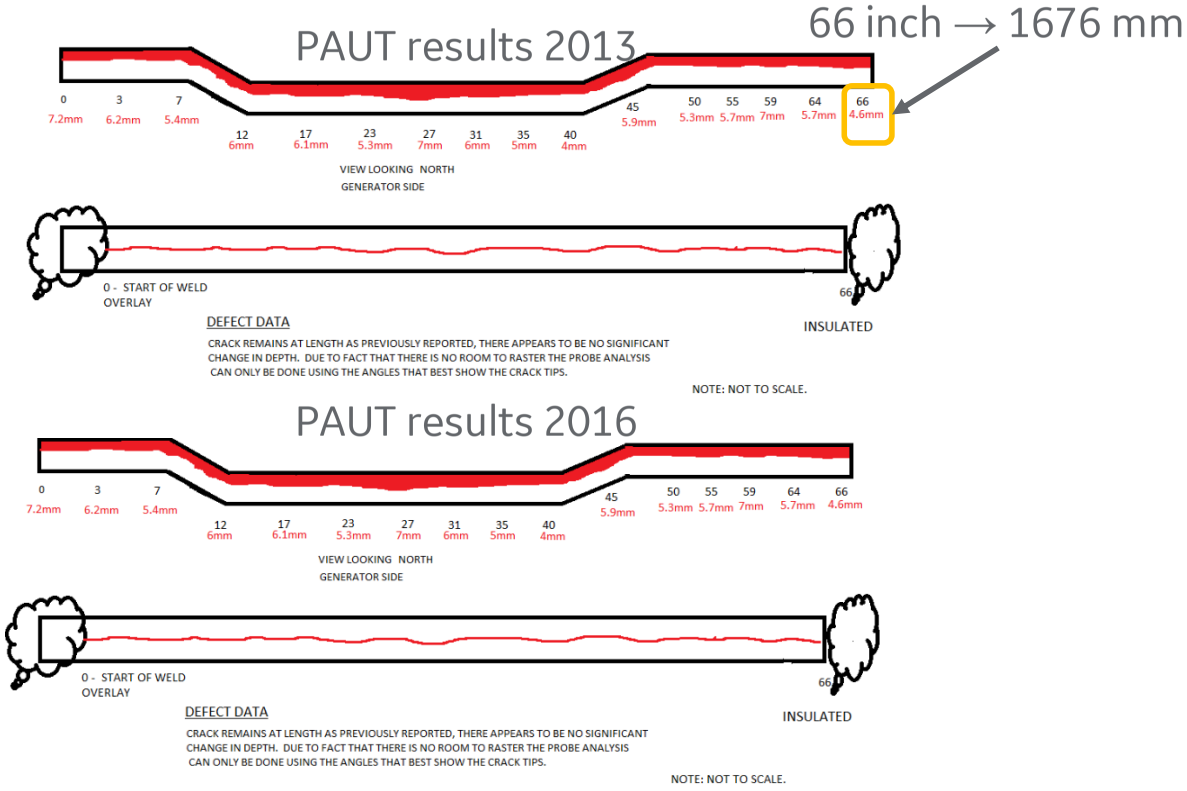


Max depth from PAUT results 12 mm → a_i = 12 mm

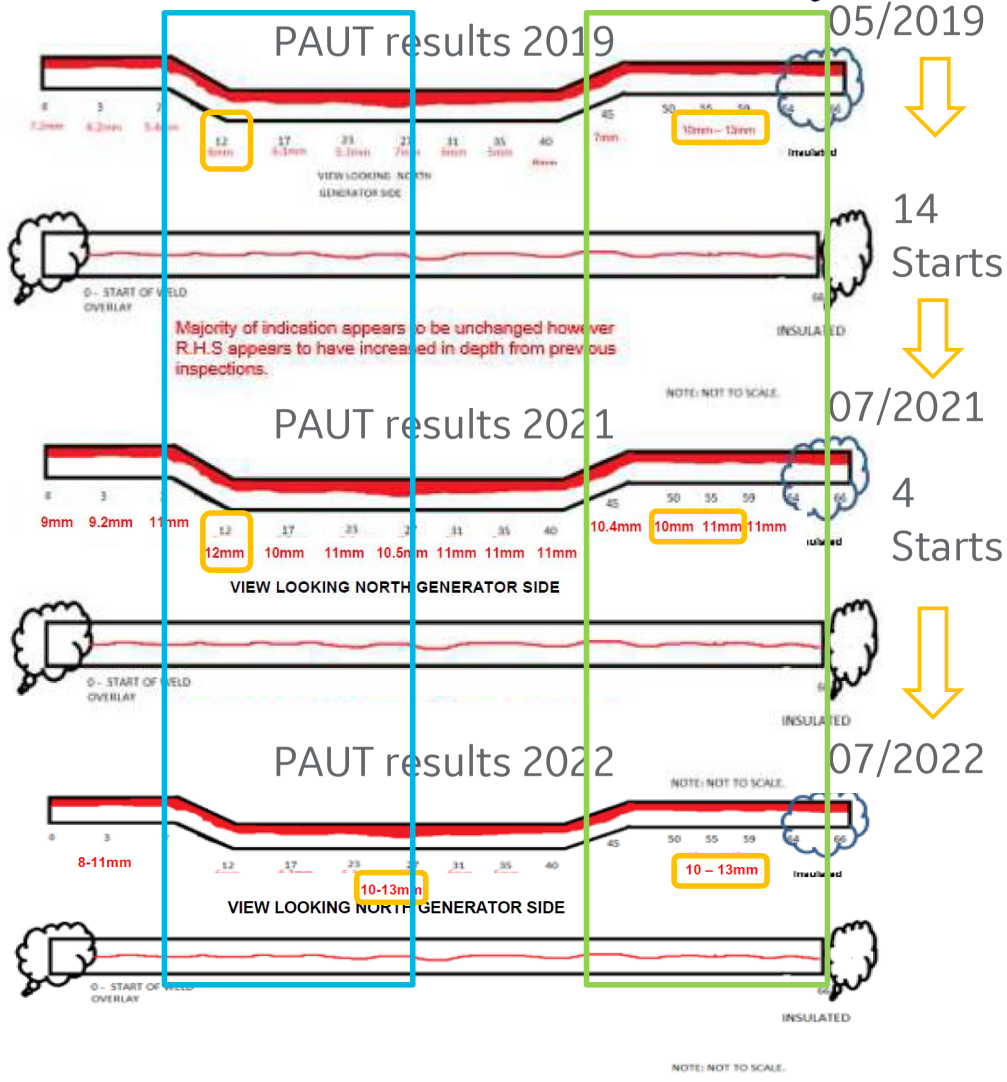
Source: PAUT-SS072821-001 R0.pdf

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Findings – PAUT Results Update 2022/12/13



FULL Steam AHEAD



Max depth from PAUT results 12 mm → a_i = 12 mm

Source: Phased Array Report 2019.pdf

Source: PAUT-SS072821-001 R0.pdf
PAUT-SS071822-001 R0 (official).pdf

Link to slide 47

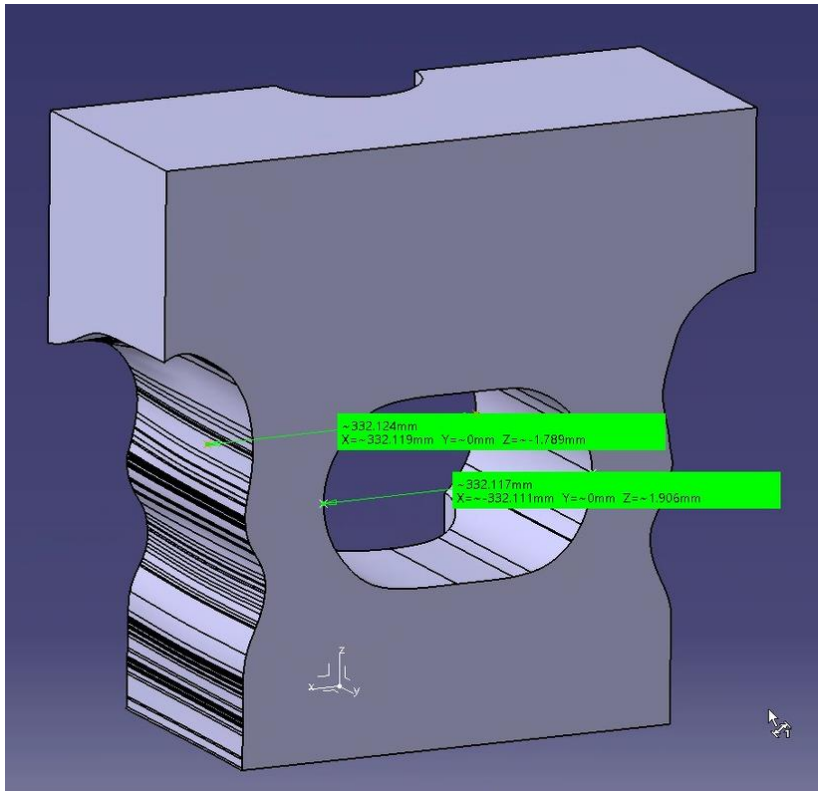
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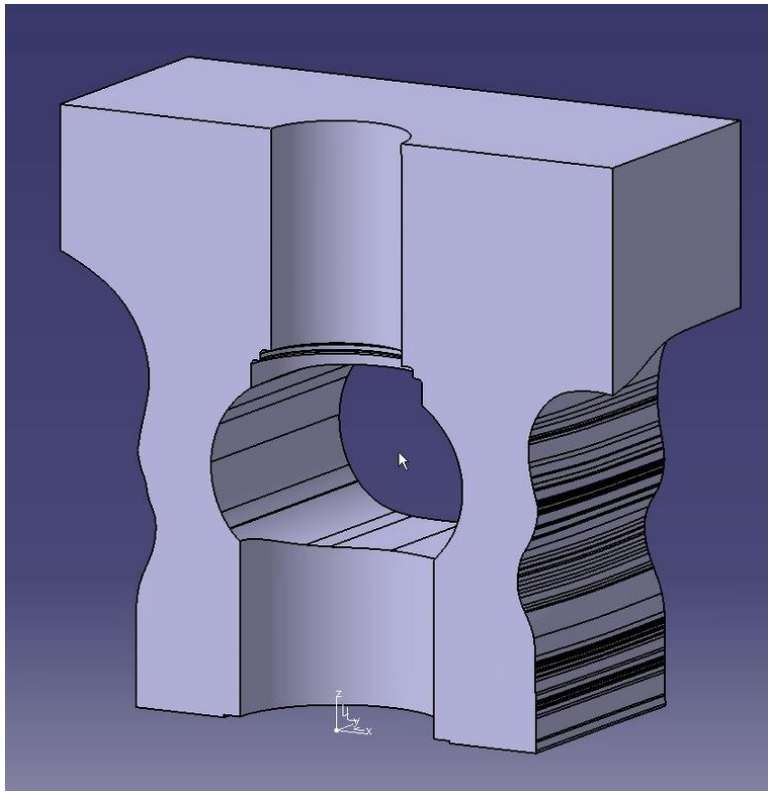
HP-Valve Casing CAD



CAD-Model of Scanned Valve Casing

Clear Span





Clear span of 332 mm → converted into diameter of 332 mm

Source: valve chest1.CATPart

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Fracture Mechanics Assessment HP-Valve Casing Weld



Stress Input – Holyrood 3

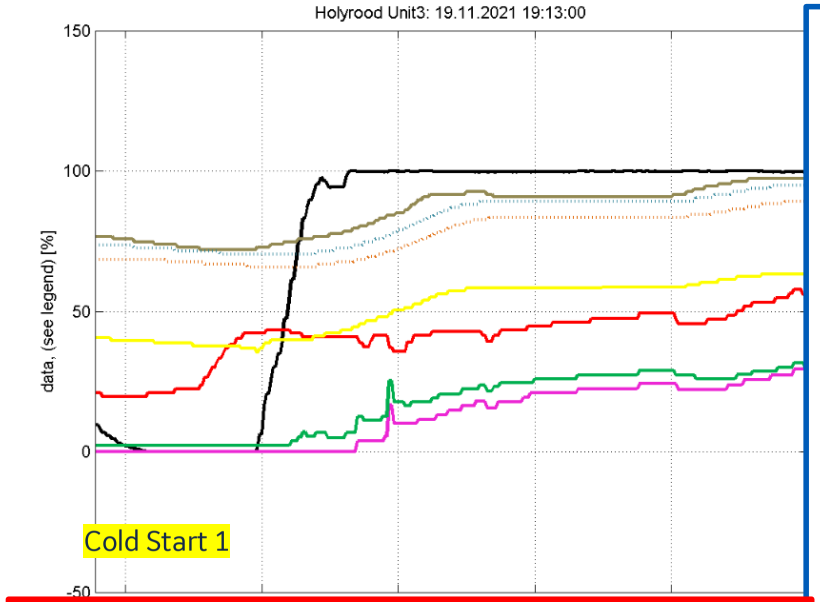
Start up

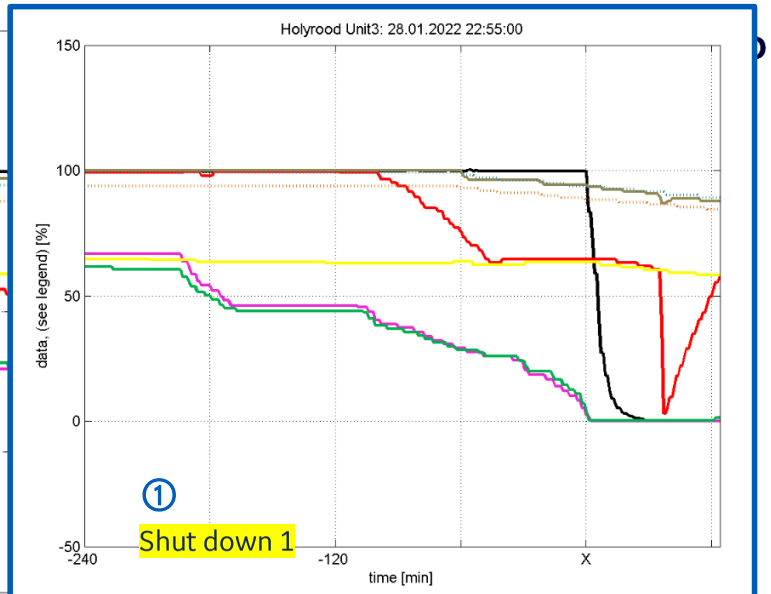
- Turbine speed (3600 RPM)
- Turbine load (150 MW)
- Mass flow (121 kg/s)
- Live pressure (125 bar)
- Exhaust temperature (538 °C)
- Live temperature (538 °C)
- Metal temperature inner (538 °C)
- Metal temperature outer (538 °C)

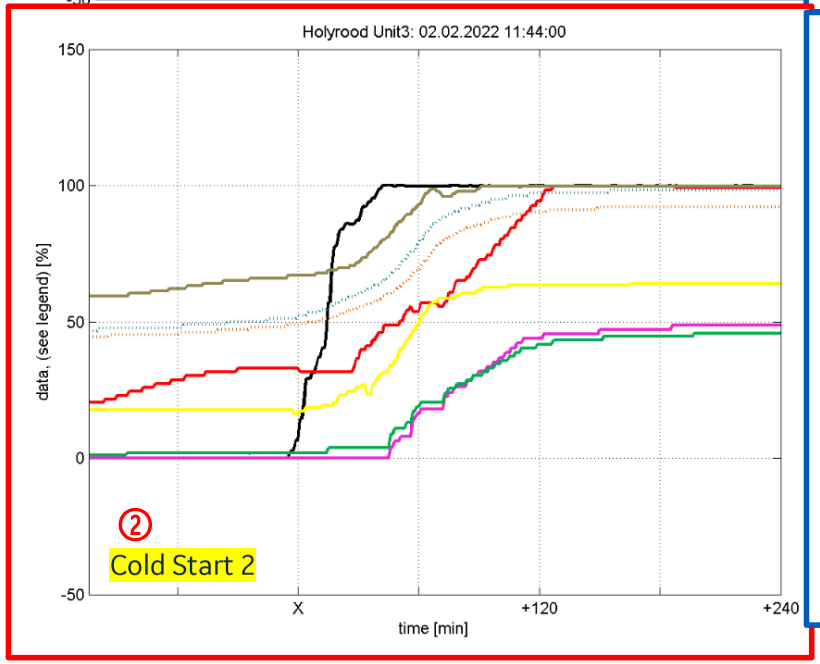
a. 1 complete cycle to be assessed
b. Pre-shutdown-start-shutdown
c. Natural cooling to be performed after shutdown1 ① to be inline with metal temp. at cold start 2 ②
d. In shutdown 2 ③, speed data is not consistent
e. In coldstart2, do we need to perform prewarming to achieve temperature (increase of 25deg.cel) when start is detected.

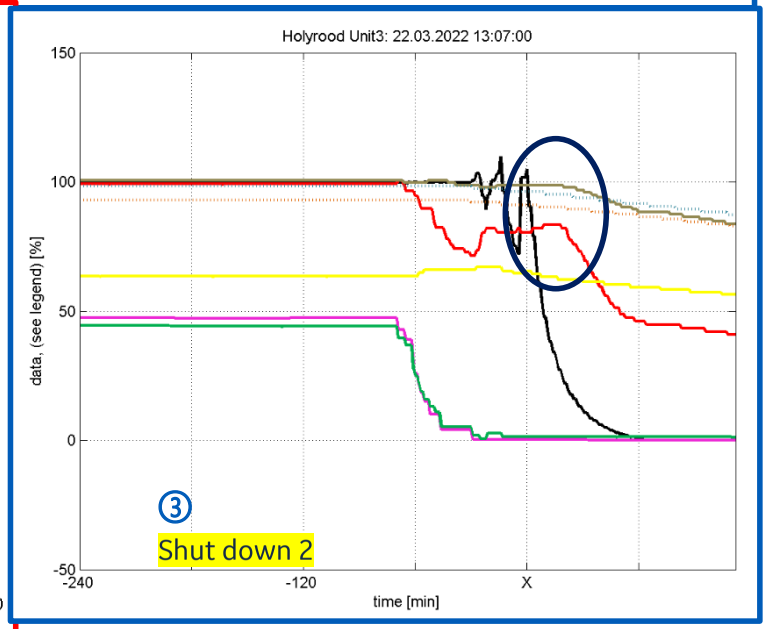
→ cycle for Fracture Mechanics Assessment consists of Cold Start 2, steady state and Shutdown 1 as shown in the graphs

- upper loading for fatigue crack growth: stop/steady state condition (“Shutdown 1”)
- lower loading for fatigue crack growth: start-up (“Cold start 2”)





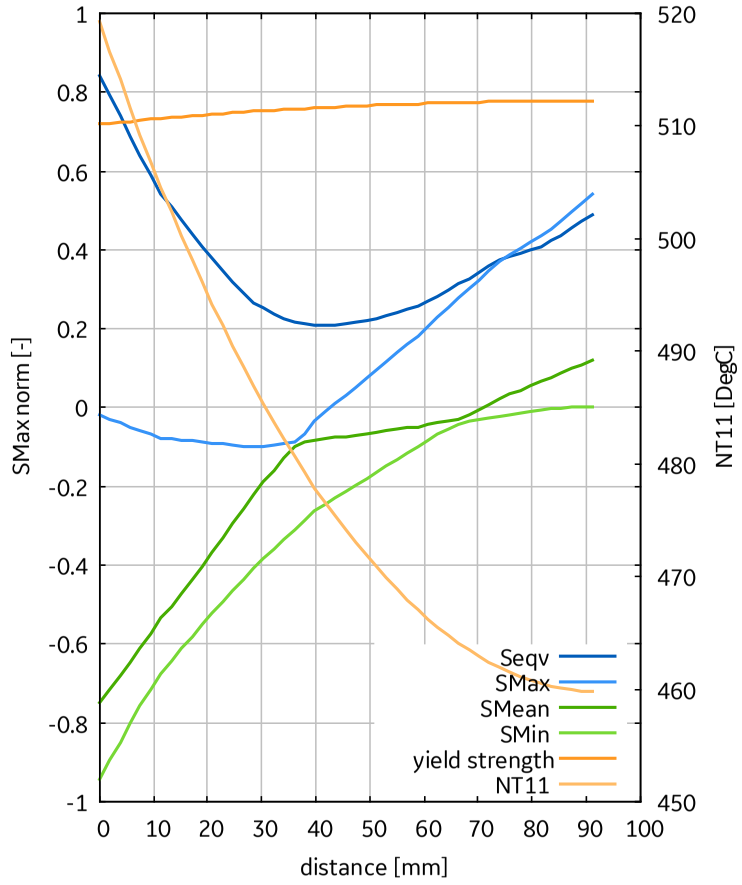


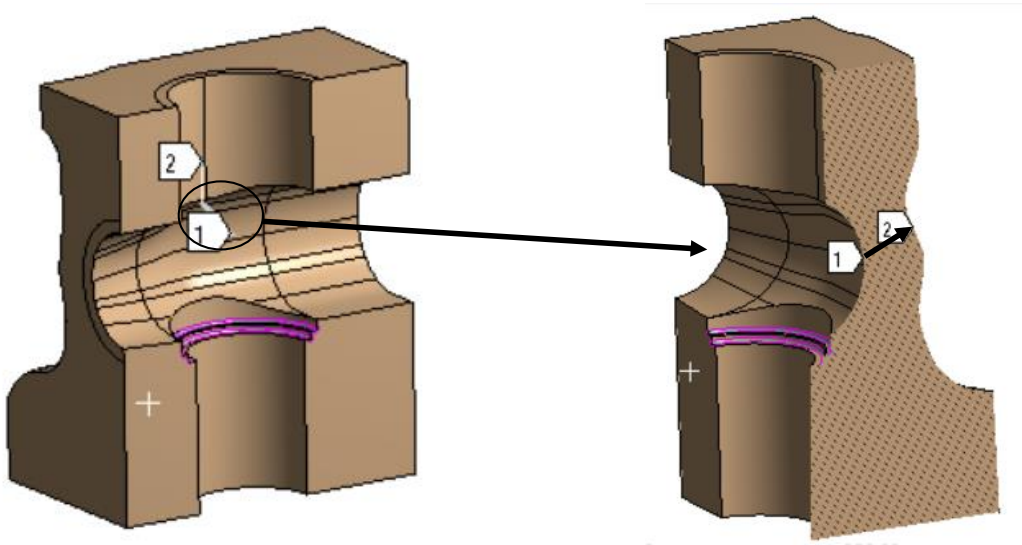


Source: Holyrood_Valve_results.pptx

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Stress and Temperature variation at crack location for fatigue crack growth calculation





Source: Holyrood_Valve_results.pptx

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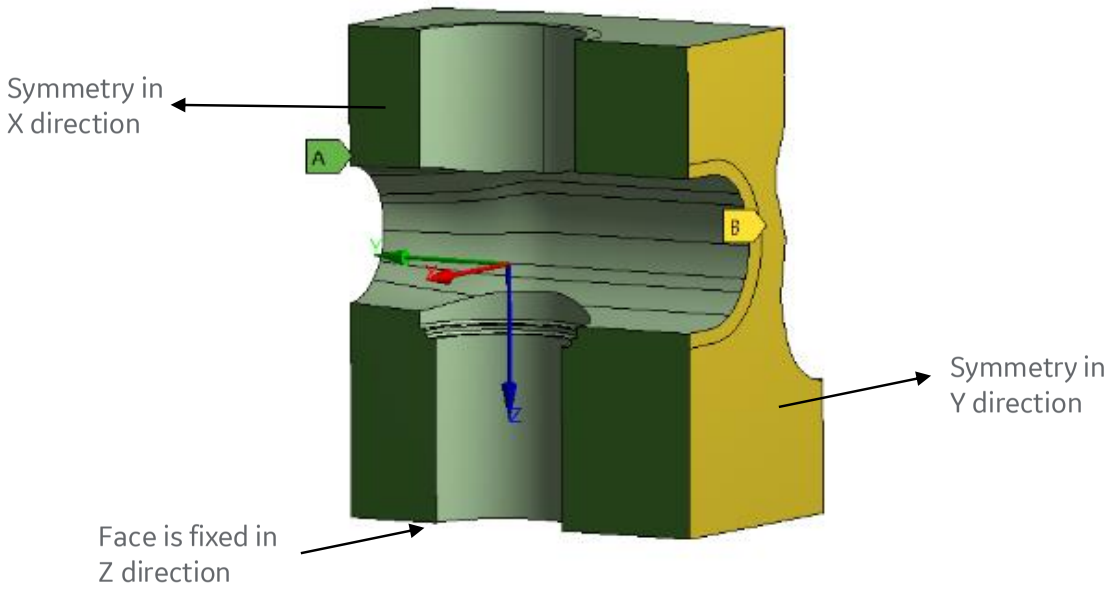
Limit Load Calculation

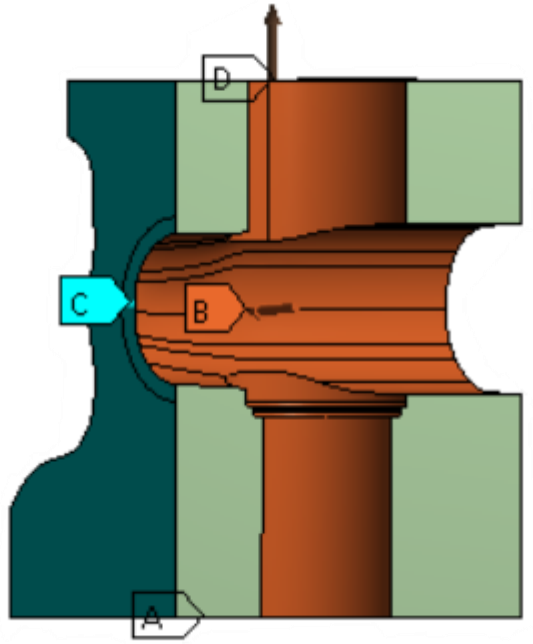


FE Model - Boundary Conditions and Material Information

Boundary conditions are as per GE-internal guideline STD0016987.

Quarter model is analysed





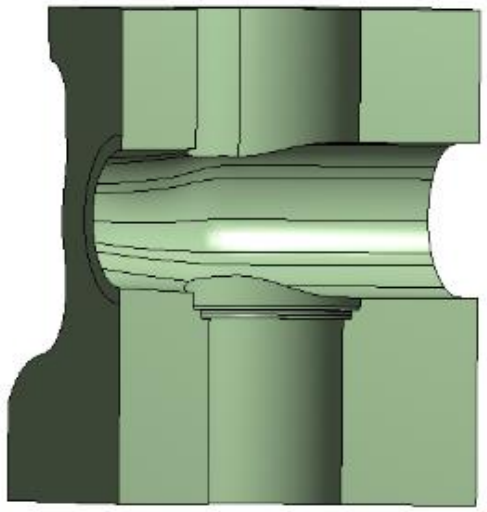
Material considered for valve– STG50T

Temperature = 538°C
Pressure = 12.5 MPa

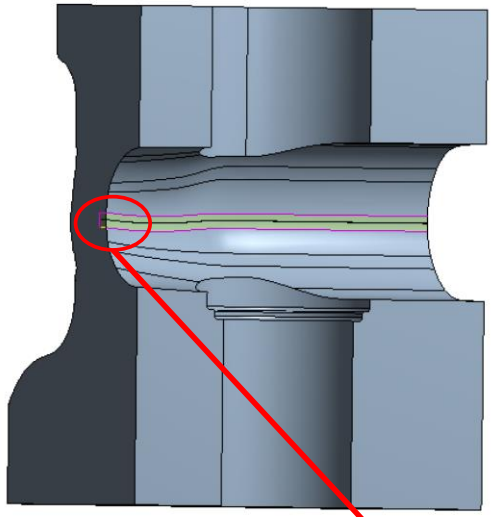
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Model Details–

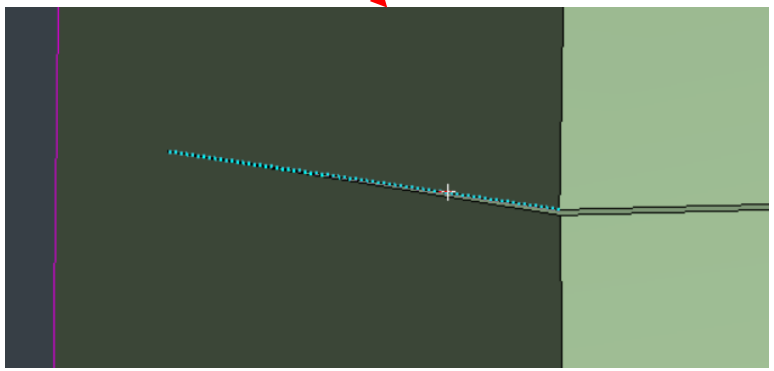
Case 1- Base Model



Case 2- Crack Model

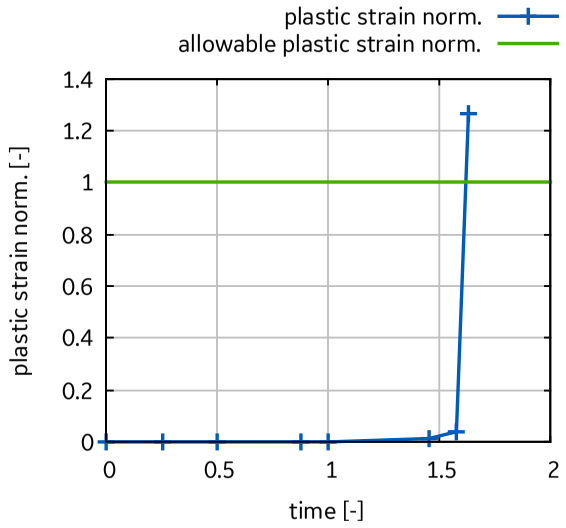


opening of 0.1mm and depth 13mm throughout the length incl. pressure applied to crack face



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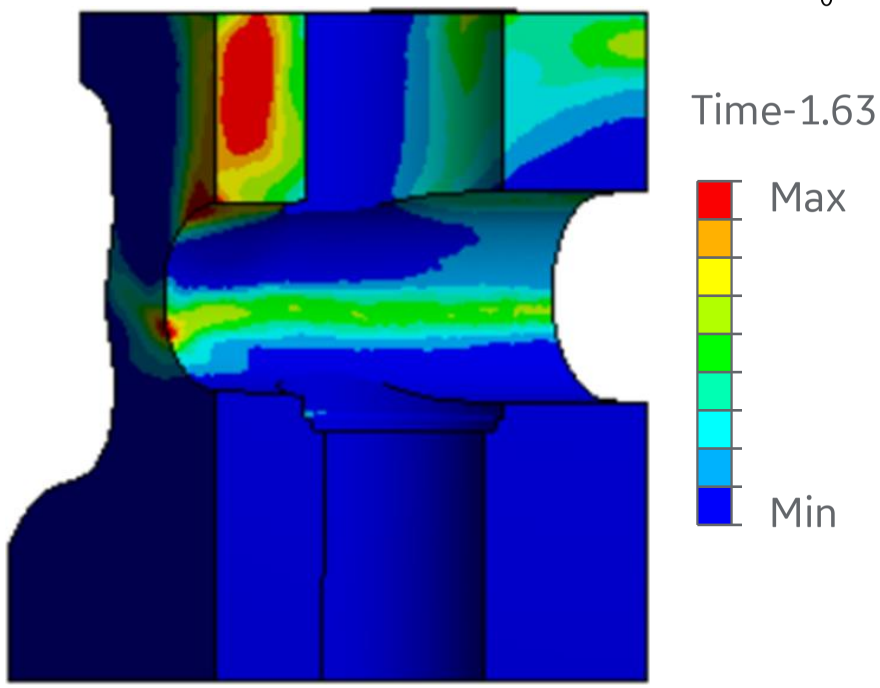
Limit Load



Conclusion Limit Load:

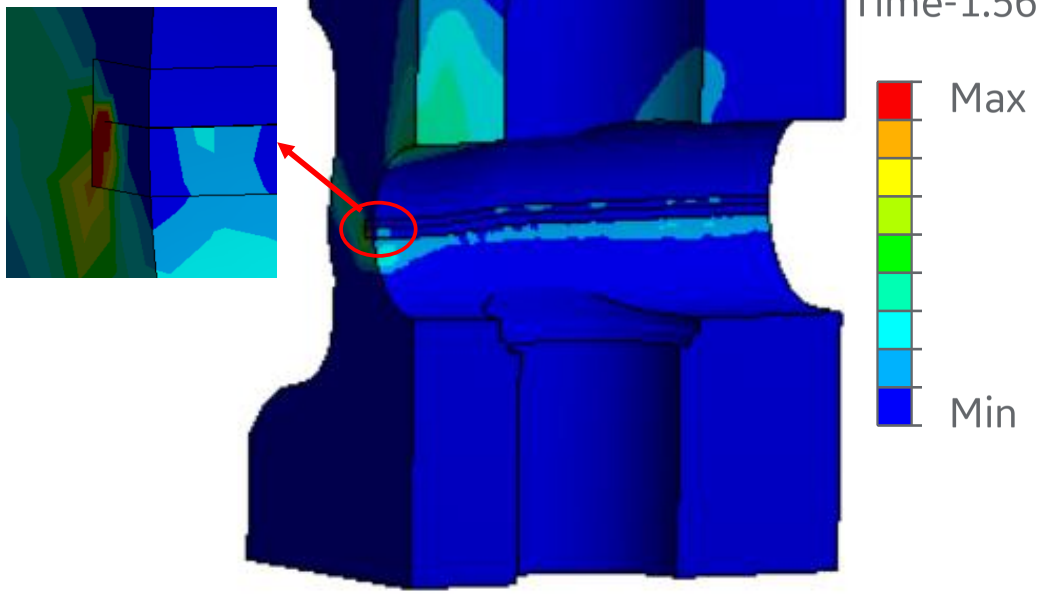
- The base model will show at 163% of the nominal pressure plastic collapse at the crack location
- The crack model shows only a slightly reduced value of 156% of nominal pressure at the ligament of the crack

Case 1- Base Model



Time-1.63

Case 2- Crack Model



Time-1.56

Result of Limit Load Calculation for cracked body shows only slight reduction compared to intact model.

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HP-Valve Casing
Crack configuration:

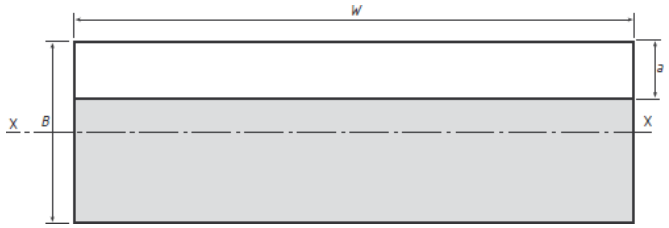
a_i = 12 mm

c_i = long surface flaw

Wall thickness: B = 100 mm



Fracture Mechanics Assessment Model and Solution, Geometry



BS7910 – Model and Solution

Type	
Structural model	Plate
Loading type	membrane and bending stress based on FEM stress distribution
Crack type	Long Surface crack
Stress intensity factor	BS7910
Limit load solution	BS7910

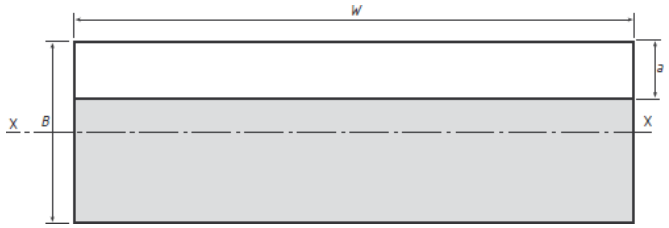
BS7910 - Geometry

Type		Source
Wall thickness B [mm]	100	CAD Model
Plate width W [mm]	1676	PAUT report
Initial crack depth a_i [mm]	6 / 12	PAUT report 07/2021 ①
Initial crack length c_i [mm]	Long surface crack	Assumption

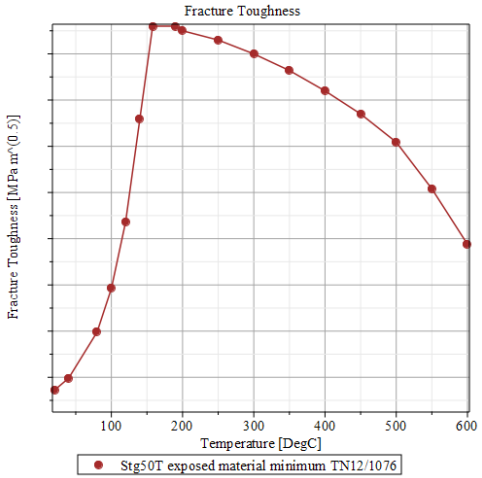
Source: bs7910-creep_04-20_10-surface-crack-plate-tss527_tlcf519527-a12-STG50T-maxCCG-elpl.mw
① PAUT-SS072821-001 R0.pdf

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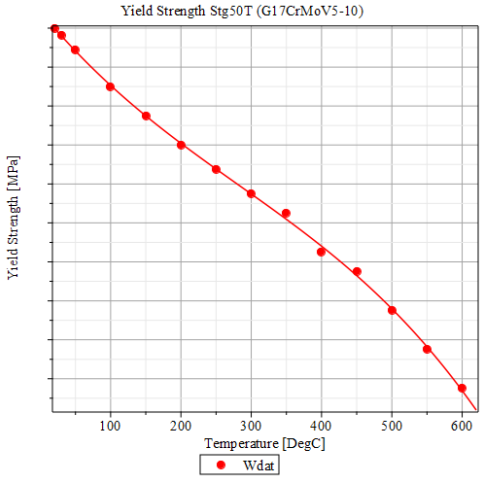
Fracture Mechanics Assessment
Material STG50T (nearest equivalent to real material, lower bound material data)



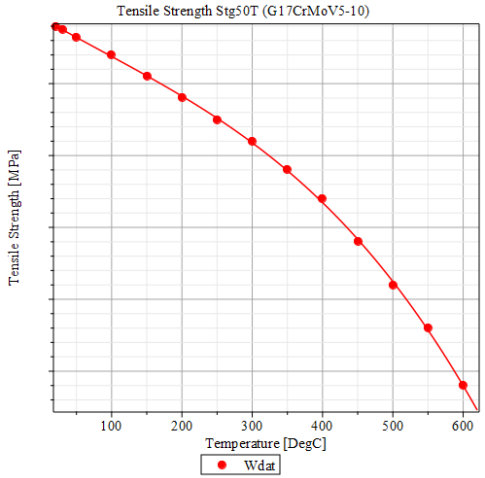
Fracture Toughness



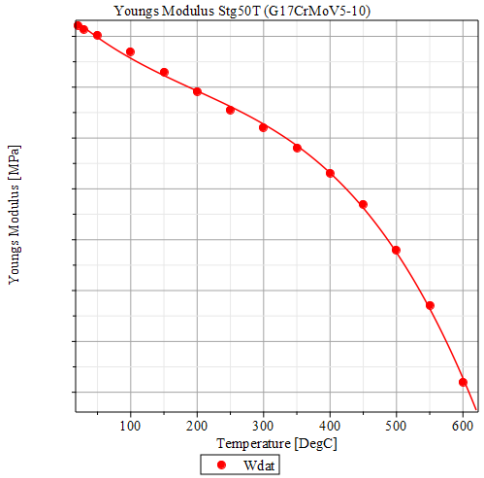
Yield Strength



Tensile Strength



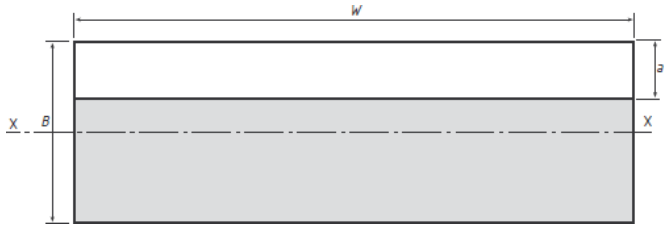
Youngs Modulus



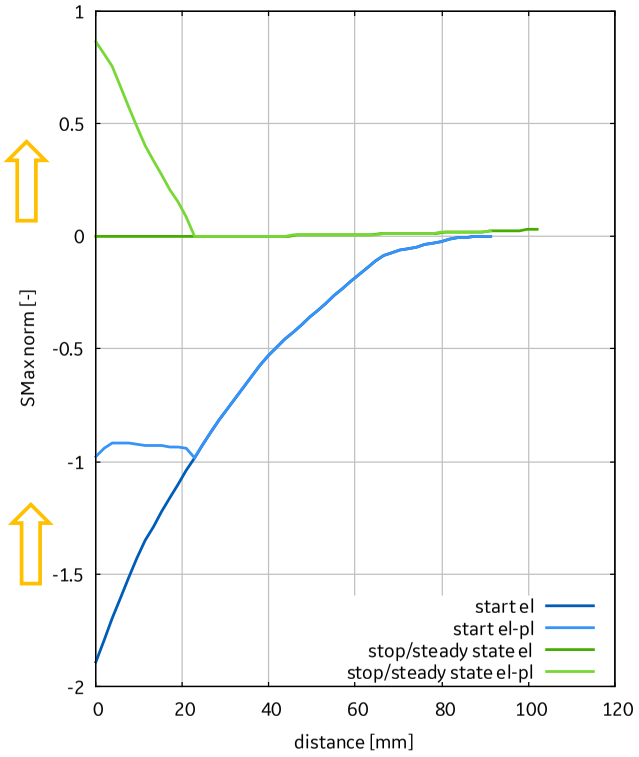
Source: bs7910-creep_04-20_10-surface-crack-plate-tss527_tlcf519527-a12-STG50T-maxCCG-elpl

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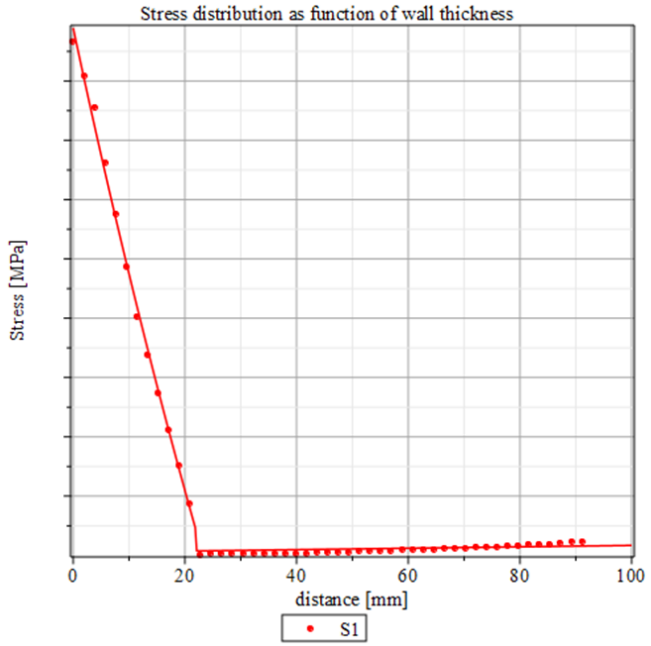
Fracture Mechanics Assessment – Loading: Steady State and Transient Condition



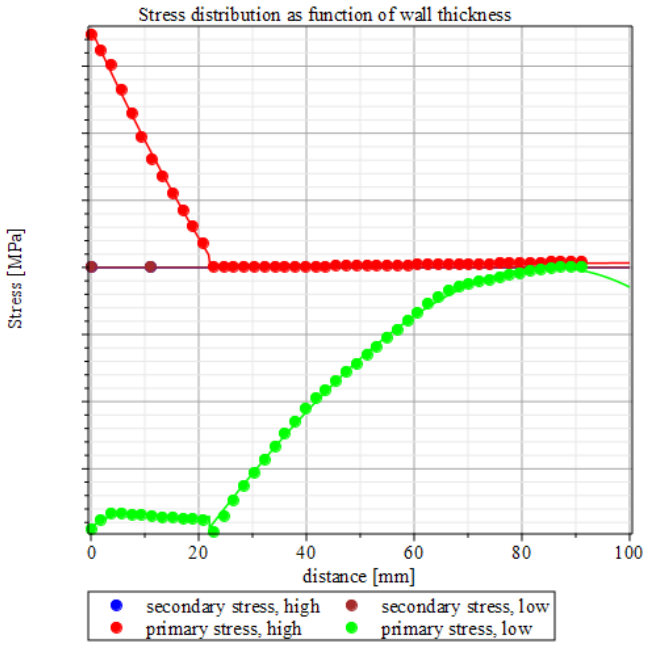
El-Pl Conversion



Stress Distribution for Steady State Condition and creep crack growth



Stress Distribution Start (CS)-Stop (SD) for fatigue crack growth



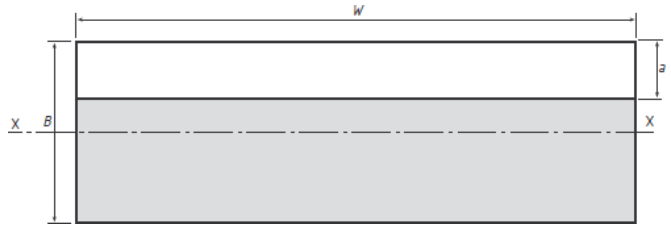
So

El-pl conversion (Neuber and Ramberg-Osgood) necessary due to over-elastic stresses during start.

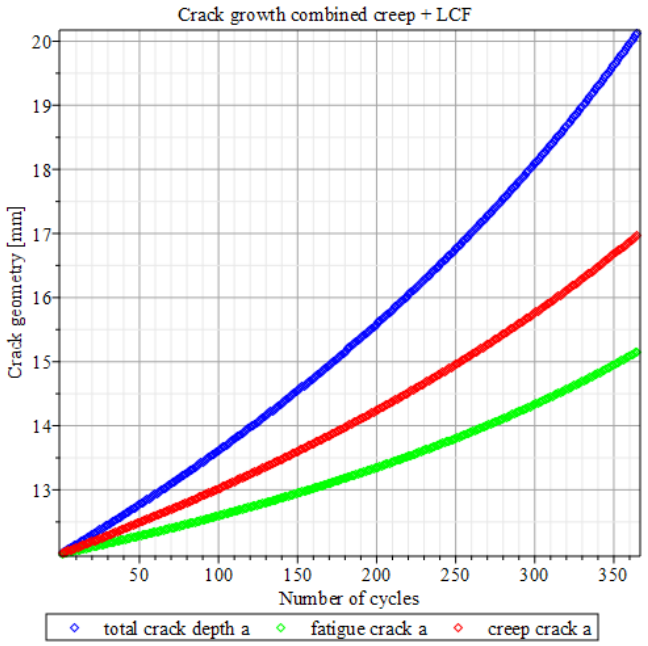
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Results – HP-Valve Casing

Fracture Mechanics Assessment



Crack Growth in Depth Direction



So

Remark

- Fracture Mechanics Assessment performed
  - using a plate with a long surface flaw as the structural model (c.f. slide 30)
  - with stress distributions
    - for FCG: Cold Start 2, Shutdown 1 (c.f. slide 23)
    - for CCG: steady state (c.f. slide 32)
  - with combined crack growth: FCG and CCG in each start-steady state-stop cycle
  - with an initial crack depth for FCG and CCG: a_i = 12 mm based on PAUT measurement from 07/2021

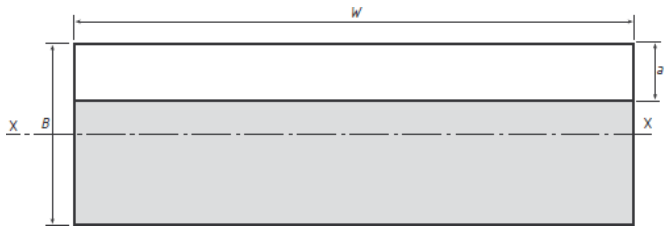
Remark

- The diagram shows results of combined crack growth for every calculated cycle:
  - FCG: green color;
  - CCG: red color;
  - Total crack growth (sum of FCG and CCG): blue color.
- Termination of calculation:
  - Calculation terminated after 365 calculated cycles including 433 h/cycle steady state operation, considering combined crack growth
  - Termination of calculation due to reaching the assessment line in the FAD (c.f. next slide)
- Influence of longer operating times in steady state:
  - This will increase the share of CCG (c.f. slide 50)

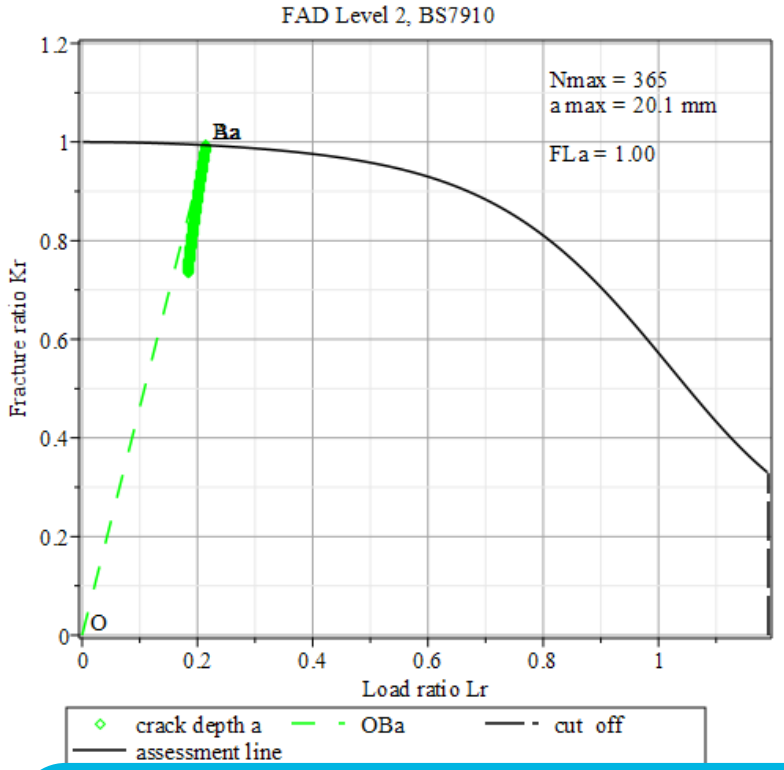
Creep and Fatigue Crack Growth considered

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Holyrood 3 HP Valve Casing – Results based on spec min and upper bound growth



FAD a_i = 12 mm



Remark

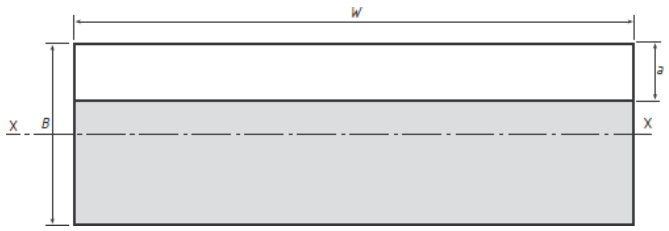
- All assessment points below the Assessment Line are acceptable in terms of FCG and CCG.
- An initial crack depth of a_i = 12 mm from the PAUT results of 07/2021
- Termination of calculation:
  - Calculation terminated after 365 calculated cycles including 433 h/cycle steady state operation, considering combined crack growth due to reaching the assessment line inside the FAD in the direction of brittle fracture.
  - Plastic collapse is not expected with this kind of crack growth.
  - Crack depth at the end of the calculation a = 20.1 mm based on nominal material properties.
  - Increase in crack depth within 365 cycles corresponds to 8.1 mm or 0.022 mm per cycle in average.
- Comparison with measured indication depths:
  - In May 2019, the indication depth was determined by PAUT to be 6 mm at the location of max indication depth in 2021
  - In July 2021, the indication depth was determined by PAUT to be 12 mm
  - Increase in indication depth by 6 mm within 14 Starts → 0.429 mm per cycle in average
  - Real crack growth much bigger than the predicted growth by ordinary fracture mechanics assessment → adjustment of Paris equation and creep crack growth necessary and performed.

Actual crack growth is much bigger than predicted.

Source: bs7910-creep_04-20_10-surface-crack-plate-tss526_tlcf520-a12-STG50T-maxCCG.mw

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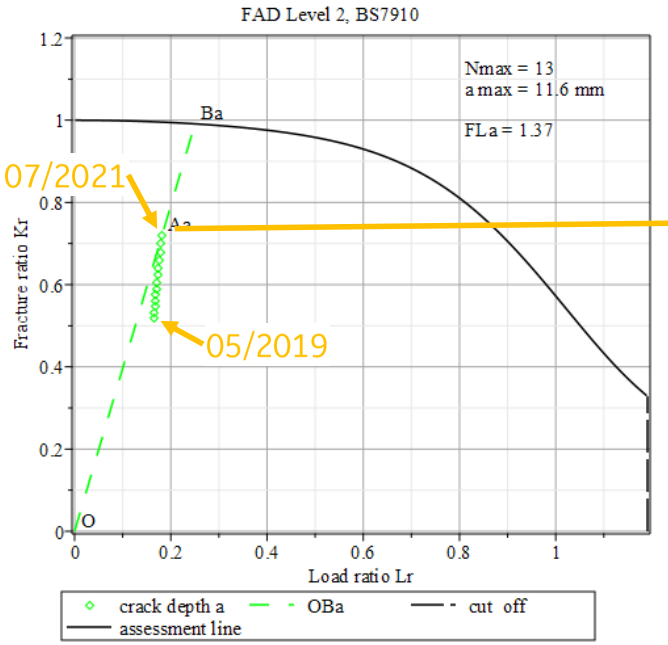
Holyrood 3 HP Valve Casing – Results based on PAUT measurement results



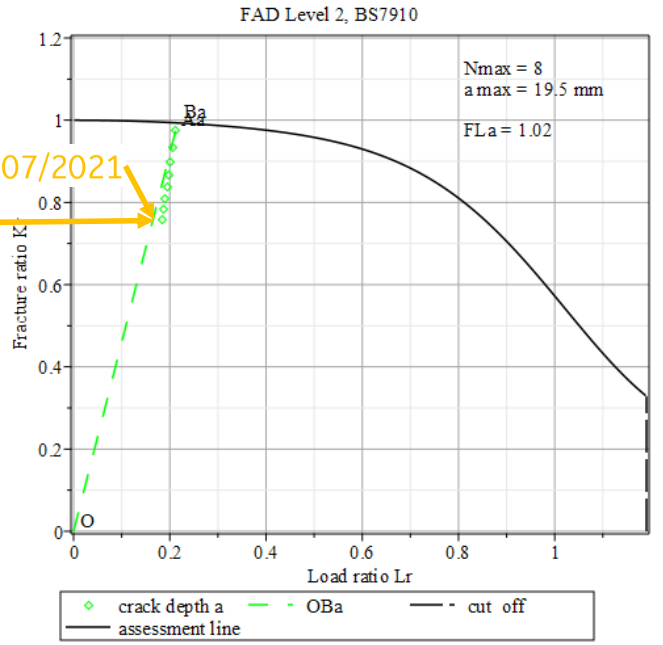
Remark

- Adjustment of fatigue crack growth to measured data:
  - Starting at a crack depth of a_i = 6 mm after 13 cycles 12 mm crack depth will be reached.
  - With the calibrated calculation 8 cycles (start-stop incl. 433 h/start steady state operation) will be admissible until the assessment line will be reached.

FAD a_i = 6 mm



FAD a_i = 12 mm



Since determined end of life in the LTA, the calculation terminates after 8 cycles under optimistic conditions.

Link to slide 47

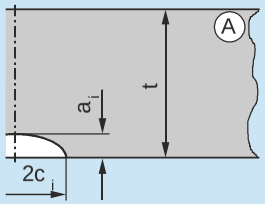
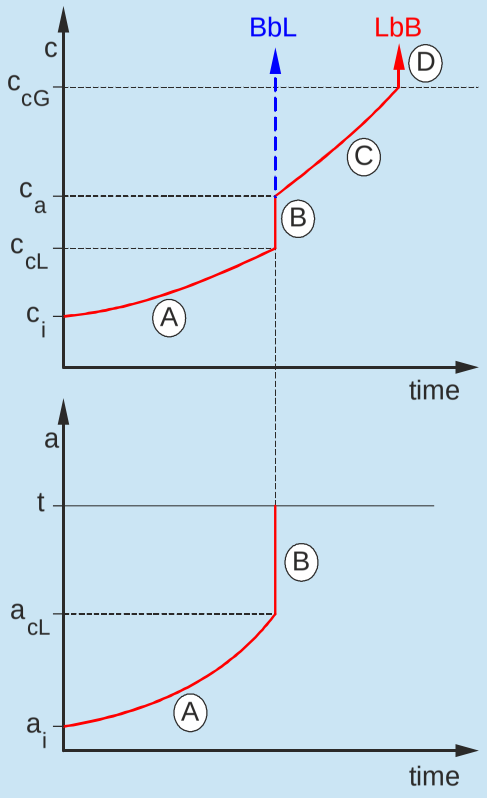
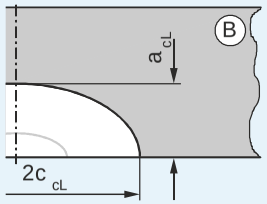
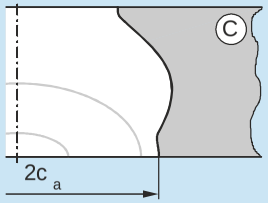
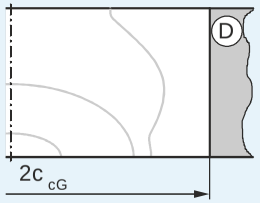
Source: bs7910-creep_04-20_10-surface-crack-plate-tss526_t1cf520-a06-STG50T-maxCCG-modC-mod_LCF-Creep
bs7910-creep_04-20_10-surface-crack-plate-tss526_t1cf520-a12-STG50T-maxCCG-modC-mod_LCF-Creep

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Leak-before-Break

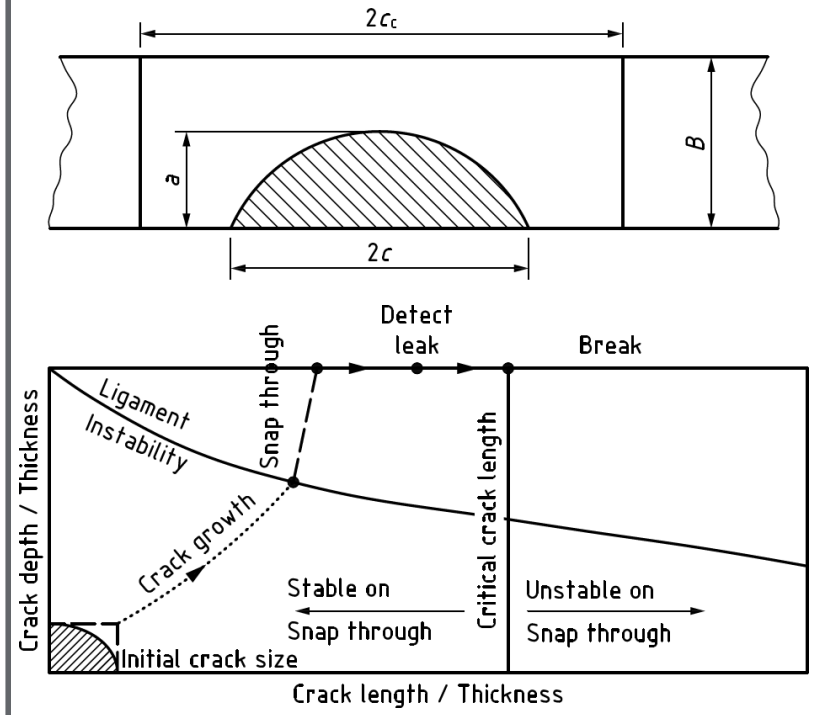


Leak-before-Break (LbB) Behavior
Munz, D.: Leck-vor-Bruch-Verhalten druckbeaufschlagter Komponenten, Fortschritt-Berichte der VDI Zeitschriften, Reihe 18, Nr. 14, 1984, VDI-Verlag GmbH Düsseldorf.

Phase	Mechanism	Figure	Graph
A	Phase with low crack growth rate in depth and length direction		
B	At a critical crack-depth a_{cL} and –length $2c_{cL}$ the crack snaps through the ligament **(local instability)**		
C	Leak-before-Break behavior: crack grows slowly in longitudinal direction as a through wall crack		
D	At a critical crack length of $2c_{cG}$ **global instability** occurs		

Source: Munz, VDI

Leak-before-Break (LbB)
BS7910:2019

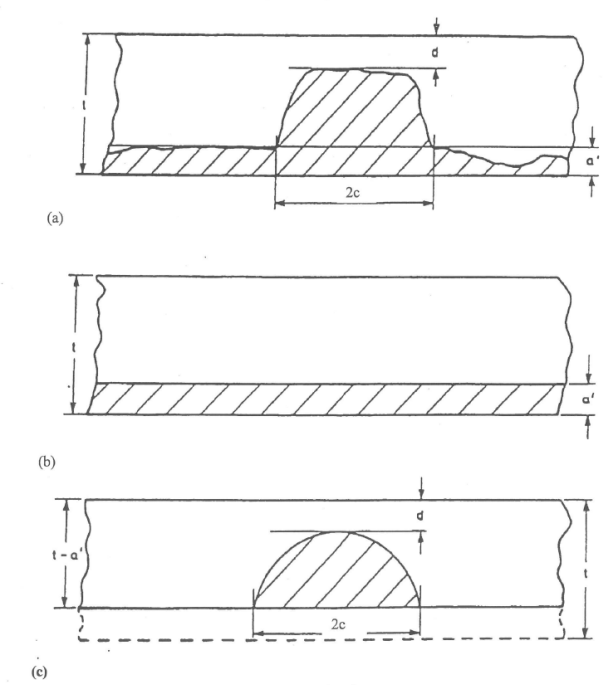


Source: BS7910:2019

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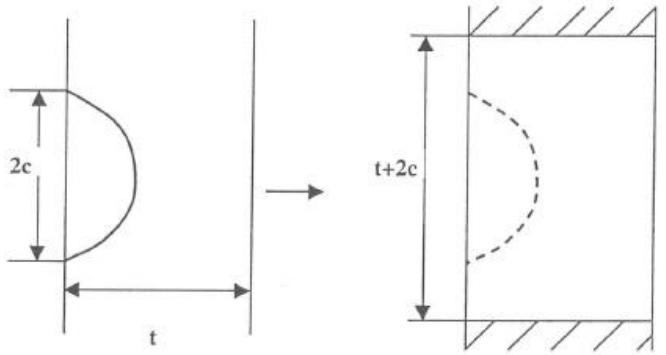
Leak-Before-Break

Re-characterization of a complex defect



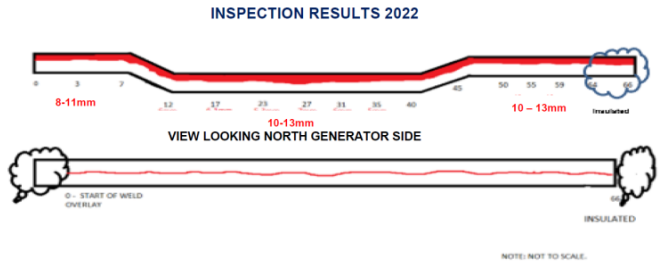
THE COMPLEX DEFECT IN (a) MAY BE SEPARATELY ASSESSED AS THE TWO SIMPLE DEFECTS IN (b) AND (c)

Re-characterization of defects for ligament failure by ductile mechanisms under dynamic loading



(ii) Surface defect

PAUT results 07/2022



Re-characterization of the PAUT indication is not possible as the indication already shows a fairly uniform depth along the entire length of the valve chest.

Source: R6 Rev 4

Source: R6 Rev 4

Source: PAUT-SS072821-001 R0.pdf

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Leak-before-Break (LbB)

Leak-before-Break Assessment

A leak-before-break assessment is most likely to be of value for:

- **part-penetrating defects with a high ratio of crack depth to surface length;**
- defects which grow through the wall, by fatigue say, under tension loading resulting in little surface crack extension;
- defects which snap through the ligament by ductile mechanisms so that the re-characterization do not lead to a significant increase in crack length.

Conclusion LbB

- Based on the PAUT report, the PAUT indication shows a characteristic similar to a long surface flaw
- Leak-before-Break analysis is not applicable for long surface flaws

Due to the long crack little support from surrounding area expected.

Source: R6 Rev 4

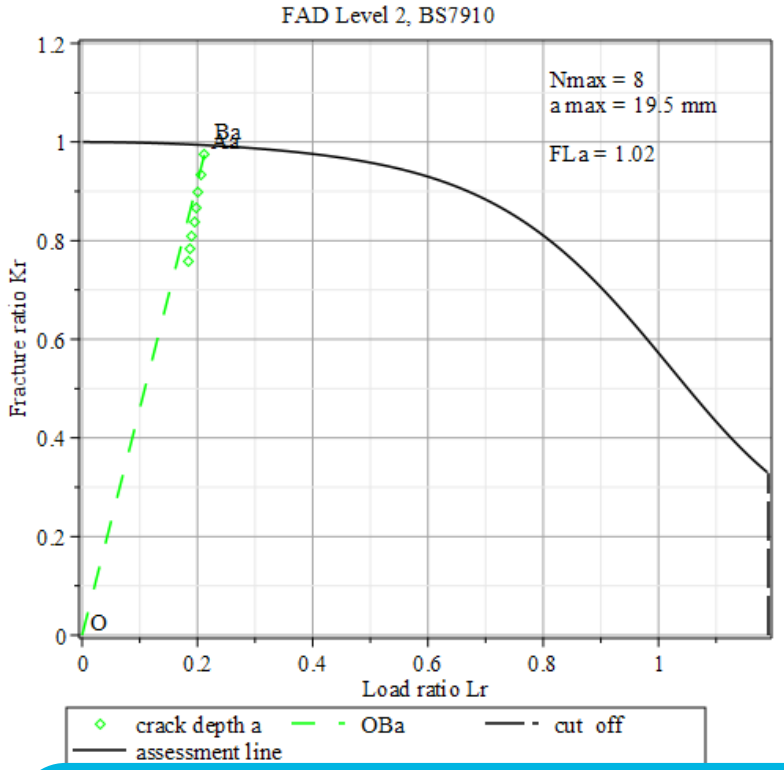
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Temperature Reduction

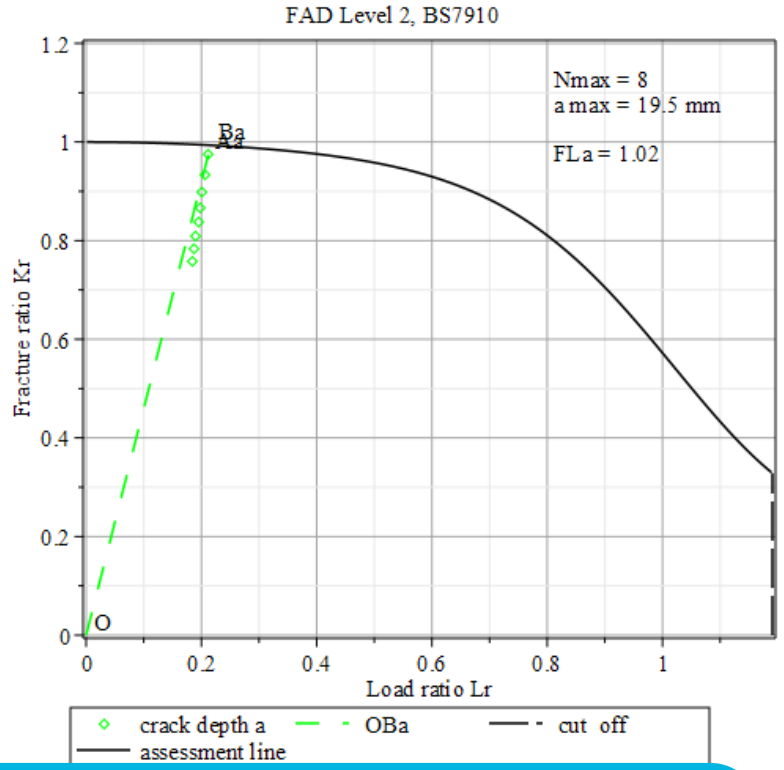


Steam Temperature Reduction $\Delta\vartheta_{steady\ state}$ = 0 K

$\vartheta_{steady\ state}$ = 527°C; Nmax = 8



$\vartheta_{steady\ state}$ = 527°C; Nmax = 8

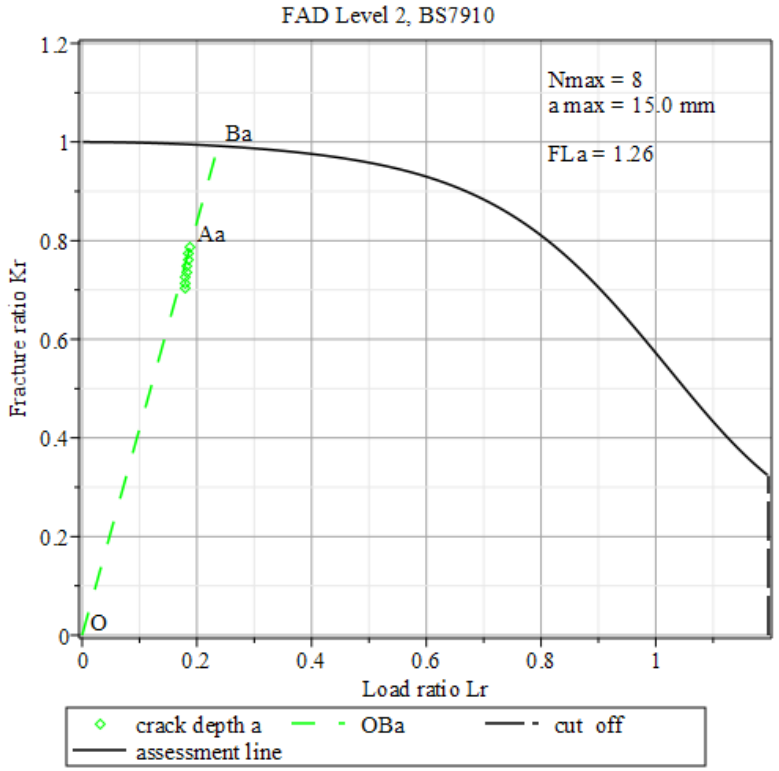


Since the end of life is determined in the LTA, the calculation ends after 8 cycles.

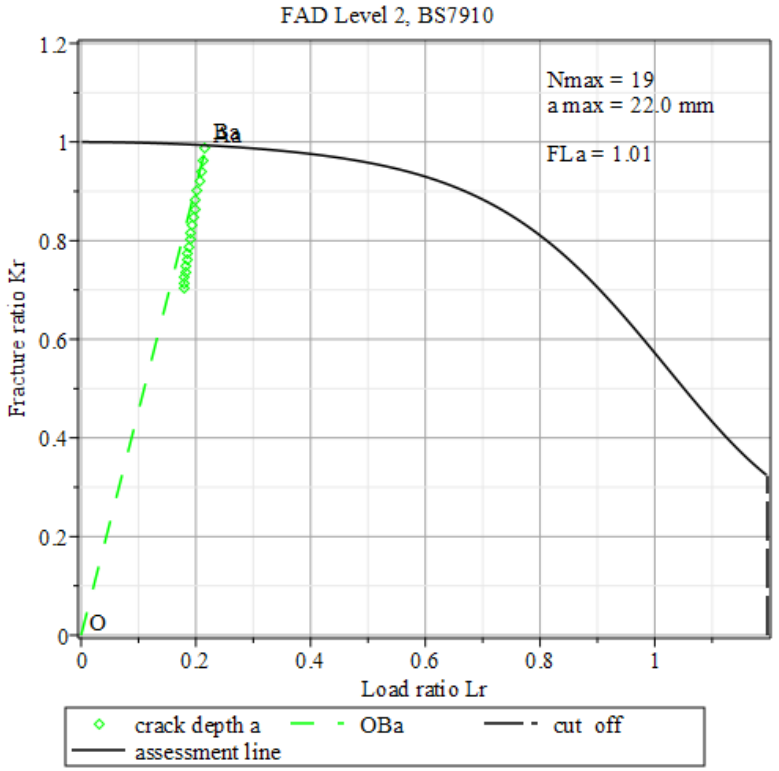
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Steam Temperature Reduction $\Delta\vartheta_{steady\ state}$ = 25 K

$\vartheta_{steady\ state}$ = 502°C; Nmax = 8



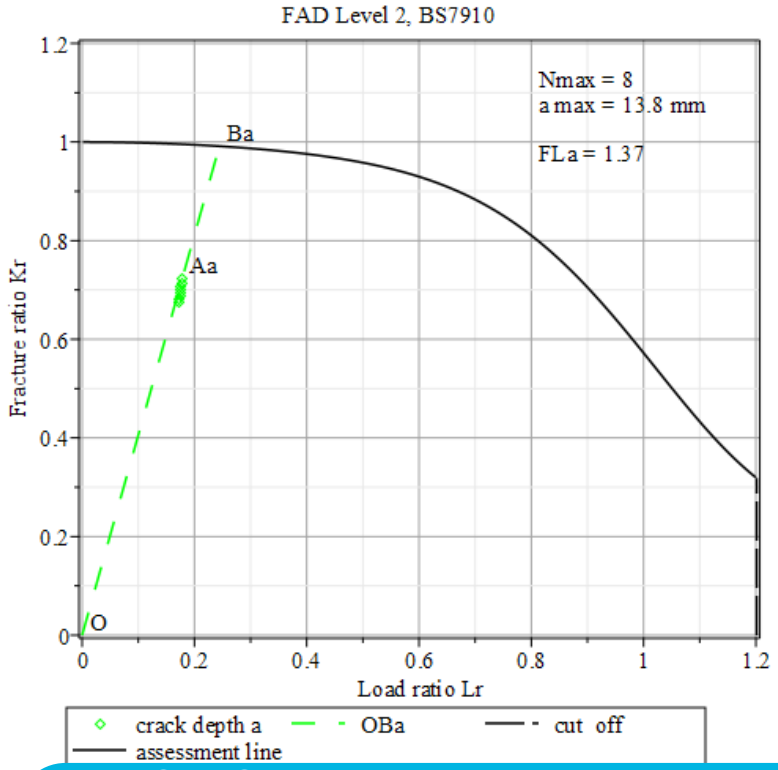
$\vartheta_{steady\ state}$ = 502°C; Nmax = 19



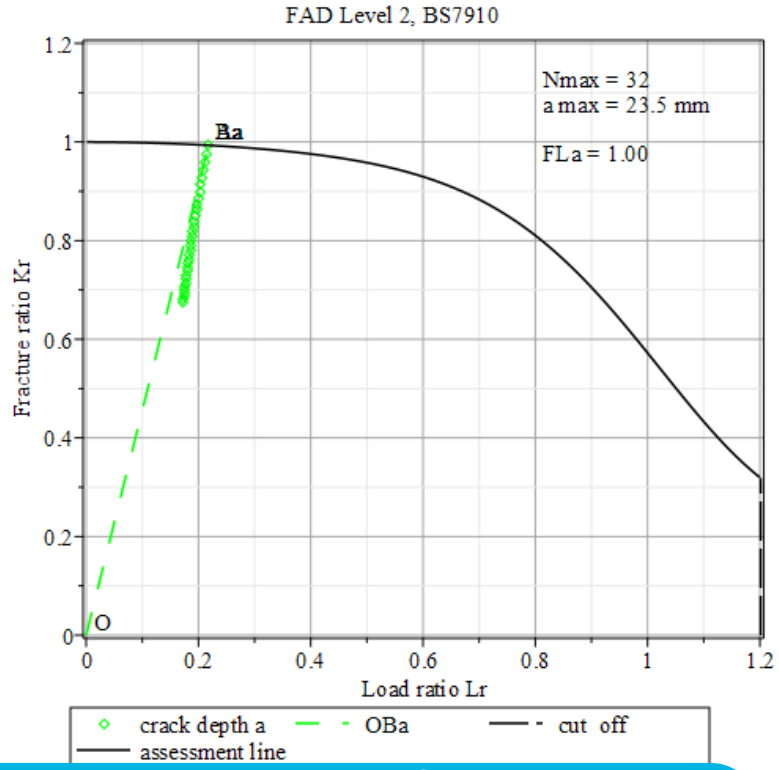
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Steam Temperature Reduction $\Delta\vartheta_{steady\ state}$ = 50 K

$\vartheta_{steady\ state}$ = 476°C; Nmax = 8



$\vartheta_{steady\ state}$ = 476°C, Nmax = 32



Safety factor against rupture can be increased by reducing steam temperature for temporary operation. This should not be used to prolong operation.

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Q&A



Q&A

Q1) What is the definition of "cycle"? We require the parameters around GEs definition as it relates to how we operate our units. For example, is a cycle considered from when we start the unit and increase temperature to when we stop the unit and it has cooled.

A1) see page 23: cycle for Fracture Mechanics Assessment consists of Cold Start 2, steady state and Shutdown 1

Q2) When referencing "steady state" are you referring to constant temperature and pressure? Or referencing load?

A2) “Steady state” is referred to when the steam temperature is constant and ideally at the nominal value (nominal values see page 3).

Q3) What are GE's recommendations regarding operating our units to reduce the number of cycles.

A3) Typically Fatigue Crack Growth (FCG) will be driven by changes in thermo-mechanical load. Mostly, by changes in steam- or metal-temperature and steam-pressure. The biggest changes occur during start-up and shutdown. Reducing the number of starts will minimize the amount of FCG. As long as the metal temperature and the steam pressure of the component remains constant, the impact on FCG is neglectable.

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Q&A

Q4) When you say "very limited time" what does this mean? See email dated Dec 21, 2023.

A4) We should discuss this topic at the customer meeting on Feb 8th, 2023

Q5) We have a major overhaul scheduled on U3 in 2025. Can we **safely** delay intervention until then? What are the safety implications of the condition? What actions do we need to take and when to ensure that there is no risk to our people? What options do we have for repair/life extension?

A5) We should discuss this topic at the customer meeting on Feb 8th, 2023

Q6) What will a break in the steam chest look like?

A6) Based on the PAUT findings, the crack depth along the internal surface is quite homogeneous. Most probably a break at the steam chest will be along the entire length of the chest. There is a considerable risk that there is break-before-leak behavior.

Q7) What recommendations or services can be provided for the 2023 inspection of this crack (i.e. are there known people, equipment, or techniques that could be applied to this to ensure we have the best possible measurement of the crack)?

A7) It may be the best solution to order the same people which did the past inspections with the same approach and the same equipment.

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Q&A

Q8) Regarding the study, what assumptions were made and what information could we provide to help firm up the final results and conclusions?

A8) Please see the information contained in the slide deck and further questions can be answered during the meeting on February 8th, 2023

Q9) As noted in the Dec 21 email, we request that GE review our start up procedure and comment. Refer to Question 6 in that email.

A9) to be answered

Q10) Page 13 of presentation: The crack depth increase from 6mm to 12mm is stated between year 2019 to 2021. The NDT reports says it was during 2016 to 2019 and no increase is recorded from 2019 to 2021. Please refer to page 3 of PAUT-SS072821-001 R0 2021 NDT report. Please explain the impact of this discrepancy have on GE crack propagation model and findings.

A10) Both results are contained in the available NDT report (PAUT-SS071822-001 R0.pdf).
Anyhow the impact is of minor importance since the load behavior is similar in both time frames. The predicted crack growth is still way above the values expected for a sound material.

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Q&A

Q11) Page 18 of presentation: The temperature data on the top left plot appears to show the casing metal temps start off at 75% of normal operating temperature yet it's labelled a cold start – this seems to be a warm start. Please clarify.

A11) This is also our observation. The label "Cold Start" was used in the operational data received from Holyrood.

Q12) The NDT data show some inconsistency which might be related to the change of service provider, tools being used, testing methods, and the competency of the person performing the test. GE seems to base their recommendation on the site inspection data and has tailored the material properties for the crack propagation analysis based on this potential inconsistent data. Hatch suggest that a more reliable base should be required for such change of material properties. Please clarify.

A12) As stated in the slide deck, no information about the quality of the NDT can be given by GE. The pure results are taken as basis for the fracture mechanics assessment.

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Q&A

Q13) If the recommendations from GE for preheating, lowering the temperature, and pressure are followed, what will be the maximum number of start-ups we can have before next PAUT.

A13) The recommendation will be the same. This measure is to increase the safety to personnel and not to increase the operation time.

Q14) Page 26 of the presentation: GE is requested to provide the normalized values for material properties used in crack propagation model.

A14) To be provided.

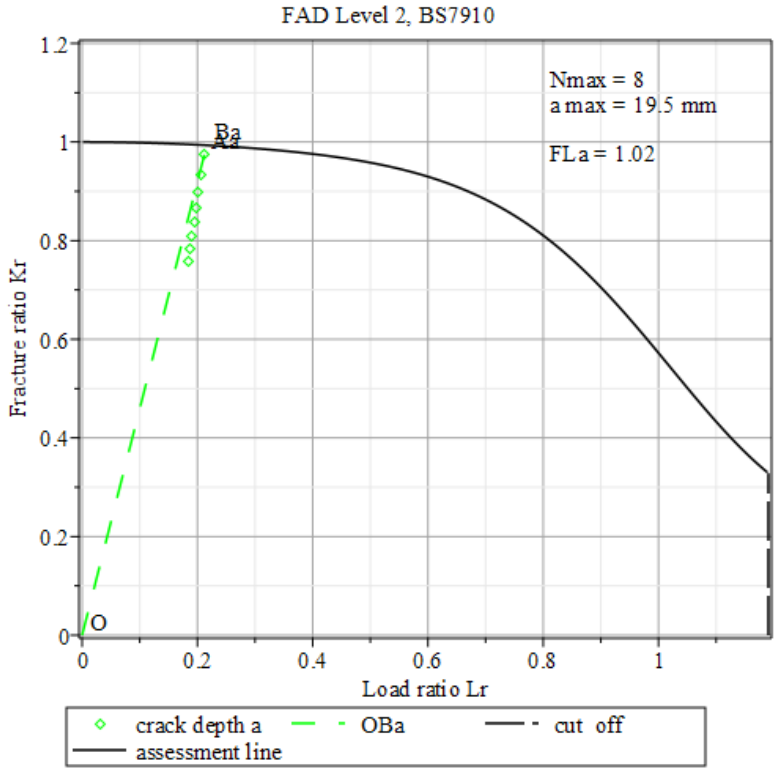
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Influence of longer steady state operation – sensitivity calculation: 433 h/cycle → 650 h/cycle

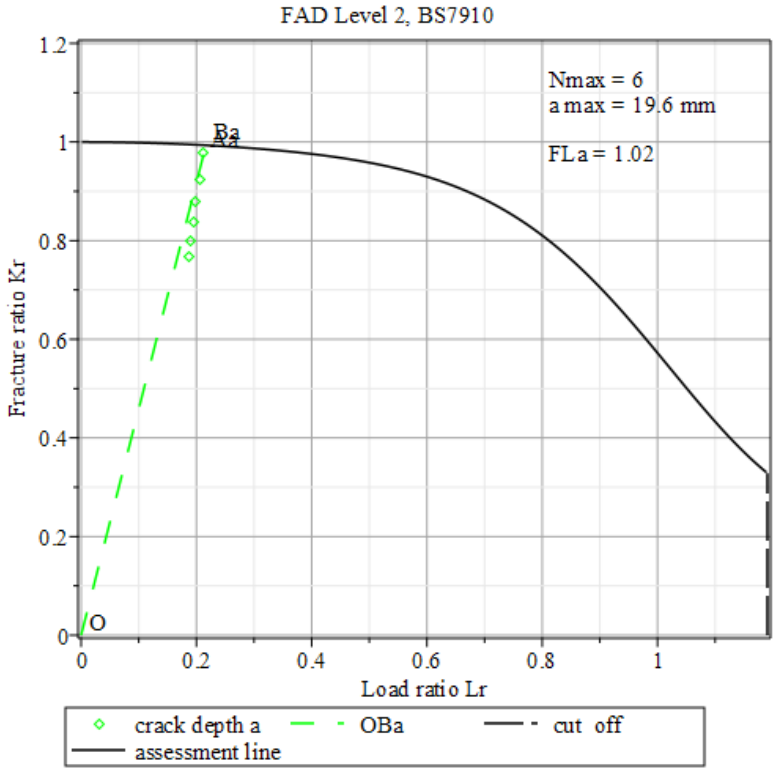


Holyrood 3 HP Valve Casing
– Results based on PAUT measurement results
– Influence of longer steady state operation

FAD a_i = 12 mm, 433 h/cycle (copy from slide 36)



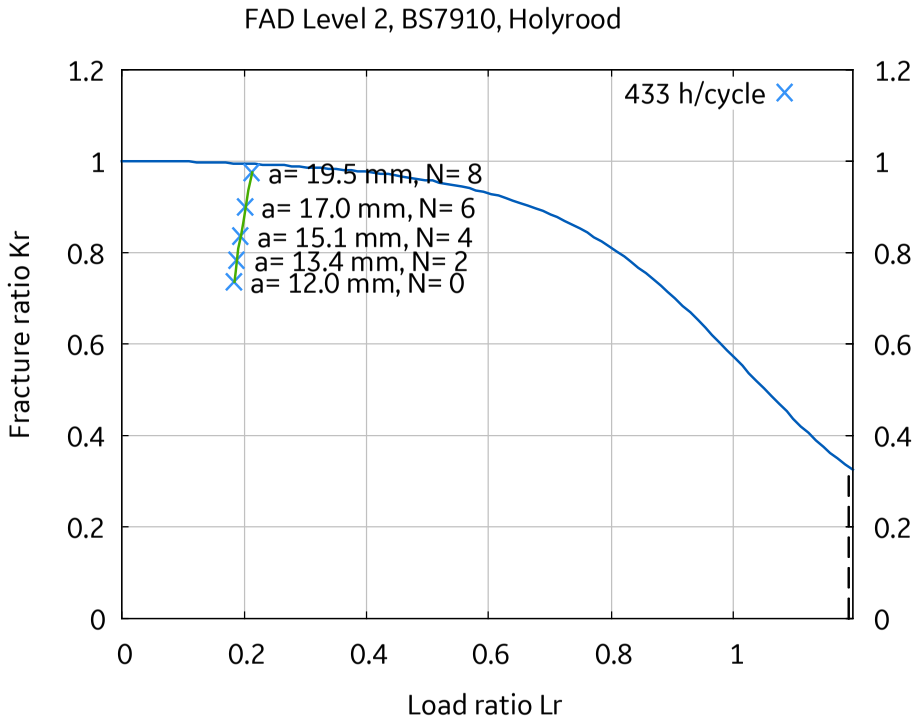
FAD a_i = 12 mm, 650 h/cycle



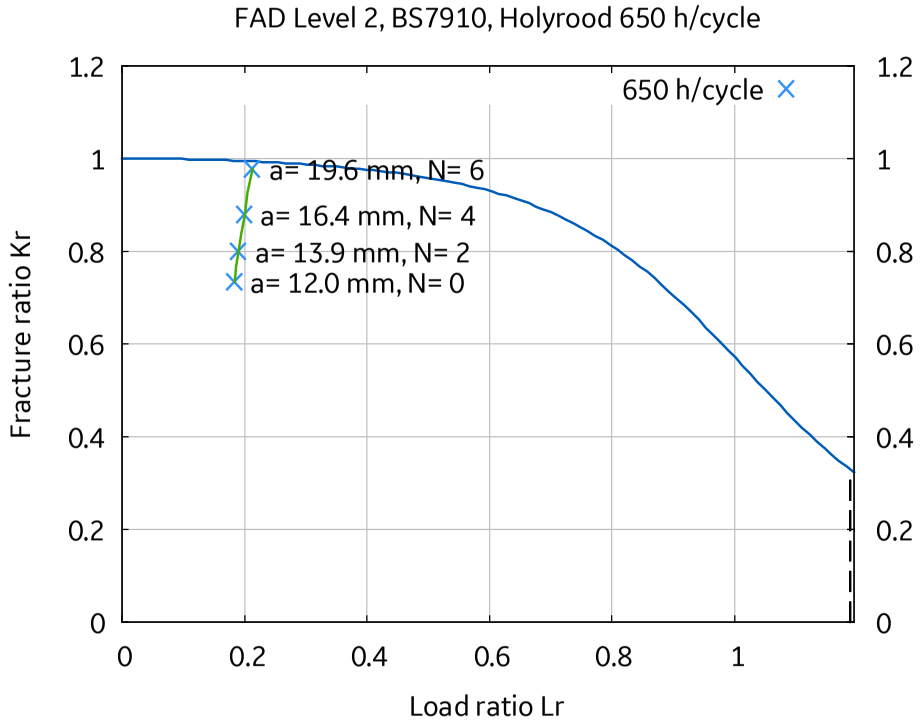
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Holyrood 3 HP Valve Casing
– Results based on PAUT measurement results
– Influence of longer steady state operation

FAD a_i = 12 mm, 433 h/cycle (copy from slide 36)



FAD a_i = 12 mm, 650 h/cycle



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Summary



Summary

Project Task

- Fracture mechanics study for HP steam valve chest
  - Location: joining weld of the HP steam valve chest
  - Crack like indications along the entire interior surface of the joining weld.
  - Fracture mechanics assessment based on
    - Scanned valve chest geometry and nearest equivalent GE material data.
    - Limited operational data provided by Holyrood 3 with the risk of being optimistic in terms of thermal stresses

Fracture Mechanics Assessment

- Fracture mechanics assessment will show 365 admissible cycles until assessment line in FAD is reached.
- Under consideration of the measured crack depth (PAUT in 2019 and 2021) the allowable number of cycles will be reduced to 8.
- The max crack depth is 19.5 mm (see slide 36)

Update December 18, 2022

- Blue box on slide 17 (left hand side)
  - The PAUT results inside the blue box show an increase in crack depth from 6 mm in 2019, to 12 mm in 2021 to max 13 mm in 2022.
  - Taking into account the operational behavior from 2021 to 2022 (4 starts, 2900 OH) the fracture mechanics assessment would predict in the same timeframe 14.5 mm of max crack depth. This would be slightly more compared to the measurement.
- Green box on slide 19 (right hand side)
  - Virtually no change in crack depth reported from 2019 to 2022
- The measurement in 2022 demonstrates that the crack growth is still much advanced.
- In the end the measurements still fit quite well to the predicted crack growth with the adjusted crack growth behavior acc. slide 37.

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Recommendation



Recommendations Holyrood 3 HP valve chest

HP Valve Casing

- The valve chest should only be operated for a very limited time until the chest has been refurbished or replaced. The operation until remedy measures took place shall be performed with reduced steam- and operational-parameters.
- Leak-before-break behavior is not assessed and therefore it is unclear what behavior to expect when the crack propagates further into the wall. Nevertheless, limit load calculation shows a value of 156% of nominal pressure at a crack depth of 13 mm.

HP Valve Casing

- To reduce future crack propagation in a limited operation
  - lower live steam
    - temperature by approx. 50 K
    - pressure by approx. 25 bara
  - pre-heat the valve chest to at least 175°C prior to applying full pressure.
  - reduce the number of starts and load changes as much as possible.
- Re-inspection by PAUT after 8 cycles strongly recommended.
- **Update 2022/12/18**: In the light of the recently reported PAUT values from 2022, it is further strongly recommended to perform a weld repair or replacement after 8 cycles starting in 07/2021.

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Program 2

Upgrade Worst-Performing Distribution Feeders

2025–2027

newfoundland labrador hydro

Upgrade Worst-Performing Distribution Feeders (2025–2027)

Location: English Harbour West, Line 1

Investment Classification: Service Enhancement

Asset Category: Distribution

Cost: $8,886,072

Executive Summary

This program includes the refurbishment of a distribution feeder located in the English Harbour West 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 2025–2027 scope of this program is required to improve the reliability of the English Harbour West Line 1 ("EHW-L1") feeder.

The EHW-L1 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 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 indicates 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.

The EHW-L1 feeder has also been selected for refurbishment under the Renew Distribution Feeders Program, a condition-based asset renewal program initiated in Hydro's 2024 Capital Budget Application ("CBA"). Therefore, in 2025, Hydro has included the scope of the Renew Distribution Feeders Program under the Upgrade Worst-Performing Distribution Feeders (2025–2027) Program.

This program has a multi-year approach, with completion planned in 2027 at an estimated cost of $8,886,100.

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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 a 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.[4] Since 2019, Hydro has also been prioritizing the refurbishment of distribution feeders that have poor reliability performance. The Upgrade Worst-Performing Distribution Feeders (2025–2027) Program includes the refurbishment of the EHW-L1 feeder, 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.

As the EHW-L1 feeder has also been selected for upgrade under the Renew Distribution Feeders Program; in 2025, Hydro has combined the scope of the two programs for completion under the Upgrade Worst-Performing Distribution Feeders (2025–2027) Program.

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,[5] and CIKM.[6] 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

[4] Renew Distribution Feeders is a condition-based asset renewal program, first initiated in Hydro's 2024 CBA, complementary to the Worst-Performing Feeders program.
[5] 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.
[6] 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.

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 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 EHW-L1 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 based on 2019–2023 data.

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 would be identified for continued monitoring.

Hydro's most recent analysis of worst-performing distribution feeders has identified EHW-L1 as requiring upgrades. EHW-L1 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 CHI, SAIDI and SAIFI lists in Appendix A that are higher or close in priority to the ranking for EHW-L1; 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, Bottom Waters Line 1, Fleur-de-Lys Line 1, and L'Anse-au-Loup Line 2.
- 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.
- 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 L'Anse-au-Loup Line 1.

3.0 Asset Overview

3.1 Asset Background

EHW-L1 is a three-phase, 25 KV distribution feeder that originates from the English Harbour West Terminal Station ("EHW TS"). It was originally constructed in the 1960s and services approximately 804 customers. The location of the EHW-L1 feeder is shown in Figure 1 and Figure 2.

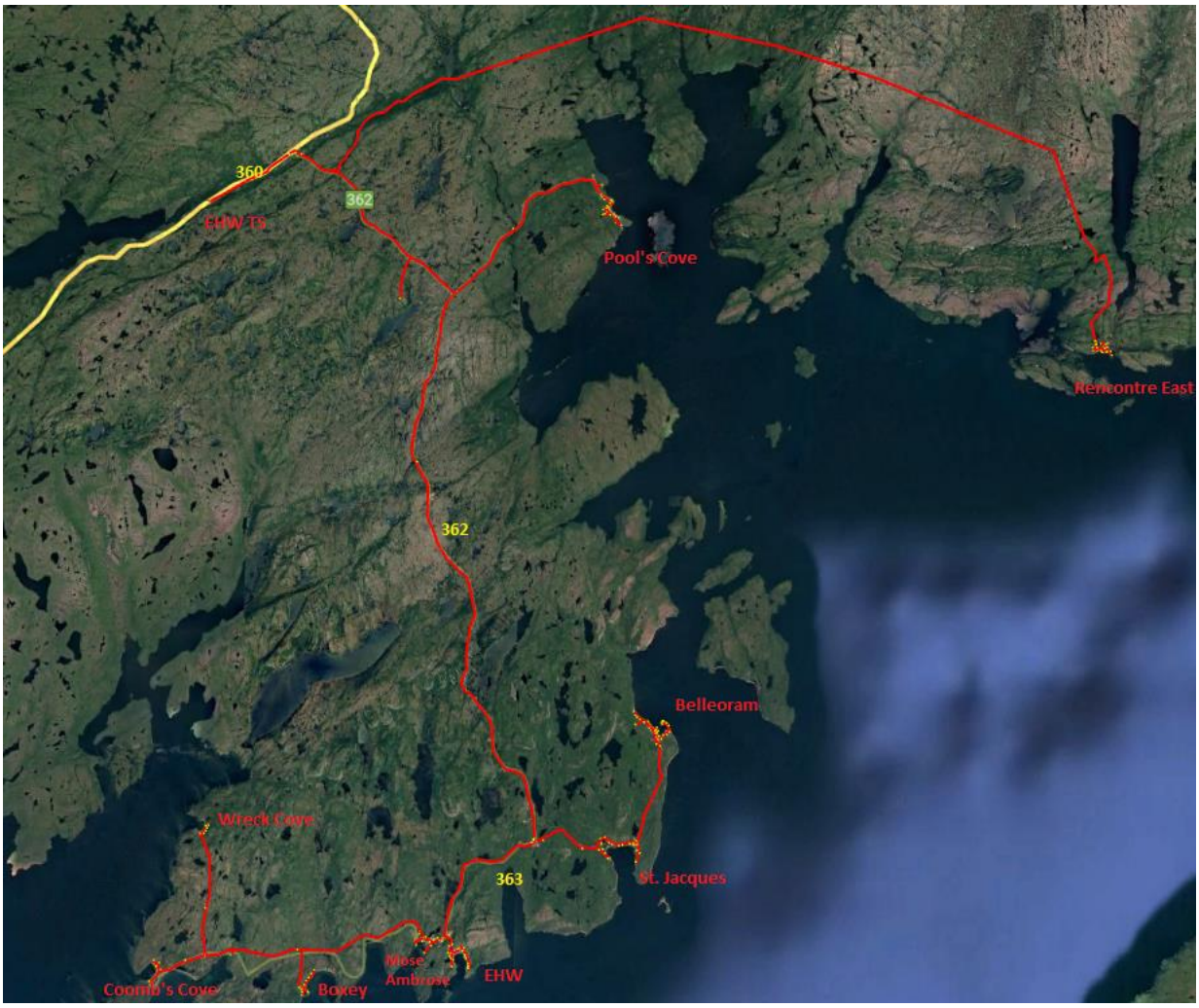


Figure 1: Layout of EHW-L1

EHW-L1 runs from the EHW TS for approximately 3.5 kilometres along the Bay d'Espoir Highway, Route 360, as a three-phase overhead feeder. The line then runs approximately 1.5 kilometres along Route 362 and connects to a 41-kilometre single-phase tap which provides power to the community of Rencontre East. The line continues approximately 6 kilometres along Route 362 as a three-phase feeder and connects to an 8.5-kilometre single-phase tap which provides power to the community of Pool's Cove. The line then extends approximately 20 kilometres along Route 362 and splits into two major taps at the intersection of Route 362 and 363. The east side tap provides power to the communities of St. Jacques and Belleoram, and the west side tap provides power to the communities of English Harbour West, Mose Ambrose, Boxey, Coombs Cove and Wreck Cove.



Figure 2: Location of EHW-L1

3.2 Asset Condition

As observed in recent pole line inspection records, this feeder has a large number of deteriorated poles, cross arms, damaged conductor spans, substandard primary conductors and substandard insulators. It also has damaged cribs, anchors and several long spans. As a result of the deteriorated or substandard components, the feeder's reliability performance is below Hydro's average reliability performance for distribution feeders, as detailed in Section 4.1.

For condition analysis and justification, the main, three-phase portion of this feeder has been divided into two sections, as shown in Figure 3.

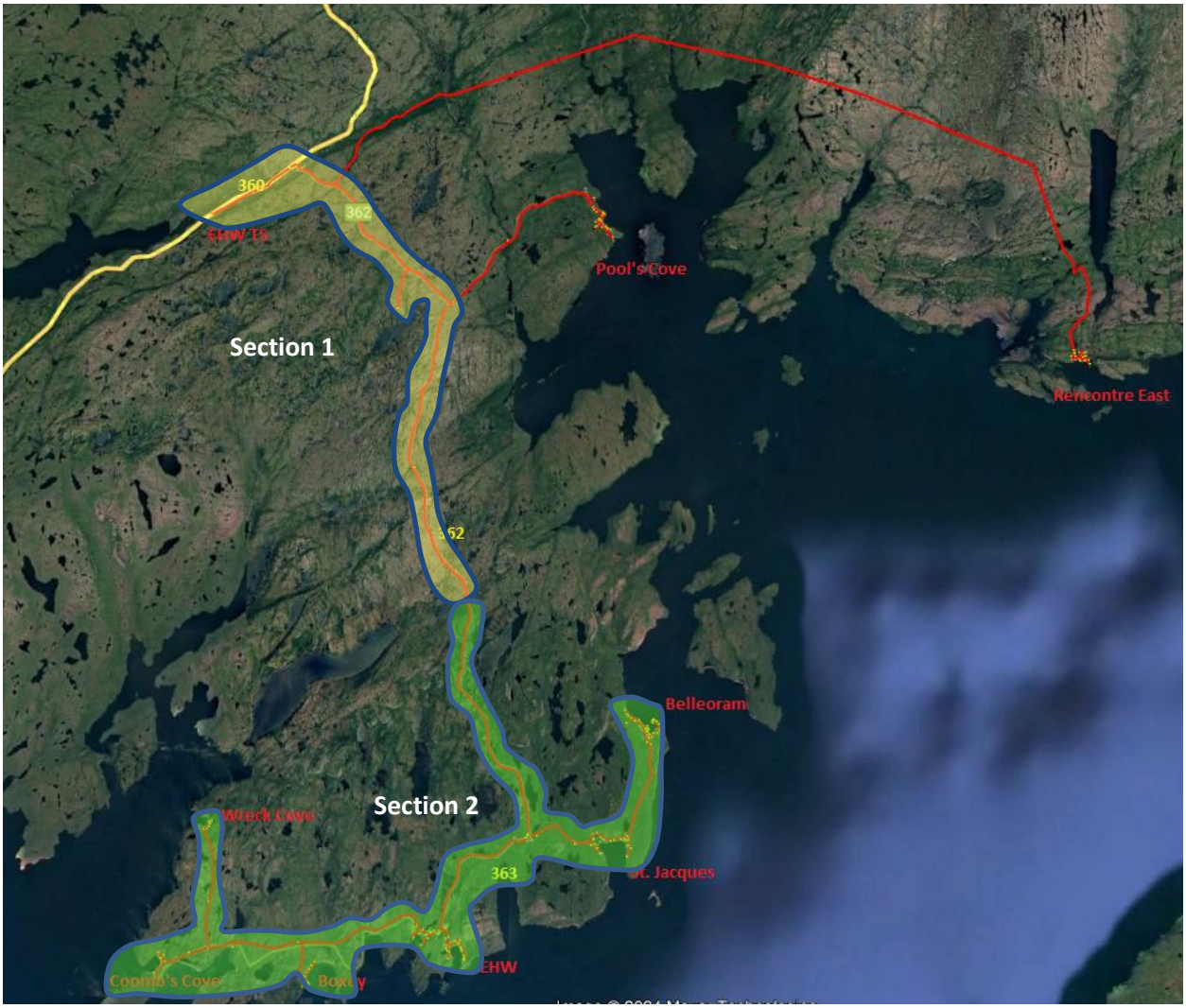


Figure 3: Sections 1 and 2 – EHW-L1

3.2.1 EHW-L1 Section 1

Section 1 is approximately 23 kilometres in length, and is the worst section of EHW-L1 from both a reliability and asset condition perspective. This section has been identified as an at-risk area for ice storm damage. Most of the poles in this section are located at high elevations, and experience performance issues due to severe ice loading. Figure 4 and Figure 5 show pictures of EHW-L1 conductor and structures during a severe icing event in 2022.



Figure 4: Ice Covered Conductor – EHW-L1 – 2022 Icing event



Figure 5: Ice Covered Structure – EHW-L1 – 2022 Icing Event

A field survey has identified numerous deteriorated cross arms on this feeder that require replacement. Figure 6 shows a picture of a deteriorated cross arm in this section. In the past, broken cross arm incidents on this feeder have caused prolonged power outages. Figure 7 shows a picture of a broken cross arm damaged by a severe icing event in 2022.

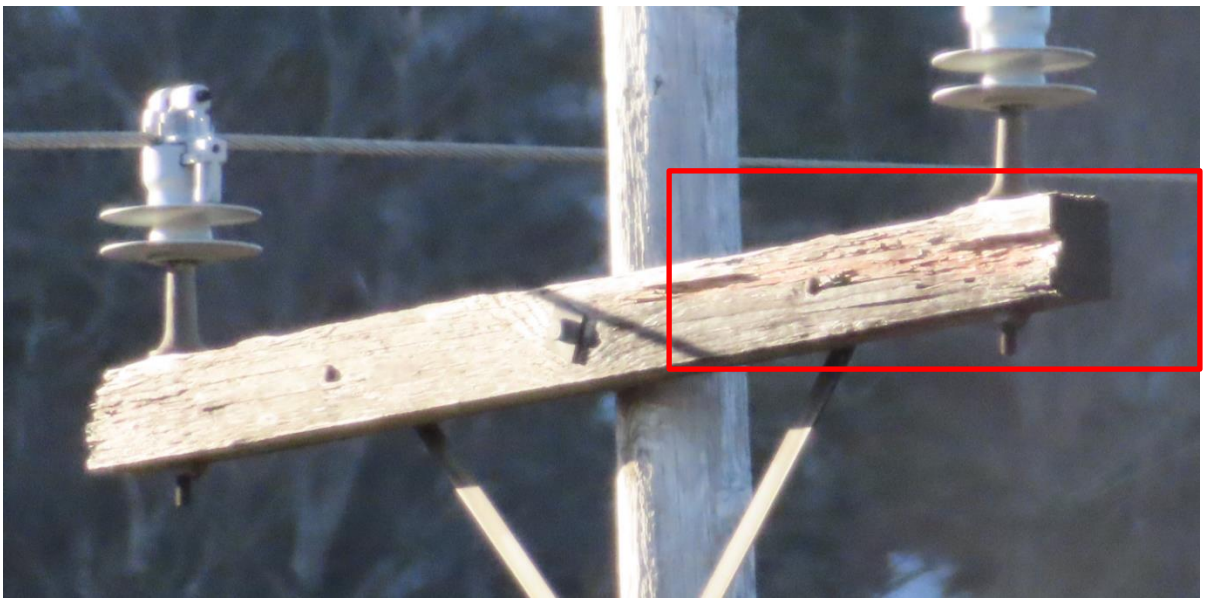


Figure 6: Deteriorated Cross Arm of EHW-L1 (Section 1)



Figure 7: Damaged Cross Arm – 2022 Icing Event

Due to the location and deteriorating condition of the existing structures, this feeder is becoming more prone to damage when exposed to heavy winds, ice, and snow loading. It has been identified that this section has several long-span structures, which increase the risk of galloping and line component failure. This section also has several structures located off road with rough access, which greatly increases response times and therefore outage duration. Figure 8 and Figure 9 show pictures of off-road structures and repair activities.



Figure 8: Line Crews Accessing Damage to an Off-Road Structure



Figure 9: Line Crews Repairing an Off-Road Structure

Most of the insulators on this section are non-standard, and several have insufficient creepage distance for a 25 kV system. Figure 10 and Figure 11 show pictures of substandard insulators on EHW-L1, which have impacted feeder reliability.[7] 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.

[7] For a 25 kV system, three-unit insulators are needed to prevent arcing; the insulators shown in Figure 10 are two-unit insulators.

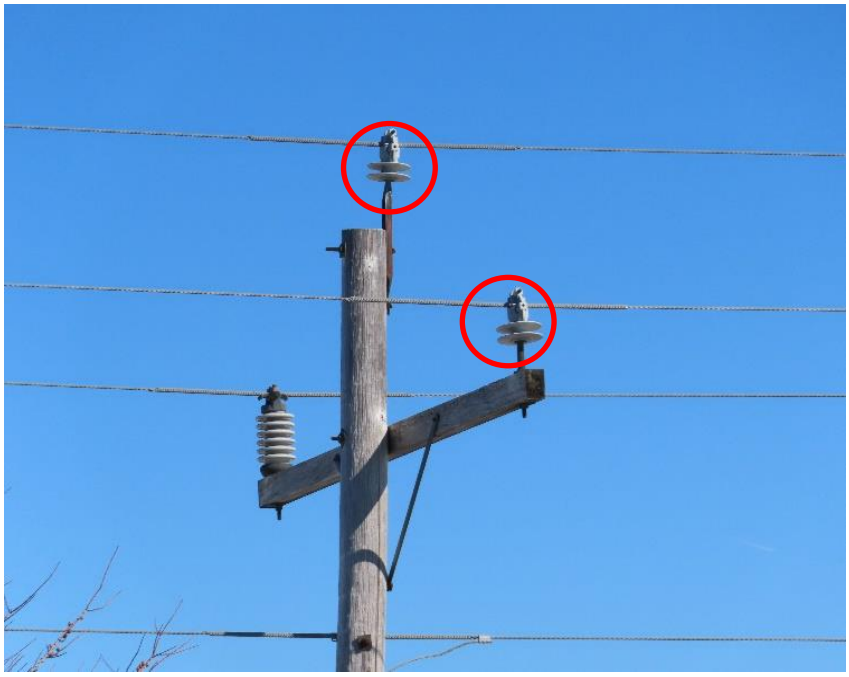


Figure 10: Substandard 2 Skirts Hendrix Insulators

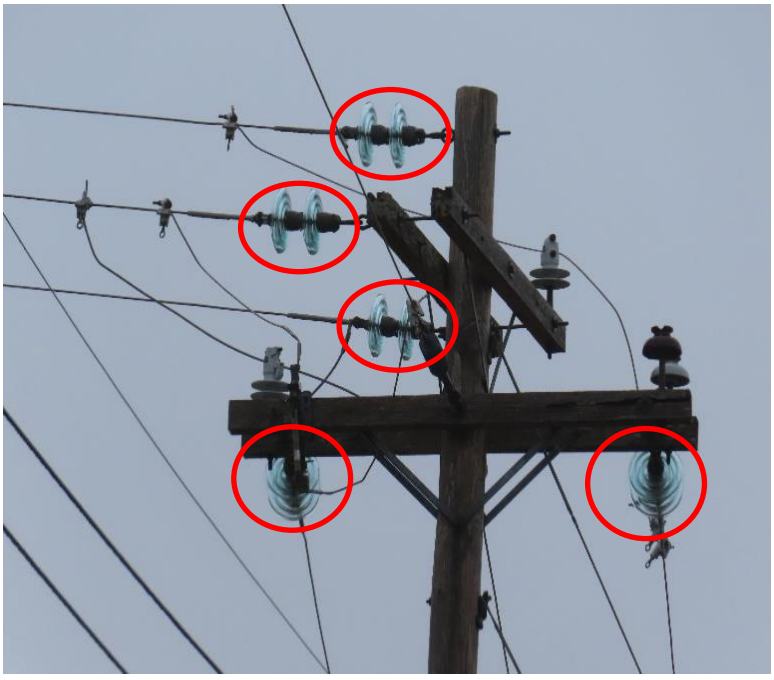


Figure 11: Substandard Glass Type Suspension Insulators

In addition, failure of the primary conductor has been an issue over the past number of years, with multiple in-line splice repairs in this section. Figure 12 shows an instance of a deteriorated conductor with multiple sleeves on EHW-L1.

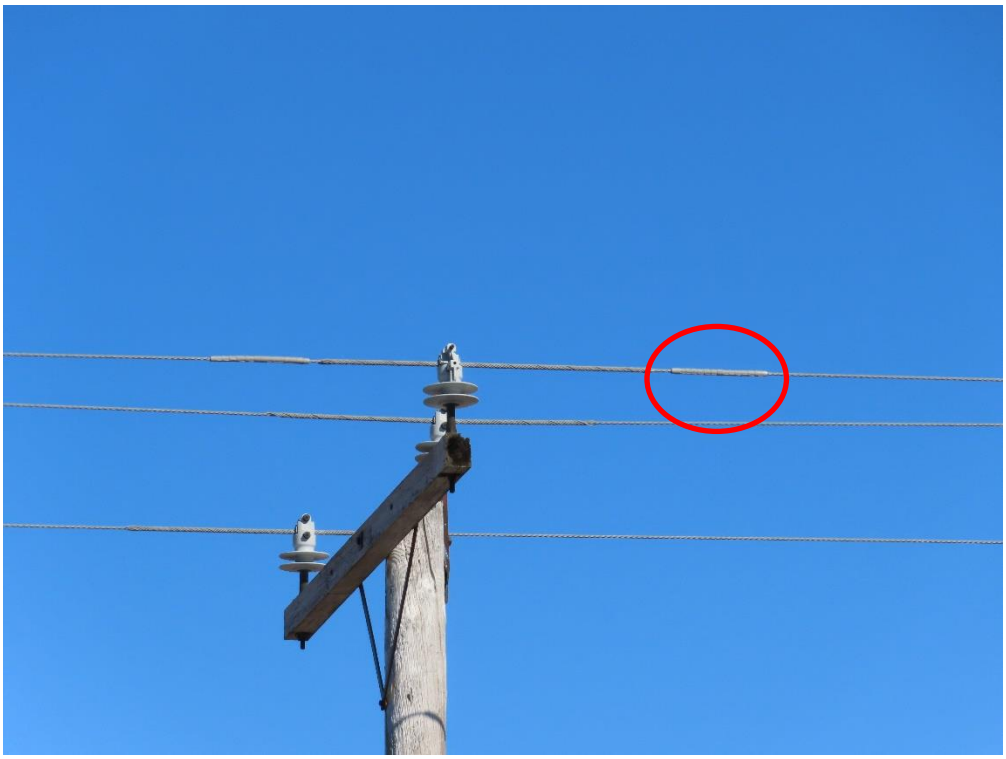


Figure 12: Deteriorated Conductor with Multiple Sleeves (Section 1)

Therefore, reconstruction of this section with higher class poles, armless constructions, anti-cascade structures, shorter spans, standard insulators and new conductors is required to improve the reliability of EHW-L1. Reconstruction of this section is required to: address deteriorated cross arms, conductors and insulators; address the long spans; reduce structural damage risk from ice loads; and improve structure accessibility and visibility.

3.2.2 EHW-L1 Section 2

Section 2 is approximately 43 kilometres in length, and contains deteriorated poles, cross arms, and substandard insulators. The primary line of this section has multiple spans of #2 ACSR,[8] which is non-standard and prone to failure. ACSR is not recommended for saltwater environments because of the

[8] Aluminum-conductor steel reinforced ("ACSR").

potential for excessive corrosion caused by oxidization between the steel core and the aluminum outer strands. In addition, this section has multiple spans 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, wind and ice storms, and while line work is ongoing. The spans of non-standard conductors require replacement. Figure 13 to Figure 16 show pictures of deteriorated assets in this section.



Figure 13: Deteriorated Pole of EHW-L1



Figure 14: Damaged Pole of EHW-L1



Figure 15: Deteriorated Cross Arm of EHW-L1 (Section 2)

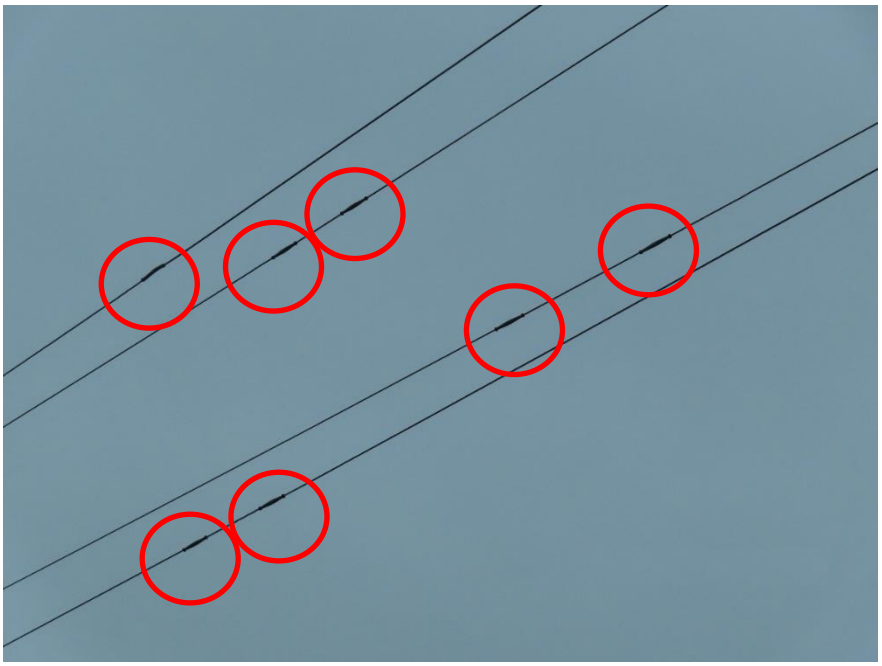


Figure 16: Deteriorated Conductor with Multiple Sleeves (Section 2)

EHW-L1 is a lengthy radial feeder. The beginning of this feeder near the EHW TS is protected by a three-phase recloser (R1) with the next three-phase recloser (R2) approximately 31 kilometres away. R2 is located just before the feeder splits into two major taps at the intersection of Route 362 and 363. When a fault occurs downstream of this location, the operation of R2 results in an outage to all customers supplied by those two major taps. Therefore, to minimize this effect, two separate reclosers are proposed for installation. This will reduce both the number of affected customers and the outage duration time. Figure 17 provides the proposed locations of the reclosers. In addition to the reclosers, 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.

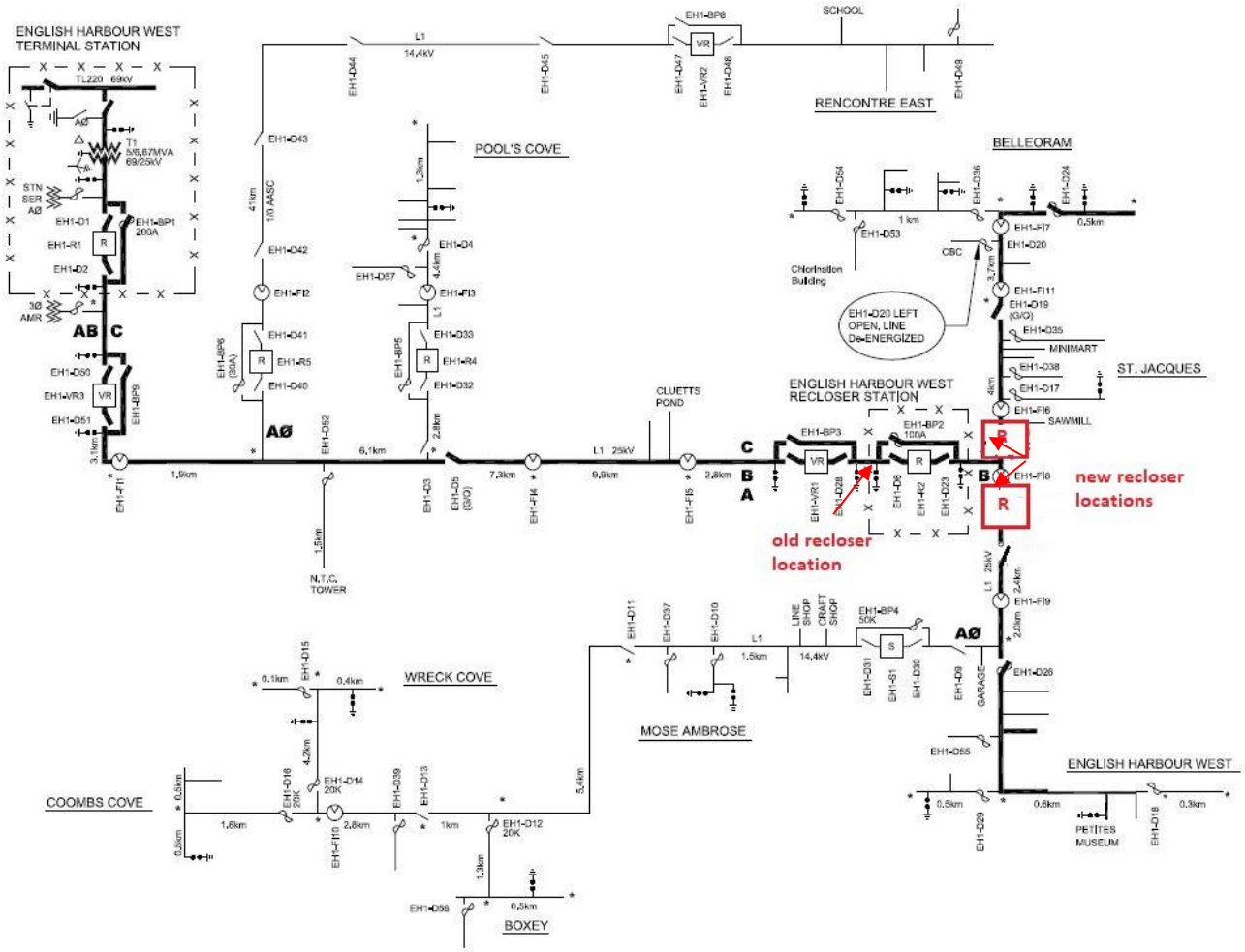


Figure 17: New Recloser Locations

3.3 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 useful service life. The remaining line components not addressed under this program are considered to be in adequate to good condition and have an expected remaining service life from six years (until the next preventive maintenance cycle) to 20 years, or beyond.

3.4 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. Components of the EHW-L1 feeder date back to the 1960s.

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.

4.1 Historical Reliability

Table 1 provides the reliability data for EHW-L1 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 EHW-L1 (2019–2023)

Location	SAIDI	SAIFI	CHI
EHW-L1	10.01	3.11	8,039
Hydro	3.84	1.55	1,121[9]

A feeder assessment completed in 2024 identified that the reliability experienced by the customers serviced by this feeder during the 2019–2023 period was impacted by hardware failures, such as insulator failures, broken cross arms, and broken conductor incidents.

[9] Hydro CHI represents the average number of CHI per feeder. It is calculated by dividing the number of total customer outage hours by the number of distribution feeders.

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro considered the following alternatives:

- Pace reduction;
- Pace advancement;
- Continue program at current pace; and
- Construct a new feeder.

5.1.1 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.

5.1.2 Pace Advancement

Hydro's historical experience with this program has not demonstrated a need to accelerate assessments and associated upgrades.

5.1.3 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.

5.1.4 Construct New Feeder

Hydro has considered constructing a new feeder for the entirety of EHW-L1; however, this feeder is approximately 115 kilometres long and approximately 63% of the poles are less than 43 years old.[10] Other existing feeder components which have not been identified for replacement are still in operable condition, such as conductors, insulators, and cross arms. The complete replacement of the existing

[10] Hydro uses 43 years as the anticipated useful or economic life for its distribution of wood poles.

feeder requires a level of investment that is not required for the continuation of reliable service and is not considered a viable option.

5.2 Least-Cost Evaluation

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

5.3 Recommended Alternative

Hydro proposes the continuation of this program at the current pace, with the upgrade of EHW-L1 beginning in 2025.

5.3.1 Risk of Asset Stranding

Hydro does not anticipate a change in service requirements in this area; therefore, the risk of asset stranding is low.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025–2027 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-Implementation	3	5	**15**
Post-Implementation	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**1.4**

6.0 Scope of Work

An overview of the work to be completed under this program beginning in 2025 is as follows:

- Reconstruction of 23 kilometres of the three-phase section of EHW-L1;
- Install approximately 180 poles to address deteriorated poles;
- Replace approximately 80 non-standard or deteriorated cross arms;
- Replace all non-standard or deteriorated conductors, approximately 20 kilometres;

- Replace substandard insulators for approximately 350 structures;
- Install two reclosers (three-phase); and
- Install fault circuit indicators.

6.1 Program Budget

The estimate for the 2025–2027 program is shown in Table 3.

Table 3: Program Estimate ($000)[11]

Program Cost	2025	2026	2027	Total
Material Supply	431.7	1,430.5	435.9	**2,298.1**
Labour	332.8	911.6	793.2	**2,037.7**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	1,326.9	485.7	0.0	**1,812.6**
Other Direct Costs	89.1	34.7	557.8	**681.6**
Interest and Escalation	172.4	443.4	557.8	**1,173.6**
Contingency	326.0	371.5	185.1	**882.5**
Total	**2,678.9**	**3,677.4**	**2,529.8**	**8,886.1**

Chart 1 shows the historical expenditures since the program was initiated, the forecast 2024 expenditures, the proposed 2025 budget, and the forecast costs through 2029. Hydro began the program in 2019, with construction activities commencing in 2020. The 2020 budget included construction activity on three feeders. The increased program budget in 2025 reflects the inclusion of the scope of the Renew Distribution Feeders Program for EHW-L1 under the Upgrade Worst-Performing Distribution Feeders Program in 2025.

[11] Numbers may not add due to rounding.

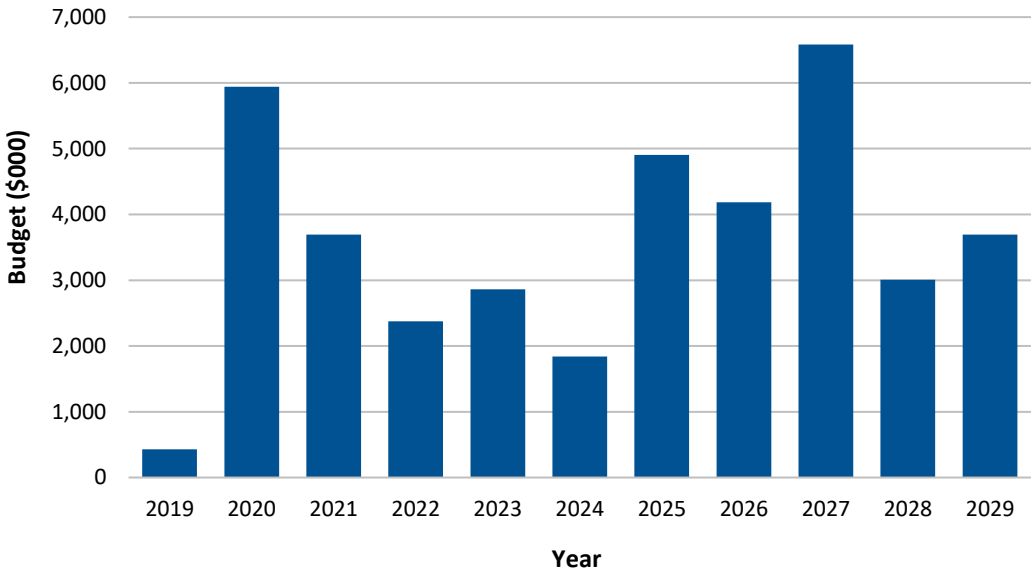


Chart 1: Historical and Forecast Program Budget

6.2 Program Schedule

The anticipated schedule for this program is shown in Table 4.[12]

Table 4: Program Schedule

Activity	Start Date	End Date
Planning:		
Resource planning.	January 2025	January 2025
Design:		
Conduct site visits and detailed design.	January 2025	October 2025
Procurement:		
Order materials.	April 2025	November 2025
Construction:		
Construction.	July 2025	September 2027
Commissioning:		
Commissioning of refurbished work.	July 2025	September 2027
Closeout:		
Complete closeout documentation.	September 2027	November 2027

[12] As a result of the significant work required to upgrade EHW-L1, the work will be executed over three years instead of two, as is typically completed under the Upgrade Worst-Performing Distribution Feeders Program.

7.0 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 2025–2027 program is required to improve the reliability and address the deteriorated condition of the EHW-L1 feeder.

Appendix A

Worst-Performing Feeder List and Summary of Data Analysis





Table A-1: Worst-Performing Feeders Sorted by CHI

Rank	Feeder	CHI
1	English Harbour, Line 1	8,039
2	Happy Valley, Line 7	7,972
3	Barachoix, Line 4	7,108
4	Barachoix, Line 1	6,106
5	St. Anthony, Line 1	5,617
6	L'Anse-au-Loup, Line 2	5,434
7	Bottom Waters, Line 1	4,878
8	Kings Point, Line 1	4,203
9	Jackson's Arm, Line 2	3,824
10	Farewell Head, Line 1	3,729
11	Bay d'Espoir, Line 1	3,581
12	L'Anse-au-Loup, Line 1	3,262
13	South Brook, Line 1	3,113
14	Rocky Harbour, Line 1	2,993
15	Roddickton, Line 1	2,899
16	Hawke's Bay, Line 3	2,864
17	Farewell Head, Line 5	2,767
18	Bottom Waters, Line 4	2,636
19	Bear Cove, Line 6	2,599
20	Cartwright, Line 1	2,443

Table A-2: Worst-Performing Feeders Sorted by SAIDI

Rank	Feeder	SAIDI
1	Black Tickle, Line 1	21.81
2	Farewell Head, Line 1	15.34
3	Bottom Waters, Line 1	13.50
4	Jackson's Arm, Line 2	13.05
5	Fleur-de-Lys, Line 1	11.36
6	Barachoix, Line 1	10.83
7	English Harbour, Line 1	10.01
8	L'Anse-au-Loup, Line 2	8.84
9	Barachoix, Line 4	8.76
10	St. Anthony, Line 1	8.59
11	Happy Valley, Line 7	8.55
12	Main Brook, Line 2	8.49
13	L'Anse-au-Loup, Line 1	7.75
14	Monkstown, Line 2	7.61
15	Bottom Waters, Line 3	7.45
16	Cartwright, Line 1	7.41
17	Kings Point, Line 1	6.28
18	St. Brendan's, Line 1	5.98
19	Bottom Waters, Line 4	5.85
20	Bottom Waters, Line 2	5.48

Table A-3: Worst-Performing Feeders Sorted by SAIFI

Rank	Feeder	SAIFI
1	Happy Valley, Line 15	3.63
2	Bottom Waters, Line 1	3.43
3	L'Anse-au-Loup, Line 2	3.38
4	L'Anse-au-Loup, Line 1	3.18
5	English Harbour, Line 1	3.11
6	Barachoix, Line 4	2.92
7	Happy Valley, Line 7	2.87
8	Barachoix, Line 1	2.71
9	Happy Valley, Line 6	2.66
10	St. Anthony, Line 1	2.58
11	Jackson's Arm, Line 2	2.52
12	Black Tickle, Line 1	2.49
13	Fleur-de-Lys, Line 1	2.42
14	Farewell Head, Line 6	2.25
15	Farewell Head, Line 5	2.19
16	Happy Valley, Line 1	2.06
17	St. Anthony, Line 7	2.06
18	Farewell Head, Line 1	2.06
19	Farewell Head, Line 4	1.87
20	Bottom Waters, Line 3	1.87

Table A-4: Summary of Data Analysis

Feeder	Summary
Barachoix, Line 1	In 2019–2021 tree contacts impacted the reliability. Overall reliability statistics on this feeder have been impacted by several broken primary conductors, and hardware and equipment failure incidents. This feeder performed well in 2023. No work is required at this time.
Barachoix, Line 4	In 2019–2023, this feeder was impacted by several broken primary conductors, and hardware and equipment failure incidents; however, there was only one notable outage in 2023 on this feeder due to salt contamination, which otherwise performed well. No 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. Bird deterrents were added to the affected structures. Tree contacts in the past caused frequent outages but improved in 2022–2023. This feeder will continue to be monitored.
Bear Cove, Line 6	Feeder performed well in 2023. 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	Poor reliability statistics were significantly driven by the 2023 storm event. Access issues during the storm led to extended outage length. In general, the customers of this feeder experienced power outages due to weather-related events or defective line hardware issues during 2019–2023; however, the reliability of this feeder was mainly impacted by the remoteness of the site. No capital work is required at this time but this feeder will continue to be monitored.
Bottom Waters, Line 1	Reliability statistics were impacted by tree contacts, broken insulators and damaged conductor incidents in the 2019–2023 period. Line upgrading work has been completed on this feeder in December 2023 under the Upgrade Worst-Performing Distribution Feeders (2022–2023) Program.
Bottom Waters, Line 2	No outage in 2023. There were a few isolated outages, which placed this feeder on the list. No work is required at this time.
Bottom Waters, Line 3	Only one power outage in 2023, an ice storm downed a conductor over a long span. Overall reliability statistics on this feeder have been impacted by several weather events, 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. Regulator Bank was completely replaced in 2021. No work is required at this time.
Bottom Waters, Line 4	A single tree contact in 2023 impacted overall reliability indices. No capital work is required at this time.
Cartwright, Line 1	No outages in 2023. Previous reliability issues were related to adverse weather and isolated events. No work is required at this time.

Feeder	Summary
English Harbour, Line 1	Poor reliability statistics were driven by several weather events, broken cross arm and other line hardware failures. A feeder assessment of this feeder has been completed recently and upgrade of this feeder is recommended. Details are provided in report "Upgrade of Worst-Performing Distribution Feeders (2025–2027)."
Farewell Head, Line 1	This feeder reliability has been impacted by hardware 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 (2023–2024) Program.
Farewell Head, Line 4	A variety of issues on this feeder contributed to poor reliability statistics. This feeder was upgraded as part of the Upgrade of Worst Performing Distribution Feeders (2021–2022) Program. Feeder performance has improved in 2022–2023.
Farewell Head, Line 5	Feeder performed well in 2023. Previous poor reliability was driven by numerous line component issues. This feeder was upgraded as part of the Upgrade of Worst Performing Distribution Feeders (2021–2022) Program.
Farewell Head, Line 6	Defective protection device events, broken insulator incidents and line slaps impacted the reliability. Protection device repair is scheduled for the summer of 2024. No capital work is required at this time but this feeder will continue to be monitored.
Fleur-de-Lys, Line 1	Overall reliability statistics on this feeder have been impacted by several defective insulator incidents. No work is proposed at this time but this feeder will continue to be monitored.
Happy Valley, Line 1	Feeder performed well in 2023. Previous poor reliability was driven by isolated events. No work is required at this time.
Happy Valley, Line 15	Broken conductors and line slaps were the largest outage causes. Human error during the Happy Valley Terminal Station project and 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 6	In the period 2020–2021, tree contacts were the most significant contributors to outages on this feeder. Tree cutting was completed in 2022. HVY L6 has exhibited traits of a feeder requiring protection investigation, which has been planned for 2024. A new recloser is being prepared for the Mud Lake tap where tree contacts were occurring most often. No additional work is required at this time.
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 cross arm. The metering tank was removed and the upgrading work for L7 loading was completed in 2022. Feeder performed well in 2023. No capital work is required at this time.

Feeder	Summary
Hawke's Bay, Line 3	A vehicle-damaged pole incident in 2023 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 mainly by tree-related events. Tree trimming and ground cutting were completed in 2022–2023. This feeder performed well in 2023. No work is required at this time but the feeder will continue to be monitored.
Kings Point, Line 1	Poor reliability statistics were principally driven by multiple tree-related incidents. Tree trimming and ground cutting were completed in 2022. No work is required at this time.
L'Anse-au-Loup, Line 1	Major outages to this line over the period were associated with salt tracking on multiple components. Insulator failure on a gang switch due to salt was a major outage in 2022. Previously, insulator, surge arrester and instrumentation transformer flashovers have caused outages related to salt spray. 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. Salt contamination and line slap from wind also contributed to the poor reliability. This feeder has many other problematic issues. Work is being carried out on this feeder under the Upgrade of Worst Performing Distribution Feeders (2024–2025) Program
Main Brook, Line 2	Insulator failure and tree contacts were the greatest cause of outages. The coordination and functionality of protection devices on this system caused issues, protection study was completed. No work is proposed at this time but the feeder will continue to be monitored.
Monkstown, Line 2	No outages for 2023. Overall reliability statistics on this feeder have been impacted by an ice storm in 2022. No work is required at this time.
Rocky Harbour, Line 1	A substation hardware failure incident in 2022 and a defective recloser incident in 2023 impacted the reliability significantly. No capital work is required at this time.
Roddickton, Line 1	Feeder performed well in 2023. Previous poor reliability was driven by tree contacts, 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.
South Brook, Line 1	Overall reliability statistics on this feeder have been impacted by trees falling across the line during wind/snow storms. Recloser CLPU issues and a burned recloser bypass switches were also significant causes. The switches were replaced in 2021, and recloser was upgraded in 2022. No capital work is required at this time.

Feeder	Summary
St. Anthony, Line 1	Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents in 2019–2022 and one damaged insulator incident in 2021. In 2023, there were a couple of outages of unknown cause that are suspected to be related to the fusing on the tap to Quipon Island due to a line slap, which has since been resolved by installing the correct fuse. There was also a regulator that failed and caused a large event but has been replaced. No capital work is required at this time but this feeder will continue to be monitored.
St. Anthony, Line 7	Variety of issues on this feeder over the period 2019–2023. A saddle clamp failed leading to the largest outage in 2023. Nesting birds, tree contacts and insulator failure are the other causes of trouble on this feeder. Continue to monitor.
St. Brendan's, Line 1	Poor reliability statistics were mainly driven by an isolated event in 2022. No work is required at this time.

Program 3

Replace Light- and Heavy-Duty Vehicles

2025–2027

newfoundland labrador hydro

Replace Light- and Heavy-Duty Vehicles (2025–2027)

Location: Various

Investment Classification: General Plant

Asset Category: Transportation

Cost: $7,537,578

Executive Summary

Newfoundland and Labrador Hydro (”Hydro”) operates a fleet of vehicles comprised of approximately 235 light-duty vehicles and approximately 70 heavy-duty vehicles. The fleet is distributed across Hydro’s operating areas throughout the province and 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 replacement 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 35 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 2027, due to ongoing supply chain challenges,[1] at an estimated cost of $7,537,600.

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

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1.0 Introduction

Hydro operates a fleet of vehicles comprised of light-duty vehicles and heavy-duty vehicles 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 key replacement criteria for light- and heavy-duty vehicles are provided in Table 1. Age and odometer readings are average conditions for units requiring replacement; however, a review of asset condition and the criticality of the unit to operations is also considered in whether to replace a vehicle in the upcoming year.

Table 1: Replacement Criteria

Vehicle	Replacement Criteria
Light-Duty	7 years or 200,000 kilometres (odometer reading), dependent on condition/maintenance cost and reliability
Heavy-Duty – Classes 4 and 6	9 years or 200,000 kilometres (odometer reading), dependent on condition/maintenance cost and reliability.

3.0 Asset Overview

3.1 Asset Background

Entering 2025, the composition of Hydro's light-duty fleet is forecast to include approximately 175 pickup trucks, 20 specialized box vans, and 40 small vehicles, including SUVs,[2] cars, and minivans.[3] On average, Hydro's vehicles accumulate 25,000–30,000 kilometres per year or an average of 175,000–210,000 kilometres over the seven-year life of the vehicle. On occasion, a small number of vehicles receive greater usage, requiring replacement before the conclusion of their seven-year life; while other vehicles will incur significantly lower total kilometres driven, and provide a longer service life. Hydro's experience with heavy-duty vehicles is similar, except useful reliable service life is approximately nine years on average.

[2] Sport utility vehicle ("SUV").
[3] Forecast includes vehicle data as of mid-2024; fleet numbers may vary year-to-year depending on the specific timing of vehicle replacements and retirements.

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. Hydro continues to monitor practices of other Canadian utilities, as well as statistics on Hydro's vehicle usage rates, to ensure Hydro's criteria and vehicle replacement rates are appropriate and conducive to Hydro's operations.

3.2 Asset Condition

As equipment ages, failures and resulting downtime will 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 align with 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 does consider the option to extend the service life of the asset. This decision must weigh the increased chance of failure against its potential impact on utility reliability.

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. Replacements in the 0–5-year age range category are typically a result of the vehicles meeting the mileage and condition criteria.

For light-duty vehicles, the average age of the fleet entering 2025 will be just under four years, which is on target for the average seven-year service life.

For heavy-duty vehicles, the average age of the fleet entering 2025 will be just over five years which is higher than optimal for the average nine-year service life. Supply chain constraints in which orders could not be taken on a timely basis and production delays on orders placed have been substantial. This has led to Hydro having no choice but to continue to use vehicles longer than ideal. The experience has validated that excessive failures and operational impacts do result and the replacement criteria are valid.

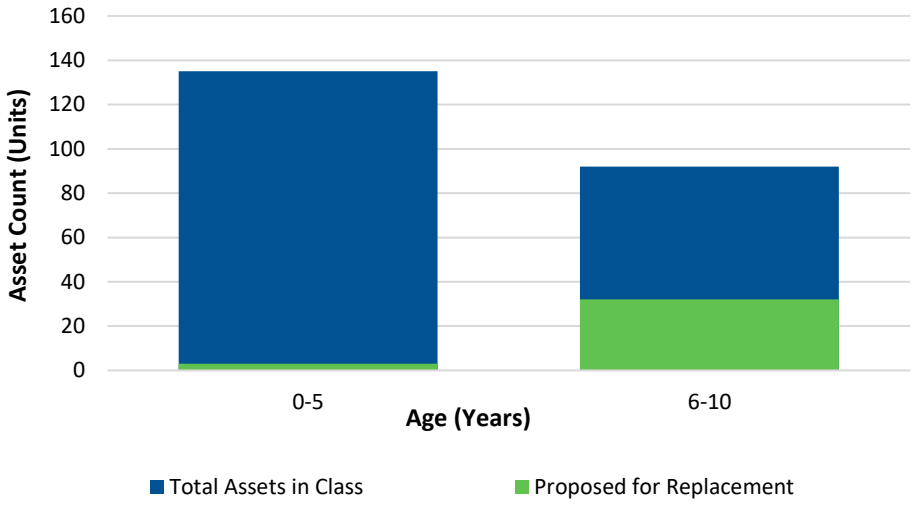


Chart 1: Light-Duty Vehicle Asset Counts by Age

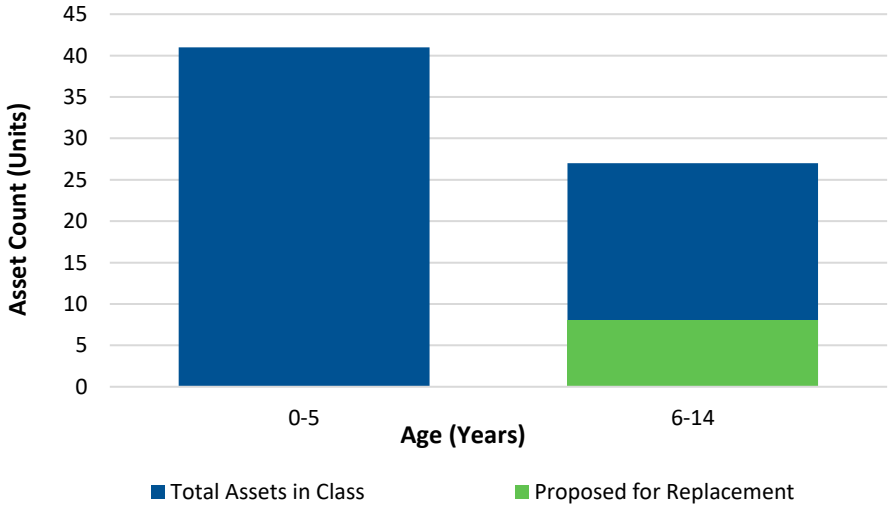


Chart 2: Heavy-Duty Vehicle Asset Counts by Age

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 forecast for future years is based on the outcome of Hydro's review of average age versus service life as discussed in Section 3.4, and reduces volatility in annual replacement rates. These projections are reflected in Chart 3 and consider current fleet size requirements, with some variances observed due to uneven age distributions within the fleet.

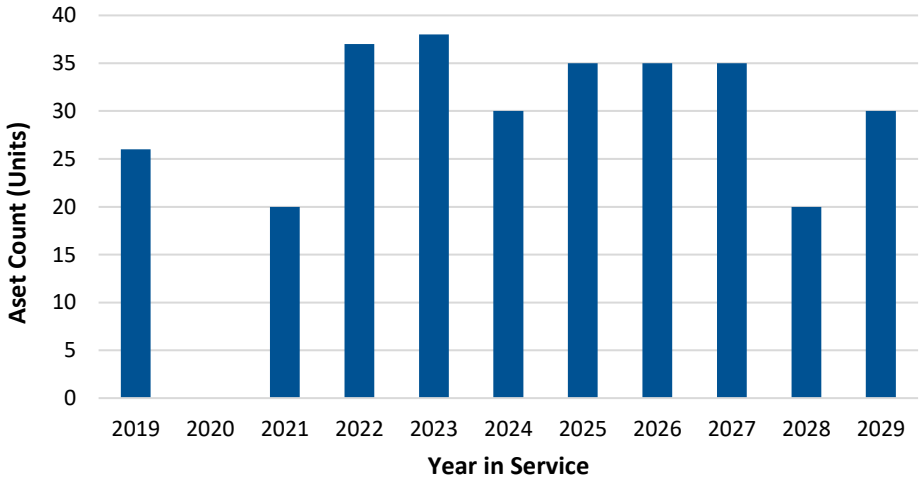


Chart 3: Historical and Forecast Number of Assets – Light-Duty Vehicles

Chart 4 provides the five-year historical, current, and five-year forecast number of heavy-duty vehicles replaced under this program. Assets in service from 2020 to 2023 are below average due to global supply chain challenges; deliveries in 2024 to 2026 are higher than normal, primarily due to delayed delivery of orders from previous years. The forecast for future years is based on Hydro's review of average age versus service life as discussed in section 3.4, and reduces volatility in annual replacement rates. These projections are reflected in Chart 4 and consider current fleet size requirements, with some variances observed due to uneven age distributions and varying delivery times within the fleet.

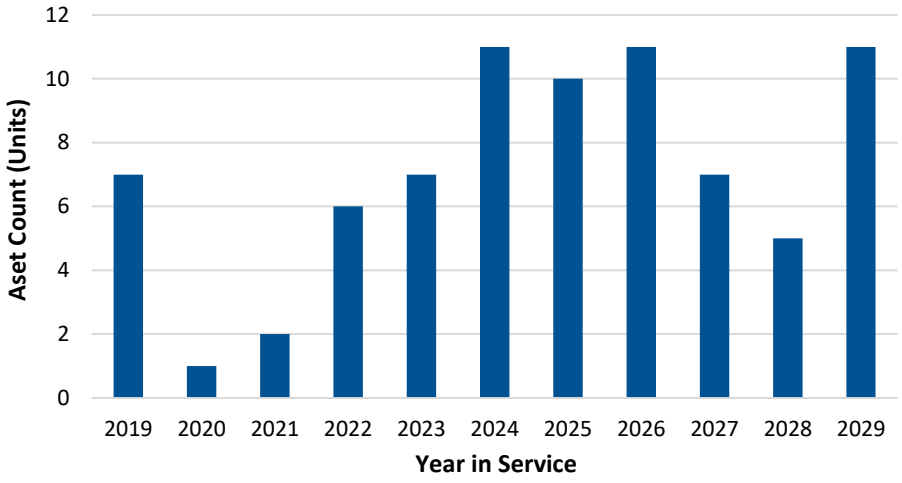


Chart 4: Historical and Forecast Assets Replaced – Heavy-Duty Vehicles

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. 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.

Substantial cost escalation has been experienced in both the light- and heavy-duty segments since 2020. The variation in average costs in heavy-duty vehicles is attributed to the procurement of varying types of vehicles under this program.

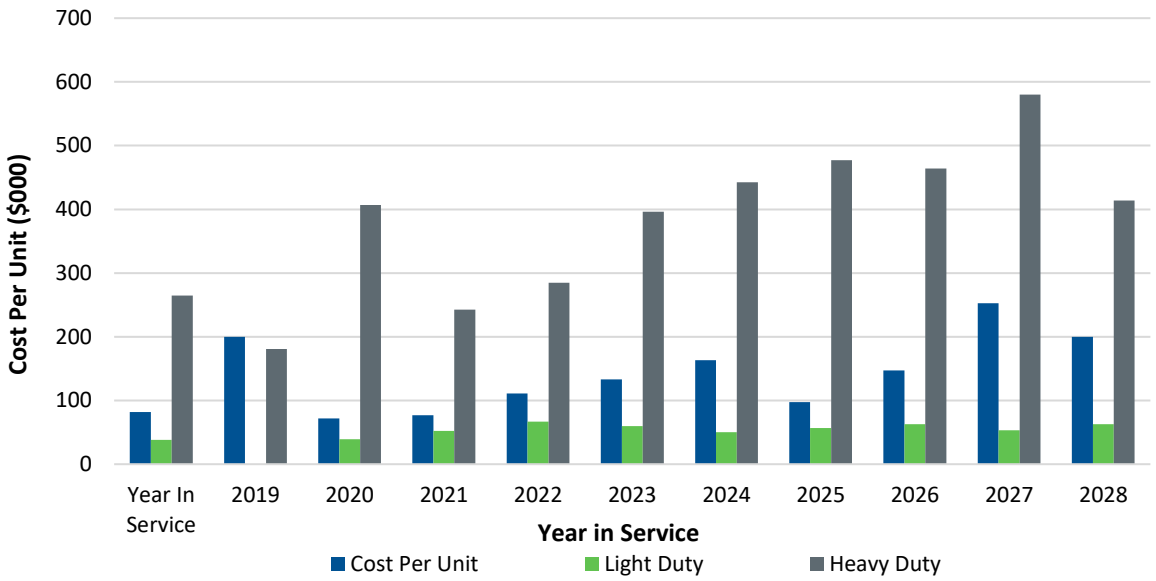


Chart 5: Historical and Forecast Average Unit Costs of Assets Installed/Replaced

4.3 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.

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro considered the following alternatives:

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

5.1.1 Pace Reduction

In 2020, Hydro re-evaluated its replacement criteria and reduced the pace based on review of industry standards 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. Unplanned pace reduction imposed by supply chain constraints from 2020 to present confirmed an increased rate of vehicle failure that has resulted in challenges to completing required work. For this reason, pace reduction is not considered a viable option.

5.1.2 Pace Advancement

Advancing the pace of this program may result in premature retirement of existing, functional assets, requiring a level of investment that is not required for the continuation of safe, reliable, least-cost electricity in an environmentally responsible matter. Hydro is continuing to evaluate the appropriate pace for vehicle replacement, particularly heavy duty vehicles, based on average asset age and service life as discussed in section 3.4. For this reason, pace advancement is not considered a viable option at this time.

5.1.3 Continue Program at Current Pace

Hydro has determined the current criteria is 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.

5.1.4 Alternative Strategies – Vehicle Rentals

Hydro has considered supplementing its fleet vehicle needs with rental vehicles. Hydro utilizes light-duty rental vehicles as much as is practical; however, they are frequently in short supply. Additionally, much of Hydro's light-duty fleet is customized to industrial work usage to the extent that there is no direct replacement option possible from the rental market. Hydro also determined there are currently no heavy-duty vehicles available to rent that can perform consistently with Hydro's fleet, which are mostly customized with aerial devices. As such, Hydro does not consider this a viable alternative for this program.

5.2 Least-Cost Evaluation

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

5.3 Recommended Alternative

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

5.3.1 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.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025–2027 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-Implementation	3	4	**12**
Post-Implementation	3	1	**3**
		Risk Mitigated	**9**
		Risk Mitigated per $1 Million	**1.2**

6.0 Scope of Work

This program proposes the replacement of 35 light-duty mobile and 8 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] This program also includes $100,000 in 2025 to address in-service failures for fleet vehicles. Hydro will evaluate the cost of repair or refurbishment versus replacement prior to executing in-service failure repairs.

[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.

6.1 Program Budget

The estimate for this program is shown in Table 3.

Table 3: Program Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	2,330.0	1,400.0	2,650.0	**6,380.0**
Labour	51.0	43.3	25.7	**120.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	18.0	13.5	13.5	**45.0**
Interest and Escalation	75.7	73.3	189.1	**338.1**
Contingency	239.9	145.7	268.9	**654.5**
Total	**2,714.6**	**1,675.8**	**3,147.2**	**7,537.6**

Light-duty vehicles shall be requisitioned and received in 2025. Heavy-duty vehicles will be requisitioned in 2025, with delivery expected in 2026 and 2027.

Chart 6 shows the five-year historical expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and forecast costs through 2029. 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 up to 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 the purchase of the vehicles can be broken down into categories, there are overheads and efficiencies gained from combining the scopes of work that are reflected below; as such, these expenditures have not been split between the light- and heavy-duty vehicles.

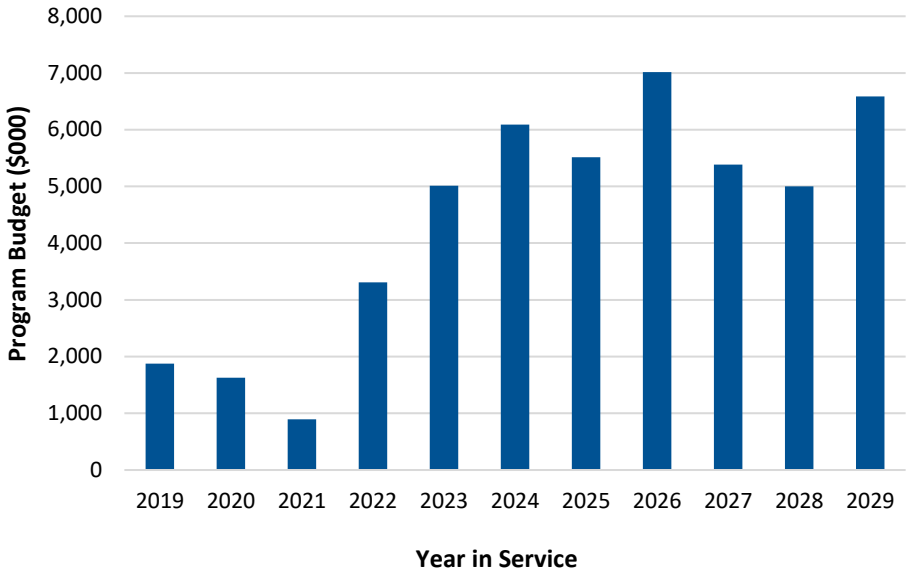


Chart 6: Historical and Forecast Program Budget

6.2 Program Schedule

The schedule for this program is shown in Table 4.

Table 4: Program Schedule

Activity	Start Date	End Date
Planning: Open work orders, plan, and develop detailed schedules.	January 2025	February 2025
Procurement: Tender and award contracts to purchase light- and heavy-duty vehicles.	February 2025	April 2025
Commissioning: Receive and commission light-duty vehicles. Receive and commission heavy-duty vehicles.	May 2025 April 2026	November 2025 October 2027
Closeout: Close work orders, complete all documentation, and complete lessons learned.	November 2027	December 2027

7.0 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 2025.

Program 4

Distribution System In-Service Failures, Miscellaneous Upgrades and Street Lights

2025

newfoundland labrador hydro

Distribution System In-Service Failures, Miscellaneous Upgrades and Street Lights (2025)

Location: Various

Investment Classification: Renewal

Asset Category: Distribution

Cost: $6,397,979

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 as required to ensure fulfillment of Hydro's legislated mandate to provide reliable service at the least cost, in an environmentally responsible manner. The program also includes expenditures related to the replacement of existing street lights, outdated high-pressure sodium ("HPS") and mercury vapour ("MV"), with light-emitting diode ("LED") fixtures and for the purchase of selected capital spare equipment.

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 2025 is $6,397,000, which is based on the average expenditures over the past three years, from 2021 to 2023, and includes an addition of $1,042,442 for the purchase of a new capital spare substation power transformer.

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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, or existing installation deficiencies. 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, replacement 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. Deferral of work that is justified under this program could result in a detrimental impact on customer power supply or an unacceptable risk to workers 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.

The purchase of capital spare equipment, or their refurbishment, is also a part of this program. Items which are of critical importance in the delivery of energy to customers, have long lead times and may be

needed quickly during an emergency.

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. 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.

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;
- Cross arms, insulators, conductors, hardware;
- Pole top distribution transformers; and
- Street lights.

3.2 Asset Condition

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure. The methodologies indicated in this section also apply to its replacement in a similar fashion to all other distribution assets.

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 life cycle.

4.0 Trending

Data from 2023 indicates that Hydro replaced 226 distribution assets during that year. The average over the past five years has been 249 assets replaced per year, excluding the street light modernization effort.

4.1 Assets Installed/Replaced/Upgraded

Chart 1 indicates the total number of assets installed under the program during the five years from 2019 to 2023.[1] The types of assets replaced vary from year to year. As of April 2024, Hydro has replaced more than 5,480 street lights with LED technology, representing 58% of all fixtures. Hydro anticipates full completion of the street light modernization effort in 2026 as planned.

[1] Excluding street lights.

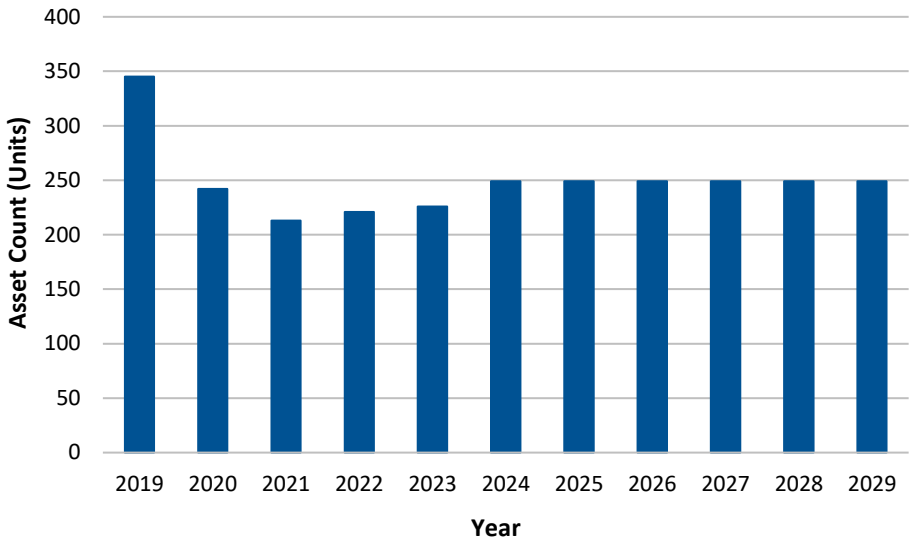


Chart 1: Historical and Forecast Number of Assets Installed/Replaced/Upgraded

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 Section 6.1.

4.3 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,[2] SAIFI,[3] CHI,[4] CHIKM,[5] and CIKM.[6] A summary of Hydro's distribution reliability performance is provided in Section 4.0 of Schedule 1.

[2] System Average Interruption Duration Index ("SAIDI"). SAIDI indicates the average length of time a customer is without power in the respective distribution system per year.
[3] System Average Interruption Frequency Index ("SAIFI"). SAIFI indicates the average number of power outages a customer has experienced in the respective distribution system per year.
[4] 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.
[5] Customer Hours of Interruption per Kilometre ("CHIKM") is calculated by dividing the number of customer outage hours by the kilometres of feeder.
[6] Customers Interrupted per Kilometre ("CIKM") is calculated by dividing the sum of the number of customers that have experienced an outage within a one-year period by the kilometres of feeder.

5.0 Analysis

5.1 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.

5.1.1 Pace Reduction

Hydro has not identified any pace reduction options for this program. Due to the immediate and emergency nature of failures noted under this program, delays in asset replacement are not conducive to maintaining a continuous, reliable supply of energy to customers.

5.1.2 Pace Advancement

Any opportunity to perform pace advancement on the replacement of distribution assets, in an economical way, is taken advantage of by Hydro under separately-defined distribution projects such as the Upgrade Worst-Performing Distribution Feeders Program, Renew Distribution Feeders Program and other, limited scope projects such as Bay d'Espoir Terminal Station 2. Accelerating the replacement of deteriorated distribution assets is preferred rather than allowing the assets to experience unplanned failure due to the large number of assets which are being identified as having reached end-of-life through Hydro's inspection program. This is expected as the vast majority of like assets were originally installed at a similar time period and are deteriorating at similar rates.

5.1.3 Alternative Strategies

Hydro has not identified any alternative strategies for this program.

5.2 Least-Cost Evaluation

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

5.3 Recommended Alternative

5.3.1 Risk of Asset Stranding

The assets installed under this program can generally be redeployed should the service requirements change in a given location. The capital spare substation transformer will be designed such that it can be utilized in a half dozen individual locations across Hydro's system. For this reason, the risk of asset stranding is very low.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	3	5	**15**
Post-Implementation	1	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**1.9**

6.0 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, accommodate small-scale infrastructure replacements and purchase/refurbish distribution capital spares. The scope of this program also includes the ongoing conversion of Hydro's existing street lights to efficient LED technology.

6.1 Program Budget

The estimate for this 2025 program is shown in Table 2. The estimate is based on the average expenditures from 2021 to 2023.

Table 2: Program Estimate ($000)[7]

Program Cost	2025	2026	Beyond	Total
Material Supply	2,604.8	0.0	0.0	**2,604.8**
Labour	2,641.0	0.0	0.0	**2,641.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	378.1	0.0	0.0	**378.1**
Other Direct Costs	480.7	0.0	0.0	**480.7**
Interest and Escalation	292.3	0.0	0.0	**292.3**
Contingency	0.0	0.0	0.0	**0.0**
Total	**6,397.0**	**0.0**	**0.0**	**6,397.0**

Chart 2 shows the five-year historical expenditures, the forecast 2024 expenditures, the proposed 2025 budget, and forecast costs through 2029. The estimated cost for work executed under this program in 2025 is $6,397,000; which is based on the average expenditures over the past three years, from 2021 to 2023, with an additional $1,042,442 included for the one-time purchase of a capital spare substation transformer in 2025 only.

The reduced forecast for years 2027, 2028, and 2029 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 2025 program budget with cost escalation applied. The capital spare transformer replacement amount for 2025 is not included in the calculation of the forecast 2027 to 2029 values as this purchase is outside of typical program costs.

[7] Numbers may not add due to rounding.

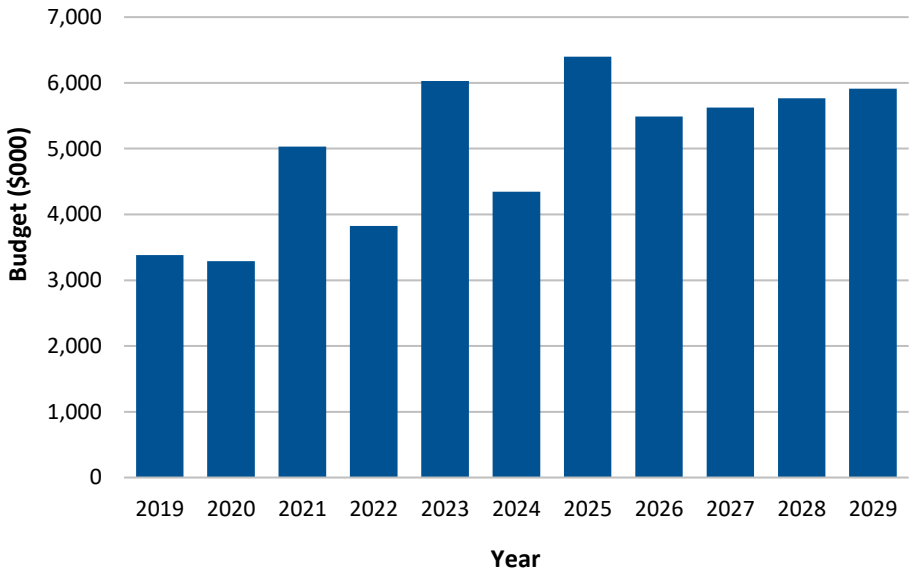


Chart 2: Historical and Forecast Program Budget

6.2 Program Schedule

Work schedules are established subsequent to an unplanned failure or incipient failure event. Street light installations are performed on an ongoing basis.

7.0 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. Purchase of the new substation power transformer will dramatically reduce operational risks. Street light modernization efforts will result in cost savings for Hydro and its customers.

Replace Diesel Gensets

2025–2027

newfoundland labrador hydro



Replace Diesel Gensets (2025–2027)

Location: L'Anse-au-Loup and Grey River

Investment Classification: Renewal

Asset Category: Generation

Cost: $6,223,584

Executive Summary

The community of L'Anse-au-Loup is located on the south coast of Labrador, where Newfoundland and Labrador Hydro ("Hydro") provides electrical service to approximately 1,060 customers. The majority of the electricity is supplied by the Lac-Robertson Generating Station in Québec through a surplus energy purchase agreement with Hydro-Québec with standby power supplied by a diesel generating plant owned and operated by Hydro.[1] The L'Anse-au-Loup Diesel Generating Station contains five units, with an additional mobile unit located outside the building. Unit 2005 in L'Anse-au-Loup is an 800 kW, 1,800 rpm diesel generating set ("genset"), was installed in 1988, and has reached the end of its useful life. The load profile in L'Anse-au-Loup expects modest load growth over the next 20 years.

The community of Grey River is located on the south coast of Newfoundland, where Hydro provides electrical service to approximately 65 customers. The Grey River Diesel Generating Station contains three units, two of which are proposed for replacement. Unit 2062 is a 136 kW, 1,800 rpm diesel genset installed in 2001. Unit 2067 is a 136 kW, 1,800 rpm diesel genset installed in 2002. The load profile in Grey River is expected to remain stable throughout 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. Units 2062 and 2067 are forecast to reach this threshold in 2026 and Hydro is recommending replacement with like-for-like units. Work in Grey River is scheduled for completion in 2027 with an estimated cost of $2,632,500.

[1] Due to the nature of the surplus energy purchase agreement with Hydro-Québec, Hydro's customers in L'Anse-au-Loup can be interrupted at any time.

Hydro is recommending the replacement of Unit 2005 in L'Anse-au-Loup with a 1,500 kW, 1,800 rpm unit, which will address the need for increased firm capacity due to forecast load growth.[2] Work in L'Anse-au-Loup is scheduled for completion in 2027, with an estimated cost of $3,591,100.

This program has a multi-year approach, with completion planned in 2027 at an estimated cost of $6,223,600.

[2] To ensure a competitive tendering process, Hydro may consider gensets in the range of 1,500 kW–1,600 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 owned and operated by Hydro.

The community of L'Anse-au-Loup is located on the south coast of Labrador, where Hydro provides electrical service to approximately 1,060 customers. The majority of the electricity is supplied by the Lac-Robertson Generating Station in Québec through a surplus energy purchase agreement with Hydro-Québec. Due to the nature of the contract, Hydro's customers can be interrupted at any time; as such, standby power is supplied by a diesel generating station owned and operated by Hydro.[3] The L'Anse-au-Loup Diesel Generating Station contains five units, with an additional mobile unit located outside the building. There is a modest growth load profile in L'Anse-au-Loup .

The community of Grey River is located on the south coast of Newfoundland, where Hydro provides electrical service to approximately 65 customers. Electricity is supplied by a diesel generating station operated and owned by Hydro. Currently, the plant contains three units, and the load profile in Grey River is expected to remain stable.

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. Units 2062 and 2067 in Grey River are projected to reach this milestone in 2026. Unit 2005 in L'Anse-au-Loup has accumulated approximately 58,000 operating hours. This unit was installed in 1988 and has reached the end of its useful life, as parts required for maintenance are difficult to find or obsolete. As such, an overhaul of this unit is not feasible, and Hydro is recommending the replacement of Unit 2005 in L'Anse-au-Loup, and Units 2062 and 2067 in Grey River under this program.

[3] In 2023, Hydro-Québec experienced historically low water levels, and the plant had to supply power to the community of L'Anse-au-Loup for seven months.

3.0 Asset Overview

3.1 Asset Background

3.1.1 L'Anse-au-Loup Diesel Generating Station

There are six gensets installed at the L'Anse-au-Loup Diesel Generating Station. The size and installation date of each unit is shown in Table 1.

Unit 2005 in L'Anse-au-Loup is an 800 kW diesel genset, which was installed in 1988. It has reached the end of its useful life due to performance, condition, and obsolescence. Unit 2005 has been overhauled three times, most recently in 1994.[4] At the end of 2023, the unit had accumulated approximately 58,000 operating hours.

Table 1: L'Anse-au-Loup Diesel Generating Station Gensets

Unit	Size (kW)	Year Installed
2005	800	1988
2012[5]	1,600	2025
2041	1,000	1988
2095	1,500	2017
2091	1,800	2015
2082 (Mobile)	1,825	2009

The L'Anse-au-Loup Diesel Generating Station is used to meet peak load requirements and as a backup when the power supply from Hydro-Québec is limited.

The load growth forecast for L'Anse-au-Loup is shown in Table 2. The current 20-year forecast for the system expects modest load growth to occur. The final year in the forecast puts the expected peak load at 6,238 kW, which is 93% of the stations firm capacity of 6,700 kW.[6]

[4] As per Hydro's Asset Management Program, the unit has not been overhauled since 1994 as the operating hour criteria was not met.
[5] The purchase and installation of Unit 2012 was approved in Board Order No. P.U. 37(2022). While Hydro initially proposed the 2024 installation of a 1,500 kW unit to ensure a competitive tendering process, Hydro considered gensets in the range of 1,500 kW–1,600 kW. The suitable unit with the lowest life cycle cost was selected, which was a 1,600 kW unit, planned for installation in 2025 due to increased genset lead times.
[6] Firm capacity refers to the plant's capacity with the largest unit out of service.

Table 2: L'Anse-au-Loup 2023 Peak Load Forecast

Year	Gross Peak (kW)
2024	5,975
2025	6,010
2026	6,060
2027	6,060
2028	6,090
2029	6,101
2030	6,114
2031	6,126
2032	6,136
2033	6,145
2034	6,154
2035	6,164
2036	6,173
2037	6,182
2038	6,191
2039	6,201
2040	6,210
2041	6,219
2042	6,229
2043	6,238

3.1.2 Grey River Diesel Generating Station

Unit 2062 in Grey River is a 136 kW diesel genset installed in 2001. Unit 2067 in Grey River is a 136 kW diesel genset installed in 2002. Unit 2062 has been overhauled four times, most recently in 2020. At the time of overhaul in 2020, the unit had accumulated 78,599 operating hours. As of the end of 2023, the unit has accumulated approximately 88,000 operating hours. Unit 2067 has been overhauled four times as well, most recently in 2022. At the time of overhaul in 2022, the unit had accumulated 83,356 operating hours. As of the end of 2023, the unit had accumulated approximately 89,000 operating hours. As per Hydro's Asset Management Program, 1,800 rpm diesel gensets are to be replaced when they reach 100,000 operating hours. Units 2062 and 2067 are forecasted to reach this threshold in 2026.

3.2 Asset Condition

Diesel gensets are typically replaced based on operating hours. 1,200 rpm units are replaced at 120,000 hours, and 1,800 rpm units are replaced at 100,000 hours.[7] 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 2005 in L'Anse-au-Loup, which was installed in 1988, has accumulated approximately 58,000 operating hours at the end of 2023. Many parts for this unit are no longer available due to obsolescence, and to continue using this genset would present a risk to customer reliability. Units 2062 and 2067 in Grey River are forecasted to reach the 100,000 operating hour threshold in 2026.

Chart 1 provides the asset count for all assets covered under the program.

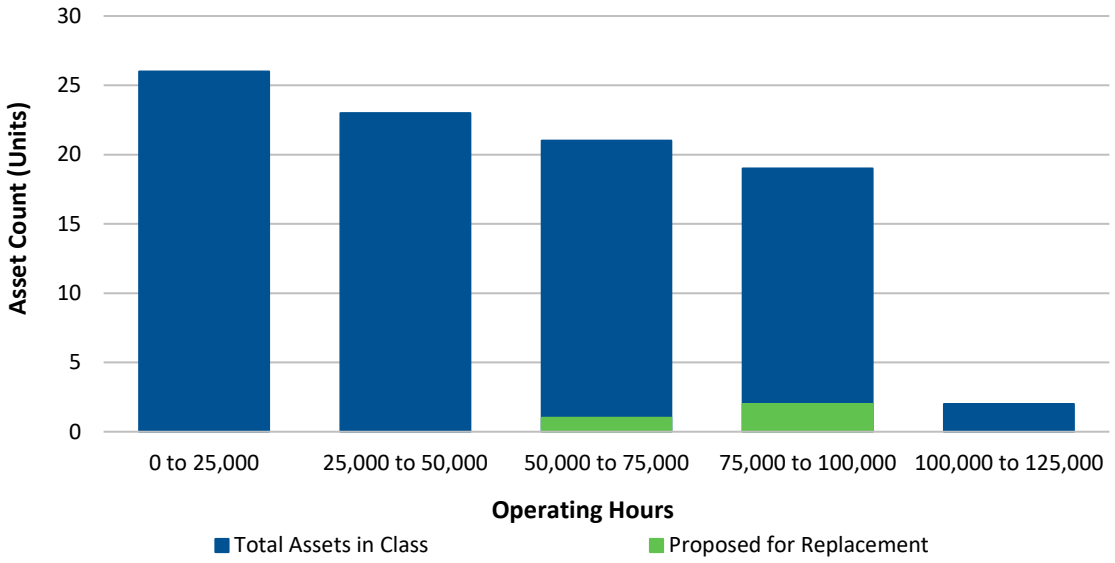


Chart 1: Asset Count Based on Operating Hours

[7] There are no 1,200 rpm units included within the scope of the 2025–2027 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. Age does not typically inform Hydro's decisions around replacement for diesel gensets as it would for other infrastructure unless there is an issue with the obsolescence of parts as has been identified for Unit 2005.

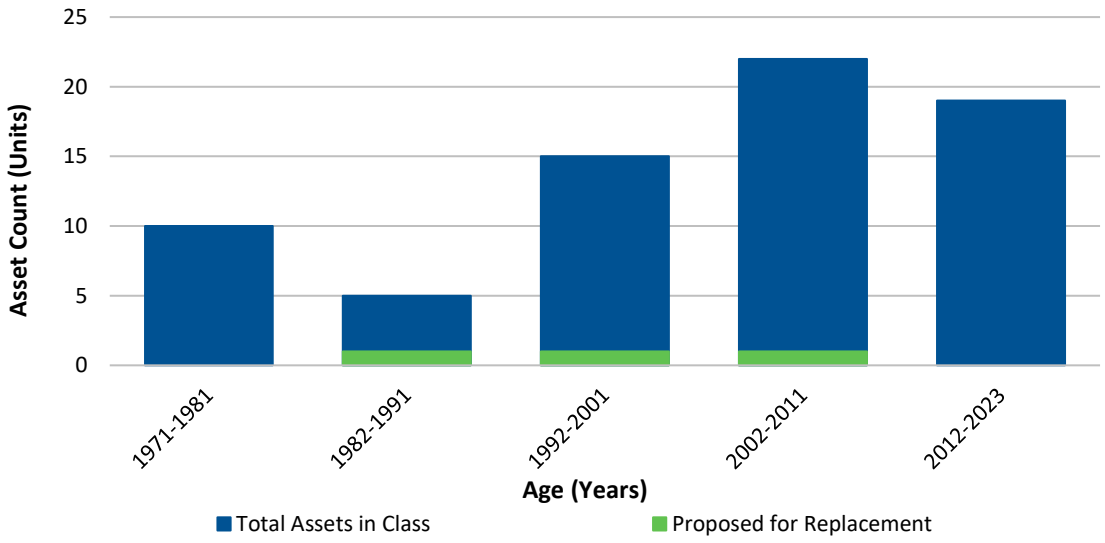


Chart 2: Asset Counts by Asset Age

4.0 Trending

Between 2019 and 2023, an average of 1.5 engines (nine over five years) have been replaced annually. Hydro is forecasting another ten genset replacements over the next five years, starting in 2024. This number may increase or decrease based on genset usage, lead time of the required genset, and electricity demand in the communities they serve.

4.1 Assets Installed

Chart 3 indicates the historical and forecast number of diesel gensets replaced and in-service year under this program.

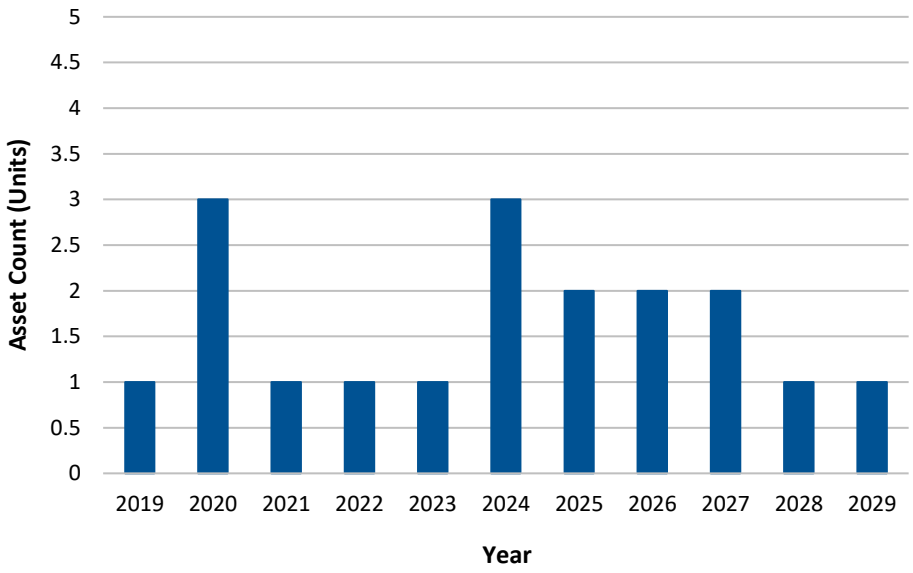


Chart 3: Historical and Forecast Assets Replaced

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.

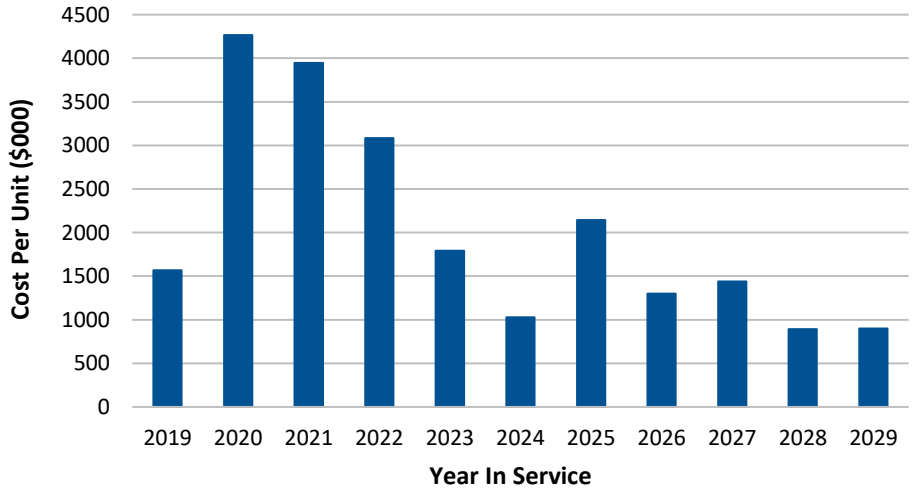


Chart 4: Historical and Forecast Average Unit Costs of Assets Replaced

4.3 Historical Reliability

Hydro tracks reliability for diesel communities similar to its other locations using SAIDI[8] and SAIFI;[9] 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 reaching the end of their operating hour lifespan.

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro has evaluated the following alternatives:

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

5.1.1 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 or useful life of the unit would increase the risk of failure.

5.1.2 Pace Advancement

Hydro has determined the current operating hours' approach is appropriate based on the OEM's recommendations and historical experience. There are instances where these replacement intervals are advanced, and this is evaluated on a case-by-case basis. Pace advancement is often triggered by asset condition, availability of parts, or system load growth.

[8] System Average Interruption Duration Index ("SAIDI").
[9] System Average Interruption Frequency Index ("SAIFI").

5.1.3 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.

5.2 Least-Cost Evaluation

5.2.1 L'Anse-au-Loup Unit 2005 Replacement

Hydro completed a sizing study in 2021 to determine the most cost-effective genset size to replace L'Anse-au-Loup Unit 2012.[10] The sizing study considered how the replacement of Unit 2012 could influence the future replacements of Units 2005 and 2041. The study determined that replacing Unit 2012 with a 1,500 kW unit would address the forecasted load growth and eliminate the need for Hydro to add capacity through the addition of a new unit ahead of schedule.[11] This replacement would also allow Units 2005 and 2041 to be replaced with a single, 1,500 kW unit when they were due for replacement. At that time, a cost-benefit analysis determined that this would remain the least-cost option provided that Units 2005 and/or 2041 required replacement at any time prior to the year 2071; as a result, Hydro reviewed this cost-benefit analysis and its 2023 spring Isolated Load Forecast and concluded that replacing Unit 2005 with a larger 1,500 kW unit remains the least-cost alternative and will enable Hydro to avoid replacing Unit 2041.

5.2.2 Grey River Unit 2062 and 2067 Replacement

A sizing study was not completed for the unit replacements in Grey River as the load profile in the community is forecasted to remain stable, and Hydro is therefore recommending like-for-like replacement of these units.

[10] "2022 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 17, 2021 (originally filed July 31, 2021), vol. II, sch. 8, tab 24.
[11] The purchase and installation of Unit 2012 was approved in Board Order No. P.U. 37(2022); a 1,600 kW unit with planned installation in 2025 was selected as the suitable unit with the lowest life cycle cost.

5.3 Recommended Alternative

Hydro recommends the replacement of Unit 2005 at the L'Anse-au-Loup Diesel Generating Station with a 1,500 kW,[12] 1,800 rpm unit, and Units 2062 and 2067 in Grey River Diesel Generating Station with 136 kW, 1,800 rpm units.

5.3.1 Risk of Asset Stranding

Diesel generating stations are isolated and, in most cases, are the sole sources of power to a community. Gensets in the L'Anse-au-Loup Diesel Generating Station and Grey River Diesel Generating Station are required to meet firm capacity. As the load profile in Grey River is expected to remain stable, and the load in L'Anse-au-Loup is forecasted to continue to grow throughout the next five years, the risk of asset stranding is low.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025–2027 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-Implementation	4	4	**16**
Post-Implementation	4	2	**8**
		Risk Mitigated	**8**
		Risk Mitigated per $1 Million	**1.3**

6.0 Scope of Work

This program will replace Unit 2005 at the L'Anse-au-Loup Diesel Generating Station with a new 1,500 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

[12] To ensure a competitive tendering process, Hydro may consider gensets in the range of 1,500 kW–1,600 kW; the suitable unit with the lowest life cycle cost will be selected.

("P&C") equipment will be required, including additions to the motor control centre, Programmable Logic Controller ("PLC") Cabinet, modifications to main PLC, and modification and testing of PLC logic.

Units 2062 and 2067 at the Grey River Diesel Generating Station will be replaced with 136 kW, 1,800 rpm gensets. The scope of work includes the design, procurement and installation of two new gensets, angled outlet exhaust stack, hospital plus grade silencers, remote radiators, aftercoolers, switchgear with breakers and all other equipment necessary to facilitate the proper function of the new units.

6.1 Program Budget

The estimates for the 2025–2027 program are shown in Table 4, Table 5, and Table 6.[13]

Table 4: Program Estimate – Combined ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	0.0	344.0	2,164.0	**2,508.0**
Labour	334.1	655.4	1,095.7	**2,085.3**
Consultant	0.0	4.8	61.5	**66.3**
Contract Work	0.0	0.0	70.0	**70.0**
Other Direct Costs	34.7	91.8	364.6	**491.1**
Interest and Escalation	20.1	93.4	399.6	**513.0**
Contingency	29.3	97.2	363.3	**489.8**
Total	**418.2**	**1,286.6**	**4,518.7**	**6,223.6**

The estimate for the work in L'Anse-au-Loup is shown in Table 5.

Table 5: Program Estimate – L'Anse-au-Loup ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	0.0	69.0	1,475.6	**1,544.6**
Labour	160.7	241.5	673.4	**1,075.7**
Consultant	0.0	0.0	37.5	**37.5**
Contract Work	0.0	0.0	70.0	**70.0**
Other Direct Costs	23.9	16.4	254.7	**295.0**
Interest and Escalation	10.1	33.6	239.6	**283.3**
Contingency	14.8	26.3	243.9	**285.0**
Total	**209.5**	**386.9**	**2,994.7**	**3,591.1**

[13] Numbers in Tables 4, 5, and 6 may not add due to rounding.

The estimate for the work in Grey River is shown in Table 6.

Table 6: Program Estimate – Grey River ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	0.0	275.0	688.5	**963.5**
Labour	173.4	413.9	422.3	**1,009.7**
Consultant	0.0	4.8	24.0	**28.8**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	10.8	75.4	109.9	**196.1**
Interest and Escalation	10.0	59.7	160.0	**229.7**
Contingency	14.5	70.9	119.4	**204.8**
Total	**208.7**	**899.8**	**1,524.1**	**2,632.5**

Chart 5 provides the five-year historical program expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast budget through 2029.

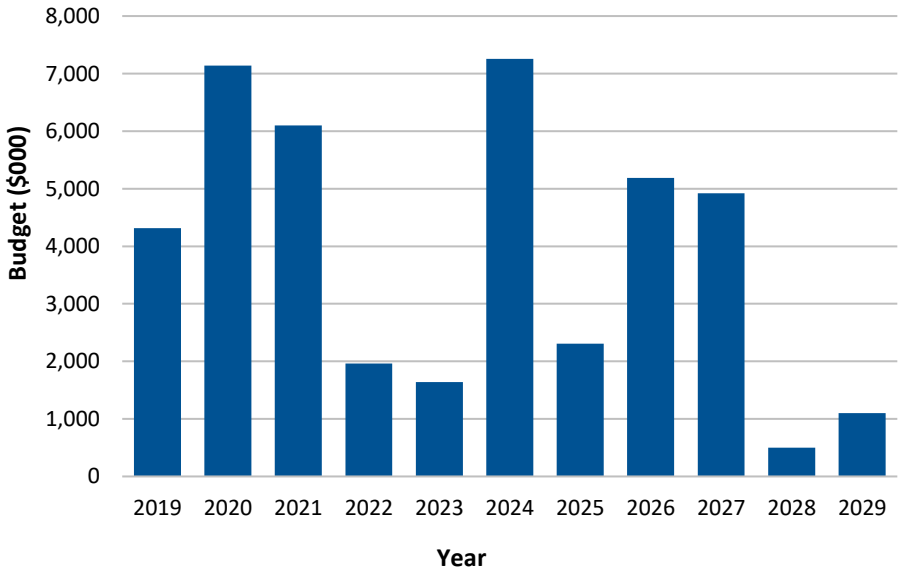


Chart 5: Historical and Forecast Program Budget

6.2 Program Schedule

The program schedule for L'Anse-au-Loup is provided in Table 7.

Table 7: Program Schedule – L'Anse-au-Loup

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules.	January 2025	February 2025
Engineering: Design/specification development for tender/procurement.	March 2025	August 2026
Procurement: All the required materials for genset and P&C upgrade.	February 2025	October 2026
Construction: Remove old genset, electrical, and P&C equipment.	July 2026	August 2027
Commissioning: Commissioning manual mode: run up the new genset without automation; confirm operation, and release to operations.	August 2026	September 2027
Closeout: Close work order, complete all documentation, and complete lessons learned.	November 2027	December 2027

The program schedule for Grey River is provided in Table 8.

Table 8: Program Schedule – Grey River

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules.	January 2025	February 2025
Engineering: Site visit, design for P&C upgrade.	March 2025	August 2026
Procurement: All the required materials for P&C, electrical, mechanical– supply contract develop and publish tender.	February 2025	October 2026
Construction: Remove old gensets, P&C equipment, and install new equipment.	July 2026	August 2027
Commissioning: Run up the new gensets; confirm operation and release to operations.	August 2026	September 2027
Closeout: Close work order, complete all documentation, and complete lessons learned	November 2027	December 2027

7.0 Conclusion

Hydro's Asset Management Program requires the replacement of 1,800 rpm diesel gensets when they reach 100,000 operating hours. Units 2062 and 2067 in the Grey River Diesel Generating Station are forecast to reach this threshold in 2026. Continuing to operate these units beyond their recommended operating hours would increase the likelihood of engine failure and reduce reliability for customers. Unit 2005 in L'Anse-au-Loup was installed in 1988 and is at its end-of-life. This model is obsolete and many parts are discontinued and no longer available; as such, an overhaul of this unit is not possible and replacement is the only viable option. Under this program, Hydro is proposing to replace the units to maintain reliable operation of the L'Anse-au-Loup Diesel Generating Station and Grey River Diesel Generating Station.

$1,000,000 to $5,000,000

Program 6

Overhaul Hydraulic Units

2025

newfoundland labrador hydro

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Overhaul Hydraulic Units (2025)

Location: Bay d'Espoir

Investment Classification: Renewal

Asset Category: Hydraulic Plant

Cost: $4,972,371

1.0 Introduction

Preventive maintenance ("PM") is performed on all hydraulic units within Newfoundland and Labrador Hydro's ("Hydro") fleet. Yearly inspections, called PM6 inspections, are performed on all hydraulic units. More detailed inspections, identified as PM9 inspections, are executed on all hydraulic units at a frequency of six years. PM9 inspections incorporate PM6 inspection items with additional recommendations from the original equipment manufacturer ("OEM") and required refurbishments to support the long-term reliability of the hydraulic unit. Units 1 and 2 at the Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir") require PM9 inspections and associated refurbishment in 2025.

2.0 Program Description and Justification

Hydro's hydraulic generation units make up 954 MW of the generation capacity available on the Island portion of the system. Regular PM on these assets plays a crucial role in Hydro's ability to meet system load requirements. The overhaul Hydraulic Units Program consists of inspections and associated refurbishments completed every six years on all major hydraulic units on the Island. On occasion, these inspection intervals and scopes must be modified to align work with other capital projects and provide operational synergies.

The overhaul frequency and scope of work are based on OEM recommendations and Hydro's operational experience, and involve partial dismantling of the turbine and generator to inspect, test, clean, and refurbish the required unit(s). The work within these overhauls is required in this specific timeframe to address items historically present after six years of continual operation.

Completing these overhauls will ensure continued reliable operation of the hydraulic units, significantly contributing to reducing forced outages and unit deratings and directly decreasing unplanned maintenance outages. The units proposed under this program, Bay d'Espoir Units 1 and 2, received their

last PM9 inspections in 2019 and 2018, respectively, and require their next PM9 inspections in 2025 to maintain reliable operation.1 The proposed 2025 program will also include an expanded refurbishment scope due to the required overhaul of the spherical valves for Units 1 and 2.

3.0 Asset Overview

3.1 Asset Background

Units to be overhauled in 2025 are as follows:

- Bay d'Espoir Unit 1: Rated for 76.5 MW, last overhauled in 2019; and
- Bay d'Espoir Unit 2: Rated for 76.5 MW, last overhauled in 2018.

Bay d'Espoir produces an average of 2,650 GWh annually, making it the largest hydroelectric generating facility on the Island and consists of two powerhouses feeding seven units. Powerhouse 1, commissioned in 1967, relies on three buried penstocks[2] to feed six generating units. Powerhouse 2, commissioned in 1977, has one separate penstock that supplies Unit 7. Bay d'Espoir Units 1 and 2, fed through Penstock 1, are major hydroelectric units in the Bay d'Espoir generating fleet that are operated to meet system load requirements on the Island Interconnected System.[3] Both units are currently in good working condition and available for service, except during maintenance or forced outages.

The spherical valves associated with the expanded refurbishment scope for Units 1 and 2 have an approximately 65-year service life, with regular maintenance. These valves have been in service since the units were commissioned in 1967 and have performed reliably with regular yearly PM. Hydro will consider overhauling spherical valves before the approximate service life based on performance, condition, or as part of pooled work. The age of these valves approaching 58 years in 2025, and although nearing the average lifespan for the assets, Hydro has determined the valves to be suitable for refurbishment. This is due to functional issues identified through the operation of the asset which affects reliability, as well as the opportunity to align work with the extended Penstock outage. A major overhaul is required to ensure they remain in good working condition. Spherical valves are required for

[1] Based on Hydro's established inspection interval; Unit 2 was due for PM9 inspection in 2024. However, Hydro decided to reduce the pace of the PM9 inspection on Unit 2 by one year to align with the extended outages for this Unit in 2025 resulting from the approved Penstock Refurbishment 1 Life Extension project.
[2] The three penstocks split at Powerhouse 1 for each to supply water to two hydraulic generating units. All six units in Powerhouse 1 are equipped with a spherical valve also known as a main inlet valve allowing one unit to run while the other can be serviced or for both units to be quickly isolated from penstock water.
[3] Unit 1 is also one of two units at the Bay d'Espoir Facility that provides station service power to the Bay d'Espoir site.

safe unit operation, their main function is to shut off the penstock to one or both units during a normal shutdown, or automatically in case of emergency.

3.2 Asset Ages

Bay d'Espoir Units 1 and 2 have been in service for 57 years, since commissioning in 1967. The age of Hydro's hydraulic units ranges from 21 years[4] to 57 years.[5] Chart 1 shows the age of all 13 hydraulic units[6] on which Hydro performs PM9 inspections.

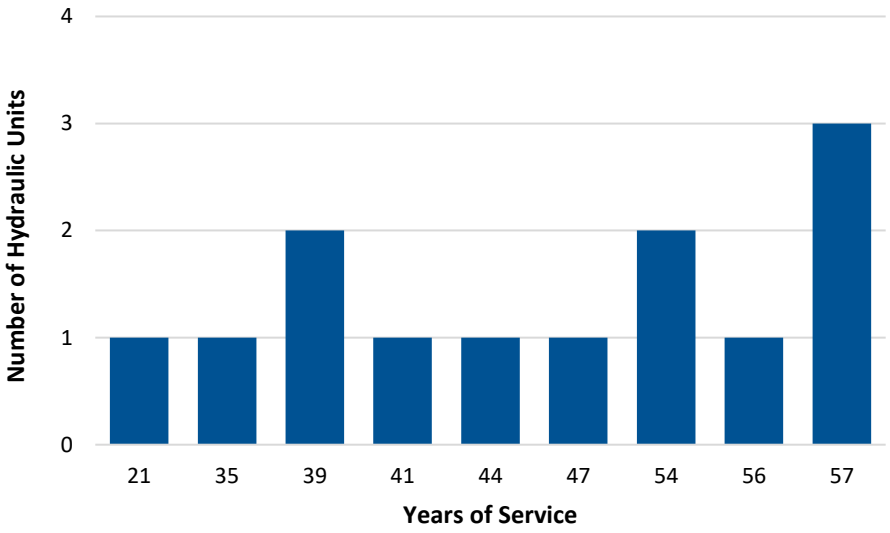


Chart 1: **Asset Counts by Asset Age (Hydraulic Units)**

4.0 Trending

4.1 Units Overhauled

Chart 2 provides the five-year historical, current, and forecast number of assets overhauled per year.

The Hydraulic Unit Overhauls Program consists of inspections and associated refurbishments completed every six years on all major hydraulic units on the Island. While these inspection intervals and scopes may be modified on occasion, the overhaul frequency and scope of work are based on OEM

[4] The Granite Canal Hydroelectric Generating Station ("Granite Canal") was commissioned in 2003.
[5] Bay d'Espoir Units 1, 2, and 3 were commissioned in 1967.
[6] Hydro also has three units that are classified as Mini-Hydro Units in Snook's Arm, Venams Bight, and Roddickton. These units are not subject to PM9 inspections and are thus not included in this program.

recommendations and Hydro's operational experience and are required in this specific timeframe to address items that are historically present after six years of continual operation.

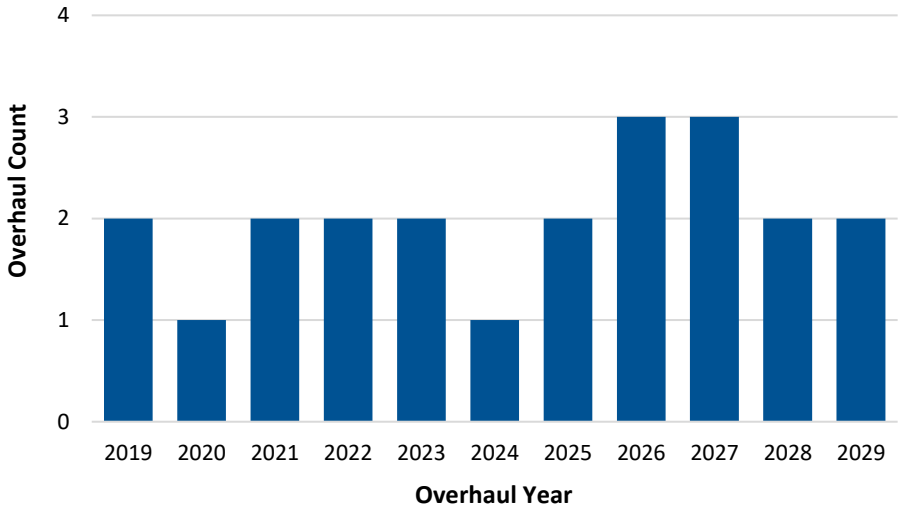


Chart 2: Historical and Forecast Number of Assets Overhauled

4.2 Historical and Forecast Average Unit Costs

Chart 3 provides the five-year historical, current, and forecast average unit cost of units overhauled per year.

Chart 3 indicates a significant increase in the average unit cost of assets overhauled, beginning in 2025 and extending to 2029. These increases are due to expanded scopes for the program over these five years; one example is the required refurbishment of the spherical valves for Bay d'Espoir Units 1–6.

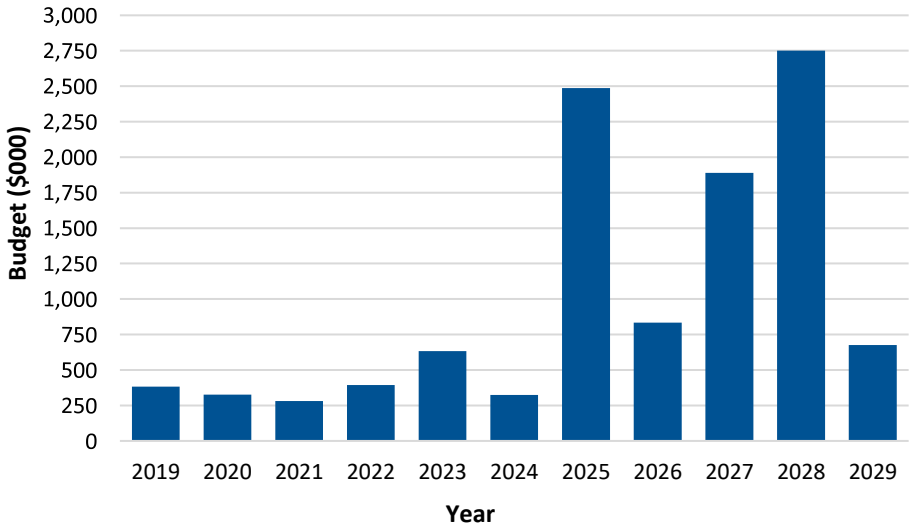


Chart 3: Historical and Forecast Average Unit Costs of Assets Overhauled

4.3 Historical Reliability

This program plays a key role in allowing Hydro to minimize the Derated Adjusted Forced Outage Rate ("DAFOR")[7] of its hydraulic units to ensure the provision of reliable service to customers. Hydro tracks performance data for its hydraulic units using the DAFOR; this data is filed quarterly with the Board of Commissioner of Public Utilities.[8]

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro evaluated the following alternatives:

- Planned overhauls on a six-year interval;
- Pace reduction; and
- Alternative strategies – pooling and clustering options

[7] 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] "Quarterly Report on Asset Performance in Support of Resource Adequacy for the Twelve Months Ended March 31, 2024," Newfoundland and Labrador Hydro, April 30, 2024.

5.1.1 Planned Overhauls on a Six-Year Interval

Under this alternative, Hydro would perform PM9 inspections at a frequency of six years, as described in Section 2.0. This would involve PM9 inspections of Bay d'Espoir Unit 1 in 2025, as well as the required refurbishment of other components.

5.1.2 Pace Reduction

Hydro would typically perform PM9 inspections at a frequency of six years, as described in Section 2.0. To determine the exact time interval between overhauls, Hydro considers several factors, including but not limited to asset condition and criticality, frequency of operation, and reliability. Reduction in the frequency of hydraulic unit overhauls is not typical, as it would increase the risk of unit failures; however, Hydro decided to reduce the pace of the PM9 inspection on Unit 2 by one year as described in Section 5.1.3.

5.1.3 Alternative Strategies – Pooling and Clustering Options

As noted in Section 5.1.1, PM9 inspections are typically performed every six years. However, Hydro deferred the PM9 inspection of Unit 2 by one year due to the operational synergies gained by aligning this work with the scope of the previously approved Penstock 1 Life Extension Project.[9]

The replacement and refurbishment of the penstock is currently scheduled to begin in the second quarter of 2025. The Unit 2 PM9 inspection has been slated to occur immediately before this penstock work is set to take place. Thus, any work identified by the inspection can be performed in tandem with the associated replacement and refurbishment work for the penstock. This will ensure Hydro can mitigate potential cost increases while eliminating an additional occurrence of reduced capacity caused by maintenance-based outages.

Hydro has mitigated the risks of a delayed inspection to maximize the benefits to ratepayers achieved through pooling this work.

5.2 Least-Cost Evaluation

As Hydro has not identified any alternatives to the completion of PM9 inspections, no least-cost evaluation was performed.

[9] "Penstock 1 Section Replacement and Weld Refurbishment – Bay d'Espoir Hydroelectric Generating Facility," approved in Board Order No. P.U. 6(2023).

5.3 Recommended Alternative

Hydro recommends proceeding with the planned PM9 inspection and associated refurbishments on a six-year interval for Unit 1, and the reduced pace of seven years for the PM9 inspection on Unit 2. This approach will align work with the extended outages required for these units in 2025 due to the Penstock 1 Life Extension Project.

5.3.1 Risk of Asset Stranding

Hydraulic generating units have a typical service life of 80–100 years when properly maintained. This overhaul program is a critical asset management activity necessary to ensure safe and reliable operation and maximize the service life of the assets. Units 1 and 2 were both commissioned in 1967 and have been in operation for 57 years. Throughout these years, Hydro has performed both preventative and corrective maintenance on these units; therefore, Hydro considers the risk of asset stranding to be negligible.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	4	4	**16**
Post-Implementation	4	1	**4**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**2.4**

6.0 Scope of Work

6.1 Bay d'Espoir Unit 1 and 2 Overhaul

This project involves a partial dismantling of Bay d'Espoir Units 1 and 2 to inspect, test, clean, refurbish, and replace defective components based on information from the maintenance records for the unit. The records provide details on the history, present condition, and any unusual maintenance problems of the units. This PM9 inspection involves:

- Cleaning and inspecting rotor and stator assembly;
- Electrical testing on rotor/stator assembly;
- Calibrating and testing of turbine and generator protection devices;
- Verifying bearing and seal clearances; and
- Completing a thorough inspection of the turbine and draft tube.

Hydro will complete other identified refurbishment work on both Units 1 and 2. This expanded scope has identified the addition of:

- Spherical valve seals;
- Spherical valve trunnion seals;
- Spherical valve piston ring;
- Expansion joint seals;
- Repair of shear pin insert holes on wicket gate linkages; and
- Removal of the turbine auto-greasing system and replacement of components with greaseless material. These components include:
  - Operating ring wear pads;
  - Operating ring linkage bushings;
  - Top, intermediate and bottom wicket gate bushings for Unit 1; and
  - Top wicket gate bushings for Unit 2.[10]

[10] The intermediate and bottom wicket gate bushings for Unit 2 were completed in 2018; as such, the estimate for Unit 1 is larger due to this additional scope.

6.2 Program Budget

Table 2 contains the program estimate for 2025, while Table 3 and Table 4 provide the individual estimates for the Bay d'Espoir Unit 1 and Unit 2 PM9 inspections and associated refurbishment.

Table 2: Overhaul Hydraulic Units Program Estimate ($000)[11]

Program Cost	2025	2026	Beyond	Total
Material Supply	2,924.8	0.0	0.0	**2,924.8**
Labour	1,087.2	0.0	0.0	**1,087.2**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	200.0	0.0	0.0	**200.0**
Other Direct Costs	32.6	0.0	0.0	**32.6**
Interest and Escalation	149.5	0.0	0.0	**149.5**
Contingency	578.4	0.0	0.0	**578.4**
Total	**4,972.4**	**0.0**	**0.0**	**4,972.4**

Table 3: Bay d'Espoir Unit 1 PM9 Inspection Estimate ($000)[12]

Program Cost	2025	2026	Beyond	Total
Material Supply	1,517.4	0.0	0.0	**1,517.4**
Labour	576.4	0.0	0.0	**576.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	100.0	0.0	0.0	**100.0**
Other Direct Costs	16.9	0.0	0.0	**16.9**
Interest and Escalation	78.4	0.0	0.0	**78.4**
Contingency	300.8	0.0	0.0	**300.8**
Total	**2,589.8**	**0.0**	**0.0**	**2,589.8**

Table 4: Bay d'Espoir Unit 2 PM9 Inspection Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	1,407.4	0.0	0.0	**1,407.4**
Labour	510.8	0.0	0.0	**510.8**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	100.0	0.0	0.0	**100.0**
Other Direct Costs	15.7	0.0	0.0	**15.7**
Interest and Escalation	71.1	0.0	0.0	**71.1**
Contingency	277.6	0.0	0.0	**277.6**
Total	**2,382.6**	**0.0**	**0.0**	**2,382.6**

[11] Numbers may not add due to rounding.
[12] Numbers may not add due to rounding.

Chart 4 provides the five-year historical program expenditures, the current year forecast, the proposed 2025 program budget, and the forecast budget for the next five years. Chart 4 indicates a significant increase in program costs beginning in 2025 due to the expanded program scope resulting from the required refurbishment of the spherical valves for Bay d'Espoir Units 1 and 2. Hydro is planning to expand the scopes in the overhaul program extending out to 2029 for 12 of the 13 hydraulic units. For example, it is expected that the spherical valves associated with Bay d'Espoir Units 3, 4, 5 and 6 will require similar refurbishment projects during this time.[13]

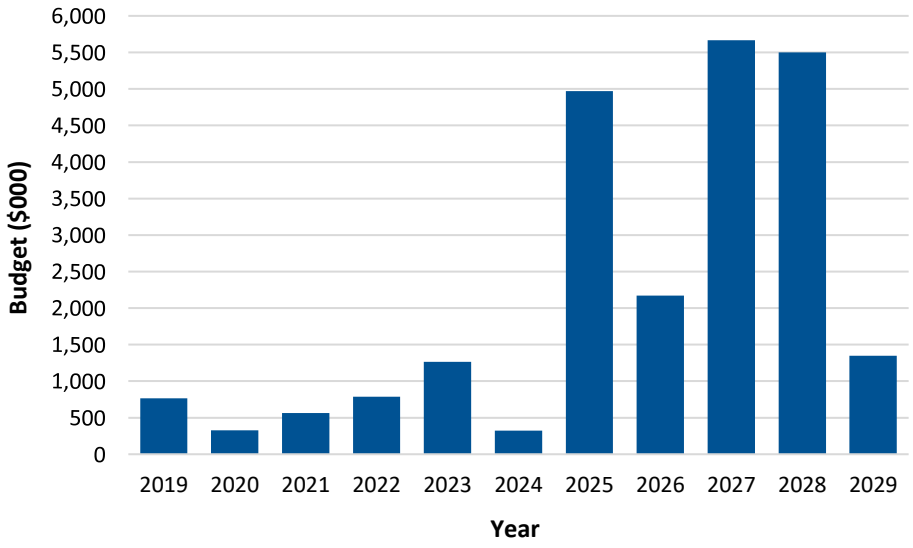


Chart 4: Historical and Forecast Program Budget

[13] The detailed scopes for 2026–2029 will be included in the corresponding capital budget application along with the typical PM9 inspections. Expanded scopes will be specific to each unit and may include items such as spherical valve overhauls, wicket gate bushing replacement, generator winding condition assessments, runner replacements, and operating ring replacements. Please note that the Granite Canal is not expected to have an expanded scope during this time.

6.3 Program Schedule

The schedule for the program is shown in Table 5 .

Table 5: Program Schedule

Activity	Start Date	End Date
Planning: Open work order and plan and develop detailed plan and schedules.	January 2025	March 2025
Procurement: Develop contracts for material procurement, tender, and award contract.	January 2025	April 2025
Construction: Perform PM9 Inspection and additional work identified.	April 2025	November 2025
Commissioning: Run-up Units 1 and 2 to confirm operation and release to operations.	November 2025	November 2025
Closeout: Close work order, complete all documentation, and complete lessons learned.	December 2025	December 2025

7.0 Conclusion

Hydro performs time-based preventive maintenance annually on all major hydraulic units on the Island Interconnected System. At a frequency of six years, Hydro performs inspections that incorporate annual activities in addition to more detailed inspection activities, called a PM9 inspection. On occasion, this six-year interval must be modified due to other considerations or to provide operations with flexibility. Hydro recommends proceeding with the planned PM9 inspection on a six-year interval for Unit 1 and the reduced pace of seven years for the PM9 inspection on Unit 2, in addition to the associated refurbishment scopes. This approach will align work with the extended outages for these units in 2025 due to the Penstock 1 Life Extension project to provide operational synergies. Based on Hydro's operational experience, it is recommended that this program continue to support the reliable and safe operation and long-term reliability of the hydraulic units within Hydro's fleet.

Program 7

Perform Boiler Condition Assessment and Miscellaneous Upgrades

2025

Holyrood



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Perform Boiler Condition Assessment and Miscellaneous Upgrades (2025)

Location: Holyrood

Investment Classification: Renewal

Asset Category: Thermal Plant

Cost: $4,905,770

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") is proposing to continue with the Boiler Condition Assessment and Miscellaneous Upgrades Program in 2025. This will support the continued safe and reliable operation of the Holyrood Thermal Generating Station ("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 2025.

This program has been completed annually 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 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. Therefore, Hydro believes it is prudent to continue this program in 2025.

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.

[1] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.

Annual boiler condition assessments maintain reliability by discovering damaged or deteriorated components that are at risk of failure. Examples of damage 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 2025 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 2025–2026 winter operating season. The program for 2025 also includes miscellaneous upgrades identified in the 2024 and 2025 condition assessments scheduled for completion in 2025 to support safe and reliable operation through the 2025–2026 winter operating season. Additionally, for upgrades identified and executed in 2025 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 ("Board") in its 2025 Capital Expenditures and Carryover Report.[2]

The detailed scope of the boiler condition assessment follows the inspection and test plan prepared for the Holyrood TGS by the original equipment manufacturer for Unit 1 and Unit 2 boilers, Alstom SA ("Alstom"), and the engineering consulting firm, AMEC NSS Limited ("AMEC"). 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 and AMEC. Hydro will

[2] Hydro's 2025 Capital Expenditures and Carryover Report is to be filed on or before April 1, 2026.

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.

Miscellaneous upgrades that have been identified in previous condition assessments and are scheduled for completion in 2025 include the following:

- Replacement of boiler expansion joints;
- Replacement of boiler refractory;
- Replacement of air heater baskets;
- Replacement of fuel oil steam tracing piping;
- Replacement of exhaust gas expansion joints; and
- Level 2 Condition Assessment and refurbishment of high-pressure boiler feedwater heaters.

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 boilers for all three units to be in adequate condition. The main issues Hydro has experienced with the boilers relate to the boiler tube failures referenced in Section 4.3.

[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 has completed 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 6.0.

[4] "HTGS Condition Assessment and Life Extension Study," Hatch Ltd., March 31, 2022, vol. I and vol. II.
[5] Currently General Electric (GE).

4.3 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 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 within the last year, which resulted in the following forced outages:

- 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 12 days;
- 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; and
- On December 16, 2023, a small boiler tube leak was identified on Unit 3. The leak was assessed by site personnel and, given the location and nature of the leak, it was agreed that the unit could remain online, with a precautionary forced derating to 70 MW with close monitoring by Operations. Unit 3 was removed from service on January 9, 2024, to facilitate the planned investigation and repair of this leak. Repairs were made and the unit was returned to service on January 17, 2024 with full capability.

5.0 Analysis

5.1 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.

5.1.1 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.

5.1.2 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.

5.1.3 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.

5.2 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.

5.3 Recommended Alternative

Hydro recommends the continuation of the Boiler Condition Assessment and Miscellaneous Upgrades Program in 2025.

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.

5.3.1 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]

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	5	4	**20**
Post-Implementation	5	1	**5**
		Risk Mitigated	**15**
		Risk Mitigated per $1 Million	**3.1**

6.0 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 2024 investigation and required interventions identified during the 2025 assessment that are necessary to support safe and reliable operation through the 2025–2026 winter operating season.

[6] Due to the extension of the Holyrood TGS through the Bridging Period, Hydro submitted an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account. The Board approved the extension of the account and related amendments in Board Order No. P.U. 1(2024). Hydro also was directed to file a report on the account in its next general rate application.

6.1 Program Budget

The estimate for the 2025 program is shown in Table 2.

Table 2: Program Estimate ($000)[7]

Program Cost	2025	2026	Beyond	Total
Material Supply	10.0	0.0	0.0	**10.0**
Labour	371.4	0.0	0.0	**371.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	3,970.0	0.0	0.0	**3,970.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	119.2	0.0	0.0	**119.2**
Contingency	435.1	0.0	0.0	**435.1**
Total	**4,905.8**	**0.0**	**0.0**	**4,905.8**

Chart 1 shows the five-year historical expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast costs through 2029.[8]

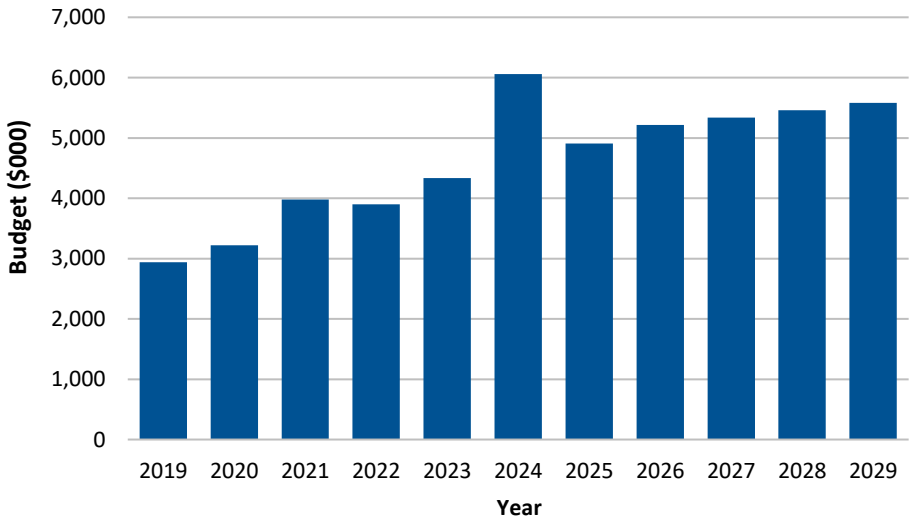


Chart 1: Historical and Forecast Program Budget[9]

[7] Numbers may not add due to rounding.
[8] 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.
[9] A third-party contractor conducts a condition assessment each year to determine the scope of the following year's capital budget application program. As this condition assessment happens closer to the actual occurrence of the associated work, it is possible that budgetary adjustments could occur between the time of application and the applicable timing of the work. The 2024 Capital Expenditures Overview in Schedule 5 of this application outlines the additional scope identified for 2024 beyond what was estimated in the 2024 Capital Budget Application, based on the third-party condition assessment conducted this year.

6.2 Program Schedule

The schedule for the program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Complete planning documentation.	January 2025	January 2025
Procurement:		
Order long lead parts.	February 2025	March 2025
Construction:		
Perform condition assessment[10] and upgrade work.	April 2025	October 2025
Closeout:		
Prepare closeout documentation.	November 2025	December 2025

7.0 Conclusion

To support the continued safe and reliable operation of the Holyrood TGS through the 2025–2026 winter operating season, Hydro recommends continuing the Boiler Condition Assessment and Miscellaneous Upgrades Program in 2025, 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.

[10] The condition assessment and upgrade work will take place during the outage period for each of the three boilers.

Provide Service Extensions

2025

newfoundland labrador hydro

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Provide Service Extensions (2025)

Location: Various

Investment Classification: Access

Asset Category: Distribution

Cost: $4,662,517

1.0 Introduction

Newfoundland and Labrador Hydro ("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 new service requests ("NSR"), 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, Contributions in Aid of Construction ("CIAC") funded by the requestor are required and 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, 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]

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 2019–2023 shows that the number of NSRs received continues to trend above 500. This program trend is expected to continue in the coming years.

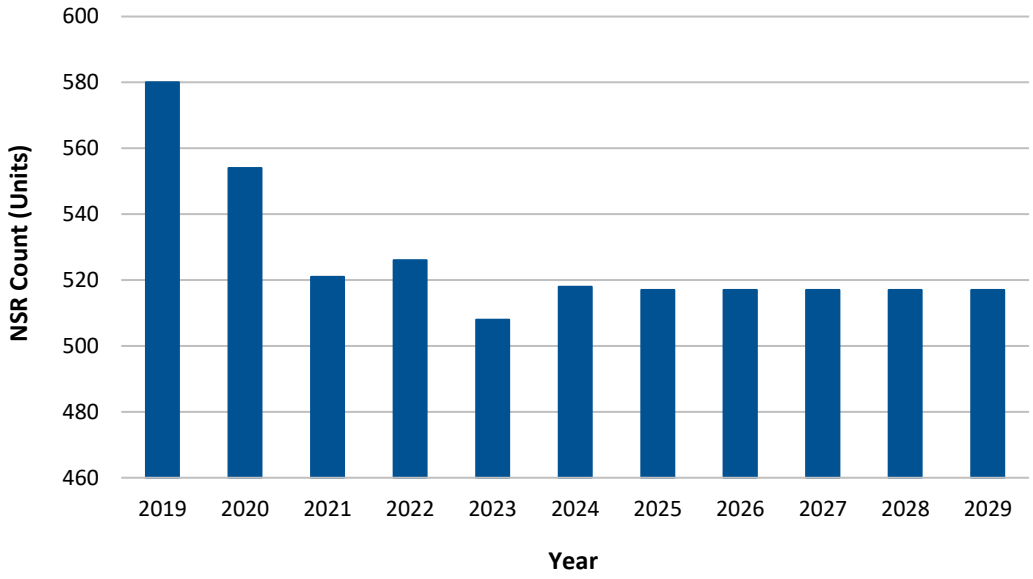


Chart 1: Historical and Forecast New Service Requests Received

4.2 Historical and Forecast Average Unit 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 2025 costs are based on the average expenditures from 2021 to 2023. Costs per service request vary greatly depending on the nature of the request and the magnitude of infrastructure modifications required to

[1] Approved in Board Order No. P.U. 34(2019).

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.

5.1.1 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 2025 program is shown in Table 1.

Table 1: Program Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	997.9	0.0	0.0	997.9
Labour	2,633.6	0.0	0.0	2,633.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	321.9	0.0	0.0	321.9
Other Direct Costs	498.6	0.0	0.0	498.6
Interest and Escalation	210.5	0.0	0.0	210.5
Contingency	0.0	0.0	0.0	0.0
Total	**4,662.5**	**0.0**	**0.0**	**4,662.5**

Chart 2 shows the five-year historical expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast costs through 2029. Hydro has forecast future expenditures for this program based on the 2025 program budget with cost escalation applied.

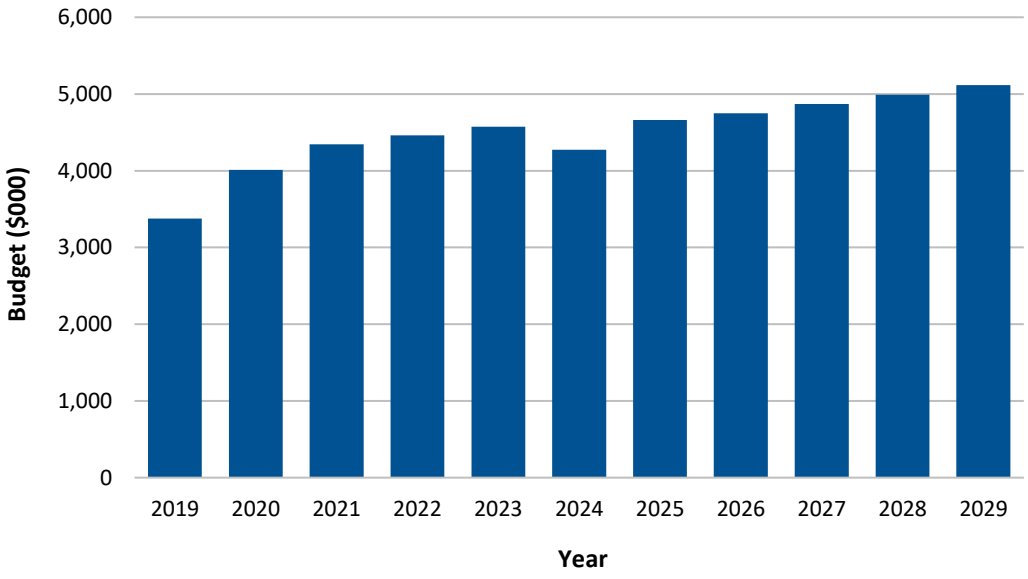


Chart 2: Historical and Forecast Program Budget

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 yearly, 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.

Replace Mobile Equipment

2025–2027



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Replace Mobile Equipment (2025–2027)

Location: Various

Investment Classification: General Plant

Asset Category: Tools and Equipment

Cost: $4,647,594

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") operates a fleet of mobile equipment comprised of approximately 34 heavy-duty assets and more than 350 non-heavy-duty assets. The heavy-duty group includes mainly track-equipped units used to service transmission and distribution lines in remote areas as well as wheeled heavy construction equipment including excavators, loaders, etc.[1] The non-heavy-duty group consists of snowmobiles, all-terrain vehicles ("ATVs"), trailers, and a small numbers of boats, compressors, and other equipment. The fleet is distributed across Hydro's operating areas throughout the province and utilized daily to support staff engaged in the maintenance and repair of the electrical system.

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 fulfill their duties. Hydro also requires specialized mobile equipment to maintain roads and properties and for material handling. These varied requirements comprise the mobile equipment fleet.

Under this program, mobile equipment is replaced as required per Hydro's replacement criteria for the reliable operation of its mobile equipment fleet. In accordance with Hydro's replacement criteria in relation to this program, Hydro proposes the replacement of 3 heavy-duty assets (2 tracked aerial device units and 1 wheel loader), and 38 light-duty assets (14 snowmobiles, 12 ATVs, 11 trailers, and 1 forklift).

[1] Heavy-duty mobile equipment assets were not included in previous iterations of this program and were proposed in past capital budget applications ("CBA") as individual projects; however, Hydro has determined efficiencies could be gained upon inclusion of these assets in the Replace Mobile Equipment Program going forward.

2.0 Program Description and Justification

Hydro's mobile equipment fleet is strategically distributed across Hydro's operating areas throughout the province. This equipment 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.

Hydro has updated the ongoing scope of this program to include a wider range of equipment. In previous years, off-road heavy-duty equipment would typically be applied for in a separate project proposal. Hydro now include these equipment types under the scope of this program.

In addition to the non-heavy-duty equipment previously included in this program, such as trailers (both over and under 4,500 kg), ATVs/smaller off-road vehicles, forklifts, snowmobiles, compressors and boats, the following heavy-duty equipment types are now included in the redefined scope of the program:

- Line service boom and general service tracked units;
- Excavators and mini-excavators;
- Material handling equipment including loaders, graders, tractors, backhoes; and
- Snow removal equipment (snow groomers).

In tandem with its increased scope, Hydro has developed an updated age-based replacement criteria for equipment in this program. Hydro's replacement criteria for the main mobile asset categories, shown in Table 1, have been updated for 2025 based on an analysis of the life cycles of retired units.

Table 1: Hydro's Replacement Criteria for Mobile Equipment

Equipment	Average Age at Replacement (Years)
Heavy-Duty – All Types	15
Snowmobiles	8
ATVs	7
Trailers <4,500 kg	9
Trailers >4,500 kg	18

In addition to age, Hydro considers the equipment's condition before its replacement, as usage of mobile equipment will vary considerably resulting in retention and continued use of some assets well beyond the average age criteria. Miscellaneous equipment, such as forklifts, boats, compressors, etc. have no formally defined replacement criteria. Replacement is based on equipment condition, age, and availability of spare parts and service.

3.0 Asset Overview

3.1 Asset Background

Hydro's fleet of mobile equipment is essential to performing planned and unplanned work on critical transmission and distribution systems, in particular the extensive off-road sections that cannot be reached or serviced by the regular highway-driven fleet of light-duty and heavy-duty vehicles.

Most heavy-duty mobile equipment assets were not included in previous iterations of this program and were typically proposed in past CBAs as individual projects. Hydro has identified opportunities for potential efficiencies by including these assets in this program going forward. Within the 2025–2027 program, the three heavy-duty mobile assets represent approximately three-quarters of the overall program cost.

3.2 Asset Condition

As equipment ages, it experiences increased downtime that could negatively impact emergency outage response times or planned maintenance. In many cases, heavy-duty mobile equipment is regularly operated under rough conditions and is subject to accelerated wear and tear. Mobile equipment is routinely inspected in accordance with the preventive maintenance schedule, and all maintenance and repairs are performed by Hydro maintenance personnel or third-party service providers as needed to ensure maximum potential reliable service life is attained.

3.3 Condition-Based Remaining Life

Hydro evaluates assets as they near the retirement criteria to determine if it is appropriate to extend the life of the assets or replace them. This could include reassignment to an area with less or different usage or usage in easier terrain, among other considerations. Hydro has found it appropriate to maintain some mobile assets beyond the average replacement age, as those units are both in adequate

condition, and the risk of their failure is considered to be a manageable event. For some assets, failure risk is much less tolerable, and a fixed life cycle period endpoint is more prudent.

Asset Ages

Chart 1 provides asset age and counts for heavy-duty mobile equipment. There are three existing units included in the program that will have an average age of between 14 and 15 years upon replacement. Some 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.

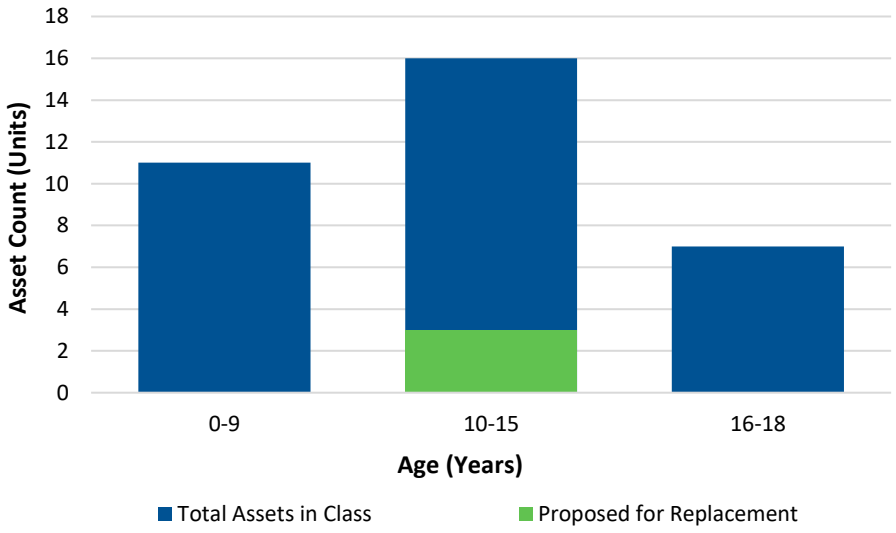


Chart 1: Asset Counts by Asset Age – Heavy-Duty Mobile Equipment

Chart 2 provides asset age and count for the aggregate of all non-heavy-duty equipment types. As replacement criteria vary between assets type, the quantity of replacement units in various age groups is appropriate.

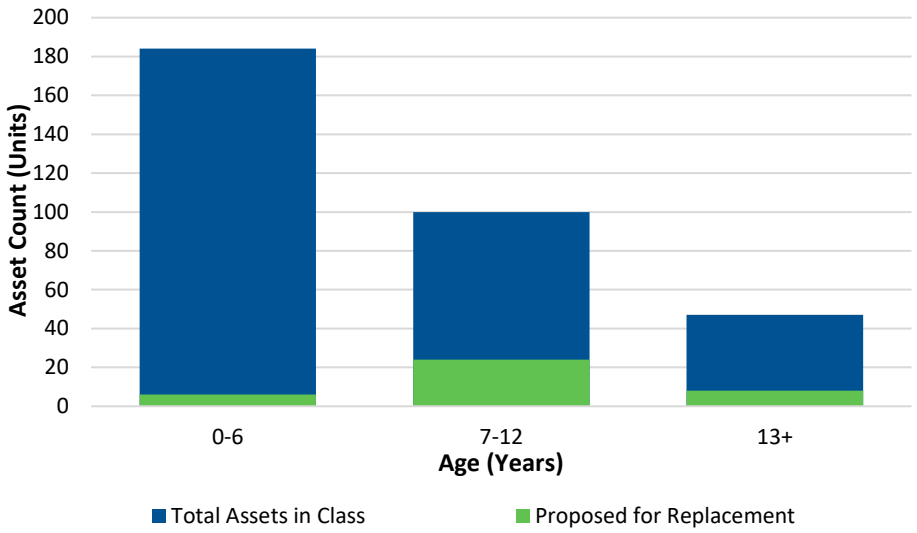


Chart 2: Asset Counts by Asset Age – Aggregate of Non-Heavy-Duty Mobile Equipment

4.0 Trending

4.1 Assets Installed/Replaced/Upgraded

Chart 3 provides the five-year historical, current, and five-year forecast number of heavy-duty mobile equipment replacement under this program. Heavy-duty mobile equipment assets were not included in previous iterations of this program and were proposed in past CBAs as individual projects. The heavy-duty mobile equipment procured under these individual projects comprises the five-year historical number of asset replacements. As such, the projection for 2024 includes two tracked units ordered in 2022,[2] and a grader ordered in 2024.[3]

Hydro's projected heavy-duty mobile equipment replacements are reflected in Chart 3 and consider current fleet age and sizing requirements, with some variances observed due to the small number of

[2] Purchase 85' Material Handler Aerial Device on Track Unit and Purchase 46' Material Handler Aerial Device on Track Unit. Please refer to "2022 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 17, 2021 (originally filed August 2, 2021), vol. II, sch. 8, tab 9 and tab 14.
[3] Replace Grader Unit V9829 (2024) - Bay d'Espoir. Please refer to "2024 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 21, 2023 (originally filed July 12, 2023), sch. 6, proj. 12.

heavy-duty assets within the fleet.[4] An above-average number of older units, as evidenced in Chart 1, forecasts a longer-term trend toward increased replacement requirements.

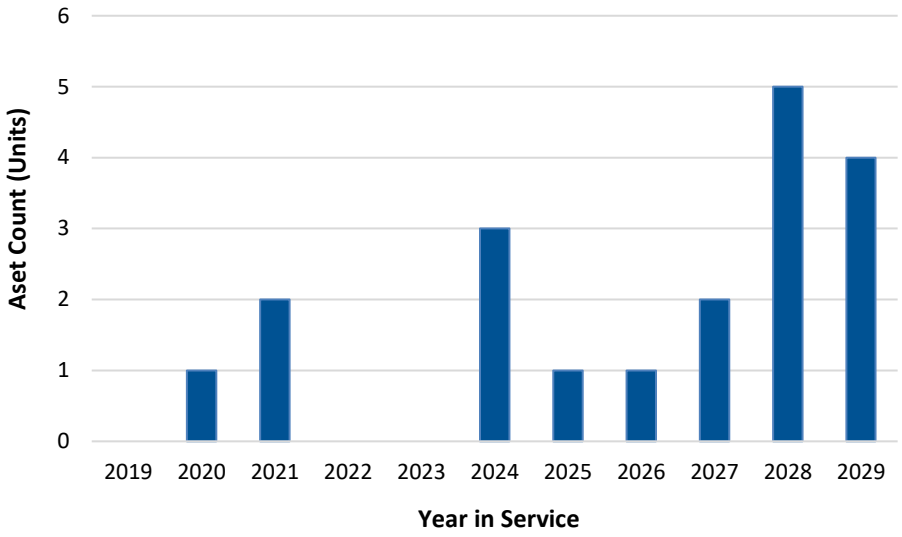


Chart 3: Historical and Forecast Number of Assets – Heavy-Duty Mobile Equipment

Chart 4 provides the five-year historical, current, and five-year forecast number of aggregated non-heavy-duty mobile equipment replacement under this program. Pandemic-period challenges resulted in zero acquisitions in 2020 and nearly double the usual number in 2022. Going forward, Hydro is aiming to stabilize the pace of replacements. The replacement scope for 2025 is estimated to include 14 snowmobiles, 12 ATVs, 11 trailers, and 1 forklift for a total of 38 units.

[4] This average may differ from future proposals as a result of ongoing reviews of age versus service life and fluctuations in equipment lead time.

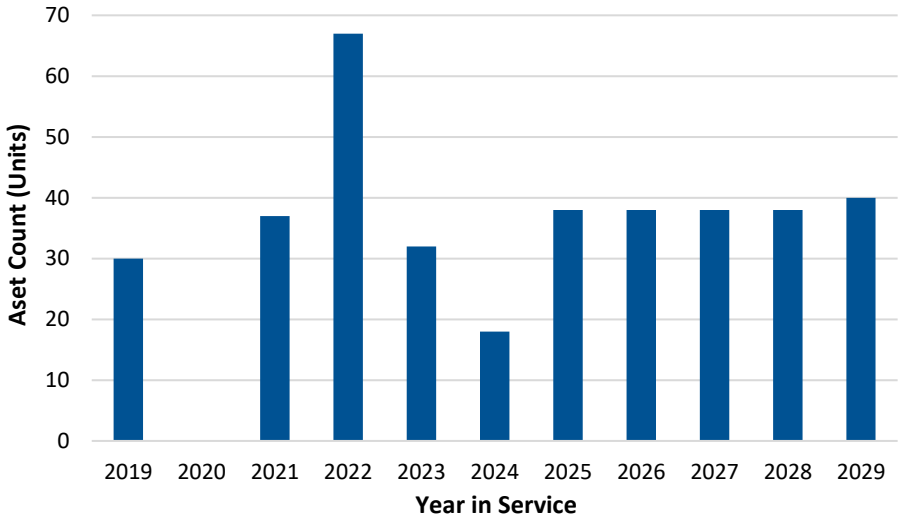


Chart 4: Historical and Forecast Number of Assets – Non-Heavy-Duty Mobile Equipment

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro considered the following alternatives:

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

5.1.1 Pace Reduction

Hydro's annual long-term asset planning review incorporates asset condition and risk review that permits the life cycle extension of some units. Further pace reduction is not considered a viable option.

Unplanned pace reduction imposed by supply chain constraints from 2020 to present confirmed an increased rate of equipment failure that has resulted in challenges to completing required work. The increased rate of failure among aging equipment whose replacement has been delayed has validated that the current planning criteria and review methodology are near optimal.

5.1.2 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.

5.1.3 Continue Program at Current Pace

Hydro has determined the current criteria are appropriate based on industry standards, the condition of the units upon replacement, and vehicle usage statistics. This approach allows Hydro to balance cost with the reliability of Hydro's mobile equipment fleet. The mobile equipment is required to facilitate required maintenance and timely response to system events and, as such, are required to be available and in appropriate reliable working condition.

5.1.4 Alternative Strategies

Many of the heavy-duty mobile equipment assets Hydro depends on, such as tracked units with aerial devices, are highly specialized with no alternative procurement strategy available. Other equipment such as ATVs, snowmobiles and trailers also need to be on-site at key locations when needed. To ensure that Hydro will have the right equipment to maintain its system when needed, Hydro does not consider there to be any viable alternative for this program.

5.2 Least-Cost Evaluation

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

5.3 Recommended Alternative

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

5.3.1 Risk of Asset Stranding

This program is necessary to maintain a safe and reliable mobile equipment fleet. Failure to replace this equipment will lead to increased maintenance costs, less-reliable equipment, delays in scheduled and

unscheduled work, and possible safety risks for operators. Hydro does not foresee any changes in its requirements for mobile equipment; therefore, the risk of asset stranding is low.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025–2027 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-Implementation	3	4	**12**
Post-Implementation	3	1	**3**
		Risk Mitigated	**9**
		Risk Mitigated per $1 Million	**1.9**

6.0 Scope of Work

The 2025–2027 program proposes the replacement of 3 heavy-duty assets (2 tracked aerial device units and 1 wheel loader) and 38 non-heavy-duty assets (14 snowmobiles, 12 ATVs, 11 trailers, and 1 forklift), in accordance with Hydro's replacement criteria. The two tracked units will be delivered in 2027, while all other deliveries are anticipated in 2025. This program also includes $100,000 in 2025 to address in-service failures for mobile equipment. Hydro will evaluate the cost of repair or refurbishment versus replacement prior to executing in-service failure repairs.

6.1 Program Budget

The estimate for the 2025–2027 program is shown in Table 3.

Table 3: Program Estimate ($000)[5]

Program Cost	2025	2026	Beyond	Total
Material Supply	1,680.0	0.0	2,200.0	**3,860.0**
Labour	52.2	38.6	29.3	**120.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	12.0	9.0	9.0	**30.0**
Interest and Escalation	55.0	2.2	157.4	**214.6**
Contingency	174.4	4.8	223.8	**403.0**
Total	**1,973.6**	**54.6**	**2,619.4**	**4,647.6**

Chart 5 shows the five-year historical expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast costs through 2029. Most heavy-duty mobile equipment assets were not included in previous iterations of this program and were typically proposed in past CBAs as individual projects. The heavy-duty mobile equipment procured under these individual projects has been included in the five-year historical expenditures and the forecast 2024 expenditures shown in Chart 5. An above-average number of older heavy-duty units forecasts a longer-term trend toward increased replacement requirements from 2024 onward.

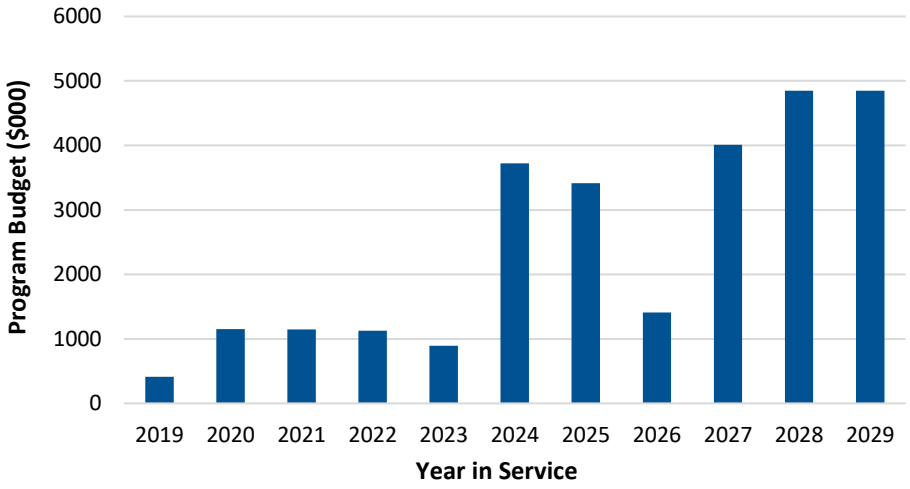


Chart 5: Historical and Forecast Program Budget[6]

[5] Numbers may not add due to rounding.

[6] The increased budgets for 2024 through 2029 compared to the expenditure history for this program reflects an increased number of projected heavy-duty assets that will be due for replacement based on Hydro's selection criteria. The historical data (2024 and earlier) noted in this chart reflects the updated scope of the program, with assets previously approved under separate application proposals included in the reflected expenditures for each year.

6.2 Program Schedule

The schedule for this 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 2025	February 2025
Procurement:		
Tender and award contracts.	February 2025	April 2025
Receive and commission short-lead equipment.	May 2025	November 2025
Receive and commission long-lead equipment.	April 2027	October 2027
Closeout:		
Close work orders, complete all documentation, and complete lessons learned.	November 2027	December 2027

7.0 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. The established replacement guidelines have been determined to be appropriate. Hydro proposes to continue with the replacement of non-heavy-duty and heavy-duty mobile equipment under this program for 2025.

Program 10

Wood Pole Line Management

2025

newfoundland labrador hydro



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Appendix A: IOWA Curve – Island Interconnected System

Wood Pole Line Management (2025)

Location: Various

Investment Classification: Renewal

Asset Category: Transmission

Cost: $4,281,302

1.0 Introduction

Many of Newfoundland and Labrador Hydro's ("Hydro") 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 identify and assess deterioration.

The Wood Pole Line Management ("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 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 was presented to the Board of Commissioners of Public Utilities ("Board") as part of Hydro's 2005 Capital Budget Application.[1]

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

[1] "2005 Capital Budget Application," Newfoundland and Labrador Hydro, rev. September 28, 2004 (originally filed August 10, 2004), sec. G, app. 2.

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.

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[2]



Figure 2: Examples of Wood Pole Inspection Results

[2] Clockwise from bottom left: (1) Field Data Collector; (2) Installing Boron treatment; (3) Climbing inspection; and (4) Destructive testing at Memorial University of Newfoundland.

Historically, Hydro used 40 years as the anticipated useful or economic life for its wooden lines. As of 2024, Hydro has 35 wood pole transmission lines that have surpassed this anticipated useful life. Of these lines, 27 are over the age of 45 years, with the oldest wood pole line having been installed 59 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 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-centered 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 typically 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.

[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.

The WPLM Program inspection schedule generally reflects plans to complete older lines first and work toward newer lines. The specific lines and the number of poles included in the program are reviewed on 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 2023 WPLM Program Review

One of the objectives of the 2023 WPLM program was to inspect, test, and treat 2,233 poles and associated line components. Table 1 summarizes the 2023 inspections.

Table 1: 2023 Inspections Completed

Regions	Line Name	Year	Voltage Level (kV)	Planned Number of Poles to Inspect	Actual Number of Poles Inspected	Percent Complete (%)
Central	TL222	1967	138	693	693	100
	TL234	1981	230	100	100	100
Western	TL245	1969	138	281	281	100
Northern	TL221	1970	69	244	244	100
	TL226	1970	69	414	414	100
	TL256	1996	138	224	224	100
Labrador	L1303	1976	138	277	277	100
Totals				**2,233**	**2,233**	**100**

Another objective of the 2023 WPLM Program was the refurbishment of defective components identified in previous inspections. A summary of the work completed in 2023 is provided in Table 2.

Table 2: Summary of 2023 Refurbishment

	Region					
Component	**Eastern**	**Central**	**Western**	**Northern**	**Labrador**	**Total**
Poles	1	8	10	-	4	**23**
Cross Arms	8	17	12	1	-	**38**
Cross Bracing	9	10	5	-	-	**24**
Knee Bracing	1	16	1	-	-	**18**
Foundations	2	-	-	-	-	**2**

2.2.2 2024 WPLM Program Update

The inspection and treatment work scheduled for 2024 is summarized in Table 3. This work is scheduled to be executed between April and October of 2024.

Table 3: 2024 Inspection Plan

Regions	Line Name	Year	Voltage Level (kV)	Planned Number of Poles to Inspect
Eastern	TL203	1965	230	424
Central	TL224	1968	138	602
	TL263	2002	230	152
Western	TL250	1987	13	300
Northern	TL227	1970	69	426
	TL262	2002	69	48
Labrador	L40	1963[6]	46	300
Total				**2,252**

A list of the refurbishment work scheduled for completion in 2024 is provided in Table 4. Hydro has accounted for these refurbishment activities in the approved 2024 WPLM Program.

Table 4: 2024 Refurbishment Plan

	Region				
Component	**Eastern**	**Central**	**Western**	**Northern**	**Total**
Poles	44	22	8	10	**84**
Cross Arms	44	7	13	3	**67**
Cross Bracing	56	33	4	1	**94**
Knee Bracing	23	7	3	0	**33**
Foundations	1	0	1	1	**3**
Miscellaneous (e.g., Insulators, hardware, etc.)	121	54	19	51	**245**

[6] Line 40 is part of the 46 kV system in Labrador West. As this line was not constructed by Hydro, the exact age of the line is unknown but it is assumed to have been constructed with lines between Twin Falls and Wabush in 1963.

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 2005, 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 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 2,500 kilometres of wood pole transmission lines operating at voltages of 46 kV, 69 kV, 138 kV, and 230 kV. These lines consist of over 24,000 poles of varying ages from new to 59 years old. As of 2024, approximately 95% of Hydro's transmission pole assets are more than 20 years old; approximately 62% 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.

[7] *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 53(2004) REASONS FOR DECISION, Board of Commissioners of Public Utilities, April 13, 2005, p. 23/13–18.

Table 5: Wood Pole Line Management 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.

1 Chart 1 presents Hydro's wood transmission pole assets by condition rating as of April 2024.

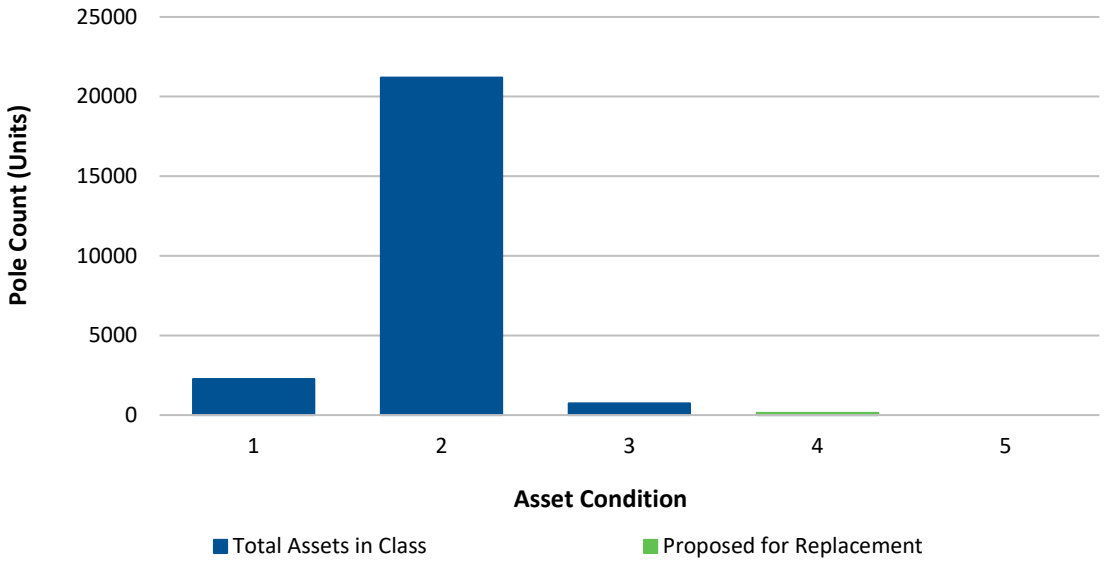


Chart 1: Asset Condition

3.3 Condition-Based Remaining Life

Chart 2 presents Hydro's wood transmission pole assets by expected remaining life as of April 2024.

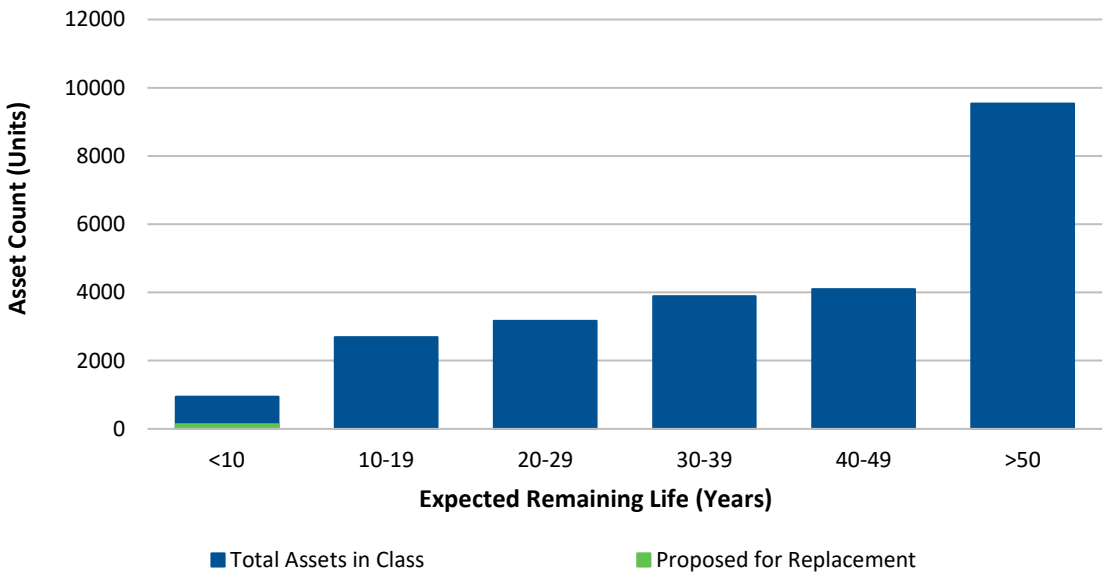


Chart 2: Condition-Based Expected Remaining Life

3.4 Asset Ages

Chart 3 presents Hydro's wood transmission pole assets by age as of April 2024.

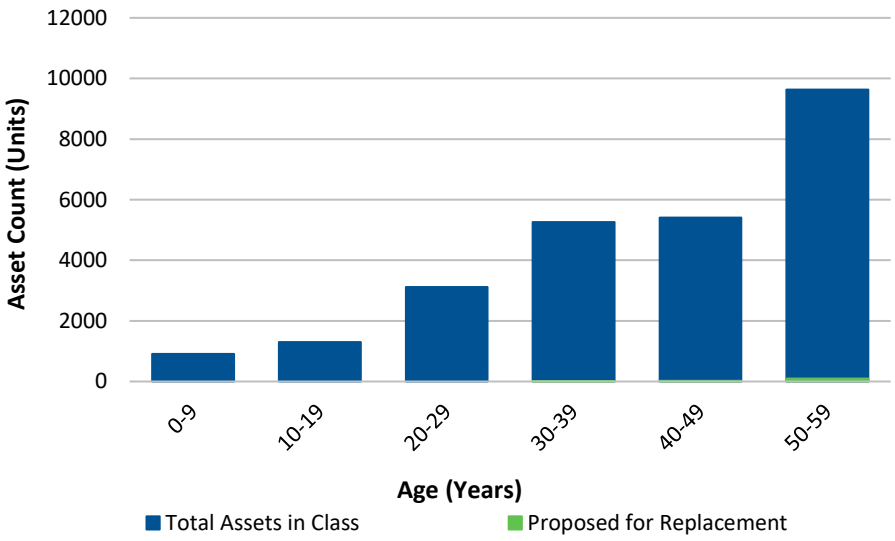


Chart 3: Asset Counts by Asset Age

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 were developed in a study at the University of Iowa and display functional failures or retirements of asset classes. 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 6.1.

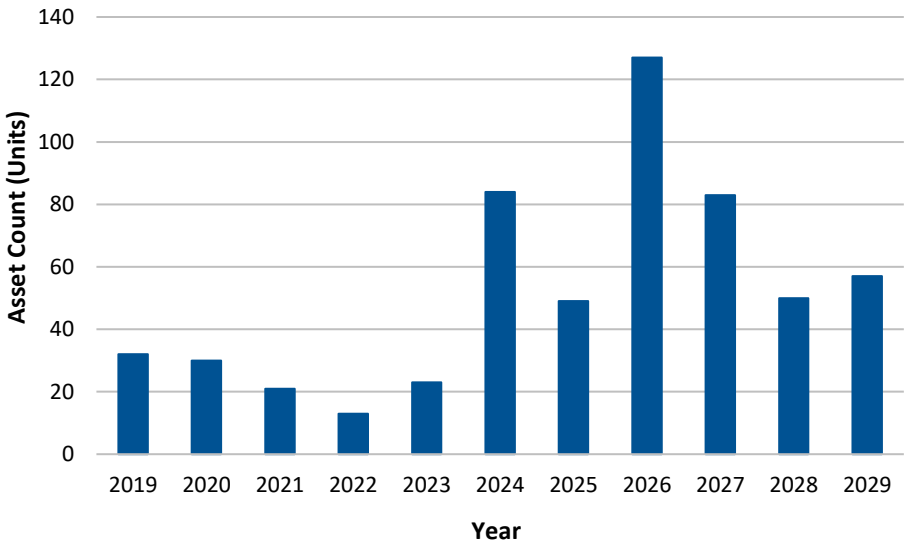


Chart 4: Historical and Forecast Number of Assets Installed/Replaced/Upgraded

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 cross arms, 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 cross

arm or an insulator replacement). The same is true for a breakdown by individual transmission lines, where the cost will be affected by the configuration, voltage, age, and geographical location of the line. Additionally, environmental sensitivities are higher for some areas and, in recent years, a significant amount of environmental mitigation has been required to travel over wetlands to complete pole replacements.

4.3 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.

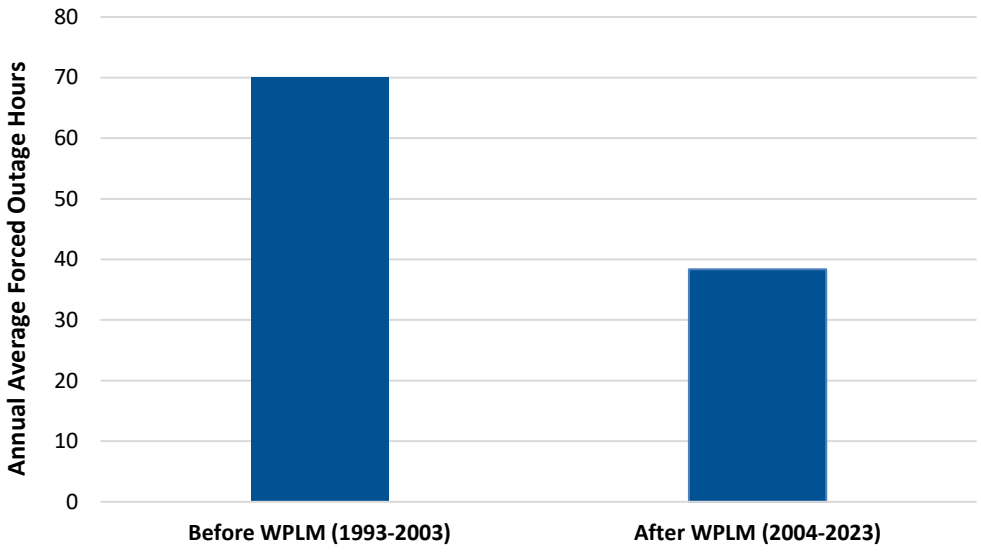


Chart 5: Outage Data for Hydro's Wooden Transmission System (1993–2023)

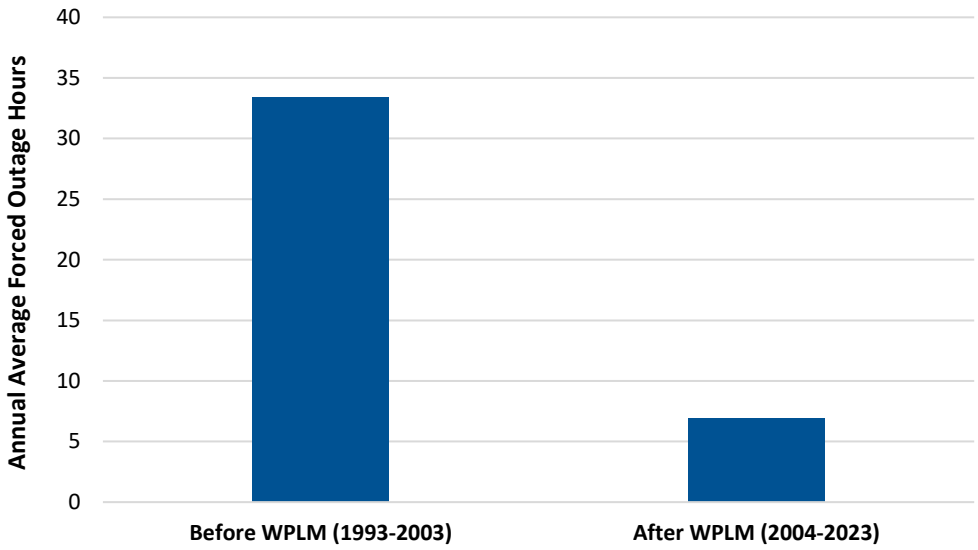


Chart 6: Outage Data for Hydro's Wooden Transmission System on the Avalon Peninsula (1993–2023)

Chart 7 and Chart 8 show the historical total outage frequencies and durations for Hydro's wooden transmission lines from 2019 to 2023. The total outage duration for 2023 (as seen in Chart 8) can be attributed mainly to a pole fire on TL221 in early February 2023. TL221 was out of service for ten days before the pole was replaced; however, there were no customer outages due to this event.

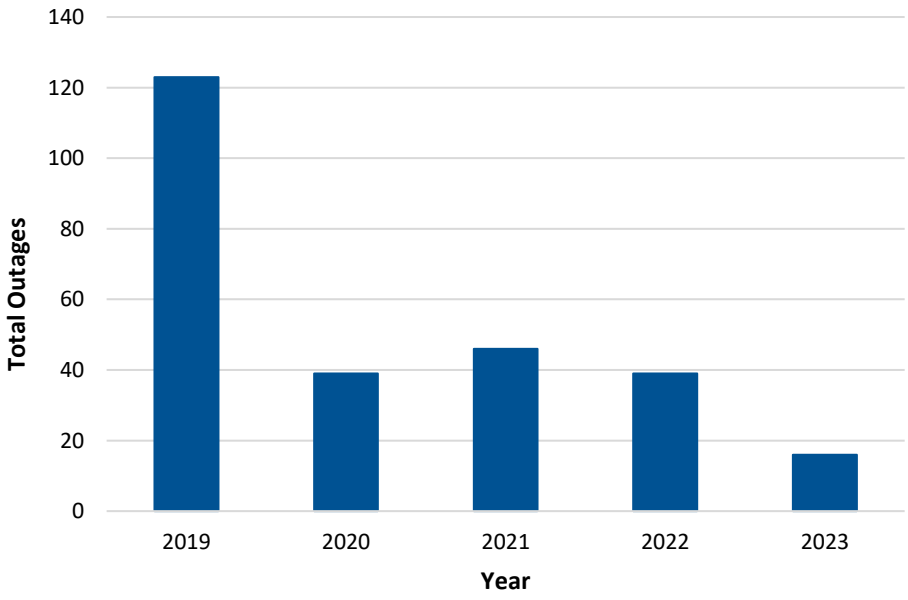


Chart 7: Historical Line Outage Frequency for Wooden Transmission Lines (All Causes)

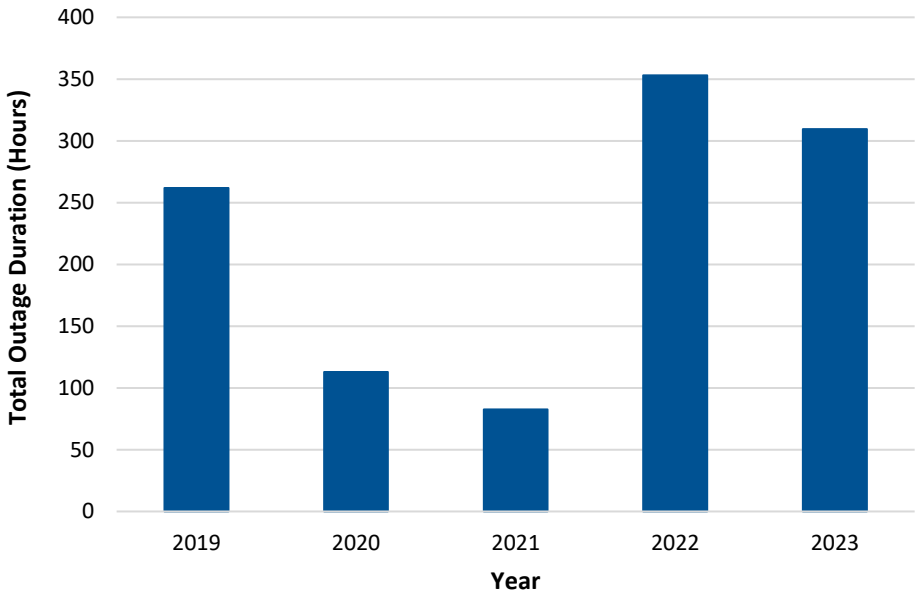


Chart 8: Historical Line Outage Duration for Wooden Transmission Lines (All Causes)[8]

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro considered the following alternatives:

- Pace Reduction; and
- Continuation of the program at the current pace.

5.1.1 Pace Reduction

The program employs a balanced ten-year inspection cycle that includes inspection, treatment, and replacement, as required, following reliability-centered 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.

[8] The increase in total outage duration for 2022 can be attributed mainly to failures that occurred on TL203 and TL219 during an ice storm in early February 2022, as reported to the Board in "Power Outage and Incident Advisory Report 2022-H-010-a."

5.1.2 Continuation of 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 little or no consideration of their condition.

5.2 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 program and the average inspection interval of 10 years is well justified by cost-avoidance savings through reduced in-service failures and unplanned repair costs, as well as life extension of existing pole plant assets by 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 proactively identifying the right level of expenditure on the right poles at the right time.

5.3 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.

5.3.1 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.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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 6.

Table 6: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	4	4	**16**
Post-Implementation	4	1	**4**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**2.8**

6.0 Scope of Work

The inspection and treatment work scheduled for 2025 is summarized in Table 7. This work is scheduled to be executed between April 2025 and October 2025.

Table 7: 2025 Inspection Plan

Region	Line Name	Year Built	Age of Line	Target Number of Poles to Inspect
Eastern	TL218	1966	59	425
Central	TL224	1968	57	225
	TL263	2002	23	554
Western	TL250	1987	38	300
Northern	TL227	1970	55	480
	TL239	1982	43	347
Labrador[9]	L32	c1963	62	50
	L33	c1963	62	50
	L36	c1963	62	50
Total				**2,481**

[9] Lines 32, 33, and 36 are part of the 46 kV system in Labrador West. As these lines were not constructed by Hydro, their exact age is unknown, but are assumed to have been constructed with lines between Twin Falls and Wabush in 1963.

Scheduled refurbishment for 2025 is summarized in Table 8.

Table 8: 2025 Refurbishment Plan

	Region					
Component	**Eastern**	**Central**	**Western**	**Northern**	**Labrador**	**Total**
Poles	3	20	11	13	2	**49**
Crossarms	3	10	6	18	2	**39**
Cross bracing	1	41	0	0	0	**42**
Knee bracing	0	1	0	0	0	**1**
Foundations	0	0	0	3	0	**3**
Miscellaneous (e.g., insulators, hardware, etc.)	1	45	18	60	0	**134**

6.1 Program Budget

The estimate for the 2025 program is shown in Table 9.

Table 9: Project Estimate ($000)

Project Cost	**2025**	**2026**	**Beyond**	**Total**
Material Supply	302.5	0.0	0.0	**302.5**
Labour	2,078.8	0.0	0.0	**2,078.8**
Consultant	19.9	0.0	0.0	**19.9**
Contract Work	827.0	0.0	0.0	**827.0**
Other Direct Costs	848.7	0.0	0.0	**848.7**
Interest and Escalation	204.4	0.0	0.0	**204.4**
Contingency	0.0	0.0	0.0	**0.0**
Total	**4,281.3**	**0.0**	**0.0**	**4,281.3**

Chart 9 provides the five-year historical program expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast budget through 2029.

The 2023 program expenditures were approximately 80% greater than the initial budget of $2,824,400.

For further information on the work executed under this program iteration, please refer to Hydro's "Capital Expenditures and Carryover Report for the Year Ended December 31, 2023."[10]

[10] Provided as Appendix B to Schedule 5 of this application.

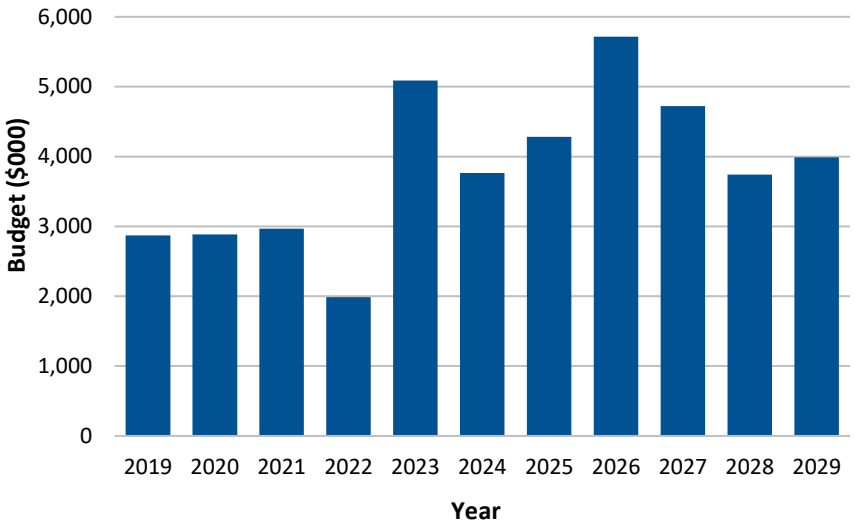


Chart 9: Historical and Forecast Program Budget

6.2 Program Schedule

The 2025 program schedule involves many transmission lines and is dependent on the annual workload and availability of outages. Work scheduled for 2025 will commence as early in the year as system conditions allow. The detailed annual work schedule for 2025 will be determined during the spring of 2025.

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 2025	September 2025
Inspection Data Analysis	June 2025	October 2025
Material Procurement	February 2026	November 2026
Refurbishment Work Field Planning	May 2026	September 2026
Refurbishment	April 2027	October 2027

7.0 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 2025.

Appendix A

Iowa Curve

Island Interconnected System





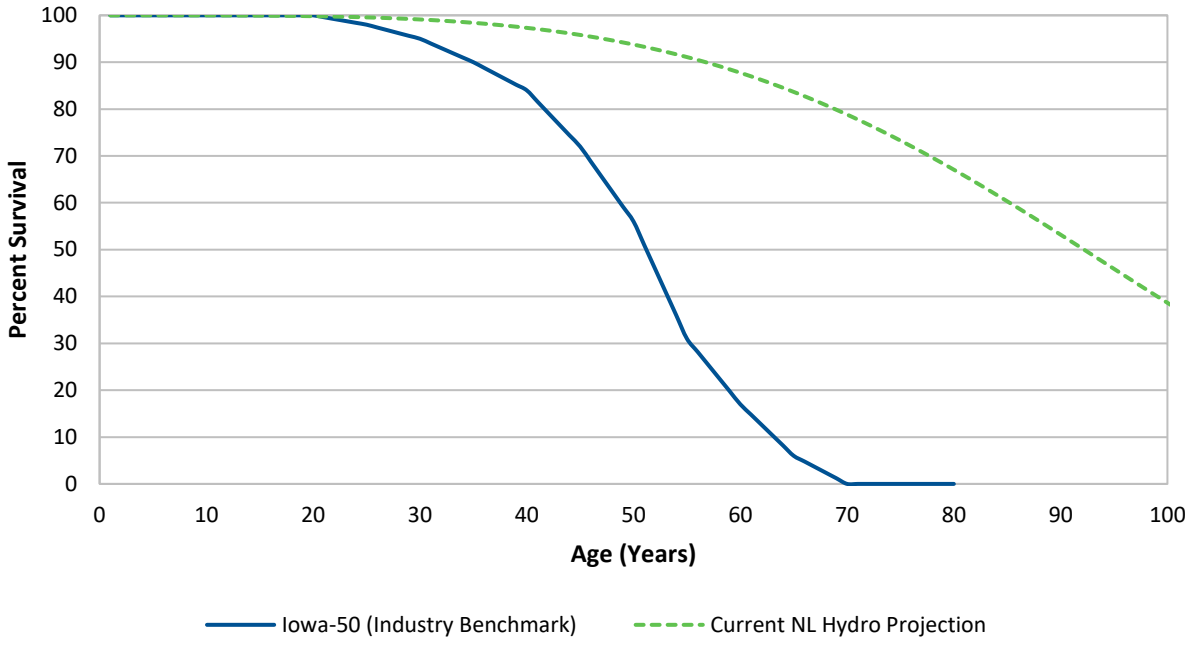


Figure A-1: Survival Plot – Hydro's Wood Pole Line Network

Program 11

Thermal In-Service Failures

2025

newfoundland labrador hydro

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Thermal In-Service Failures (2025)

Location: Holyrood

Investment Classification: Renewal

Asset Category: Thermal Plant

Cost: $3,899,992

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") has an Asset Management Program that governs the life cycle of its thermal generation assets. 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 capital budget application ("CBA"). This is achieved through the preventive maintenance program using various condition-based assessments and testing procedures.

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. 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.

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. Hydro uses historical data and engineering judgment to predict the magnitude of in-service failure expenditures.

As per the "Reliability and Resource Adequacy Study – 2022 Update," ("2022 Update")[1] the Holyrood Thermal Generating Station ("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. 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.

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 2025, 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.

[1] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.

Information on project scopes of $750,000 or more executed under the Thermal In-Service Failures (2023) Program is included in Hydro's "Capital Expenditures and Carryover Report." There were no project scopes of this magnitude for the 2023 reporting year.

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

As assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure, 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 refurbishment or replacement 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 33 unplanned projects per year under this program.

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.

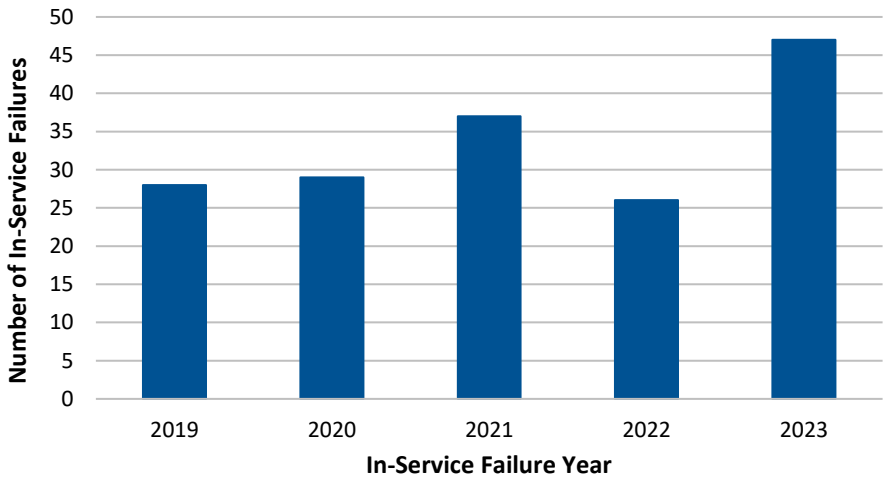


Chart 1: In-Service Failure Frequency

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 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.

5.0 Historical Reliability

Hydro tracks performance data for its thermal generation 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

[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 Asset Performance in Support of Resource Adequacy for the Twelve Months Ended March 31, 2024," Newfoundland and Labrador Hydro, April 30, 2024.

thermal generation units to ensure the provision of reliable service to customers. In its 2023 May Near-Term Reliability Update,[4] Hydro's modelling indicated that a Derated Adjusted Utilization Forced Outage Probability ("DAUFOP")[5] in excess of 20%, coupled with Labrador-Island Link 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.

6.1.1 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]

[4] "Reliability and Resource Adequacy Study 2023 Update – Volume II: Near-Term Reliability Report – May 2023," Newfoundland and Labrador Hydro, June 2, 2023.
[5] "DAUFOP" is the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.
[6] Due to the extension of the Holyrood TGS through the Bridging Period, Hydro submitted an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account. The Board approved the extension of the account and related amendments in Board Order No. P.U. 1(2024). Hydro also was directed to file a report on the account in its next general rate application.

6.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	3	5	**15**
Post-Implementation	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**3.1**

7.0 Scope of Work

Work executed under this program in 2025 will be reported to the Board in Hydro's 2025 Capital Expenditures and Carryover Report.[7]

7.1 Program Budget

The estimate for the 2025 program is shown in Table 2. The estimate is based on the average expenditures from 2021 to 2023. 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] Hydro's 2025 Capital Expenditures and Carryover Report is to be filed on or before April 1, 2026.

Table 2: Program Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	1,250.0	0.0	0.0	**1,250.0**
Labour	1,061.5	0.0	0.0	**1,061.5**
Consultant	15.0	0.0	0.0	**15.0**
Contract Work	1,573.5	0.0	0.0	**1,573.5**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	0.0	0.0	0.0	**0.0**
Contingency	0.0	0.0	0.0	**0.0**
Total	**3,900.0**	**0.0**	**0.0**	**3,900.0**

The Thermal In-Service Failures Program started in 2018. Chart 2 shows the historical expenditures in the last five years, the forecast 2024 expenditures, the proposed 2025 budget, and the forecast costs through 2029.[8] 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 2025 program budget with cost escalation applied.

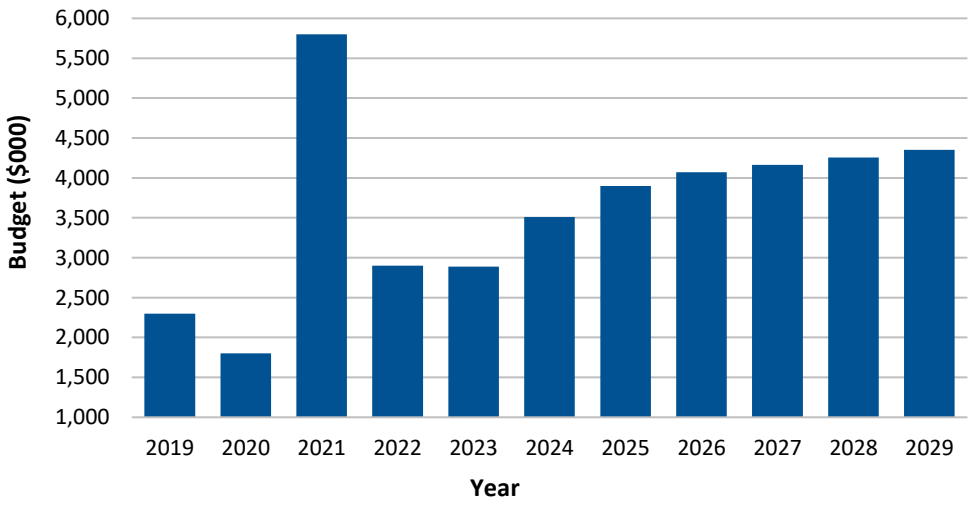


Chart 2: Historical and Forecast Program Budget

[8] The 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 2025.

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.

Program 12

Replace Protective Relays

2025–2026

newfoundland labrador hydro

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Appendix A: Five-Year Plan

Replace Protective Relays (2025–2026)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Cost: $2,739,525

1.0 Introduction

Protective relaying is a vital component of an electrical system, particularly during trouble, faults, and abnormal operating conditions. Protective relays are found in all of Newfoundland and Labrador Hydro's ("Hydro") terminal stations and generating stations. Protective relays function to protect major electrical equipment such as, 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.

Within Hydro's system, existing protective relays are either electromechanical, solid state (digital) or microprocessor-based, and are scheduled for replacement based on criteria outlined in the Terminal Station Asset Management Strategy,[1] which outlines Hydro's approach to protection, control, and modernization asset management.

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.

This program was initiated in 2016, with a plan to replace all existing electromechanical protective relays for 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

[1] Provided as Appendix F to Schedule 1 of this application.

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 operating 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 ten different protection systems located at terminal stations and generating stations across the system.

3.0 Asset Overview

3.1 Asset Background

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 (2025–2026) Program are operational. The justification for each project within this program is obsolescence or lack of required functionality. Protective relays continuously monitor for abnormal operating conditions in 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) or it may operate inadvertently (causing unplanned outages).

[2] Liquid-crystal display ("LCD").

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.

The information in Chart 1 represents Hydro's protective relay fleet. All protective relays in the scope of the Replace Protective Relays (2025–2026) 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 40 to 50 years old are obsolete electromechanical relays or not compliant with Hydro's current standards.[3] 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.

Chart 1 provides asset age for all assets covered under the program.

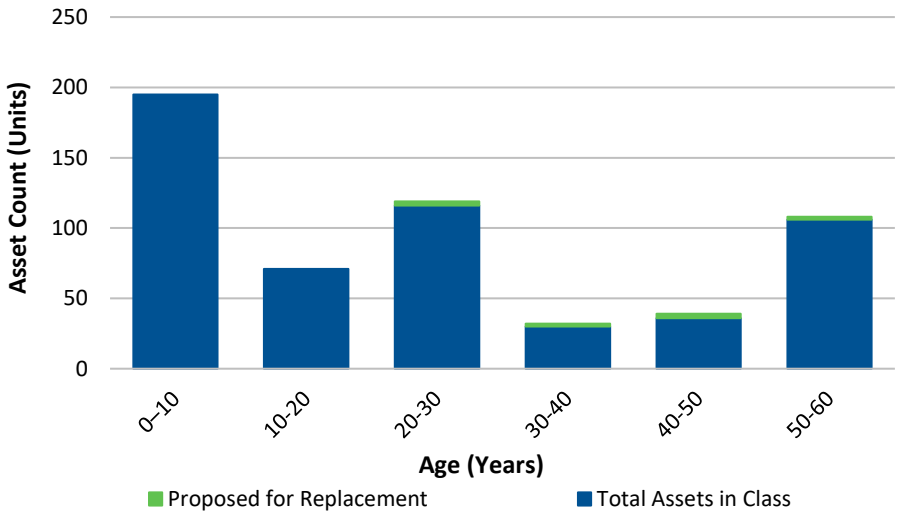


Chart 1: Asset Counts by Asset Age

[3] Hydro's current standard for 69 kV transmission line protection requires a primary and backup form of protection using two different relays.

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 protective relays installed, replaced, or upgraded per year. The number of installations in 2019 was higher than typical due to the number of installations 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 the number of assets through 2029 will be higher than that year.

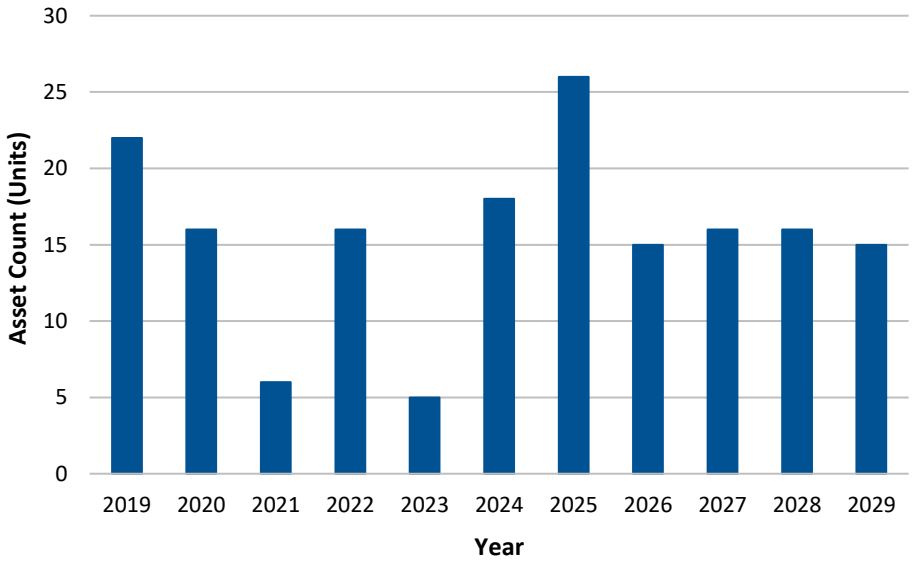


Chart 2: Historical and Forecast Number of Assets Installed/Replaced/Upgraded

4.2 Historical and Forecast Average Unit Costs

Chart 3 shows the five-year historical, current, and five-year forecast average unit cost of protective relay installations, replacements, or upgrades each year.

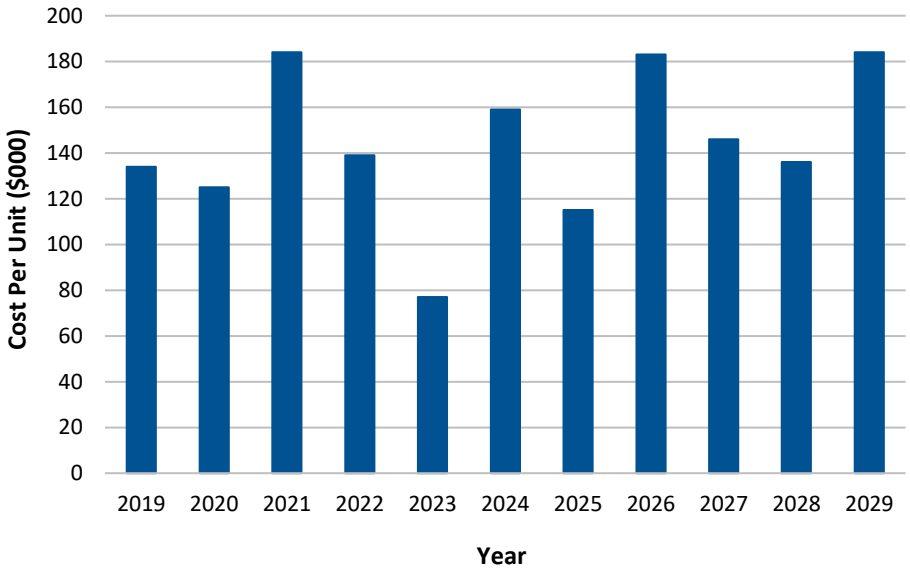


Chart 3: Historical and Forecast Average Unit Costs of Assets Installed/Replaced/Upgraded

4.3 Historical Reliability

Hydro does not record protective relay outage statistics; therefore, Hydro is unable to provide this data at this time.

5.0 Analysis

5.1 Evaluation of Alternatives

The following alternatives were considered:

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

5.1.1 Pace Reduction

The protective relays 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. Further deferral of this work increases the risk of relay misoperation and is not a viable alternative.

5.1.2 Pace Advancement

Pace advancement is not a viable option due to resource and outage availability concerns.

5.1.3 Continue Program at Current Pace

The protective relay replacements 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, reliable, least-cost service in an environmentally responsible manner.

5.2 Least-Cost Evaluation

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

5.3 Recommended Alternative

Hydro recommends proceeding with the proposed protective relay replacements.

5.3.1 Risk of Asset Stranding

For the assets included within the 2025–2026 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.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025–2026 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 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	5	3	**15**
Post-Implementation	5	1	**5**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**3.7**

6.0 Scope of Work

Hydro's five-year plan for the Replace Protective Relays Program is provided in Appendix A.[4] Based on current conditions and asset data, Hydro plans to replace ten different protection systems located within terminal stations and generating stations under this program. Two potential transformers will also be added to the Berry Hill Terminal Station to facilitate line protection upgrades at this station. All work is planned to be completed by the end of 2026. 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.

6.1 Program Budget

The estimate for this program is shown in Table 2.

Table 2: Program Estimate ($000)[5]

Program Cost	2025	2026	Beyond	Total
Material Supply	174.9	390.4	0.0	**565.2**
Labour	413.5	1,346.6	0.0	**1,760.1**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	29.8	0.0	**29.8**
Other Direct Costs	24.6	93.1	0.0	**117.6**
Interest and Escalation	25.0	118.1	0.0	**143.1**
Contingency	30.6	93.0	0.0	**123.6**
Total	**668.6**	**2,070.9**	**0.0**	**2,739.5**

[4] Replacement of line, generator, or transformer protection may involve replacement of multiple protective relays.
[5] Numbers may not add due to rounding.

Chart 4 provides the five-year historical program expenditures, the forecast 2024 expenditures the proposed 2025 program budget, and the forecast costs through 2029. The actual expenditures and budget for the program vary due to the variation in the number of relays installed, and the average cost from year to year.

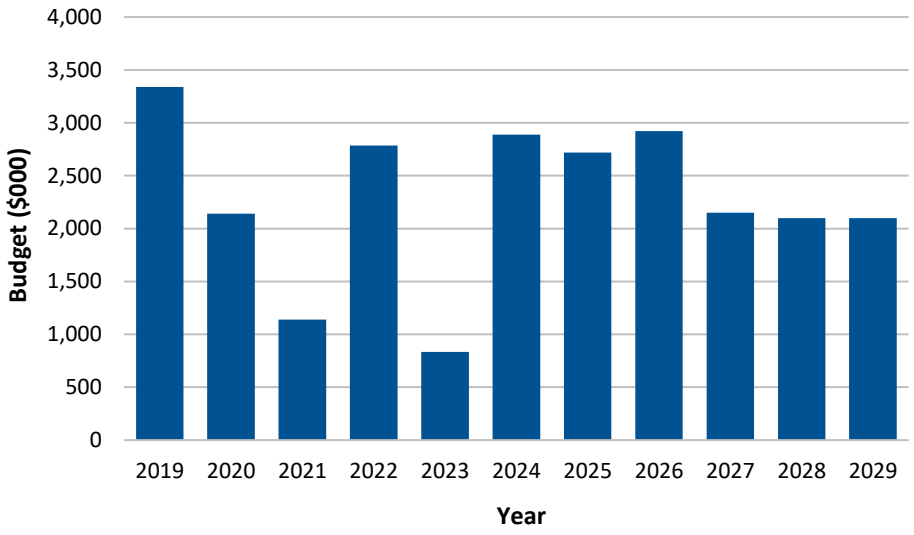


Chart 4: Historical and Forecast Program Budget

6.2 Program Schedule

The schedule for this program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Initial planning and scheduling.	January 2025	March 2025
Design:		
Prepare drawings and settings.	March 2025	May 2026
Procurement:		
Order relays, potential transformers, and long lead items.	February 2025	April 2026
Construction/Commissioning:		
Install potential transformers.	June 2026	August 2026
Complete protection upgrades.	March 2026	November 2026
Closeout:		
Completion of closeout documentation.	November 2026	December 2026

7.0 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, consistent with Hydro's Terminal Station Asset Management Strategy. 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

Five-Year Plan





Assets planned for replacement from 2025 to 2029 under the Replace Protective Relays Program are provided in Table A-1 to Table A-5.

Table A-1: 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
Granite Canal Unit G1 & Transformer T1	230
Hardwoods Transformer T3	230
Holyrood Unit U1 & Transformer T1	230
Holyrood Unit U2 & Transformer T2	230
Indian River Transmission Line TL224	138
Massey Drive Transmission Line TL228	230
Massey Drive Transformer T1	230
Massey Drive Transformer T3	230
Stony Brook Transmission Line TL232	230
Western Avalon Transformer T5	230

Table A-2: Assets Planned for Replacement in 2026

Name	Voltage of Protected Equipment (kV)
Berry Hill Transmission Line TL227	69
Cat Arm Transformer T2	230
Deer Lake Transformer T2 & Bus B3	230
Deer Lake Transmission Line TL226	69
Oxen Pond Transformer T2	230
Sunnyside Transmission Line 100L	138
Sunnyside Transmission Line TL219	138
Stony Brook Transmission Line TL210	138
Stony Brook Transmission Line TL235	230
Western Avalon Transformer T3	230

Table A-3: Assets Planned for Replacement in 2027

Name	Voltage of Protected Equipment (kV)
Bay d'Espoir Terminal Station 2 Transformer T11	69
Cat Arm Unit G1	13.8
Hardwoods Transformer T1	230
Massey Drive Bus B2B3	69
Massey Drive Transformer T2	230
Stony Brook Bus B1B2	230
Sunnyside Transmission Line 109L	138
Sunnyside Transmission Line TL212	138
Wabush Terminal Station Service Diesel	0.6
Wabush Terminal Station Transmission Line L6	46

Table A-4: Assets Planned for Replacement in 2028

Name	Voltage of Protected Equipment (kV)
Cat Arm Unit G2	13.8
Deer Lake Bus B2	69
Deer Lake Transformer T1	138
Hardwoods Bus B6B7	66
Hardwoods Transformer T5	66
Hawkes Bay Diesel Generator 1	0.6
Hawkes Bay Diesel Generator 2	0.6
Howley Transformer T2	138
Stony Brook Bus B3	138
Sunnyside Bus B1	230
Wabush Terminal Station Service Grounding Transformer SS1	46
Wabush Terminal Station Service Grounding Transformer SS2	46

Table A-5: Assets Planned for Replacement in 2029

Name	Voltage of Protected Equipment (kV)
Berry Hill Bus 1	138
Cow Head Transmission Line TL227	69
Deer Lake Transmission Line TL225	69
Deer Lake Transmission Line TL239	138
Deer Lake Transmission Line TL245	138
Hardwoods Transformer T4	230
Hinds Lake Iso-Phase Bus	13.8
Holyrood Bus B8B9	138
Indian River Transmission Line TL224	138
Massey Drive Transmission Line TL248	230
Springdale Bus 1	138
Springdale Synch Check	138
Western Avalon Bus B2	66

Terminal Station In-Service Failures

2025



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Terminal Station In-Service Failures (2025)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Cost: $2,500,045

1.0 Introduction

Newfoundland and Labrador Hydro ("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 capital budget application ("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 judgement 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 is completing a review of its power transformer bushings, and any identified for replacement will be acquired under this program. Throughout 2025,

Hydro may purchase other capital spares identified as requiring immediate procurement to offset deficiencies in its capital spares inventory.

Deferral of work justified under this program could result in a detrimental impact on customer power supply or an unacceptable risk to workers 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 (2023) Program, please refer to Hydro's "Capital Expenditures and Carryover Report for the Year Ended December 31, 2023."[1]

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 life cycle.

4.0 Trending

Hydro implemented the Terminal Station In-Service Failures Program in 2017. In the past five years, on average, Hydro has initiated 11 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 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.

[1] Provided as Appendix B to Schedule 5 of this application.

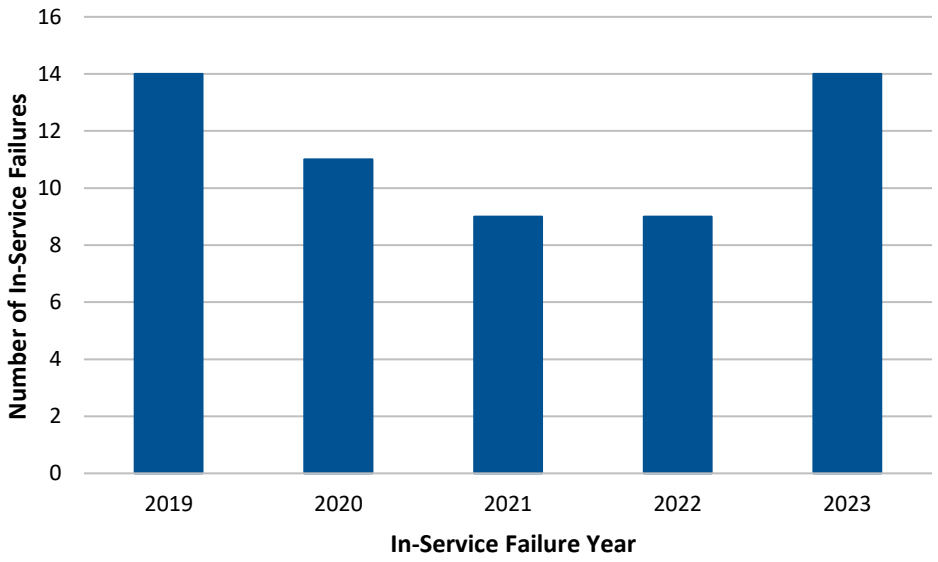


Chart 1: In-Service Failure Frequency

4.2 Historical and Forecast Average Unit Costs

Historical and forecast program costs are provided in Chart 2 in Section 6.1. 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.

4.3 Historical Reliability

As this program addresses a wide range of asset types, the specific assets to be addressed within this program for 2025 are not known. As such, historical reliability data for the individual assets covered within this program is not applicable.

5.0 Analysis

5.1 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.

5.1.1 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.

5.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	3	5	**15**
Post-Implementation	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**4.8**

6.0 Scope of Work

Work executed under this program in 2025 will be reported to the Board in Hydro's 2025 Capital Expenditures and Carryover Report.[2]

6.1 Program Budget

The estimate for the 2025 program is shown in Table 2. The estimate is based on the average expenditures from 2021 to 2023. The expenditures in 2022 were not included in average calculations for previous iterations of this program, as this year was initially considered an outlier due to the significant costs associated with the failure of Bay d'Espoir Transformer T5. However, Hydro has re-introduced the 2022 data in the program budget for 2025 due to expenditures which continue to exceed the 2019–

[2] Hydro's 2025 Capital Expenditures and Carryover Report is to be filed on or before April 1, 2026.

2021 average. 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.

Table 2: Program Estimate ($000)[3]

Program Cost	2025	2026	Beyond	Total
Material Supply	1,514.8	0.0	0.0	1,514.8
Labour	190.9	0.0	0.0	190.9
Consultant	91.0	0.0	0.0	91.0
Contract Work	600.0	0.0	0.0	600.0
Other Direct Costs	10.9	0.0	0.0	10.9
Interest and Escalation	92.5	0.0	0.0	92.5
Contingency	0.0	0.0	0.0	0.0
Total	**2,500.0**	**0.0**	**0.0**	**2,500.0**

The Terminal Station In-Service Failure Program started in 2017. Chart 2 shows the five-year historical expenditures since 2019, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast costs through 2029. 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 2025 program budget with cost escalation applied.

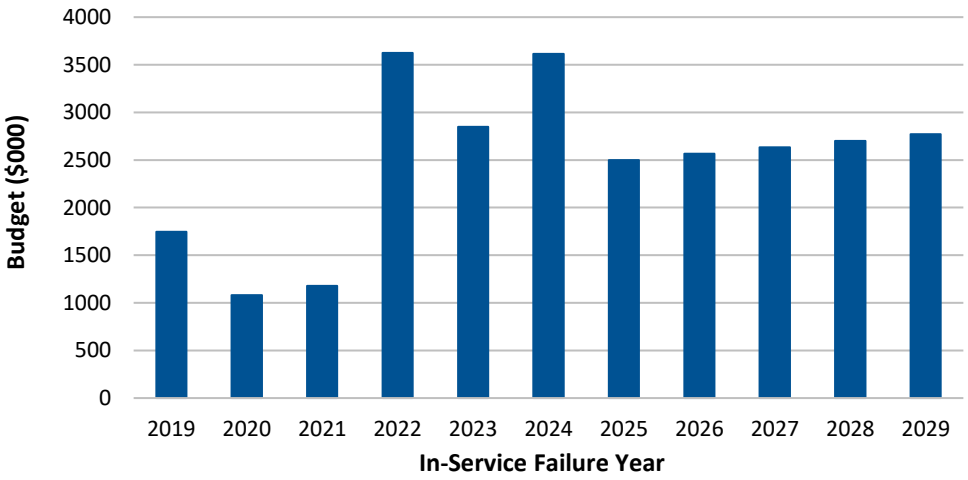


Chart 2: Historical and Forecast Program Budget

[3] Numbers may not add due to rounding.

6.2 Program Schedule

Work schedules are established subsequent to an unplanned failure or incipient failure event. Hydro does not have any planned capital spare acquisitions identified under this program in 2025; however, Hydro is currently completing a review of its power transformer bushings, and any identified for replacement will be acquired under this program.

7.0 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.

Hydraulic In-Service Failures

2025



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Appendix A: 2023 Hydraulic In-Service Failure Activities

Hydraulic In-Service Failures (2025)

Location: Various

Investment Classification: Renewal

Asset Category: Hydraulic Plant

Cost: $1,999,956

1.0 Introduction

Newfoundland and Labrador Hydro ("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 capital budget application ("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 2025, 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 on customer power supply or an unacceptable risk to workers 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 items, 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 (2023) Program, please refer to Hydro's "Capital Expenditures and Carryover Report for the Year Ended December 31, 2023."[1]

3.2 Asset Condition

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit signs of incipient failure.

[1] Provided as Appendix B to Schedule 5 of this application.

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 life cycle.

4.0 Trending

Hydro implemented the Hydraulic In-Service Failures Program in 2018. Over the past five years, on average, Hydro has initiated 13 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.

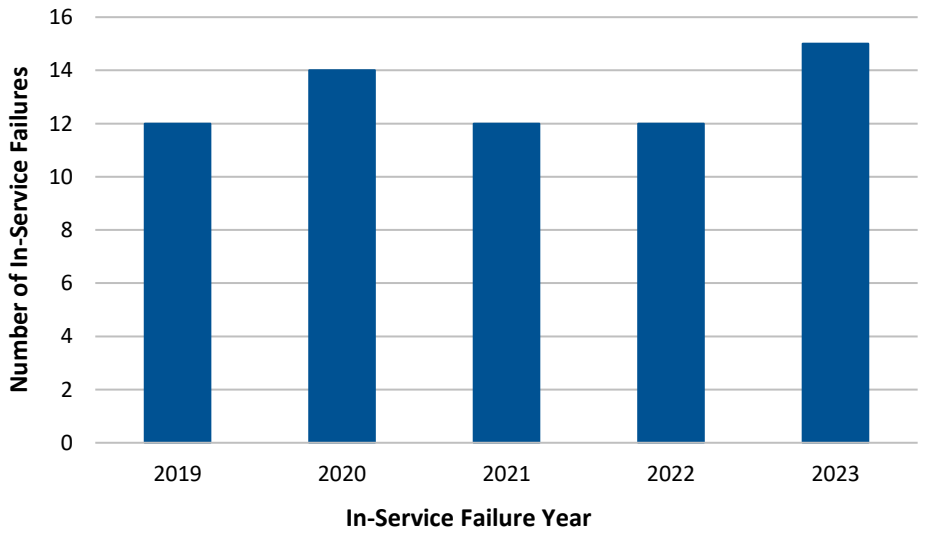


Chart 1: In-Service Failure Frequency

4.2 Historical and Forecast Average Unit Costs

Historical and forecast program costs are provided in Chart 2 in Section 6.1. 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.

4.3 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 2025 are not known, historical reliability data for the individual assets covered within this program is not applicable.

5.0 Analysis

5.1 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.

5.2 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.

[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 Asset Performance in Support of Resource Adequacy for the Twelve Months Ended March 31, 2024," Newfoundland and Labrador Hydro, April 30, 2024.

5.3 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	3	5	**15**
Post-Implementation	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**6.0**

6.0 Scope of Work

Work executed under the 2025 program will be reported to the Board in Hydro's 2025 Capital Expenditures and Carryover Report.[4]

6.1 Program Budget

The estimate for this program is shown in Table 2. The estimate is based on the average expenditures from 2021 to 2023. 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.

The expenditures in 2023 associated with the refurbishment of the Penstock 1 rupture in Bay d'Espoir were not included in the average calculation, as this cost was considered an outlier due to the unlikelihood of this failure to reoccur.[5] Hydro will re-evaluate the inclusion of this cost in future program budgets if Penstock 1 rupture refurbishment expenditures continue to increase the program estimate beyond the 2020–2022 average.

[4] Hydro's 2025 Capital Expenditures and Carryover Report is to be filed on or before April 1, 2026.
[5] The cost associated with refurbishment of the Penstock 1 rupture in Bay d'Espoir was $1,450,000.

Table 2: Program Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	74.5	0.0	0.0	**74.5**
Labour	461.7	0.0	0.0	**461.7**
Consultant	130.0	0.0	0.0	**130.0**
Contract Work	1,301.5	0.0	0.0	**1,301.5**
Other Direct Costs	32.3	0.0	0.0	**32.3**
Interest and Escalation	0.0	0.0	0.0	**0.0**
Contingency	0.0	0.0	0.0	**0.0**
Total	**2,000.0**	**0.0**	**0.0**	**2,000.0**

The Hydraulic In-Service Failures Program started in 2018. Chart 2 provides the five-year historical program expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast budget through 2029. Since Hydro is unable to predict the quantity and nature of failures that will need to be addressed within this program in future years, the forecasted expenditures for this program are based on the 2025 program budget with cost escalation factored in.

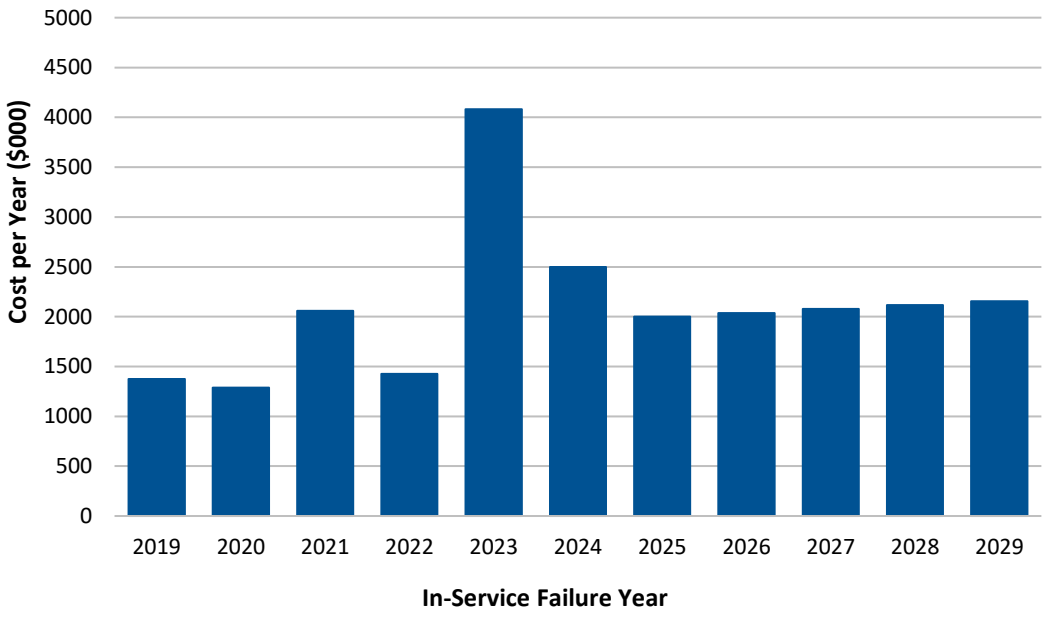


Chart 2: Historical and Forecast Program Budget[6]

[6] The significant program cost in 2023 is associated with the aforementioned unplanned project executed for the refurbishment of Penstock 1 in Bay d'Espoir. This project required expenditures exceeding $1.4 million and was omitted from the program's average calculation.

6.2 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 2025.

7.0 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.

Appendix A

2023 Hydraulic In-Service Failure Activities





Hydro has committed to providing a summary of activities completed under the Hydraulic In-Service Failures Program. Table A-1 outlines 2023 expenditures under this program.

Table A-1: 2023 Hydraulic In-Service Failures[1]

Total Approved Budget:	**$1,500,000**
Total Expenditure:	**$4,081,091**

Program Work Scope	**Expenditure**[2] **($000)**	**Failure Identified**	**Scope Description**
Refurbish Penstock 1 Defects – Bay d'Espoir	1,432.1	Penstock 1 supplies water from Intake 1 to Bay d'Espoir Units 1 and 2, and is approximately 1,000 metres in length and is a steel fabrication. Inspection and testing of Penstock 1 during the planned outage in 2023 revealed a higher-than-normal percentage of defects in the longitudinal weld seams. A more extensive test and refurbishment program was recommended to reduce the risk of penstock failure during operation.	Non-destructive testing of the Penstock 1 longitudinal seam welds was completed. Identified defects were refurbished, and the penstock was returned to service.
Work Scopes Under $750,000	2,649.0		

[1] Hydro will provide a summary of scopes of work undertaken under the Hydraulic Generation In-Service Failures Program that exceeds $750,000. Table A-1 outlines 2023 expenditures under this program.
[2] Numbers may not add due to rounding.

Program 15

Upgrade Power Transformers

2025–2026

newfoundland labrador hydro

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Appendix A: Upgrade Power Transformers Program – 2025–2029 Plan

Upgrade Power Transformers (2025–2026)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Cost: $1,985,786

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

Newfoundland and Labrador Hydro ("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[1]-contaminated, failure of the protective devices, and cooling fan failures.

Under the scope of the 2025–2026 program, 12 transformers will be refurbished.[2] The following transformer upgrades and/or refurbishments are planned for 2025–2026:

- Replacement of bushings;
- Replacement or refurbishment of oil;
- Transformer dry out;
- Overhaul of tap changers;
- Installation of online oil dehydrator; and

[1] Polychlorinated biphenyls ("PCB").
[2] Some transformers are due for major refurbishment, which includes two or more of the upgrades/refurbishments listed.

- Installation of online dissolved gas analysis ("DGA") monitors.

A detailed list of the activities planned for completion in 2025 and 2026 is provided in Appendix A.

3.0 Asset Overview

3.1 Asset Background

The power transformers in the Upgrade Power Transformer 2025–2026 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 Terminal Station Asset Management Strategy.[3]

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;
- Power transformer bushing replacement; and
- Power transformer oil replacement and refurbishment.

Chart 1 to Chart 4 included in this proposal for the various power transformer components range from Category 1 to Category 4.[4]

[3] Provided as Appendix F to Schedule 1 of this application.
[4] A Category 1 assessment indicates that the component is in normal operating condition. A Category 4 assessment indicates that the component requires either replacement or refurbishment or the component is being monitored to determine what actions are appropriate. Category 2 and Category 3 assessments are scaled between Categories 1 and 2.

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. Chart 1 shows the number of transformers within each category, which are defined as follows:

- Category 1: Less than 1.5%;
- Category 2: Between 1.5% and 2.4%;
- Category 3: Between 2.5% and 3.5%; and
- Category 4: Greater than 3.5%.

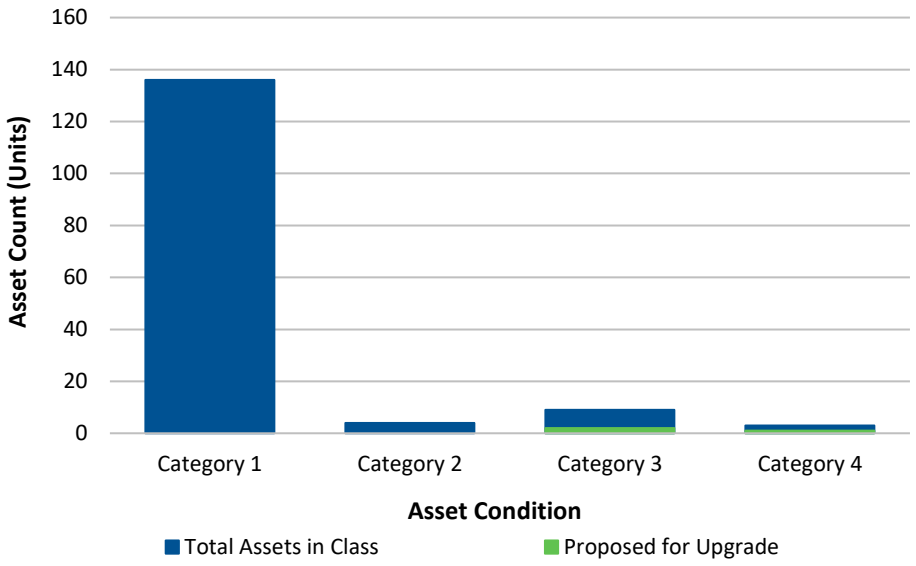


Chart 1: Asset Condition – Power Transformer Solid Insulation Moisture

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. Chart 2 shows the number of transformers within each category, which are defined as follows:[6]

- Category 1: Asset Condition = A;
- Category 2: Asset Condition = B;
- Category 3: Asset Condition = C; and
- Category 4: Asset Condition = D.

The transformers selected for tap changer upgrades are based on condition or the original equipment manufacturer's recommended number of operations at which to complete a refurbishment.

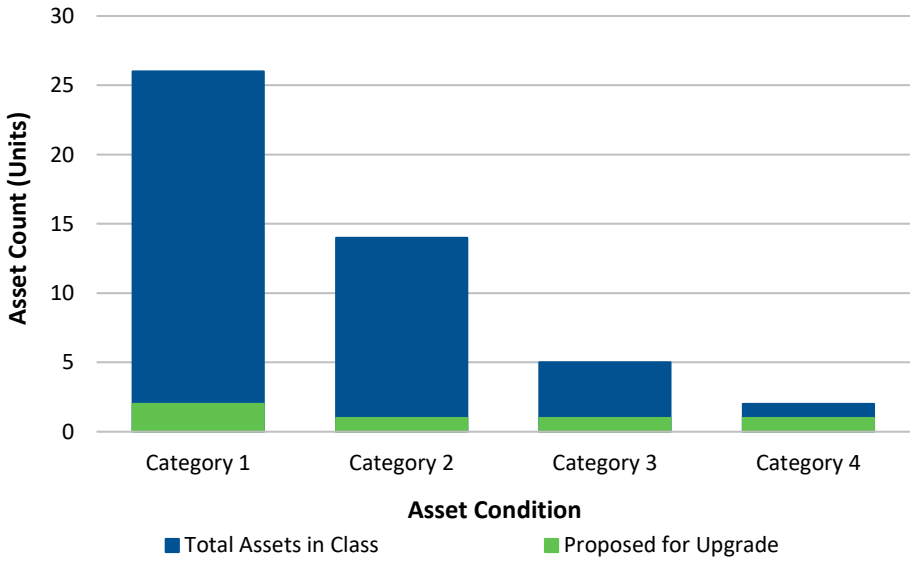


Chart 2: Asset Condition – Power Transformer OLTC

[5] 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.

3.2.3 Asset Condition – Power Transformer Bushings

The power transformer bushings asset condition categories represent severity, as defined by Hydro, based on voltage/test tap leaks, insulator condition and bushing C1 and C2 ratings (as per Doble test results).[7] Chart 3 shows the number of transformers within each category, which are defined as follows:

- Category 1: No voltage/test tap leaks, acceptable C1 and C2 ratings;
- Category 2: Voltage/test tap leaking, damaged insulator skirt, C1 "I" rating, C2 "I" rating;
- Category 3: Voltage/test tap leaking, C1 "D" rating, C2 "B" rating; and
- Category 4: C1 "B" rating.

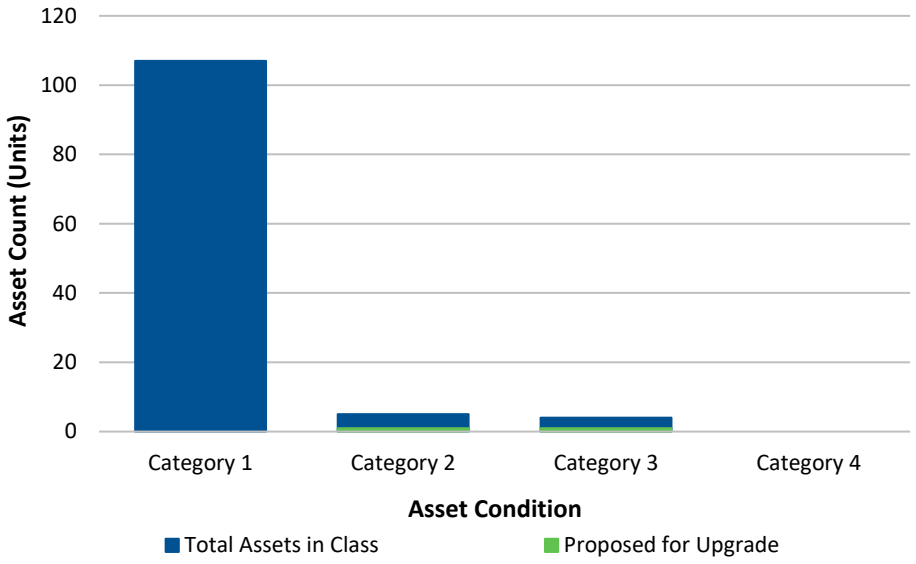


Chart 3: **Asset Condition – Power Transformer Bushings**

[7] The C1 and C2 ratings of 'I', 'D' and 'B' mean "investigate", "deteriorated", and "bad," respectively.

3.2.4 Asset Condition – Power Transformer Oil

The power transformer oil asset condition categories represent severity based on an overall oil quality score, which is calculated from several parameters including dielectric, interfacial tension, acidity and power factor. Chart 4 shows the total assets within each category, which are defined as follows:

- Category 1: Greater than 99%;
- Category 2: Between 67% and 99%;
- Category 3: Between 34% and 66%; and
- Category 4: Less than 34%.

The transformer selected for oil refurbishment is based on condition and asset criticality.

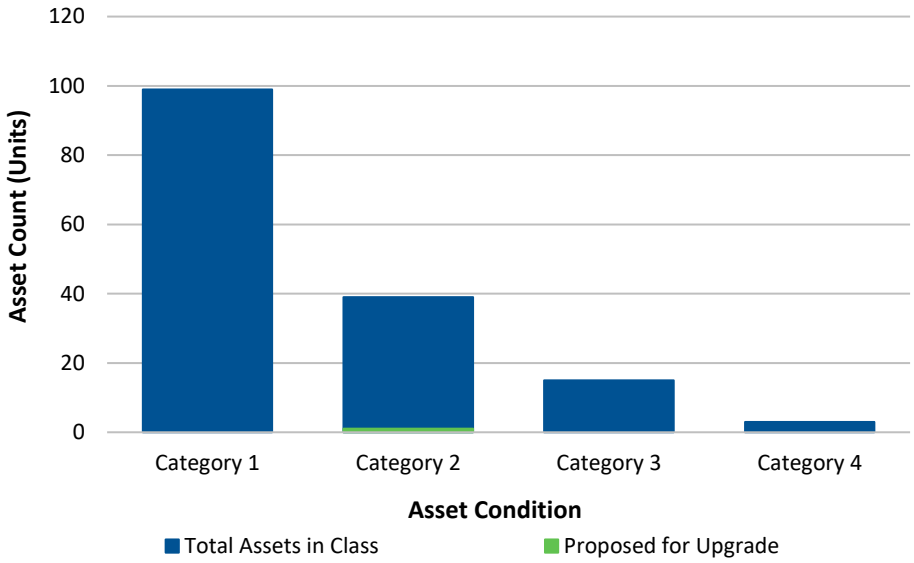


Chart 4: Asset Condition – Power Transformer Oil

3.3 Asset Ages

Chart 5 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 2025–2026 Program is justified based on age.

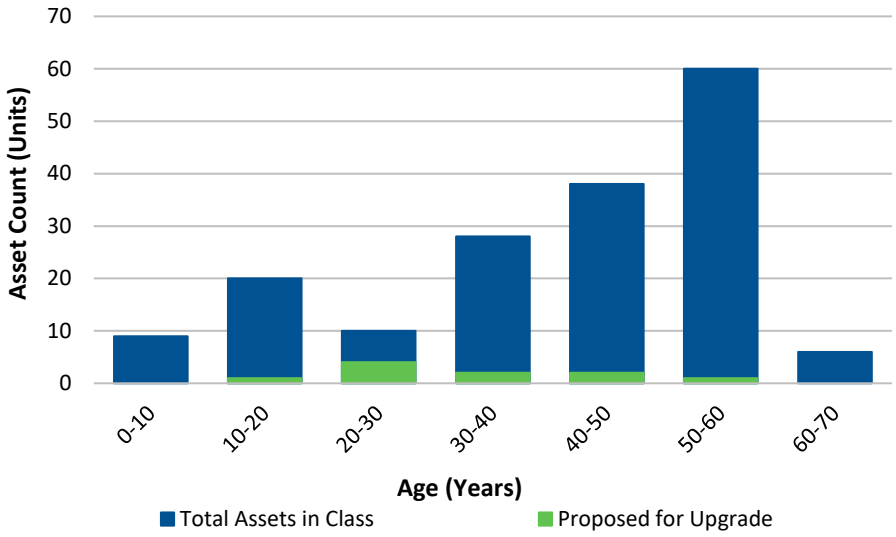


Chart 5: Asset Counts by Asset Age

4.0 Trending

4.1 Assets Replaced/Upgraded

Chart 6 provides the five-year historical, current, and five-year forecast number of assets replaced/upgraded per year.

There is a reduction in the forecast number of refurbishments beyond 2025, as all of the suspected PCB-contaminated units will have been removed.

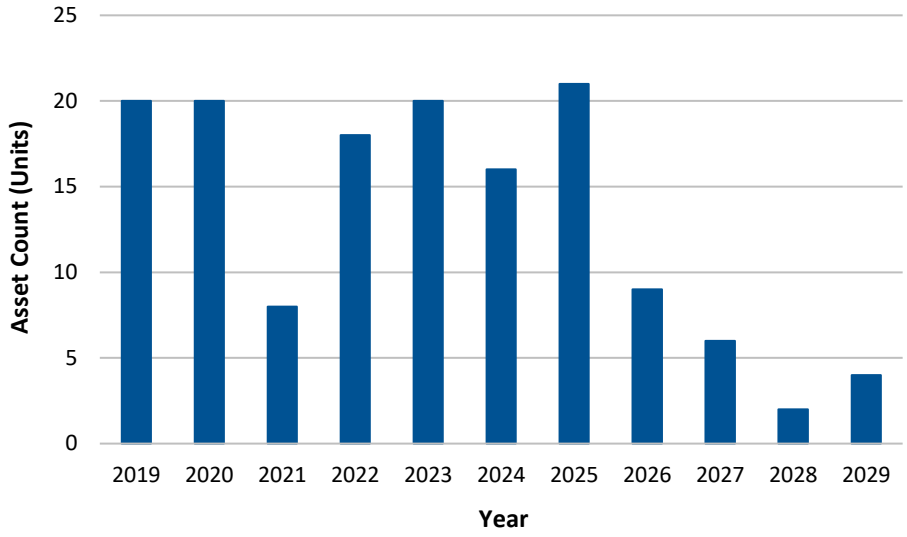


Chart 6: Historical and Forecast Number of Assets Replaced/Upgraded[8]

4.2 Historical and Forecast Average Unit Costs

Chart 7 provides the five-year historical, current, and the five-year forecast average unit cost of asset replacement/upgrades in each year.

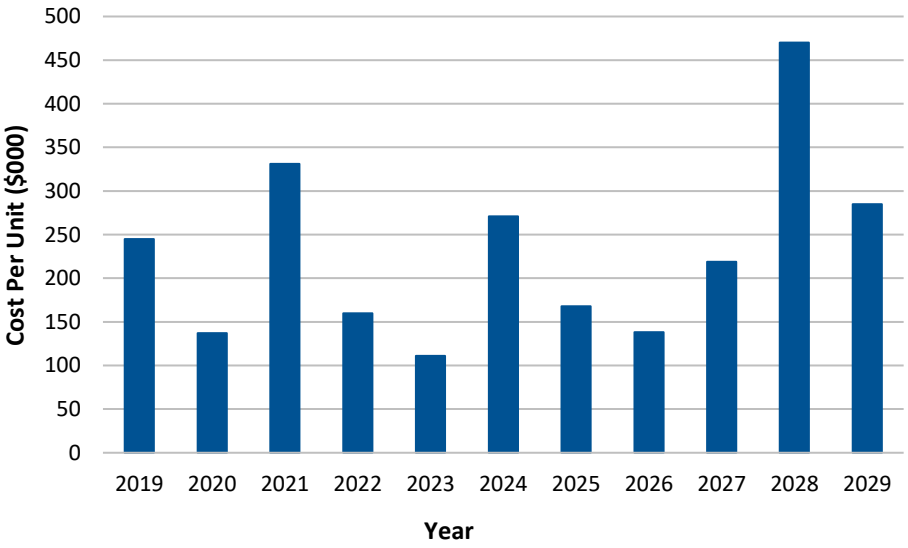


Chart 7: Historical and Forecast Average Unit Costs of Assets Replaced/Upgraded

[8] No assets have yet to be identified for replacement or upgrade in 2029. The forecast 2029 budget outlined in Chart 8 has been estimated based on the number of units and average unit cost of the preceding years.

4.3 Historical Reliability

A listing of sustained forced outages for the last five years is shown is Table 1.

Table 1: **Power Transformer Outages and Durations from 2019 to 2023**

Start Date	Transformer	Outage Duration (Minutes)
25-Jul-2023	Bay d'Espoir T6	105,169
6-Jun-2023	St. Anthony Diesel Plant T1	300,591
25-May-2023	Daniel's Harbour T2	194,440
6-Aug-2022	Grandy Brook T1	241
3-Jul-2022	Bay d'Espoir T5	171,902
28-Apr-2022	Sunnyside T1	5
28-Apr-2022	Sunnyside T4	5
22-Apr-2022	Deer Lake T2	337
21-Mar-2022	Holyrood T10	1,475
21-Mar-2022	Holyrood T5	1,376
12-Nov-2021	Holyrood T2	87,485

5.0 Analysis

5.1 Evaluation of Alternatives

The following alternatives were considered:

- Pace reduction; and
- Pace advancement.

5.1.1 Pace Reduction

Tap Changer Overhauls/Refurbishment

The scope of work includes tap changer refurbishments for four 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 two transformers. The bushings 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.

Installation of Online DGA Monitors

The scope of work includes the installation of online DGA monitors for three 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 two transformers.

Oil samples from these transformers 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 these transformers experiencing a serious fault and is not a viable alternative.

Oil Replacement and Refurbishment

The scope of work includes the replacement or refurbishment of oil in two transformers. The oil identified for replacement contains PCBs and the oil in the transformer identified for oil refurbishment is ranked poor. Deferral of this work is not a viable alternative as the oil-containing PCBs must be removed by December 31, 2025, to ensure compliance with federal environmental PCB Regulations.

5.1.2 Pace Advancement

Pace advancement is not a viable option due to resource and outage availability concerns.

5.1.3 Alternative Strategies

The tap changer overhauls, bushing replacements, online DGA monitor installations, online oil dehydrator installations and oil replacement and refurbishment 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. As such, no alternative strategies have been identified.

5.2 Least-Cost Evaluation

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

5.3 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.

5.3.1 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.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025-2026 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-Implementation	4	3	**12**
Post-Implementation	4	1	**4**
		Risk Mitigated	**8**
		Risk Mitigated per $1 Million	**4.0**

6.0 Scope of Work

Hydro's five-year plan for the Upgrade Power Transformers program is provided in Appendix A. Based on current conditions and asset data, Hydro plans to refurbish 12 power transformers under this program, with completion scheduled by the end of 2026. 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.

6.1 Program Budget

The estimate for this 2025–2026 program is shown in Table 3.

Table 3: Program Estimate ($000)[9]

Program Cost	2025	2026	Beyond	Total
Material Supply	124.5	293.0	0.0	**417.5**
Labour	339.1	241.2	0.0	**580.3**
Consultant	17.5	55.0	0.0	**72.5**
Contract Work	185.0	355.5	0.0	**540.5**
Other Direct Costs	46.6	62.9	0.0	**109.5**
Interest and Escalation	28.0	65.5	0.0	**93.5**
Contingency	71.3	100.8	0.0	**172.0**
Total	**811.9**	**1,173.9**	**0.0**	**1,985.8**

Chart 8 provides the five-year historical program expenditures, the forecast 2024 expenditure, the proposed 2025 program budget, and the forecast budget through 2029.

[9] Numbers may not add due to rounding.

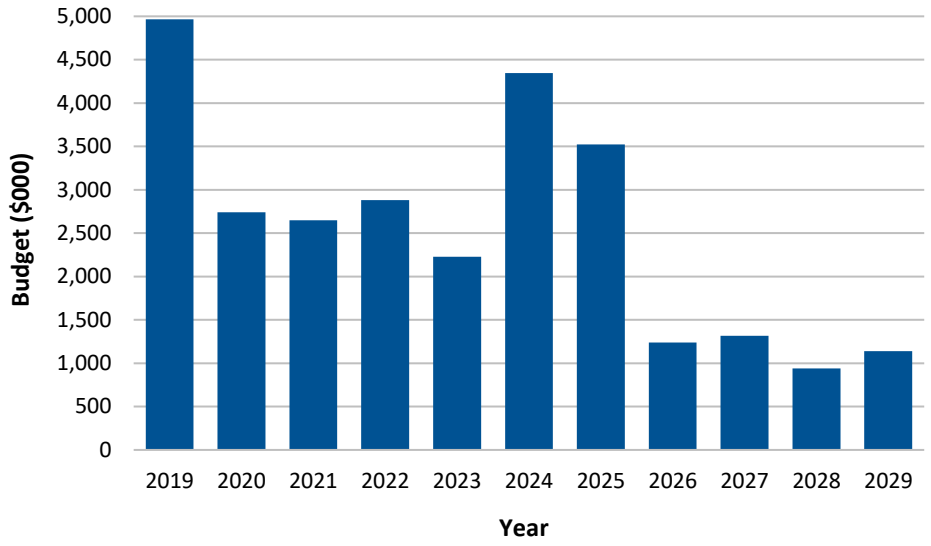


Chart 8: Historical and Forecast Program Budget

6.2 Program Schedule

The schedule for this program is shown in Table 4.

Table 4: Program Schedule

Activity	Start Date	End Date
Planning:		
Initial planning and scheduling.	January 2025	May 2025
Design:		
Conduct site visits and complete detailed design.	May 2025	November 2026
Procurement:		
Ordering and delivery of equipment.	March 2025	September 2026
Construction:		
Install new equipment.	January 2026	November 2026
Commissioning:		
Commissioning.	January 2026	November 2026
Closeout:		
Complete closeout documentation.	October 2026	December 2026

7.0 Conclusion

The scope of work identified within this program is required to refurbish 12 power transformers to allow Hydro to continue to provide safe, reliable, least-cost electricity in an environmentally responsible manner. The 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

2025–2029 Plan





Assets planned for upgrade from 2025 to 2029 under the Upgrade Power Transformers Program are provided in Table A-1 to Table A-5.

Table A-1: Assets Planned for Upgrade in 2025[1,2]

Name	Voltage (kV)	Activity
Bay d'Espoir SST2	13.8	Replace oil.
Bay d'Espoir T3	230	Replace bushings (HV).
Berry Hill T1	138	Install online composite gas monitor.
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 painting.
Grand Falls Frequency Convertor T2	230	Replace bushings (H1, H3).
Grandy Brook T1	138	Major Refurbishment – Install online composite gas monitor, 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), leak refurbishment.
Peter's Barren T1[3]	138	Major refurbishment – Refurbish tap changer, install online composite gas monitor.
Quartzite T2	69	Refurbish tap changer.
Rocky Harbour T1	69	Install online composite gas monitor.
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, install online oil dehydrator.
Wabush Terminal Station T2	230	Replace bushings (HV, N).
Wabush Terminal Station T6	230	Major Refurbishment – Replace bushing (N), oil refurbishment.

[1] The Assets Planned for Upgrade in 2025, as listed in Table A-1, are planned for completion in 2025 and were approved as part of the Upgrade Power Transformers (2024–2025) Program included in the "2024 Capital Budget Application," Newfoundland and Labrador Hydro, rev. December 15, 2023 (originally filed July 12, 2023), sch. 6, prog. 8, approved by the Board of Commissioners of Public Utilities in Board Order No. P.U. 35(2023).

[2] HV refers to all high-voltage bushings, LV refers to all low-voltage bushings, and N refers to neutral. 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] Subject to internal approval, this job will be rescheduled to 2026 to combine with the 2026 Peter's Barren T1 included in this program.

Table A-2: Assets Planned for Upgrade in 2026[4]

Name	Voltage (kV)	Activity
Bay d'Espoir T12	230	Refurbish tap changer.
Grand Falls Frequency Convertor T1	230	Major Refurbishment – Oil refurbishment, moisture reduction.
Happy Valley T1	138	Refurbish tap changer.
Happy Valley T2	138	Moisture reduction.
Massey Drive T1	230	Moisture reduction.
Paradise River T1	25	Replace bushings (LV).
Peter's Barren T1	138	Replace bushing (X1).
Quartzite T1	69	Refurbish tap changer.
St. Anthony Airport T1	69	Major Refurbishment – OLTC refurbishment, install online composite gas monitor.

Table A-3: Assets Planned for Upgrade in 2027[5]

Name	Voltage (kV)	Activity
Bear Cove R1	138	Replace bushing (H03).
Buchans T1	230	Tap changer oil replacement.
Deer Lake T2	230	Tap changer oil replacement.
Doyles T1	138	Replace bushings (LV).
Massey Drive T2	230	Moisture reduction, leak refurbishment.
Stony Brook T1	230	Major Refurbishment – OLTC replacement, OLTC leak refurbishment.

Table A-4: Assets Planned for Upgrade in 2028

Name	Voltage (kV)	Activity
Massey Drive T1	230	Refurbish tap changer.
Stony Brook T1	230	Major Refurbishment – OLTC replacement, OLTC leak refurbishment.

[4] *Supra,* f.n. 2.
[5] *Supra,* f.n. 2.

Table A-5: Assets Planned for Upgrade in 2029[6]

Name	Voltage (kV)	Activity
Power Transformer TBD 1	TBD	Unknown
Power Transformer TBD 2	TBD	Unknown
Power Transformer TBD 3	TBD	Unknown
Power Transformer TBD 4	TBD	Unknown

[6] Hydro anticipates that approximately four jobs will be identified for inclusion in the Upgrade Power Transformers (2029) Program. These anticipated jobs are ones that do not presently meet any of the eligibility criterion but are anticipated to meet a condition-based or usage-based eligibility criterion by 2027.

Program 16

Purchase Tools and Equipment

2025

newfoundland labrador hydro

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Purchase Tools and Equipment (2025)

Location: Various

Investment Classification: General Plant

Asset Category: Tools and Equipment

Cost: $1,399,089

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") requires specific tools and equipment to ensure the delivery of safe, reliable, least-cost electricity in an environmentally matter. This program outlines the purchase of tools and equipment that support the operation of Hydro's generation, transmission, and distribution systems.

2.0 Program Description and Justification

Hydro requires an adequate supply of tools and equipment to safely maintain reliable service to customers; therefore, it is necessary to add or replace tools and equipment required to complete system work which has become deteriorated or obsolete.

Tools and equipment procured through this program are primarily driven by the operating requirements of Hydro's Generation, Telecontrol, and Transmission and Rural Operations ("TRO") groups. Required tools and equipment differ for each group, and cannot be shared due to operational restrictions. Proposed expenditures in 2025 are primarily the result of increased live line work, replacement of deteriorated tools or equipment, and required safety equipment.[1]

3.0 Asset Overview

3.1 Asset Background

Assets purchased as part of this program vary based on the requirements of the business in the year of project execution. Tools and equipment purchased under this program support daily operations, align with safety procedures and allow Hydro to maintain reliable service to customers.

[1] Typical tools and equipment purchased as part of this program can include: safety rails, gas monitors, drones, and hand tools.

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 replaced or refurbished 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

Due to the nature of this program and the range of assets covered in 2025, trending information and historical reliability data are not available. Historical and forecast program costs are provided in Chart 1 in Section 6.0.

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro evaluated the following alternatives:

- Pace reduction;
- Pace advancement; and
- Alternative strategies.

This program is for the purchase of specific tools and equipment that have been identified for purchase in 2025. These tools and equipment are required to ensure the delivery of safe, reliable, least-cost electricity in an environmentally matter.; therefore, there are no other alternatives.

5.1.1 Pace Reduction

Hydro has not identified any pace reduction options for this program. Hydro requires tools and equipment to support safe and reliable operation of the electrical system and evaluates tool and equipment requirements on an annual basis, proposing the procurement of those necessary to support

system operations. Delayed procurement of these tools and equipment is therefore not considered a viable option.

5.1.2 Pace Advancement

Hydro has not identified any need to advance the procurement of tools and equipment and evaluates its tools and equipment needs on an annual basis, proposing procurement of those necessary to support the safe and reliable operation of the electrical system.

5.1.3 Alternative Strategies

No alternative strategies have been identified for this program.

5.2 Least-Cost Evaluation

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

5.3 Recommended Alternative

5.3.1 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 and support Hydro's day-to-day operations. The risk of asset stranding would be considered on a case-by-case basis. The assets installed under this program can generally be redeployed should the service requirements change in a given location.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	4	3	**12**
Post-Implementation	4	1	**4**
		Risk Mitigated	**8**
		Risk Mitigated per $1 Million	**5.7**

6.0 Scope of Work

The scope of work of this program covers the annual expenditures required for the purchase of tools and equipment to execute safe, reliable work. Tools and equipment identified under this program are required to support day-to-day operations within Hydro's Generation, Telecontrol, and TRO groups. The scope of work includes the purchase and procurement of tools and equipment and does not include any costs associated with the installation of these items.

6.1 Program Budget

The estimate for this 2025 program is shown in Table 2.

Table 2: Tools and Equipment Program Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	1,221.8	0.0	0.0	**1,221.8**
Labour	43.0	0.0	0.0	**43.0**
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	18.3	0.0	0.0	**18.3**
Contingency	116.0	0.0	0.0	**116.0**
Total	**1,399.1**	**0.0**	**0.0**	**1,399.1**

The program costs are broken down between Generation, TRO, and Telecontrol as follows:[2]

- Generation: $328,761
- TRO: $1,025,003
- Telecontrol Services Cost: $45,325

Chart 1 provides the five-year historical program expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast budget through 2029. Increased expenditures in 2025 are primarily the result of increased live line work in 2025, replacement of deteriorated tools or equipment, and required safety equipment.

[2] Numbers may not add due to rounding.

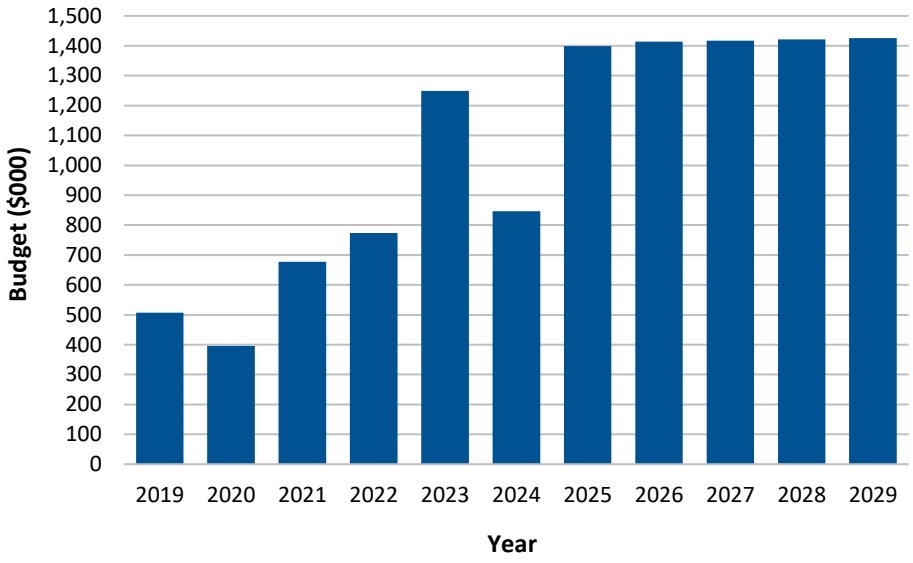


Chart 1: Historical and Forecast Program Budget

6.2 Program Schedule

This program is for the purchase of specific tools and equipment in 2025 that involves no construction or unit outages; therefore, the main milestone for this program is to have the identified tools and equipment on-site as required and before the end of 2025.

7.0 Conclusion

Hydro requires specific tools and equipment to ensure the delivery of safe, reliable, least-cost electricity in an environmentally matter. This program outlines the purchase of tools and equipment that support the operation and maintenance of Hydro's generation, transmission, and distribution systems; it is necessary to add or replace tools and equipment which have become deteriorated or obsolete that are required to complete this work. Hydro proposes to purchase the tools and equipment to ensure all operational groups have the proper tools and equipment to safely perform required tasks.

Program 17

Replace Disconnects

2025–2026

newfoundland labrador hydro

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Appendix A: Replace Disconnects Program – 2025–2029 Plan

Replace Disconnects (2025–2026)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Cost: $1,390,825

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,[1] 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 (2025–2026) Program are currently in service.

As detailed in the Terminal Station Asset Management Strategy,[2] Newfoundland and Labrador Hydro ("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

Under this program, 12 disconnect switches require replacement, as they meet the applicable replacement criteria. All disconnect switches planned for replacement in this program are currently in service. These units will be between 47 and 56 years of age at the scheduled time of replacement, some

[1] This system is used to produce the necessary documentation to isolate pieces of equipment that require maintenance safely.
[2] Provided as Appendix F to Schedule 1 of this application.

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.

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.

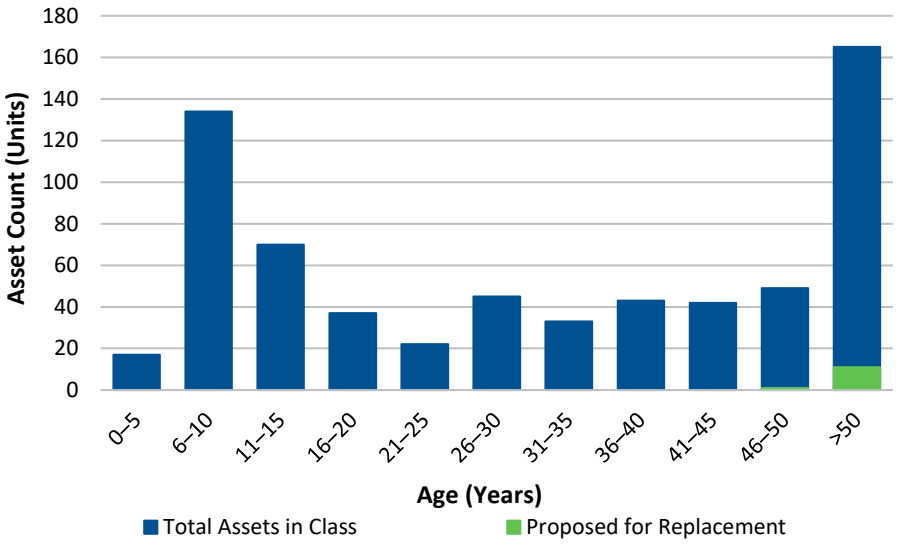


Chart 1: Asset Counts by Asset Age[3]

[3] Assets over 50 years of age without operating deficiencies are not replaced.

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.

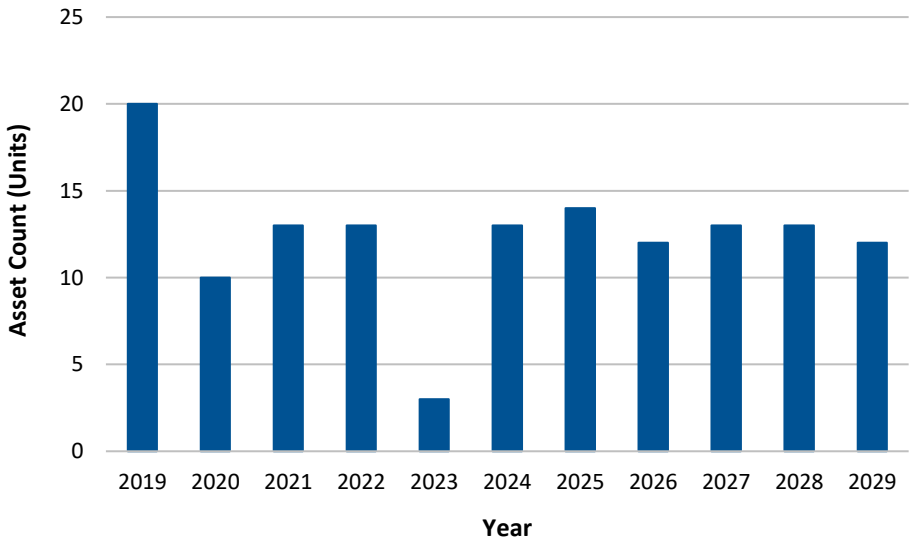


Chart 2: Historical and Forecast Number of Assets Installed/Replaced/Upgraded[4,5]

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.

[4] The historical number of assets replaced has been updated since the 2024 Capital Budget Application ("CBA"). Hydro has amended its reporting of assets in this program to exclude units that were replaced or installed through another capital project or program. This prevents duplicative reporting and ensures the provision of accurate historical information for capital work directly related to this program.

[5] Due to longer-than-anticipated delivery timelines, 2023 saw a decrease to the number of disconnect switches replaced compared to the number originally approved in the 2023 CBA. These switches were deferred to subsequent years.

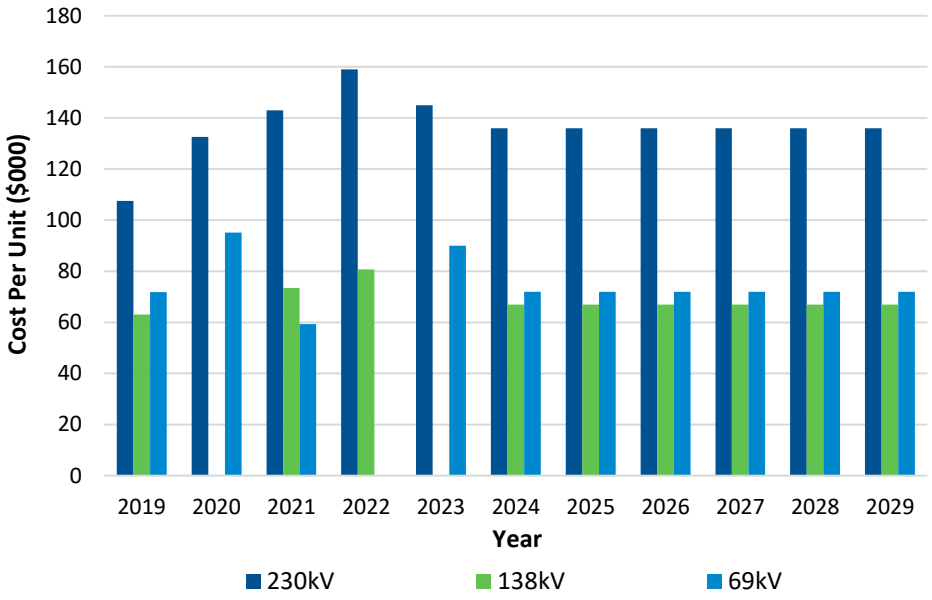


Chart 3: Historical and Forecast Average Unit Costs of Assets Installed/Replaced/Upgraded

4.3 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.

5.0 Analysis

5.1 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.

5.1.1 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.

5.1.2 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.

5.1.3 Continue Program at Current Pace

Proceeding with the identified upgrades ensures 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 the least-cost procurement and installation.

5.2 Least-Cost Evaluation

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

5.3 Recommended Alternative

Hydro recommends the replacement of the identified disconnect switches to minimize the potential of in-service failures at the affected operational sites.

5.3.1 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.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025–2026 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 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	5	2	**10**
Post-Implementation	5	1	**5**
		Risk Mitigated	**5**
		Risk Mitigated per $1 Million	**3.6**

6.0 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 2026. 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.

6.1 Program Budget

The estimate for the 2025–2026 program is shown in Table 2.

Table 2: Program Estimate ($000)[6]

Program Cost	2025	2026	Beyond	Total
Material Supply	0.0	474.0	0.0	**474.0**
Labour	95.2	517.4	0.0	**612.7**
Consultant	24.4	24.4	0.0	**48.8**
Contract Work	0.0	31.0	0.0	**31.0**
Other Direct Costs	8.3	24.0	0.0	**32.3**
Interest and Escalation	4.6	67.7	0.0	**72.3**
Contingency	12.8	107.1	0.0	**119.9**
Total	**145.3**	**1,245.5**	**0.0**	**1,390.8**

Chart 4 shows the five-year historical expenditures, the forecast 2024 expenditures, the proposed 2025 budget, and the forecast costs through 2029. Variability in budgets can be attributed to the quantity and voltage class of disconnects to be replaced in a given year.

[6] Numbers may not add due to rounding.

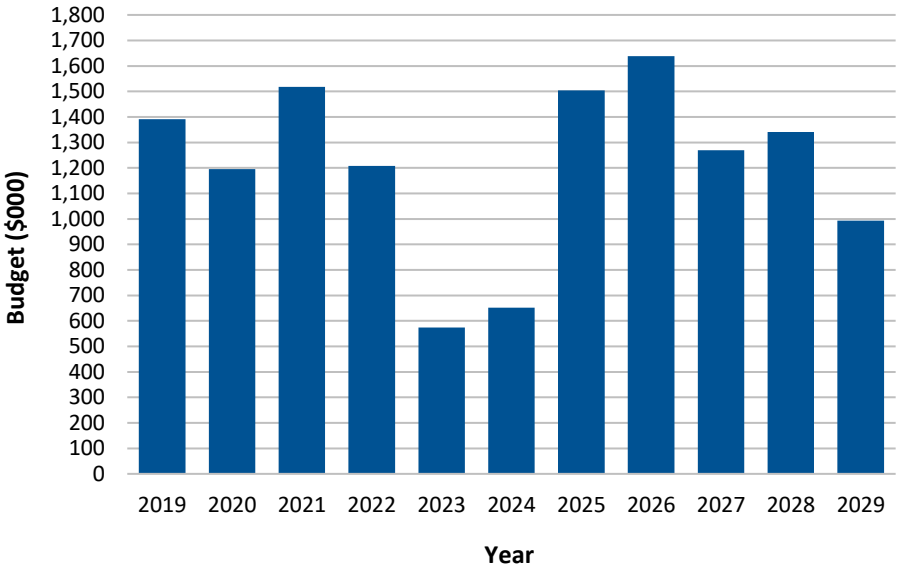


Chart 4: Historical and Forecast Program Budget[7]

6.2 Program Schedule

The schedule for this program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Initial planning and scheduling.	January 2025	February 2025
Design:		
Conduct site visits and complete detailed design.	March 2025	April 2025
Procurement:		
Order disconnects and miscellaneous materials.	May 2025	December 2025
Construction:		
Replace disconnect switches.	May 2026	September 2026
Commissioning:		
Commission disconnect switches.	May 2026	September 2026
Closeout:		
Complete closeout documentation.	November 2026	December 2026

[7] As noted in Section 4.2, average unit prices can vary, and as such, annual expenditures do not necessarily directly correspond with the number of replaced units. The units planned to be replaced in 2024 are made up of a higher proportion of units that cost less on average. Please refer to footnote 5 for more information on 2023 budgetary expenditures.

7.0 Conclusion

Under the Replace Disconnects 2025–2026 Program, 12 disconnect switches require replacement, as they meet the applicable replacement criteria. Only one 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 11 disconnect switches meet the age criterion, with 10 of those also having no replacement parts available due to obsolescence.

Appendix A

Replace Disconnects Program

2025–2029 Plan





Assets planned for replacement from 2025 to 2029 under the Replace Disconnects Program are provided in Table A-1 to Table A-5.

Table A-1: Assets Planned for Replacement in 2025

Name	Voltage (kV)
Holyrood B12L68-1	230
Massey Drive B5L11-1	230
Massey Drive B5L11-2/L11G	230
South Brook L22T1-1	138
Stony Brook L05L31-1	230
Stony Brook L05L31-2	230
Stony Brook L05L35-1/L05G	230
Stony Brook L05L35-2/L35G	230
Sunnyside B1L03-1	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-2: Assets Planned for Replacement in 2026

Name	Voltage (kV)
Doyles B1L15-1	69
Hardwoods B2T3	230
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 B1T3/T3G	230
Wabush Terminal Station B4L34-1	69

Table A-3: Assets Planned for Replacement in 2027

Name	Voltage (kV)
Doyles B1T1-1	69
Doyles L14AG	138
Doyles L14T1/L14G	138
Happy Valley B13L03-1	138
Happy Valley B13L03-2	138
Holyrood B15T6	230
Holyrood B8T6	138
Holyrood B8T8	138
Massey Drive B1T1	230
Stony Brook B1L31-1	230
Stony Brook B1L31-2/L31G	230
Stony Brook B1L35-1	230
Sunnyside L02L07-2	230

Table A-4: Assets Planned for Replacement in 2028

Name	Voltage (kV)
Bay d'Espoir TS1 B1B10-1	230
Bay d'Espoir TS1 B2B3-1	230
Bay d'Espoir TS1 B4B5-2	230
Bay d'Espoir TS1 B5L04/L04G	230
Holyrood B15T7	230
Holyrood B8T7	138
Massey Drive B1L48-1	230
Massey Drive B1L48-2/L48G	230
Sunnyside B2B3	138
Sunnyside B3L19-1	138
Wabush Terminal Station B1L24-1	230
Western Avalon L01L03-1/L01G	230
Western Avalon L01L03-2/L03G	230

Table A-5: Assets Planned for Replacement in 2029

Name	Voltage (kV)
Bottom Brook TS1 L400G	69
Bottom Brook TS1 L400T2-1	69
Grand Falls Frequency Converter L35AG	230
Holyrood B7L2-1	69
Holyrood B7L2-2/L2G	69
Indian River B1L363-BP	138
Massey Drive B3L357-1	69
Massey Drive B3L351-1	69
Oxen Pond B2SSVT1	69
South Brook L22-1/L22G-1	138
Stony Brook B2T2	230
Sunnyside B3L19-2/L19G	138

Renew Circuit Breakers

2025–2026

newfoundland labrador hydro

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Appendix A: Renew Circuit Breakers Program – 2025–2029 Plan

Renew Circuit Breakers (2025–2026)

Location: Various

Investment Classification: Renewal

Asset Category: Terminal Stations

Cost: $1,151,400

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 Newfoundland and Labrador Hydro's ("Hydro") established plan for the replacement of circuit breakers, SF_6 circuit breakers will be refurbished after approximately 20 years of service and be considered for replacement at or near 40 years. Hydro's long-term plan for circuit breakers is as follows:

- 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*[1] *Regulations*, bulk-oil circuit breakers will not be refurbished and are scheduled for replacement before December 31, 2025.[2] 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

[1] Polychlorinated biphenyls ("PCB").
[2] All of the bulk-oil circuit breakers that are mandated for removal by 2025 as per the *Canadian Environmental Protection Act, 1999,* SC 1999, c 33*, PCB Regulations* (SOR/2008-273) will be completed by the end of 2025. The last of the affected breakers were approved for replacement as part of the 2024 Capital Budget Application ("CBA").

the condition and operational history of the circuit breaker. For 2025-2026, Hydro is proposing the refurbishment or replacement of six 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 are an older technology; therefore, replacements will be completed after 40 years. However, as oil circuit breakers come due, a further condition assessment will be completed to determine if life extension can be achieved through refurbishment. Two of the circuit breakers included in the program scope of the 2025 CBA are minimum oil circuit breakers that are not subject to *PCB Regulations*.

As of the end of 2023, Hydro has 210 SF_6 circuit breakers, and 14 oil circuit breakers[3] in its 46 kV and above circuit breaker fleet. Within the circuit breaker fleet, Hydro has 38 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.[4] The probability of circuit breaker failure increases with age.

[3] Of the 14 oil circuit breakers, 8 were not subject to replacement due to PCB contamination.
[4] Expected useful life is estimated to be 40 years.

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%

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. Some breakers within Asset Condition Category 1 are being planned for replacement in the next five years due to the age and availability of replacement parts. Chart 1 presents the asset condition categories for breakers with an age of 35 years or greater. All five of those with Condition 3 or 4 that are not planned for either refurbishment or replacement by 2029 are planned for either refurbishment or replacement in 2030 (which is their earliest year of eligibility, where eligibility is determined via the circuit breaker refurbishment/replacement criteria stated in Hydro's Terminal Station Asset Management Strategy.[5]

[5] Provided as Appendix F to Schedule 1 of this application.

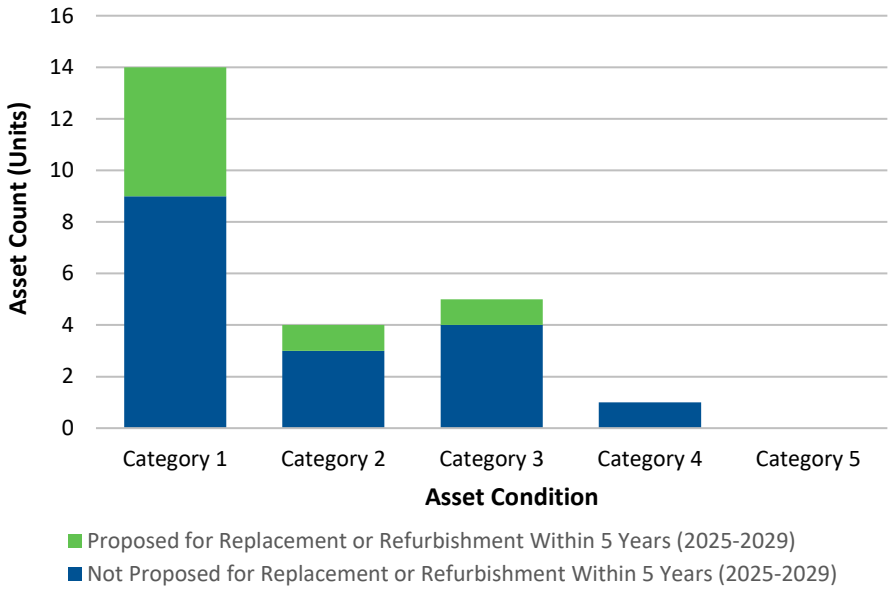


Chart 1: Asset Condition

Two of the breakers in this iteration of the program included in Chart 1 are less than 35 years old (as of 2024) but are included in this chart to indicate their condition. One breaker has an Asset Condition of 1, and the other has an Asset Condition of 2.

3.3 Asset Ages

The age of the circuit breakers proposed for replacement or refurbishment as of 2024 is provided in Chart 2. One breaker is being replaced and five breakers are being refurbished as part of the 2025–2026 program. The breaker being replaced is 52 years old. Three of the breakers being refurbished are between 40 and 45 years old, with another two due for their 20-year refurbishment by 2026.

Chart 2 provides the asset age for all assets covered under the 2025 program.

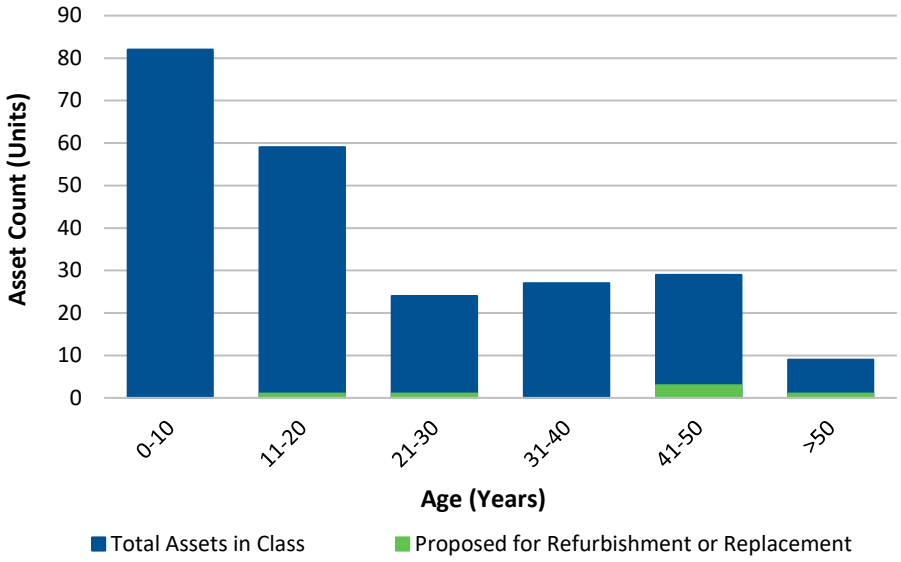


Chart 2: Asset Counts by Asset Age

4.0 Trending

4.1 Assets Installed/Replaced/Upgraded

Under this program, breakers are refurbished or replaced based on age and condition. Chart 3 provides the historical, current, and forecast assets to be replaced or refurbished, respectively.

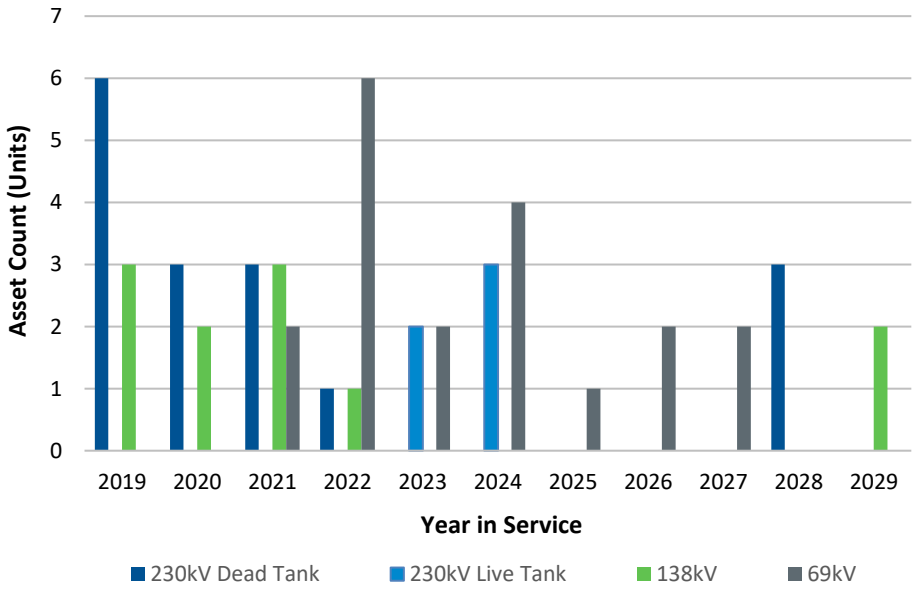


Chart 3: Historical and Forecast Number of Assets Replaced

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 breakers that were replaced between 2015 and 2023. The number of 69 kV breaker replacements peaked in 2022 and will continue to decrease into the future, as Hydro removes oil circuit breakers due to their older technology and to maintain compliance with federal environmental legislation.[6]

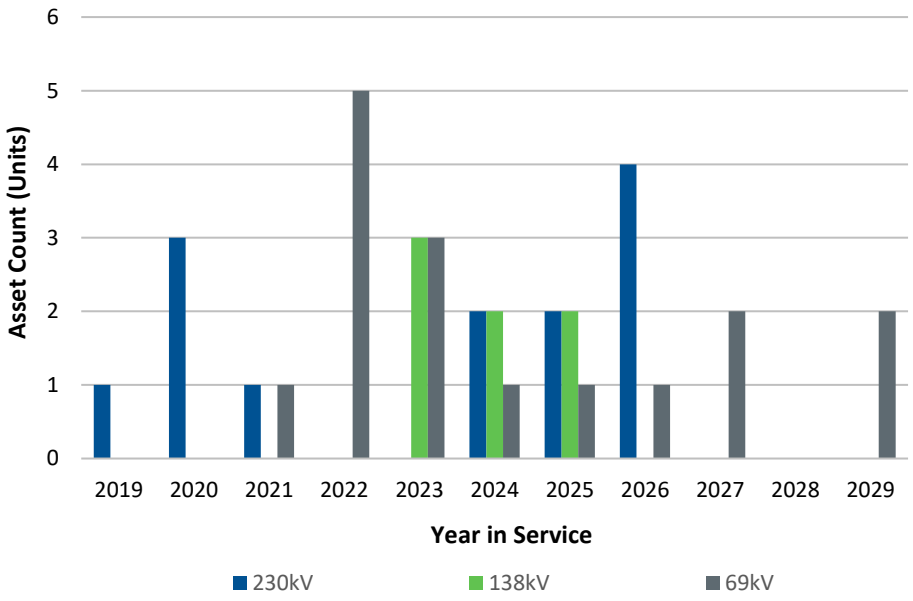


Chart 4: Historical and Forecast Number of Assets Refurbished

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; and, also at approximately 40 years of age if their condition is satisfactory to not warrant replacement at that time.

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 overall costs vary significantly by breaker voltage class, as shown in Chart 5. The 230 kV live tank breaker

[6] Following the removal of oil circuit breakers to comply with Federal *PCB Regulations*, there will be eight non-PCB contaminated oil-filled circuit breakers that remain on the system. Of these eight, one will be replaced in 2026 as part of the proposed program scope outlined in this report, and another will be refurbished. The remaining oil-filled circuit breakers will be replaced once they have reached the end of their useful service life and are not able to be refurbished.

1 replacement costs have been lower than average as they generally exclude any cable replacements or
2 protection upgrades.

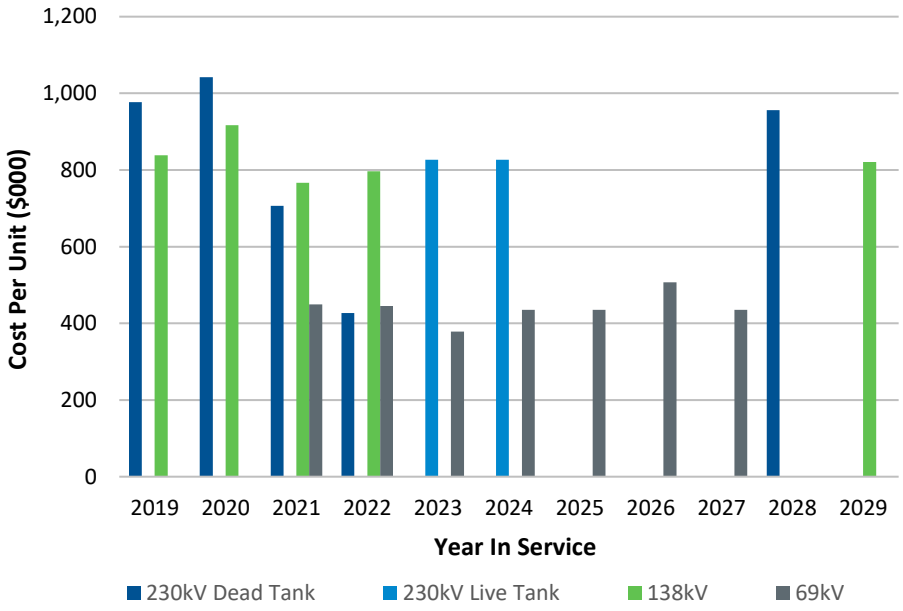


Chart 5: Historical and Forecast Average Unit Costs of Assets Replaced

3 The breaker refurbishment costs vary between breaker type and manufacturer; as such, unit costs per
4 year can show variability depending on the types of breakers refurbished.

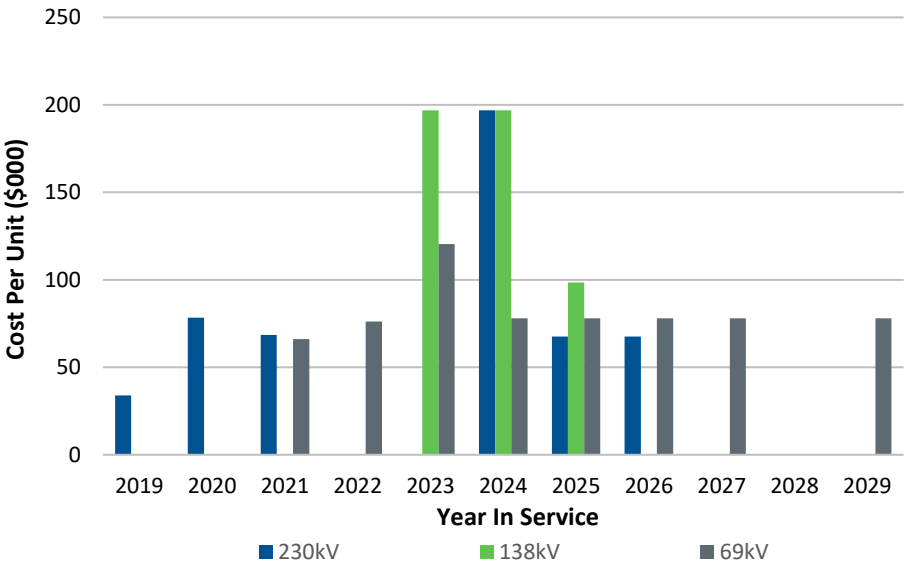


Chart 6: Historical and Forecast Average Unit Costs of Assets Refurbished

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.

4.3 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 2019 to 2023**

Start Date	Breaker	Outage Duration (minutes)
30-Sep-2023	Voisey's Bay Nickel B1T1	1,789
21-Dec-2022	St. Anthony B1C3	731
10-Dec-2022	St. Anthony B1C3	817
21-Oct-2022	Cow HeadB1L27	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

5.0 Analysis

5.1 Evaluation of Alternatives

The following alternatives were considered:

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

5.1.1 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. 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 sixteen 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.

5.1.2 Pace Advancement

Hydro has not identified any pace advancement options for this program.

5.1.3 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.

5.2 Least-Cost Evaluation

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

5.3 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.

5.3.1 Risk of Asset Stranding

With ongoing considerations related to load growth in Labrador, there is a risk that the Wabush Terminal Station breakers scheduled for replacement may not be required for the full extent of their useful life. 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.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025–2026 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 3.

Table 3: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	5	3	**15**
Post-Implementation	5	1	**5**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**8.7**

6.0 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 one circuit breaker and refurbish five circuit breakers under this program, with completion scheduled by the end of 2026. 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.

6.1 Program Budget

The estimate for the 2025–2026 program is shown in Table 4.

Table 4: Program Estimate ($000)[7]

Program Cost	2025	2026	Beyond	Total
Material Supply	0.0	182.5	0.0	**182.5**
Labour	112.4	371.1	0.0	**483.5**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	332.0	0.0	**332.0**
Other Direct Costs	7.1	33.5	0.0	**40.6**
Interest and Escalation	4.2	56.7	0.0	**61.0**
Contingency	6.0	46.0	0.0	**51.9**
Total	**129.7**	**1,021.7**	**0.0**	**1,151.4**

Chart 7 provides the five-year historical expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast costs through 2029. As shown in Chart 7, the number of circuit breakers being proposed for replacement in a given year has been decreasing since 2019[8] 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 and life extension of SF_6 breakers as a result of their refurbishment.

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.

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.

[7] Numbers may not add due to rounding.
[8] Total expenditures in 2018 are higher than average due to a larger number of refurbishments and replacements completed in that year.

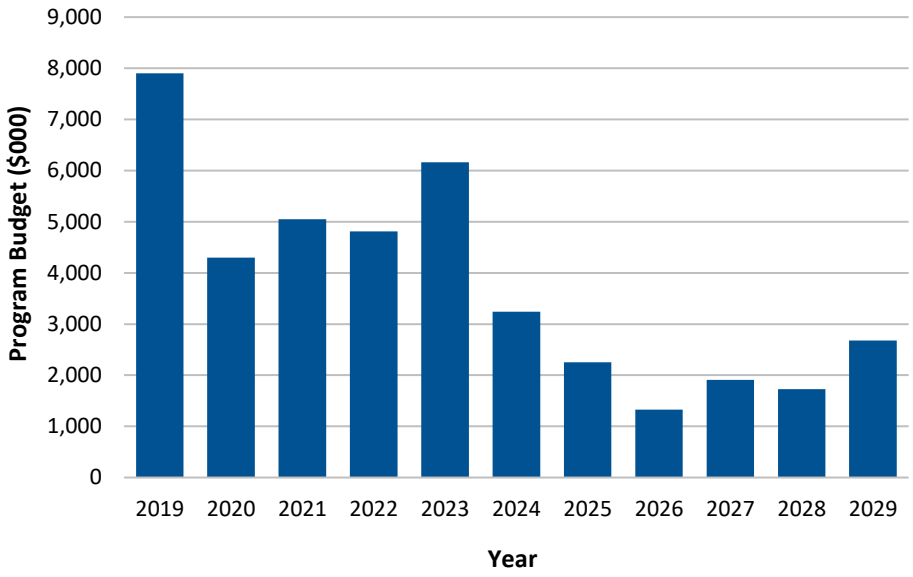


Chart 7: Historical and Forecast Program Budget

6.2 Program Schedule

The schedule for this program is shown in Table 5.

Table 5: Program Schedule

Activity	Start Date	End Date
Planning:		
Initial planning and scheduling.	January 2025	February 2025
Procurement:		
Order breakers and long lead items.	May 2025	June 2026
Detailed Design:		
Conduct site visits.	October 2025	November 2025
Complete detailed design.	November 2025	March 2026
Procurement:		
Tender and award contract(s).	March 2026	May 2026
Construction/Commissioning:		
Breaker replacements and refurbishments.	June 2026	November 2026
Closeout:		
Complete closeout documentation.	November 2026	December 2026

7.0 Conclusion

This proposal is seeking approval for the refurbishment and replacement of six circuit breakers by the end of 2026. The refurbishment and replacement of the identified circuit breakers are required to ensure a safe and reliable power system.

Appendix A

Renew Circuit Breakers Program

2025–2029 Plan





Assets planned for replacement or refurbishment from 2025 to 2029 under the Renew Circuit Breakers program are provided in Table A-1 to Table A-5.

Table A-1: 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
Wabush Terminal Station B3B4	69	Replacement

Table A-2: Assets Planned for Replacement or Refurbishment in 2026

Name	Voltage (kV)	Activity
Buchans B2L64	69	Refurbishment
Stephenville B1L09	230	Refurbishment
Upper Salmon L34L63	230	Refurbishment
Wabush Terminal Station B4L34	69	Replacement
Western Avalon B1T1	230	Refurbishment
Western Avalon B1T2	230	Refurbishment

Table A-3: Assets Planned for Replacement or Refurbishment in 2027

Name	Voltage (kV)	Activity
Hardwoods B7C1	69	Refurbishment
Oxen Pond B2T2	69	Refurbishment
Wabush Terminal Station B4L35	46	Replacement
Wabush Terminal Station B4L6	46	Replacement

Table A-4: Assets Planned for Replacement or Refurbishment in 2028

Name	Voltage (kV)	Activity
Bay d' Espoir B9L34	230	Replacement
Hardwoods B2L42	230	Replacement
Holyrood B13B15	230	Replacement

Table A-5: Assets Planned for Replacement or Refurbishment in 2029

Name	Voltage (kV)	Activity
Bottom Brook L14L50	138	Replacement
Bottom Waters L60T1	138	Replacement
Howley L51T2	69	Refurbishment
Wabush B4SS2	46	Refurbishment

Overhaul Major Pumps

2025

Holyrood



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Overhaul Major Pumps (2025)

Location: Holyrood

Investment Classification: Renewal

Asset Category: Thermal Plant

Cost: $1,101,851

1.0 Introduction

The Holyrood Thermal Generating Station ("Holyrood TGS") is a critical part of the Island Interconnected System and is required to provide safe and reliable electricity. It has three generating units: Units 1, 2, and 3 with a total generation capacity of 490 MW.

This program encompasses the completion of a detailed inspection and overhaul of major pumps at the Holyrood TGS. The pumps proposed for this scope of work in 2025 is refurbishment of the Unit 3 west boiler feed ("BF") pump and replacement of the Unit 3 north vacuum pump. They are due for overhaul based on the average interval recommended by the original equipment manufacturer ("OEM"); in Newfoundland and Labrador Hydro's ("Hydro") experience with these assets, this period has proven to be an appropriate time frame that balances the cost investment required. Failure to complete this work would increase the likelihood of in-service failure of the pumps during the 2025–2026 winter operating season, increasing the risk of derating or forced outage of Unit 3.

As per the "Reliability and Resource Adequacy Study – 2022 Update,"[1] 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 is proven, and generation reserves are met. Therefore, Hydro believes it is prudent to continue this program in 2025.

Capital investment related to the generation function of the Holyrood TGS, such as the overhaul of the major pumps, is necessary to support system reliability and maintain Hydro's ability to meet customer demand through the Bridging Period until the capacity of Holyrood TGS can be adequately replaced.

[1] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.

2.0 Program Description and Justification

This program involves the completion of inspections and associated refurbishments and replacements for the overhaul of major pumps. There are 24 major pumps, within three generating units, that are included in this program:

- Two BF pumps (east and west) per generating unit;
- Two cooling water pumps (east and west) per generating unit;
- Two vacuum pumps (north and south) per generating unit; and
- Two condensate extraction pumps (north and south) per generating unit.

All of these pumps are overhauled on an average interval of 12 years, except for the BF pumps which are typically overhauled on a six-year cycle, depending on the condition of the pump's internal components. The overhaul interval is based on OEM recommendations, industry standards, and Hydro's operational experience. Completing these overhauls will contribute to continued safe and reliable operation at the Holyrood TGS through a reduction in unplanned or forced outages, and deratings. Should a unit be required to run without its full complement of each type of pump, it cannot be run at full generating capacity.

The program scope for 2025 involves the overhaul of two of the 24 major pumps, including the Unit 3 west BF pump and Unit 3 north vacuum pump.[2] The Unit 3 west BF pump was last overhauled in 2020; it was recommended in the LECA capital plan to overhaul the Unit 3 west BF pump in 2025.

Despite continued maintenance and refurbishment of the Unit 3 vacuum pumps, reliability and operational issues have occurred due to their age and deterioration. In 2021, due to poor performance and reliability concerns, both Unit 3 vacuum pumps underwent major overhaul which involved work on various components such as the port plate, bearings, pump rotor, and shaft sleeves. Both overhauled pumps were returned to service in the fall of 2021; however, performance issues persisted, including high vibration. Because the vibration was elevated and continuous for the south pump in operation, it was judged to be a sign of increased deterioration of the port, indicating an unacceptable risk of failure.

[2] Based on Hydro's average overhaul interval, the Unit 3 west BF pump is not due for overhaul until 2026; however, Hydro decided to advance the pace of the overhaul on this pump by one year to align with the recommendation in the Life Extension Condition Assessment ("LECA") capital plan prepared by Hatch Limited ("Hatch") in 2021.

This pump was subsequently replaced during the 2023 Unit 3 shutdown under the Thermal In-Service Failure Program. Considering that the Unit 3 north vacuum pump is identical to the Unit 3 south vacuum pump and was subjected to similar operating conditions, Hydro is proposing to replace the Unit 3 north vacuum pump in 2025.

The 2025 program will ensure continued reliable operation of the Unit 3 west BF pump and Unit 3 north vacuum pump through a reduction in their in-service failures and, therefore, a reduction in forced outages or deratings of Unit 3.

3.0 Asset Overview

3.1 Asset Background

The Holyrood TGS Unit 3 west BF pump, as shown in Figure 1, was originally installed in 1979. Both the east and west BF pumps, which are identical, provide 50% of the high-pressure feedwater required for steam production in the Unit 3 boiler.

Each of the Unit 3 BF pumps contains 11 stages of impellers and is powered by a 3,000-horsepower motor capable of pumping 4,119 litres per minute at a pressure of 18,616 kPa. The two BF pumps receive water from the deaerator tank and deliver it to high-pressure heaters and then to the boiler. Each pump can individually support 70–80 MW of generation, and when operating together, they can support the total generation capability of Unit 3 (150 MW).

BF pumps are subjected to high temperatures, high pressure, and high flow velocity; all of which contribute to significant degradation of the equipment. If an overhaul is not completed, the pump could fail during operation. Such failure would lead to reduction of 70–80 MW of generating capacity from Unit 3 for several weeks. An overhaul is necessary to maintain Hydro's safety and reliability standards, including Hydro's ability to meet customer demand during peak periods.

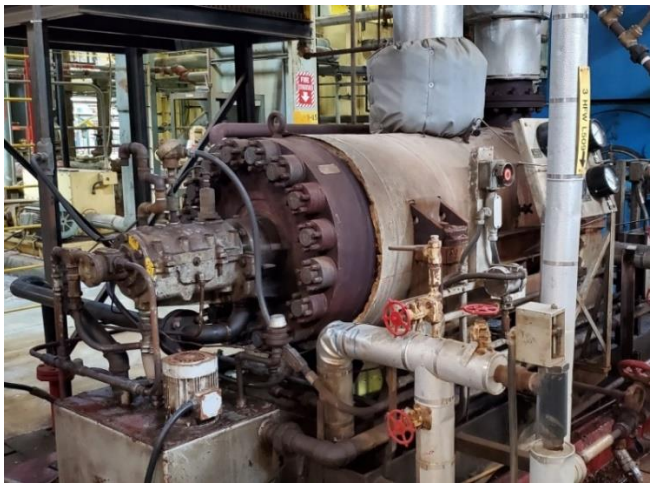


Figure 1: BF Pump

The Unit 3 north vacuum pump, as shown in Figure 2, is one of two pumps on Unit 3 that is connected to the condenser, a large seawater-cooled heat exchanger used to cool and condense steam leaving the low-pressure turbine. The vacuum pump draws incondensable gasses from the condenser, causing a vacuum and reduction of the back pressure on the low pressure turbine, required for the turbine operation. If the back pressure increases, this causes a forced derating or outage to the generating unit. Under ideal conditions, Unit 3 can reach full load with a single vacuum pump running, with the second on standby as a backup; however, due to ongoing condenser fouling issues throughout the operating season, two vacuum pumps may be required for the generating unit to achieve full load for the 2025–2026 winter season.

Originally, the Unit 3 north and south vacuum pumps were installed when Unit 3 was installed in 1979. In 2021, due to poor performance and reliability concerns, both Unit 3 vacuum pumps underwent major overhaul which involved work on various components such as the port plate, bearings, pump rotor, and shaft sleeves. Both overhauled pumps were returned to service in the fall of 2021. However, performance issues persisted, including high vibration. The elevated and continuous vibration experienced by the south vacuum pump while in operation indicated increased deterioration of the port, posing an unacceptable risk of failure. The Unit 3 south vacuum pump was subsequently replaced during the outage to Unit 3 in 2023 under the Thermal In-Service Failure Program. As the Unit 3 north vacuum pump is identical to the original Unit 3 south vacuum pump and was subjected to similar operating conditions, the original Unit 3 north vacuum pump is proposed for replacement under this program in 2025 to mitigate the likelihood of pump failure.

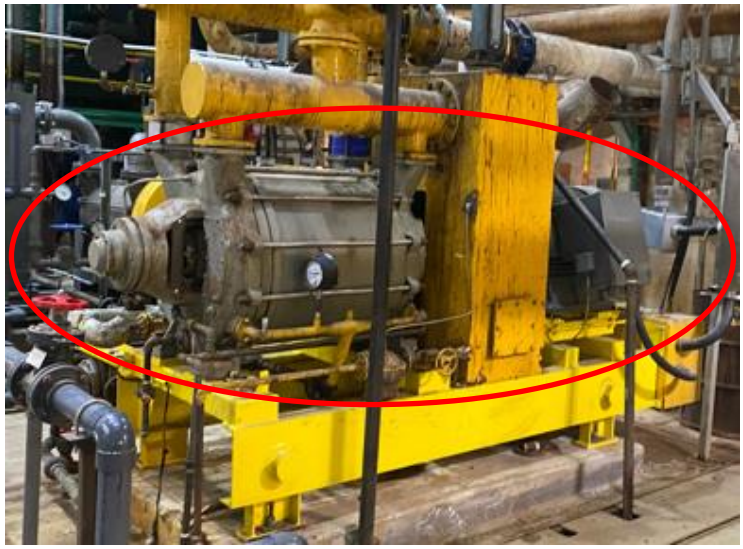


Figure 2: Vacuum Pump

3.2 Asset Ages

This program covers eight major pumps for the three generating units (Units 1, 2, and 3). The pumps for Units 1 and 2 were installed in 1970, and the pump for Unit 3 were installed in 1979. Chart 1 shows the age and count of these assets.

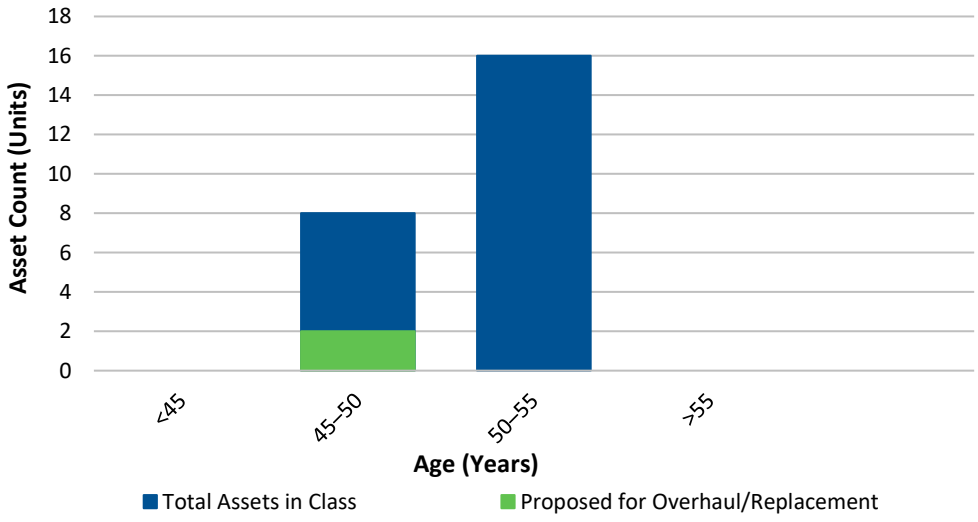


Chart 1: Asset Counts by Asset Age[3]

[3] The pumps identified for overhaul in this program are selected based on standard time intervals and operational condition. Age would not typically be a determinant of the need for an overhaul in this program; however, would be a normal component of the criteria to determine replacement of pumps. None of the units in the 50–55 year age are scheduled for overhaul.

4.0 Trending

4.1 Assets Installed/Replaced/Upgraded

Chart 2 provides the five-year historical, current, and five-year forecast number of assets overhauled per year.[4]

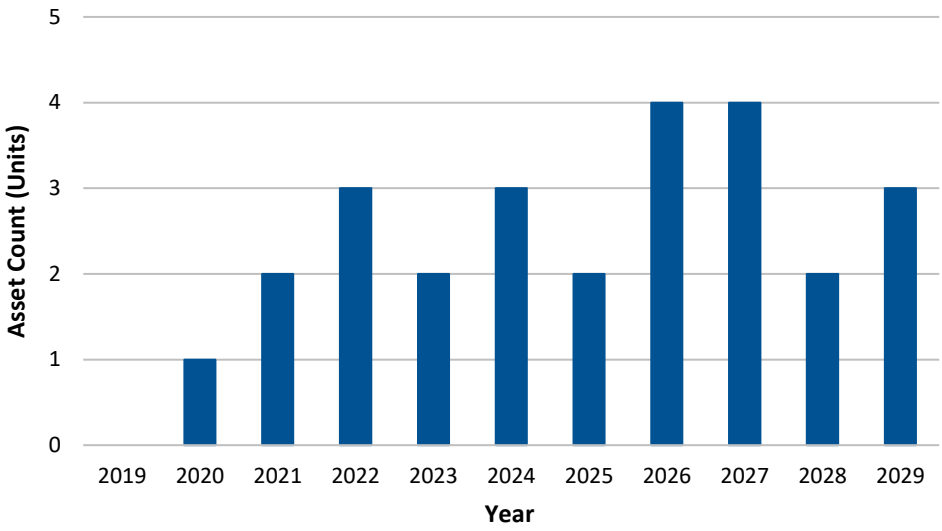


Chart 2: Historical and Forecast Number of Assets Overhauled/Replaced

[4] 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 the operating regime.

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 overhauls in each year.[5]

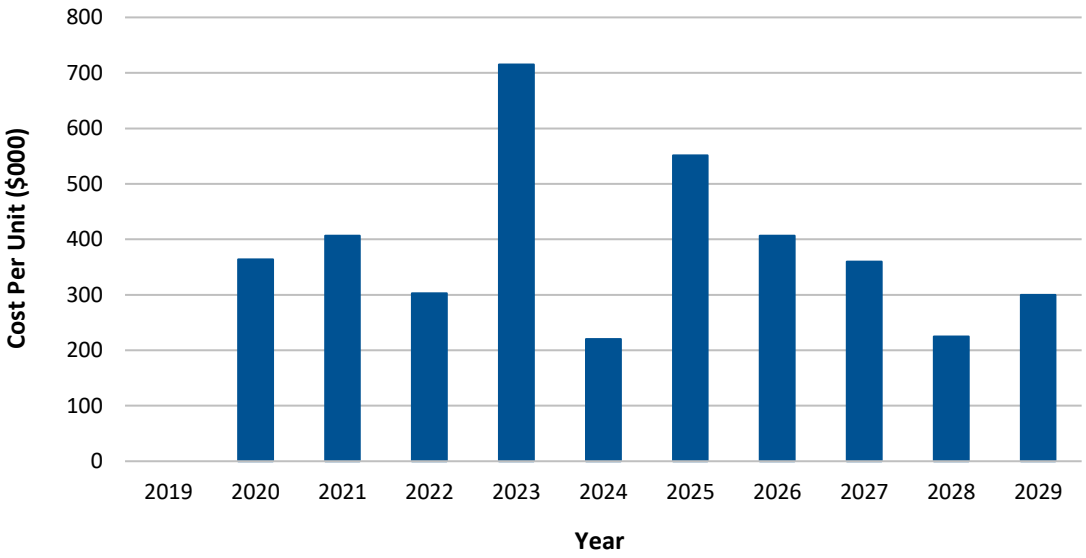


Chart 3: Historical and Forecast Average Unit Costs of Assets Overhauled/Replaced

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro evaluated the following alternatives:

- Pace reduction;
- Pace advancement;
- Condition-based refurbishment;
- Continuation of overhaul program; and
- Alternative strategies.

[5] Each year of the Overhaul Major Pumps Program requires the overhaul of varying major pumps; as such, the cost of the program varies each year. For example, the planned overhaul in 2028 will not include a BF pump, which is expensive to complete; as such, the cost in 2028 is lower than other years of the program.

5.1.1 Pace Reduction

A pace reduction of this program increases the failure risk of major pumps while in operation, which could result in a forced outage or derating for several weeks. Data obtained through preventive maintenance activities is not sufficient for Hydro to make an accurate prediction regarding the likelihood of failure in advance of the next planned overhaul.

Parts are not readily available for these pumps due to their age. In the event of failure, reverse engineering and/or fabrication of required parts may be required, which would significantly extend the overhaul schedule time. In addition, the pumps are large, possibly requiring disassembly and shipping offsite for refurbishment. Completing the overhauls on a planned outage, with a scheduled timeslot in a pump service facility, is the prudent approach as an unplanned forced outage has the potential for an extended forced derating of 50% of the unit generating capacity, lasting up to several months. Further, in-service failure of a major pump may cause additional damage to pump components, potentially resulting in additional repair costs and loss of production when compared to the cost of a planned overhaul.

5.1.2 Pace Advancement

Hydro's historical experience with this program had not previously demonstrated a need to accelerate the major pumps overhaul. Hydro typically performs BF overhauls on a six-year cycle, as described in Section 2.0. To determine the exact time interval between overhauls, Hydro considers several factors including, but not limited to asset condition, reliability and criticality, frequency of operation, OEM recommendations, industry standards, and Hydro's operational experience. Hydro decided to advance the pace of the overhaul on the Unit 3 west BF pump by one year to align with the recommendation in the LECA capital plan.

5.1.3 Condition-Based Refurbishment

Hydro collects some condition-related data from installed instrumentation while the pumps are in service. Additional data is collected through measurements and testing performed during annual preventive maintenance. To date, the data collected through each of these means has not proven to be adequately comprehensive to inform an accurate prediction as to whether the unit can operate reliably through to the next planned overhaul. Hydro has determined that, due to the limited information available, the condition of the major pumps cannot be adequately determined through external inspection or monitoring instrumentation to ensure the continued reliability of the major pumps. To

assess the condition of internal components, disassembly of the major pumps is required. As such, condition-based refurbishment of major pumps is not a viable option.

5.1.4 Continuation of Overhaul Program

This alternative consists of planned disassembly, detailed internal inspection, refurbishment or replacement as required, and reassembly of internal components of the major pumps. 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.

5.1.5 Alternative Strategies

Hydro maintains spares in its inventory for major pump components. This reduces downtime in the event of the in-service failure of major pumps; however, time will still be required for the disassembly, installation, and reassembly of pumps should an in-service failure occur. This strategy also increases the availability of major pumps to contribute to the reliable operation of the generating units; however, it is not an alternative to the planned overhaul as per the established intervals.

5.2 Least-Cost Evaluation

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

5.3 Recommended Alternative

Hydro recommends the continuation of the Major Pumps Overhaul Program in 2025. The program in 2025 includes the advanced pace of the overhaul of the Unit 3 west BF pump by one year to align with the recommendation provided by Hatch in the LECA, and the replacement of the Unit 3 north vacuum pump. Overhaul of the Unit 3 vacuum pump is not a viable option. Based on the age of the unit, this pump is obsolete and parts are not available to complete the overhaul. Overhauling the major pumps in accordance with Hydro's practice and the OEM recommendations will mitigate the risk of failure of a major pump and subsequent loss of generation capacity, contributing to the continued safe and reliable operation of the Holyrood TGS.

Continuing to operate beyond 2025 without completing an overhaul of the Unit 3 BF Pump and replacement of the Unit 3 vacuum pump would constitute an unacceptable risk to reliable operation. If the pumps are not overhauled, there is an elevated risk of not functioning as designed. Many

components of these major pumps can erode, crack, or otherwise fail, leading to poor pump performance or sudden failure, which may result in collateral damage to the pump and thus require additional repairs and associated costs. Therefore, the overhaul of the Unit 3 west BF pump and replacement of the Unit 3 north vacuum pump are required to support the continued reliable operation of the Holyrood TGS.

5.3.1 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]

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	4	4	**16**
Post-Implementation	4	1	**4**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**10.9**

[6] Due to the extension of the Holyrood TGS through the Bridging Period, Hydro filed an application with the Board of Commissioners of Public Utilities ("Board") to extend the Holyrood Accelerated Depreciation Deferral Account. The Board approved the extension of the account and related amendments in Board Order No. P.U. 1(2024). Hydro also was directed to file a report on the account in its next general rate application.

6.0 Scope of Work

The scope of work involves the following:

- Disassembly, inspection, refurbishment, and replacement of parts (as required), reassembly, and commissioning of the Unit 3 west BF pump; and
- Replacement of the original Unit 3 north vacuum pump skid, including motor and all required components such as valves, discharge separator tank, liquid cooler, instrumentation, and control devices.

For the Unit 3 west BF pump, disassembly and reassembly will be executed by internal resources. An experienced pump service contractor will be engaged to perform a condition assessment of the pumps, provide onsite technical support for the disassembly and reassembly, and complete the offsite overhaul of the BF pump. During the overhaul, the volute impeller cartridge for the Unit 3 west BF pump will be replaced with a refurbished cartridge from Hydro's spares inventory. The volute impeller cartridge, which is removed from the Unit 3 west BF pump, will then be refurbished and returned to inventory as a critical spare to support the two identical Unit 3 BF pumps prior to the next winter operating season. Figure 3 shows the volute impeller cartridge.



Figure 3: BF Pump Volute Impeller Cartridge During Removal Process

A new vacuum pump will be purchased to replace the original Unit 3 north vacuum pump. The removal of the existing pump and installation of the new pump will be completed by internal resources with technical support from a pump service contractor.

6.1 Program Budget

The estimate for the 2025 program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	10.0	0.0	0.0	**10.0**
Labour	241.2	0.0	0.0	**241.2**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	725.0	0.0	0.0	**725.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	28.1	0.0	0.0	**28.1**
Contingency	97.6	0.0	0.0	**97.6**
Total	**1,101.9**	**0.0**	**0.0**	**1,101.9**

Chart 4 shows the five-year historical expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast costs through 2029.[7] As overhauls are completed for varying quantities and/or types of pumps each year, there is a variation in the program historical and future forecast expenditures.

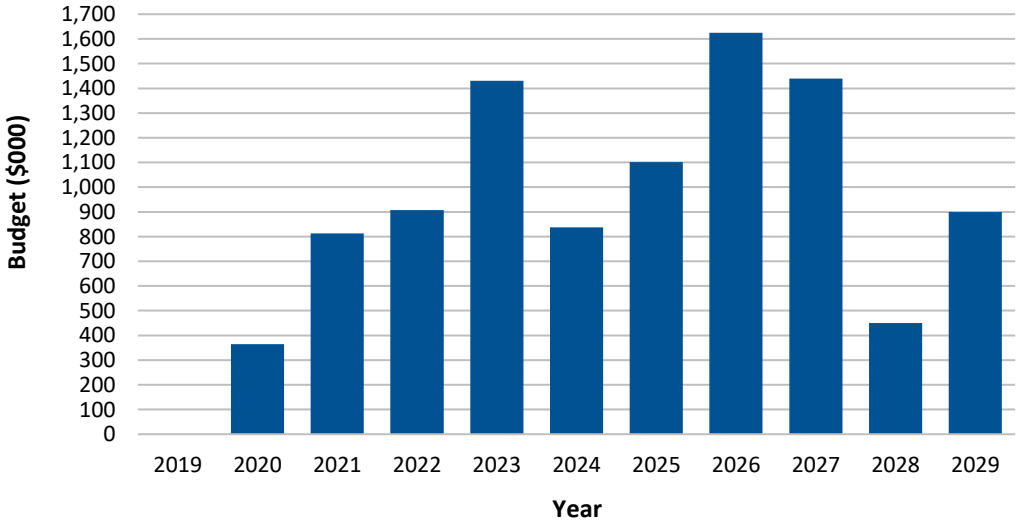


Chart 4: Historical and Forecast Program Budget

[7] *Supra,* f.n. 4.

6.2 Program Schedule

The overhaul and replacement work is planned to take place during the planned Unit 3 outage. The schedule for this program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Preparation of planned documentation.	January 2025	February 2025
Design:		
Prepare technical specifications.	February 2025	March 2025
Procurement:		
Award BF pump overhaul and vacuum pump replacement contracts.	April 2025	May 2025
Procure vacuum pump.	March 2025	August 2025
Construction:		
Disassemble, inspect, refurbish, and reassemble the BF pump using a spare volute impeller cartridge.	May 2025	August 2025
Refurbish the BF pump volute impeller cartridge at the contractor's facility.	June 2025	October 2025
Replace vacuum pump.	August 2025	September 2025
Closeout:		
Prepare closeout documentation.	October 2025	December 2025

7.0 Conclusion

To support the continued safe and reliable operation of the Holyrood TGS, Hydro proposes to overhaul the Unit 3 west BF pump and replace the original Unit 3 north vacuum pump in 2025. The 2025 program is required to maintain the acceptable operating condition of the pumps, which contributes to the reliable operation and availability of Unit 3 at full generation capacity.

Program 20

Overhaul Diesel Units

2025

newfoundland labrador hydro



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Overhaul Diesel Units (2025)

Location: Various

Investment Classification: Renewal

Asset Category: Generation

Cost: $1,000,010

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") has 23 diesel generating stations, serving between 4,400 – 4,500 customers. Of these stations, 19 are isolated and the sole source of power to a community. The number of diesel generation units ("genset") 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 53 years and currently range in operating hours from 75 hours to over 110,661 hours.[1]

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 2025. 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. To defer or skip an overhaul would increase the risk of an engine or generator failure, resulting in reduced reliability of the generating station and increasing the likelihood of customer outages. Hydro is proposing to overhaul six diesel units in 2025.

[1] As of December 31, 2023.

3.0 Asset Overview

3.1 Asset Background

A diesel genset is the combination of a diesel engine with an electric alternator,[2] used to generate electrical energy as shown in Figure 1.

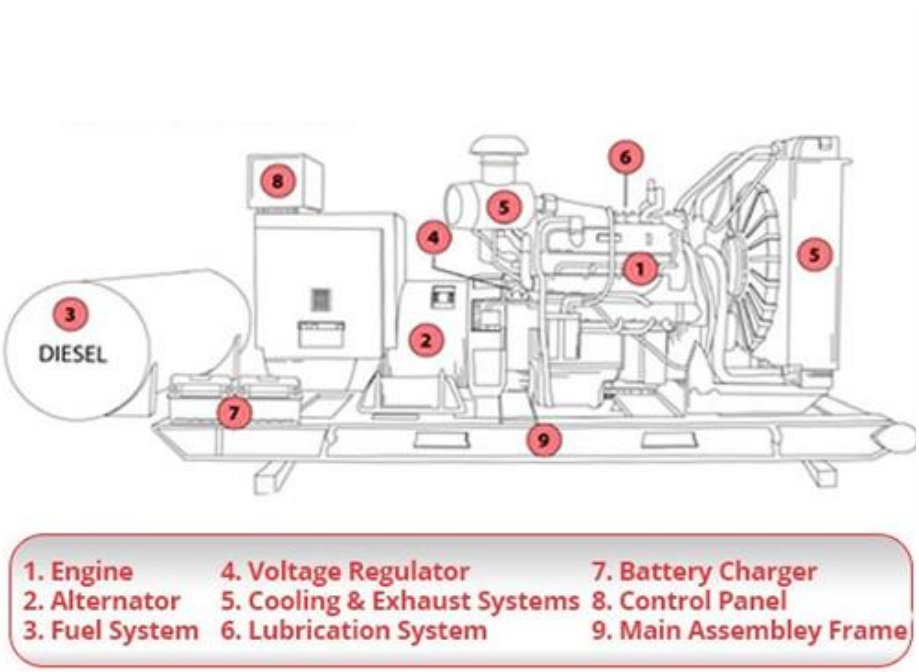


Figure 1: Diesel Genset

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.

[2] An alternator is an electric generator that converts mechanical energy to electrical energy in the form of alternating current.

3.2 Asset Ages

Diesel units across Hydro's system range in age from less than 1 year to 53 years and currently range in operating hours from 75 hours to over 110,661 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.

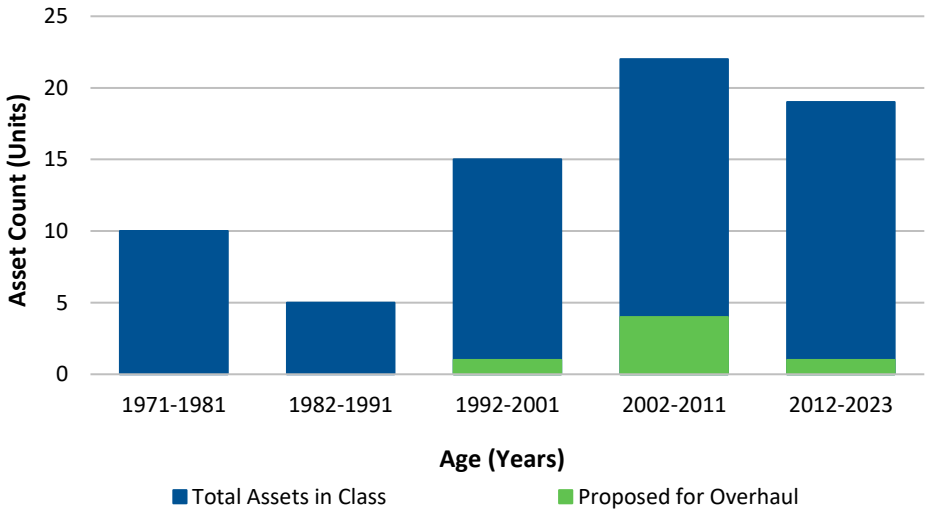


Chart 1: Asset Counts by Asset Age[3]

[3] Diesel Unit overhauls occur based on hours of service, while no assets in the two oldest asset categories are included in this year's program scopes, they have received more recent overhauls as part of this program.

4.0 Trending

Hydro's Overhaul Diesel Units Program was implemented in 2012. During the most recent five-year interval from 2019 to 2023, 45 units were overhauled, an average of nine units per year.

4.1 Assets Overhauled

Chart 2 provides the five-year historical, current, and the five-year forecast number of diesel units overhauled per year.

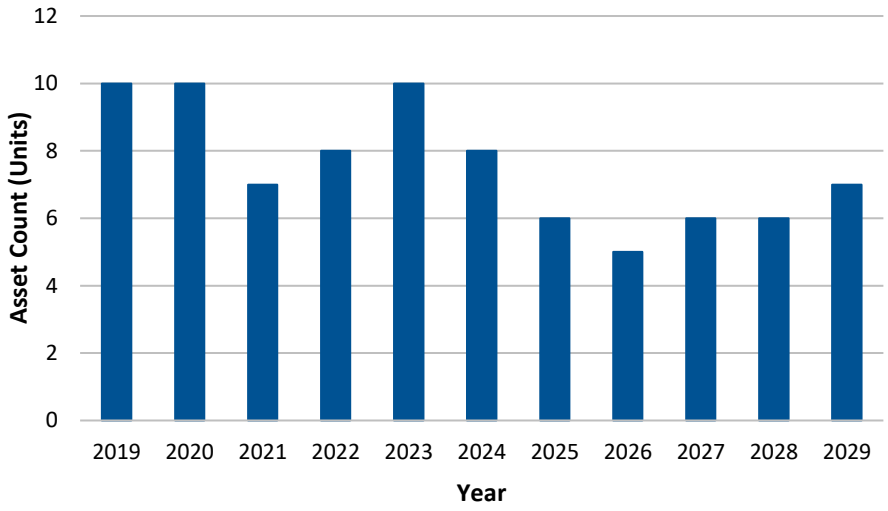


Chart 2: Historical and Forecast Number of Assets Overhauled

4.2 Historical and Forecast Average Unit Costs

Overhaul costs vary significantly based on unit engine ratings. The ratings of genset units under this program vary from 40 kW to 2,500 kW. Variability in annual budgets can be attributed to the rating and number of units overhauled each year.

Chart 3 provides the five-year historical, current, and the five-year forecast average unit cost of unit overhauls in each year.

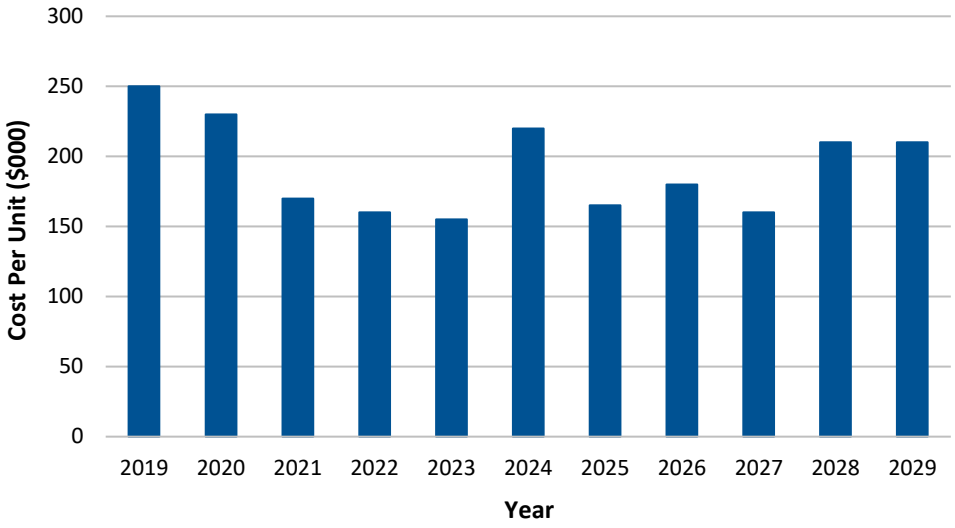


Chart 3: Historical and Forecast Average Unit Costs of Assets Overhauled

4.3 Historical Reliability

Hydro's overhaul program is configured to ensure a balance of reliability and cost-effectiveness while taking into account the original equipment manufacturers' ("OEM") recommendations for overhaul intervals. Performing overhauls at this interval is critical to maintaining reliability in isolated communities, which often rely on Hydro's diesel generating stations as their sole source of power. Failure to perform a required overhaul could have negative consequences and may lead to equipment failure in communities with limited accessibility.

Hydro tracks the reliability of diesel communities similar to its other locations using SAIDI[4] and SAIFI;[5] 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, or generator issues. If Hydro does not perform overhauls as per OEM recommendations as proposed under this program, diesel units may experience catastrophic failure prior to their operating hour lifespan.

[4] System Average Interruption Duration Index ("SAIDI").
[5] System Average Interruption Frequency Index ("SAIFI").

5.0 Analysis

5.1 Evaluation of Alternatives

Hydro evaluated the following alternatives:

- Pace reduction; and
- Continue program at current pace.

Hydro has not identified any alternative strategies for this program.

5.1.1 Pace Reduction

Hydro has determined the current number of operating hours for recommended overhauls based on the rotational speed of the unit is appropriate based on OEM recommendations, the condition of the units during overhaul, and the unit reliability. Extending the timing of these overhauls is not a viable option, as this would present an unacceptable risk to reliability.

5.1.2 Continue Program at Current Pace

Hydro has maintained overhauls at 20,000 operating hours for 1,800 rpm engines and 30,000 operating hours for 1,200 rpm engines, based on the reliable performance and the condition of parts observed during previous overhauls. The overhaul of diesel units based on Hydro's existing criteria is consistent with OEM recommendations and Hydro's experience with diesel unit overhauls, and is necessary to proactively maintain the assets to ensure safe and reliable service.

5.1.3 Alternative Strategies

Hydro has not identified any alternative strategies that would support the safe and reliable operation of its diesel generating units.

5.2 Least-Cost Evaluation

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

5.3 Recommended Alternative

Hydro recommends completing the planned overhauls to maintain the reliable operation of its diesel generating facilities.

5.3.1 Risk of Asset Stranding

Hydro's diesel generating stations are isolated and in most cases are the sole sources of power to communities. As such, the risk of asset stranding is low.

5.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	4	4	**16**
Post-Implementation	4	2	**8**
		Risk Mitigated	**8**
		Risk Mitigated per $1 Million	**8**

6.0 Scope of Work

The Overhaul Diesel Units Program for 2025 includes the planned overhaul of six diesel unit models. As the cost of parts may fluctuate, Hydro will determine the cost of the overhaul parts and replacement engines and select the least-cost option with acceptable delivery timelines. If an overhaul occurs, it will include replacement or refurbishment of such items 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.

6.1 Program Budget

The estimate for this program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	424.8	0.0	0.0	**424.8**
Labour	336.6	0.0	0.0	**336.6**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	124.9	0.0	0.0	**124.9**
Interest and Escalation	25.1	0.0	0.0	**25.1**
Contingency	88.6	0.0	0.0	**88.6**
Total	**1,000.0**	**0.0**	**0.0**	**1,000.0**

Chart 4 provides the five-year historical program expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast budget through 2029.

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.

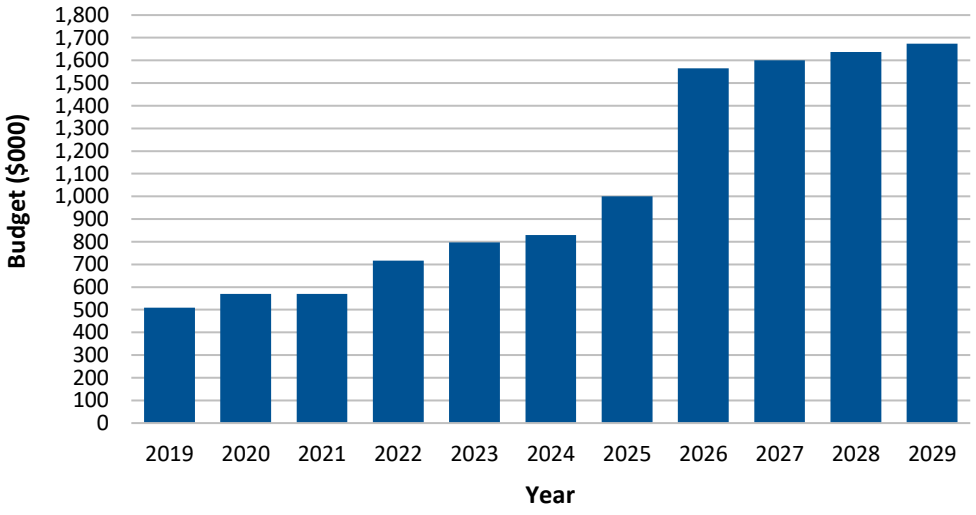


Chart 4: Historical and Forecast Program Budget

6.2 Program Schedule

The schedule for this program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning:		
Schedule Annual Overhauls.	February 2025	September 2025
Procurement:		
Purchase Overhaul Components.	March 2025	October 2025
Construction:		
Complete Overhaul.	April 2025	November 2025
Commissioning:		
Testing After Overhaul.	April 2025	November 2025
Closeout:		
Release for Service and Asset Assignment.	December 2025	December 2025

7.0 Conclusion

To support the continued safe and reliable operation of Hydro's diesel units, Hydro is proposing the overhaul of six diesel units in 2025. 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.

$750,000 to $1,000,000

Program 21

Perform Software Upgrades and Minor Enhancements

2025

newfoundland labrador hydro



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Perform Software Upgrades and Minor Enhancements (2025)

Location: Various

Investment Classification: General Plant

Asset Category: Information Systems

Cost: $808,699

1.0 Introduction

This program involves upgrading and enhancing software systems and applications used by the Newfoundland and Labrador Hydro ("Hydro") Operational Technology ("OT") group to maintain the Energy Management System ("EMS"), as well as applications that support processes in specific business areas such as Resource and Production Planning, the Newfoundland and Labrador System Operator, and Transmission and Rural Operations. This program also provides 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 2025, Hydro proposes to complete the following work scopes as part of this program:

- Modernize diary applications;
- Upgrade Windows operating systems;
- Upgrade diesel plant metering software;
- Upgrade centralized data historian;
- Modernize distribution outage reporting system;
- Centralize domain services in Supervisory Control and Data Acquisition ("SCADA") networks;
- Upgrade event and device monitoring software for OT domain;

- Upgrade meter-reading software components;
- Upgrade customer web portal and customer billing software; and
- Upgrade industrial billing software.

Unforeseen requests received in 2025 for justifiable upgrades and enhancements will also be completed within the approved budget for this program, where possible. Such unplanned work will be reported in Hydro's 2025 Capital Expenditures and Carryover Report.[1]

3.0 Asset Overview

3.1 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 on a daily basis to manage the business and are reviewed regularly to effectively plan necessary upgrades and enhancements.

The software systems and applications planned for installation or upgrade in 2025 are described herein.

- Diary Applications: Shift event diary application used in control rooms;
- Windows Operating System: Updating operation systems on various workstations to latest supported version;
- Diesel Plant Metering: Retrieves meter information from diesel plants;
- Data Historian: Centralized data historian;
- Distributed Outage Reporting: Used to track distribution outages and provides the majority of the data used by Hydro to report on distribution outages and performance;
- Domain Services in SCADA Networks: Domain modifications to improve security;
- Industrial Billing Software: System used for collecting and processing industrial billing data and interfacing with the JD Edwards billing system;

[1] Hydro's 2025 Capital Expenditures and Carryover Report is to be filed on or before April 1, 2026.

- 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
- Customer Bill Implementation: Application used to create customer bills.

3.2 Asset Condition

Software systems and applications managed under this program are in variable condition. This program is driven by software versions that have reached end-of-life in current state.

3.3 Asset Ages

Software systems and applications managed under this program have variable ages, condition, and unpredictable lifecycles. Upgrade and enhancement requirements are driven by technology advancements, changes in business requirements, and vendor-released version upgrades.

3.4 Historical and Forecast Average Unit Costs

Chart 1 provides the five-year historical, current, and the five-year forecast average unit cost of asset upgrades in each year. This chart shows that there has been a significant program budget increase since 2020; due in part to increased demand on OT systems as well as vendors releasing updates to enhance functionality and security. As software upgrades and their related costs cannot be divided into units and apply more so to overall processes and operations, an average unit cost is not calculable and is thus not applicable to this program.

3.5 Historical Reliability

Hydro's past experience with operational and corporate software applications has shown that maintaining vendor support, mitigating security risks, and migrating to modern development frameworks reduces long-term costs and the risk of application failure

4.0 Analysis

4.1 Evaluation of Alternatives

Hydro evaluated the following alternatives:

- Upgrade and enhance the software systems;
- Replace the software systems; and
- Pace reduction.

Hydro has not identified any alternative strategies for this program.

4.1.1 Upgrade and Enhance the Software Systems

Under this alternative, upgrades and enhancements to the identified software systems will be performed by software and infrastructure specialists familiar with the technologies in 2025.

In Hydro's operational experience, upgrading and enhancing existing systems have proven to be an effective and cost-efficient approach for this program.

4.1.2 Replace the Software Systems

Under this alternative, the systems described above would be replaced with alternative off-the-shelf solutions written by third-party vendors. This would include engaging vendors through the request for proposals process and creating new capital projects to replace them. Replacement is not required, as the existing software is performing adequately and upgrades or minor enhancements can be performed to address any issues identified. Replacement is an inherently more expensive alternative to upgrading and enhancing existing systems, and therefore is not a viable alternative.

4.1.3 Pace Reduction

Under this alternative, systems would be operated without any upgrades or enhancements, negatively impacting the efficiency and security of Hydro's operations. The timing and frequency of upgrades are controlled by the vendor. As such, Hydro does not consider this alternative viable.

4.2 Least-Cost Evaluation

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

4.3 Recommended Alternative

Hydro recommends upgrading and enhancing the identified software systems in 2025. 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 Energy Control Centre operators, and/or additional cybersecurity vulnerabilities.

4.3.1 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.

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025 program in accordance with Hydro's Capital Risk Assessment process, as outline 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-Implementation	4	5	**20**
Post-Implementation	4	3	**12**
		Risk Mitigated	**8**
		Risk Mitigated per $1 Million	**9.9**

5.0 Scope of Work

A preliminary analysis has identified the following software systems to be updated or upgraded as part of the 2025 program:

- Event and device monitoring software upgrade for OT domain;
- Modernization of diary applications;
- Upgrade Windows operating systems;
- Upgrade diesel plant metering software;
- Upgrade centralized data historian;

- Modernize distribution outage reporting system;
- Centralize domain services in SCADA networks;
- Meter reading software component upgrade, including mobile version;
- Upgrades to Customer billing application;
- Upgrade to Customer Web portal application;
- Upgrades to industrial billing application; 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 for upgrades and enhancements to meet changing business needs received in 2025 will be determined once the request is reviewed and justified for inclusion in the program.

5.1 Program Budget

The estimate for the 2025 program is shown in Table 2.

Table 2: Program Estimate ($000)

Program Cost	2025	2026	Beyond	Total
Material Supply	54.0	0.0	0.0	**54.0**
Labour	361.7	0.0	0.0	**361.7**
Consultant	297.5	0.0	0.0	**297.5**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	24.2	0.0	0.0	**24.2**
Contingency	71.3	0.0	0.0	**71.3**
Total	**808.7**	**0.0**	**0.0**	**808.7**

Chart 1 shows the five-year historical expenditures, the forecast 2024 expenditures, the proposed 2025 program budget, and the forecast costs through 2029.[2]

[2] 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.

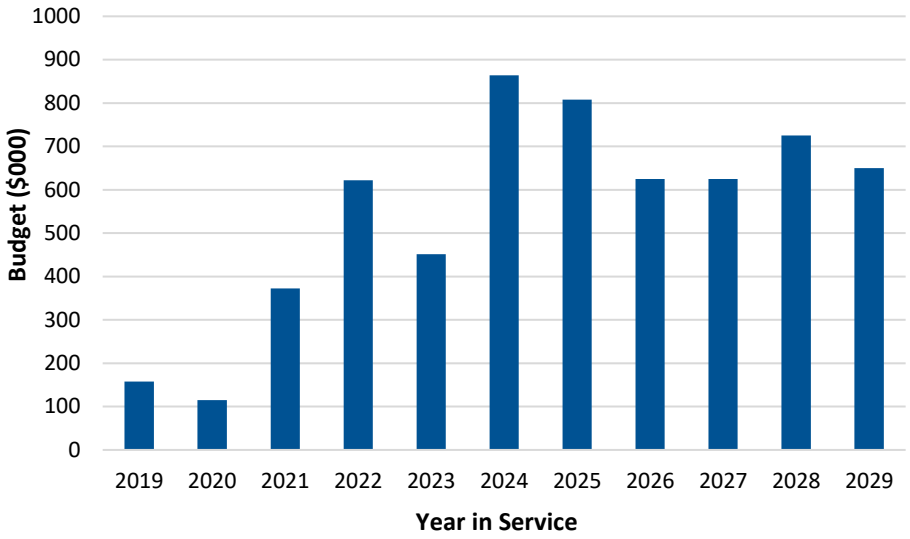


Chart 1: Historical and Forecast Program Budget

5.2 Program Schedule

The schedule for the program is shown in Table 3.

Table 3: Program Schedule

Activity	Start Date	End Date
Planning: Detailed scope definition and review schedule.	January 2025	June 2025
Design: Complete detailed design and create a program plan.	February 2025	July 2025
Procurement: Award request for proposals (if required) and secure resources.	February 2025	August 2025
Construction: Build software enhancements.	May 2025	November 2025
Commissioning: Go live with enhancements.	June 2025	November 2025
Closeout: Complete closeout documentation.	November 2025	December 2025

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.

Diesel In-Service Failures

2025



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Diesel In-Service Failures (2025)

Location: Various

Investment Classification: Renewal

Asset Category: Generation

Cost: $800,028

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") conducts asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize the disruption of service and avoid unsafe working conditions due to equipment failure. One of the primary objectives 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 capital budget application ("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 imminent 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, corrosion, and wear of mechanical components. Hydro uses historical data and engineering judgement to predict the magnitude of in-service failure expenditures.

2.0 Program Description and Justification

Under the Diesel In-Service Failures Program, Hydro completes immediate capital refurbishment and replacement work required for its diesel generating assets as needed to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner, 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; however, throughout 2025, Hydro may purchase capital spares identified by asset management personnel as requiring immediate procurement to offset deficiencies in its capital spares.

Due to the nature of internal combustion engines and diesel generation equipment, unanticipated failures and deterioration occur. This program provides an effective and timely means to undertake the immediate capital refurbishment and replacement work required for diesel generation equipment.

Deferral of work that is justified under this program could result in a detrimental impact to customer power supply or unacceptable risk to the safety of workers or the public. In most cases, diesel generating stations are the only source of power for the community served and equipment failures must be addressed promptly.

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

This program addresses unforeseen failures of various diesel generating station equipment where immediate refurbishment or replacement must be completed due to actual failures, the identification of an incipient failure, or faster-than-anticipated equipment deterioration. This program covers the assets associated with 23 diesel generating stations in Newfoundland and Labrador, which may include the execution of the following in-service failure work:

- Premature engine failure;
- Premature radiator failures;
- Premature generator failures; and
- Unexpected failure of auxiliary equipment.

For further information on the work executed under the Diesel In-Service Failures (2023) Program, please refer to Hydro's "Capital Expenditures and Carryover Report for the Year Ended December 31, 2023."[1]

[1] Provided as Appendix B to Schedule 5 of this application.

3.2 Asset Condition

Assets replaced or refurbished under this program have experienced unplanned failure or exhibit sign 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 diesel genset fleet ranges in age from less than 1 year to 53 years and currently ranges in operating hours from 75 to over 110,661.[2] Chart 1 shows the age distribution of the genset fleet. Unplanned failure of diesel generating assets can occur at any time during their life cycle.

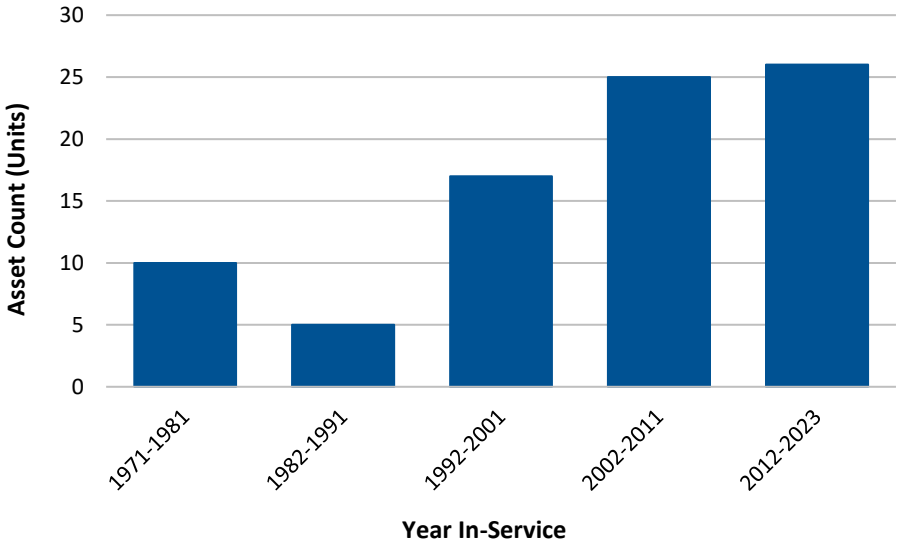


Chart 1: **Asset Count by Asset Age**

4.0 Trending

As Hydro implemented the Diesel In-Service Failures Program in 2023, Hydro does not yet have the requested trending data that would lead to budgetary determinations based on historical information. With only a singular year of actual installations, replacements and upgrades in this program, Hydro will

[2] As of December 31, 2023.

refrain from providing historical chart information at this time, and provide this information as required in future program iterations.

Ten unplanned projects were initiated under the program in 2023.

4.1 Historical and Forecast Average Unit Costs

Historical and forecast program costs are provided in Chart 2 in Section 6.1. 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, which in this year's case was based on engineering judgement as an adequate amount of historical data has yet to be obtained.

5.0 Analysis

5.1 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.

5.1.1 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. Diesel generating stations are isolated, and in most cases are the sole sources of power to a community; therefore, the risk of asset stranding is inherently low. Should a facility be identified for closure due to a change in customer service requirements,[3] Hydro will retain and redeploy assets to other locations.

[3] Such as community resettlement.

5.1.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	3	5	**15**
Post-Implementation	3	1	**3**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**15**

6.0 Scope of Work

Work executed under this program in 2025 will be reported to the Board in Hydro's 2025 Capital Expenditures and Carryover Report.[4]

6.1 Program Budget

The estimate for the 2025 program is shown in Table 2. The estimate is based on engineering judgement, as there wasn't sufficient historical information to determine budget based on an average yearly expenditure. 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.

Table 2: Program Estimate ($000)

Program Cost	**2025**	**2026**	**Beyond**	**Total**
Material Supply	400.0	0.0	0.0	**400.0**
Labour	313.8	0.0	0.0	**313.8**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	86.2	0.0	0.0	**86.2**
Interest and Escalation	0.0	0.0	0.0	**0.0**
Contingency	0.0	0.0	0.0	**0.0**
Total	**800.0**	**0.0**	**0.0**	**800.0**

[4] Hydro's 2025 Capital Expenditures and Carryover report is to be filed on or before April 1, 2026.

The Diesel In-Service Failure Program started in 2023. Chart 2 provides the historical expenditures since the program was initiated, the forecast 2024 expenditures, proposed 2025 program budget, and the forecast budget through 2029. 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 2025 program budget with cost escalation applied.

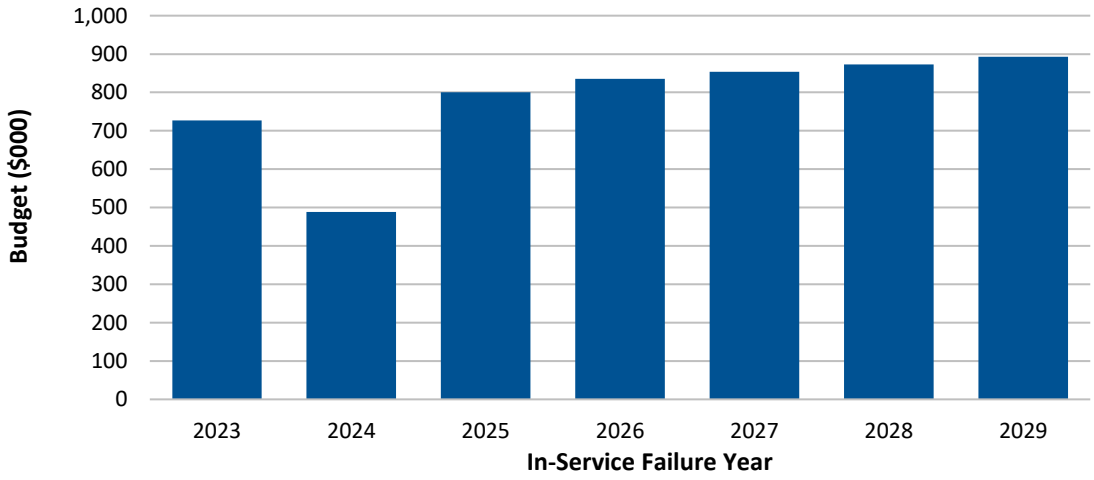


Chart 2: Historical and Forecast Program Budget

6.2 Program Schedule

Work schedules are established subsequent to an unplanned failure, or incipient failure event. There are currently no planned capital spares acquisitions for 2025.

7.0 Conclusion

The Diesel Generation 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.

Projects

Over $750,000



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Schedule 7: Capital Programs and Projects

Projects	**Project**
Over $5,000,000	
• Rewind Stator (2025–2026) – Hinds Lake	1
$1,000,000 to $5,000,0000	
• Refurbish Intake 2 (2025–2026) – Bay d'Espoir	2
• Refurbish Marine Terminal (2025–2026) – Holyrood	3
• Replace Emergency Diesel Genset (2025–2027) – Cat Arm	4
• Install Mid-Span Structures – TL220 (2025–2026)	5
• Replace Interconnect Microwave Radios (2025)	6
$750,000 to $1,000,0000	
• Upgrade Work Protection Code Application (2025–2026)	7
• Perform Level 2 Condition Assessment – Stage 1 & 2 Cooling Water Sump Structures (2025) – Holyrood	8
Programs and Projects under $750,000	

Over $5,000,000

Project 1

Rewind Stator

2025–2026

Hinds Lake

newfoundland labrador hydro



Rewind Stator (2025–2026)

Location: Hinds Lake Hydroelectric Generating Station

Investment Classification: Renewal

Asset Category: Hydraulic Plant

Cost: $14,928,726

Executive Summary

To support the continued safe and reliable operation of the Hinds Lake Hydroelectric Generating Station ("Hinds Lake"), Newfoundland and Labrador Hydro ("Hydro") is proposing to replace the stator winding of the Hinds Lake generating unit ("Unit 1").

Hydro completes routine testing and monitoring of the Hinds Lake Unit 1. Recent visual and electrical testing has revealed that the condition of the unit's stator winding has deteriorated, and replacement of the stator winding is required to ensure continued reliable operation. Failure to complete the stator rewind could lead to a forced unit outage, resulting in the loss of 75 MW for an extended period, depending on the magnitude of the failure.

The project is expected to take two years to complete with engineering and procurement planned for 2025 and execution in 2026. The budget estimate for this project is $14,928,700.

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List of Attachments

Attachment 1: Impact Test Report

Attachment 2: Partial Discharge Test Report

Attachment 3: Hinds Lake Turbine and Generator Condition Assessment

1.0 Introduction

Hinds Lake was commissioned in 1980 and has one 75 MW generating unit, Unit 1, that produces an average of 340 GWh of energy for the Island Interconnected System each year. Unit 1 consists of two major components: the rotor and the stator which work together to produce electricity, as shown in Figure 1. Unit 1 is mechanically coupled via a shaft to the unit's Francis turbine and is the rotating component of the generator assembly, while the stator is the stationary component. The stator consists of a series of insulated copper bars connected to form what is commonly referred to as the stator winding. This winding is installed in slots located in the stacked iron stator core as shown in in Figure 2 and Figure 3.

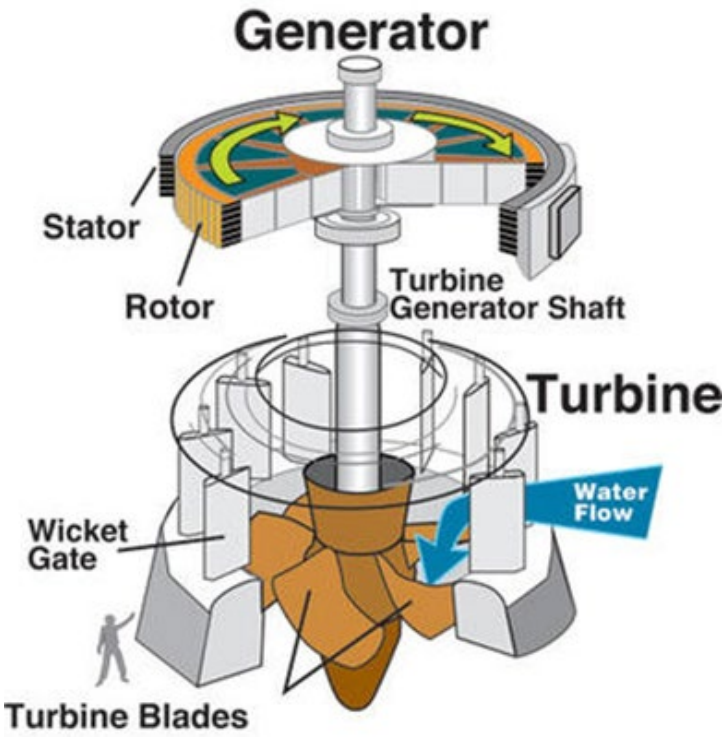


Figure 1: Typical Hydroelectric Generator



Figure 2: Hinds Lake Stator

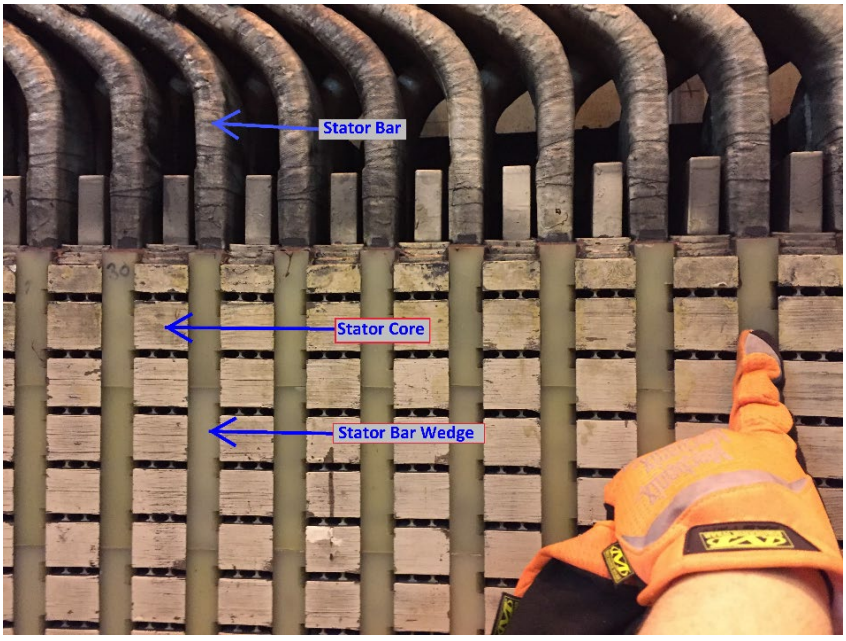


Figure 3: Stator with Components Labelled

A stator winding has a typical useful life ranging from 40 to 60 years, depending on the design and environmental and operating conditions, such as frequency of starts and stops, generation output, and normal operating temperatures. Electrical testing and visual inspection of Unit 1 has determined that the generator stator winding is nearing or have reached the end of its useful life.

2.0 Project Description and Justification

Hinds Lake provides 75 MW of generation capacity to the Island Interconnected System. To ensure the generating unit remains in reliable operating condition, Hydro is proposing to complete the replacement of the Hinds Lake Unit 1 stator winding.

The rewind of Hind's Lake Unit 1 stator will involve the following scope:

- Replacement of the stator winding;
- Cleaning and testing of stator core; and
- Installation of online generating monitoring equipment. This online monitoring equipment provides conditioning monitoring data to support the asset management of the generator.

The stator winding has been determined to be in a condition that requires replacement to maintain reliable operation. The generating unit at Hinds Lake is 44 years old and the winding is original to the unit. Partial Discharge ("PD")[1] analysis completed on the unit's stator winding indicates that the unit is experiencing high levels of PD. The most recent visual inspection, completed in the spring of 2024, determined that, since the previous inspection in 2019, there are visual indications of further deterioration[2] of the stator winding insulation. The findings from the visual inspections, when combined with issues previously identified in 2019, indicate accelerated deterioration is occurring and the risk of an in-service stator winding failure is increasing. To minimize this risk, Hydro is proposing to complete a rewind of the stator in this 2025–2026 proposed project.

[1] PD is a phenomenon that is the localized breakdown of a stator bar insulation system. PD occurs in several different areas of an affected bar but, all involve small voids and cracks within the insulation that, with the right conditions, allow the movement of electrons in the insulation layers and eventually the breakdown of insulation. Once the insulation is depleted enough there is an increased risk of bar failure from electrical flashover to ground.

[2] Visual indicators of deterioration include localized discoloration of the end winding and tape delamination.

3.0 Asset Overview

3.1 Asset Background

Hinds Lake is located on the province's west coast, on the eastern shore of Grand Lake, and was commissioned in 1980. The generating station features a single unit, Unit 1, that was manufactured by Hitachi and has a generating capacity of 75 MW. The stator winding is constructed of 528 insulated copper bars in 264 core slots that are electrically and mechanically interconnected. The stator winding is original to the unit and has not been replaced since commissioning.

The operation of Unit 1 at Hinds Lake has changed since commissioning based on Hydro's generation requirements.[3] Unit 1 was originally operated as a peaking unit, but has since been operated as a base-loaded unit, with a start/stop rate that is higher than typical compared to the average base unit. There are no operational restrictions or changes forecasted for Unit 1.

Hinds Lake undergoes an annual planned unit outage, which is typically two to three weeks in duration, to facilitate the completion of preventative and corrective maintenance activities. In addition, a more detailed inspection, referred to by Hydro as an "Overhaul" or "PM9," is conducted every six years. This level 2 condition assessment includes a thorough inspection of the generator with the rotor removed, testing, cleaning, refurbishment, and replacement of any defective components. The most recent overhaul was completed on the Hinds Lake unit in 2019.

In addition to regular maintenance, the following scopes have been executed on Unit 1:

- Rotor refurbishment, including pole rewind to correct low rotor resistance readings;
- Runner cavitation repairs; and
- Stator and runner level 1 condition assessment.

[3] Hydroelectric generating units are typically utilized for operation in one of two ways: as a base-loaded generator (with few start/stop cycles and high hours of operation) or as a peaking unit (with a high number of start/stop cycles and lower hours of operation).

3.2 Historical Reliability

Hydro tracks performance data for its hydraulic units using the Derated Adjusted Forced Outage Rate ("DAFOR").[4,5]

Forced outages occur periodically due to in-service failures of electrical or mechanical components or as a result of minor operational changes detected by the unit protection system. To date, the stator winding has not resulted in any forced outages, or in a need to restrict operation of the Hinds Lake Unit 1.

3.3 Asset Condition

Hinds Lake Unit 1 has been in operation for 44 years, and the condition of the stator winding has deteriorated and requires replacement. During the rotor refurbishment in 2019, an Impact Test Report[6] was completed by a third-party consultant and concluded that high vibrations affected the jumpers, circuit rings, and some stator winding bars, along with widespread loose stator wedges. On their own, these findings are not indicative of an incipient failure but rather provide additional information for consideration when compiled with the results of visual inspections, electrical tests, and online data such as PD. PD degradation on stator bar slots at the top and bottom of the unit was discovered, and necessary repairs were made in 2019 to prevent further winding degradation at these locations.

In 2022, to gather additional and more current information, Hydro engaged a consultant to complete a turbine and generator condition assessment report. The consultant recommended a rewedge of the unit and additional lashing to address the end-winding vibration. A project to complete the unit rewedge and end winding tightening was put in the plan to be proposed for 2025–2026. However, subsequent PD analysis completed in February 2024 confirmed high but stable levels of winding insulation discharge on Phase A of the stator winding. A follow-up visual inspection, due to high PD, was recommended by a third-party consultant to check for coil vibrations in the slots due to loose wedges, which would be visually apparent as a black powder along the sides of the bars. This inspection was conducted in April 2024 using a borescope. The inspection revealed the absence of black powder in this location; however,

[4] 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.
[5] Filed quarterly with the Board of Commissioners of Public Utilities. Please refer to "Quarterly Report on Performance of Generating Units for the Twelve Months Ended March 31, 2024," Newfoundland and Labrador Hydro, April 30, 2024, for the most recent update.
[6] A bump test is a vibratory response from the striking of a calibrated hammer on the stator end winding (tangential and radial) which identifies the potential for resonance that can lead to high-end winding vibration during operation.

the inspection of other end-winding areas that had not previously demonstrated PD during the rotor refurbishment in 2019 revealed that the stator had insulation delamination, heavy contamination, and localized end-winding discoloration from further PD activity as shown in Figure 4 and Figure 5.

With the progression of PD damage to the end winding, there is an increased risk of a potential unplanned failure of the Hinds Lake stator winding. When considering this information and the age of the stator winding, it was no longer technically viable to rewedge the stator with new end-winding lashes, and stator winding replacement was required. Replacement of wedges and lashing for the end winding is inherent to a unit rewind, meaning that all condition issues noted above will be addressed through the unit rewind.



Figure 4: Insulation Delamination

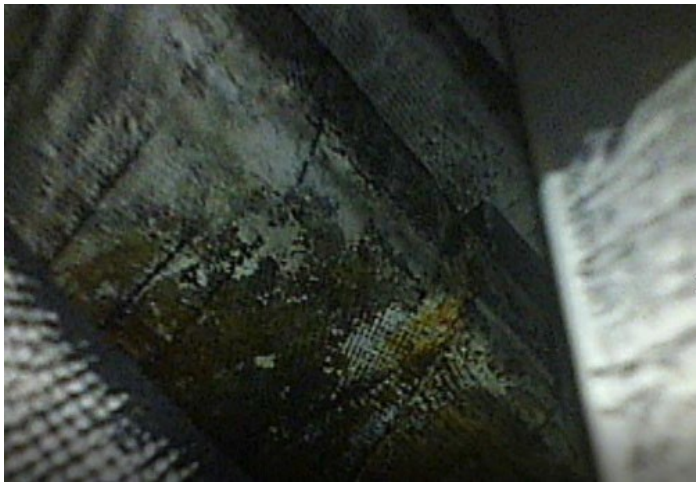


Figure 5: End Winding Discoloration

3.4 Condition-Based Remaining Life

The Hinds Lake Unit 1 stator winding is nearing the end of its useful lifecycle due to its current condition and age. The longevity of a stator winding generally depends on factors such as its design, operating conditions, and maintenance practices. Although there is no specific documented life expectancy for generator stator winding, industry experience suggests a service life of 40 to 60 years for hydrogenerator stator winding.

Annual inspections have revealed that a significant portion of the end winding, wedges, and lashings are loose. Additionally, the PD levels are high but stable, signalling that the stator winding is aging more rapidly and is either at or nearing the end of its useful life. As well, the insulation is showing localized PD activity and tape delamination. This situation suggests that replacement of the stator winding is necessary to ensure continued reliable operation.

4.0 Analysis

4.1 Evaluation of Alternatives

4.1.1 Deferral

Deferral of this project would increase the risk of stator winding failure, which would equate to the loss of 75 MW of generation for several weeks to several months, depending on the magnitude of the failure. Deferral of this project is not a viable alternative.

4.1.2 Upgrade Life Extension

Hydro has not identified any upgrade life extension options for this project. Electrical testing and visual inspection of Unit 1 have determined that the generator stator winding is nearing or has reached its end of useful life; as such, an upgrade life extension is not technically viable.

4.1.3 Like-for-Like Replacement

The like-for-like replacement of the stator winding has been determined to be the only viable option to satisfy Hydro's long-term operational needs. The replacement of the stator winding and the installation of monitoring and analysis equipment will ensure the safe and reliable operation of the generating unit.

4.1.4 Alternative Strategies

Hydro has not identified any alternative options 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

The like-for-like replacement of the Hinds Lake stator winding is the recommended alternative.

4.3.1 Risk of Asset Stranding

Hinds Lake has a maximum generation capacity of 75 MW and contributes an average annual production of approximately 340 GWh to the Island Interconnected System.

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 the 2025–2026 project in accordance with Hydro's Capital Risk Assessment process, as outlined in Section 7.0 of Schedule 1.0. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	4	4	**16**
Post-Implementation	4	1	**4**
		Risk Mitigated	**12**
		Risk Mitigated per $1 Million	**0.8**

5.0 Scope of Work

The scope of work for this project includes the following:

- Completion of engineering design for the stator winding;
- Unit disassembly and rotor removal;
- Removal and disposal of the existing winding;
- Cleaning and testing of stator core;
- Procurement, installation and commissioning of the new stator winding;

- Procurement, installation and commissioning of generating monitoring equipment including;
  - PD monitoring;
  - Rotor flux monitoring; and
  - Air gap analysis equipment.
- Unit reassembly; and
- Complete testing and commissioning of the generating unit.

The above items will be completed by an original equipment manufacturer ("OEM") contractor with support from Hydro personnel.

5.1 Project Budget

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)[7]

Project Cost	2025	2026	Beyond	Total
Material Supply	235.0	235.0	0.0	**470.0**
Labour	178.2	1,226.8	0.0	**1,405.0**
Consultant	53.7	47.0	0.0	**100.8**
Contract Work	4,052.7	6,281.6	0.0	**10,334.3**
Other Direct Costs	40.3	276.5	0.0	**316.8**
Interest and Escalation	243.8	913.5	0.0	**1,157.3**
Contingency	429.4	715.1	0.0	**1,144.5**
Total	**5,233.2**	**9,695.5**	**0.0**	**14,928.7**

[7] Numbers may not add due to rounding.

5.2 Project Schedule

The schedule for this project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
OEM contract development and award.	January 2025	June 2025
Develop project schedule/ cost structure.	January 2025	May 2025
Design:		
Data collection and drawing review.	April 2025	March 2026
Stator winding design.	July 2025	June 2026
Procurement:		
Material and equipment procurement.	August 2025	July 2026
Construction:		
Disassemble unit, remove and store rotor, install stator winding, electrical testing, and reassemble unit.	September 2026	December 2026
Commissioning:		
Testing and commissioning.	November 2026	December 2026
Closeout:		
Project closeout.	December 2026	December 2026

6.0 Conclusion

Hinds Lake 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 Unit 1 stator winding is original to the unit commissioning in 1980 and is near the end of its useful service life.

Hydro is proposing the replacement of the stator winding and installation of online monitoring equipment to ensure the continued safe and reliable operation of the Hinds Lake Unit 1.

Attachment 1

Impact Test Report



IRIS Power 3110 American Drive, Mississauga, ON, L4V 1T2, Canada; **Phone** +1 905 677-4824; **Fax** +1 905 677-8498
Email:info.iris@qualitrolcorp.com **www.irispower.com**

November 08, 2019.

Enerserv, In

Impact Test Report
Hinds Lake Generating Station
Unit 1

Attached please find a copy of our Impact Test Report for the work carried out at **Hinds Lake Generating Station** on **Unit 1**.

The results show that some of the pole jumpers, coils and ring busses, and generally the entire endwinding, is loose. Thus the endwinding will experience high endwinding vibration in service. This will eventually lead to ground faults due to insulation fretting. It would be prudent to replace blocking and cords in the relevant areas, i.e. tighten the endwinding.

At Iris, we are committed to providing you with superior products and service. We value all input. If you require further information or have any questions, please do not hesitate to contact us.

Sincerely,



Iouri Pomelkov
Manager, Field Service

QUALITROL – IRIS POWER LP

Impact Test

ENERSERV
Hinds Lake GS NALCOR
Unit 1

Service: October 29, 2019

Client Reference No.:	018209
IRIS Power Reference No.:	50362757
Issue No:	1
Revision No:	1
Date:	November 18, 2019

Prepared by: **Signature:**

Asif Tameez **Date**: November 18, 2019

Reviewed by: **Signature:**

John Letal **Date**: November 20, 2019

This document has been prepared for the titled project and should not be relied upon or used for any other project without an independent check being carried out as to its suitability and prior written authority of Iris Power LP being obtained. Iris Power LP accepts no responsibility or liability for the consequences of this document being used for a purpose other than the purposes for which it was commissioned. Any person using or relying on the document for such other purposes agrees, and will by such use or reliance be taken to confirm his agreement to indemnify Iris Power LP for all loss or damage resulting therefrom. Iris Power LP accepts no responsibility or liability for this document to any party other than the person by whom it was commissioned.

Disclaimer: It is impossible to predict time to failure.

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1.0 INTRODUCTION

Enerserv requested Iris Power to perform an Impact Test at Hinds Lake GS (NALCOR site) including driving point measurements on the connection end of the Unit 1 stator endwinding to determine the natural frequencies. The test procedure followed the method in IEC 60034-32 [1].

The Impact Test was carried out under Iris Power reference 50362757 and customer purchase order number 018209.

2.0 ASSET DESIGN

Table 1 – Machine Information

Unit	*Unit 1*	Serial No.	*151651-1*
Generator Design	*Hitachi*	Date Manufactured	*1980*
Generator Rewind	*N/A*	Rewind Date	*N/A*
Machine Type	*Hydro Generator*	RPM	*360*
Voltage / PF	*13.8kV / 0.9*	Current	*3485 A*
kVA	*83,300*	Cooling	*Air*
Insulation class	*F*	Slots/Circuits	*264/2*

3.0 TEST RESULTS

The Driving Point Test (also called an impact test or bump test) consists of hitting a particular part of the generator stator endwinding with a calibrated force and measuring its overall response. The goal is to establish a dynamic signature for the structure by doing Fourier analysis to determine the natural frequencies. A natural frequency is a structural characteristic and independent of the excited frequency during operation.

In the test, the force hammer and the response accelerometer were at the same measurement location. The measurement locations were regarded as where the maximum deflection signals can likely be obtained. The response of the impacting produced local natural frequencies which were identified in the frequency response function (FRF) plots with high magnitude accelerance ($(m/s^2)/N$) and a 180° phase shift through the natural frequency.

The recognized critical band for a hydro generator is around 120 Hz. The applied forces in the endwinding structure are at rotor rotational frequency (6Hz) and at alternating load current electromagnetic forces at twice line frequency (120Hz). For this test, only the 120 Hz frequency was analysed, although the full frequency responses are shown in the Appendix. The concept of critical band refers to the risk of vibration amplification when the structural natural frequencies are close to the forcing frequencies. In service the natural frequencies may “drift” in the bands due to temperature, aging and other variable factors. Thus, a critical band is typically defined between -10% and +20% of the fundamental excitation frequency [2]. Acceptance criteria are based on the magnitude of the displacement through the critical excitation bands. Tight endwindings should have a response below 0.221 (m/s^2)/N based on numerous tests and observations of turbo

generators successfully diagnosed. If the response exceeds 0.44 m/s^2/N near 120 Hz, then significant vibration in service can be expected [3].

There are sixty-four pairs of pole jumpers on the top side of generator connecting the windings to the circuit rings. The original stator marking was used for numbering the slots as recommended by the end user. Specific slots that have longer end-arms were chosen for testing e.g. all pole jumpers, and some portions of the circuit ring bus closer to phase leads were tested, as they are prone to more vibration than other slots and some stator bars near slot exit. In addition some of the coils were bump tested in the diamond portion of the coils.

Force and response positions are shown in the "Location" column in Table 1 below. The radial response was measured from the rotor out, the tangential response was circumferentially around the stator. All jumpers/diamond stator bars/circuit rings were measured in the radial and tangential directions. The FRF plots up to 400 Hz for all points measured are in Appendix A. Coherence is used to validate the Frequency Response Function (FRF) plots and should be greater than 0.85 at the frequencies of interest. For several test locations in this machine, coherence is low since jumpers were really loose. Coherence values are shown in the Appendix.

Coherence: According to IEC 60034-32, the coherence is the relationship between the response and the force for each sampled frequency. The value of the coherence function is always between 1 and 0 with a value closer to 1 being a closer correlation.

Frequency Response Function (FRF): A Frequency Response Function is a frequency-based measurement function, used to identify the natural frequencies of a physical structure which is expressed in the frequency domain with an amplitude of the ratio between an output (acceleration) and an input (force) and of a linear, time-invariant system.

In the table below (Table 1), abbreviations are referred to as:

TR: Top coil, Impact in Radial direction
TT: Top coil, Impact in Tangential direction
BR: Bottom coil, Impact in Radial direction
BR: Bottom coil, Impact in Tangential direction

Although there are many locations exceeding 0.44 m/s^2/N, those marked with red are prone to severe vibration in service as these spots are closer to resonant frequency.

Table 1 – Driving Point Measurement Summary

File Name	*Location & Description*		*Direction*	*108-144 Hz*	*Amplitude (m/s^2)/N*
1	***Slot 82 TR***	***Pole Jumper***	***Radial***	***120***	***0.1465***
2	***Slot 82 TT***	***Pole Jumper***	***Tangential***	***126***	***1.7901***
3	***Slot 82 BR***	***Pole Jumper***	***Radial***	***126***	***0.1321***
4	***Slot 82 BT***	***Pole Jumper***	***Tangential***	***122***	***3.6376***
5	***Slot 86 TR***	***Pole Jumper***	***Radial***	***110***	***0.2126***
6	***Slot 86 TT***	***Pole Jumper***	***Tangential***	***120***	***2.1784***

7	***Slot 86 BR***	***Pole Jumper***	***Radial***	***144***	***0.3946***
8	***Slot 86 BT***	***Pole Jumper***	***Tangential***	***144***	***5.9822***
9	***Slot 91 TR***	***Pole Jumper***	***Radial***	***140***	***0.0883***
10	***Slot 91 TT***	***Pole Jumper***	***Tangential***	***108***	***1.0393***
11	***Slot 91 BR***	***Pole Jumper***	***Radial***	***110***	***0.1862***
12	***Slot 91 BT***	***Pole Jumper***	***Tangential***	***110***	***4.0562***
13	***Slot 95 TR***	***Pole Jumper***	***Radial***	***132***	***0.3386***
14	***Slot 95 TT***	***Pole Jumper***	***Tangential***	***126***	***1.3394***
15	***Slot 95 BR***	***Pole Jumper***	***Radial***	***116***	***0.1540***
16	***Slot 95 BT***	***Pole Jumper***	***Tangential***	***110***	***2.3954***
17	***Slot 99 TR***	***Pole Jumper***	***Radial***	***108***	***0.1766***
18	***Slot 99 TT***	***Pole Jumper***	***Tangential***	***116***	***1.6338***
19	***Slot 99 BR***	***Pole Jumper***	***Radial***	***124***	***0.1848***
20	***Slot 99 BT***	***Pole Jumper***	***Tangential***	***134***	***1.8512***
21	***Slot 104 TR***	***Pole Jumper***	***Radial***	***108***	***0.2726***
22	***Slot 104 TT***	***Pole Jumper***	***Tangential***	***122***	***2.0838***
23	***Slot 104 BR***	***Pole Jumper***	***Radial***	***136***	***0.3385***
24	***Slot 104 BT***	***Pole Jumper***	***Tangential***	***122***	***1.8531***
25	***Slot 108 TR***	***Pole Jumper***	***Radial***	***114***	***0.3501***
26	***Slot 108 TT***	***Pole Jumper***	***Tangential***	***112***	***2.8462***
27	***Slot 108 BR***	***Pole Jumper***	***Radial***	***138***	***0.3916***
28	***Slot 108 BT***	***Pole Jumper***	***Tangential***	***112***	***6.4579***
29	***Slot 113 TR***	***Pole Jumper***	***Radial***	***124***	***0.1409***
30	***Slot 113 TT***	***Pole Jumper***	***Tangential***	***114***	***3.5473***
31	***Slot 113 BR***	***Pole Jumper***	***Radial***	***124***	***0.4341***
32	***Slot 113 BT***	***Pole Jumper***	***Tangential***	***118***	***8.8499***
33	***Slot 117 TR***	***Pole Jumper***	***Radial***	***114***	***0.1300***
34	***Slot 117 TT***	***Pole Jumper***	***Tangential***	***114***	***2.6806***
35	***Slot 117 BR***	***Pole Jumper***	***Radial***	***140***	***0.8369***
36	***Slot 117 BT***	***Pole Jumper***	***Tangential***	***116***	***4.6515***
37	***Slot 121 TR***	***Pole Jumper***	***Radial***	***108***	***0.3598***
38	***Slot 121 TT***	***Pole Jumper***	***Tangential***	***118***	***1.7840***
39	***Slot 121 BR***	***Pole Jumper***	***Radial***	***114***	***0.3155***
40	***Slot 121 BT***	***Pole Jumper***	***Tangential***	***112***	***7.0801***
41	***Slot 126 TR***	***Pole Jumper***	***Radial***	***130***	***0.1277***
42	***Slot 126 TT***	***Pole Jumper***	***Tangential***	***118***	***1.3788***
43	***Slot 126 BR***	***Pole Jumper***	***Radial***	***130***	***0.5617***
44	***Slot 126 BT***	***Pole Jumper***	***Tangential***	***126***	***7.8336***
45	***Slot 130 TR***	***Pole Jumper***	***Radial***	***116***	***0.2135***
46	***Slot 130 TT***	***Pole Jumper***	***Tangential***	***114***	***2.7791***
47	***Slot 130 BR***	***Pole Jumper***	***Radial***	***118***	***0.7452***
48	***Slot 130 BT***	***Pole Jumper***	***Tangential***	***116***	***7.0876***
49	***Slot 135 TR***	***Pole Jumper***	***Radial***	***140***	***0.0864***
50	***Slot 135 TT***	***Pole Jumper***	***Tangential***	***114***	***0.9091***

51	***Slot 135 BR***	***Pole Jumper***	***Radial***	***120***	***0.6680***
52	***Slot 135 BT***	***Pole Jumper***	***Tangential***	***120***	***8.7879***
53	***Slot 139 TR***	***Pole Jumper***	***Radial***	***134***	***0.1063***
54	***Slot 139 TT***	***Pole Jumper***	***Tangential***	***108***	***3.1042***
55	***Slot 139 BR***	***Pole Jumper***	***Radial***	***122***	***0.3429***
56	***Slot 139 BT***	***Pole Jumper***	***Tangential***	***120***	***6.8077***
57	***Slot 143 TR***	***Pole Jumper***	***Radial***	***110***	***0.1728***
58	***Slot 143 TT***	***Pole Jumper***	***Tangential***	***132***	***4.45***
59	***Slot 143 BR***	***Pole Jumper***	***Radial***	***108***	***0.1575***
60	***Slot 143 BT***	***Pole Jumper***	***Tangential***	***108***	***8.3982***
61	***Slot 146 DR***	***Diamond Structure***	***Radial***	***132***	***0.0228***
62	***Slot 146 DT***	***Diamond Structure***	***Tangential***	***138***	***1.9973***
63	***Slot 148 TR***	***Pole Jumper***	***Radial***	***108***	***0.4211***
64	***Slot 148 TT***	***Pole Jumper***	***Tangential***	***108***	***2.3334***
65	***Slot 148 BR***	***Pole Jumper***	***Radial***	***114***	***0.2119***
66	***Slot 148 BT***	***Pole Jumper***	***Tangential***	***114***	***3.4745***
67	***Slot 152 TR***	***Pole Jumper***	***Radial***	***120***	***0.0920***
68	***Slot 152 TT***	***Pole Jumper***	***Tangential***	***108***	***3.1779***
69	***Slot 152 BR***	***Pole Jumper***	***Radial***	***144***	***0.1771***
70	***Slot 152 BT***	***Pole Jumper***	***Tangential***	***132***	***5.8822***
71	***Slot 157 TR***	***Pole Jumper***	***Radial***	***124***	***0.3086***
72	***Slot 157 TT***	***Pole Jumper***	***Tangential***	***126***	***0.7338***
73	***Slot 157 BR***	***Pole Jumper***	***Radial***	***110***	***0.4935***
74	***Slot 157 BT***	***Pole Jumper***	***Tangential***	***110***	***5.9599***
75	***Slot 161 TR***	***Pole Jumper***	***Radial***	***112***	***0.3326***
76	***Slot 161 TT***	***Pole Jumper***	***Tangential***	***112***	***3.0571***
77	***Slot 161 BR***	***Pole Jumper***	***Radial***	***144***	***0.3848***
78	***Slot 161 BT***	***Pole Jumper***	***Tangential***	***108***	***3.9363***
79	***Slot 165 TR***	***Pole Jumper***	***Radial***	***108***	***0.2517***
80	***Slot 165 TT***	***Pole Jumper***	***Tangential***	***114***	***2.5866***
81	***Slot 165 BR***	***Pole Jumper***	***Radial***	***110***	***0.7551***
82	***Slot 165 BT***	***Pole Jumper***	***Tangential***	***112***	***2.8107***
83	***Slot 170 TR***	***Pole Jumper***	***Radial***	***114***	***0.0582***
84	***Slot 170 TT***	***Pole Jumper***	***Tangential***	***128***	***2.5579***
85	***Slot 170 BR***	***Pole Jumper***	***Radial***	***114***	***0.3931***
86	***Slot 170 BT***	***Pole Jumper***	***Tangential***	***112***	***6.7112***
87	***Slot 174 TR***	***Pole Jumper***	***Radial***	***114***	***0.2398***
88	***Slot 174 TT***	***Pole Jumper***	***Tangential***	***112***	***3.2589***
89	***Slot 174 BR***	***Pole Jumper***	***Radial***	***108***	***0.1951***
90	***Slot 174 BT***	***Pole Jumper***	***Tangential***	***112***	***1.9402***
91	***Slot 179 TR***	***Pole Jumper***	***Radial***	***120***	***0.1883***
92	***Slot 179 TT***	***Pole Jumper***	***Tangential***	***118***	***2.1902***
93	***Slot 179 BR***	***Pole Jumper***	***Radial***	***108***	***0.4967***
94	***Slot 179 BT***	***Pole Jumper***	***Tangential***	***122***	***1.5219***

95	***Slot 183 TR***	***Pole Jumper***	***Radial***	***142***	***0.0870***
96	***Slot 183 TT***	***Pole Jumper***	***Tangential***	***118***	***0.7896***
97	***Slot 183 BR***	***Pole Jumper***	***Radial***	***128***	***0.4102***
98	***Slot 183 BT***	***Pole Jumper***	***Tangential***	***116***	***7.3620***
99	***Slot 187 TR***	***Pole Jumper***	***Radial***	***140***	***0.0913***
100	***Slot 187 TT***	***Pole Jumper***	***Tangential***	***114***	***2.5518***
101	***Slot 187 BR***	***Pole Jumper***	***Radial***	***110***	***0.3198***
102	***Slot 187 BT***	***Pole Jumper***	***Tangential***	***108***	***6.5287***
103	***Slot 192 TR***	***Pole Jumper***	***Radial***	***114***	***0.1128***
104	***Slot 192 TT***	***Pole Jumper***	***Tangential***	***114***	***0.7838***
105	***Slot 192 BR***	***Pole Jumper***	***Radial***	***116***	***0.5594***
106	***Slot 192 BT***	***Pole Jumper***	***Tangential***	***108***	***2.4012***
107	***Slot 196 TR***	***Pole Jumper***	***Radial***	***128***	***0.1211***
108	***Slot 196 TT***	***Pole Jumper***	***Tangential***	***108***	***2.2996***
109	***Slot 196 BR***	***Pole Jumper***	***Radial***	***108***	***0.1343***
110	***Slot 196 BT***	***Pole Jumper***	***Tangential***	***108***	***5.1852***
111	***Slot 201 TR***	***Pole Jumper***	***Radial***	***108***	***0.1331***
112	***Slot 201 TT***	***Pole Jumper***	***Tangential***	***114***	***2.4388***
113	***Slot 201 BR***	***Pole Jumper***	***Radial***	***122***	***0.5376***
114	***Slot 201 BT***	***Pole Jumper***	***Tangential***	***122***	***4.1484***
115	***Slot 205 TR***	***Pole Jumper***	***Radial***	***116***	***0.0881***
116	***Slot 205 TT***	***Pole Jumper***	***Tangential***	***116***	***3.4619***
117	***Slot 205 BR***	***Pole Jumper***	***Radial***	***116***	***0.2634***
118	***Slot 205 BT***	***Pole Jumper***	***Tangential***	***112***	***5.7529***
119	***Slot 209 TR***	***Pole Jumper***	***Radial***	***114***	***0.3849***
120	***Slot 209 TT***	***Pole Jumper***	***Tangential***	***114***	***5.7910***
121	***Slot 209 BR***	***Pole Jumper***	***Radial***	***114***	***0.4031***
122	***Slot 209 BT***	***Pole Jumper***	***Tangential***	***130***	***7.7982***
123	***Slot 212 DR***	***Diamond Structure***	***Radial***	***134***	***0.0406***
124	***Slot 212 DT***	***Diamond Structure***	***Tangential***	***140***	***0.5095***
125	***Slot 214 TR***	***Pole Jumper***	***Radial***	***114***	***0.1121***
126	***Slot 214 TT***	***Pole Jumper***	***Tangential***	***110***	***2.3810***
127	***Slot 214 BR***	***Pole Jumper***	***Radial***	***118***	***0.4344***
128	***Slot 214 BT***	***Pole Jumper***	***Tangential***	***114***	***3.4421***
129	***Slot 218 TR***	***Pole Jumper***	***Radial***	***108***	***0.3090***
130	***Slot 218 TT***	***Pole Jumper***	***Tangential***	***122***	***2.1192***
131	***Slot 218 BR***	***Pole Jumper***	***Radial***	***112***	***0.3497***
132	***Slot 218 BT***	***Pole Jumper***	***Tangential***	***110***	***3.4383***
133	***Slot 223 TR***	***Pole Jumper***	***Radial***	***136***	***0.1399***
134	***Slot 223 TT***	***Pole Jumper***	***Tangential***	***140***	***0.9522***
135	***Slot 223 BR***	***Pole Jumper***	***Radial***	***140***	***0.4569***
136	***Slot 223 BT***	***Pole Jumper***	***Tangential***	***114***	***8.4937***
137	***Slot 227 TR***	***Pole Jumper***	***Radial***	***136***	***0.1248***
138	***Slot 227 TT***	***Pole Jumper***	***Tangential***	***108***	***1.3452***

139	***Slot 227 BR***	***Pole Jumper***	***Radial***	***136***	***0.1798***
140	***Slot 227 BT***	***Pole Jumper***	***Tangential***	***112***	***4.3866***
141	***Slot 231 TR***	***Pole Jumper***	***Radial***	***144***	***0.1470***
142	***Slot 231 TT***	***Pole Jumper***	***Tangential***	***144***	***0.6531***
143	***Slot 231 BR***	***Pole Jumper***	***Radial***	***144***	***0.1766***
144	***Slot 231 BT***	***Pole Jumper***	***Tangential***	***112***	***4.6938***
145	***Slot 236 TR***	***Pole Jumper***	***Radial***	***114***	***0.0270***
146	***Slot 236 TT***	***Pole Jumper***	***Tangential***	***112***	***1.7887***
147	***Slot 236 BR***	***Pole Jumper***	***Radial***	***122***	***3.4727***
148	***Slot 236 BT***	***Pole Jumper***	***Tangential***	***122***	***5.9007***
149	***Slot 240 TR***	***Pole Jumper***	***Radial***	***112***	***0.2347***
150	***Slot 240 TT***	***Pole Jumper***	***Tangential***	***112***	***1.3447***
151	***Slot 240 BR***	***Pole Jumper***	***Radial***	***134***	***0.2419***
152	***Slot 240 BT***	***Pole Jumper***	***Tangential***	***114***	***5.1668***
153	***Slot 245 TR***	***Pole Jumper***	***Radial***	***112***	***0.0656***
154	***Slot 245 TT***	***Pole Jumper***	***Tangential***	***140***	***0.2787***
155	***Slot 245 BR***	***Pole Jumper***	***Radial***	***124***	***0.2977***
156	***Slot 245 BT***	***Pole Jumper***	***Tangential***	***114***	***2.9199***
157	***Slot 249 TR***	***Pole Jumper***	***Radial***	***136***	***0.0938***
158	***Slot 249 TT***	***Pole Jumper***	***Tangential***	***140***	***1.2085***
159	***Slot 249 BR***	***Pole Jumper***	***Radial***	***144***	***0.1762***
160	***Slot 249 BT***	***Pole Jumper***	***Tangential***	***122***	***2.3196***
161	***Slot 253 TR***	***Pole Jumper***	***Radial***	***122***	***0.1130***
162	***Slot 253 TT***	***Pole Jumper***	***Tangential***	***142***	***0.1486***
163	***Slot 253 BR***	***Pole Jumper***	***Radial***	***112***	***0.1667***
164	***Slot 253 BT***	***Pole Jumper***	***Tangential***	***112***	***2.2843***
165	***Slot 258 TR***	***Pole Jumper***	***Radial***	***114***	***0.0988***
166	***Slot 258 TT***	***Pole Jumper***	***Tangential***	***118***	***0.7968***
167	***Slot 258 BR***	***Pole Jumper***	***Radial***	***128***	***0.1488***
168	***Slot 258 BT***	***Pole Jumper***	***Tangential***	***132***	***6.3450***
169	***Slot 262 TR***	***Pole Jumper***	***Radial***	***140***	***0.1717***
170	***Slot 262 TT***	***Pole Jumper***	***Tangential***	***138***	***0.2333***
171	***Slot 262 BR***	***Pole Jumper***	***Radial***	***108***	***0.1997***
172	***Slot 262 BT***	***Pole Jumper***	***Tangential***	***110***	***2.1620***
173	***Slot 252 CRR***	***Circuit Ring***	***Radial***	***122***	***0.3640***
174	***Slot 252 CRT***	***Circuit Ring***	***Tangential***	***144***	***0.1266***
175	***Slot 262 CRR***	***Circuit Ring***	***Radial***	***144***	***0.3858***
176	***Slot 262 CRT***	***Circuit Ring***	***Tangential***	***144***	***0.0141***
177	***Slot 3 CRR***	***Circuit Ring***	***Radial***	***110***	***0.0541***
178	***Slot 3 CRT***	***Circuit Ring***	***Tangential***	***128***	***0.0381***
179	***Slot 20 CRR***	***Circuit Ring***	***Radial***	***142***	***0.1063***
180	***Slot 20 CRT***	***Circuit Ring***	***Tangential***	***124***	***0.0607***
181	***Slot 29 CRR***	***Circuit Ring***	***Radial***	***144***	***0.0631***
182	***Slot 29 CRT***	***Circuit Ring***	***Tangential***	***120***	***0.0149***

183	***Slot 38 CRR***	***Circuit Ring***	***Radial***	***142***	***0.0446***
184	***Slot 38 CRT***	***Circuit Ring***	***Tangential***	***116***	***0.0214***
185	***Slot 47 CRR***	***Circuit Ring***	***Radial***	***126***	***0.0636***
186	***Slot 47 CRT***	***Circuit Ring***	***Tangential***	***120***	***0.0181***
187	***Slot 60 CRR***	***Circuit Ring***	***Radial***	***122***	***0.0743***
188	***Slot 60 CRT***	***Circuit Ring***	***Tangential***	***130***	***0.0174***
189	***Slot 73 CRR***	***Circuit Ring***	***Radial***	***118***	***0.1862***
190	***Slot 73 CRT***	***Circuit Ring***	***Tangential***	***140***	***0.0930***
191	***Slot 3 TR***	***Pole Jumper***	***Radial***	***140***	***0.0438***
192	***Slot 3 TT***	***Pole Jumper***	***Tangential***	***144***	***0.8685***
193	***Slot 3 BR***	***Pole Jumper***	***Radial***	***122***	***0.2783***
194	***Slot 3 BT***	***Pole Jumper***	***Tangential***	***108***	***1.5243***
195	***Slot 7 TR***	***Pole Jumper***	***Radial***	***122***	***0.2159***
196	***Slot 7 TT***	***Pole Jumper***	***Tangential***	***128***	***2.1484***
197	***Slot 7 BR***	***Pole Jumper***	***Radial***	***108***	***0.3095***
198	***Slot 7 BT***	***Pole Jumper***	***Tangential***	***112***	***2.6915***
199	***Slot 11 TR***	***Pole Jumper***	***Radial***	***112***	***0.1559***
200	***Slot 11 TT***	***Pole Jumper***	***Tangential***	***110***	***0.7945***
201	***Slot 11 BR***	***Pole Jumper***	***Radial***	***128***	***0.1332***
202	***Slot 11 BT***	***Pole Jumper***	***Tangential***	***108***	***2.0050***
203	***Slot 16 TR***	***Pole Jumper***	***Radial***	***120***	***0.2286***
204	***Slot 16 TT***	***Pole Jumper***	***Tangential***	***114***	***2.0305***
205	***Slot 16 BR***	***Pole Jumper***	***Radial***	***120***	***0.1424***
206	***Slot 16 BT***	***Pole Jumper***	***Tangential***	***126***	***2.5185***
207	***Slot 20 TR***	***Pole Jumper***	***Radial***	***120***	***0.2515***
208	***Slot 20 TT***	***Pole Jumper***	***Tangential***	***118***	***1.4919***
209	***Slot 20 BR***	***Pole Jumper***	***Radial***	***142***	***0.2257***
210	***Slot 20 BT***	***Pole Jumper***	***Tangential***	***112***	***0.7306***
211	***Slot 25 TR***	***Pole Jumper***	***Radial***	***142***	***0.0610***
212	***Slot 25 TT***	***Pole Jumper***	***Tangential***	***144***	***0.1414***
213	***Slot 25 BR***	***Pole Jumper***	***Radial***	***124***	***0.9618***
214	***Slot 25 BT***	***Pole Jumper***	***Tangential***	***120***	***3.3303***
215	***Slot 38 TR***	***Pole Jumper***	***Radial***	***108***	***0.0758***
216	***Slot 38 TT***	***Pole Jumper***	***Tangential***	***140***	***0.4912***
217	***Slot 38 BR***	***Pole Jumper***	***Radial***	***116***	***0.3771***
218	***Slot 38 BT***	***Pole Jumper***	***Tangential***	***112***	***4.0961***
219	***Slot 47 TR***	***Pole Jumper***	***Radial***	***126***	***0.0516***
220	***Slot 47 TT***	***Pole Jumper***	***Tangential***	***140***	***0.6029***
221	***Slot 47 BR***	***Pole Jumper***	***Radial***	***114***	***0.5812***
222	***Slot 47 BT***	***Pole Jumper***	***Tangential***	***114***	***3.3586***
223	***Slot 55 TR***	***Pole Jumper***	***Radial***	***124***	***0.0497***
224	***Slot 55 TT***	***Pole Jumper***	***Tangential***	***140***	***0.1982***
225	***Slot 55 BR***	***Pole Jumper***	***Radial***	***138***	***0.2885***
226	***Slot 55 BT***	***Pole Jumper***	***Tangential***	***136***	***5.0477***

227	***Slot 64 TR***	***Pole Jumper***	***Radial***	***118***	***0.0590***
228	***Slot 64 TT***	***Pole Jumper***	***Tangential***	***140***	***2.8823***
229	***Slot 64 BR***	***Pole Jumper***	***Radial***	***114***	***0.3833***
230	***Slot 64 BT***	***Pole Jumper***	***Tangential***	***108***	***3.5927***
231	***Slot 73 TR***	***Pole Jumper***	***Radial***	***120***	***0.1948***
232	***Slot 73 TT***	***Pole Jumper***	***Tangential***	***124***	***1.2458***
233	***Slot 73 BR***	***Pole Jumper***	***Radial***	***126***	***0.24***
234	***Slot 73 BT***	***Pole Jumper***	***Tangential***	***124***	***3.122***

4.0 CONCLUSION

During the test, plant personnel indicated the presence of dusting and looseness at several locations between the ring buses and the bracing blocks.

The endwinding support system can vibrate excessively if it was inadequately designed or poorly manufactured. For older machines like this one, the endwinding support system may also loosen over time due to insulation aging and/or become loose after a high current faults or power system disturbances. The failure process can be accelerated if there is a natural frequency of the endwinding close to the load current electromagnetic forces at twice line frequency (120Hz), resulting in resonance.

The bump test results at some locations showed the presence of natural frequencies in the critical band at several pole jumpers with relatively high magnitude accelerance response, in the range of 5 to 8 $(m/s^2)/N$. This is an indication of the potential for resonance which can produces very high amplitude vibration during operation. If present, this vibration can cause the following issues:

1. Relative movement between endwinding components can be severe enough to expose high voltage copper conductors within the coil. If partly conductive contamination is present, this may result in a phase to ground fault.

2. Endwinding vibration may loosen the stator wedges at the end of the stator core, which could eventually lead to the coils vibrating within the stator core and slot discharge.

3. In the most extreme case, if the copper conductors within the coil vibrate enough, they can fatigue crack resulting in extreme heating, sometimes enough to melt the copper and result in complete destruction of the stator winding.

An effort should be made to re-establish the bond between these components that have loosened during operation, for example by replacing the blocking and cords in the areas with the highest response, as described in Section 8.15 of [3].

5.0 ATTACHMENTS

Appendix A – Impact Test Data

References

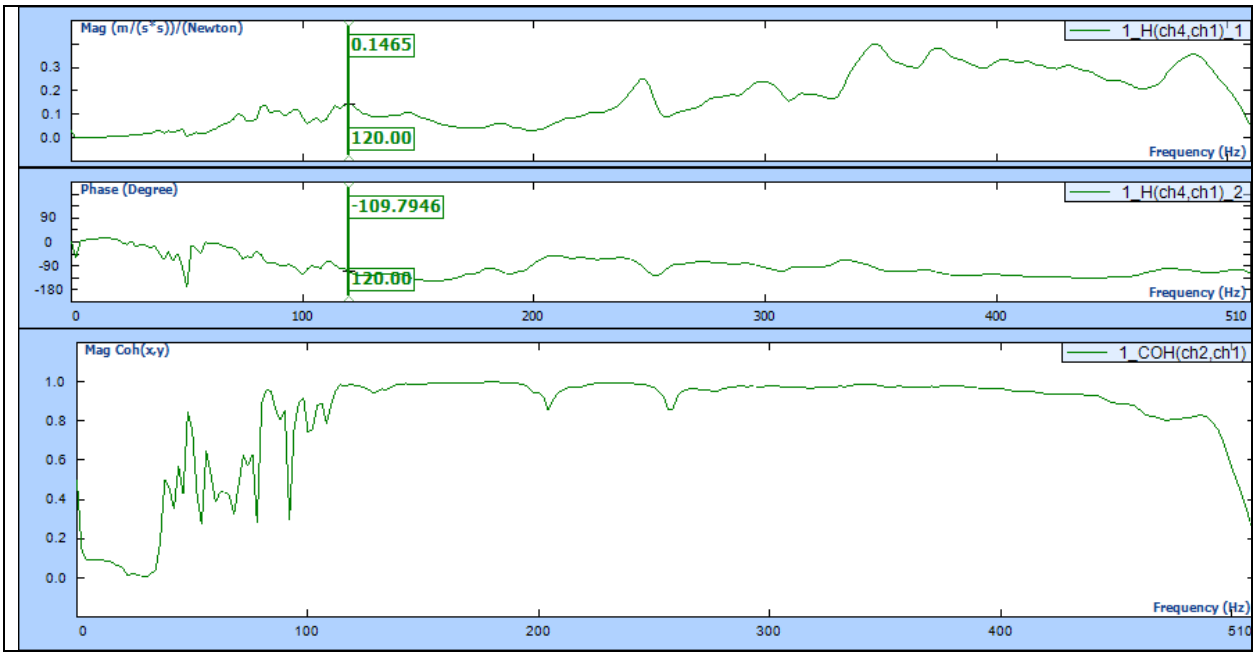
1. IEC 60034-32:2016. Measurement of stator end-winding vibration in form-wound windings.
2. IEEE 1665" IEEE Guide for the Rewind of Synchronous Generators, 50 and 60 Hz, Rated 1 MVA and Above.
3. G.C. Stone, et al, "Electrical Insulation for Rotating Machines", Second Edition, Wiley, 2014

APPENDIX A: IMPACT TEST DATA

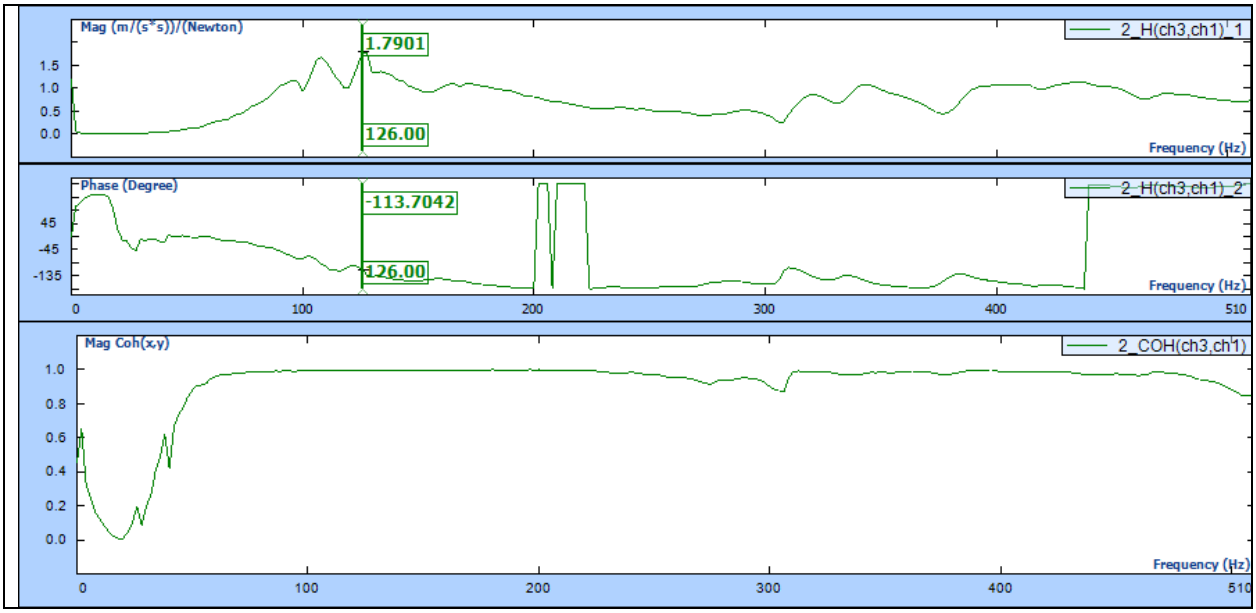
The plots below show the results of the impact test data. The Frequency Response Function for each test point are shown including the magnitude ($m/s^2/N$), phase (degrees), and coherence.

The magnitude is the transfer function of the ratio of the acceleration output and the force input, known as accelerance. The phase is the signal difference between the acceleration output and the force input, e.g. 0 degrees indicates the force and the acceleration are in phase. Natural frequencies are indicated when the magnitude approaches a maximum and the phase crosses through a 90-degree shift.

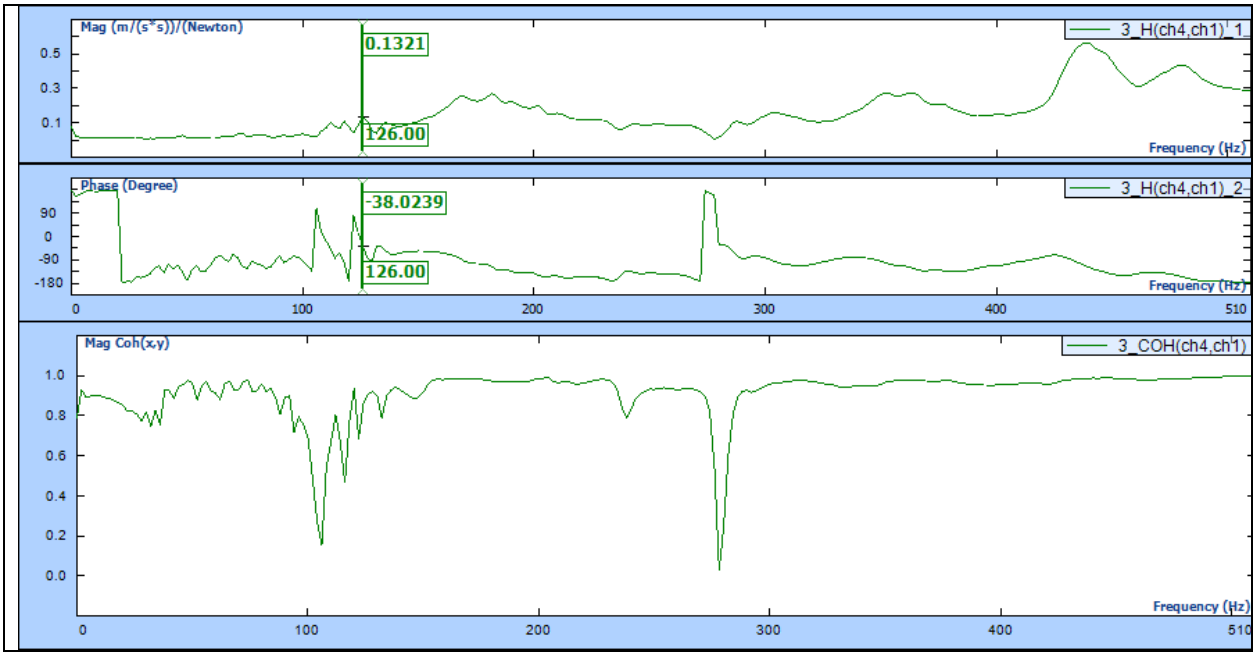
The coherence is the relationship between the response and the force for each sampled frequency and a value closer to 1 indicates a closer correlation.



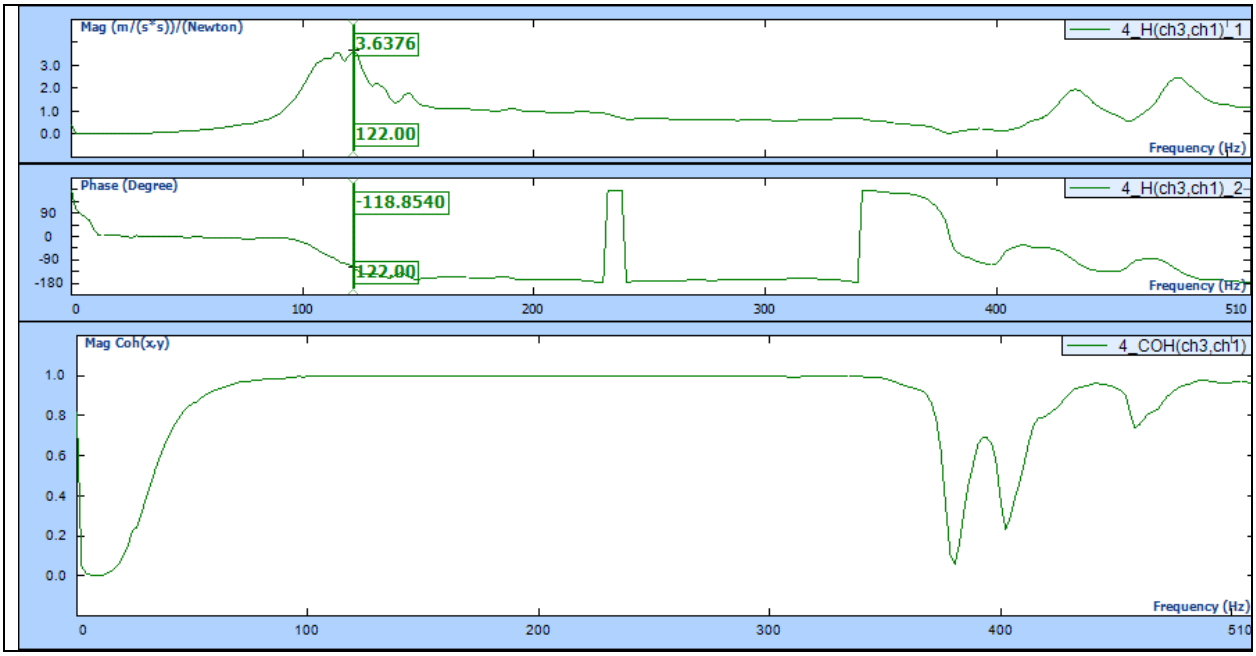
Photograph 1: ***Impact Test Data At 82 Slot Pole Jumper Top Radial***



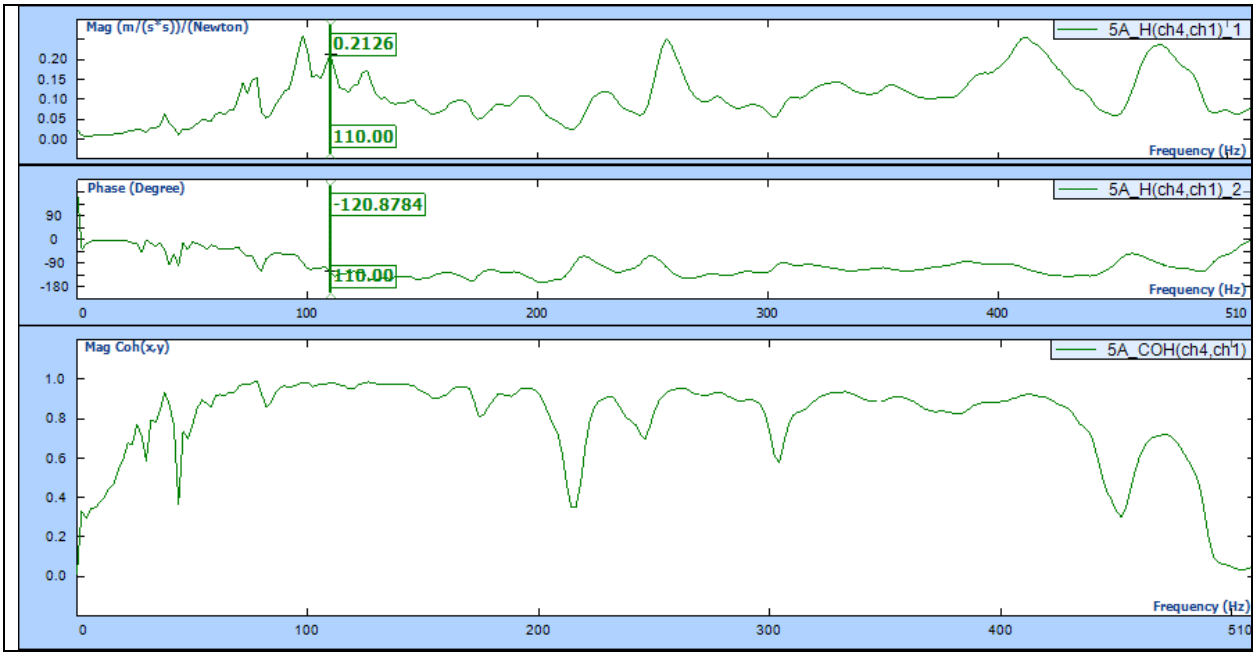
Photograph 2: ***Impact Test Data At 82 Slot Pole Jumper Top Tangential***



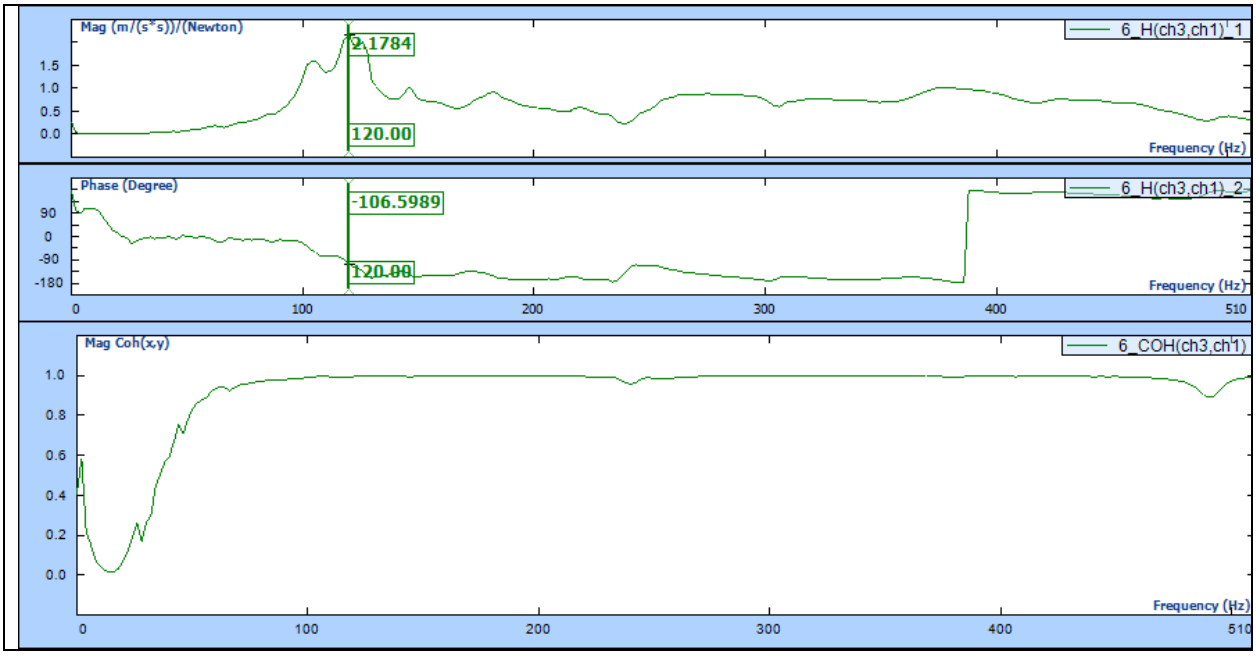
Photograph 3: ***Impact Test Data At 82 Slot Pole Jumper Bottom Radial***



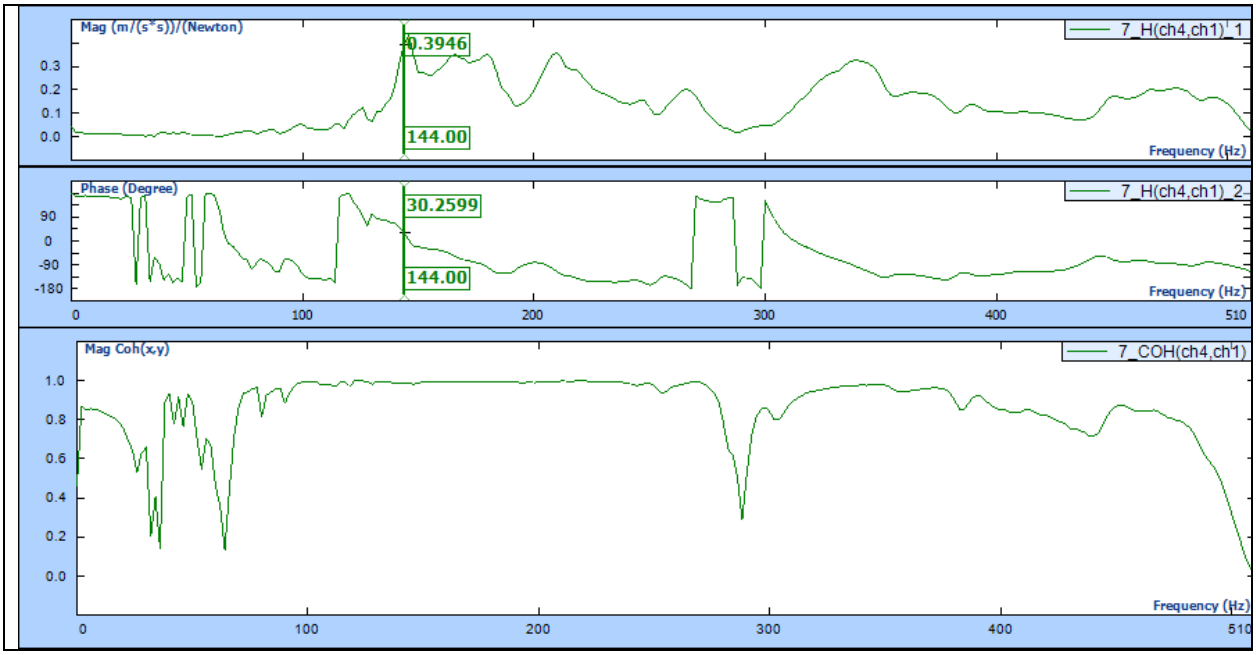
Photograph 4: ***Impact Test Data At 82 Slot Pole Jumper Bottom Tangential***



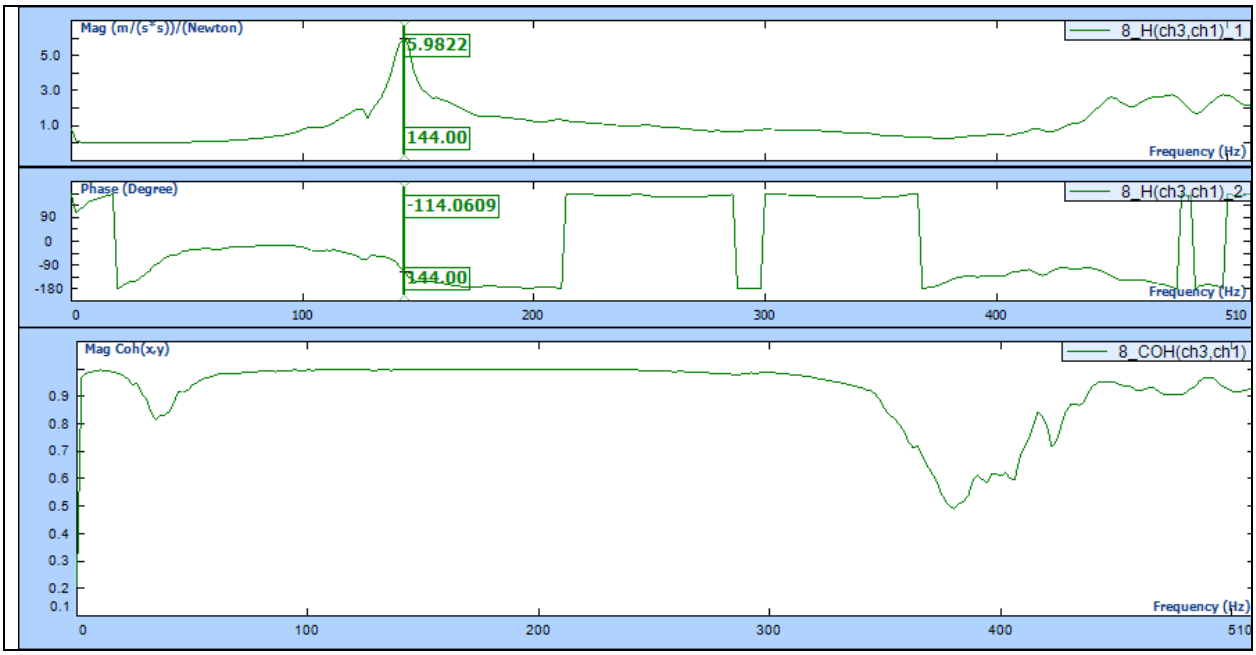
Photograph 5: ***Impact Test Data At 86 Slot Pole Jumper Top Radial***



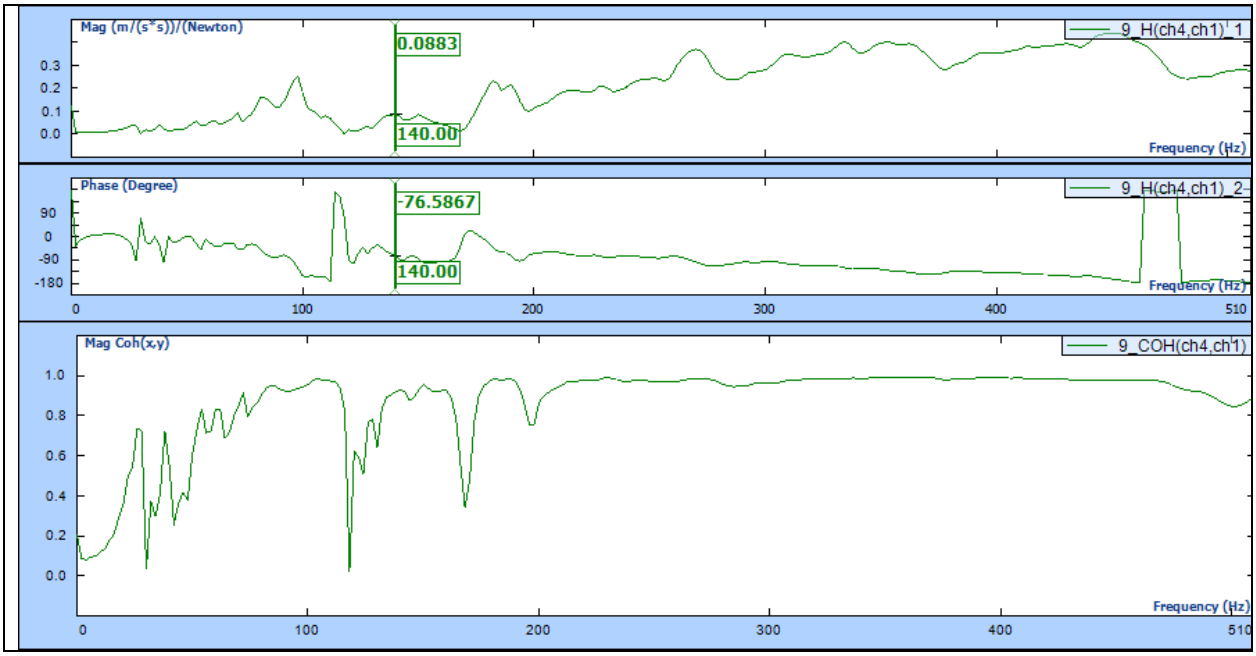
Photograph 6: ***Impact Test Data At 86 Slot Pole Jumper Top Tangential***



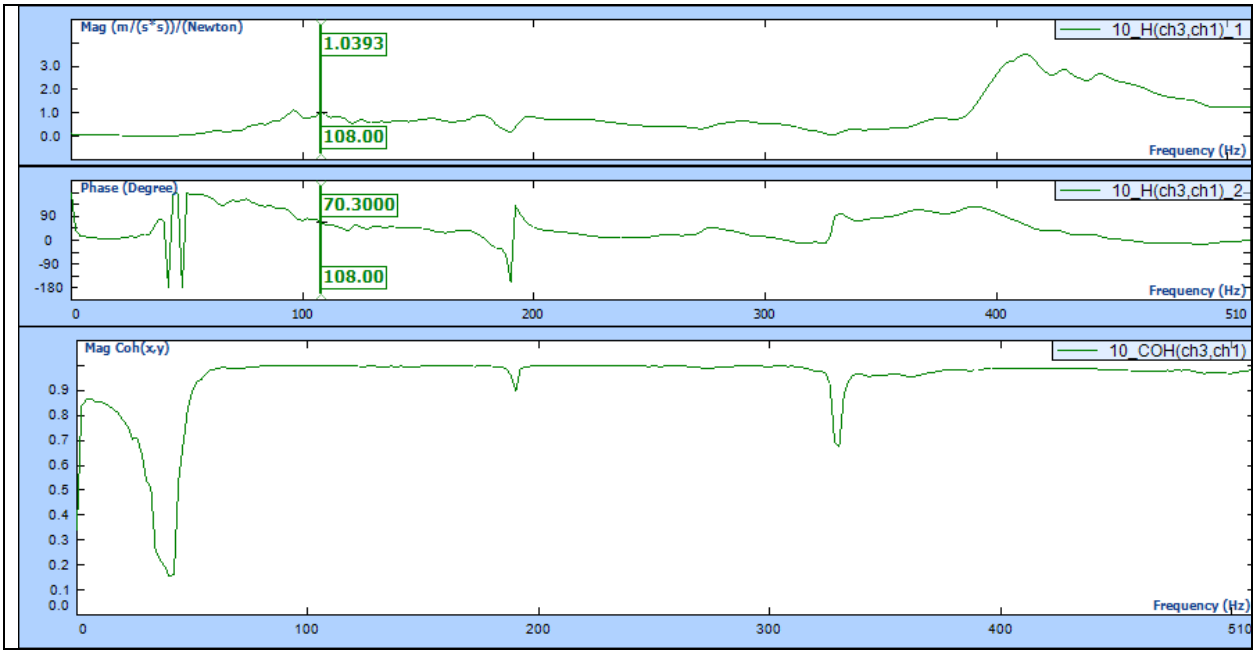
Photograph 7: ***Impact Test Data At 86 Slot Pole Jumper Bottom Radial***



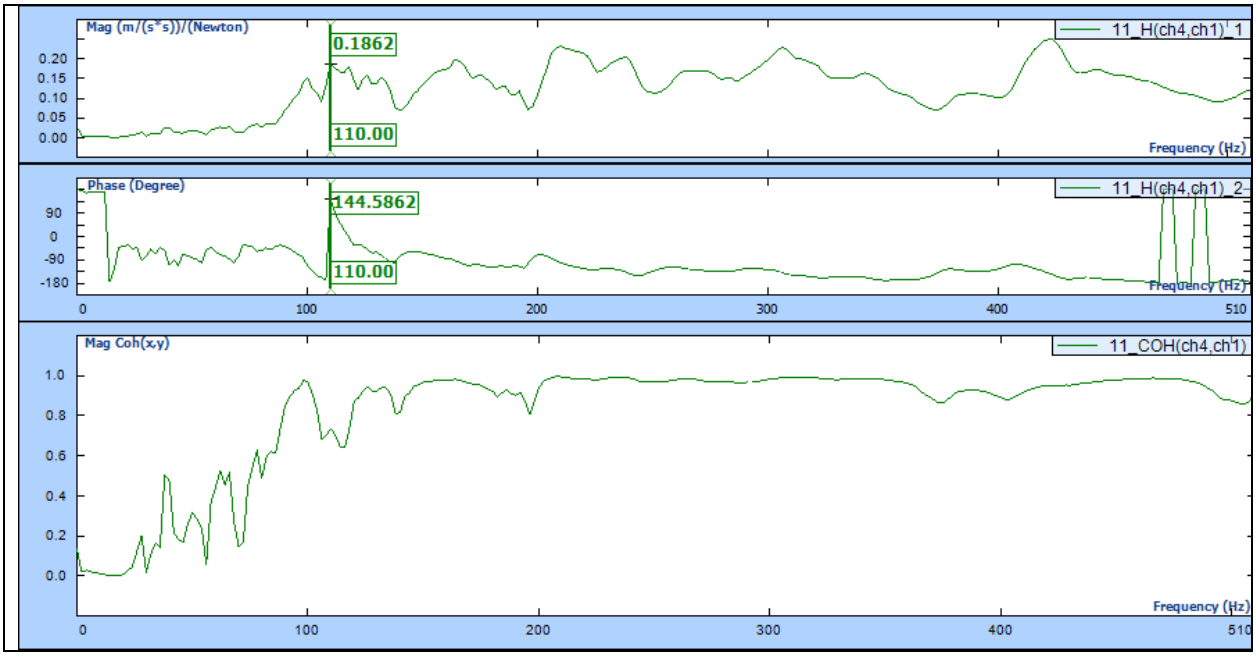
Photograph 8: ***Impact Test Data At 86 Slot Pole Jumper Bottom Tangential***



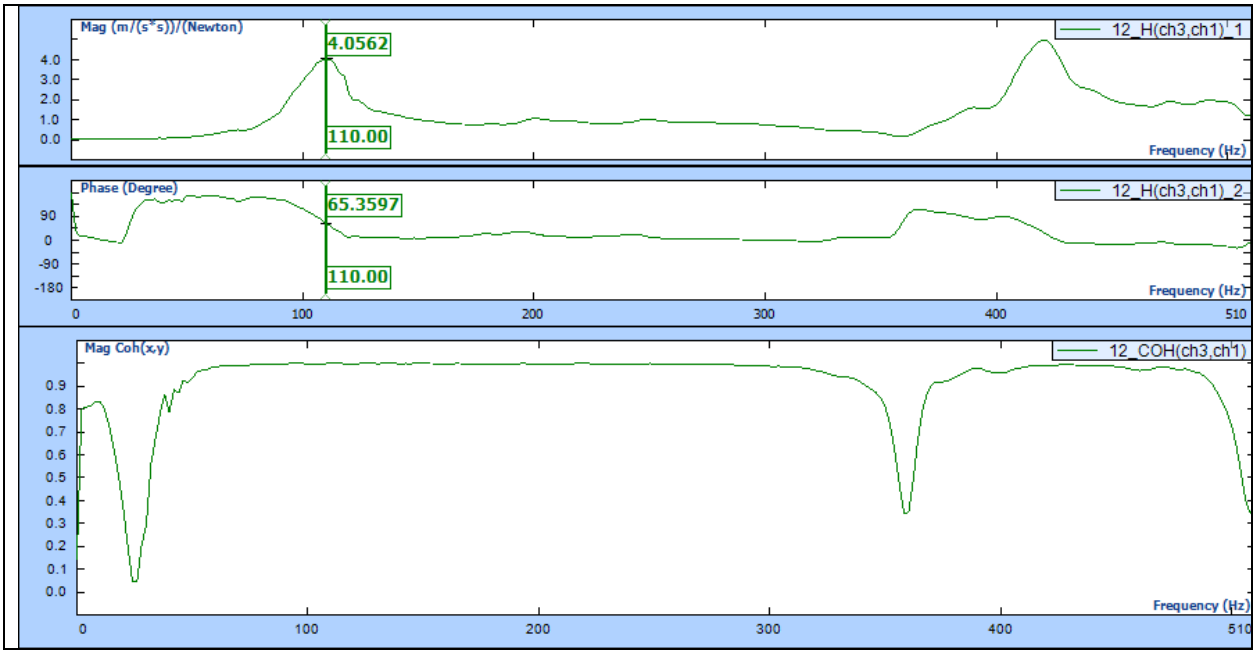
Photograph 9: ***Impact Test Data At 91 Slot Pole Jumper Top Radial***



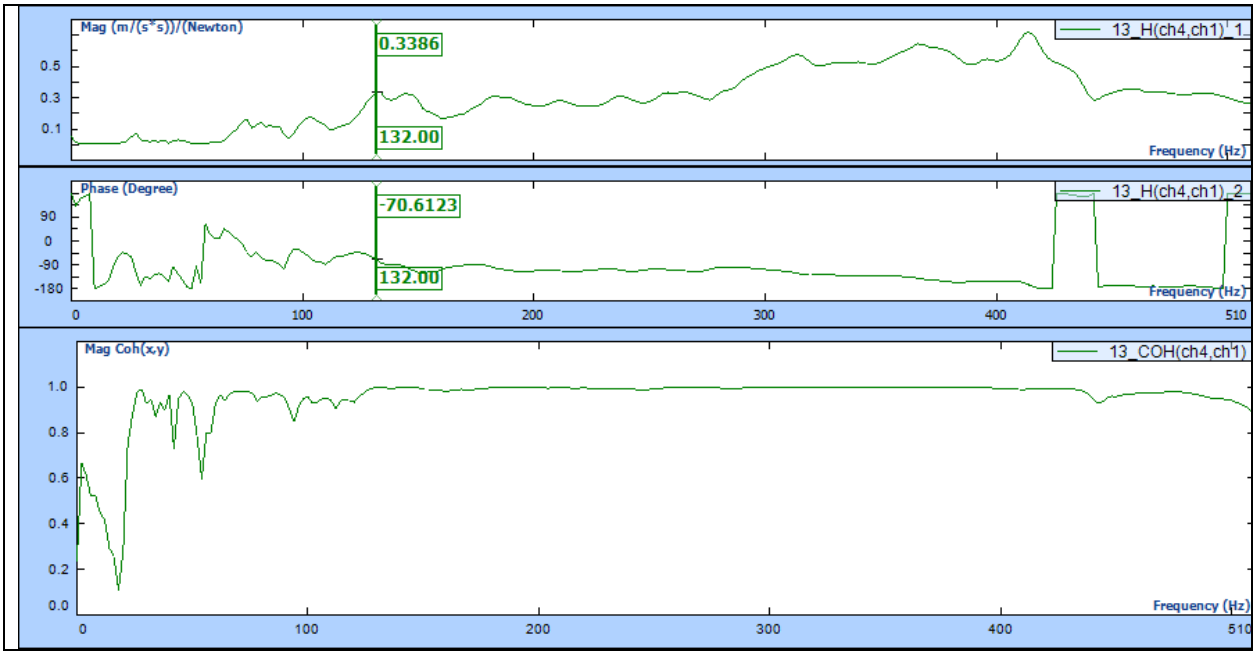
Photograph 10: ***Impact Test Data At 91 Slot Pole Jumper Top Tangential***



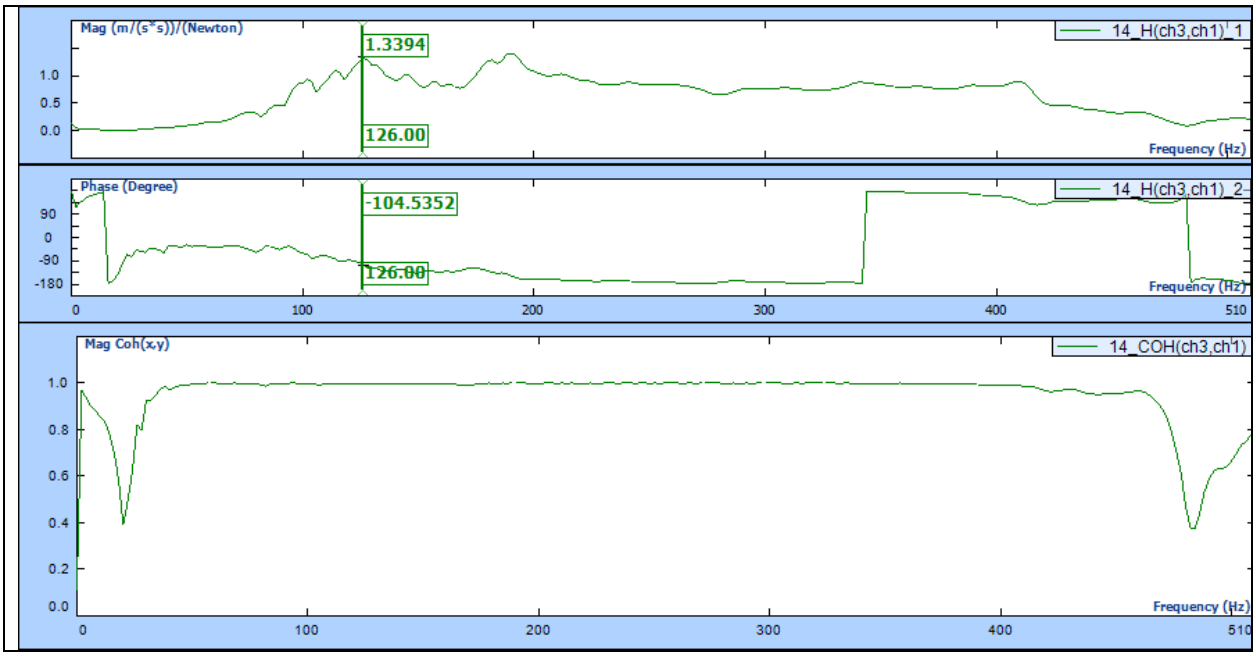
Photograph 11: ***Impact Test Data At 91 Slot Pole Jumper Bottom Radial***



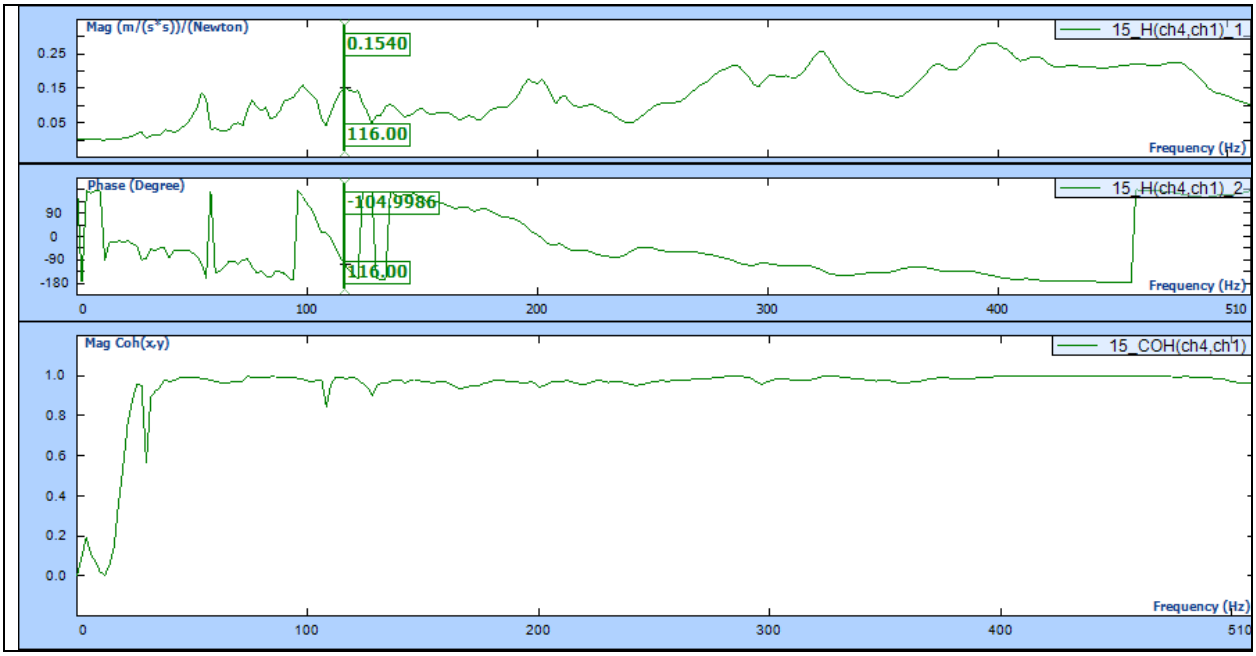
Photograph 12: ***Impact Test Data At 91 Slot Pole Jumper Bottom Tangential***



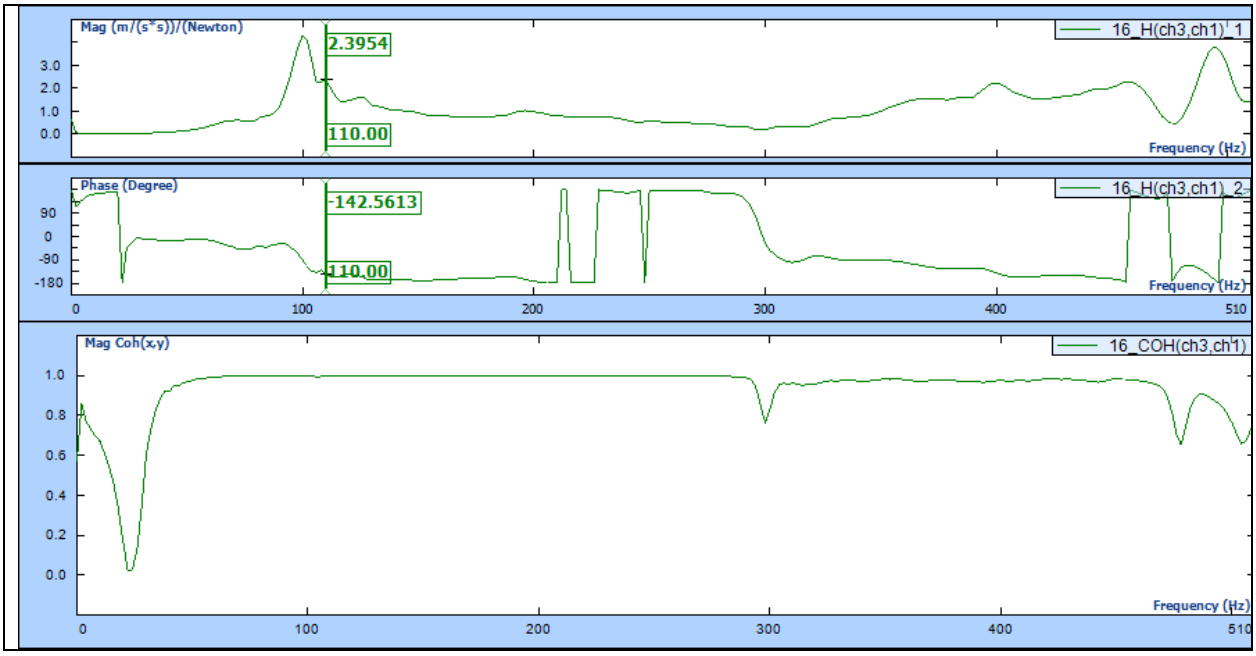
Photograph 13: ***Impact Test Data At 95 Slot Pole Jumper Top Radial***



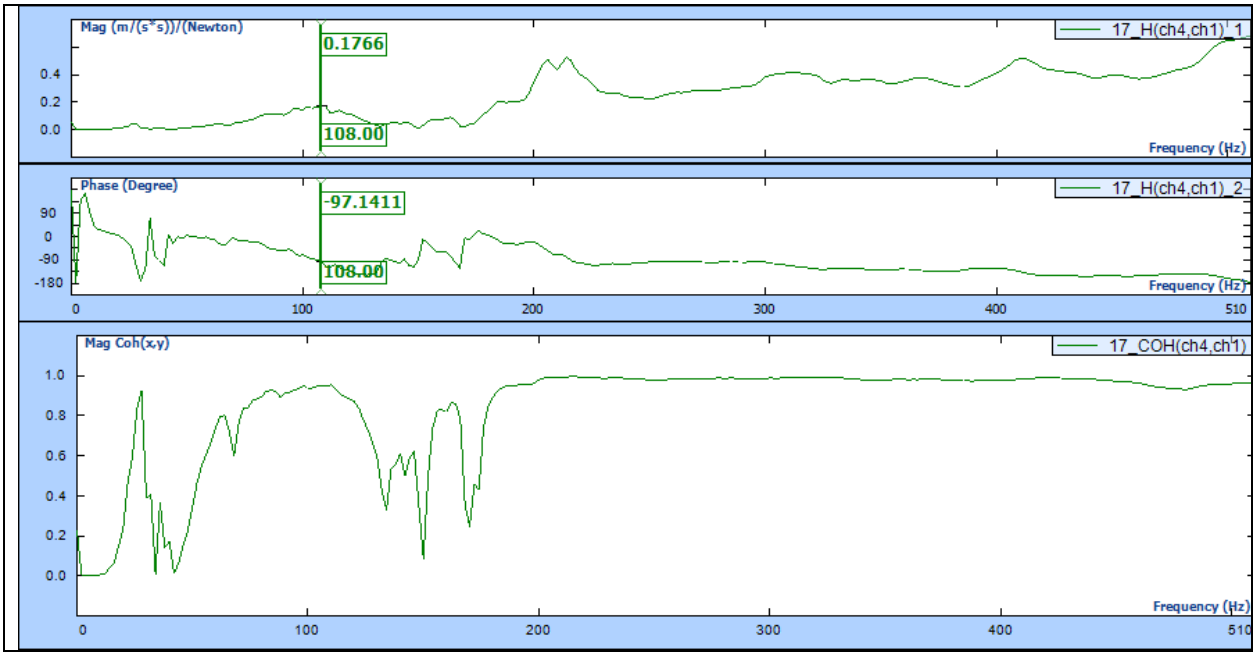
Photograph 14: ***Impact Test Data At 95 Slot Pole Jumper Top Tangential***



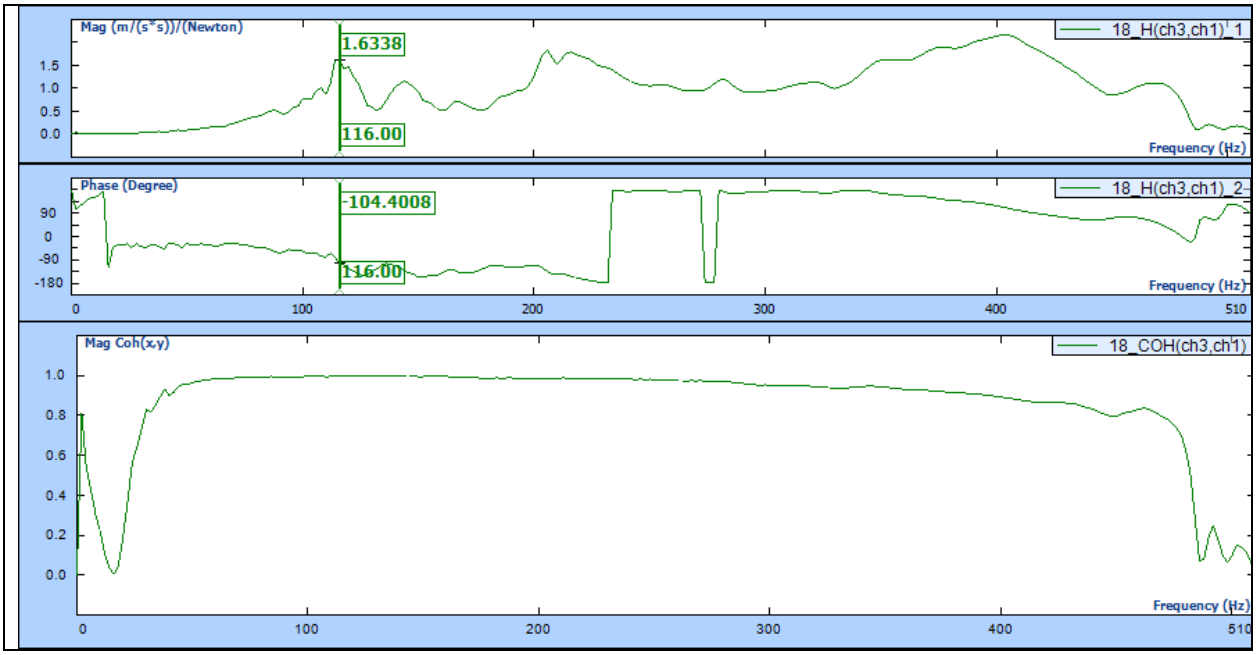
Photograph 15: ***Impact Test Data At 95 Slot Pole Jumper Bottom Radial***



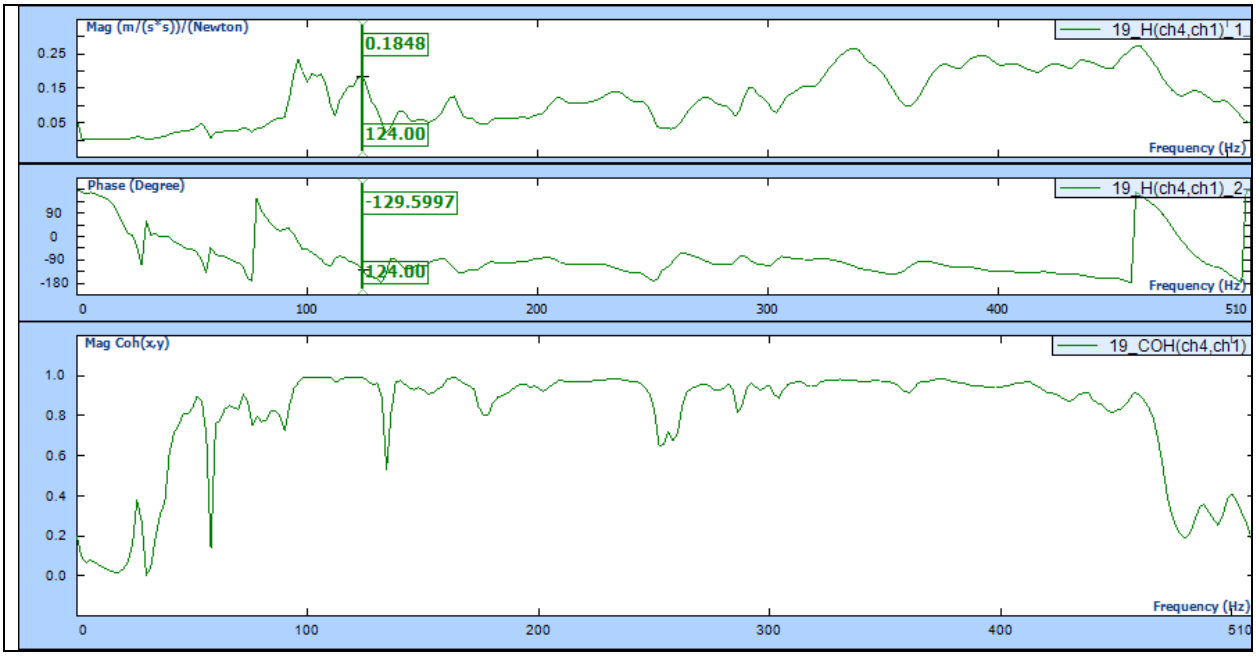
Photograph 16: ***Impact Test Data At 95 Slot Pole Jumper Bottom Tangential***



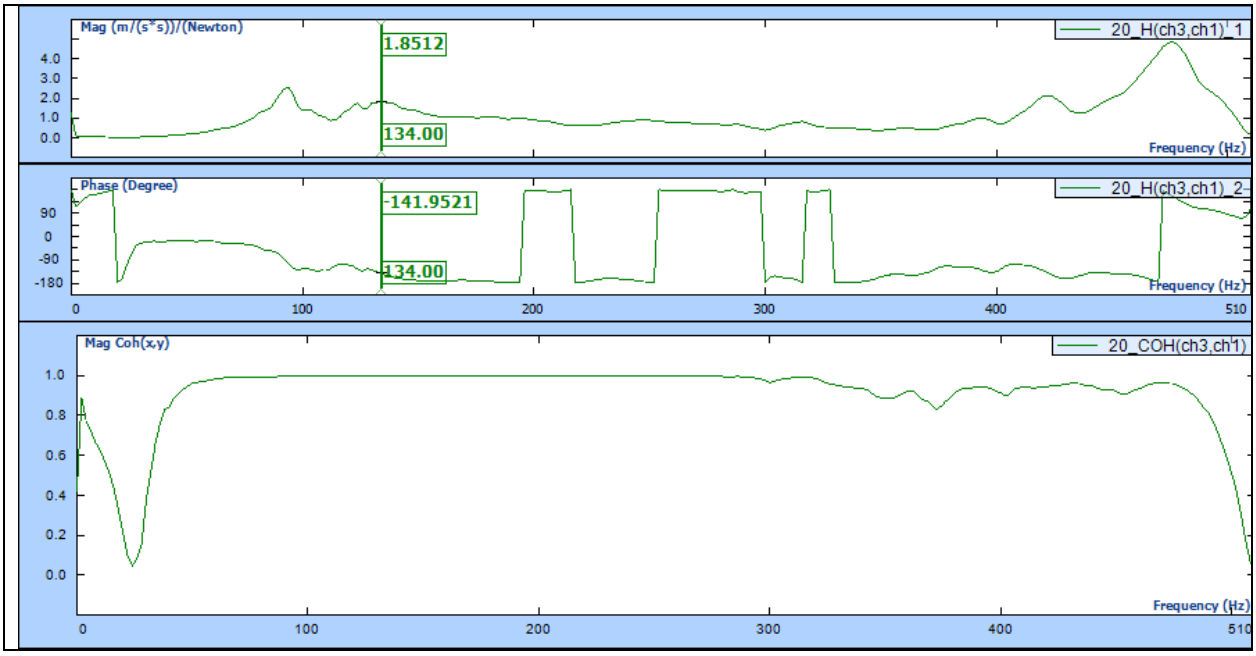
Photograph 17: ***Impact Test Data At 99 Slot Pole Jumper Top Radial***



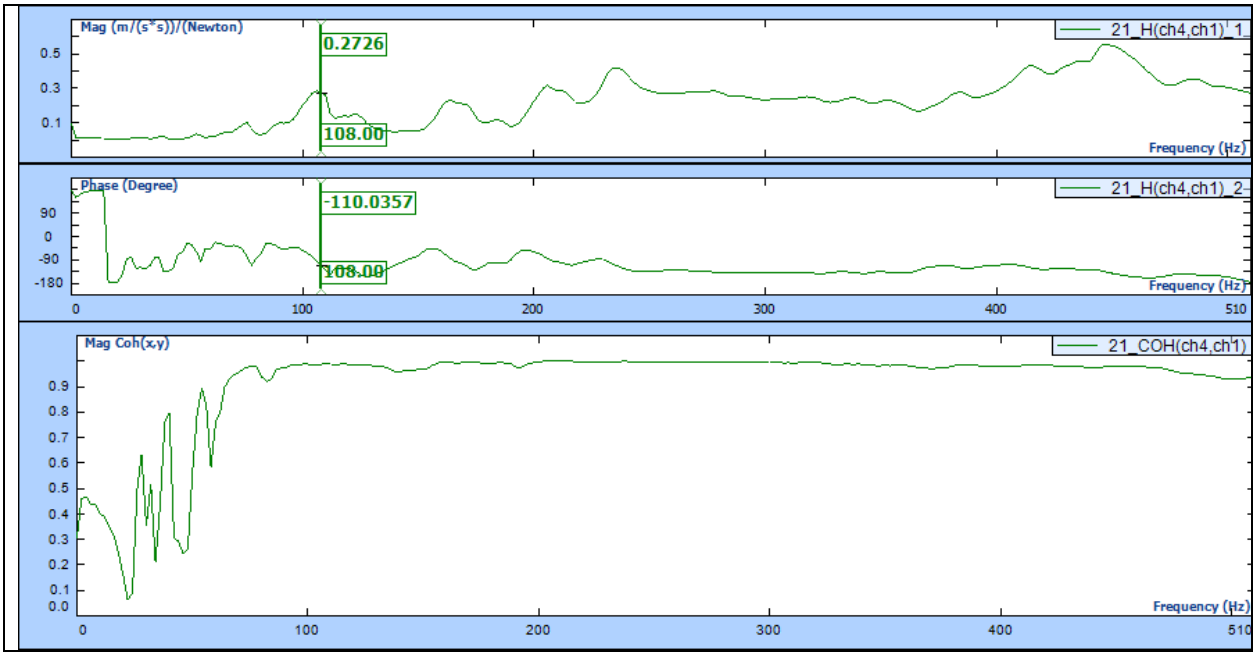
Photograph 18: ***Impact Test Data At 99 Slot Pole Jumper Top Tangential***



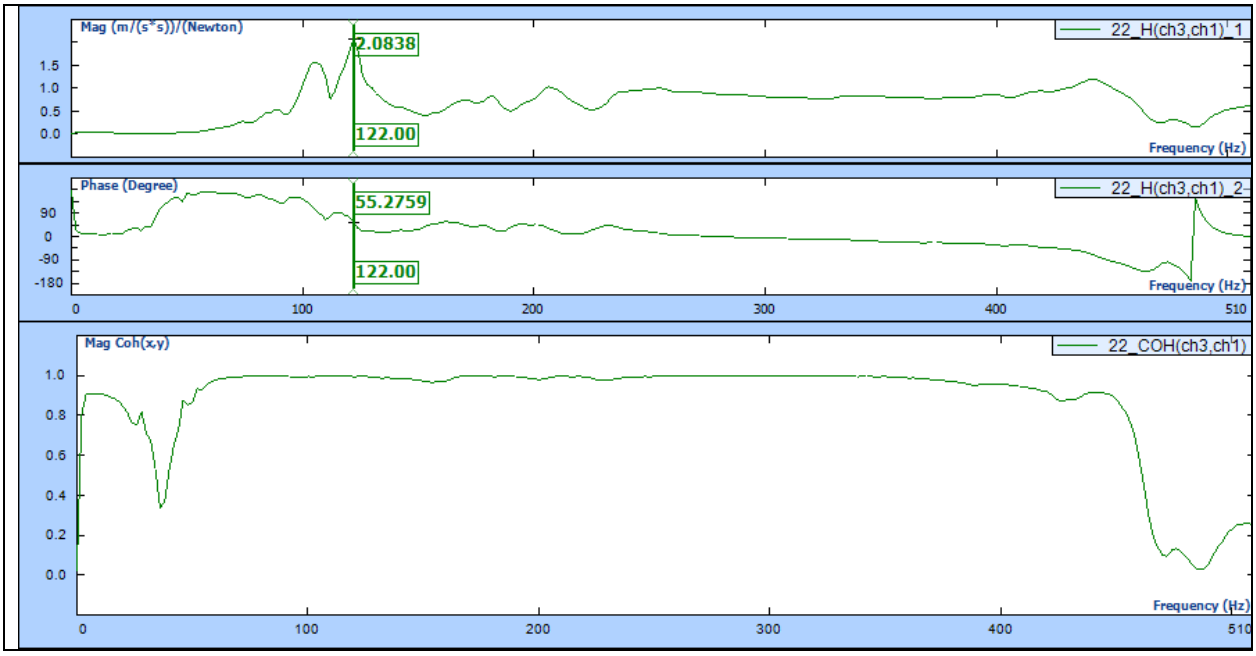
Photograph 19: ***Impact Test Data At 99 Slot Pole Jumper Bottom Radial***



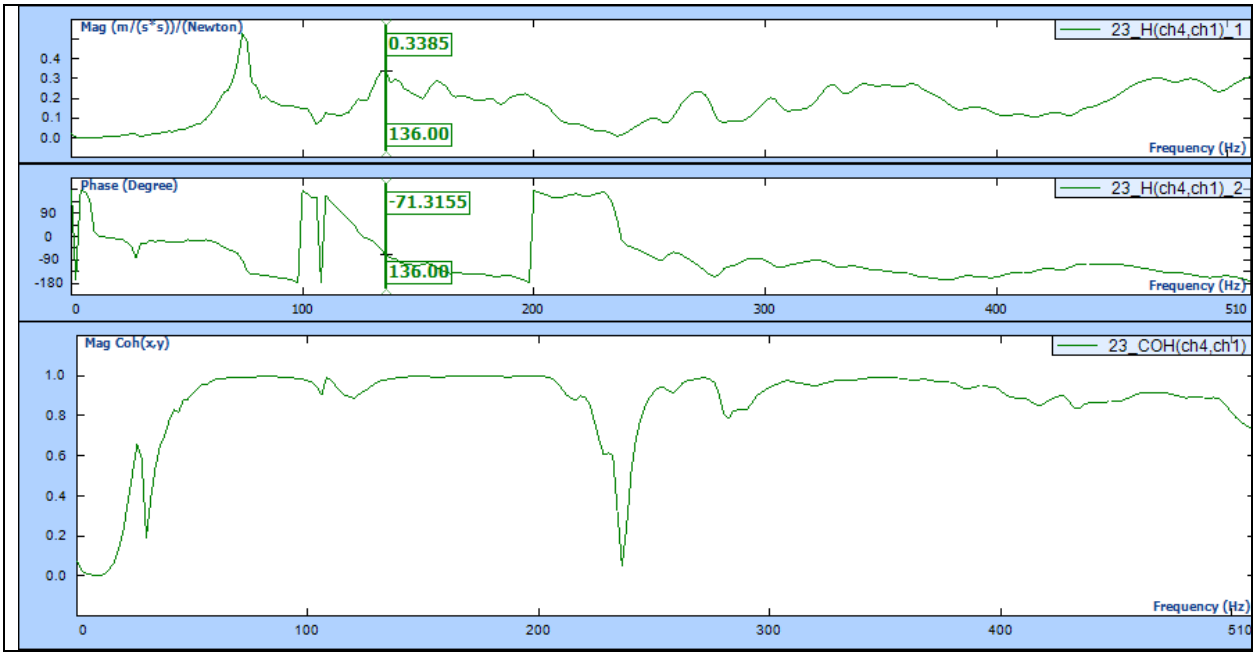
Photograph 20: ***Impact Test Data At 99 Slot Pole Jumper Bottom Tangential***



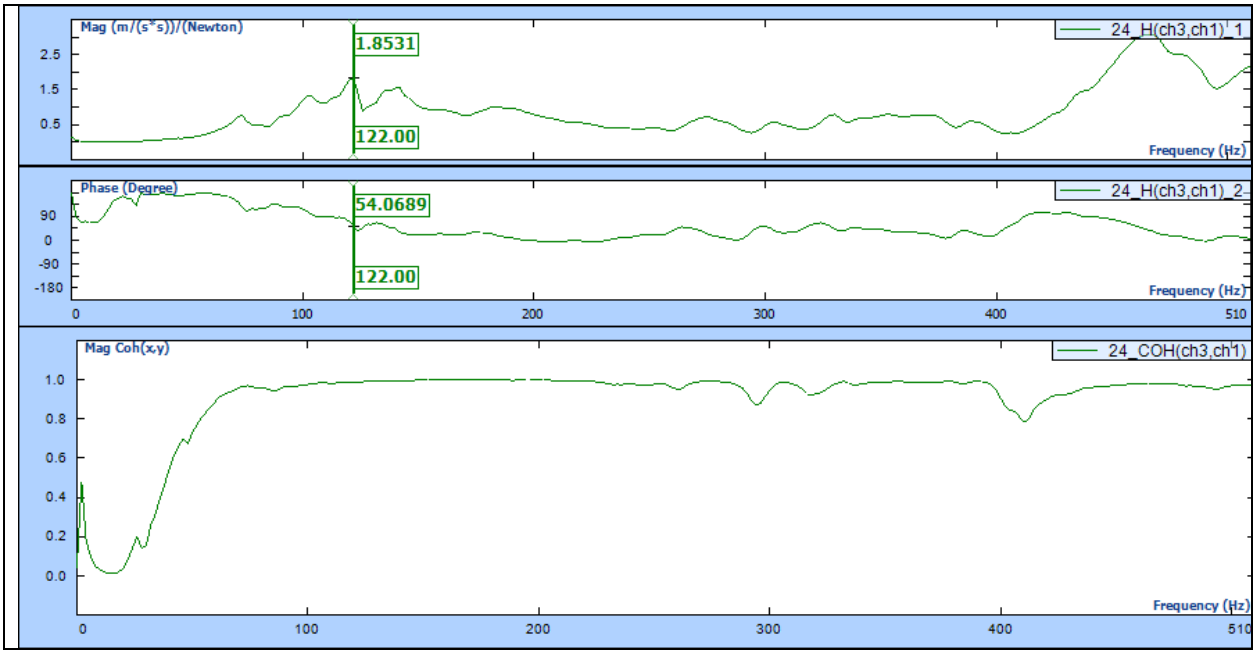
Photograph 21: ***Impact Test Data At 104 Slot Pole Jumper Top Radial***



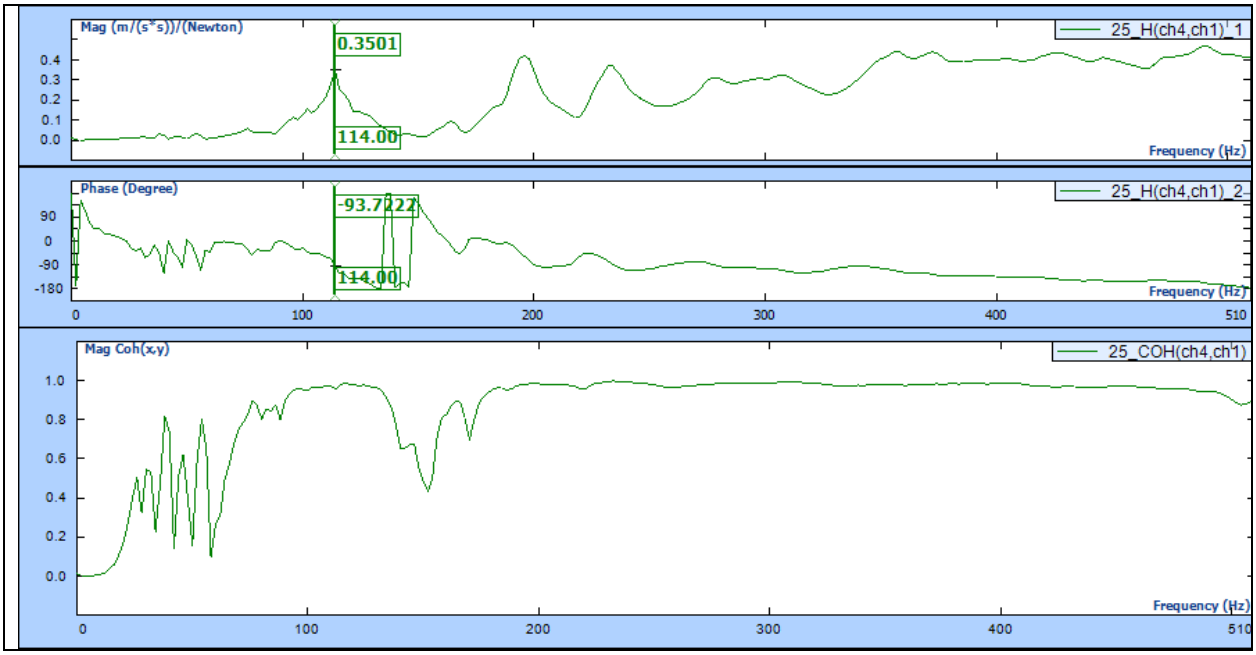
Photograph 22: ***Impact Test Data At 104 Slot Pole Jumper Top Tangential***



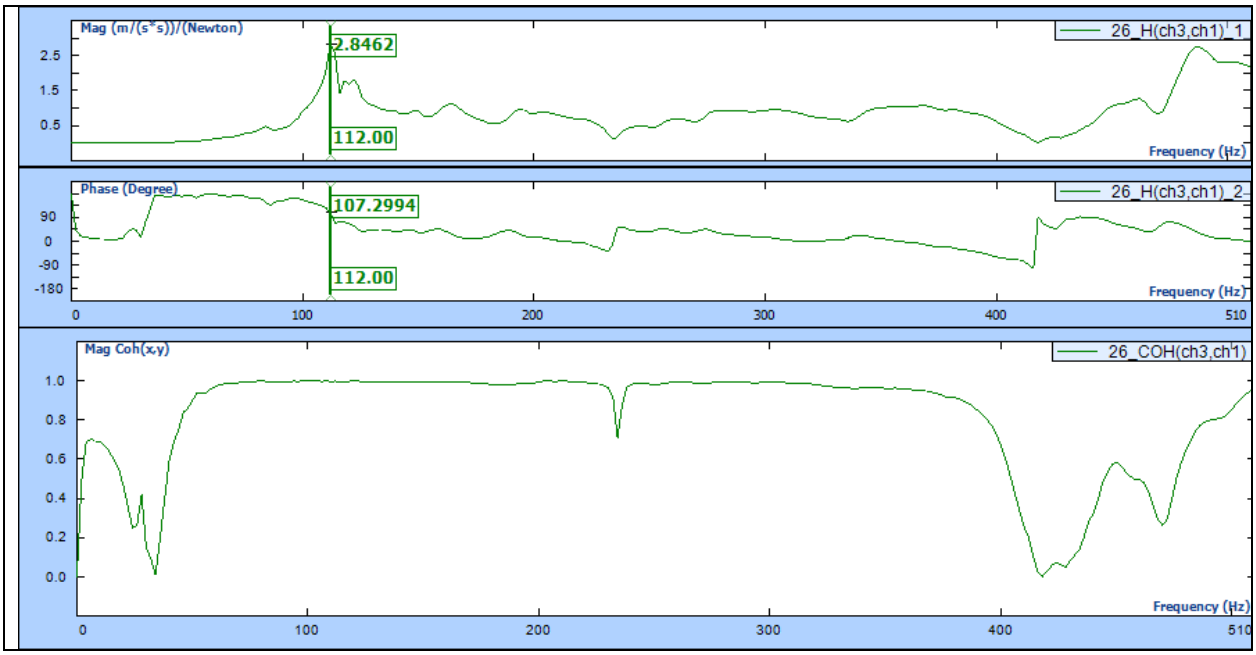
Photograph 23: ***Impact Test Data At 104 Slot Pole Jumper Bottom Radial***



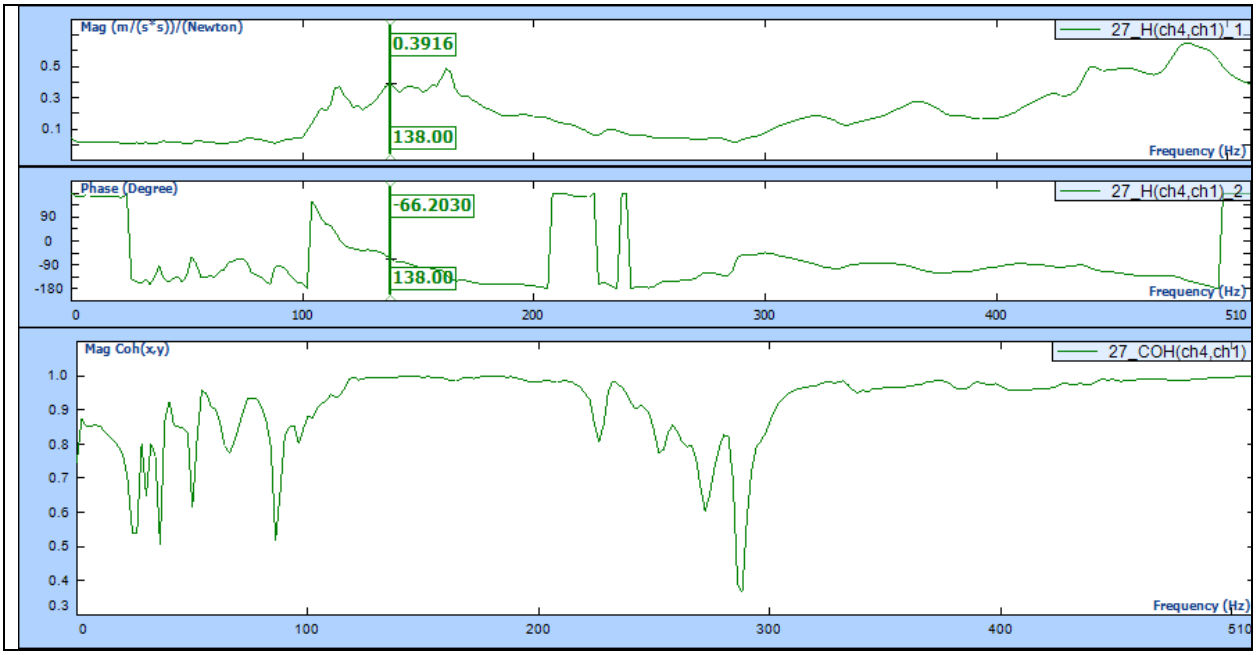
Photograph 24: ***Impact Test Data At 104 Slot Pole Jumper Bottom Tangential***



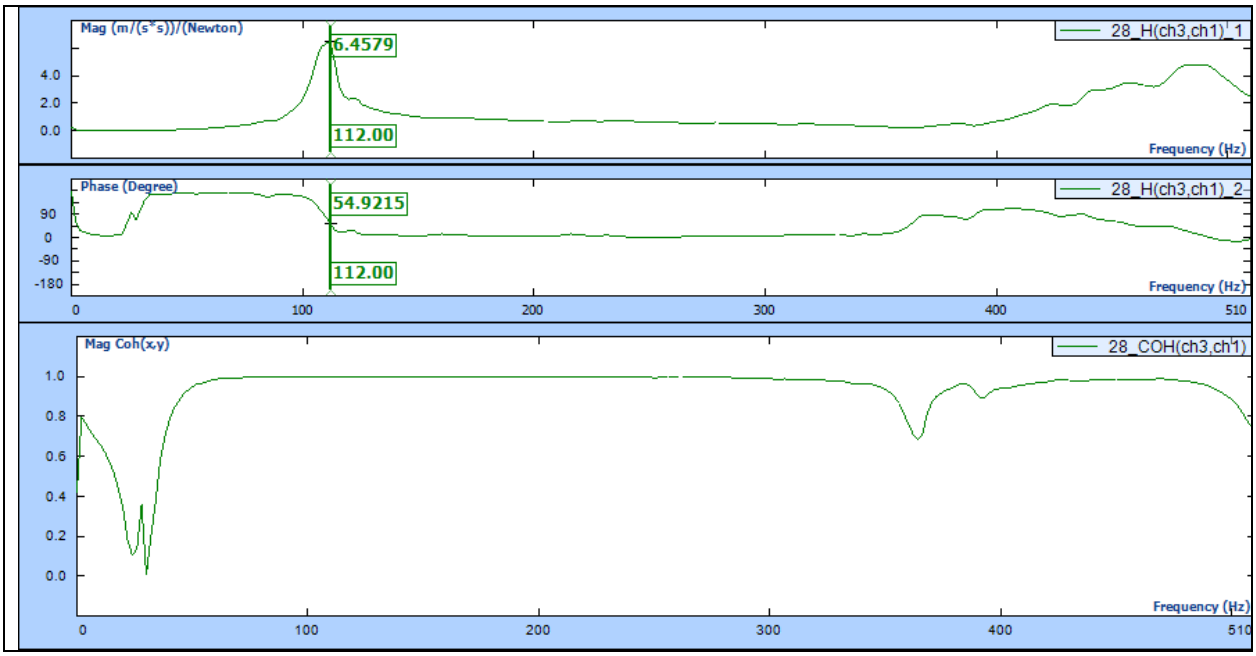
Photograph 25: ***Impact Test Data At 108 Slot Pole Jumper Top Radial***



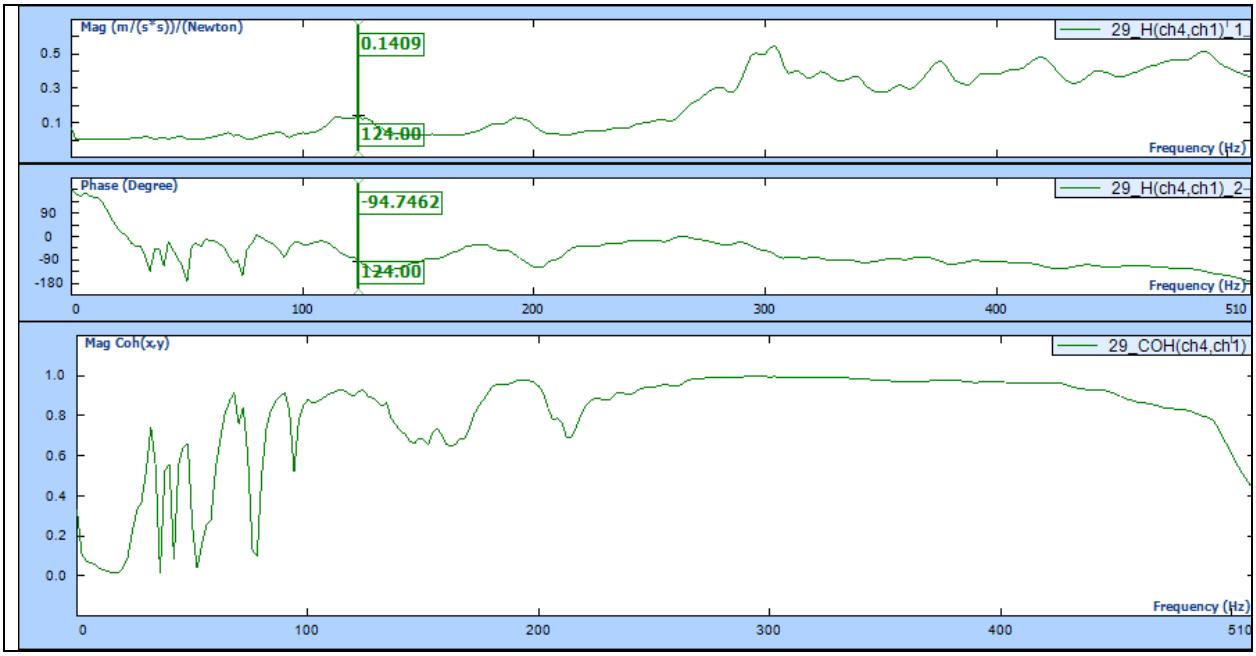
Photograph 26: ***Impact Test Data At 108 Slot Pole Jumper Top Tangential***



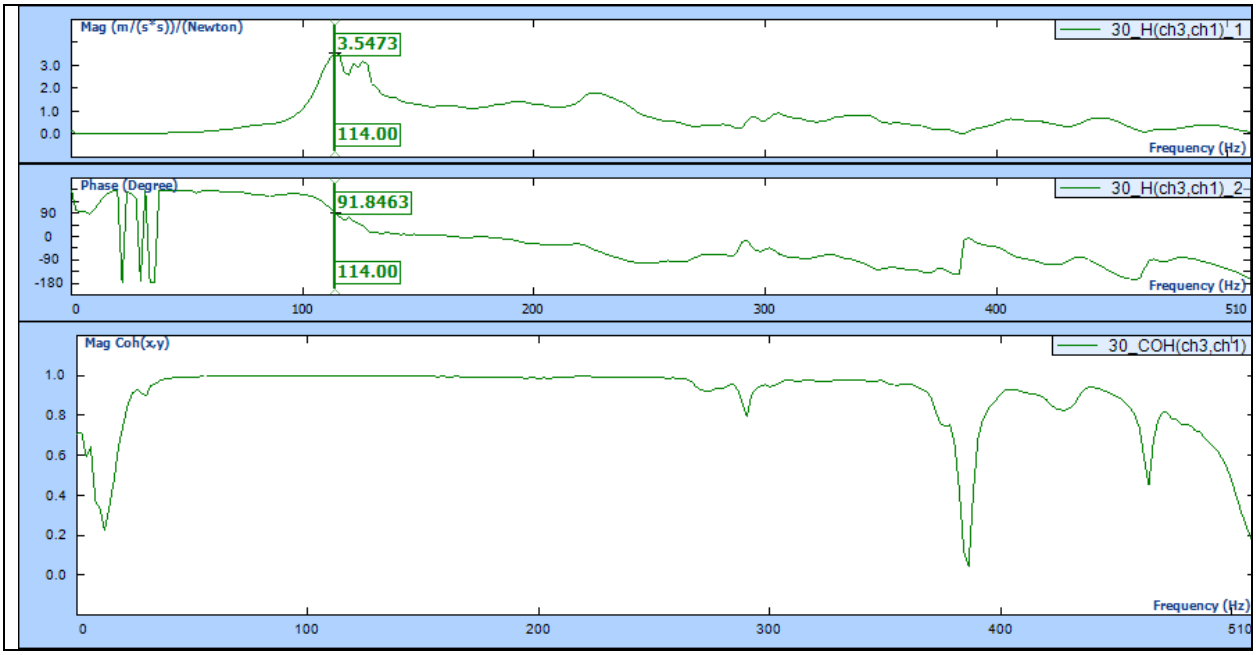
Photograph 27: ***Impact Test Data At 108 Slot Pole Jumper Bottom Radial***



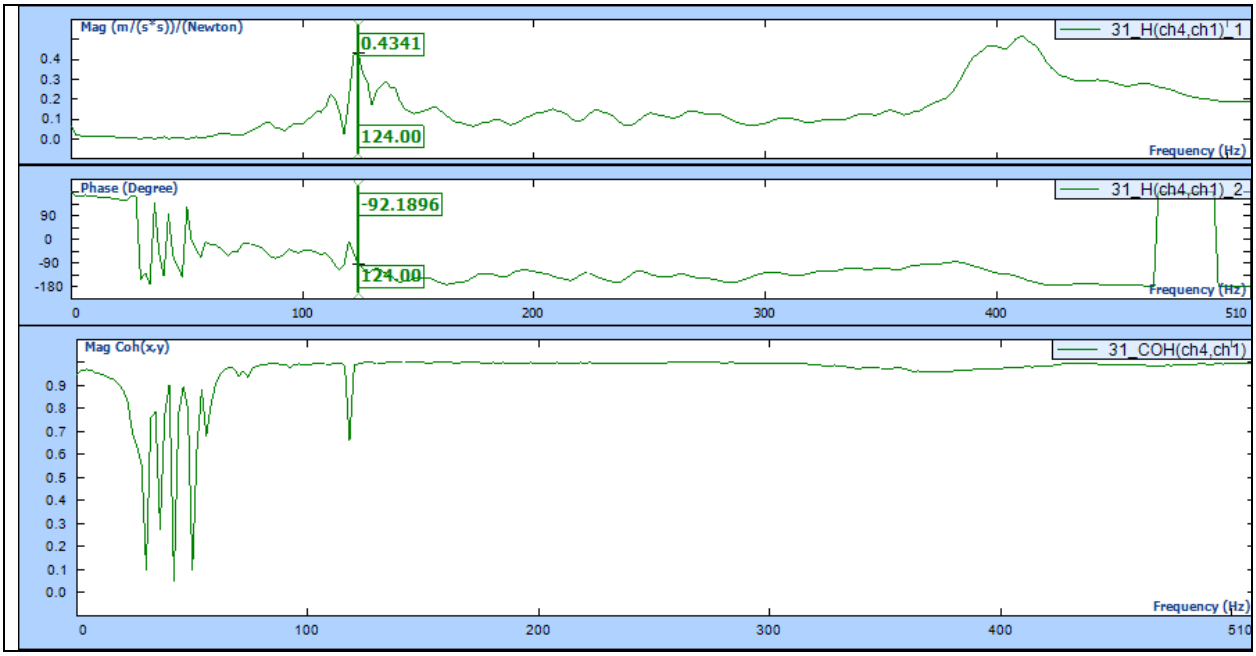
Photograph 28: ***Impact Test Data At 108 Slot Pole Jumper Bottom Tangential***



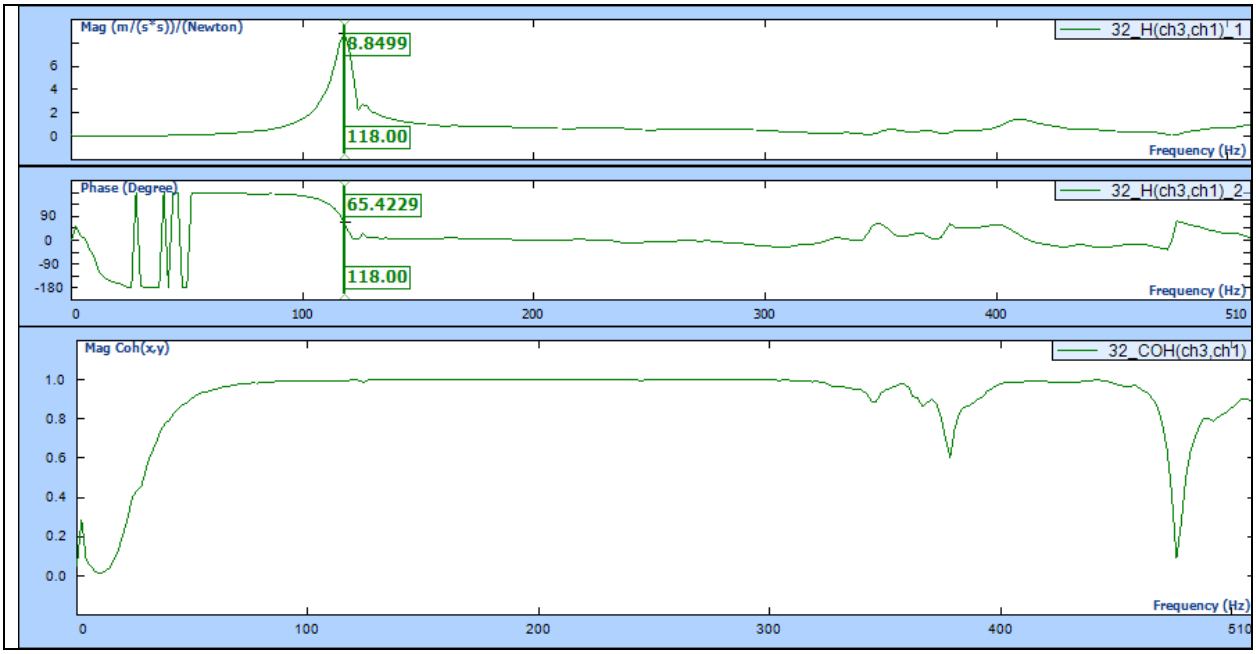
Photograph 29: ***Impact Test Data At 113 Slot Pole Jumper Top Radial***



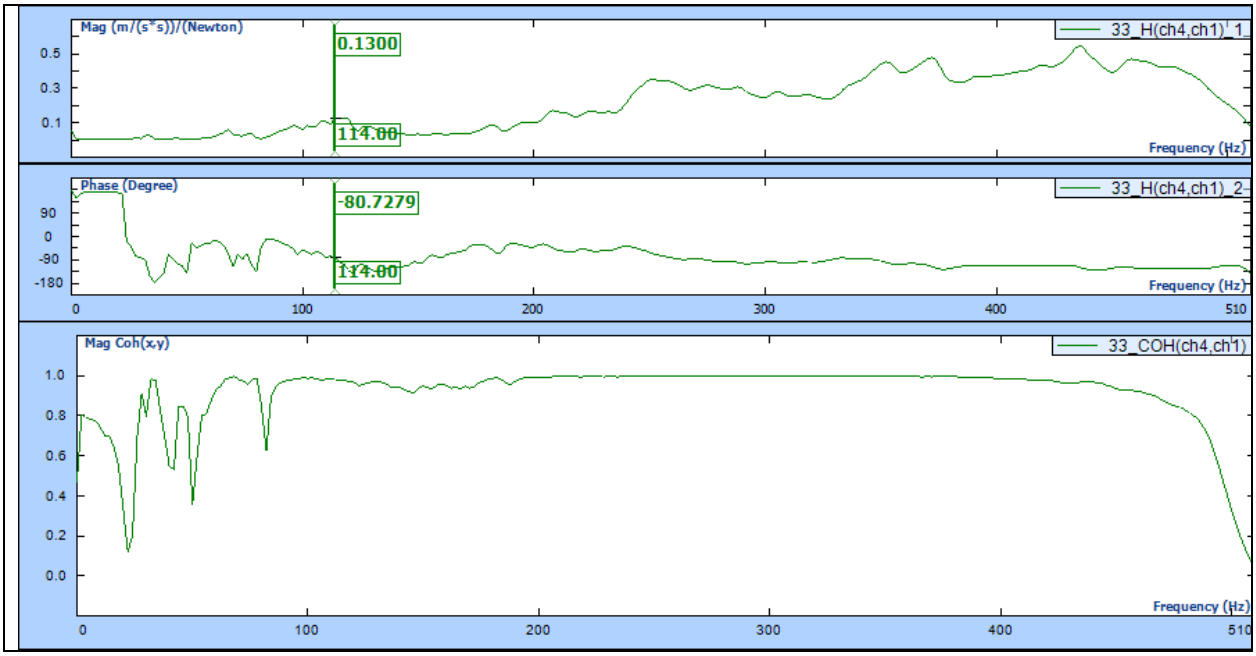
Photograph 30: ***Impact Test Data At 113 Slot Pole Jumper Top Tangential***



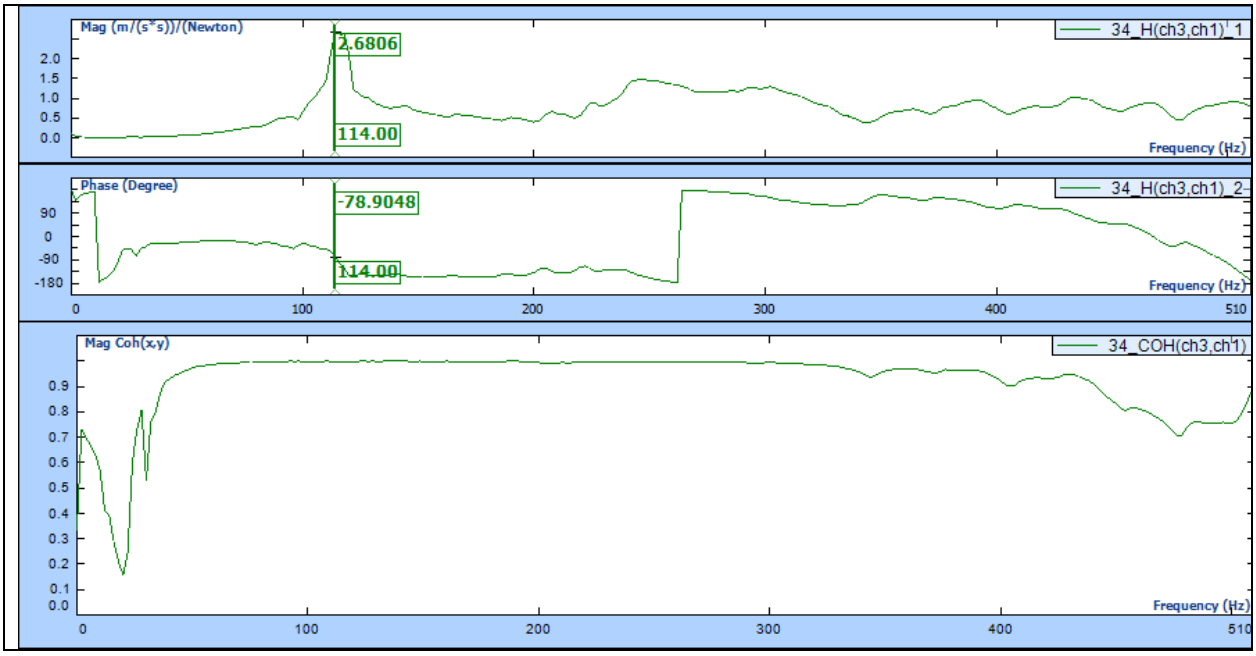
Photograph 31: ***Impact Test Data At 113 Slot Pole Jumper Bottom Radial***



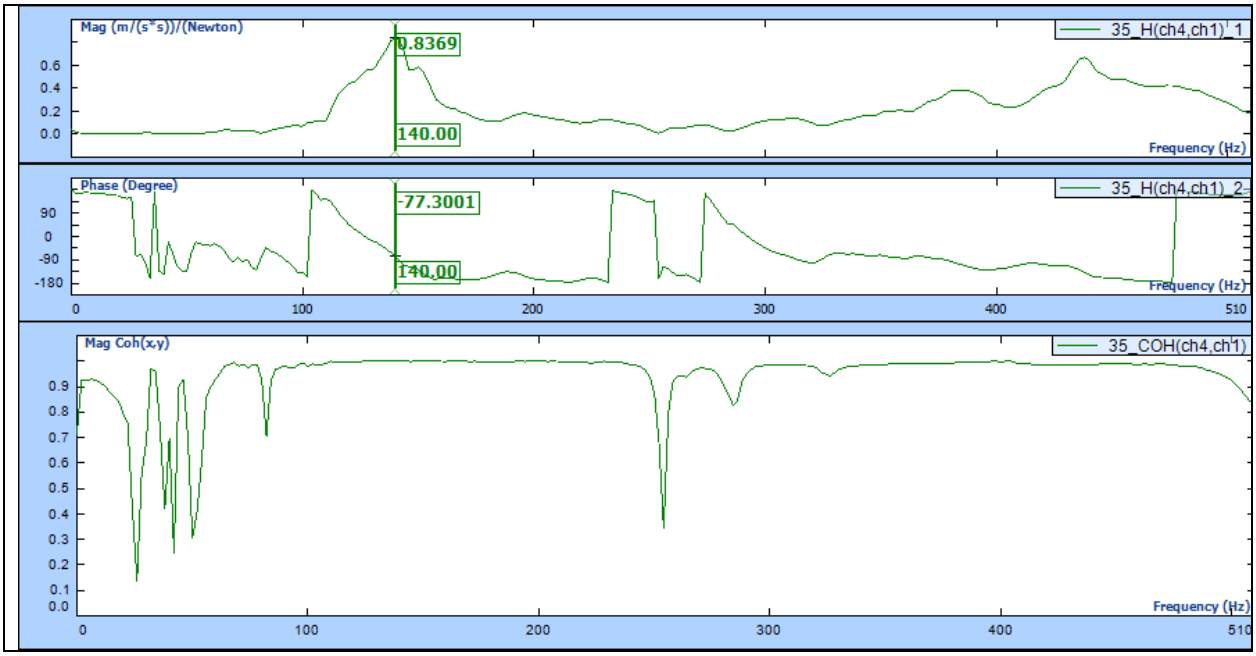
Photograph 32: ***Impact Test Data At 113 Slot Pole Jumper Bottom Tangential***



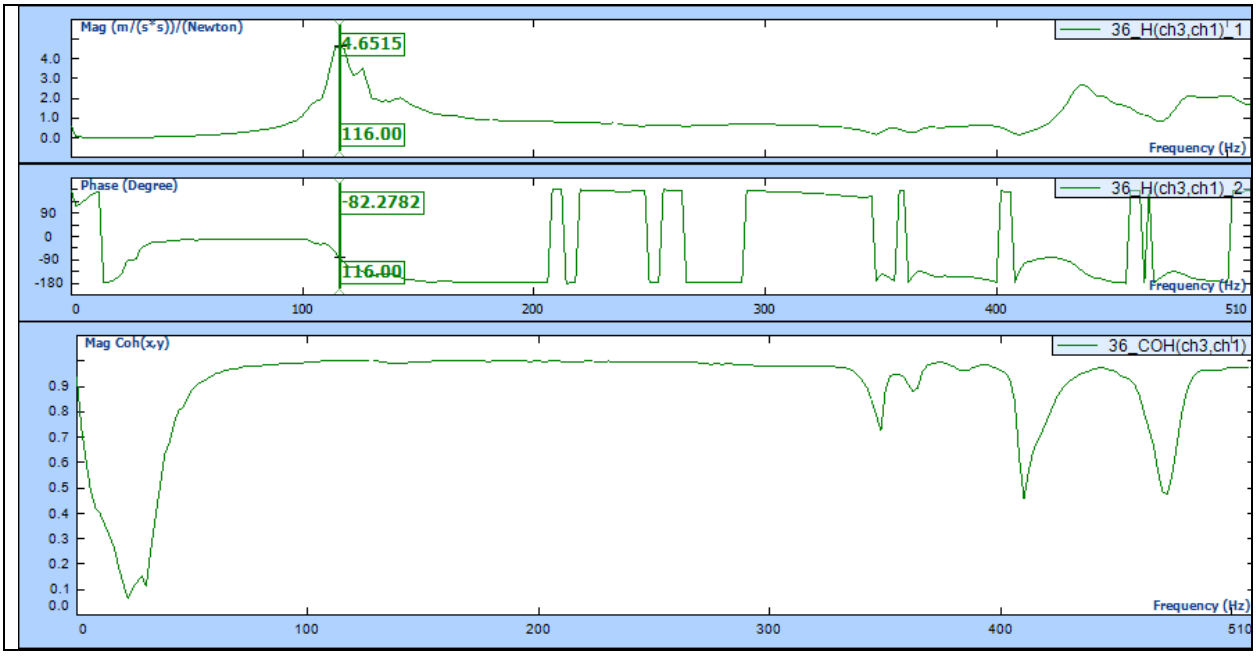
Photograph 33: ***Impact Test Data At 117 Slot Pole Jumper Top Radial***



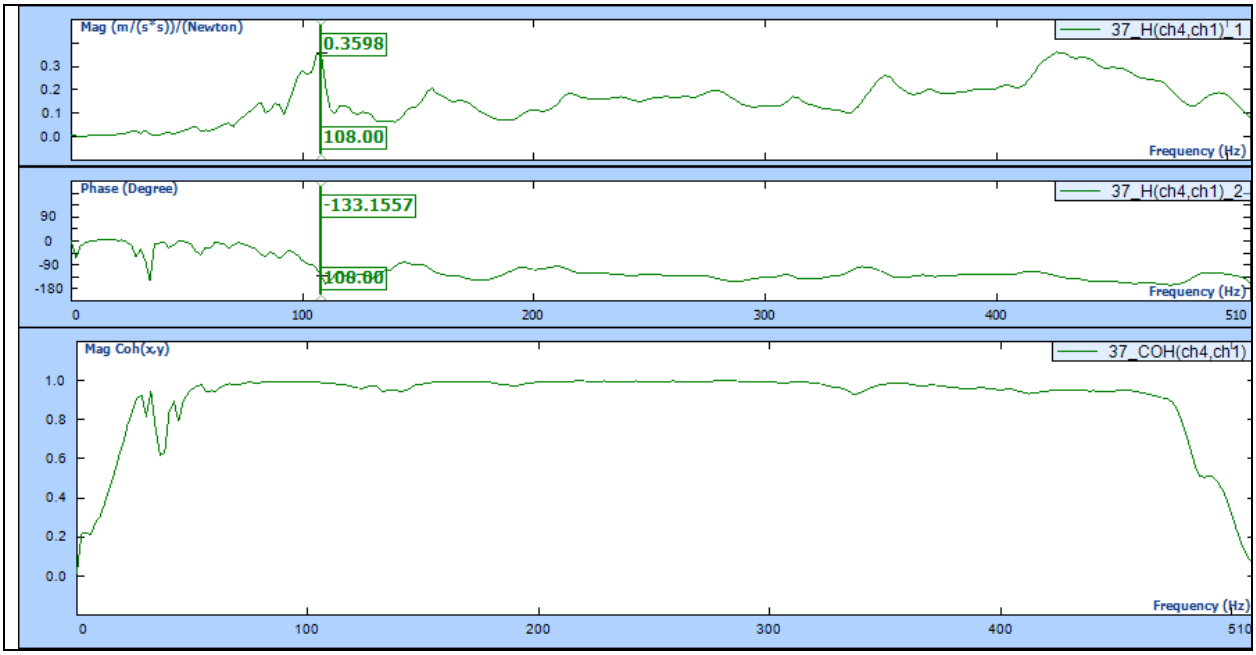
Photograph 34: ***Impact Test Data At 117 Slot Pole Jumper Top Tangential***



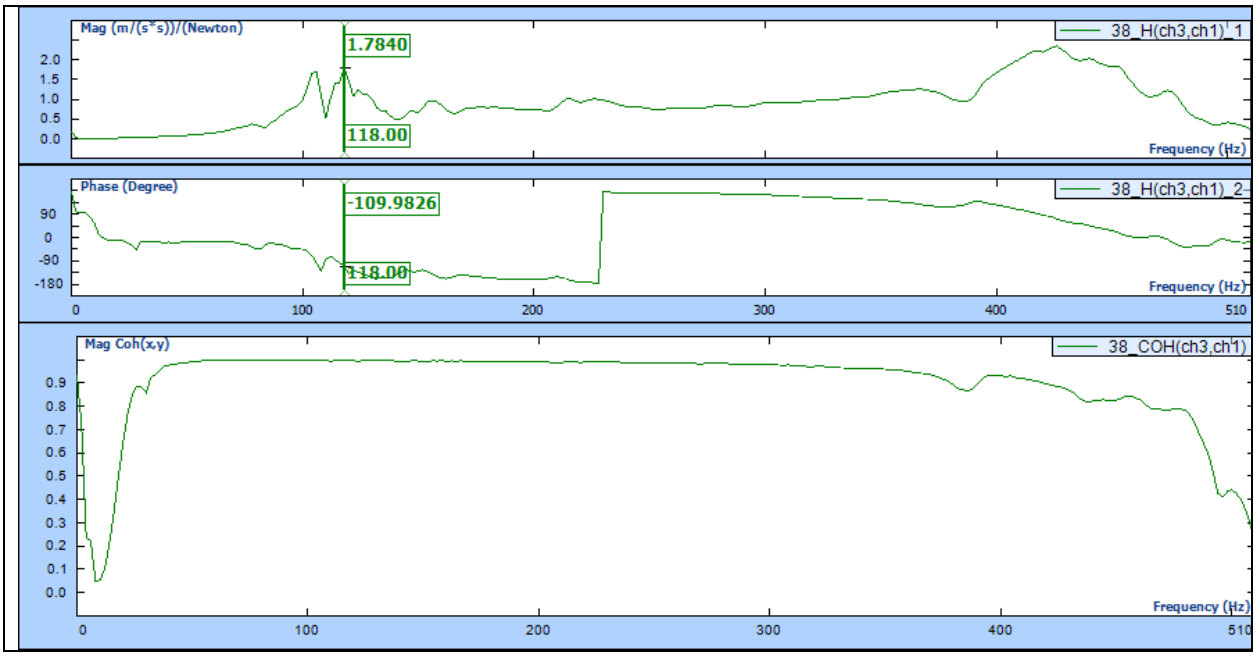
Photograph 35: ***Impact Test Data At 117 Slot Pole Jumper Bottom Radial***



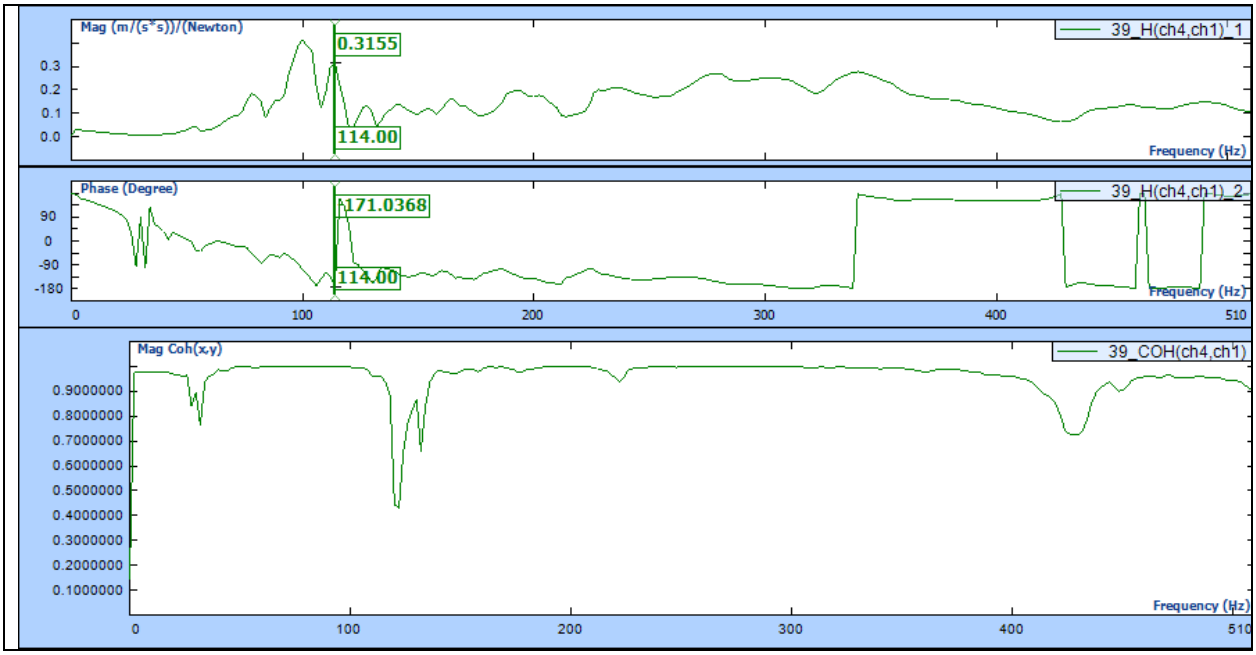
Photograph 36: ***Impact Test Data At 117 Slot Pole Jumper Bottom Tangential***



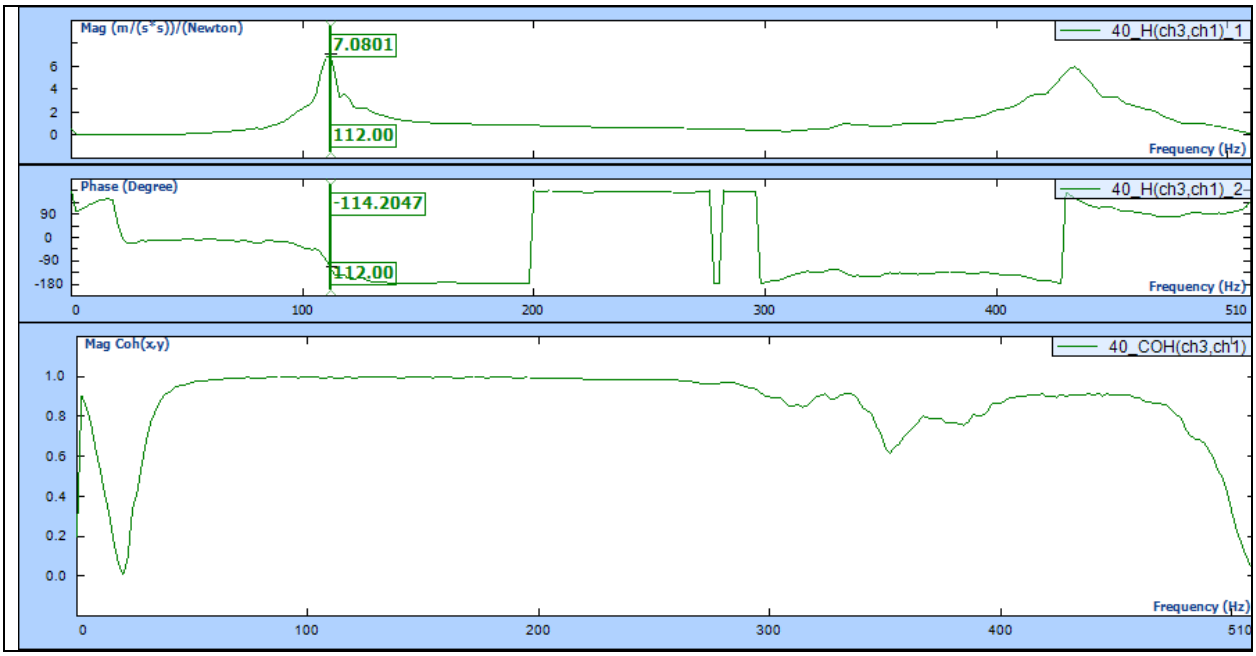
Photograph 37: ***Impact Test Data At 121 Slot Pole Jumper Top Radial***



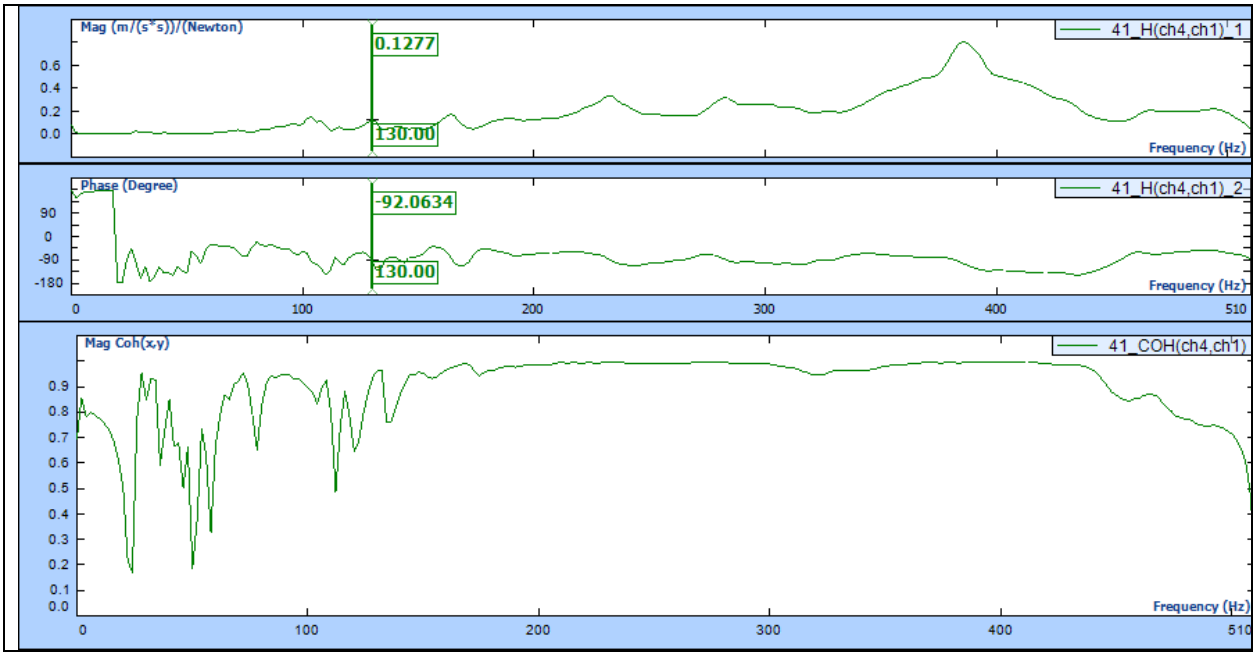
Photograph 38: ***Impact Test Data At 121 Slot Pole Jumper Top Tangential***



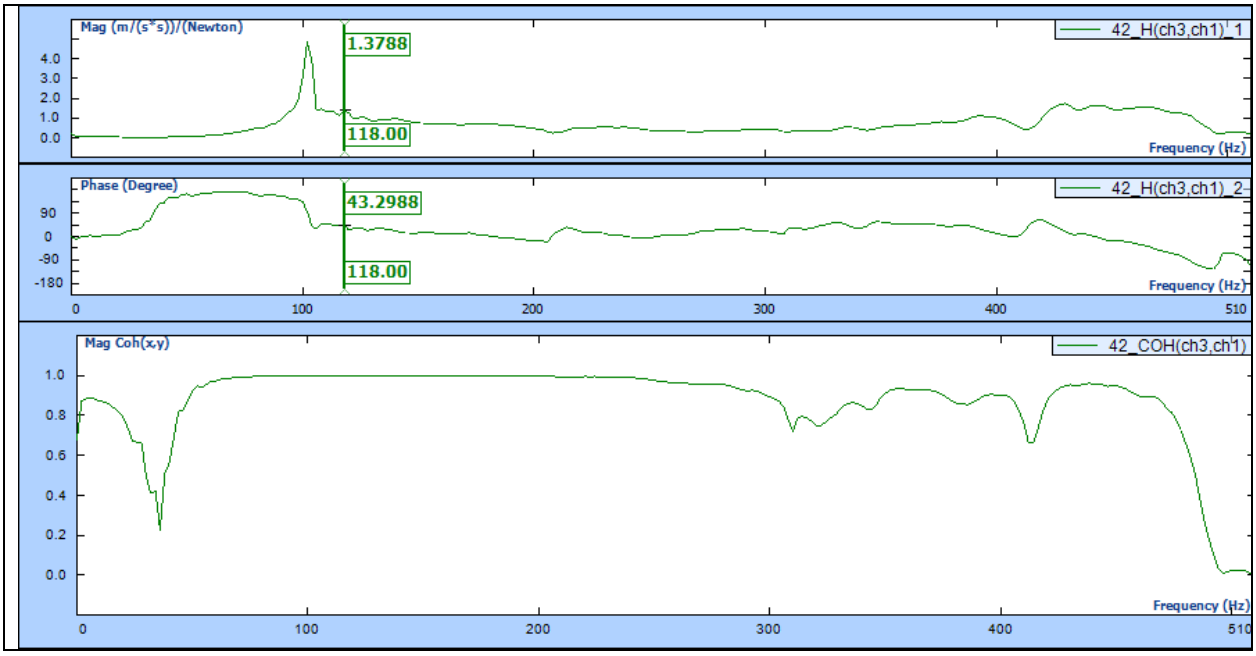
Photograph 39: ***Impact Test Data At 121 Slot Pole Jumper Bottom Radial***



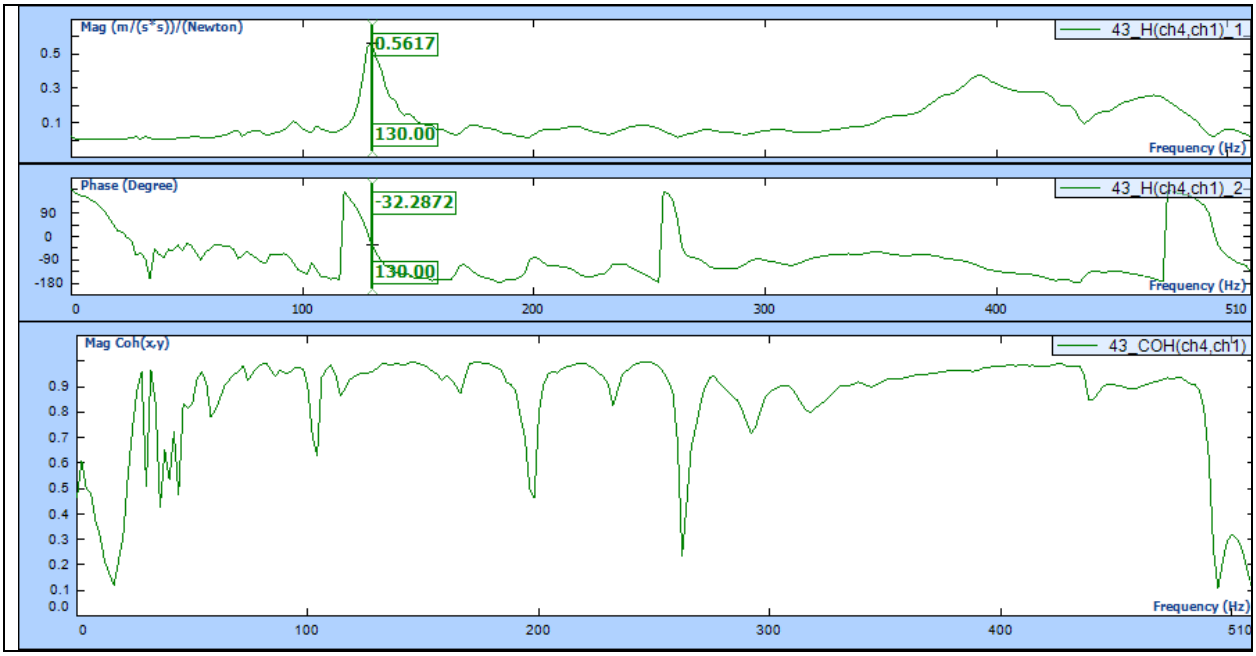
Photograph 40: ***Impact Test Data At 121 Slot Pole Jumper Bottom Tangential***



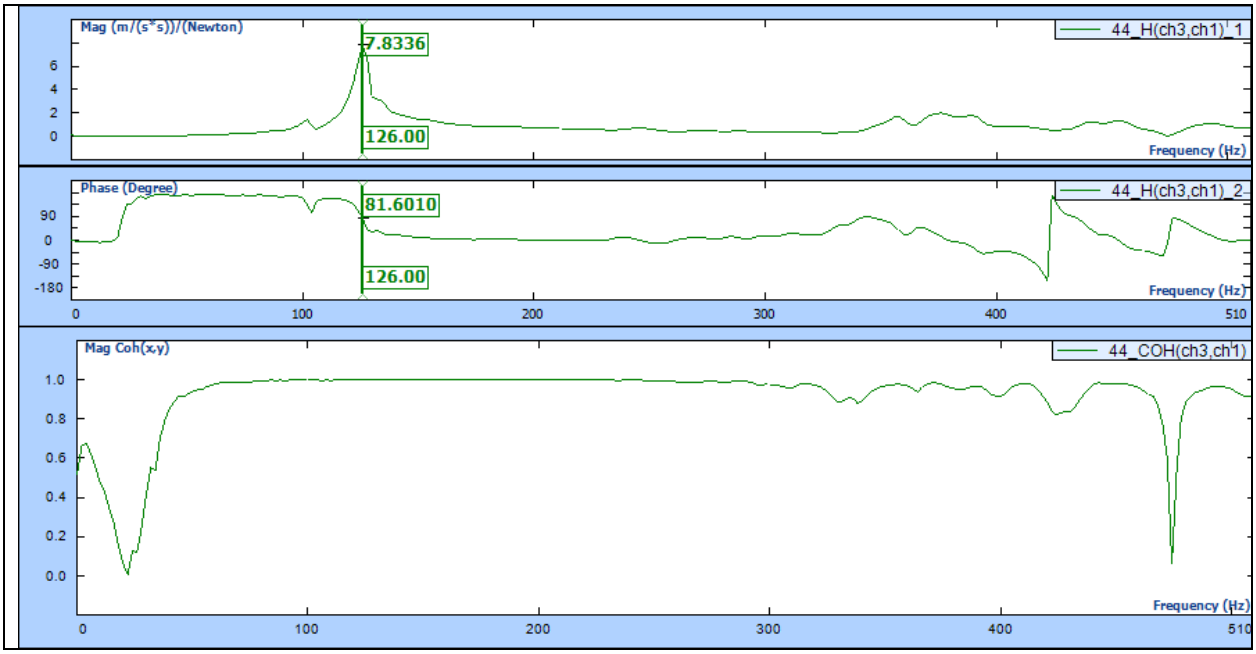
Photograph 41: ***Impact Test Data At 126 Slot Pole Jumper Top Radial***



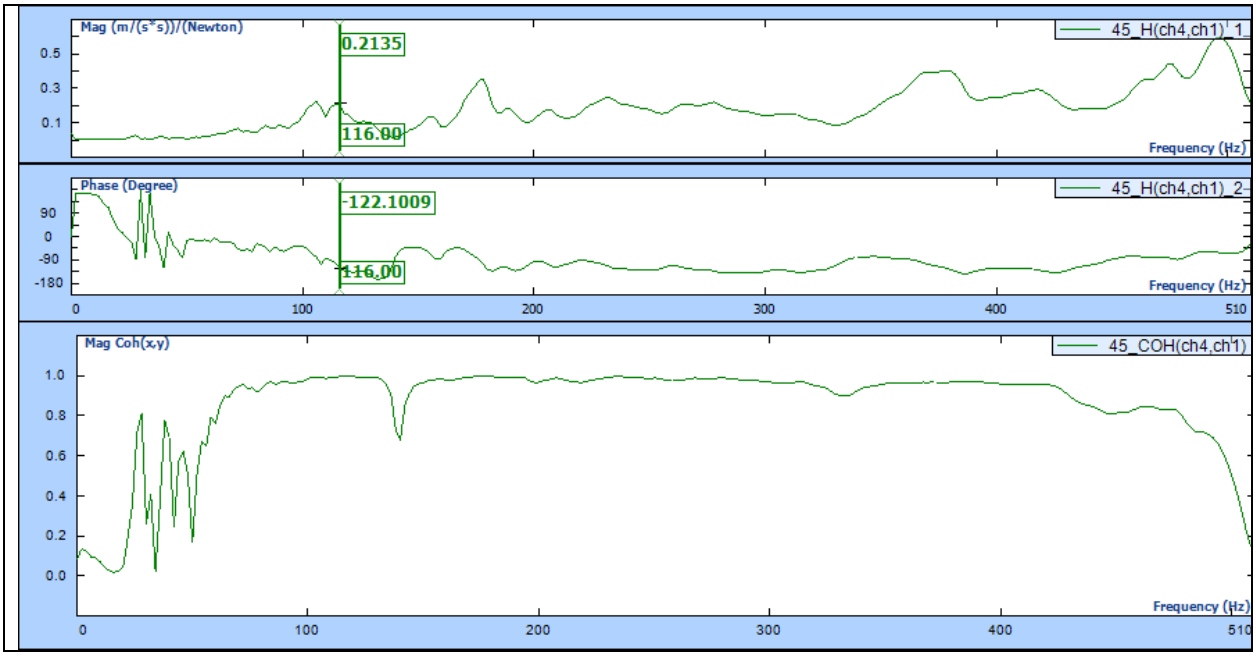
Photograph 42: ***Impact Test Data At 126 Slot Pole Jumper Top Tangential***



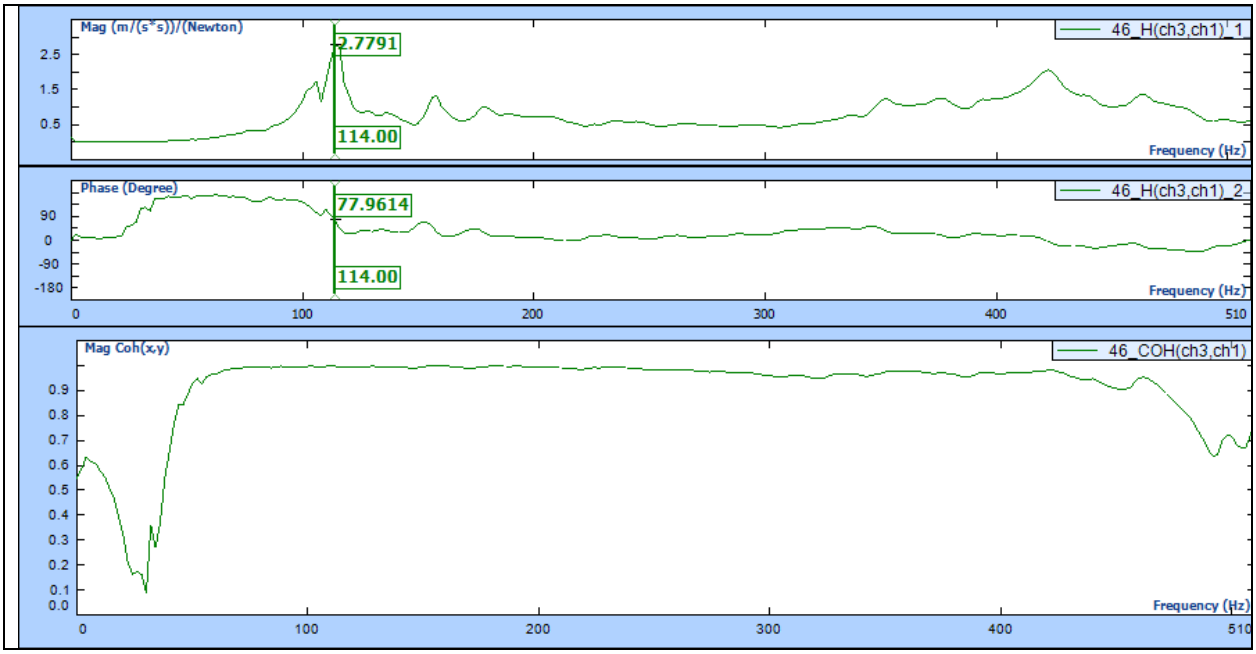
Photograph 43: ***Impact Test Data At 126 Slot Pole Jumper Bottom Radial***



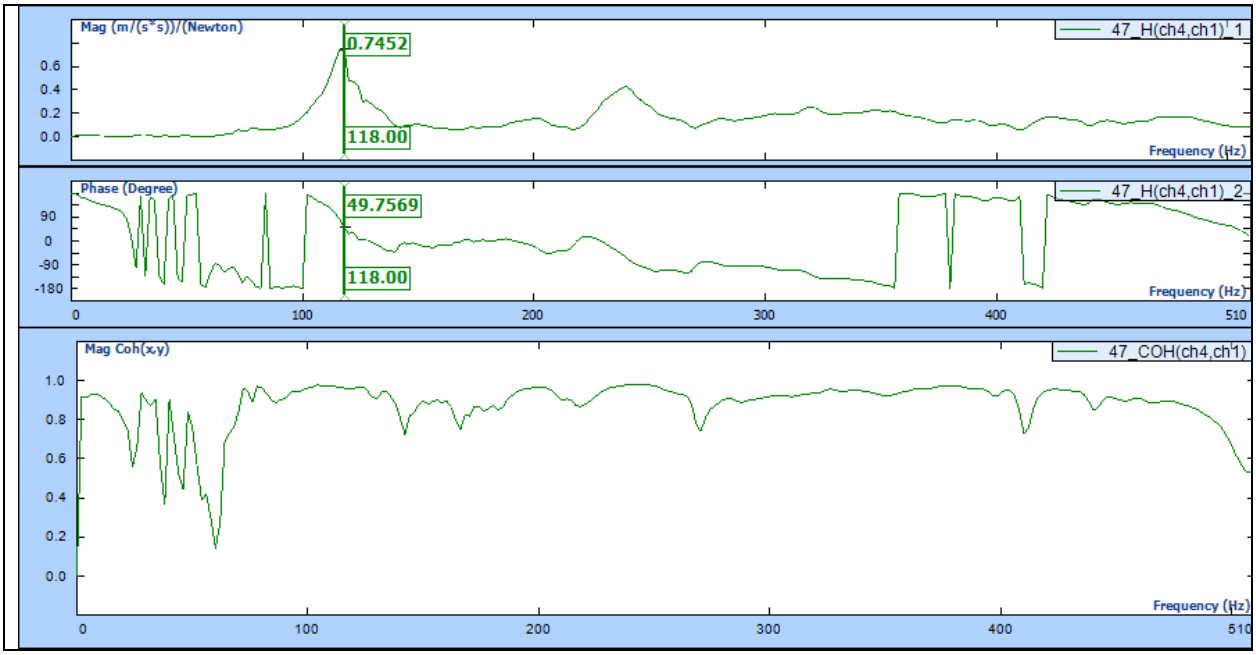
Photograph 44: ***Impact Test Data At 126 Slot Pole Jumper Bottom Tangential***



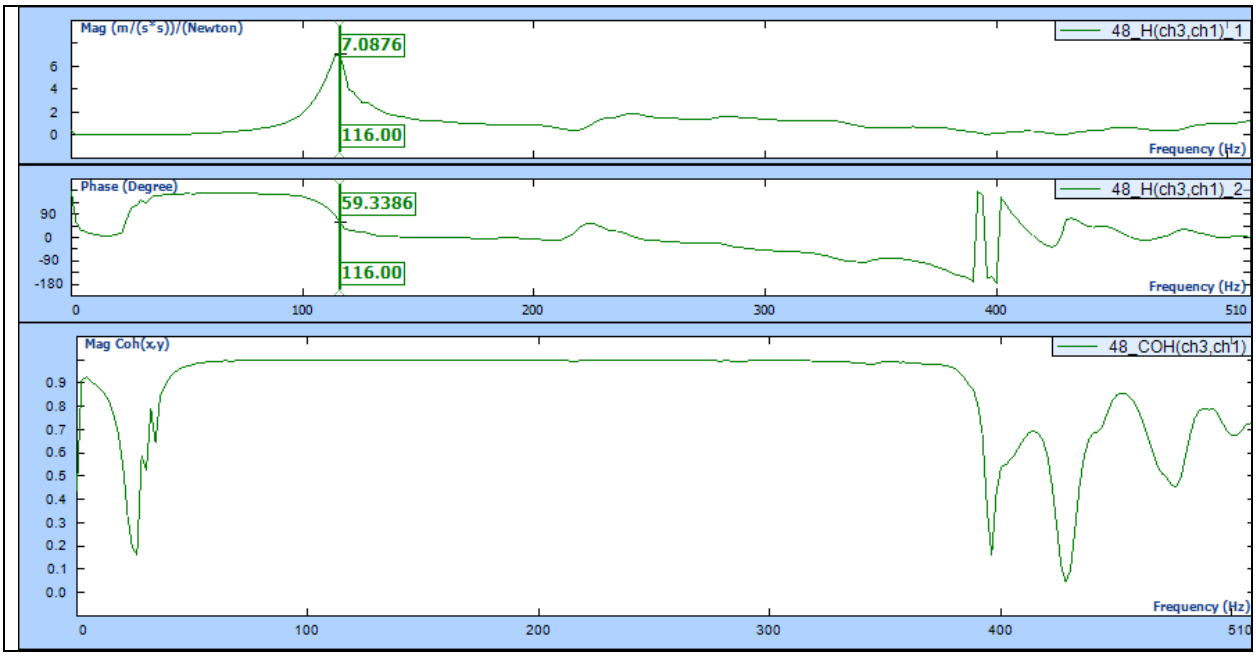
Photograph 45: ***Impact Test Data At 130 Slot Pole Jumper Top Radial***



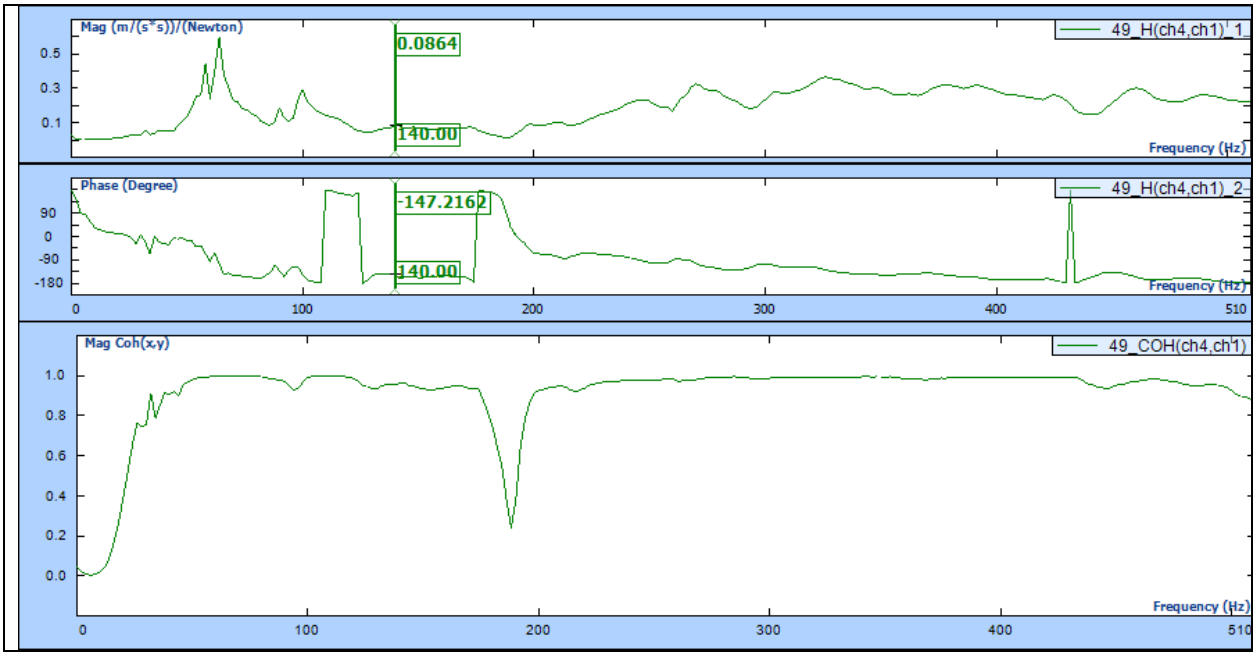
Photograph 46: ***Impact Test Data At 130 Slot Pole Jumper Top Tangential***



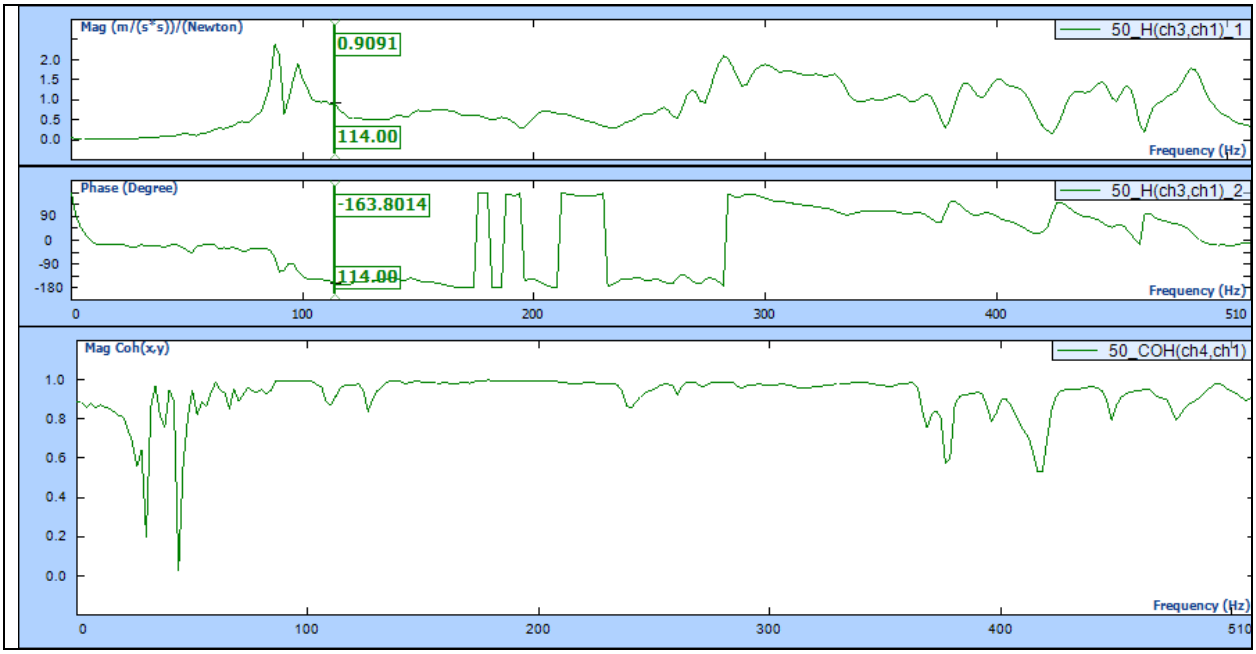
Photograph 47: ***Impact Test Data At 130 Slot Pole Jumper Bottom Radial***



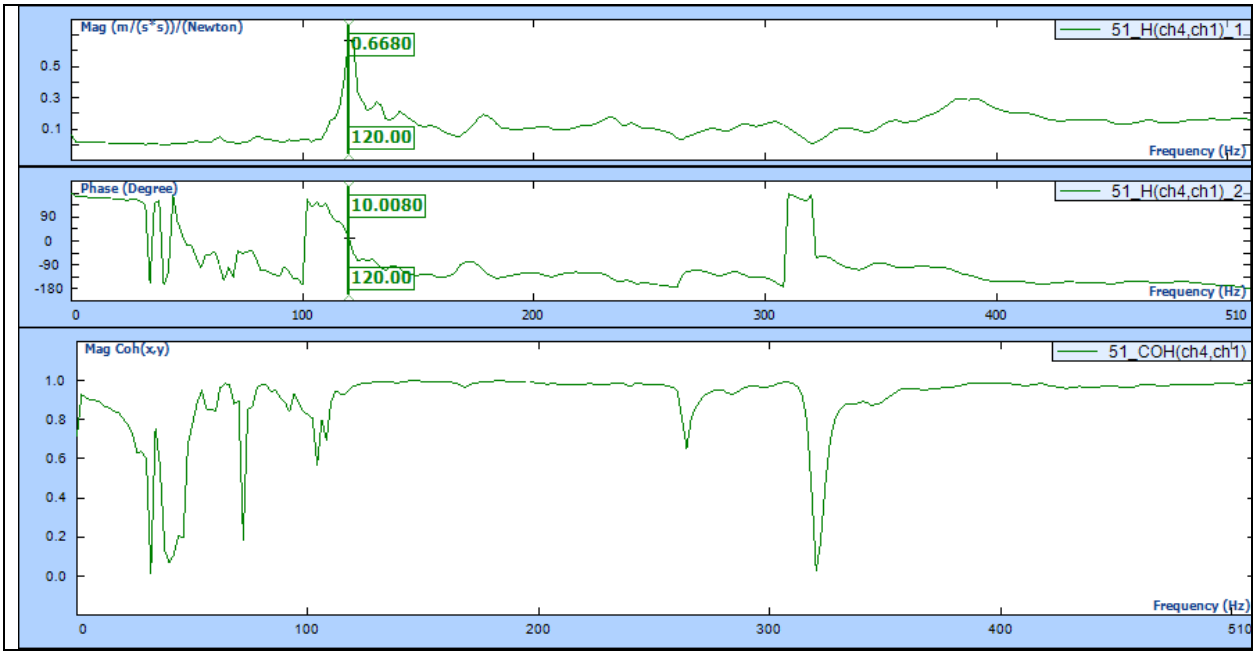
Photograph 48: ***Impact Test Data At 130 Slot Pole Jumper Bottom Tangential***



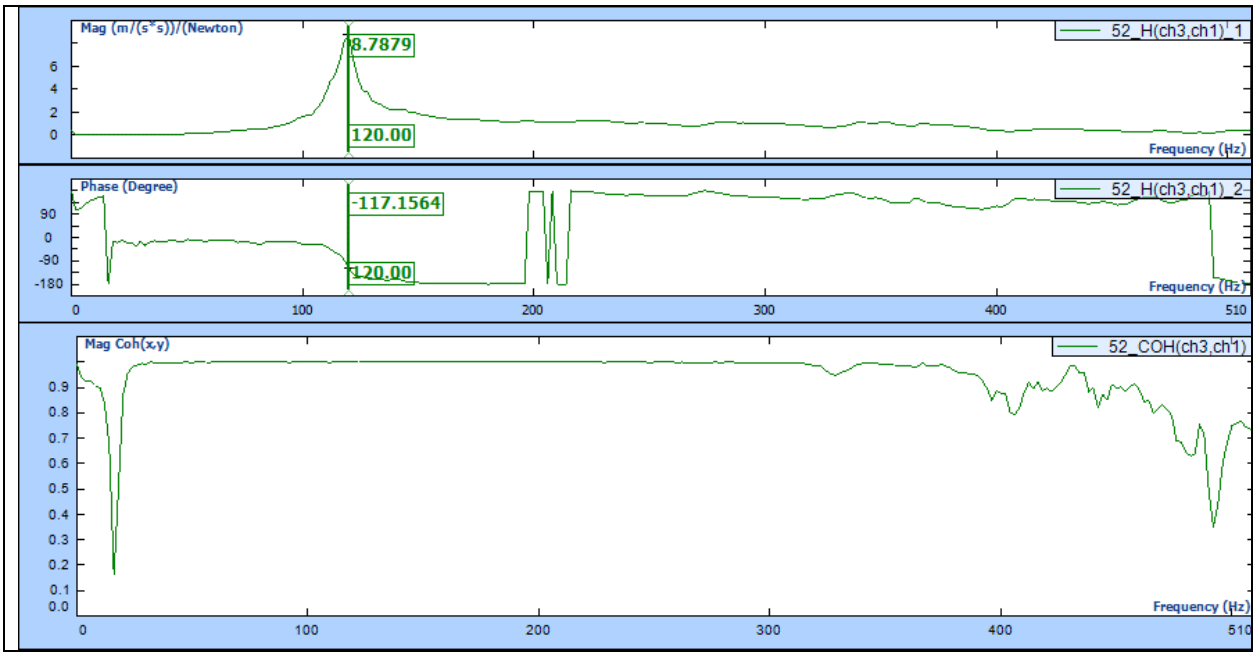
Photograph 49: ***Impact Test Data At 135 Slot Pole Jumper Top Radial***



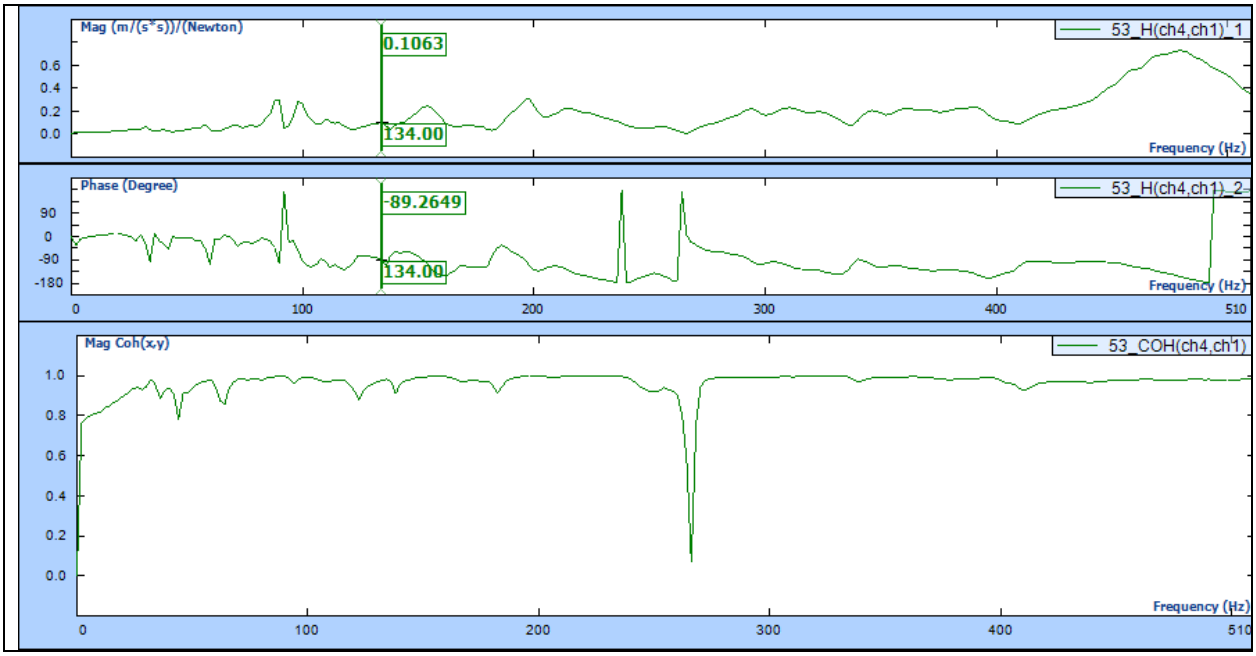
Photograph 50: ***Impact Test Data At 135 Slot Pole Jumper Top Tangential***



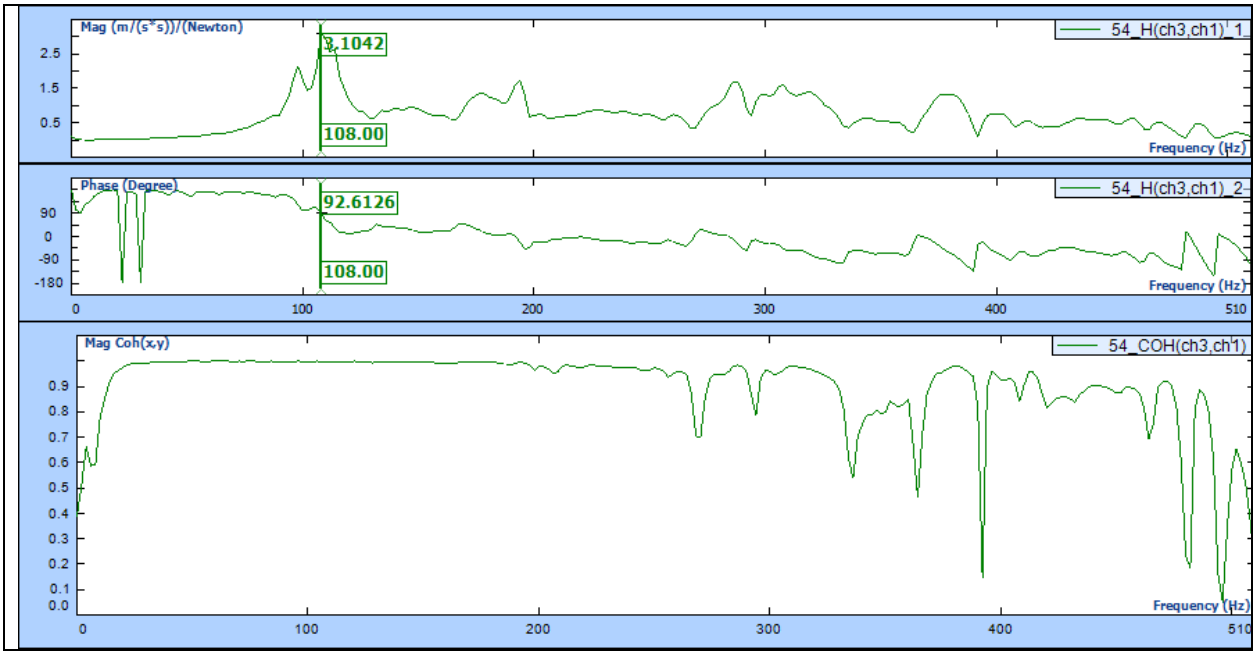
Photograph 51: ***Impact Test Data At 135 Slot Pole Jumper Bottom Radial***



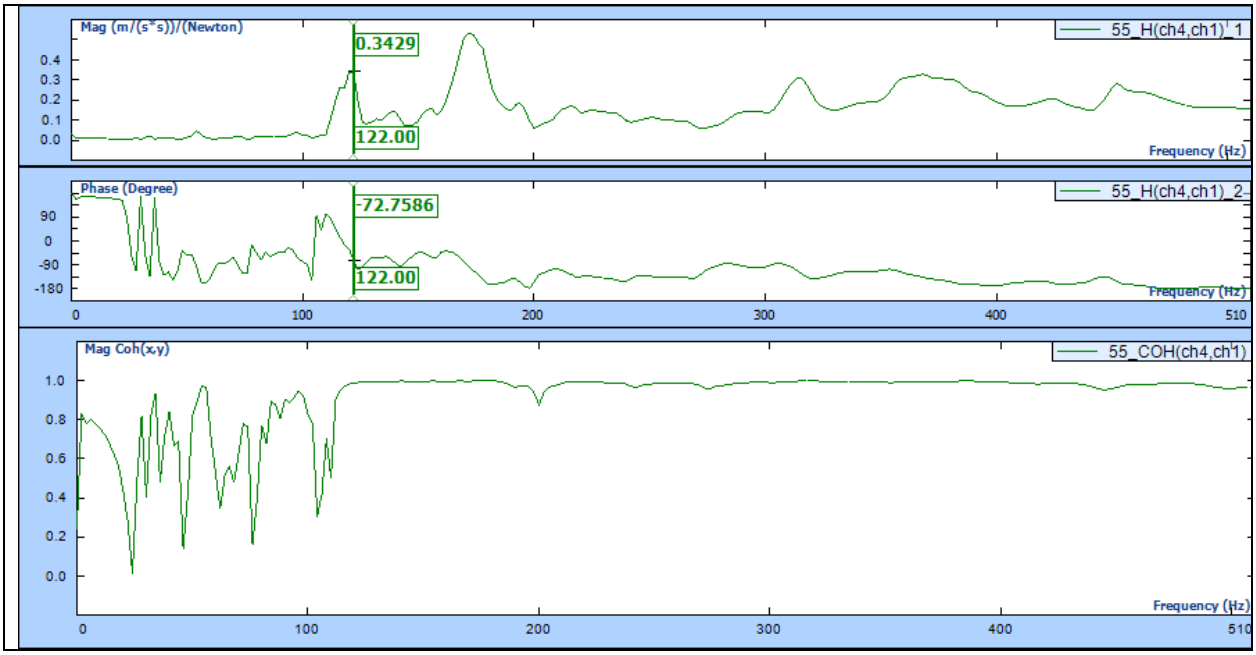
Photograph 52: ***Impact Test Data At 135 Slot Pole Jumper Bottom Tangential***



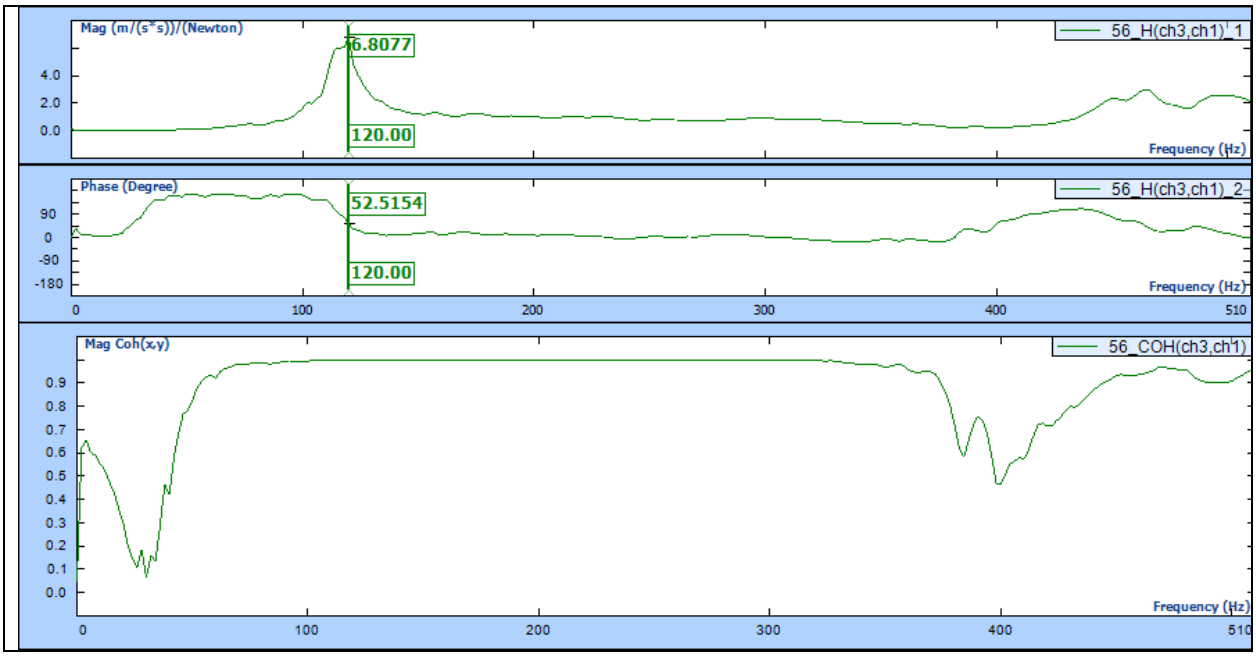
Photograph 53: ***Impact Test Data At 139 Slot Pole Jumper Top Radial***



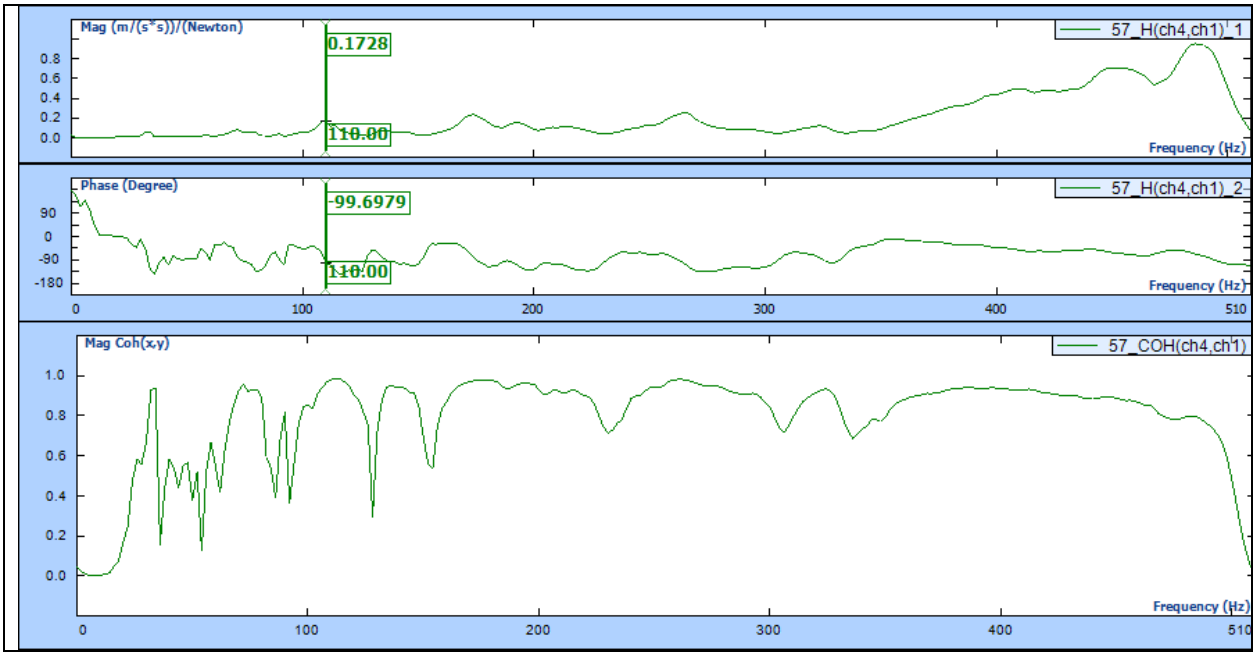
Photograph 54: ***Impact Test Data At 139 Slot Pole Jumper Top Tangential***



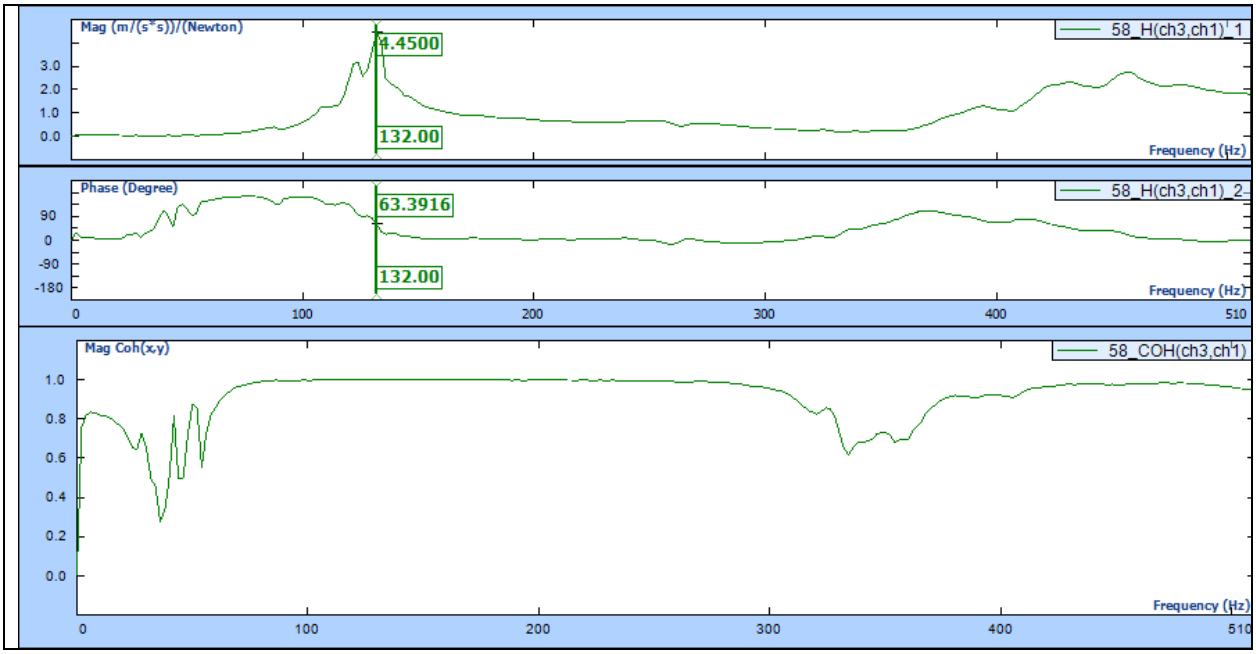
Photograph 55: ***Impact Test Data At 139 Slot Pole Jumper Bottom Radial***



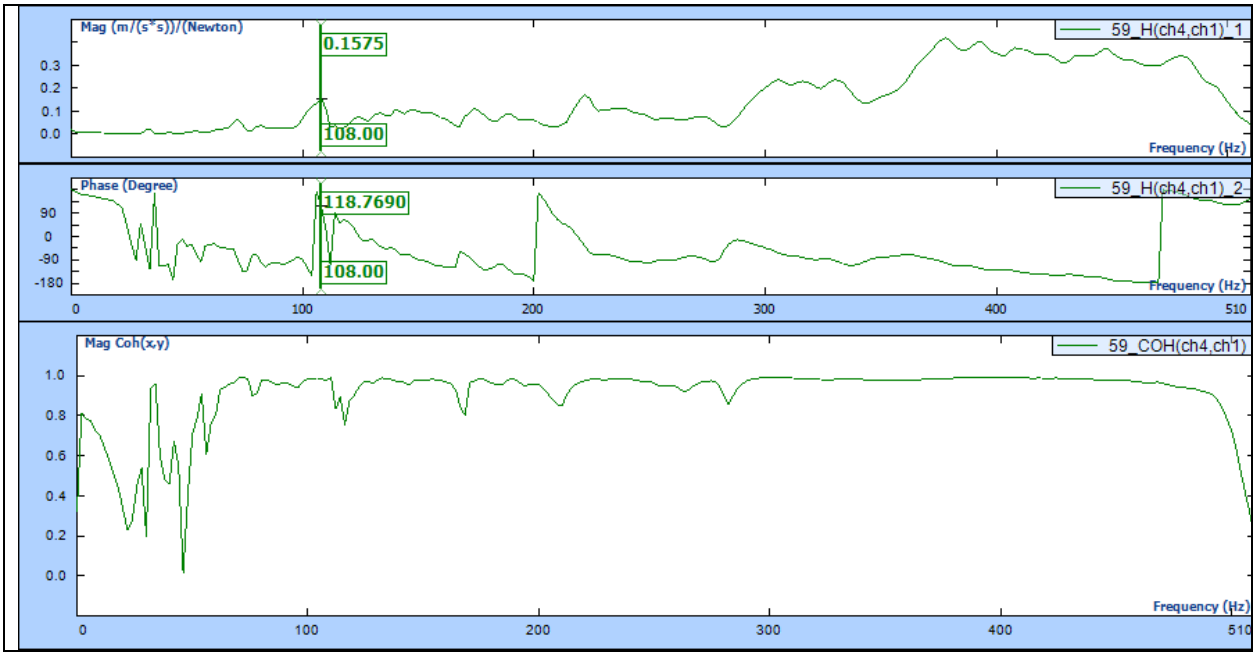
Photograph 56: ***Impact Test Data At 139 Slot Pole Jumper Bottom Tangential***



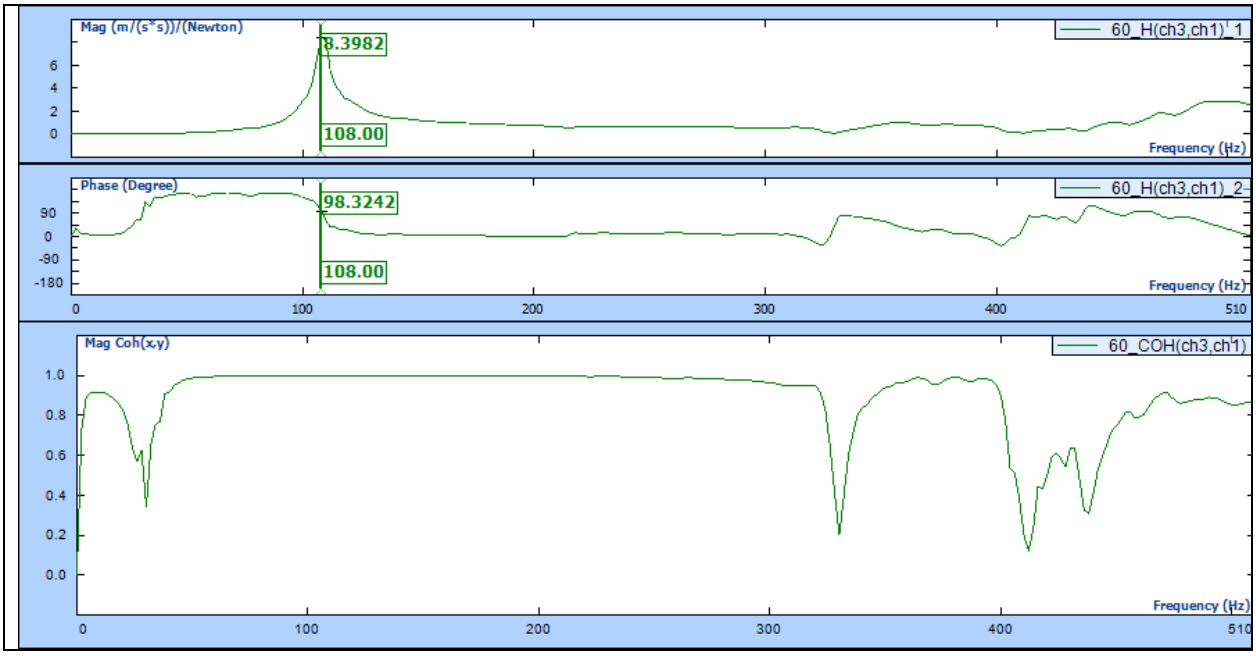
Photograph 57: ***Impact Test Data At 143 Slot Pole Jumper Top Radial***



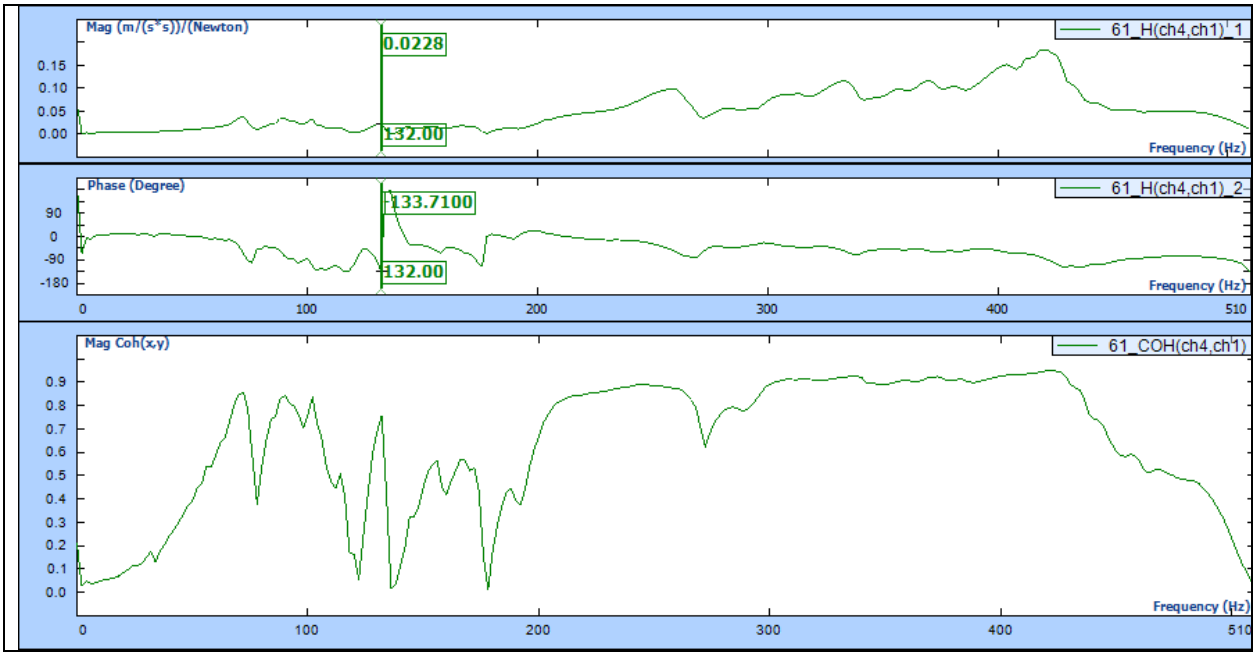
Photograph 58: ***Impact Test Data At 143 Slot Pole Jumper Top Tangential***



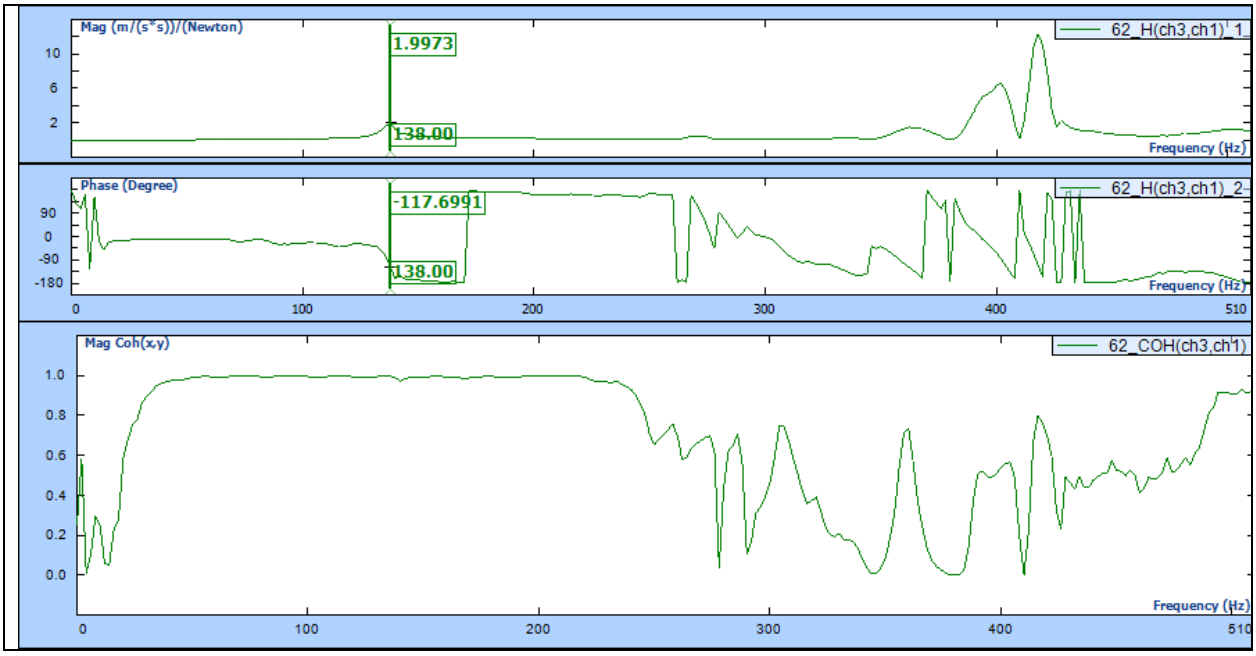
Photograph 59: ***Impact Test Data At 143 Slot Pole Jumper Bottom Radial***



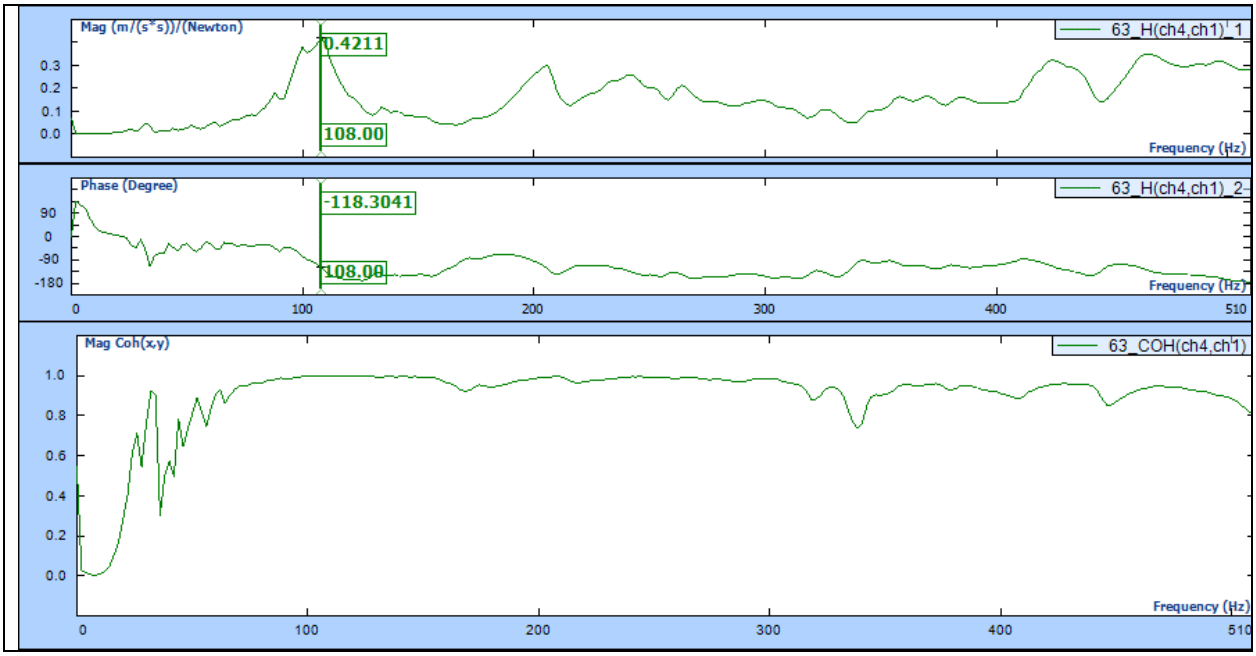
Photograph 60: ***Impact Test Data At 143 Slot Pole Jumper Bottom Tangential***



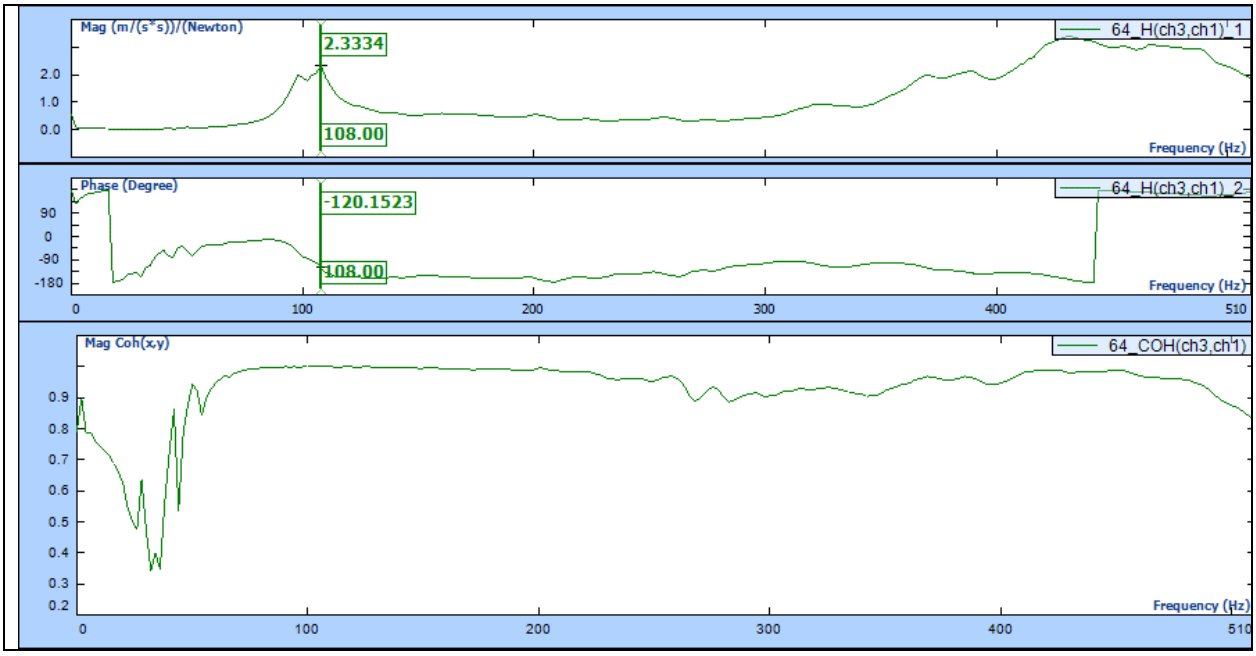
Photograph 61: ***Impact Test Data At 146 Slot Diamond Structure Radial***



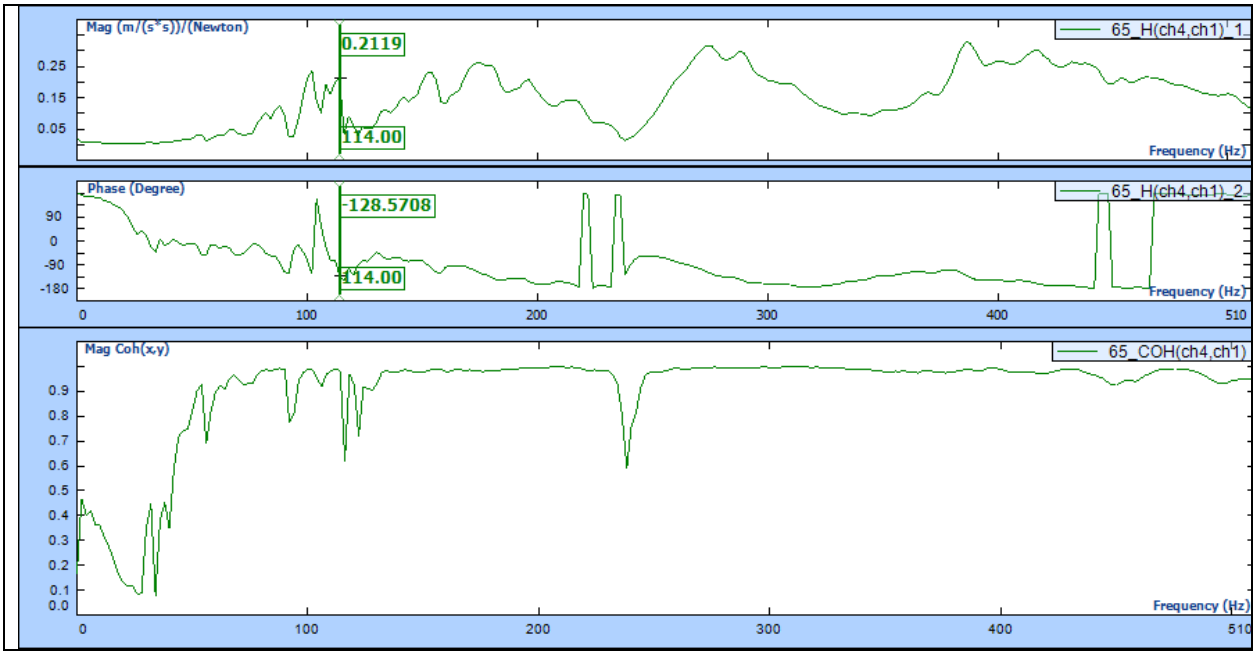
Photograph 62: ***Impact Test Data At 146 Slot Diamond Structure Tangential***



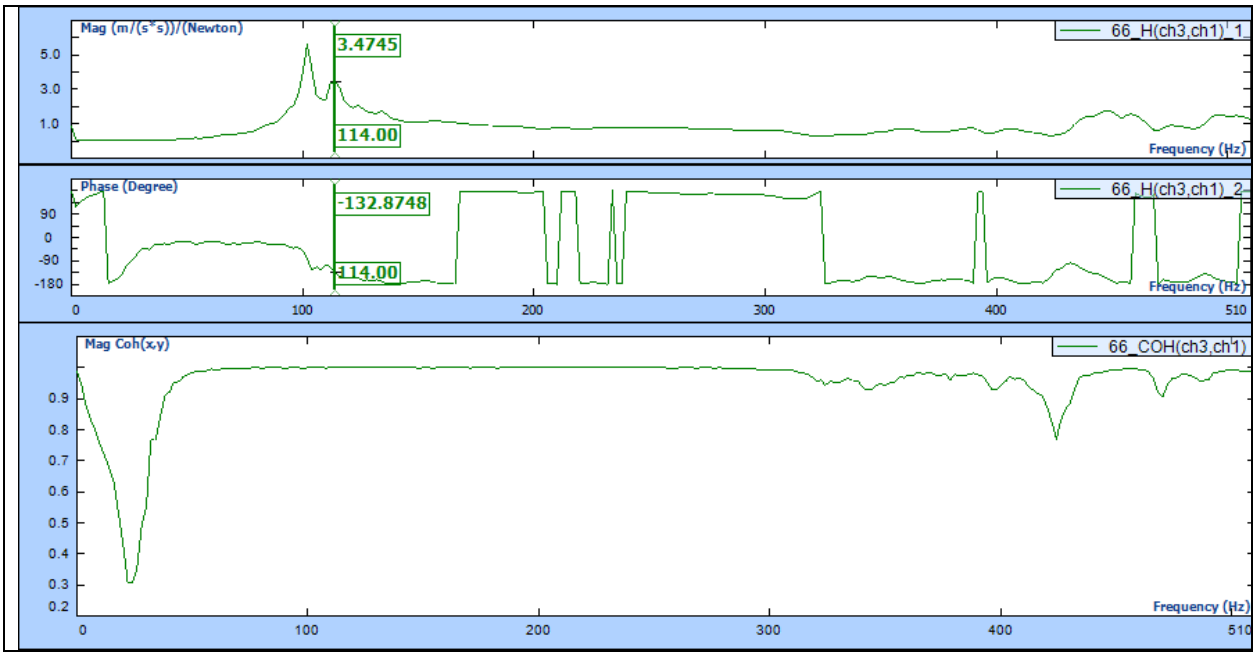
Photograph 63: ***Impact Test Data At 148 Slot Pole Jumper Top Radial***



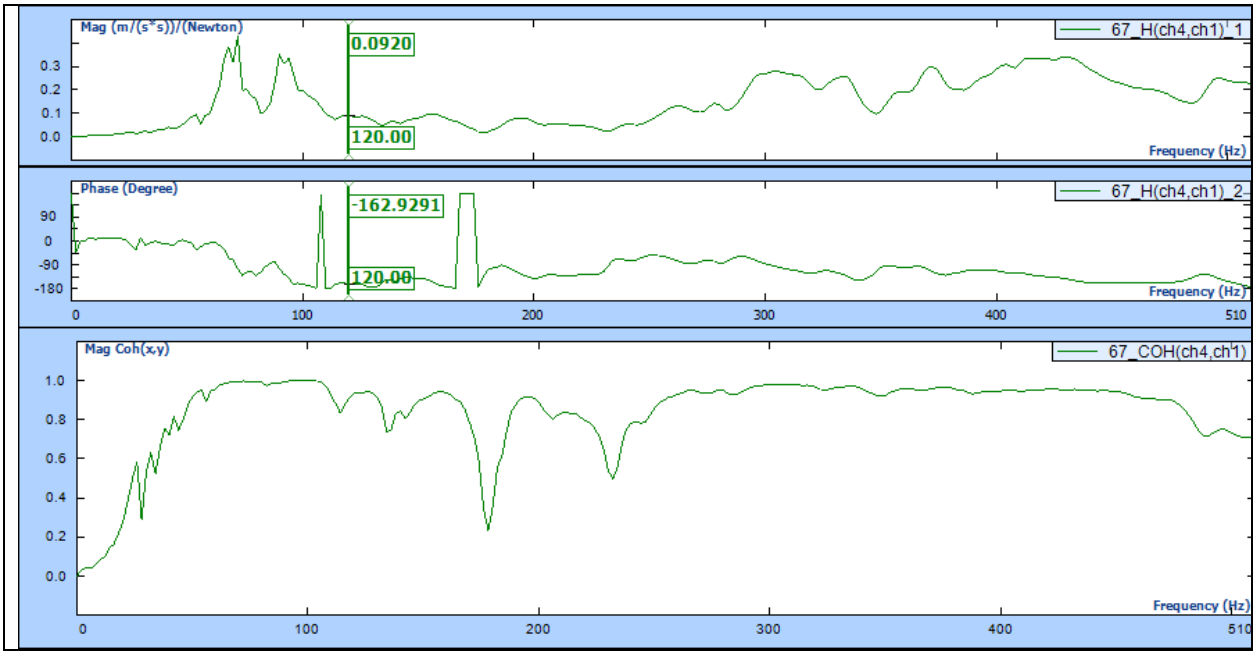
Photograph 64: ***Impact Test Data At 148 Slot Pole Jumper Top Tangential***



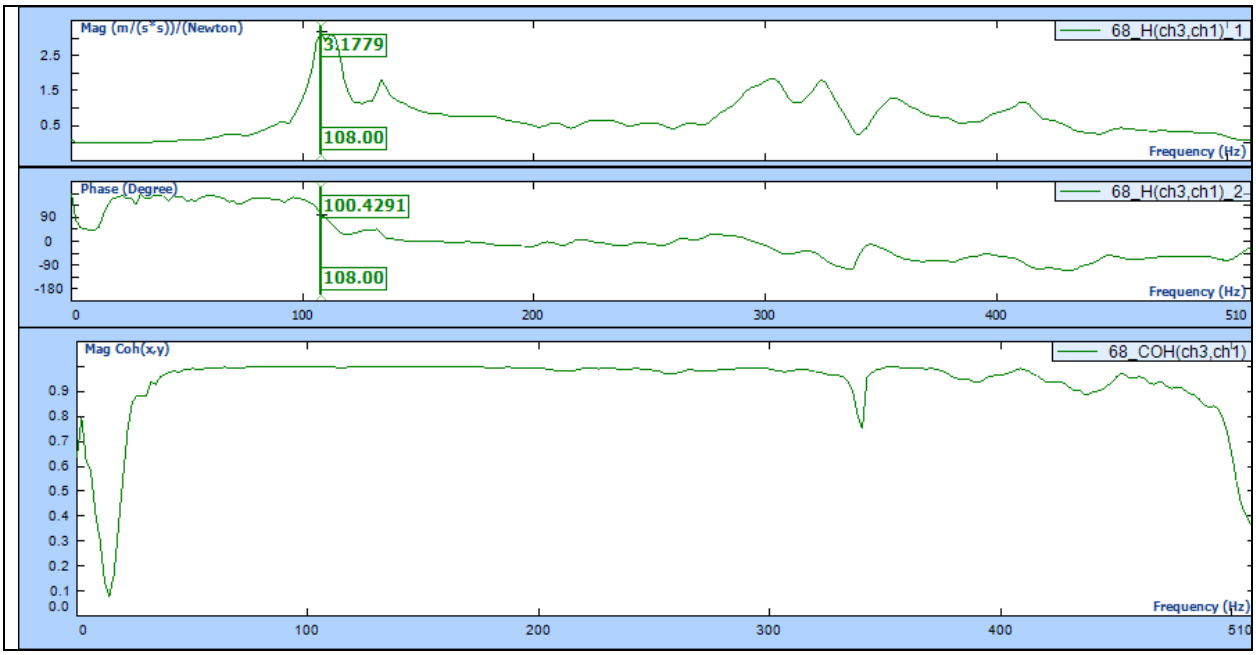
Photograph 65: ***Impact Test Data At 148 Slot Pole Jumper Bottom Radial***



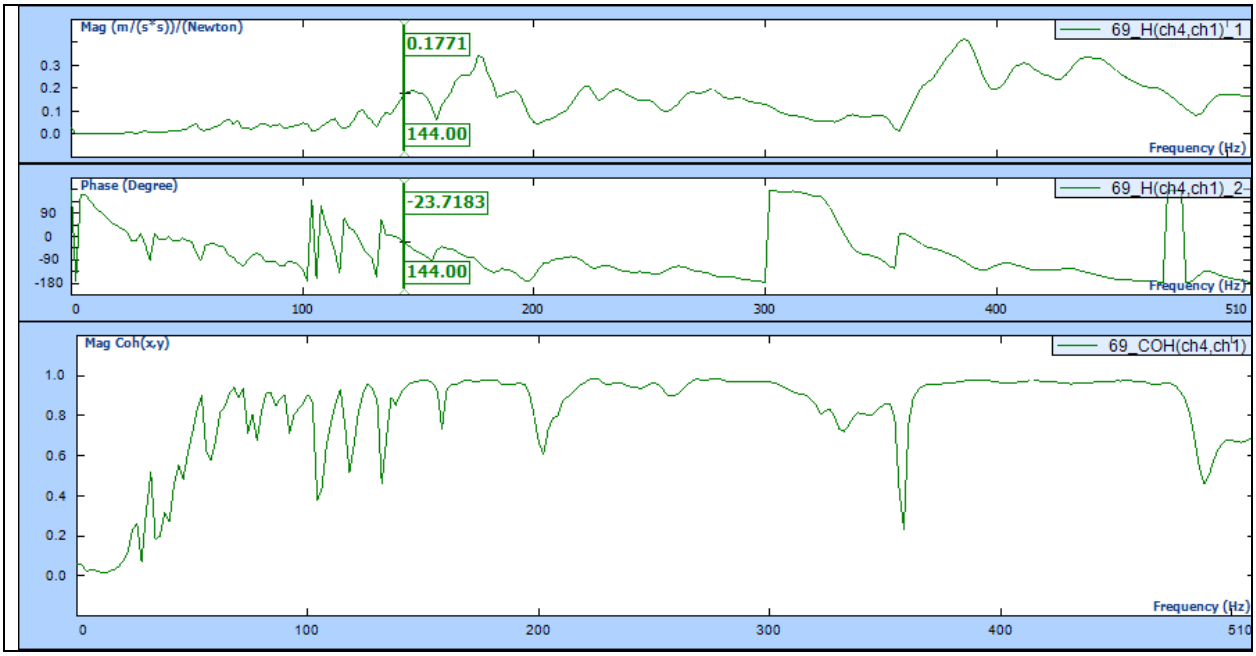
Photograph 66: ***Impact Test Data At 148 Slot Pole Jumper Bottom Tangential***



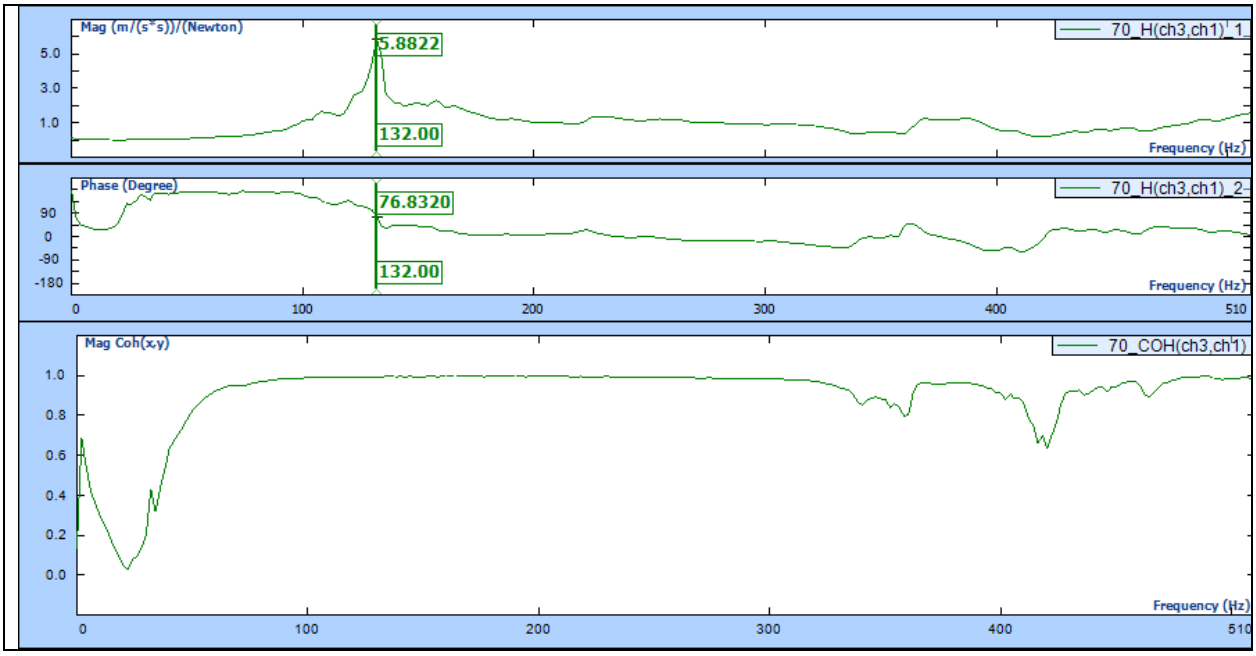
Photograph 67: ***Impact Test Data At 152 Slot Pole Jumper Top Radial***



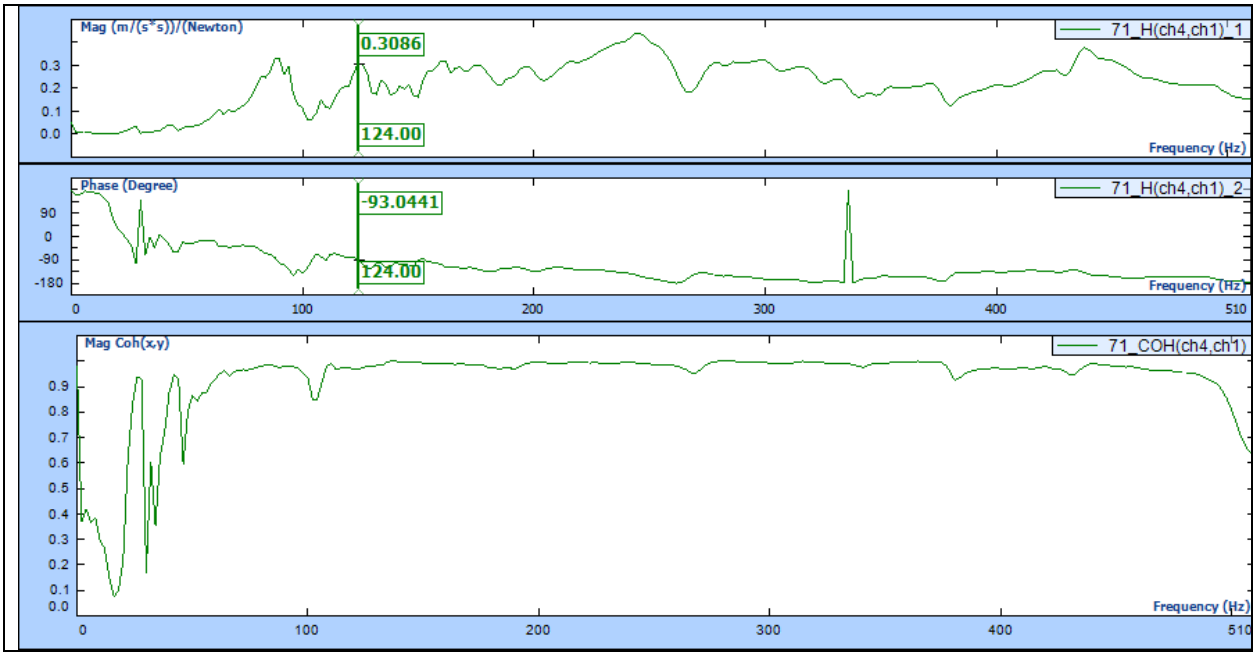
Photograph 68: ***Impact Test Data At 152 Slot Pole Jumper Top Tangential***



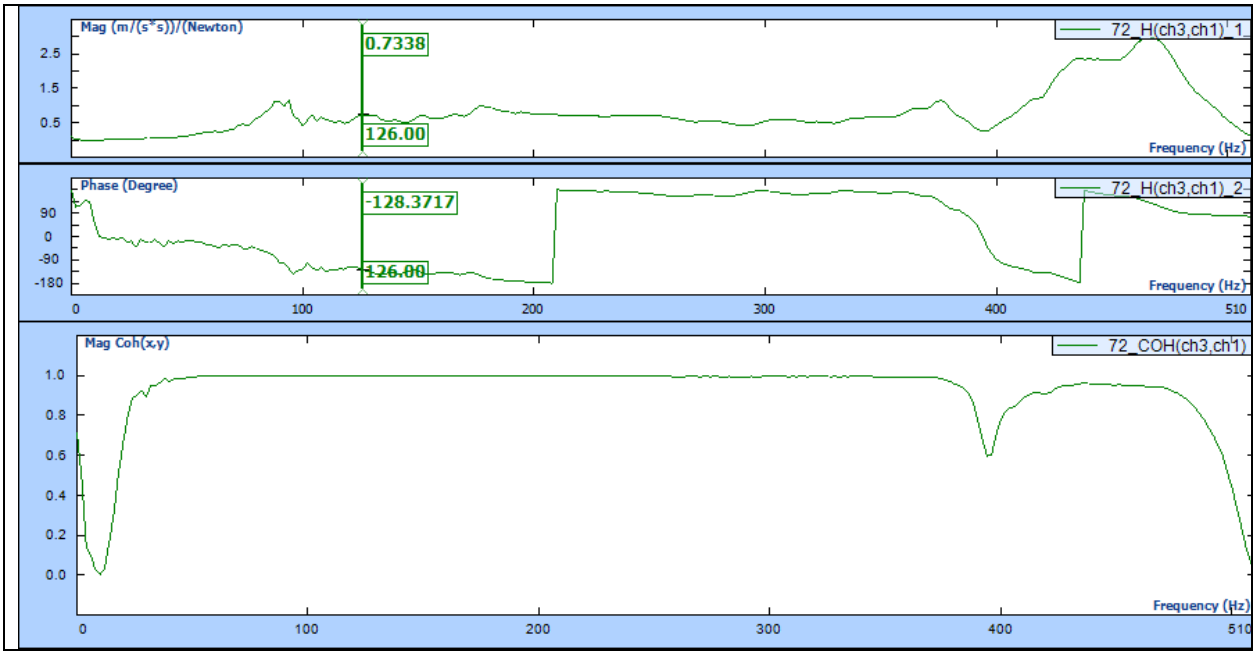
Photograph 69: ***Impact Test Data At 152 Slot Pole Jumper Bottom Radial***



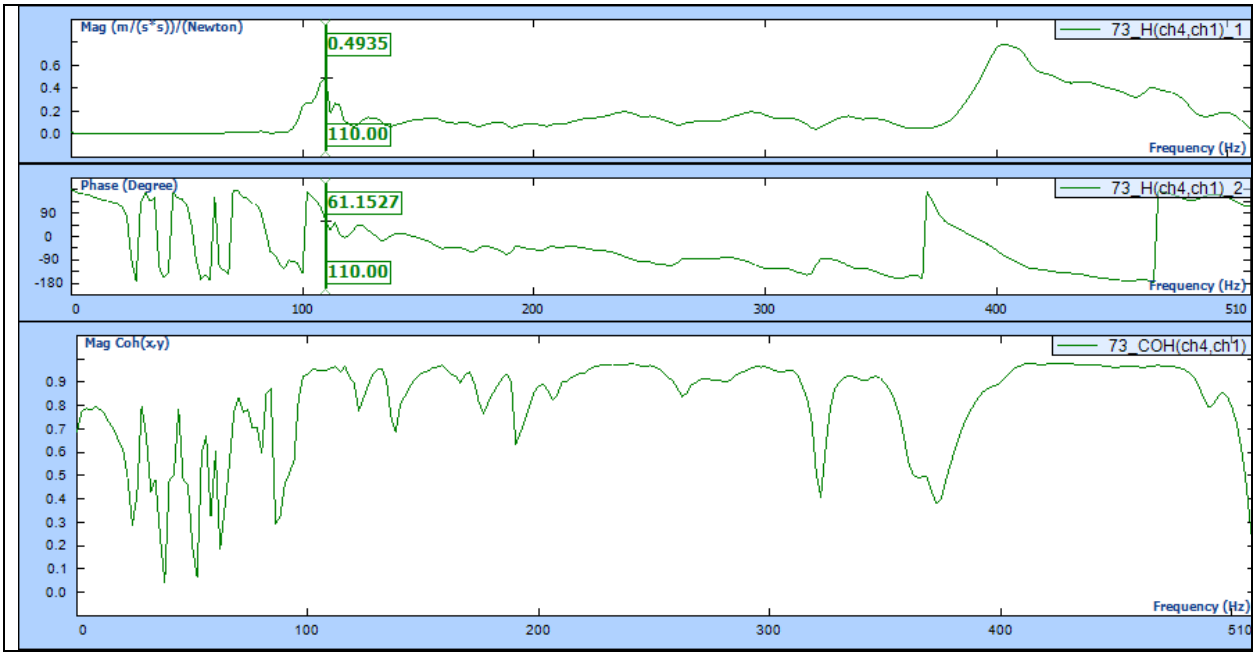
Photograph 70: ***Impact Test Data At 152 Slot Pole Jumper Bottom Tangential***



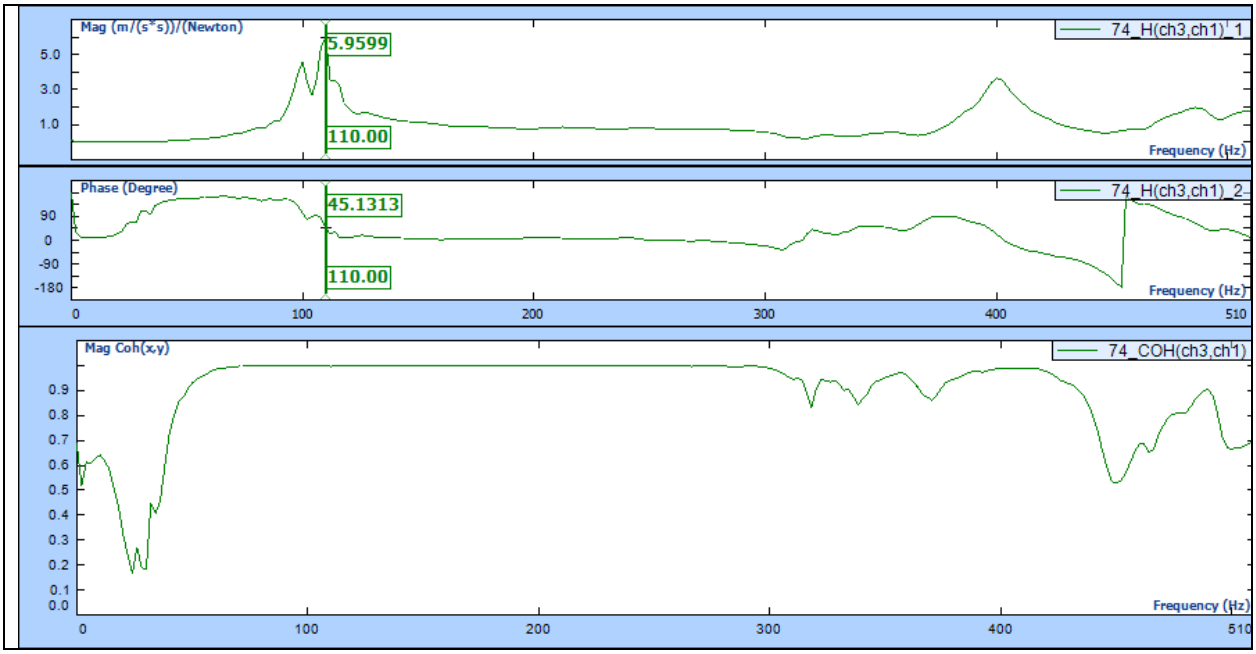
Photograph 71: ***Impact Test Data At 157 Slot Pole Jumper Top Radial***



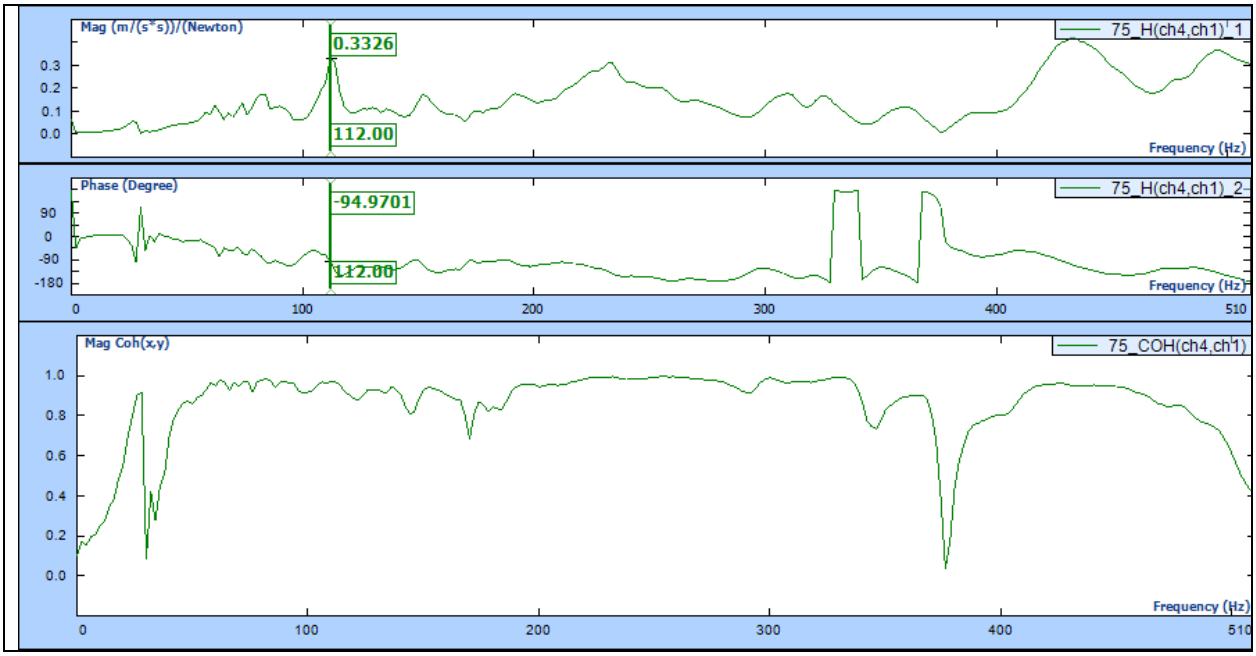
Photograph 72: ***Impact Test Data At 157 Slot Pole Jumper Top Tangential***



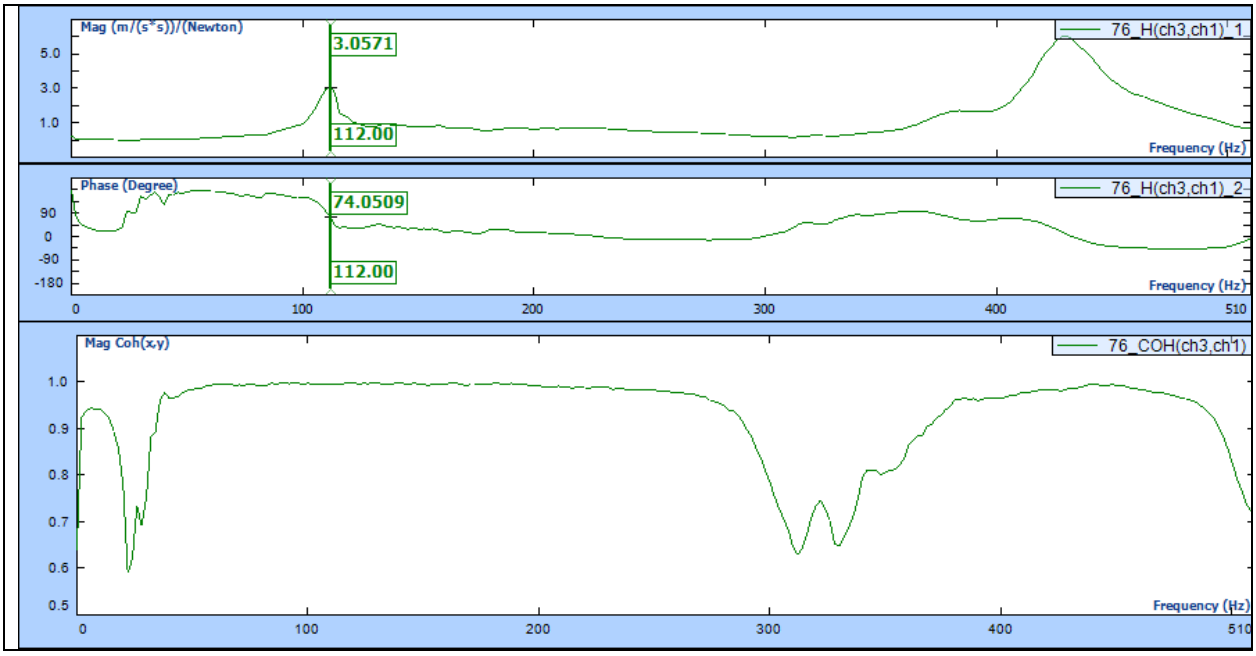
Photograph 73: ***Impact Test Data At 157 Slot Pole Jumper Bottom Radial***



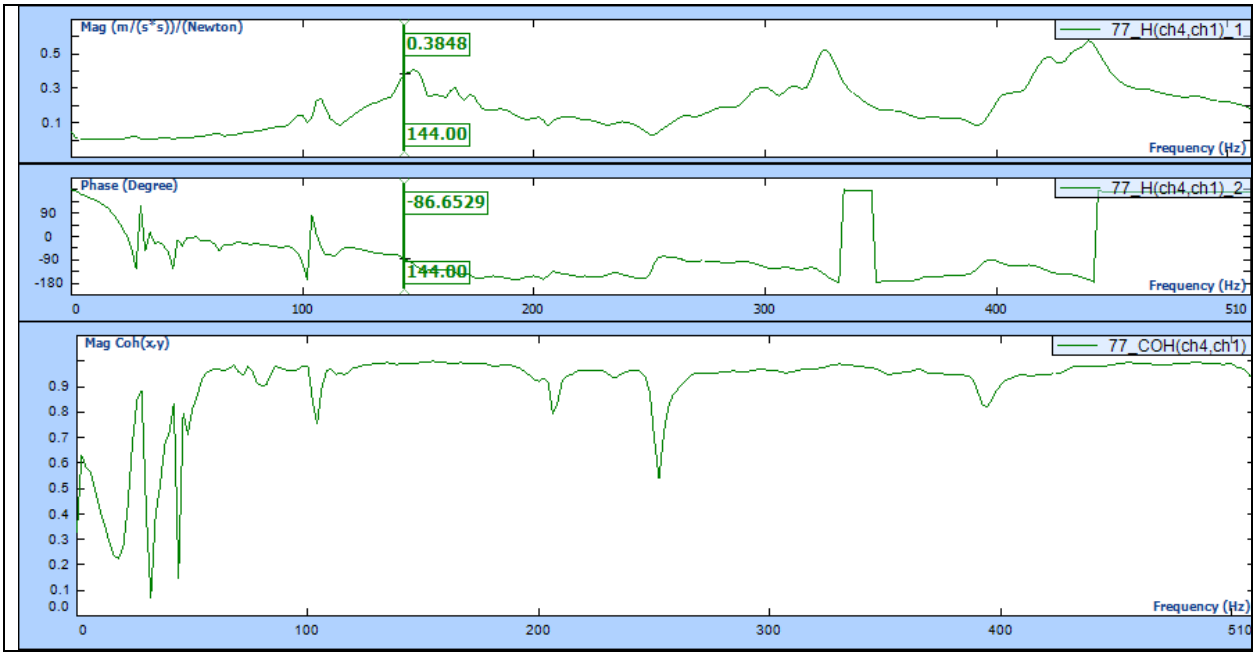
Photograph 74: ***Impact Test Data At 157 Slot Pole Jumper Bottom Tangential***



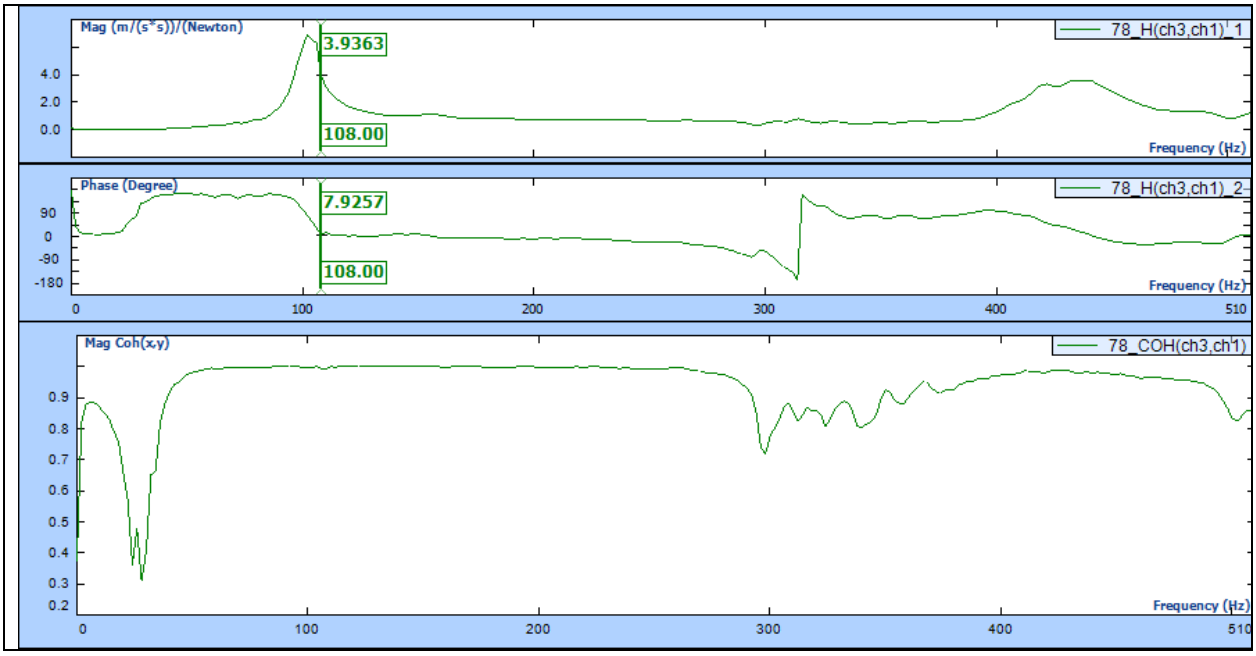
Photograph 75: ***Impact Test Data At 161 Slot Pole Jumper Top Radial***



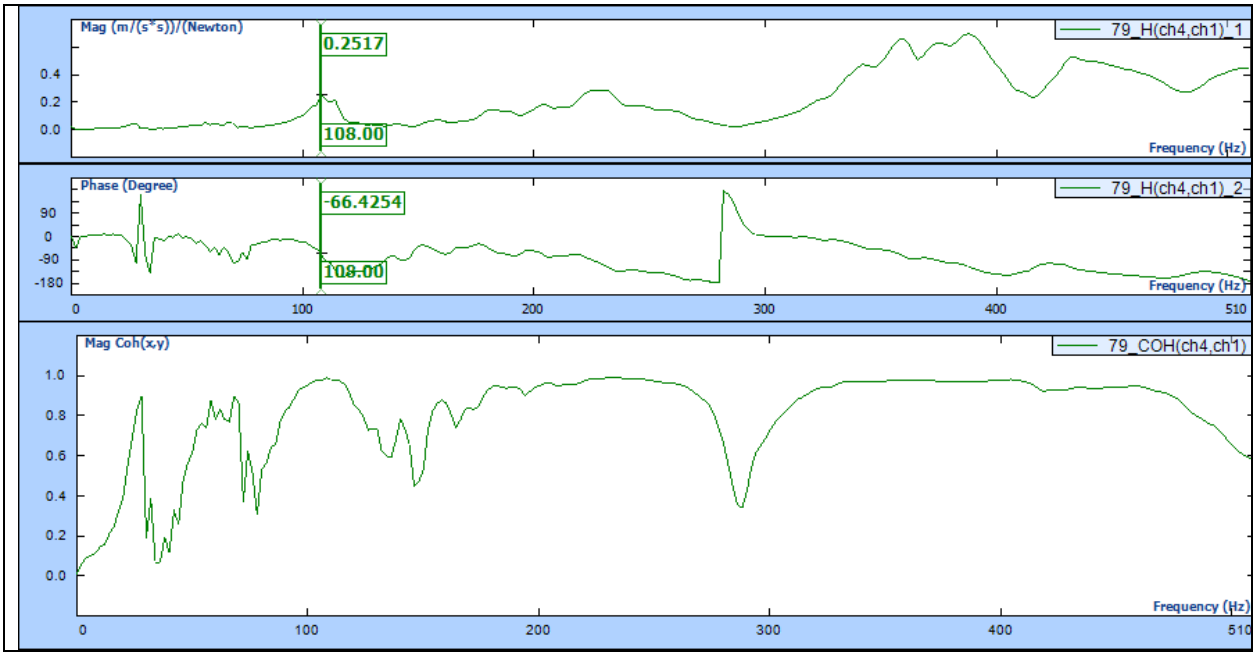
Photograph 76: ***Impact Test Data At 161 Slot Pole Jumper Top Tangential***



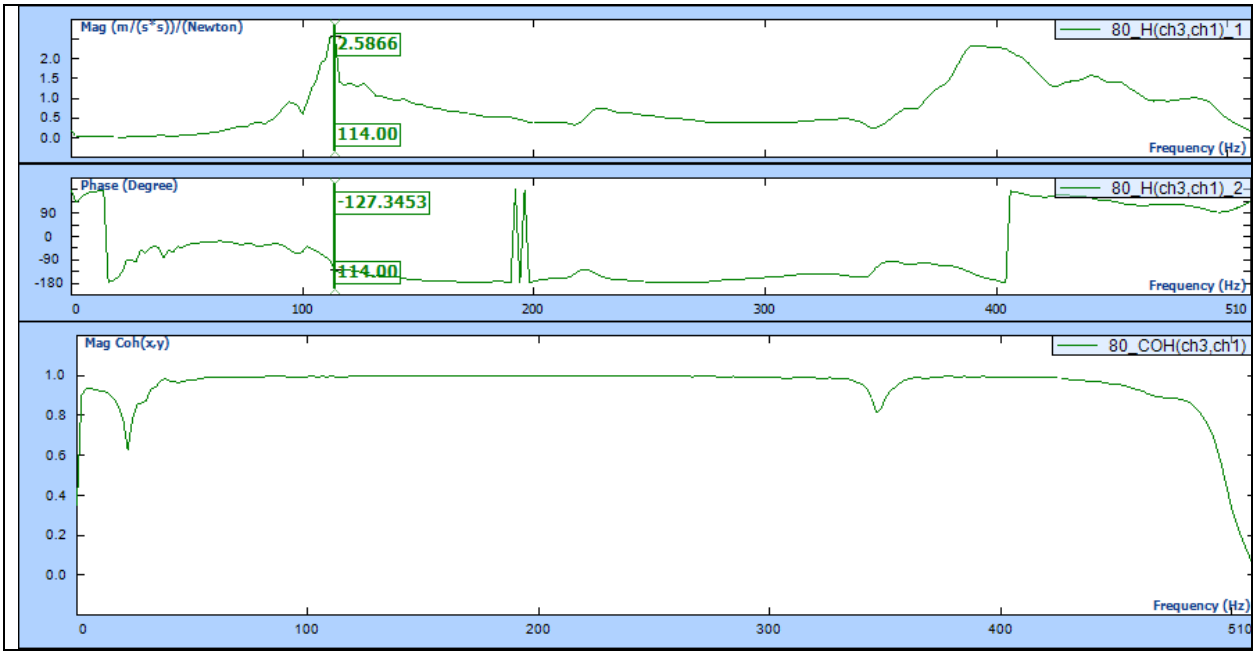
Photograph 77: ***Impact Test Data At 161 Slot Pole Jumper Bottom Radial***



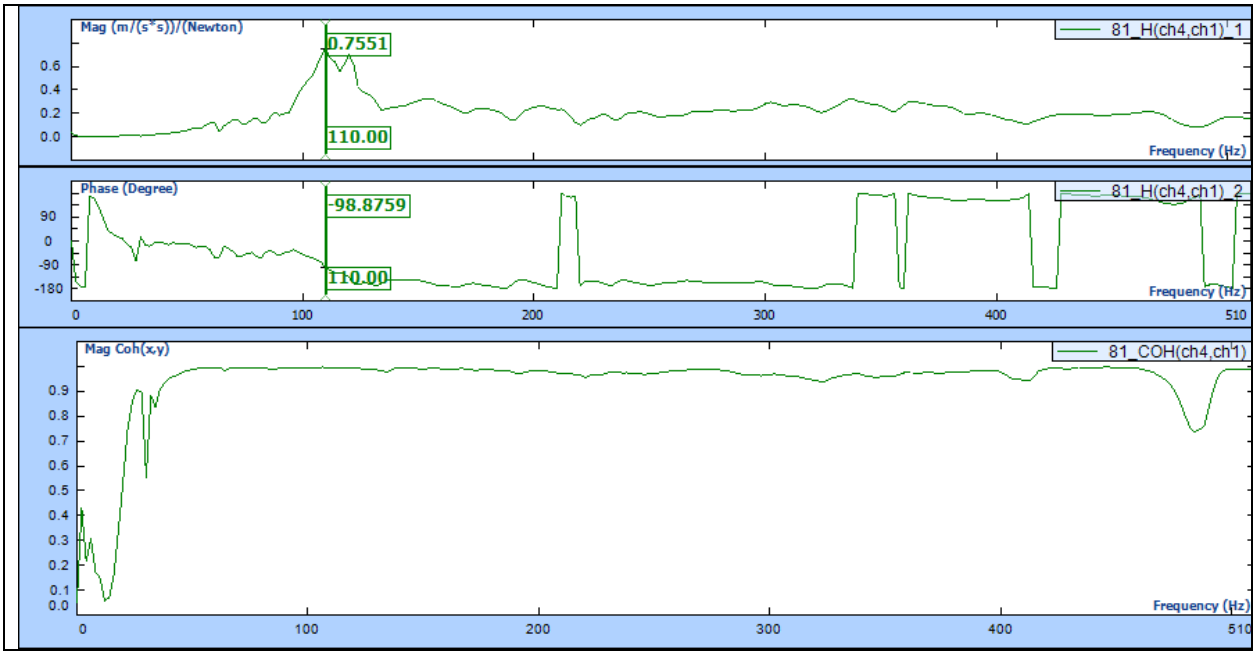
Photograph 78: ***Impact Test Data At 161 Slot Pole Jumper Bottom Tangential***



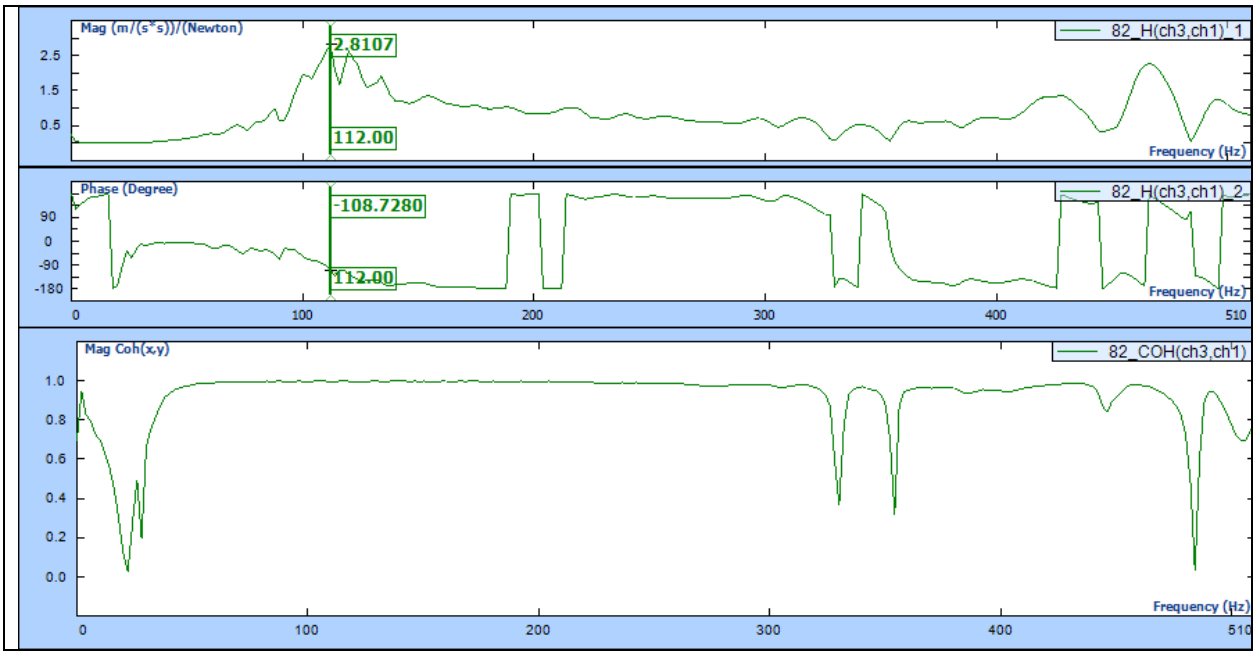
Photograph 79: ***Impact Test Data At 165 Slot Pole Jumper Top Radial***



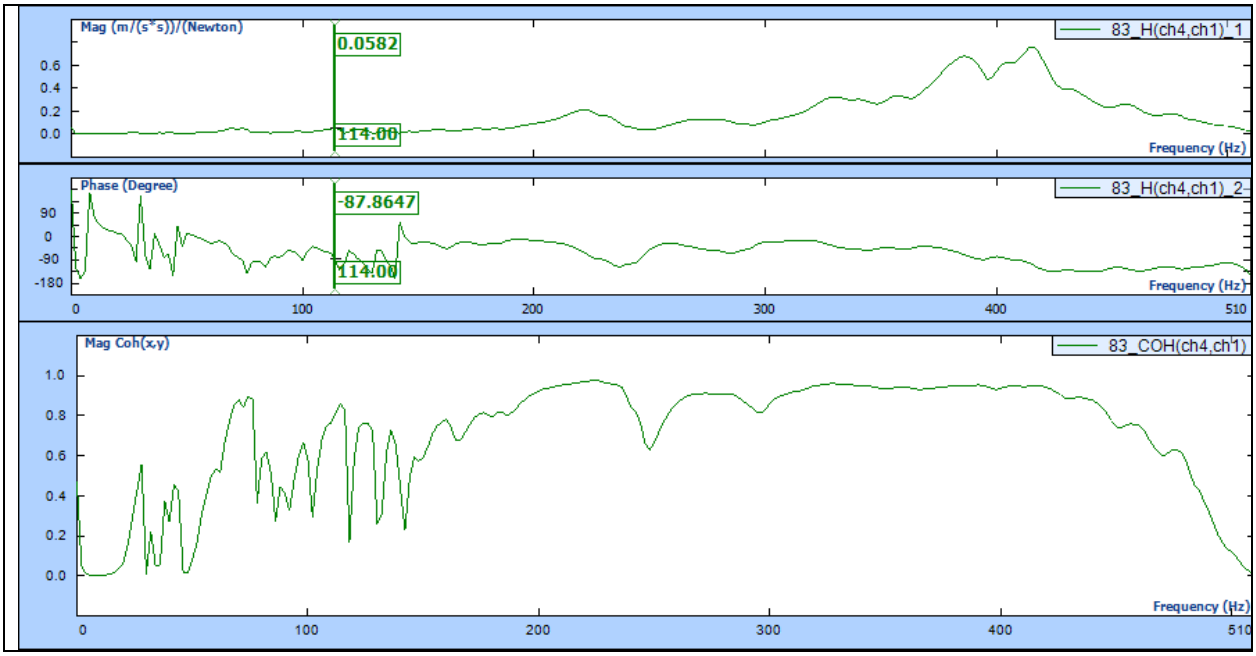
Photograph 80: ***Impact Test Data At 165 Slot Pole Jumper Top Tangential***



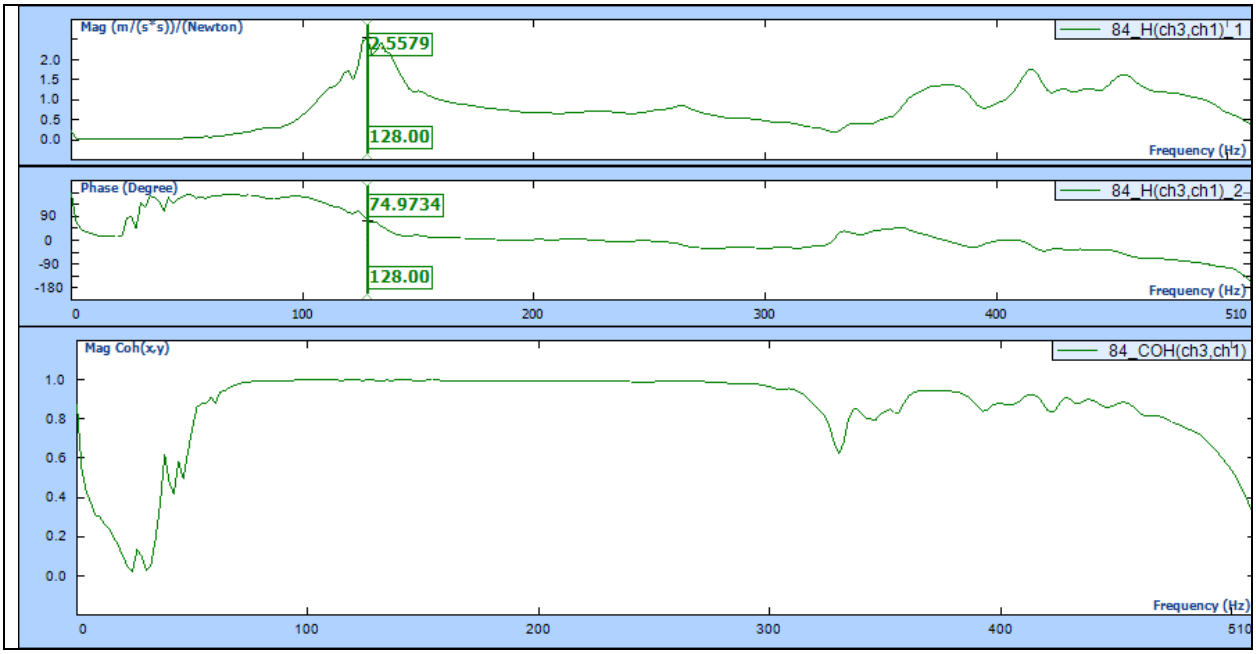
Photograph 81: ***Impact Test Data At 165 Slot Pole Jumper Bottom Radial***



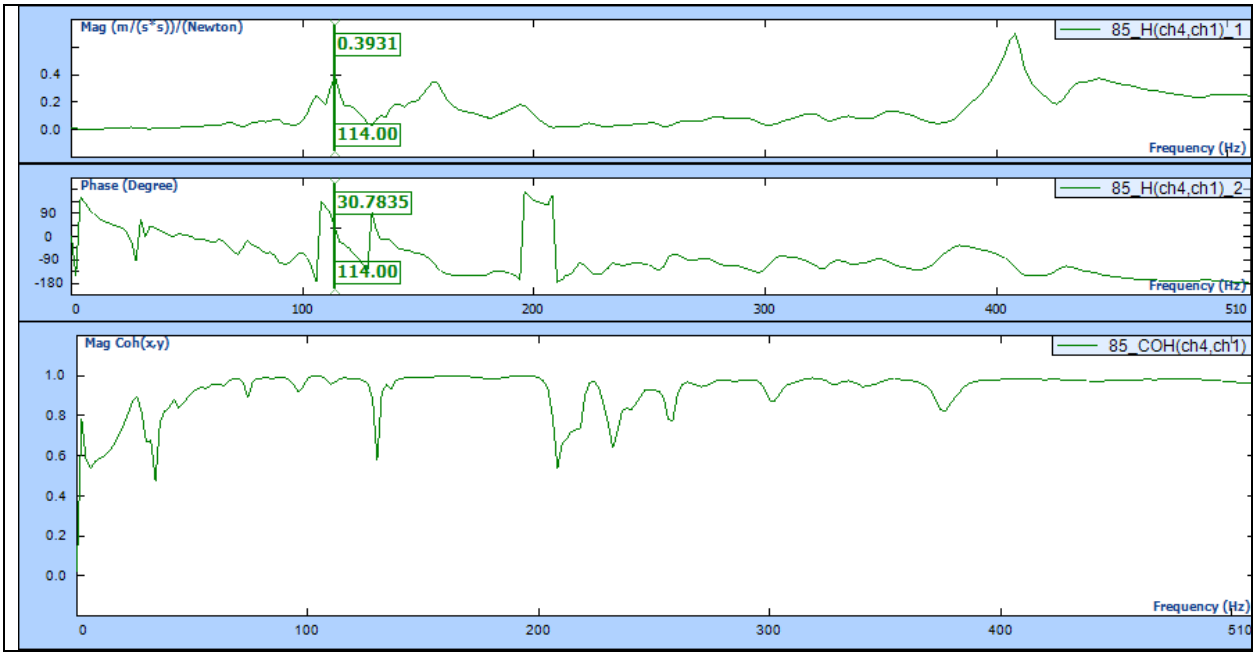
Photograph 82: ***Impact Test Data At 165 Slot Pole Jumper Bottom Tangential***



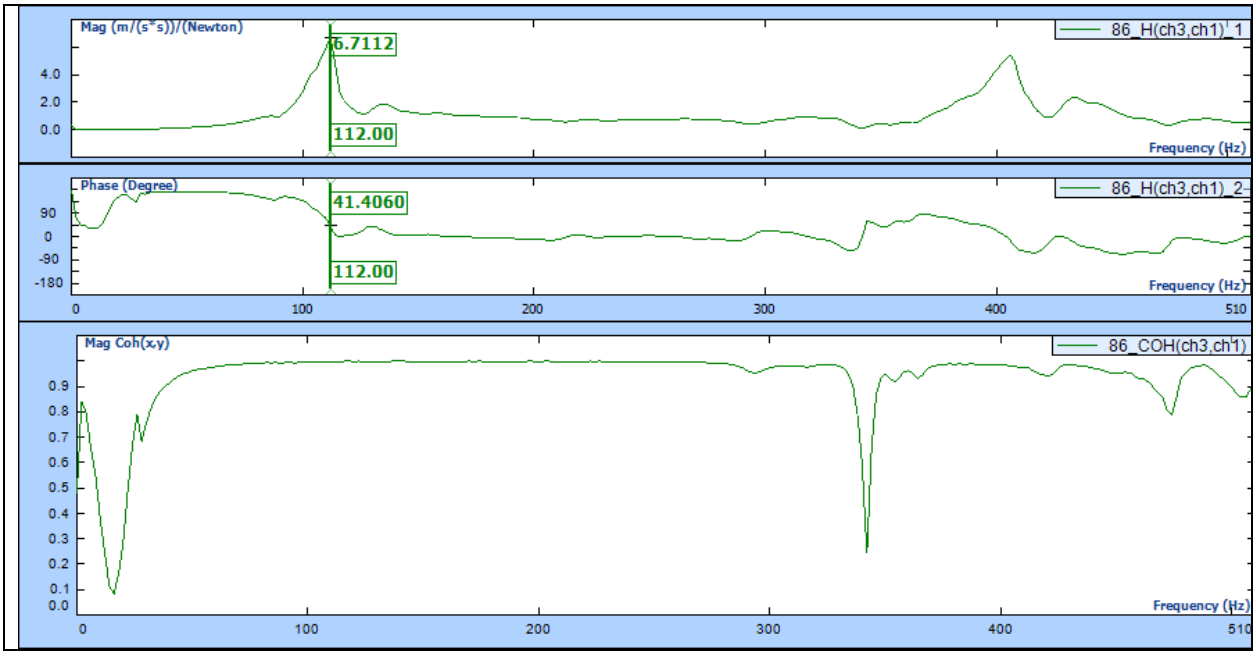
Photograph 83: ***Impact Test Data At 170 Slot Pole Jumper Top Radial***



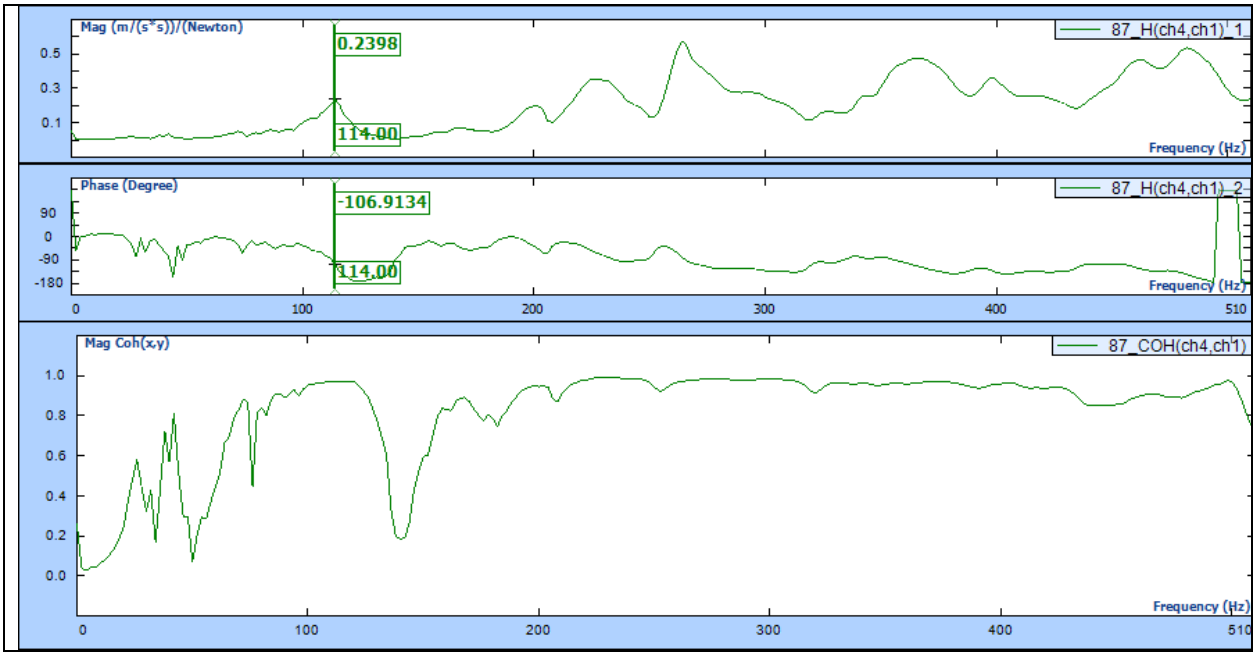
Photograph 84: ***Impact Test Data At 170 Slot Pole Jumper Top Tangential***



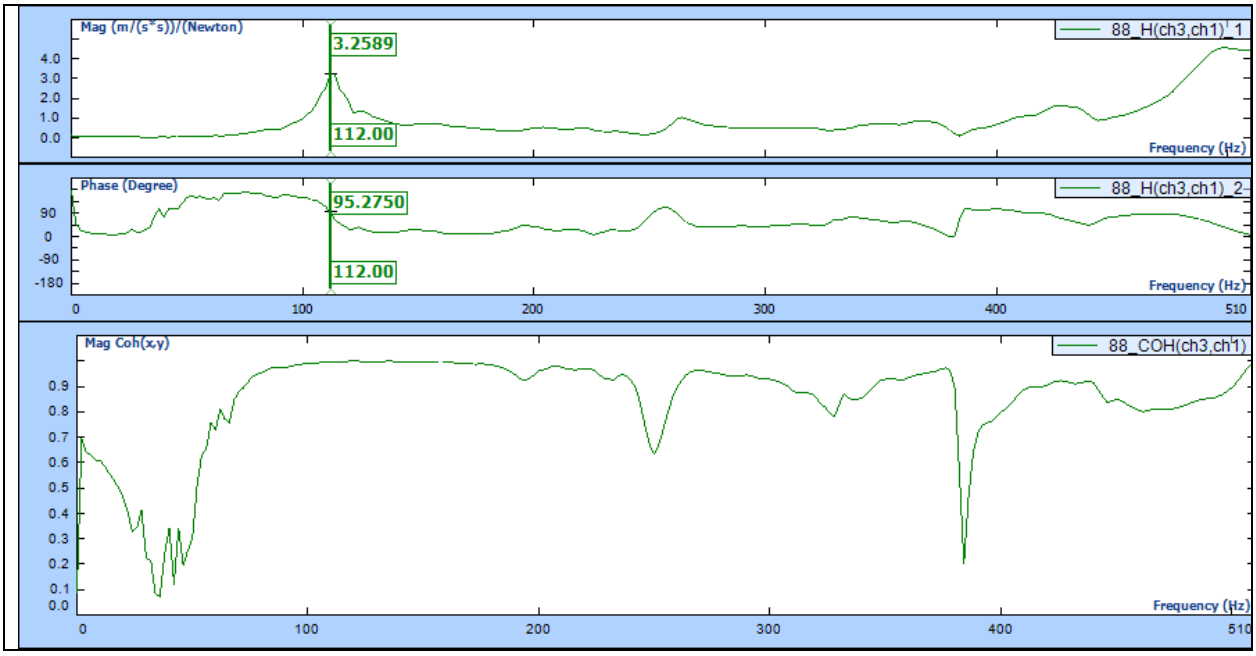
Photograph 85: ***Impact Test Data At 170 Slot Pole Jumper Bottom Radial***



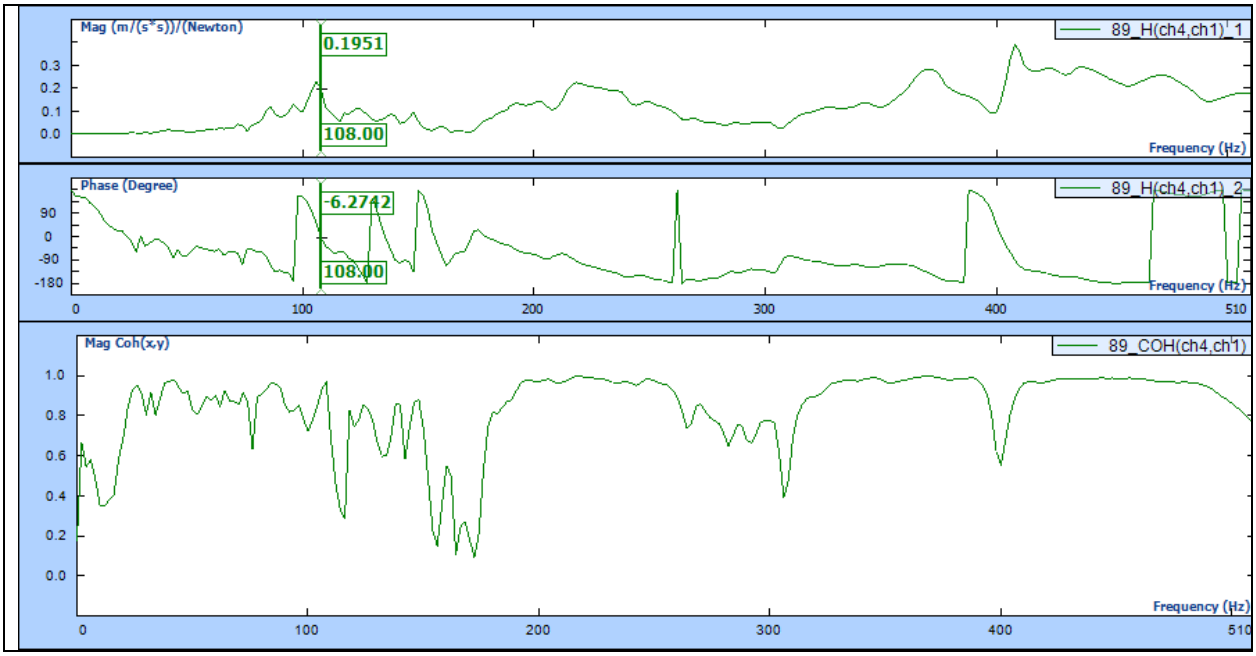
Photograph 86: ***Impact Test Data At 170 Slot Pole Jumper Bottom Tangential***



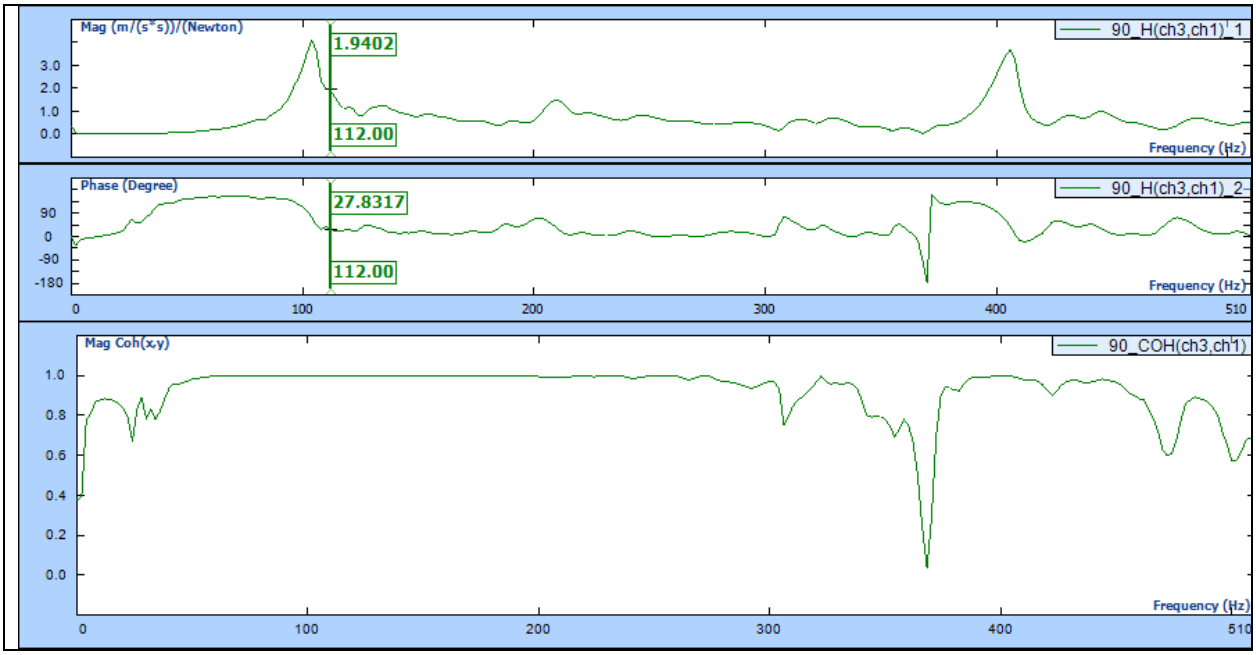
Photograph 87: ***Impact Test Data At 174 Slot Pole Jumper Top Radial***



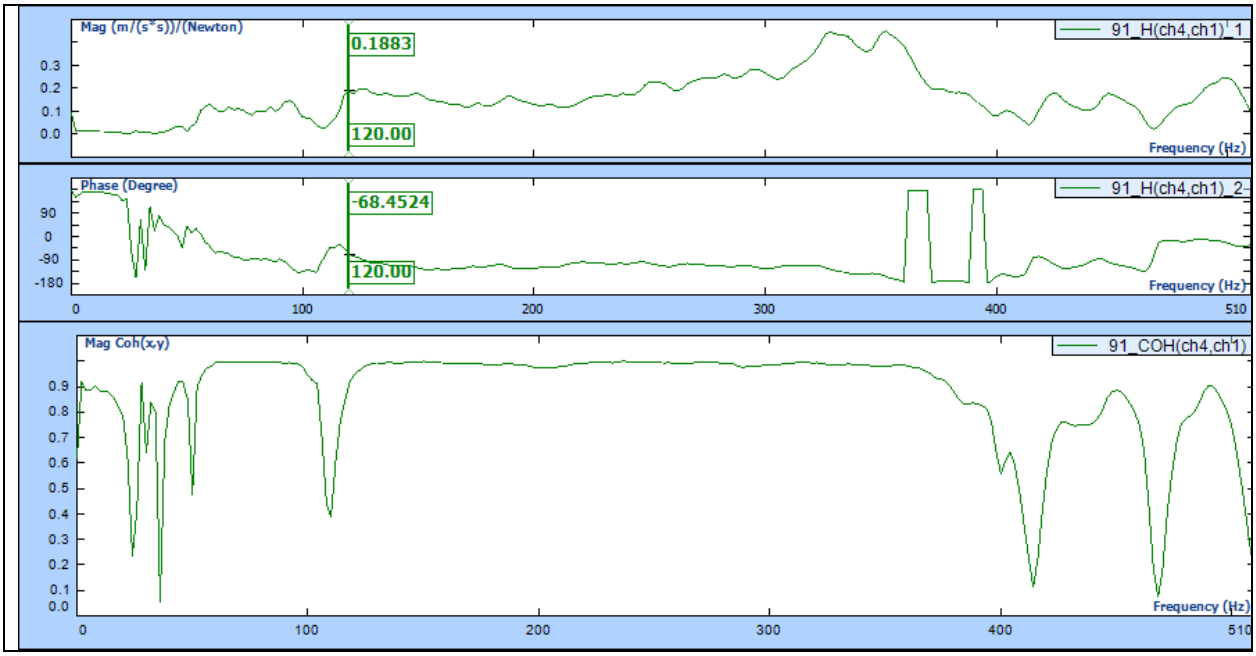
Photograph 88: ***Impact Test Data At 174 Slot Pole Jumper Top Tangential***



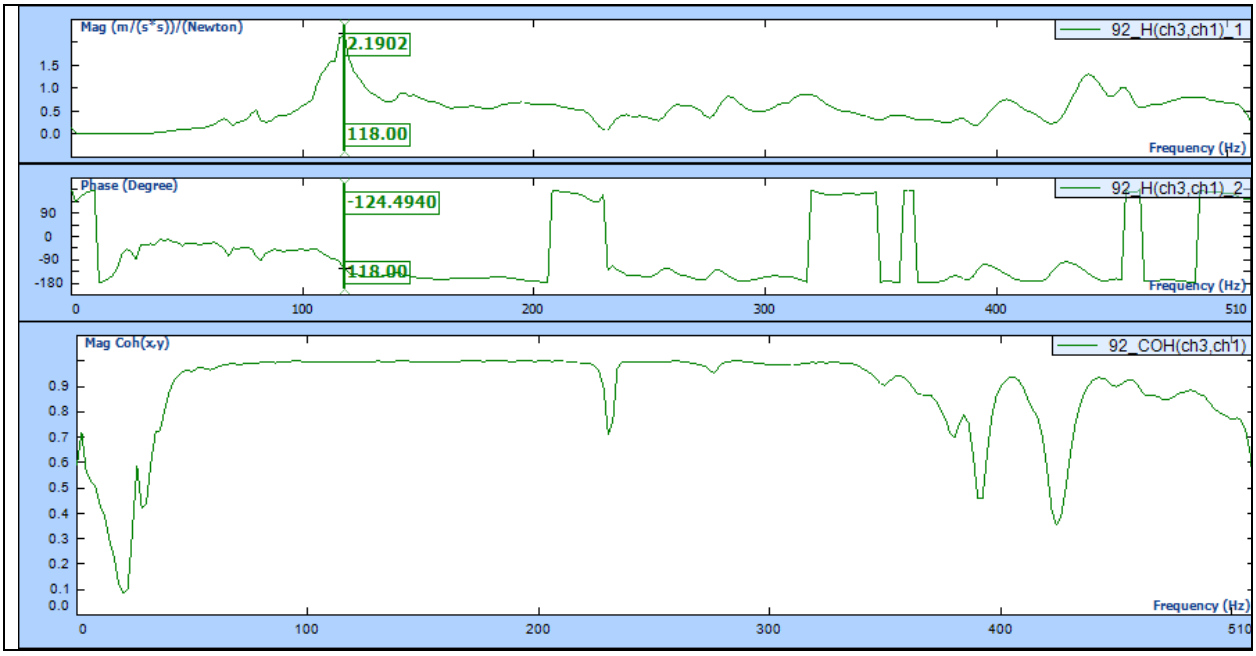
Photograph 89: ***Impact Test Data At 174 Slot Pole Jumper Bottom Radial***



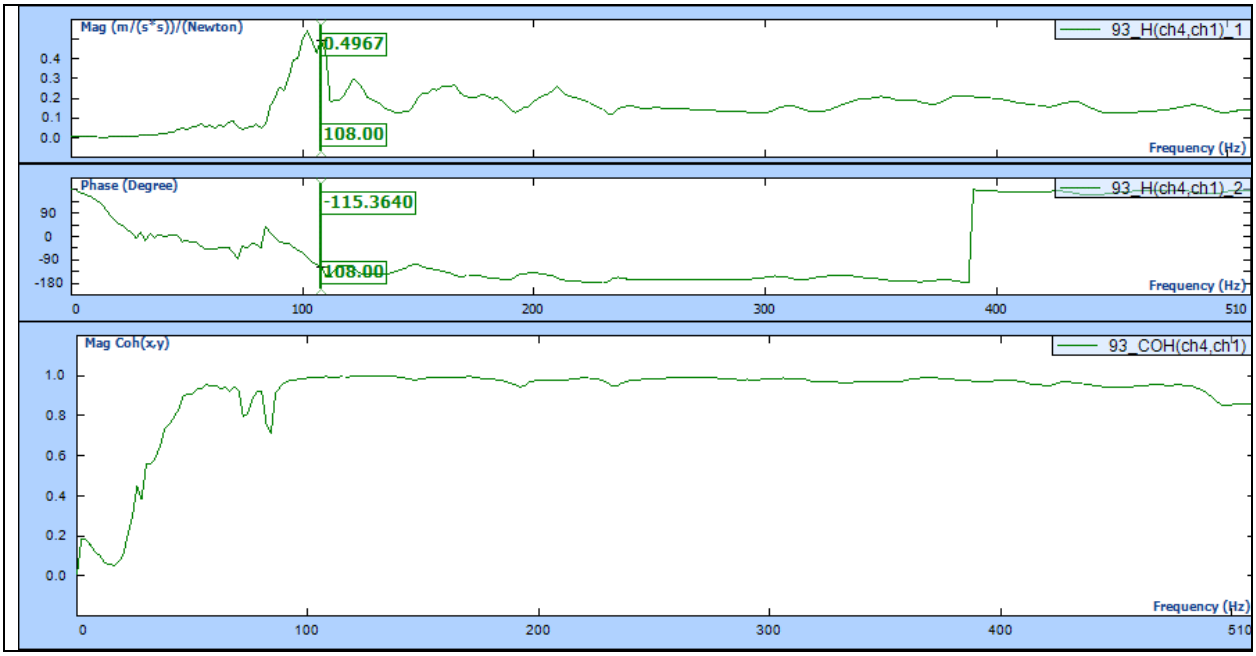
Photograph 90: ***Impact Test Data At 174 Slot Pole Jumper Bottom Tangential***



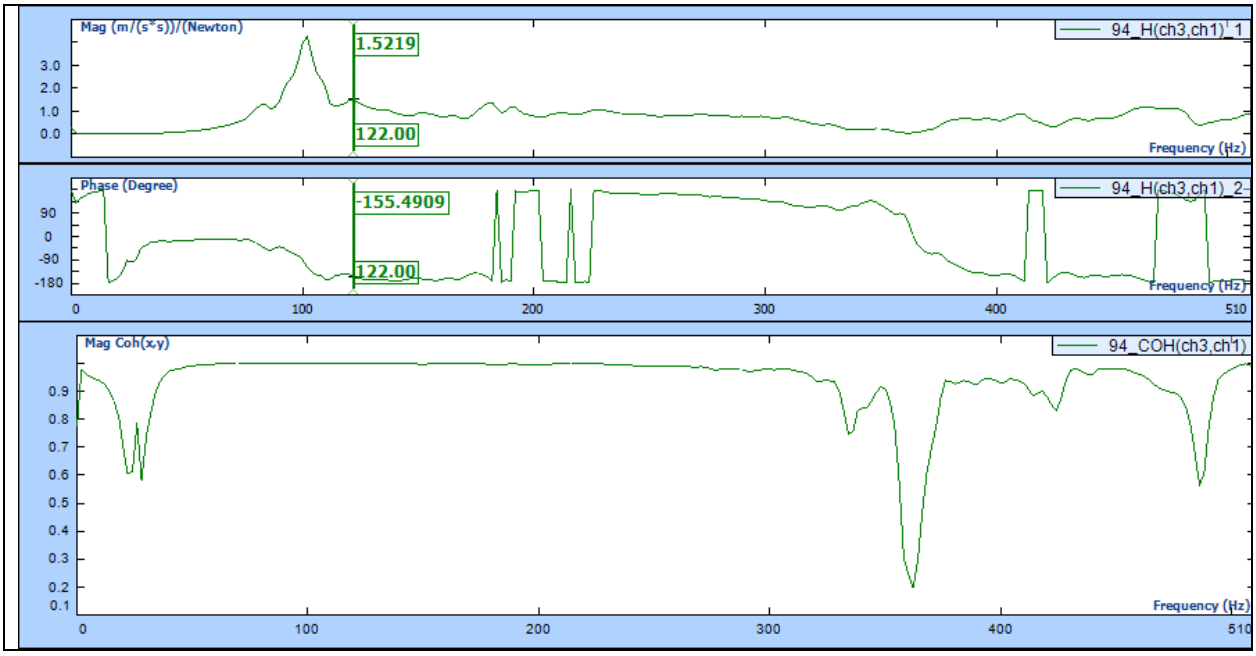
Photograph 91: ***Impact Test Data At 179 Slot Pole Jumper Top Radial***



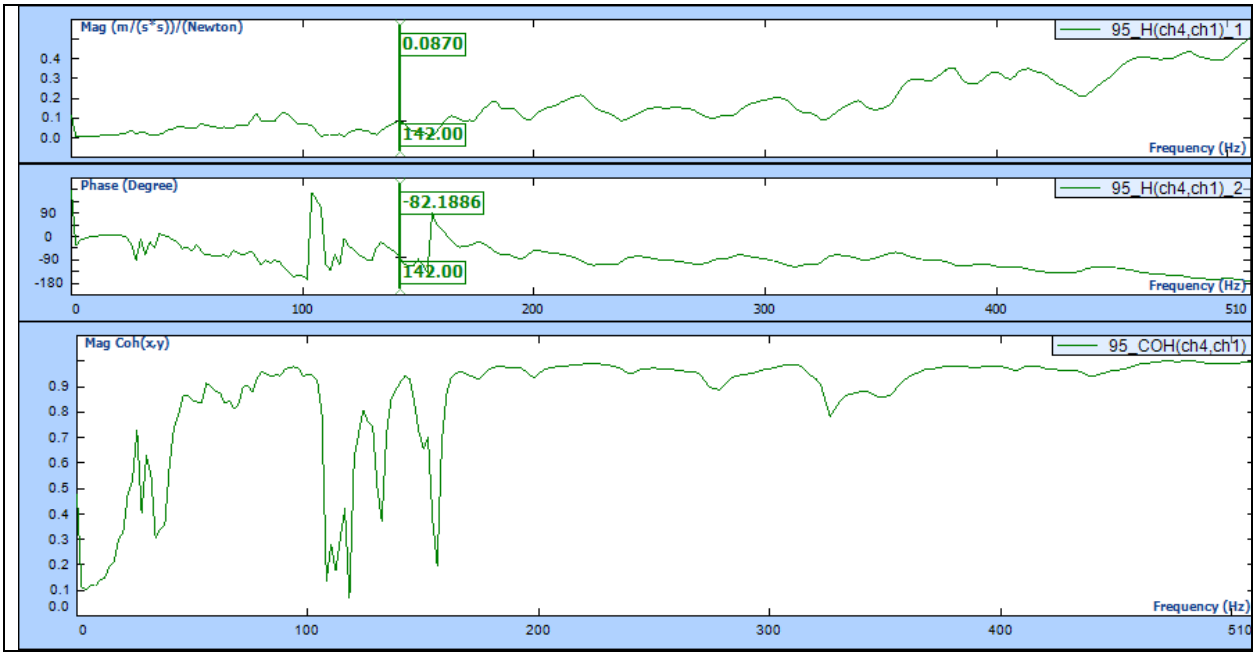
Photograph 92: ***Impact Test Data At 179 Slot Pole Jumper Top Tangential***



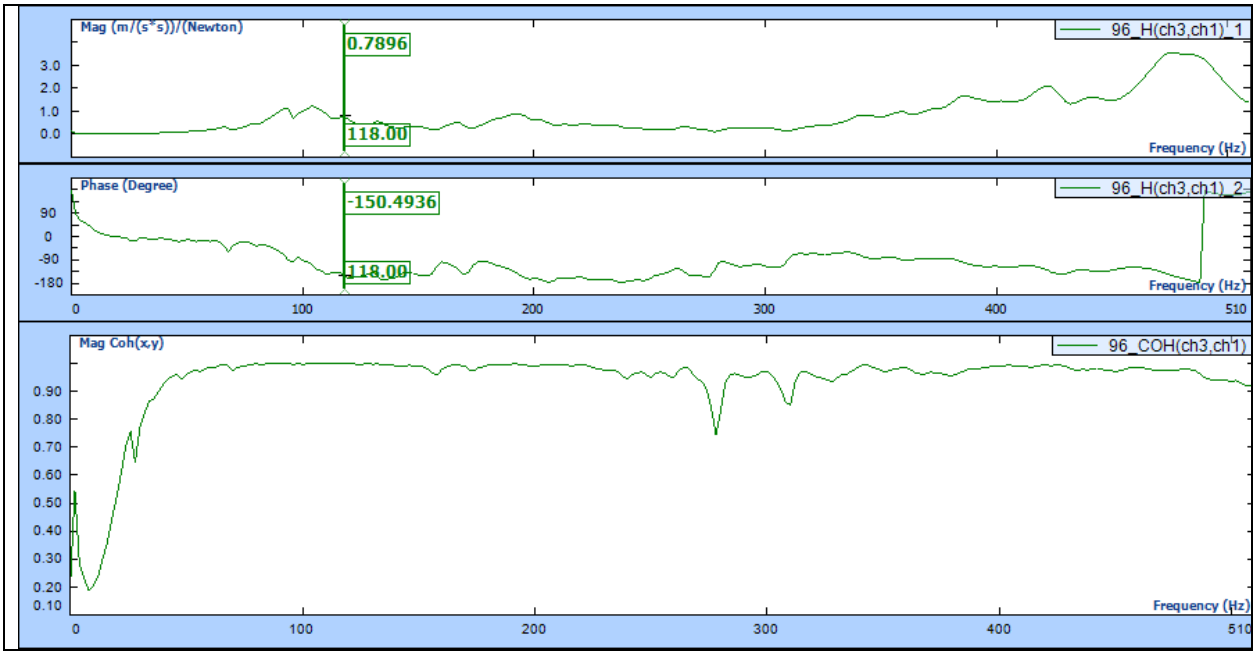
Photograph 93: ***Impact Test Data At 179 Slot Pole Jumper Bottom Radial***



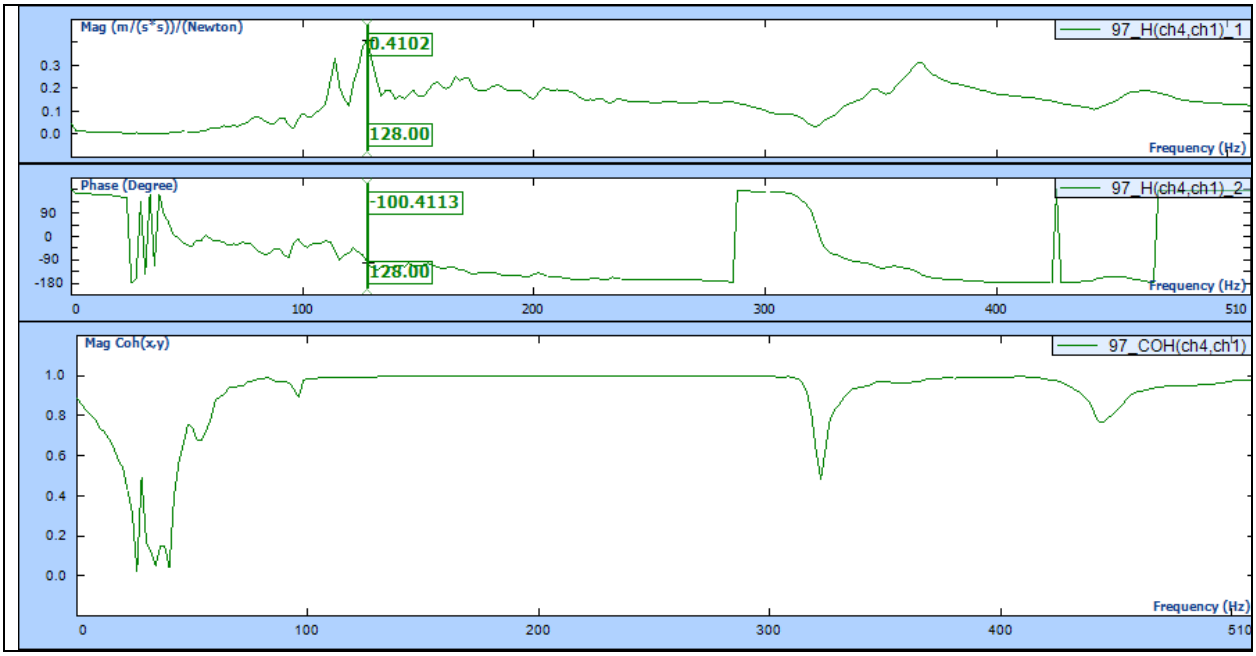
Photograph 94: ***Impact Test Data At 179 Slot Pole Jumper Bottom Tangential***



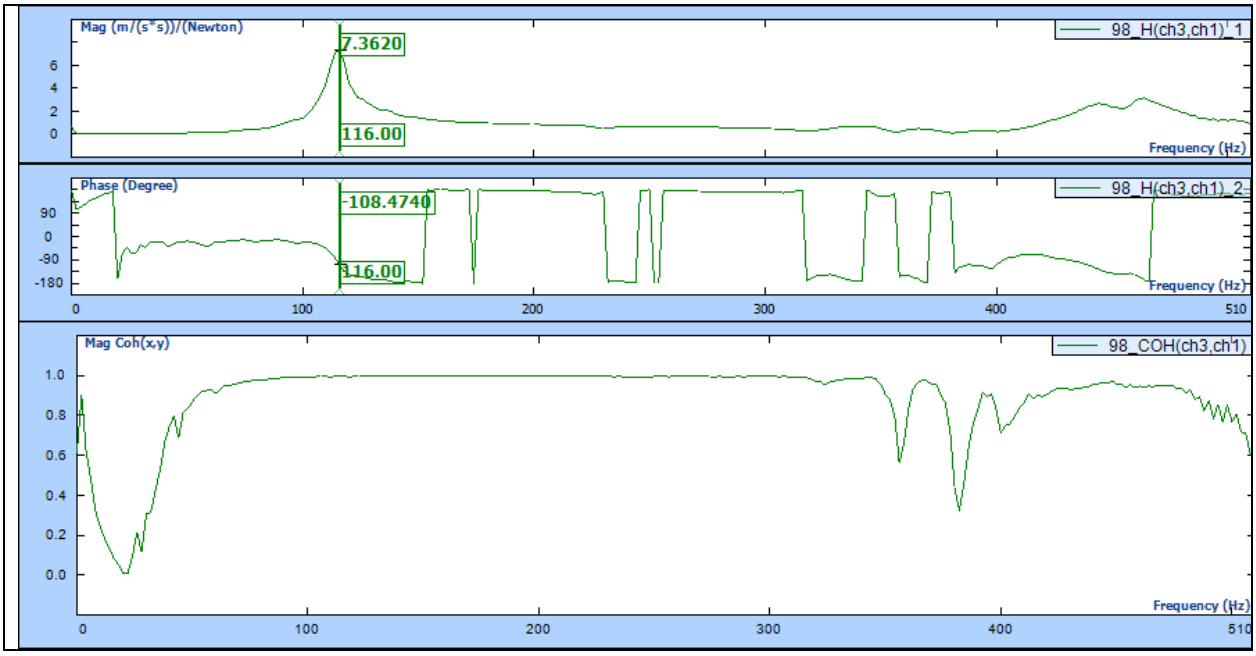
Photograph 95: ***Impact Test Data At 183 Slot Pole Jumper Top Radial***



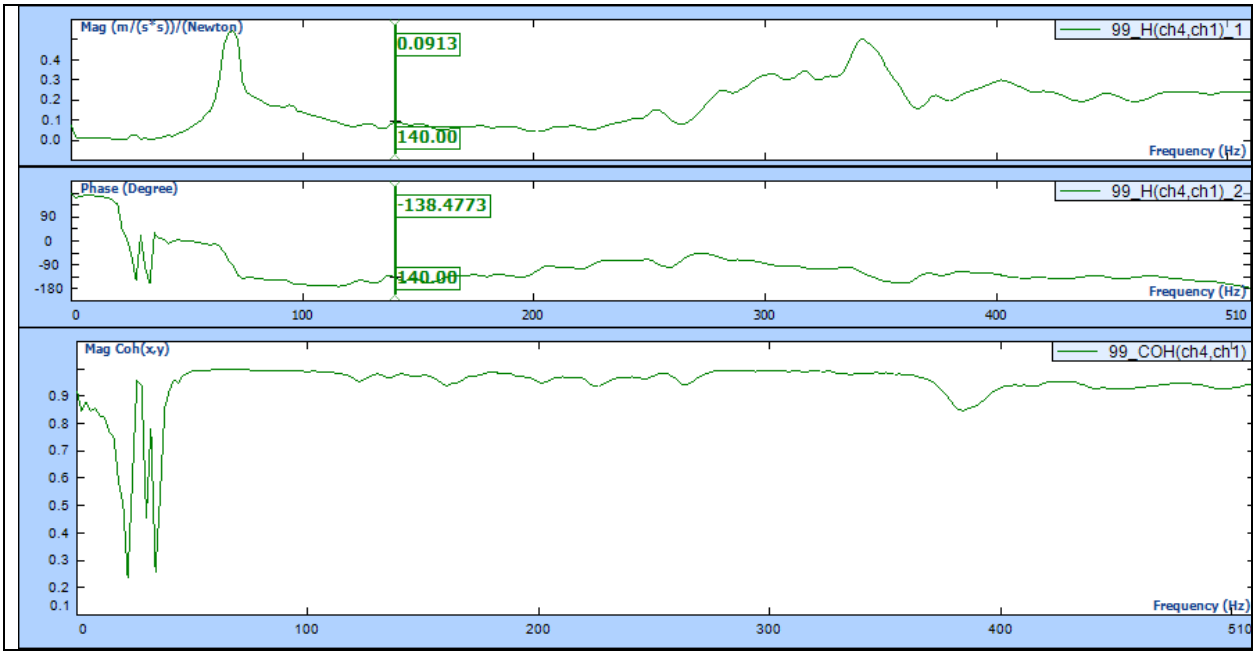
Photograph 96: ***Impact Test Data At 183 Slot Pole Jumper Top Tangential***



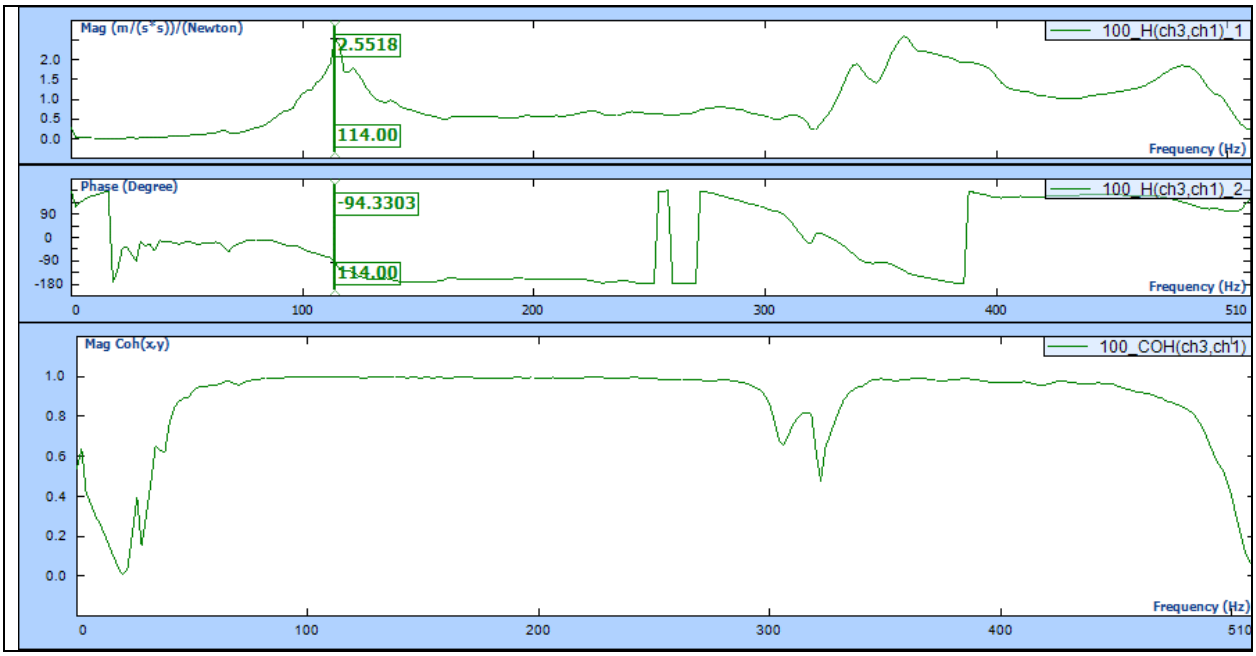
Photograph 97: ***Impact Test Data At 183 Slot Pole Jumper Bottom Radial***



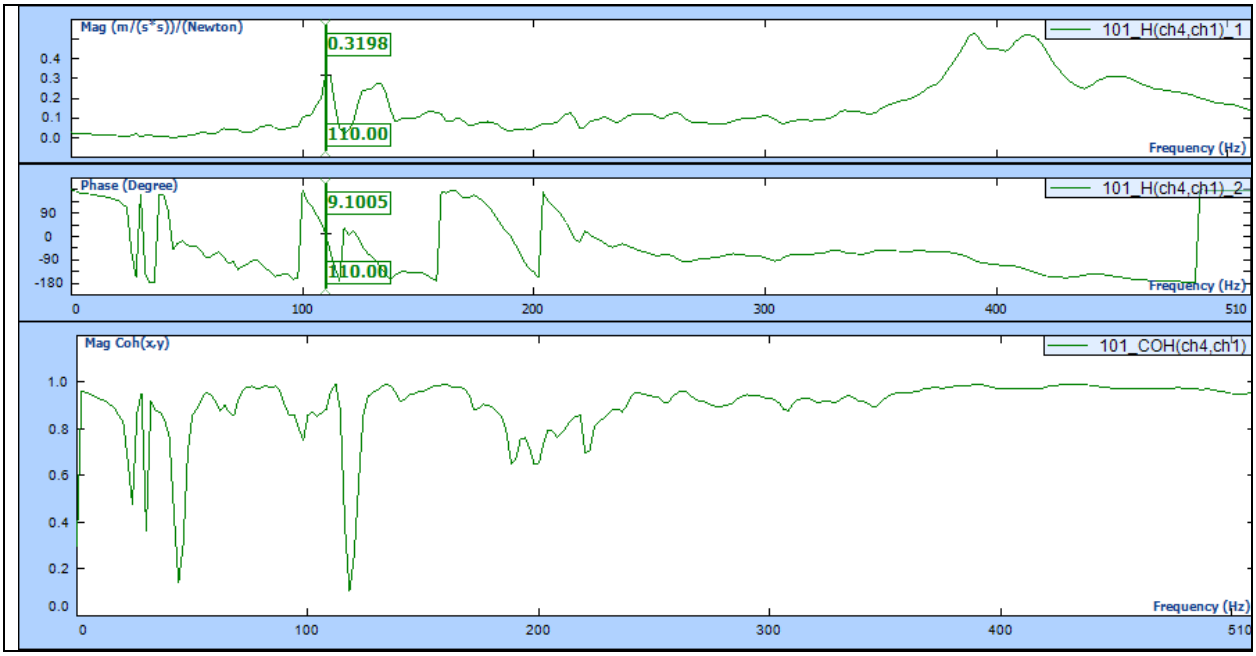
Photograph 98: ***Impact Test Data At 183 Slot Pole Jumper Bottom Tangential***



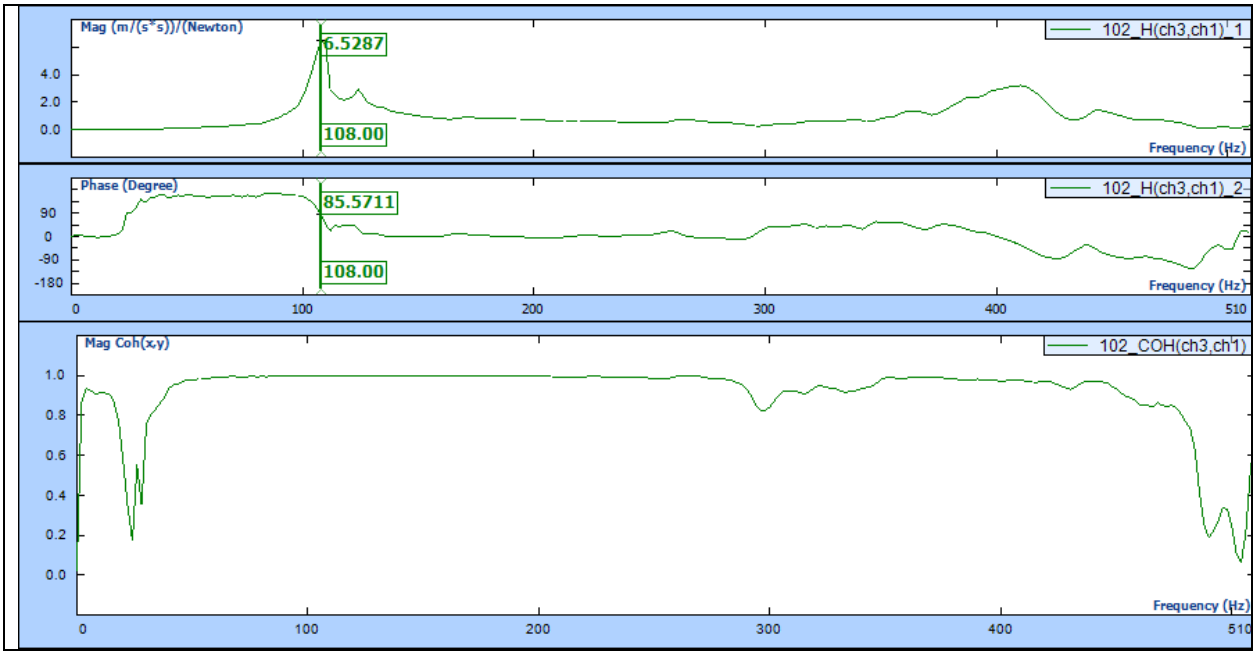
Photograph 99: ***Impact Test Data At 187 Slot Pole Jumper Top Radial***



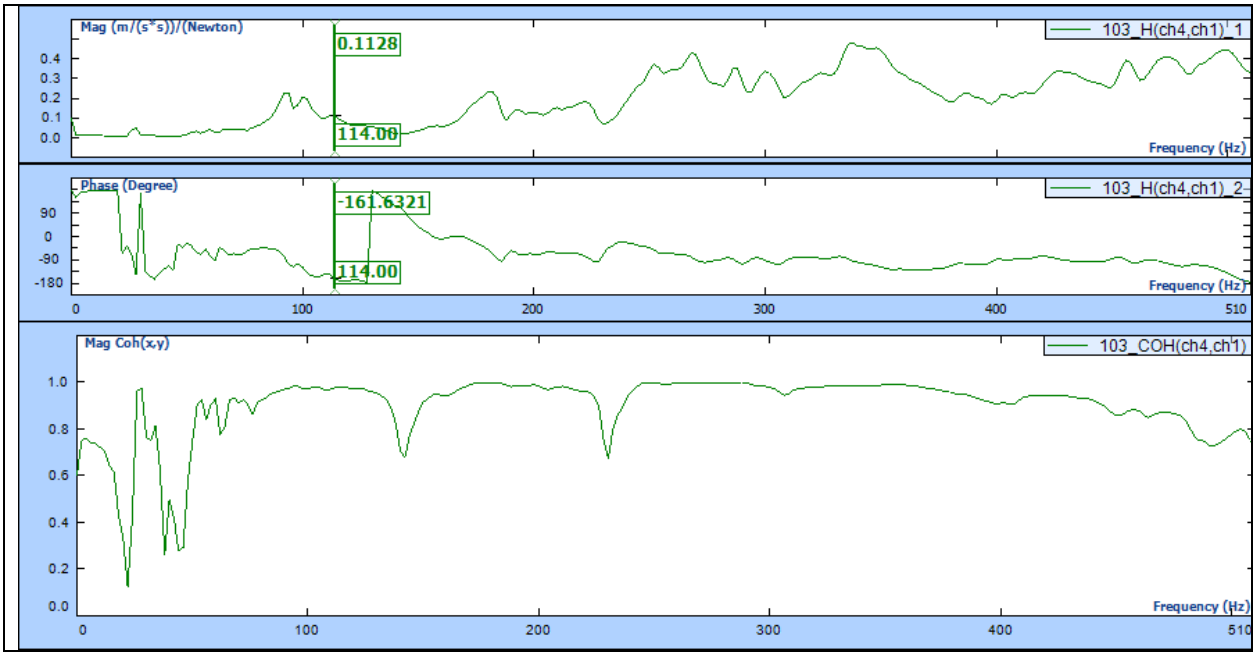
Photograph 100: ***Impact Test Data At 187 Slot Pole Jumper Top Tangential***



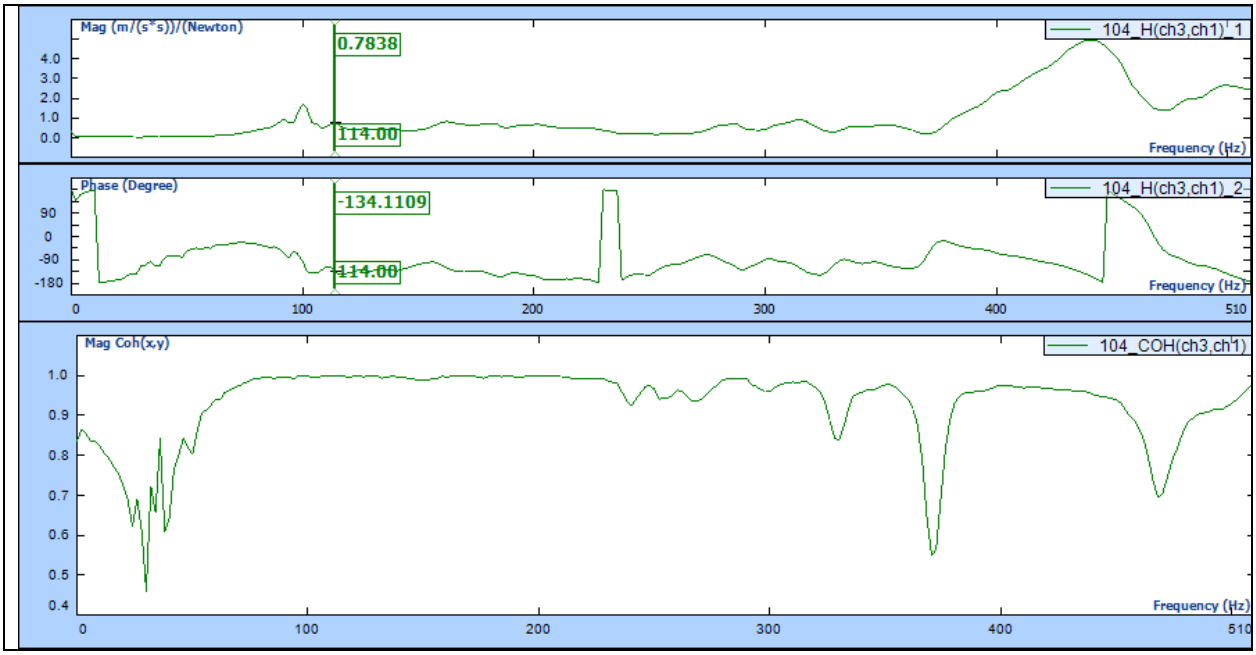
Photograph 101: ***Impact Test Data At 187 Slot Pole Jumper Bottom Radial***



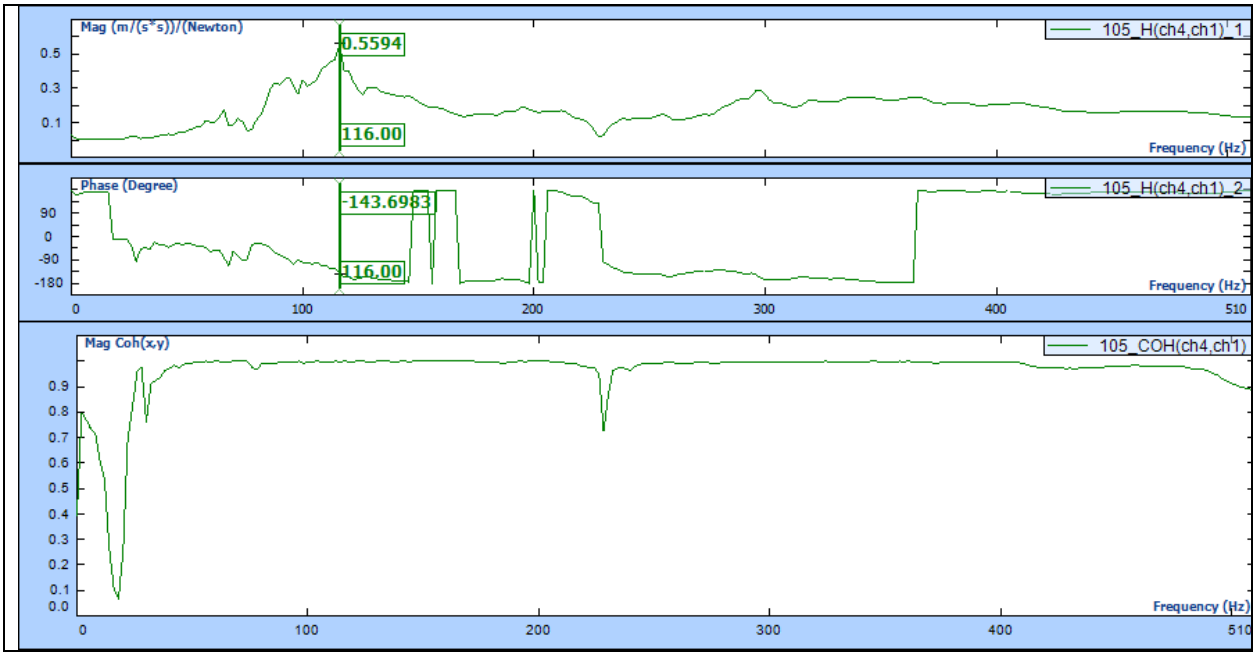
Photograph 102: ***Impact Test Data At 187 Slot Pole Jumper Bottom Tangential***



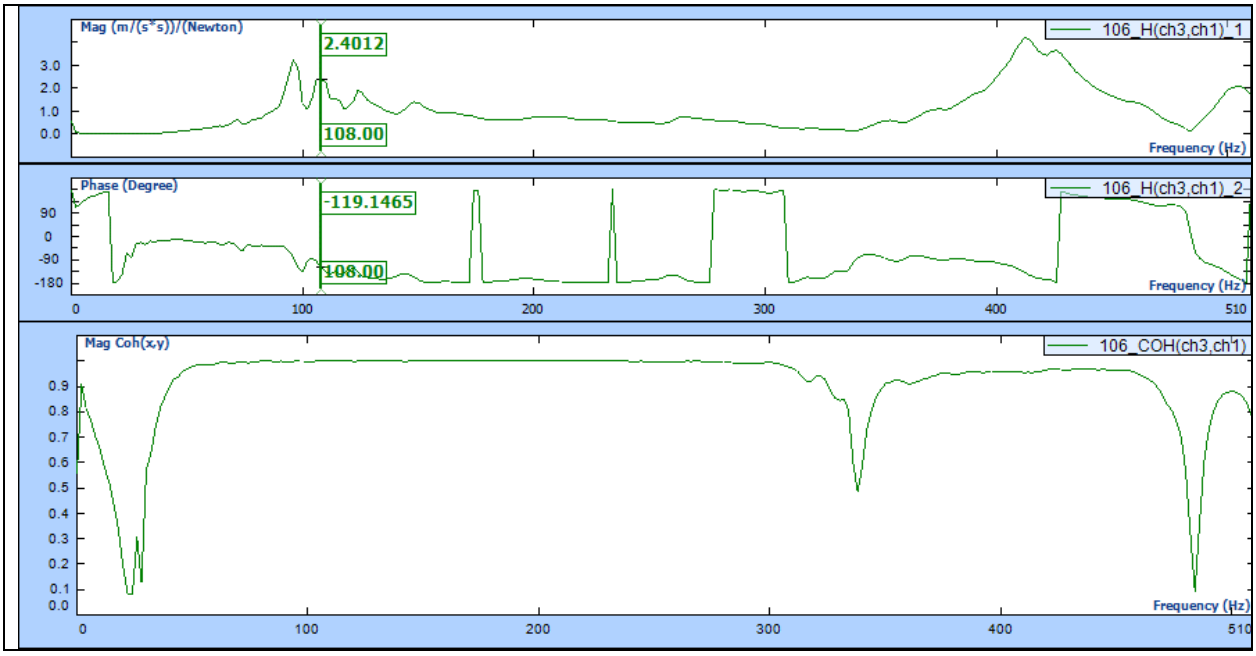
Photograph 103: ***Impact Test Data At 192 Slot Pole Jumper Top Radial***



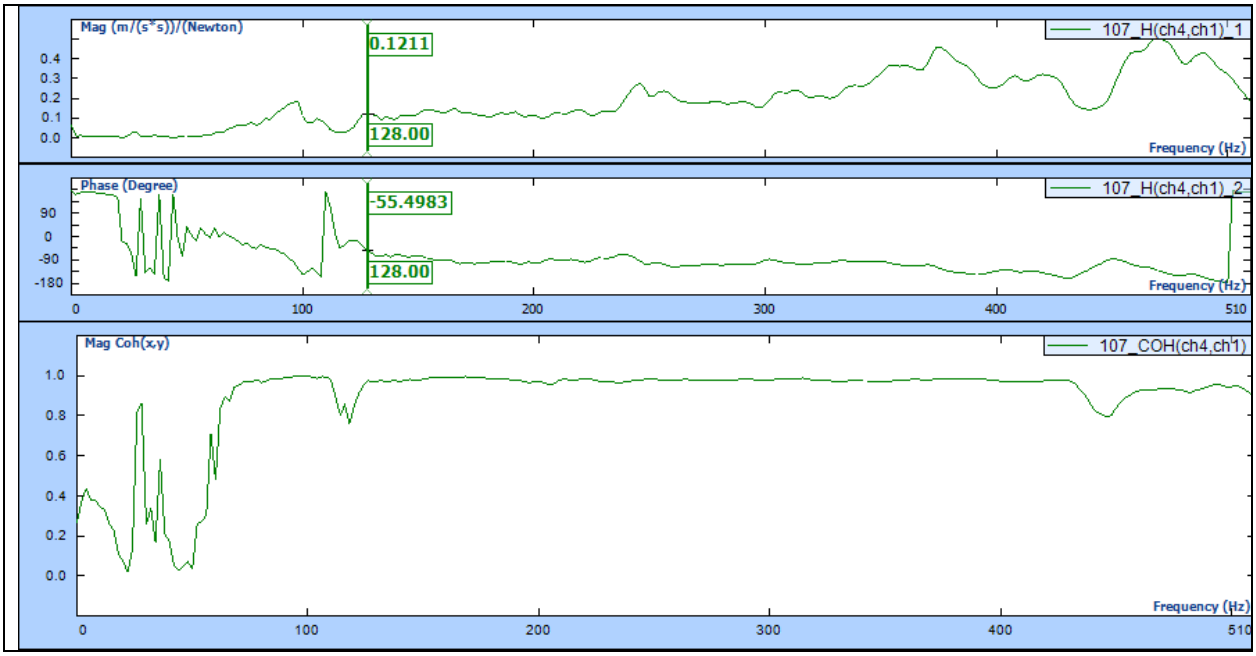
Photograph 104: ***Impact Test Data At 192 Slot Pole Jumper Top Tangential***



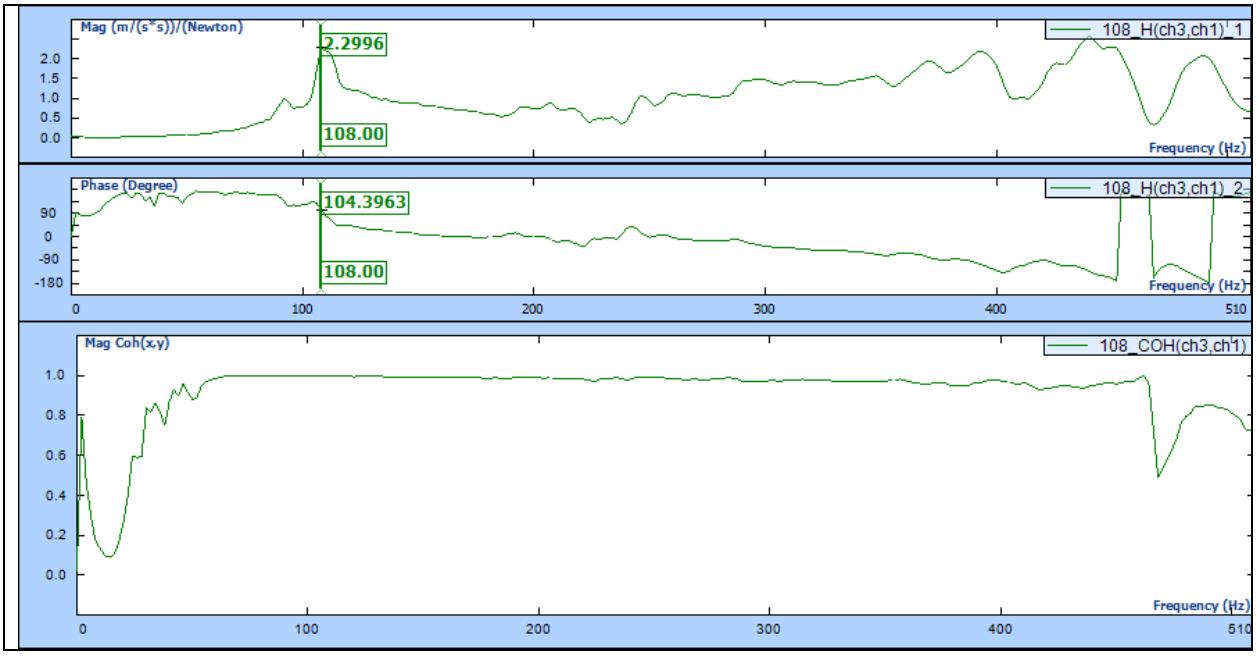
Photograph 105: ***Impact Test Data At 192 Slot Pole Jumper Bottom Radial***



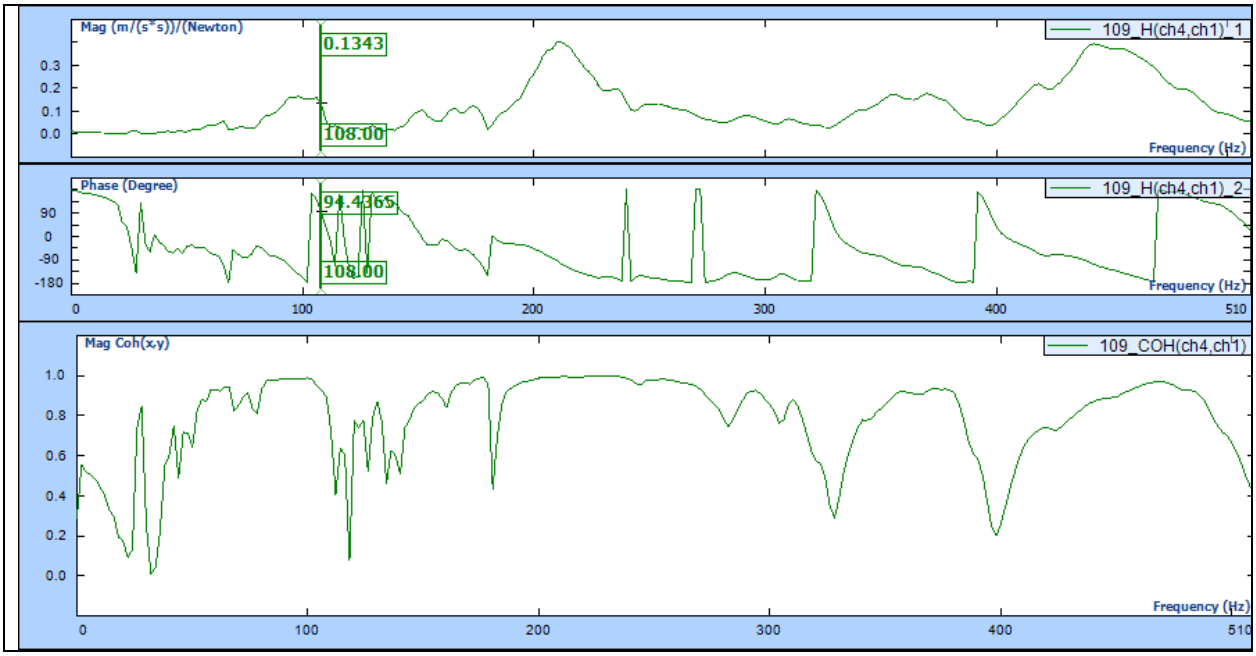
Photograph 106: ***Impact Test Data At 192 Slot Pole Jumper Bottom Tangential***



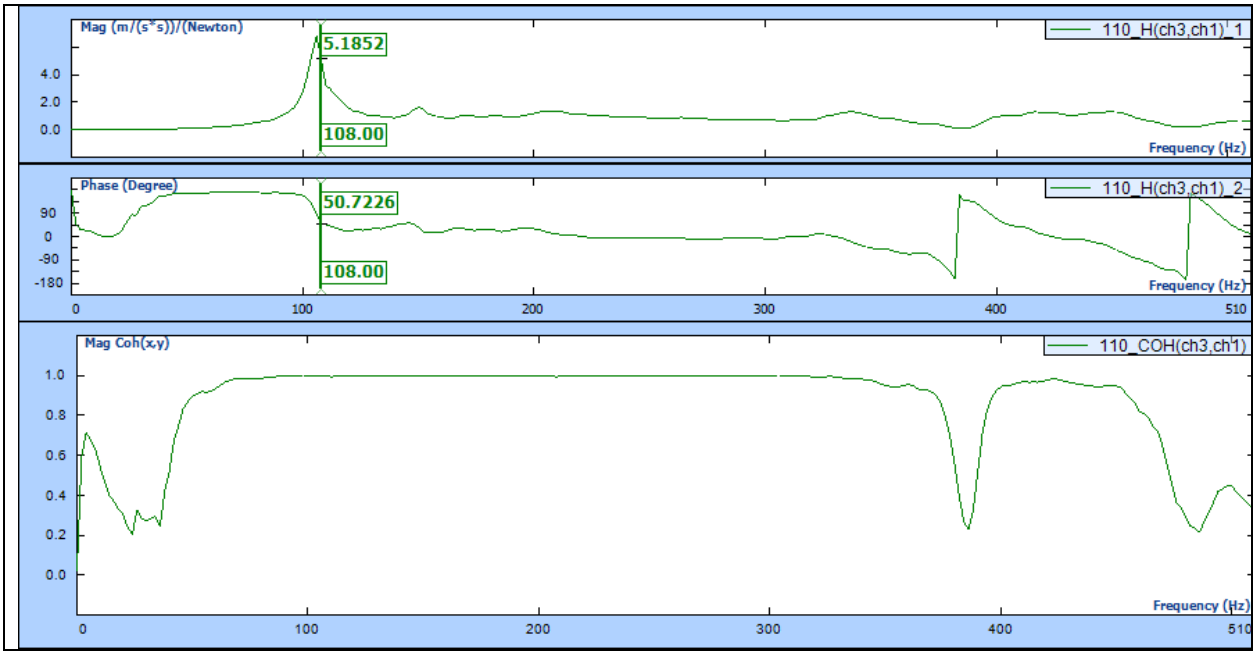
Photograph 107: ***Impact Test Data At 196 Slot Pole Jumper Top Radial***



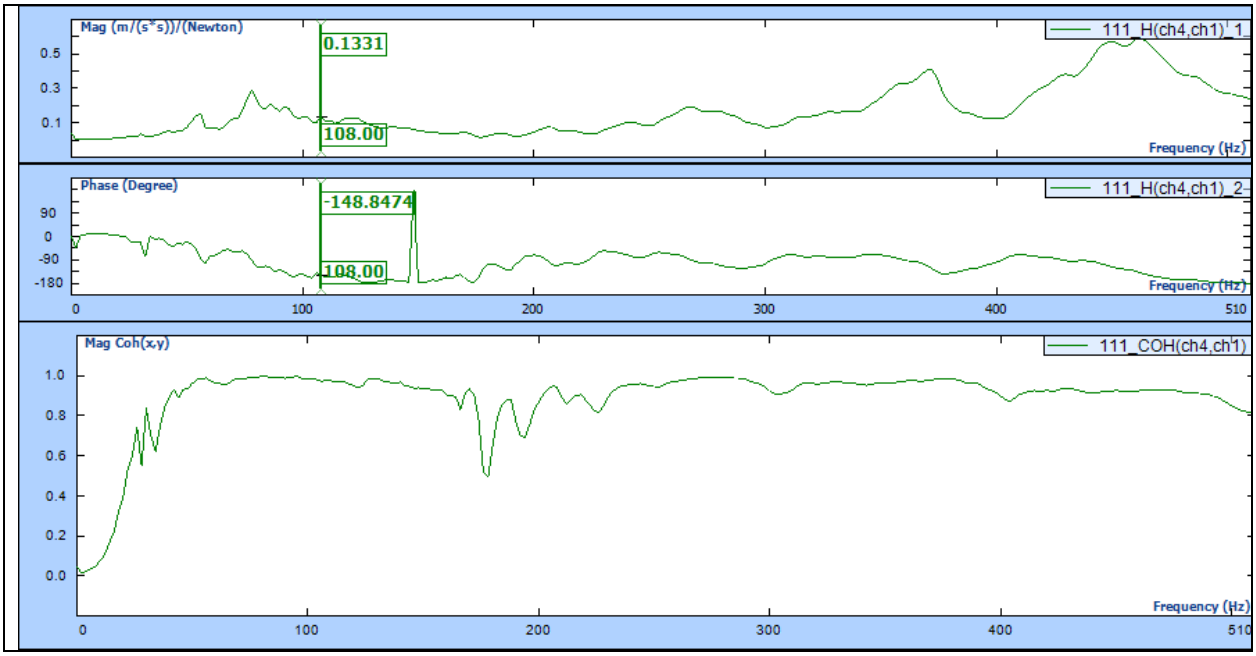
Photograph 108: ***Impact Test Data At 196 Slot Pole Jumper Top Tangential***



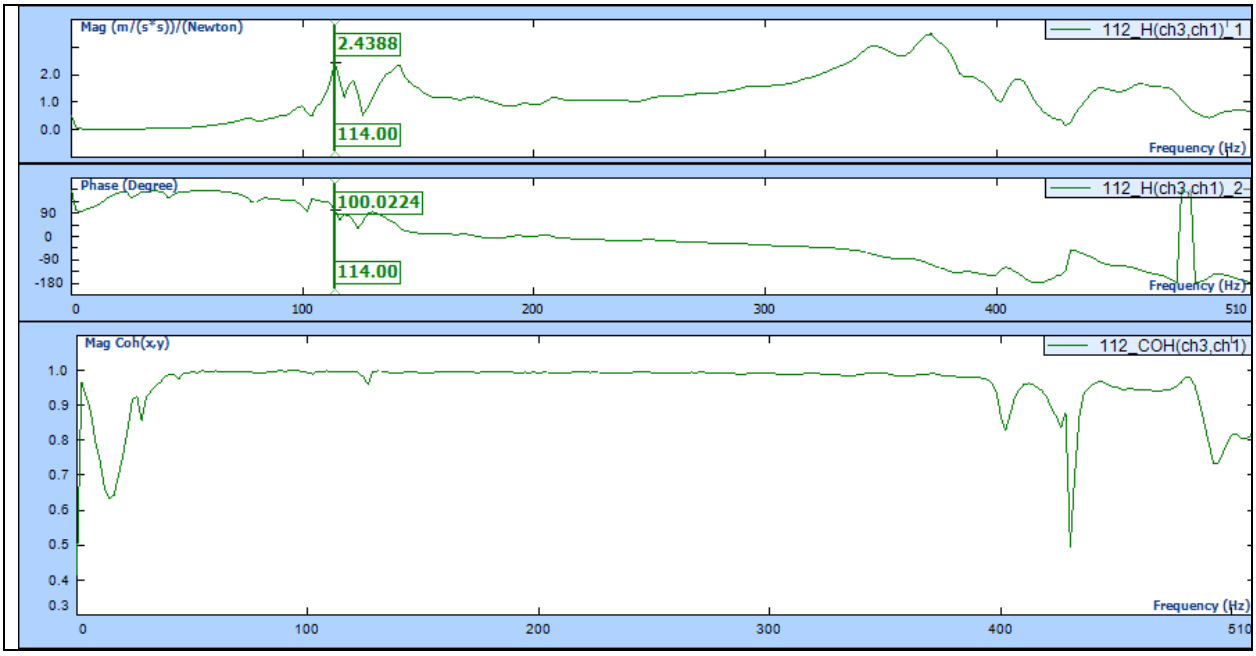
Photograph 109: ***Impact Test Data At 196 Slot Pole Jumper Bottom Radial***



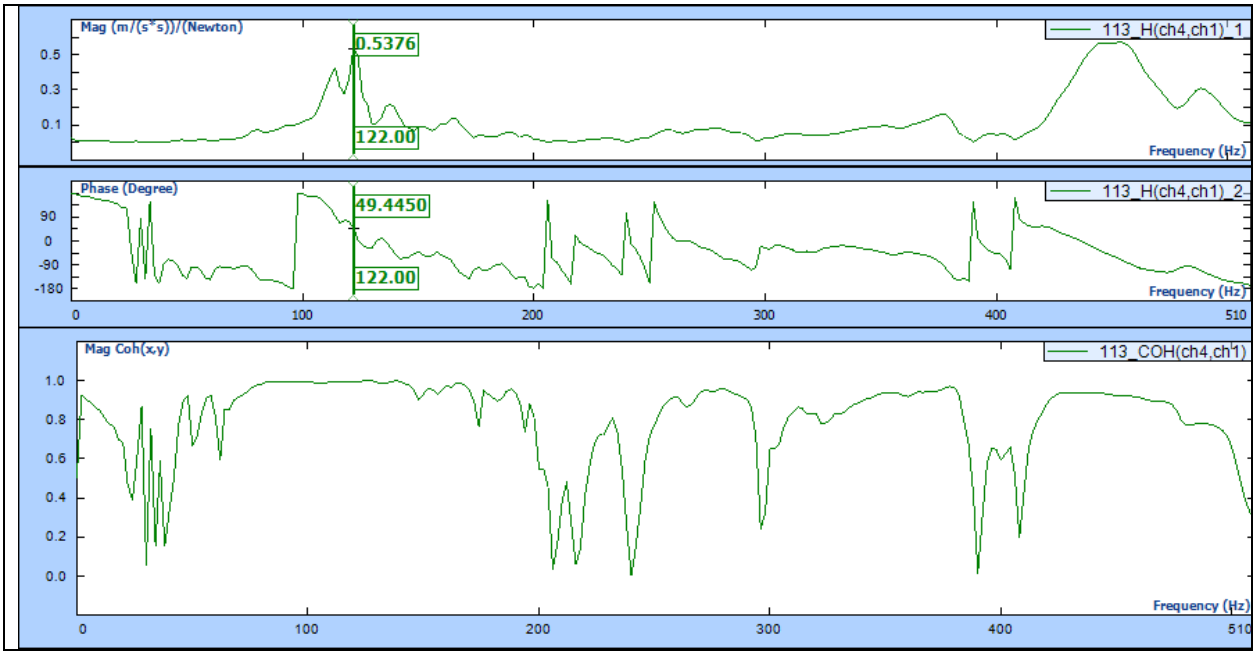
Photograph 110: ***Impact Test Data At 196 Slot Pole Jumper Bottom Tangential***



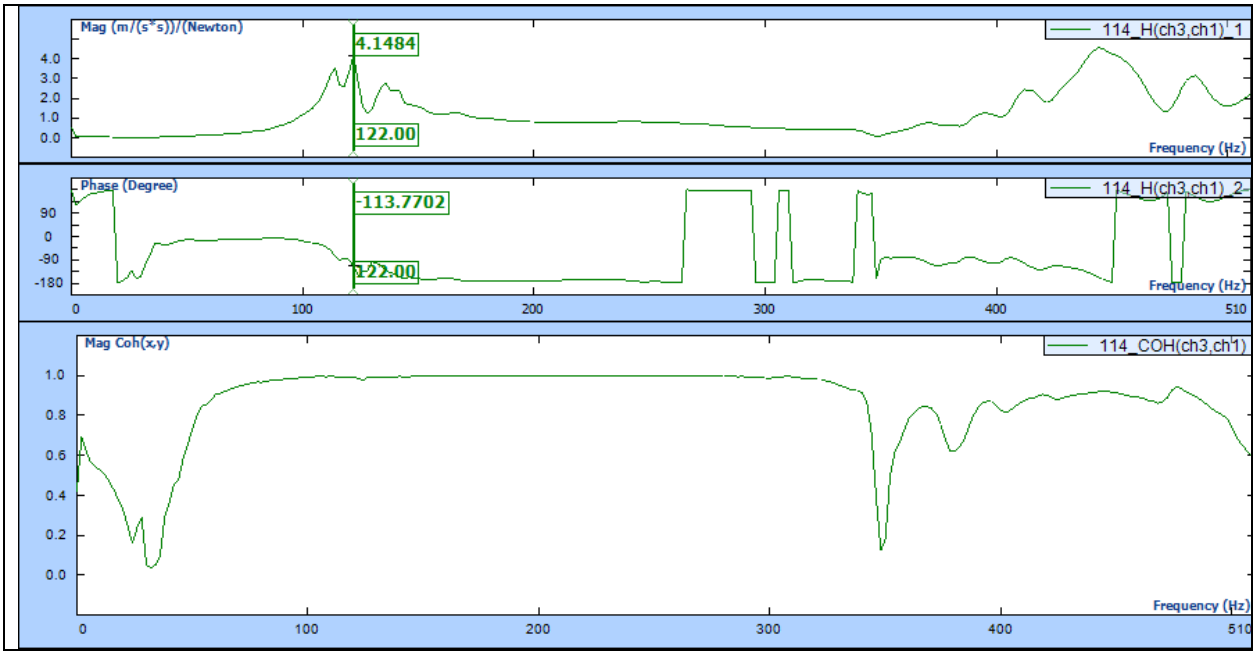
Photograph 111: ***Impact Test Data At 201 Slot Pole Jumper Top Radial***



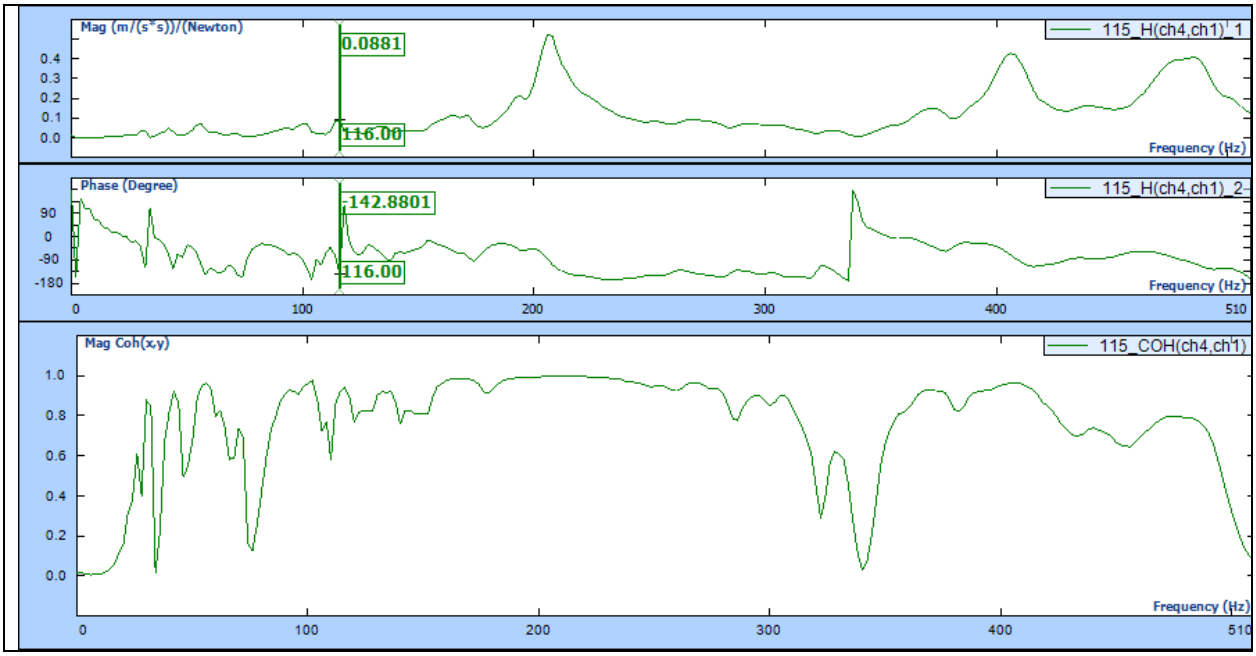
Photograph 112: ***Impact Test Data At 201 Slot Pole Jumper Top Tangential***



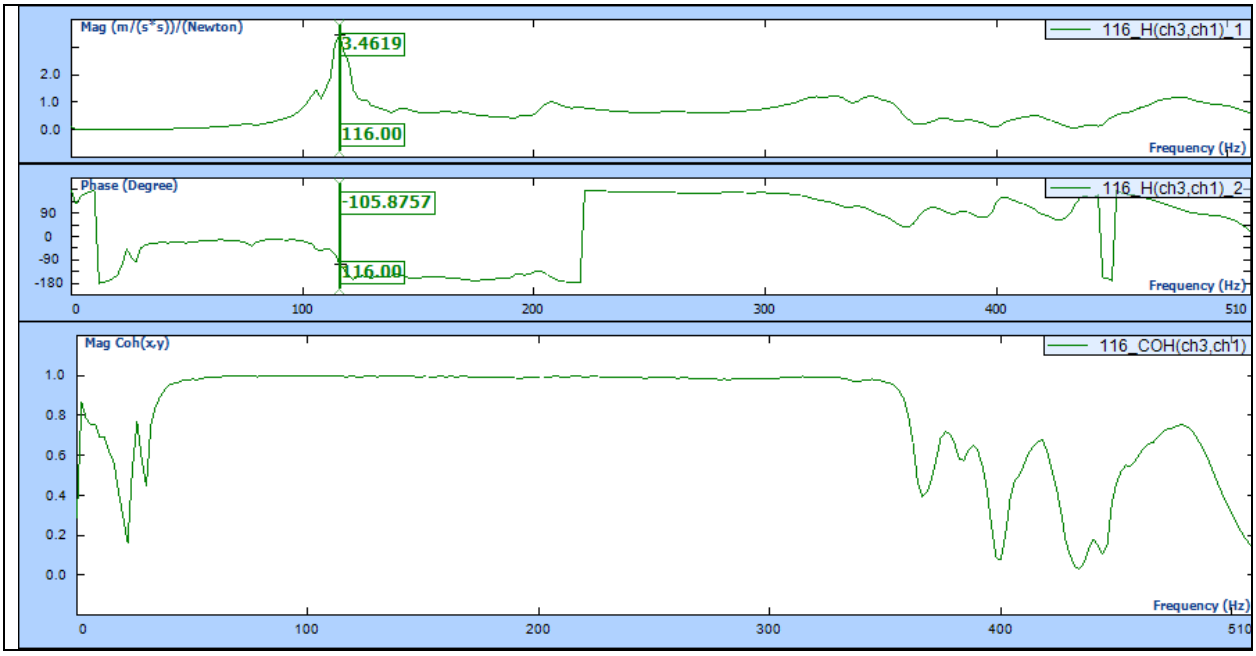
Photograph 113: ***Impact Test Data At 201 Slot Pole Jumper Bottom Radial***



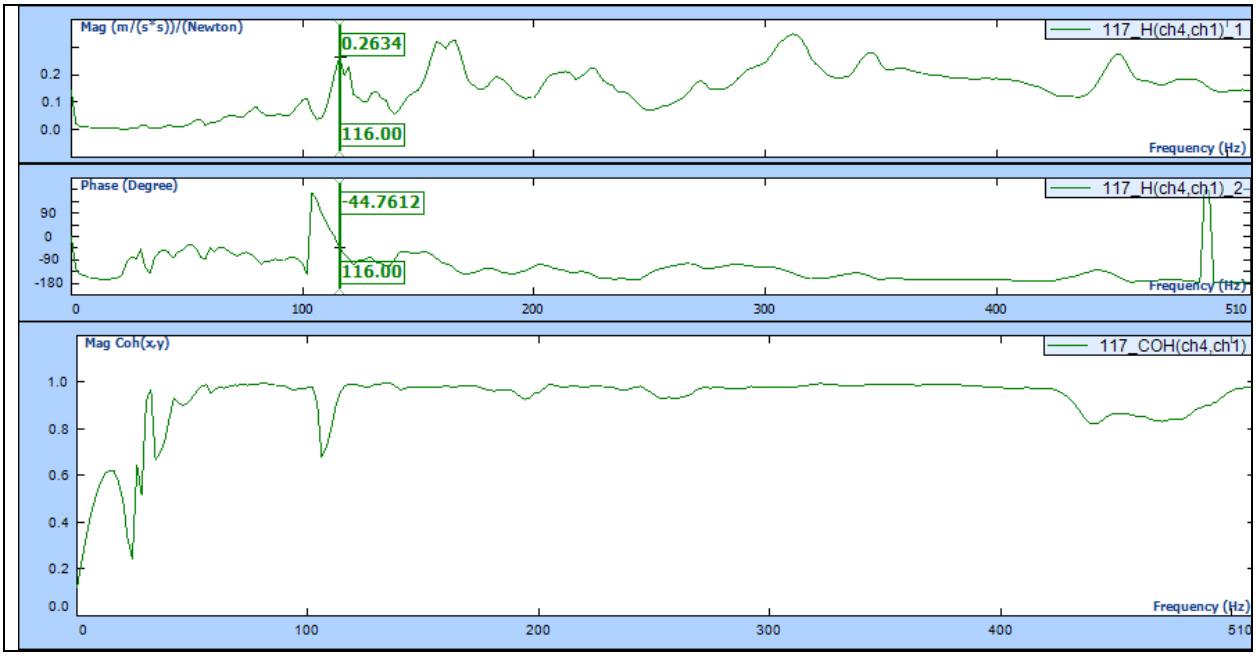
Photograph 114: ***Impact Test Data At 201 Slot Pole Jumper Bottom Tangential***



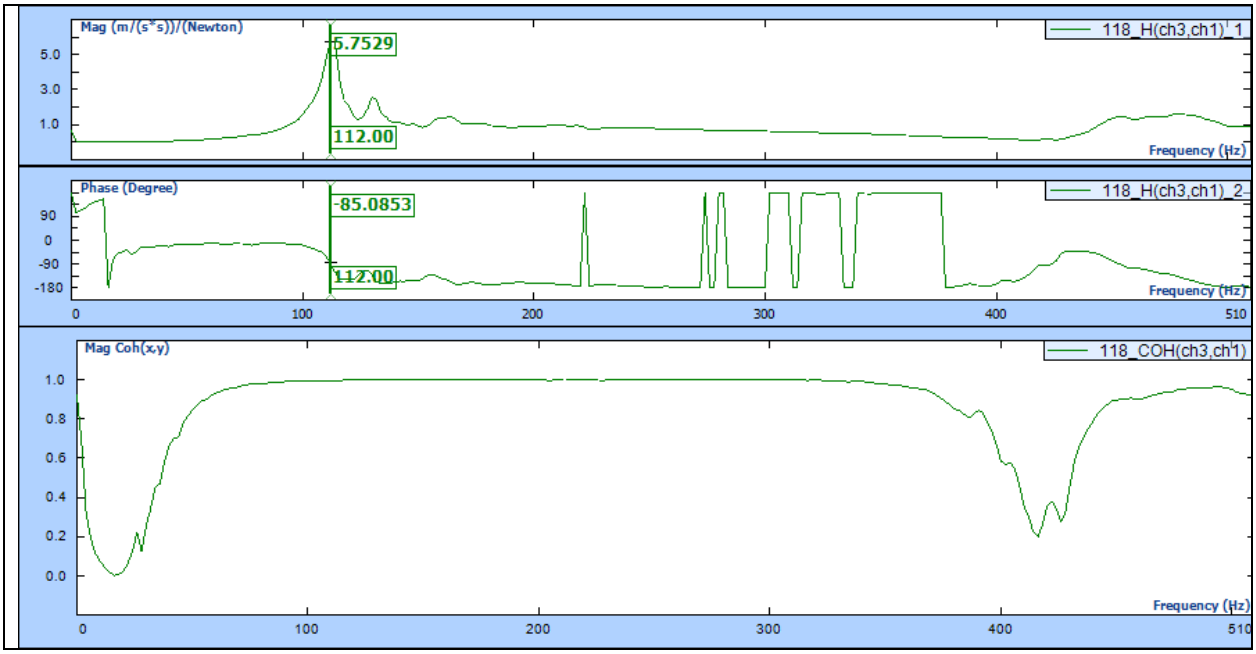
Photograph 115: ***Impact Test Data At 205 Slot Pole Jumper Top Radial***



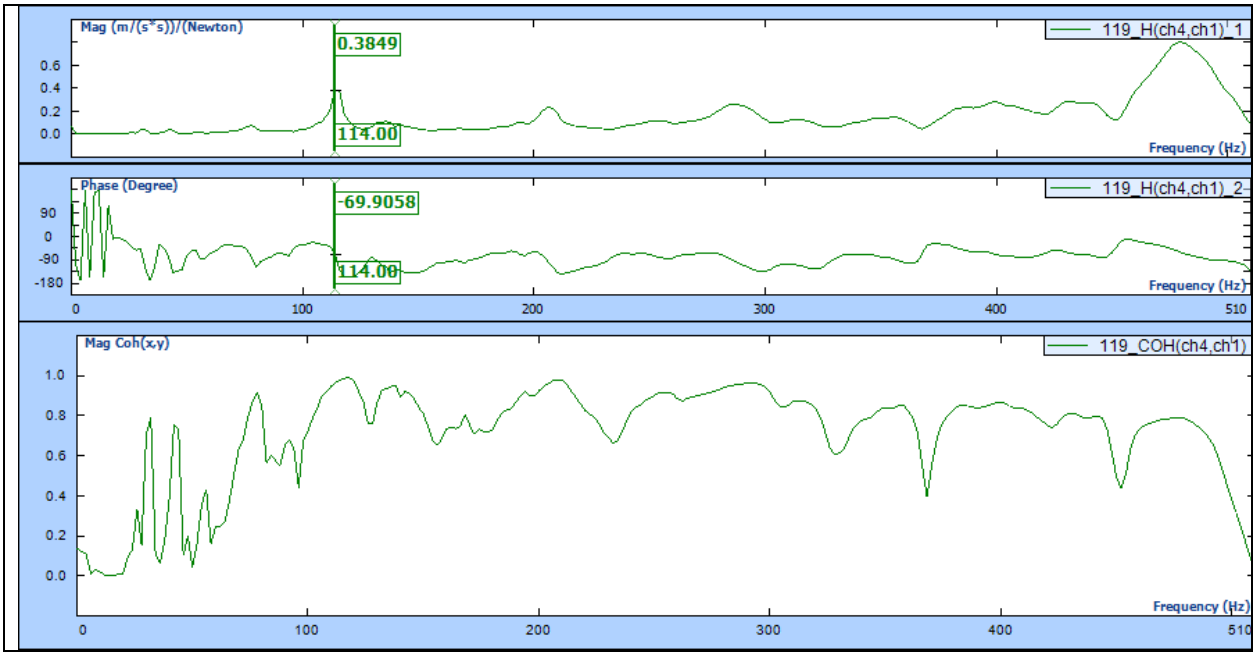
Photograph 116: ***Impact Test Data At 205 Slot Pole Jumper Top Tangential***



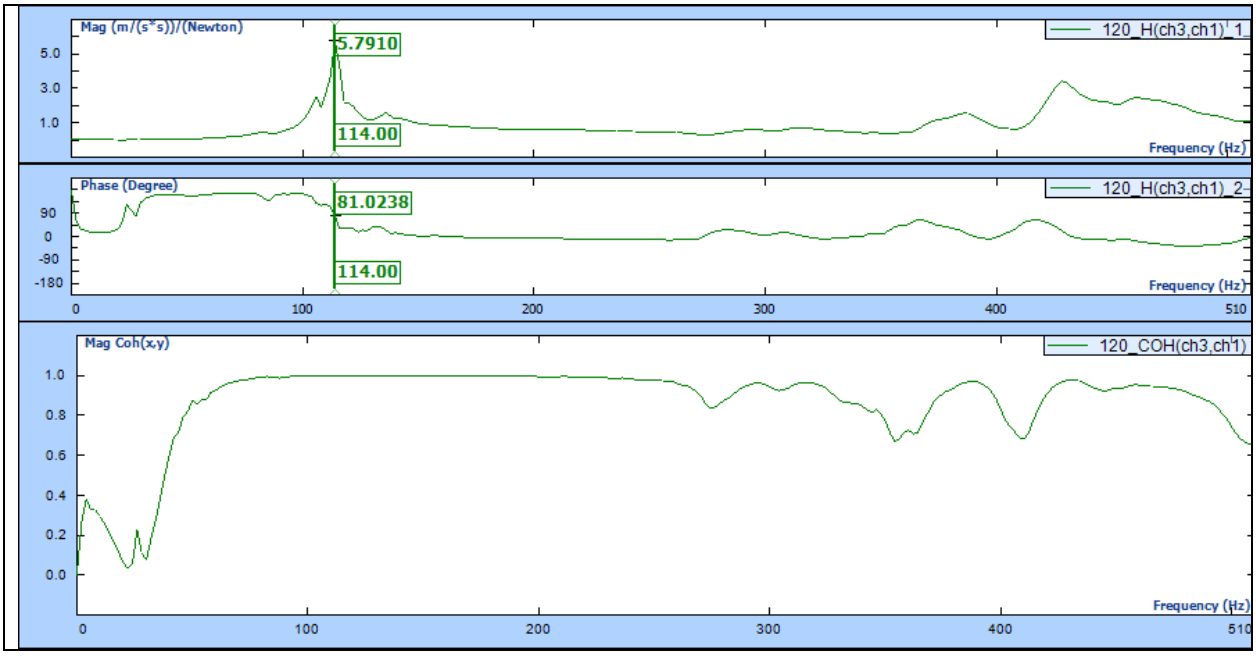
Photograph 117: ***Impact Test Data At 205 Slot Pole Jumper Bottom Radial***



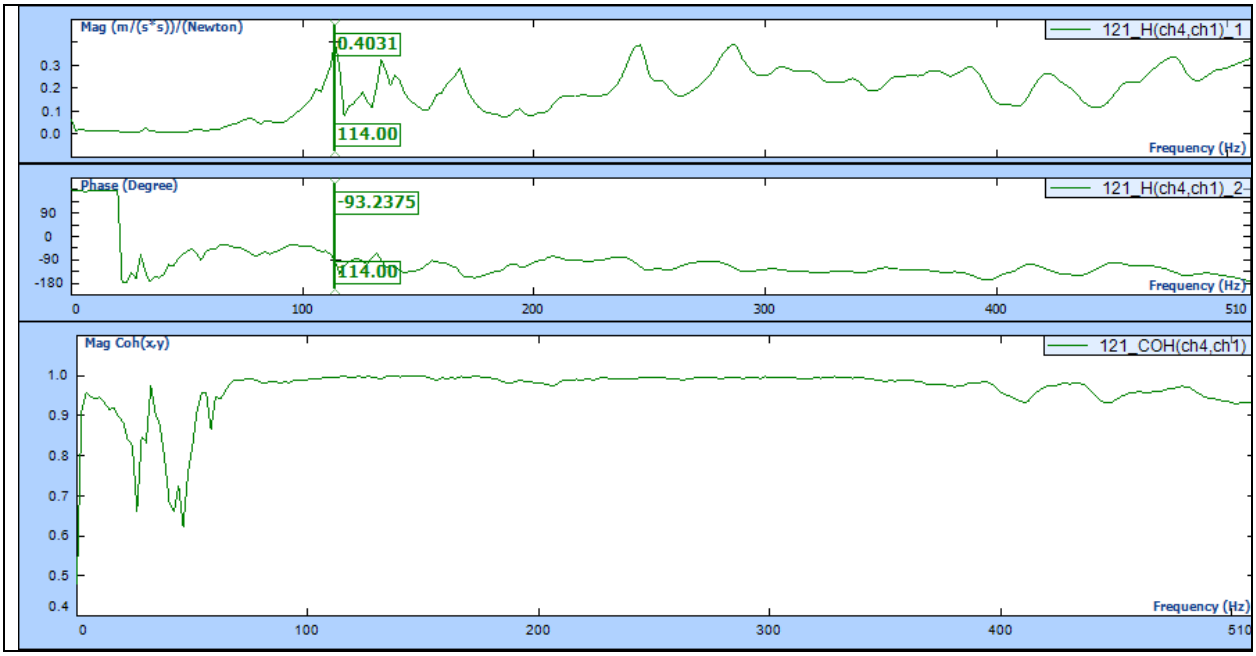
Photograph 118: ***Impact Test Data At 205 Slot Pole Jumper Bottom Tangential***



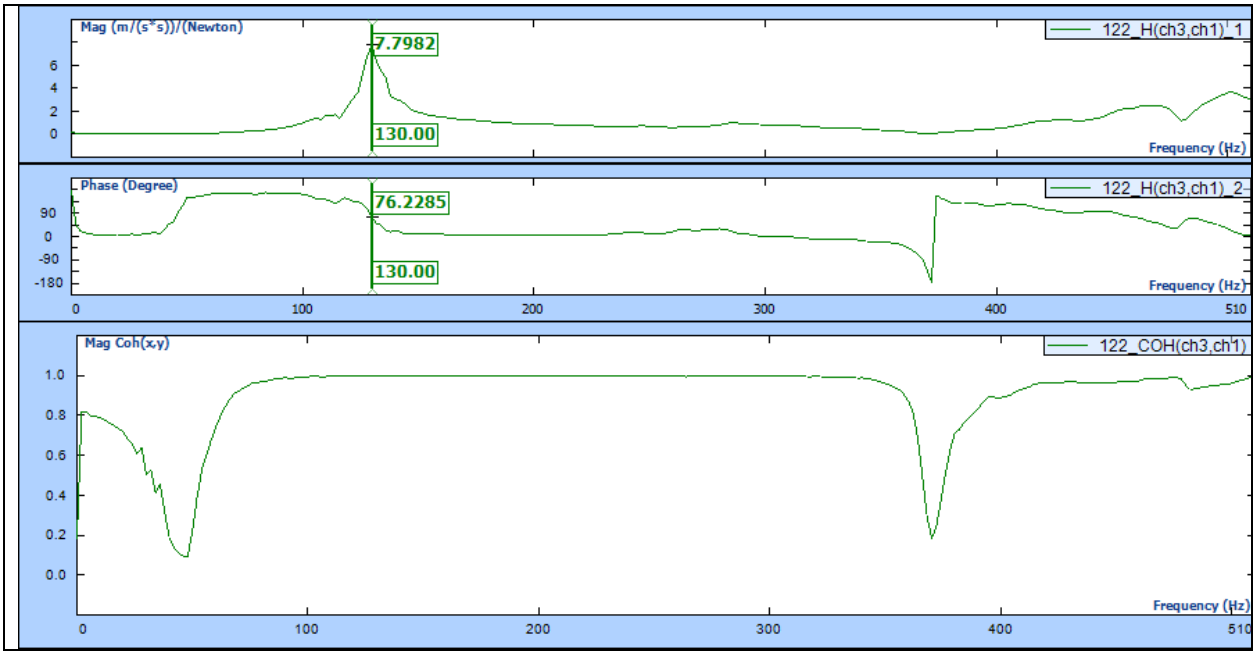
Photograph 119: ***Impact Test Data At 209 Slot Pole Jumper Top Radial***



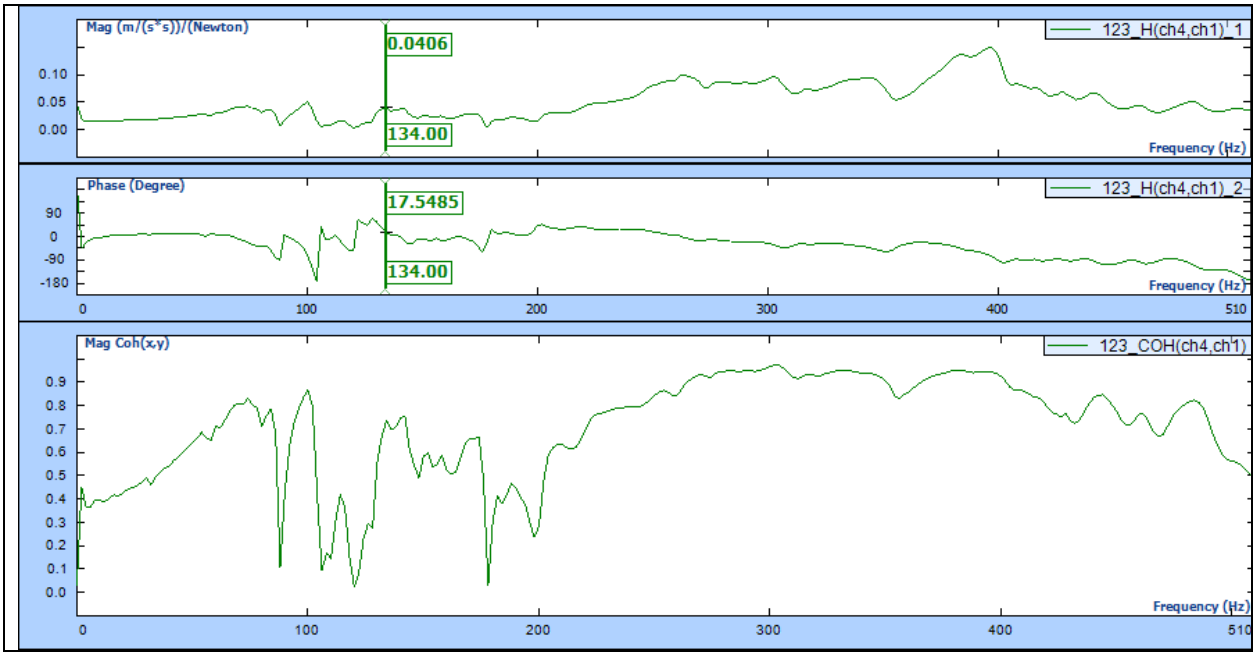
Photograph 120: ***Impact Test Data At 209 Slot Pole Jumper Top Tangential***



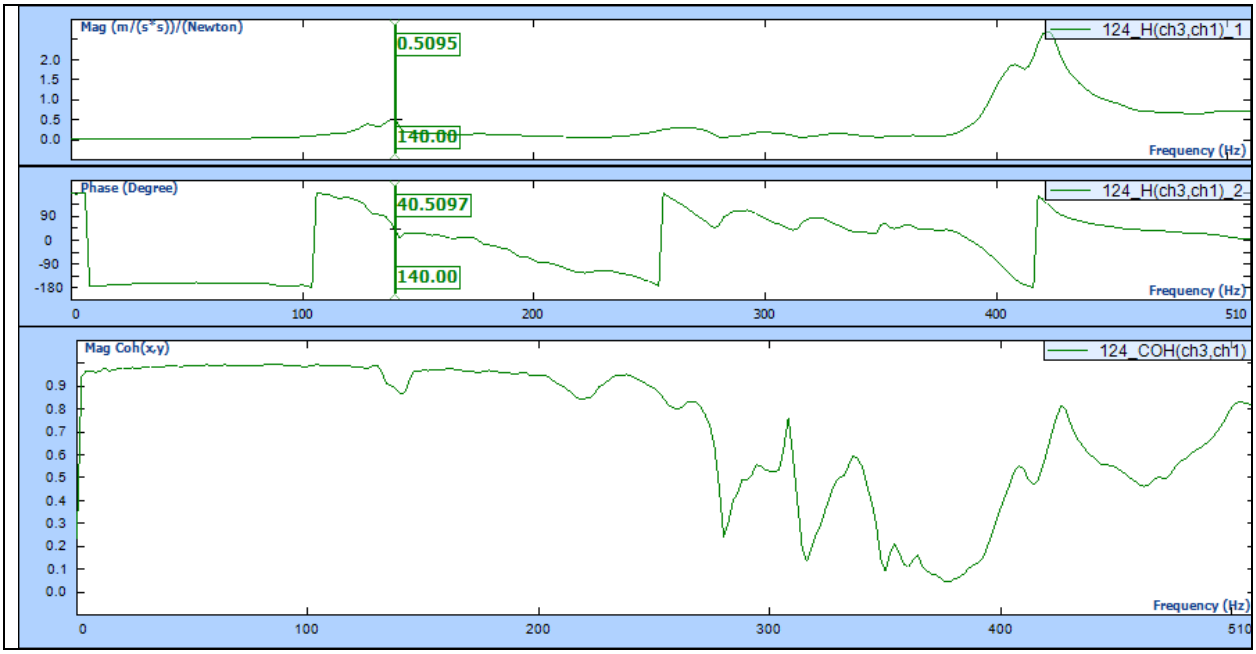
Photograph 121: ***Impact Test Data At 209 Slot Pole Jumper Bottom Radial***



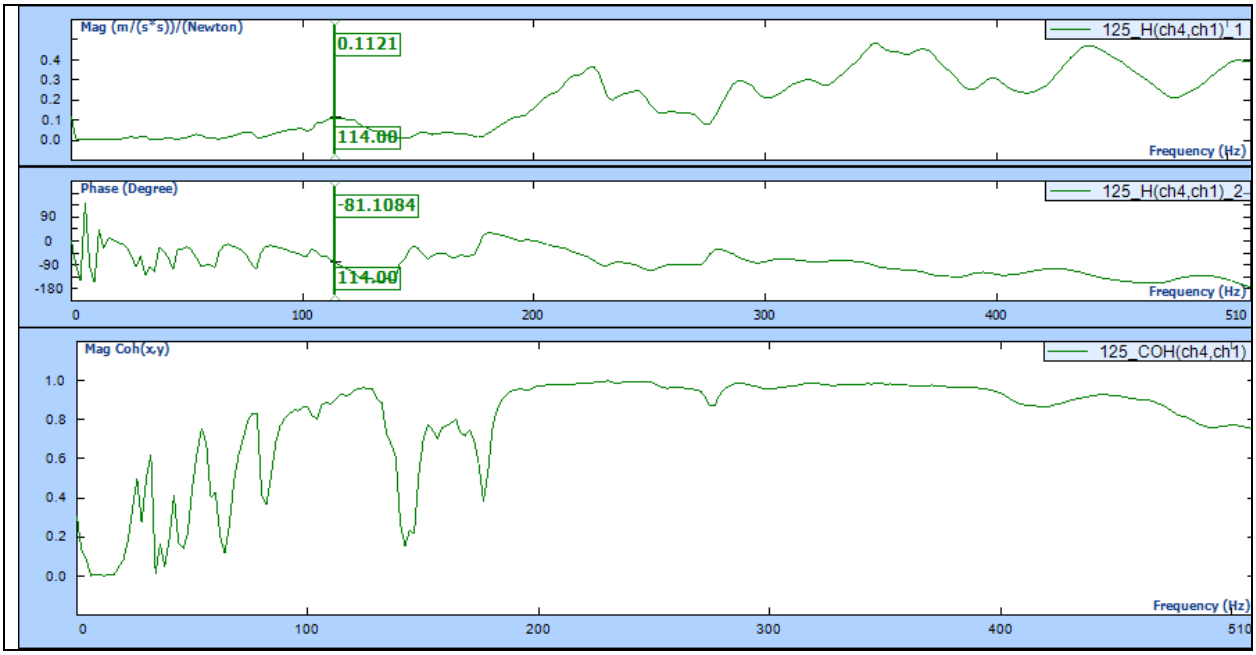
Photograph 122: ***Impact Test Data At 209 Slot Pole Jumper Bottom Tangential***



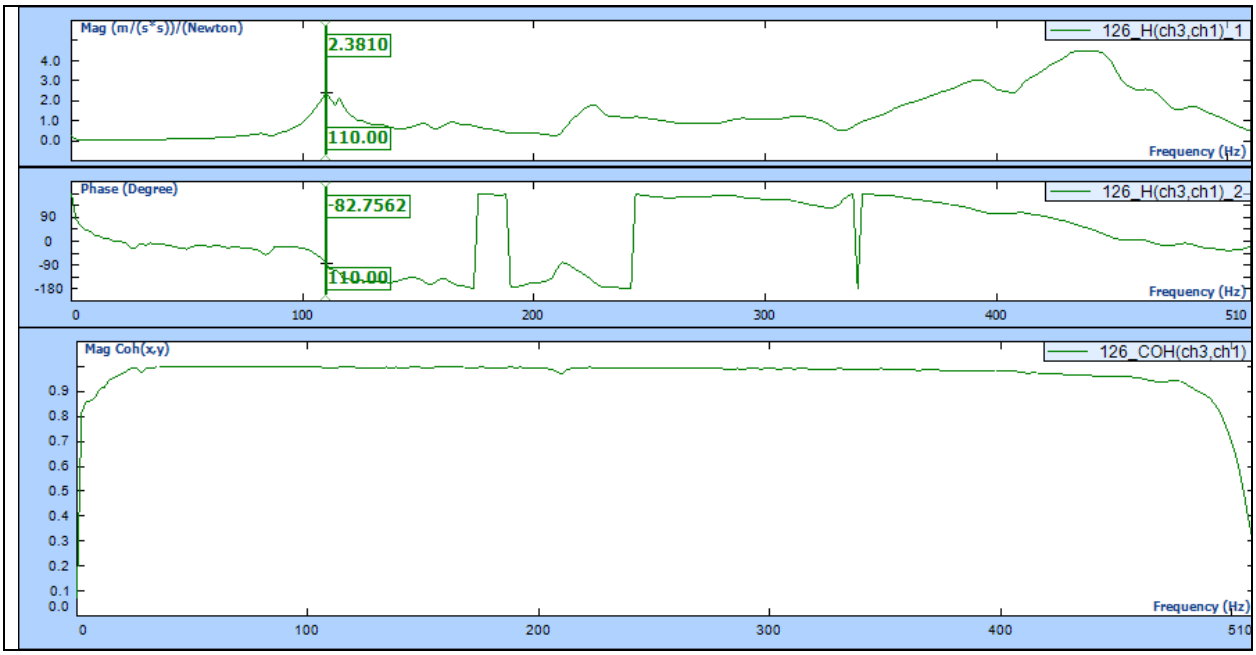
Photograph 123: ***Impact Test Data At 212 Slot Diamond Structure Radial***



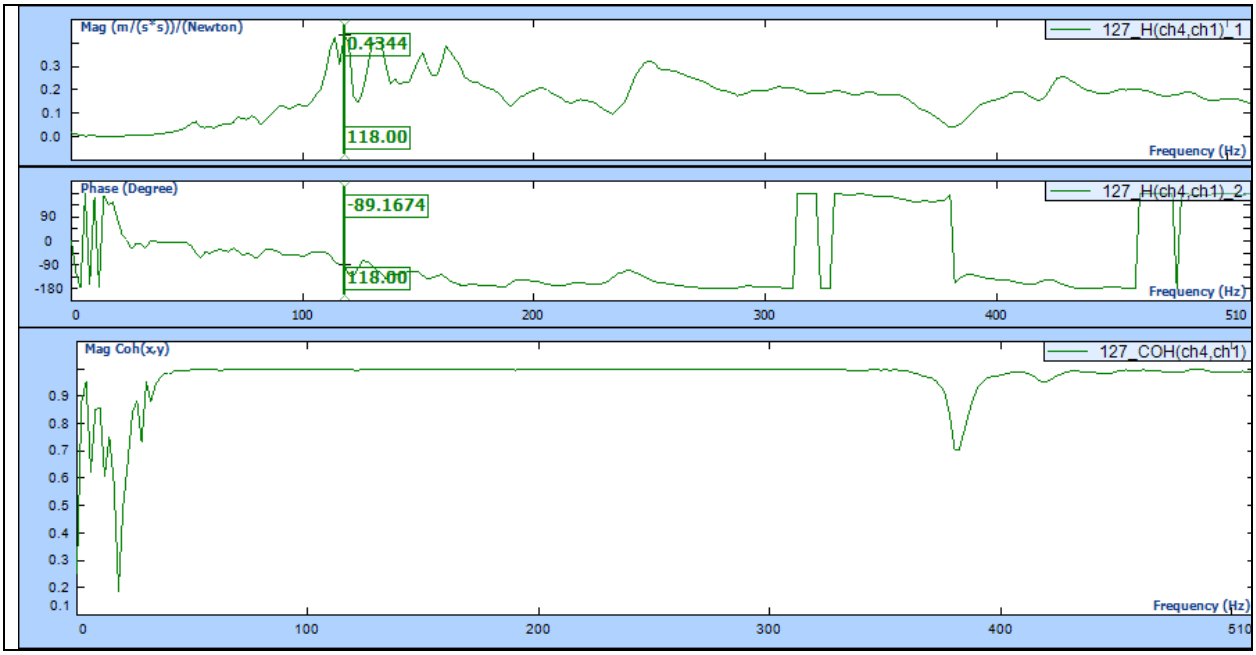
Photograph 124: ***Impact Test Data At 212 Slot Diamond Structure Tangential***



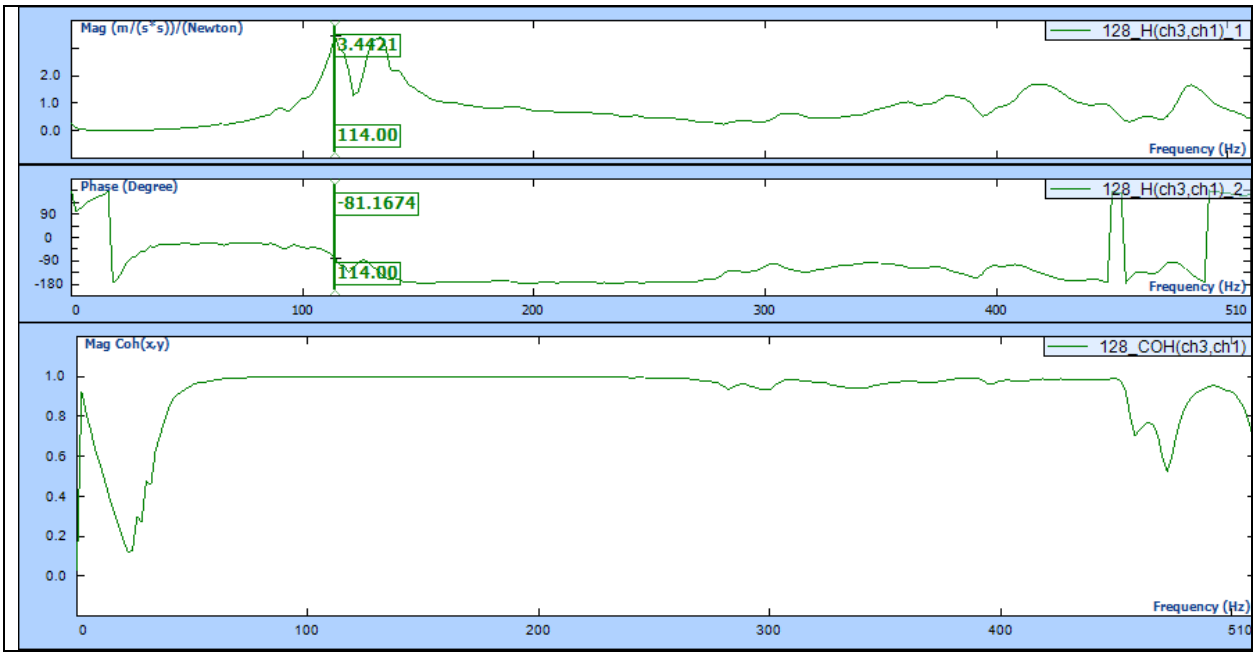
Photograph 125: ***Impact Test Data At 214 Slot Pole Jumper Top Radial***



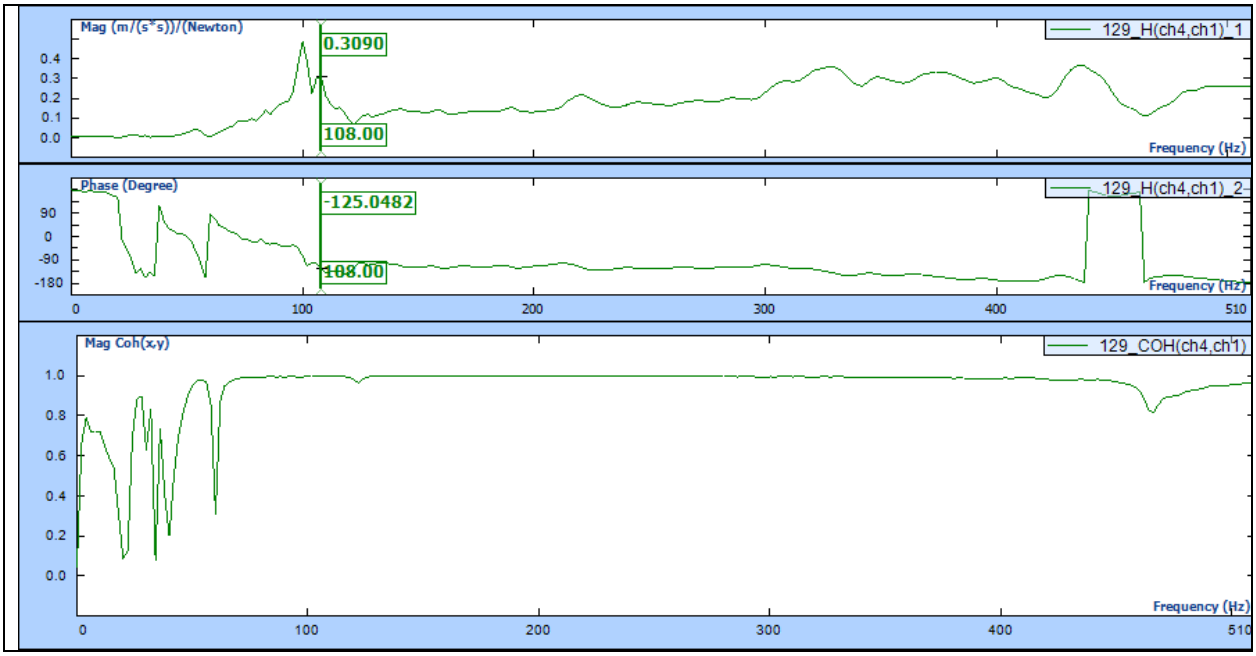
Photograph 126: ***Impact Test Data At 214 Slot Pole Jumper Top Tangential***



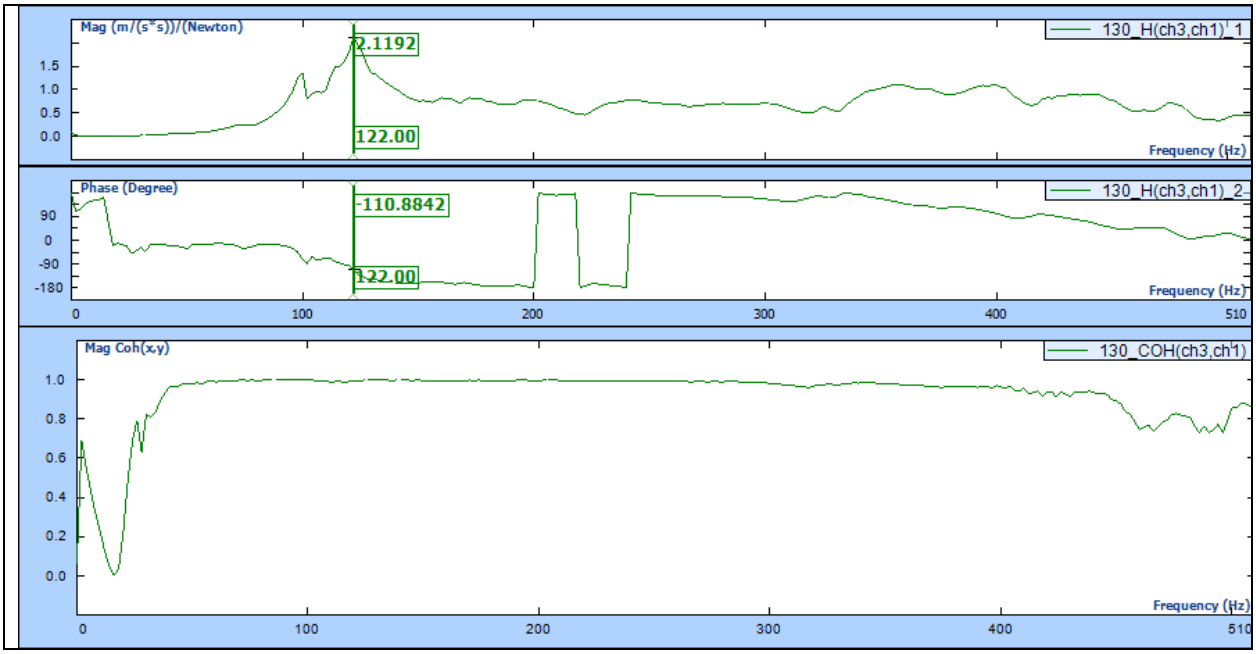
Photograph 127: ***Impact Test Data At 214 Slot Pole Jumper Bottom Radial***



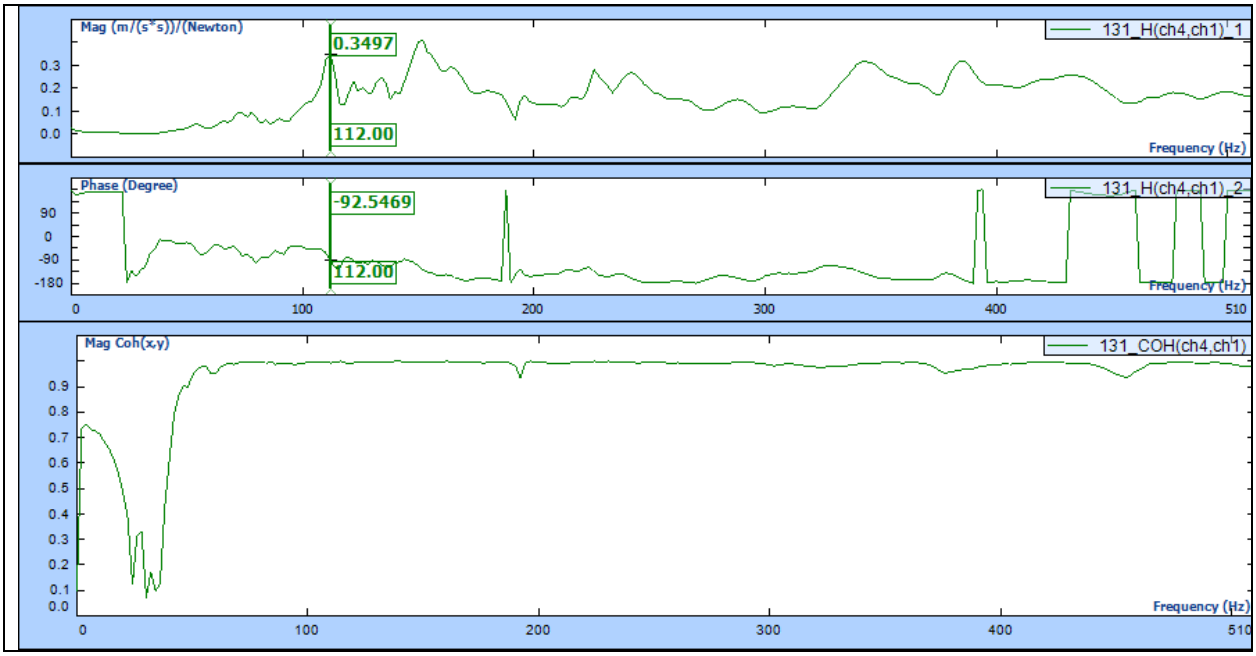
Photograph 128: ***Impact Test Data At 214 Slot Pole Jumper Bottom Tangential***



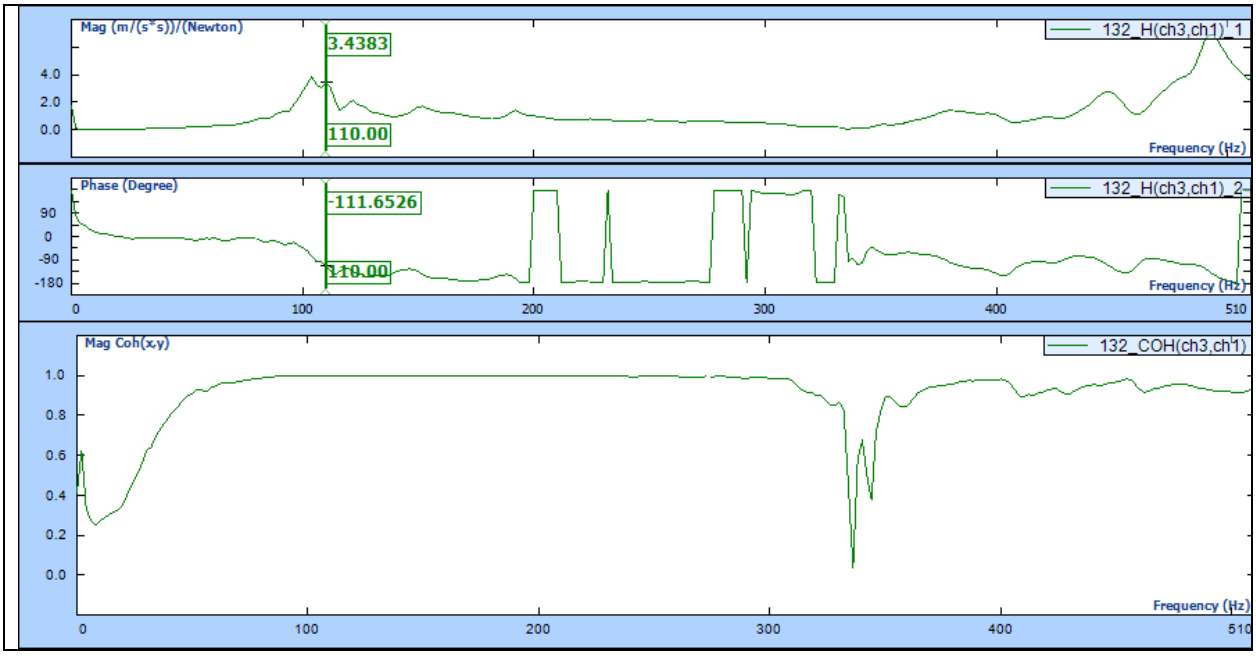
Photograph 129: ***Impact Test Data At 218 Slot Pole Jumper Top Radial***



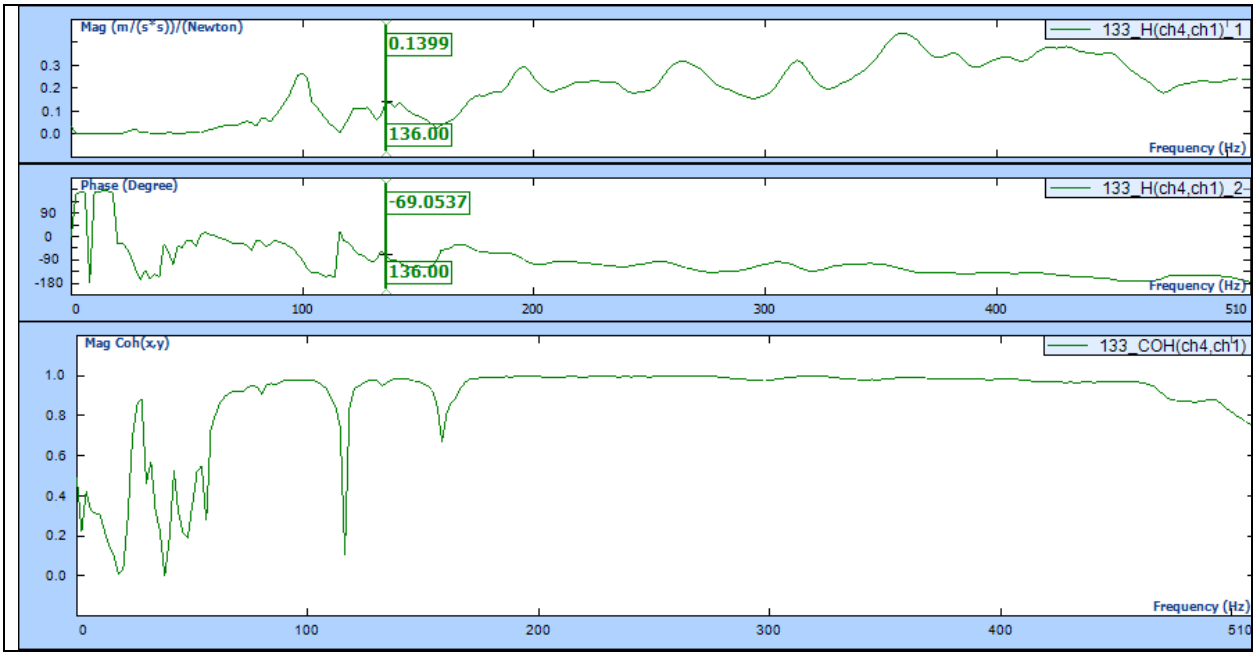
Photograph 130: ***Impact Test Data At 218 Slot Pole Jumper Top Tangential***



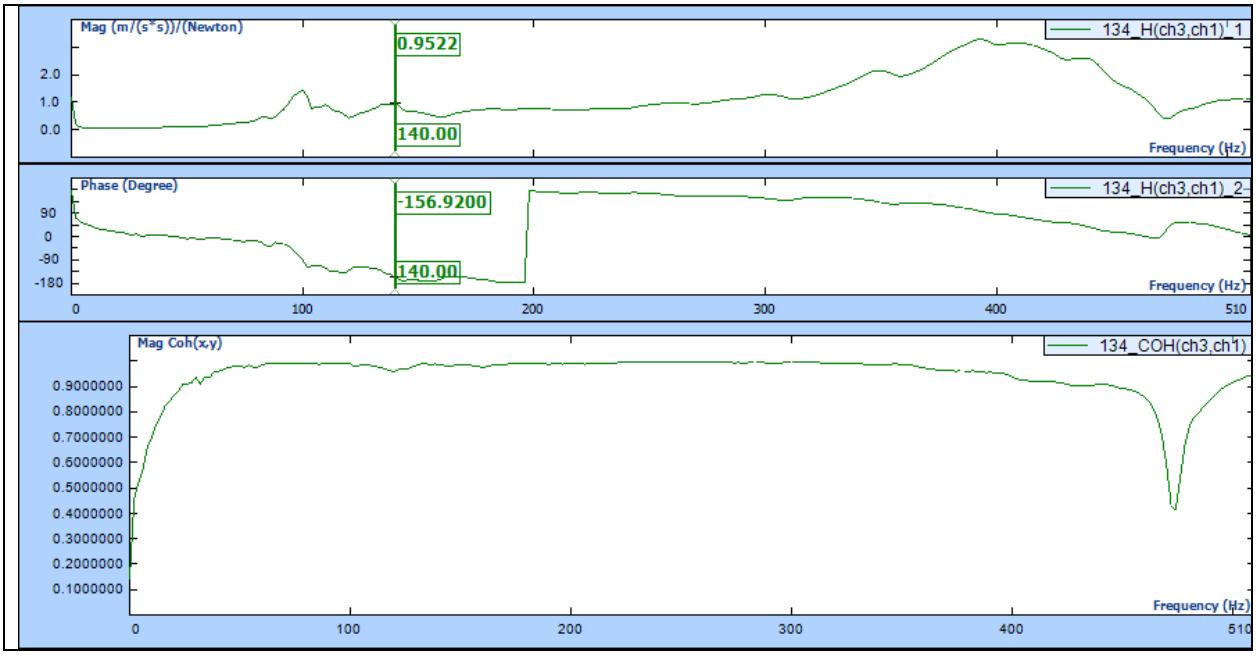
Photograph 131: ***Impact Test Data At 218 Slot Pole Jumper Bottom Radial***



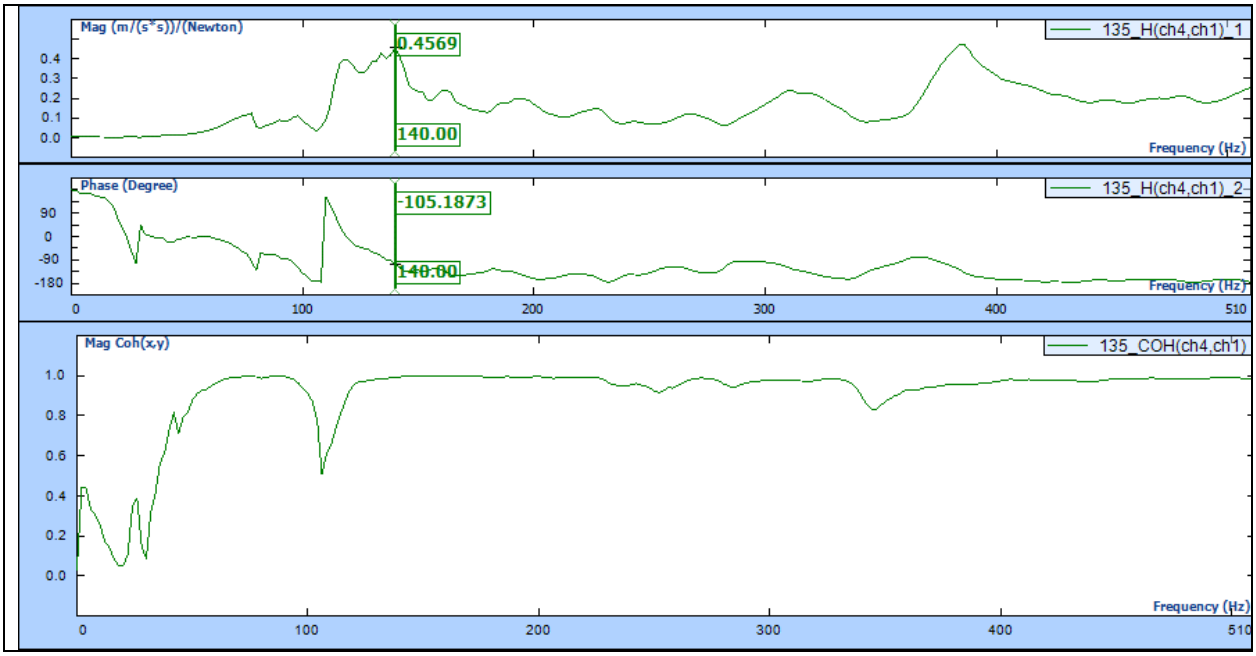
Photograph 132: ***Impact Test Data At 218 Slot Pole Jumper Bottom Tangential***



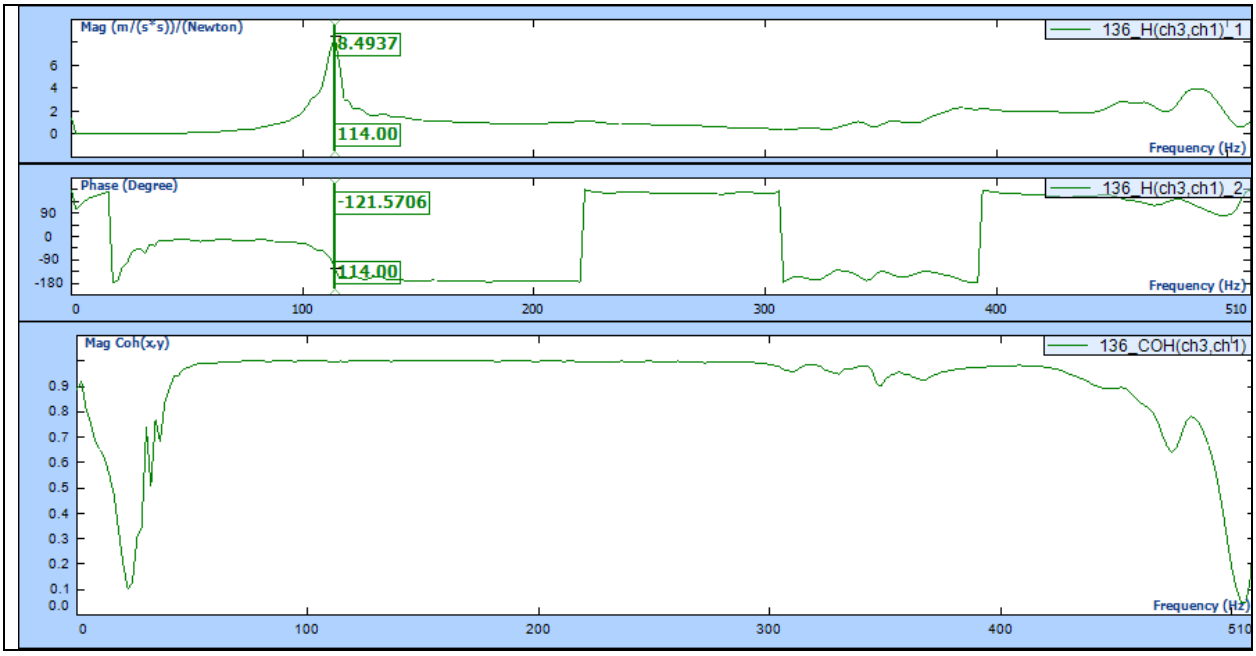
Photograph 133: ***Impact Test Data At 223 Slot Pole Jumper Top Radial***



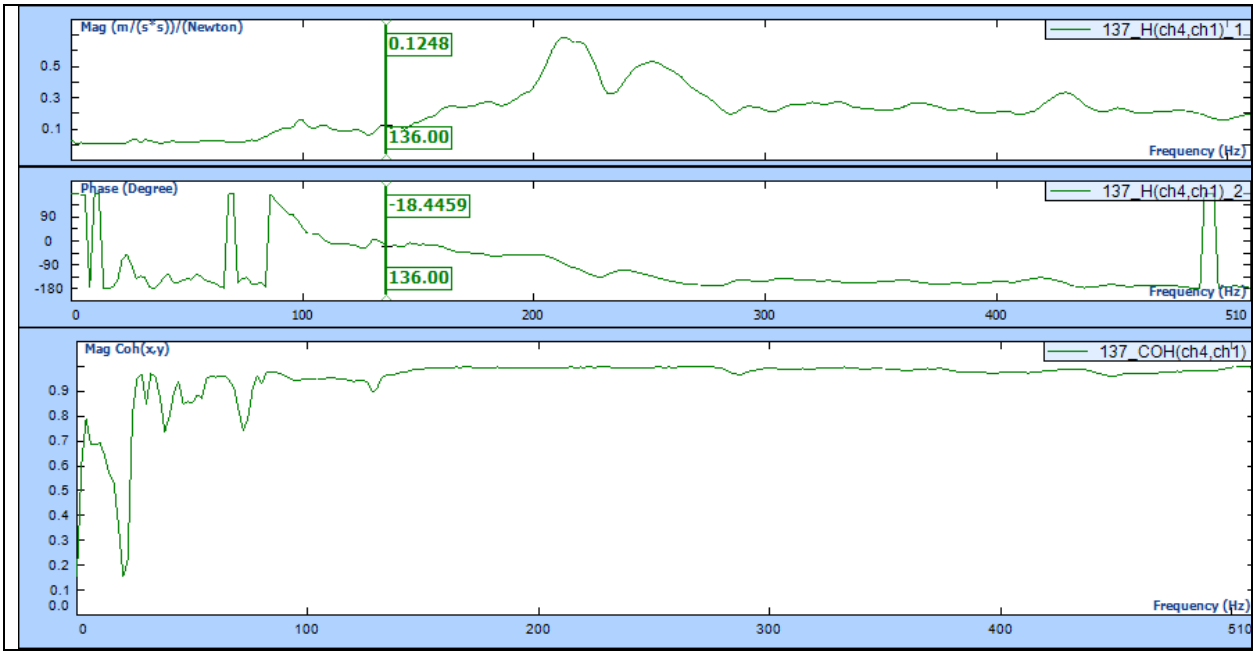
Photograph 134: ***Impact Test Data At 223 Slot Pole Jumper Top Tangential***



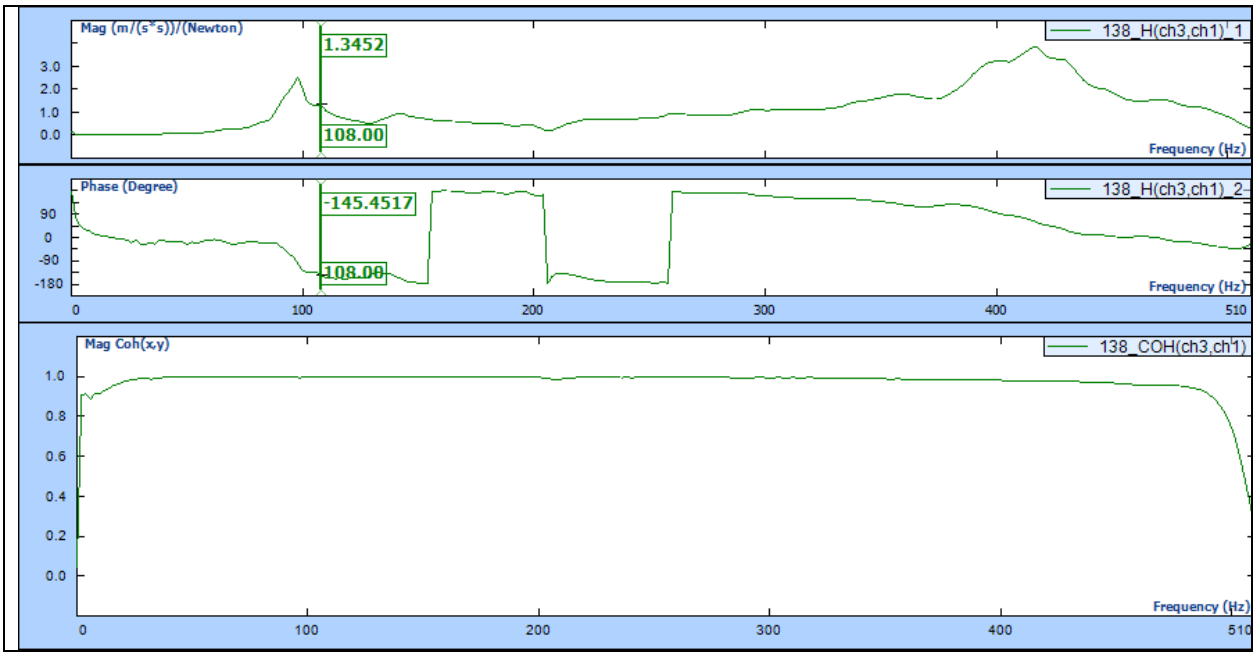
Photograph 135: ***Impact Test Data At 223 Slot Pole Jumper Bottom Radial***



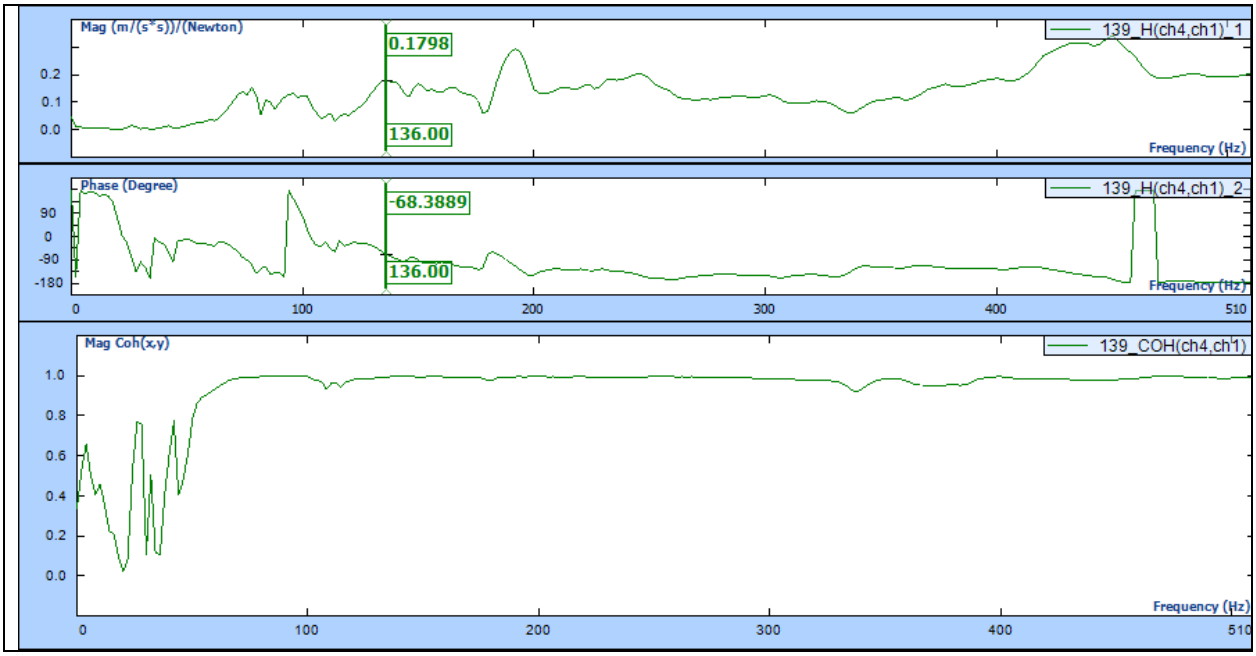
Photograph 136: ***Impact Test Data At 223 Slot Pole Jumper Bottom Tangential***



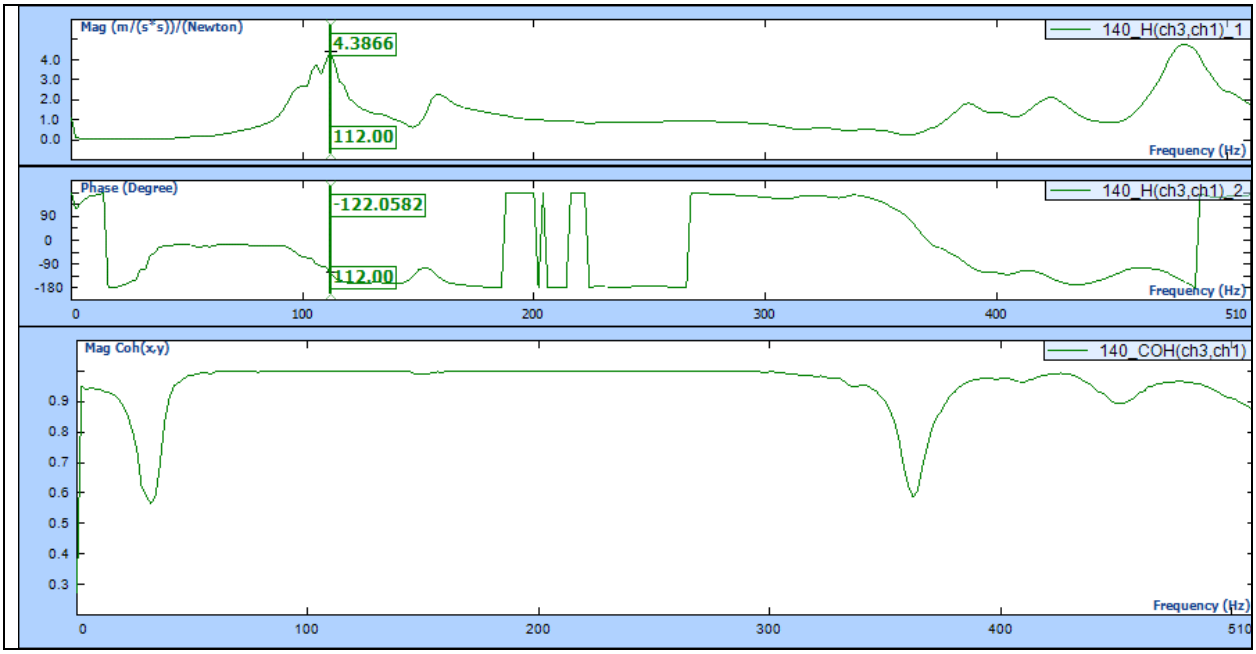
Photograph 137: ***Impact Test Data At 227 Slot Pole Jumper Top Radial***



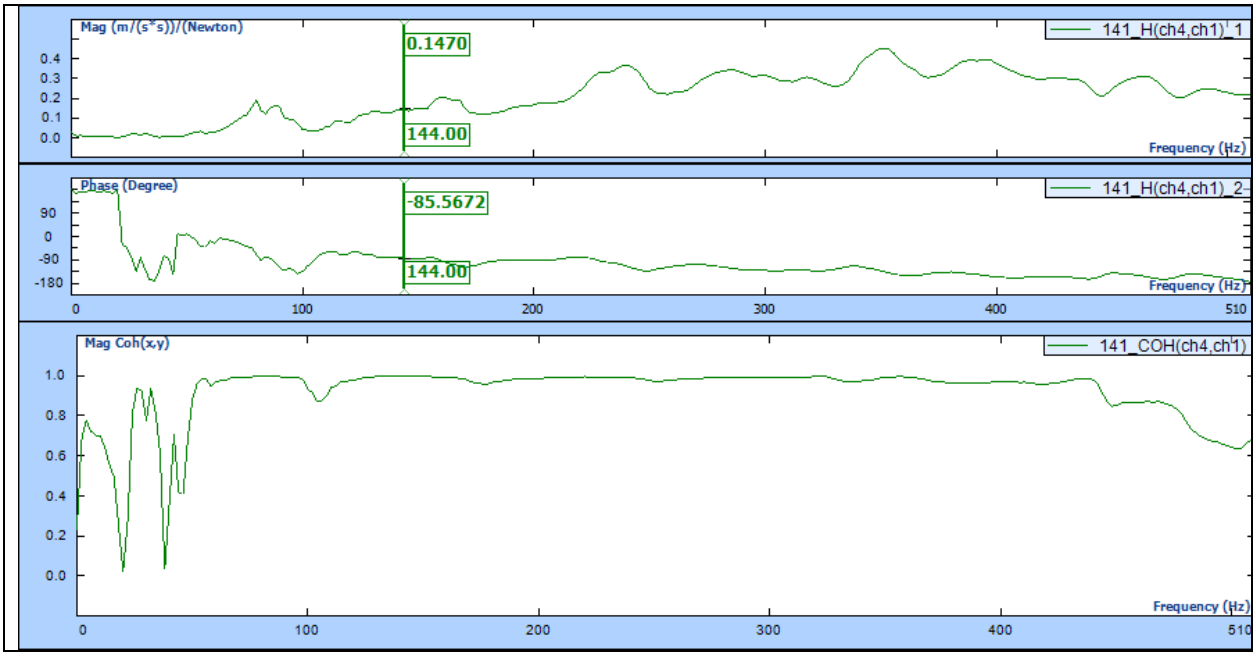
Photograph 138: ***Impact Test Data At 227 Slot Pole Jumper Top Tangential***



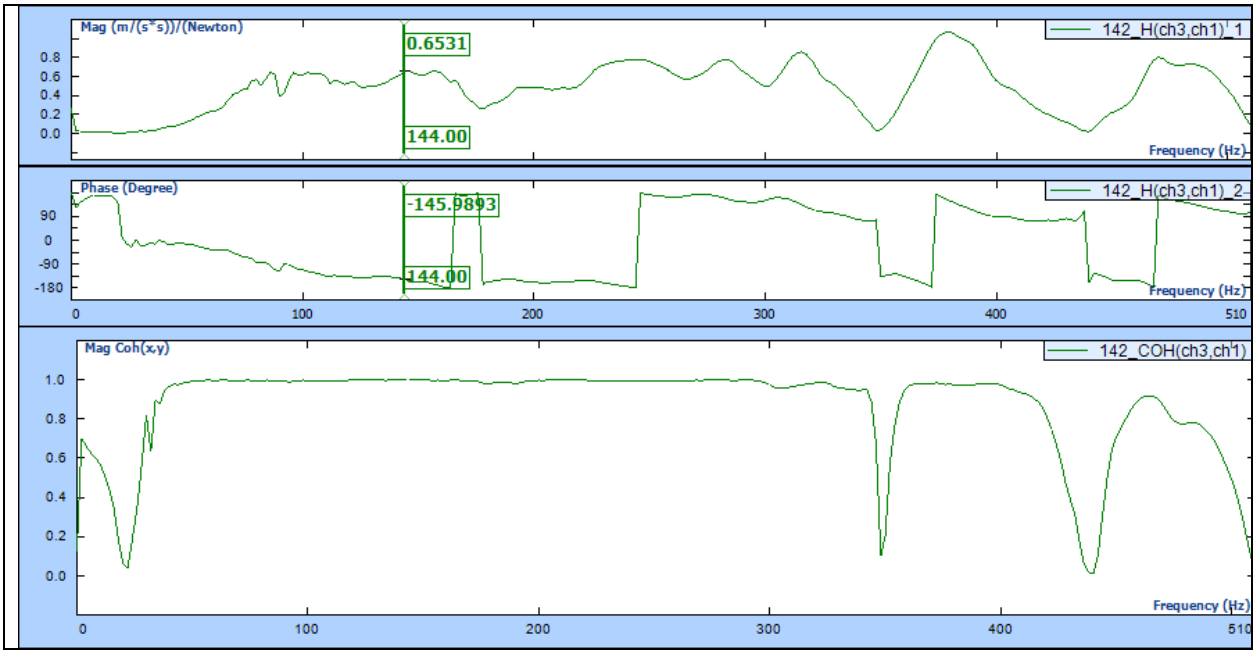
Photograph 139: ***Impact Test Data At 227 Slot Pole Jumper Bottom Radial***



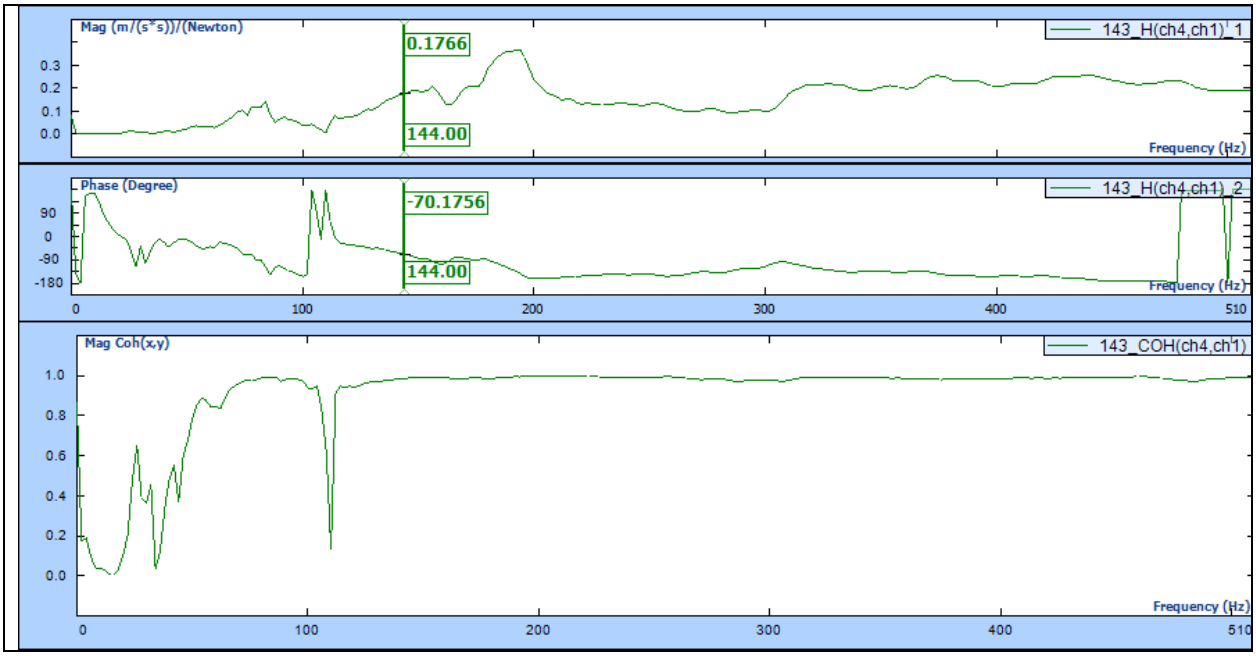
Photograph 140: ***Impact Test Data At 227 Slot Pole Jumper Bottom Tangential***



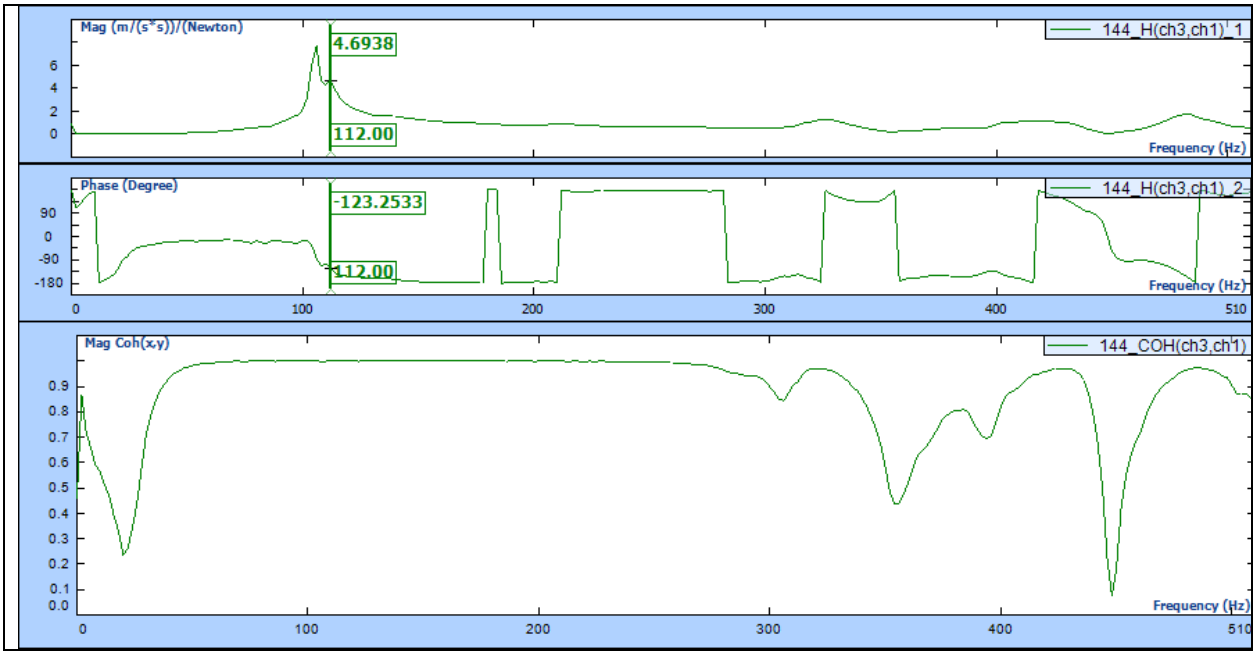
Photograph 141: ***Impact Test Data At 231 Slot Pole Jumper Top Radial***



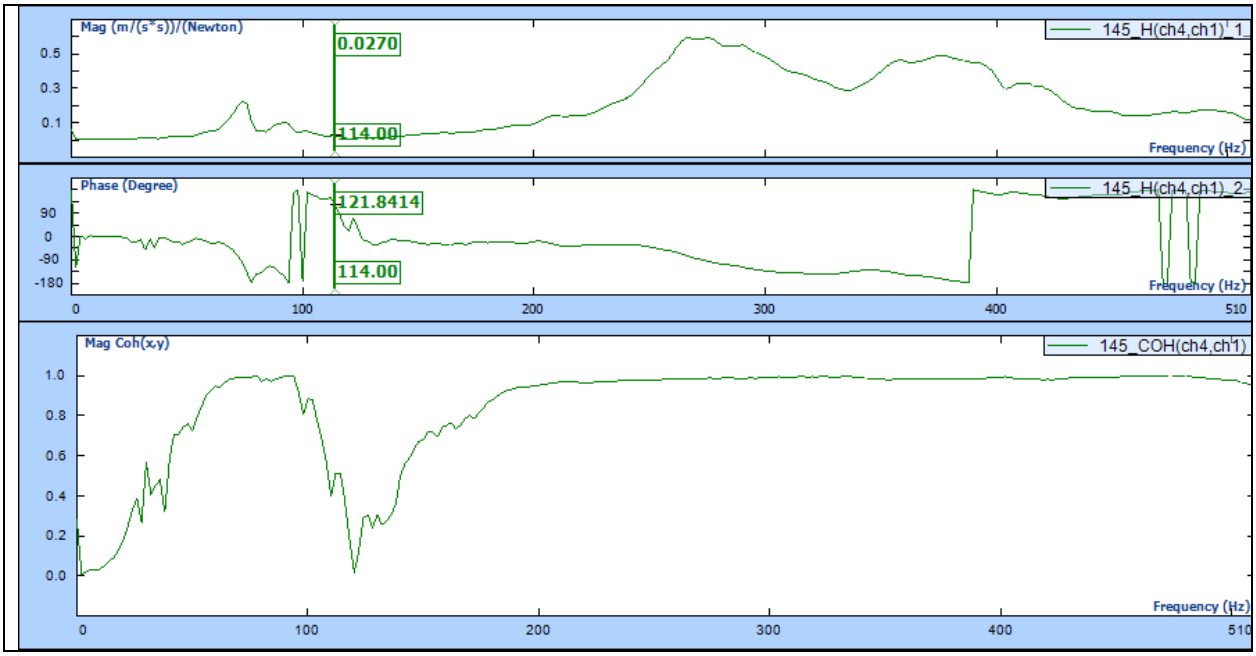
Photograph 142: ***Impact Test Data At 231 Slot Pole Jumper Top Tangential***



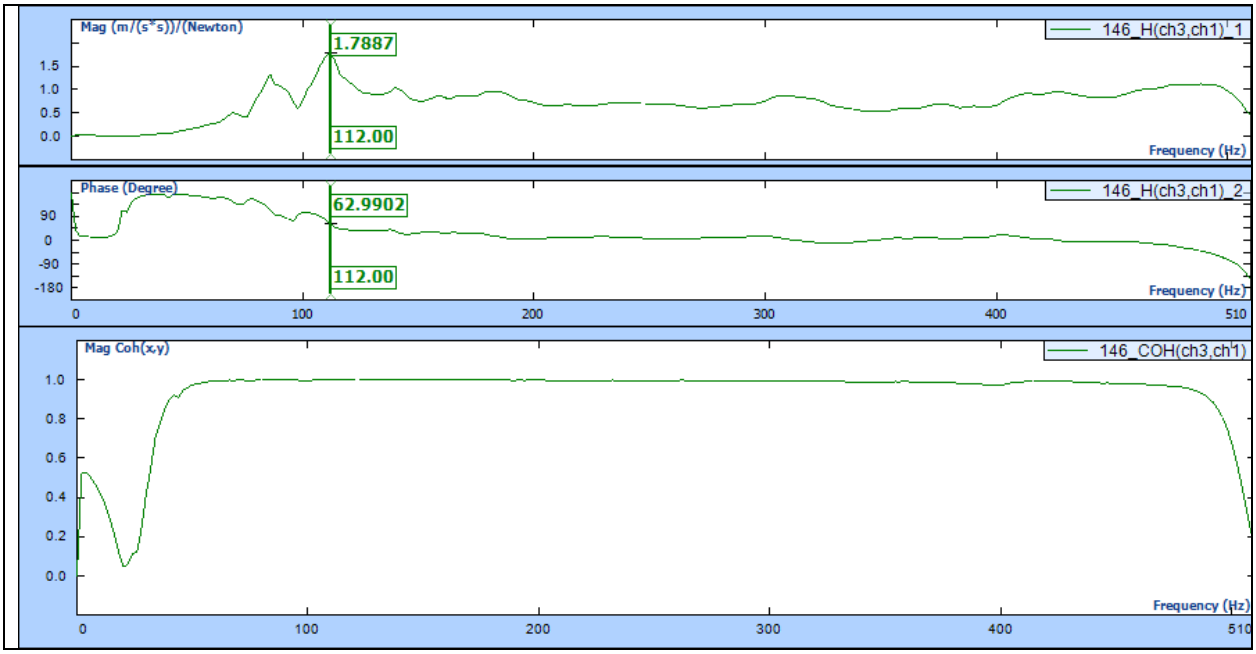
Photograph 143: ***Impact Test Data At 231 Slot Pole Jumper Bottom Radial***



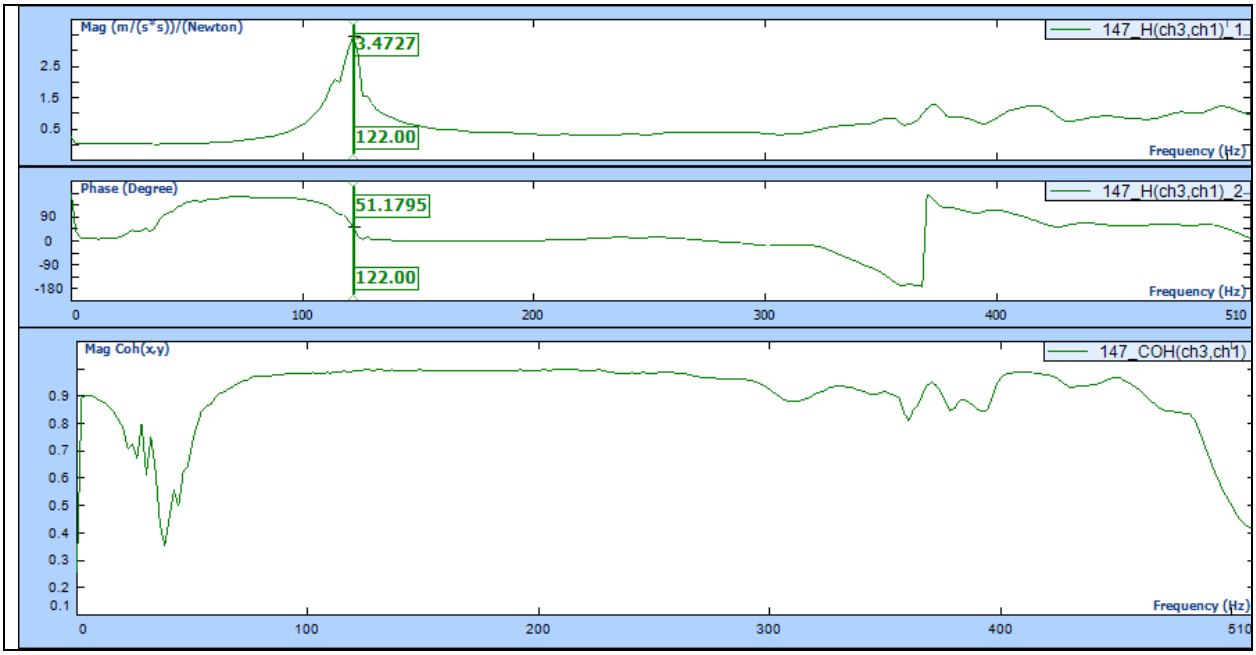
Photograph 144: ***Impact Test Data At 231 Slot Pole Jumper Bottom Tangential***



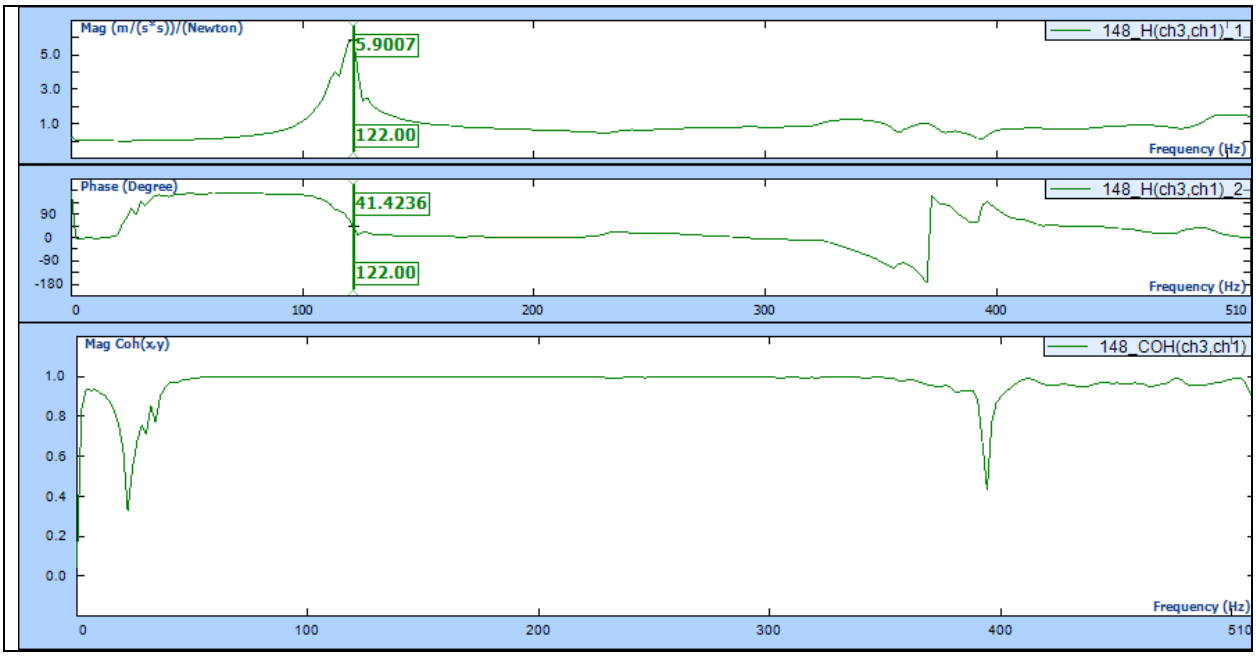
Photograph 145: ***Impact Test Data At 236 Slot Pole Jumper Top Radial***



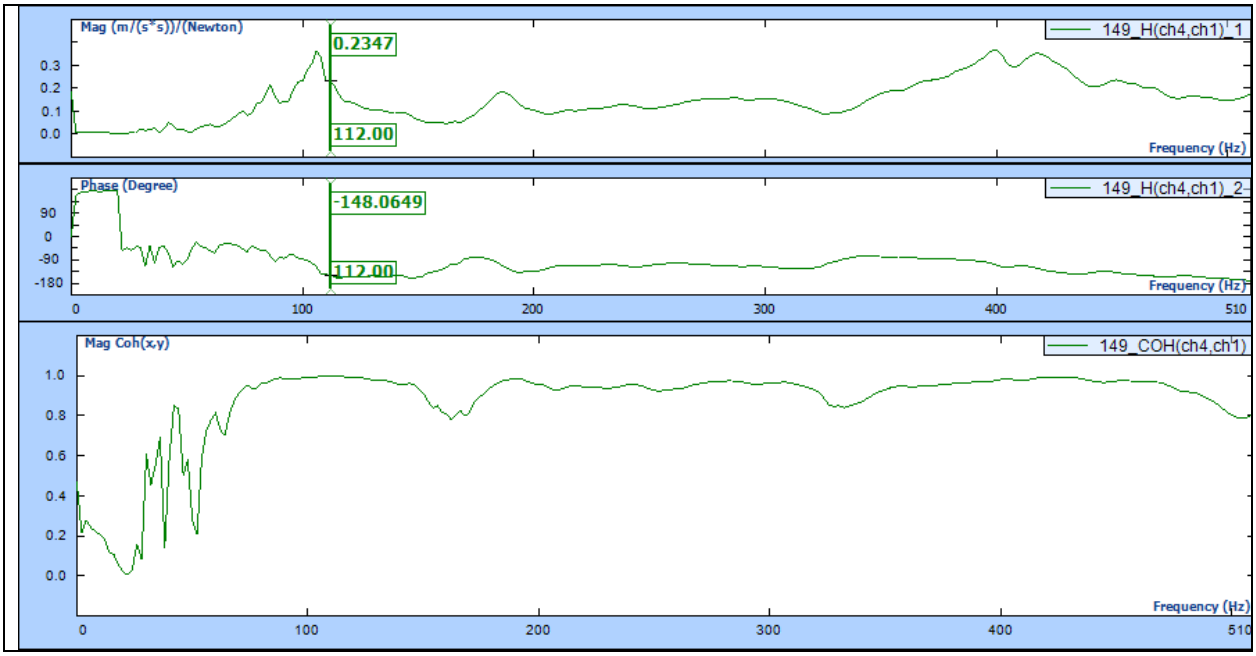
Photograph 146: ***Impact Test Data At 236 Slot Pole Jumper Top Tangential***



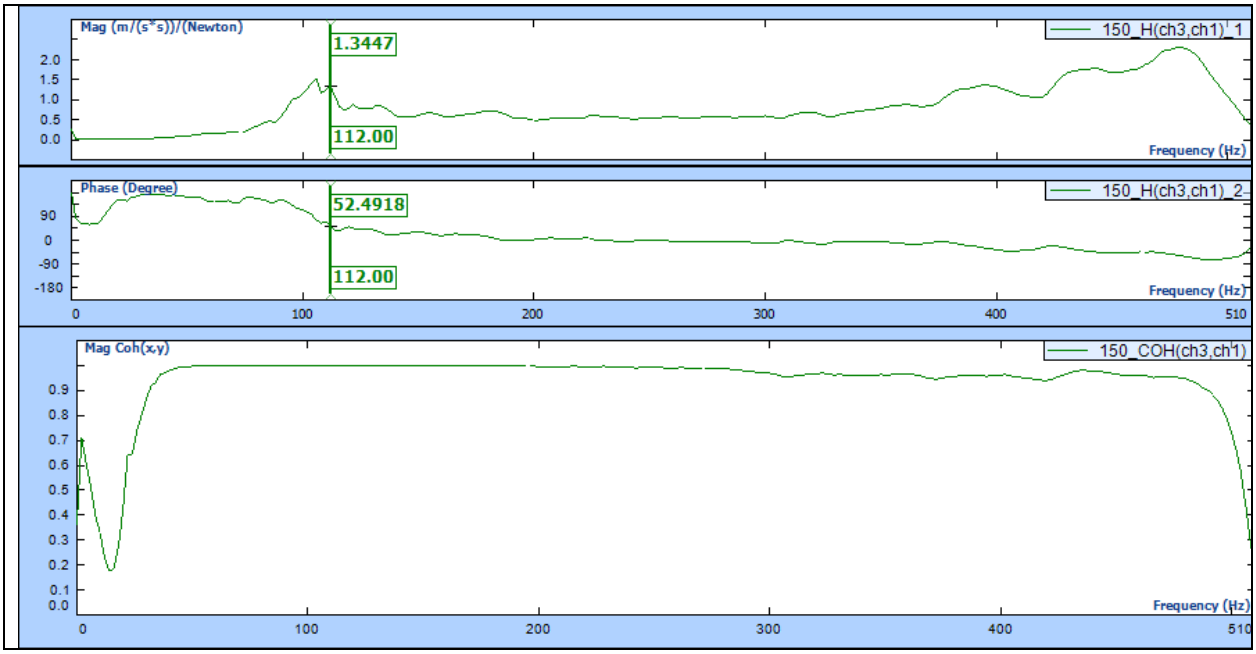
Photograph 147: ***Impact Test Data At 236 Slot Pole Jumper Bottom Radial***



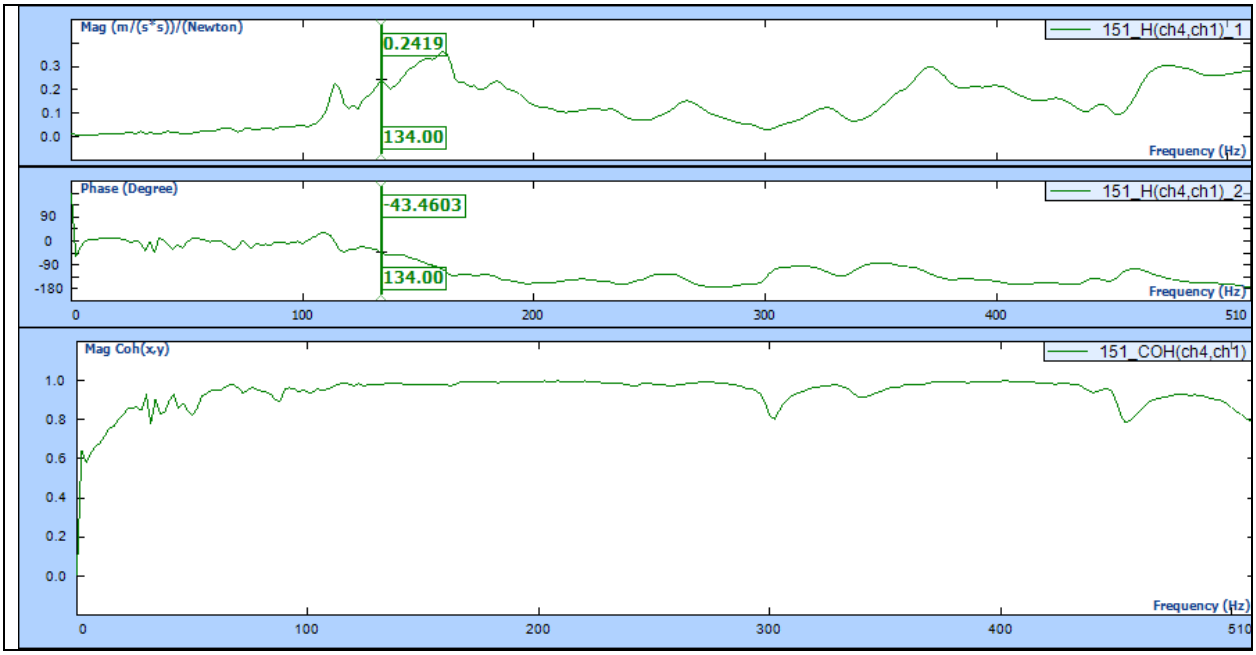
Photograph 148: ***Impact Test Data At 236 Slot Pole Jumper Bottom Tangential***



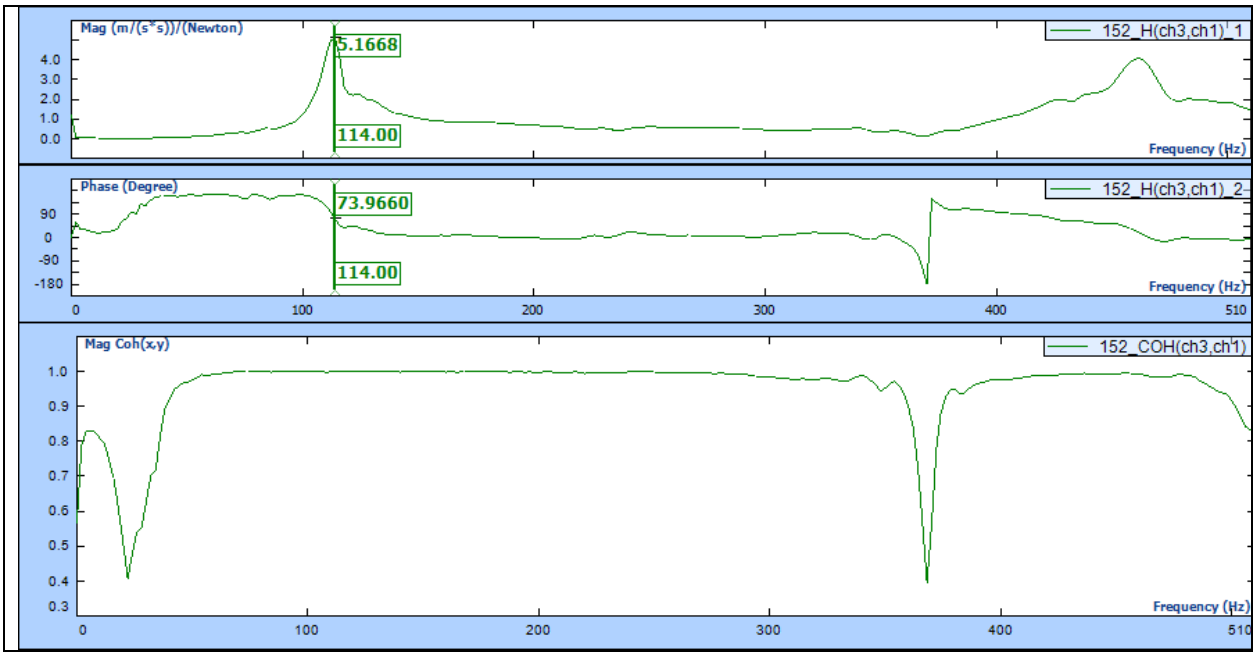
Photograph 149: ***Impact Test Data At 240 Slot Pole Jumper Top Radial***



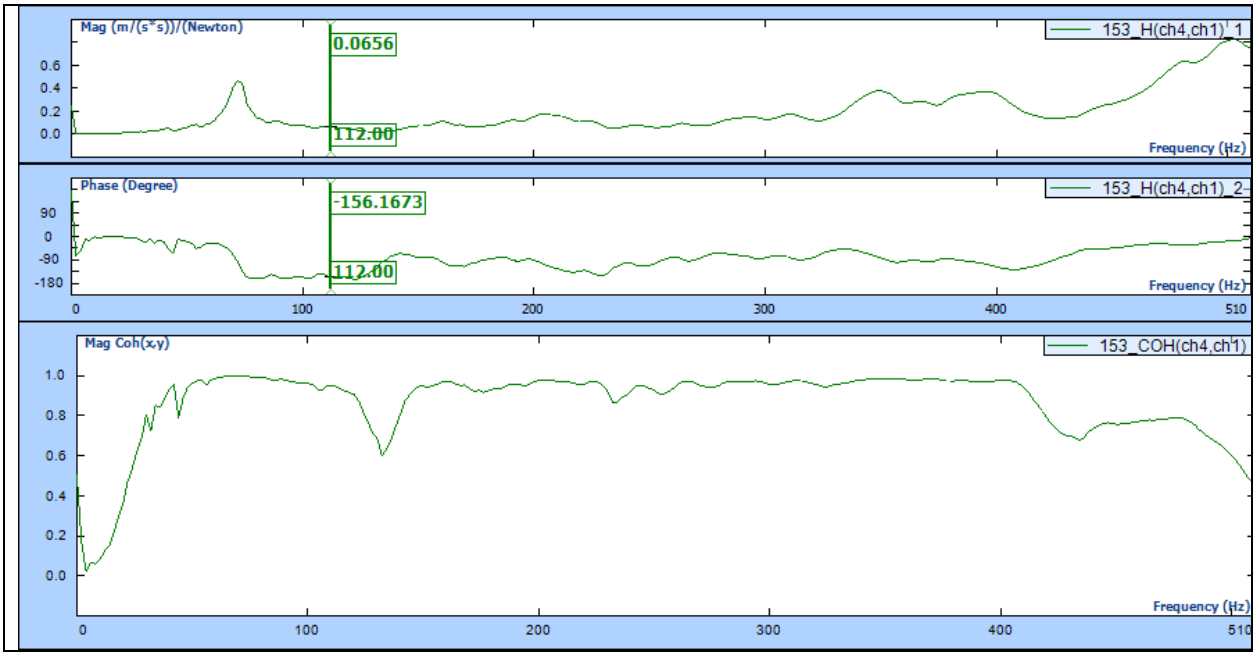
Photograph 150: ***Impact Test Data At 240 Slot Pole Jumper Top Tangential***



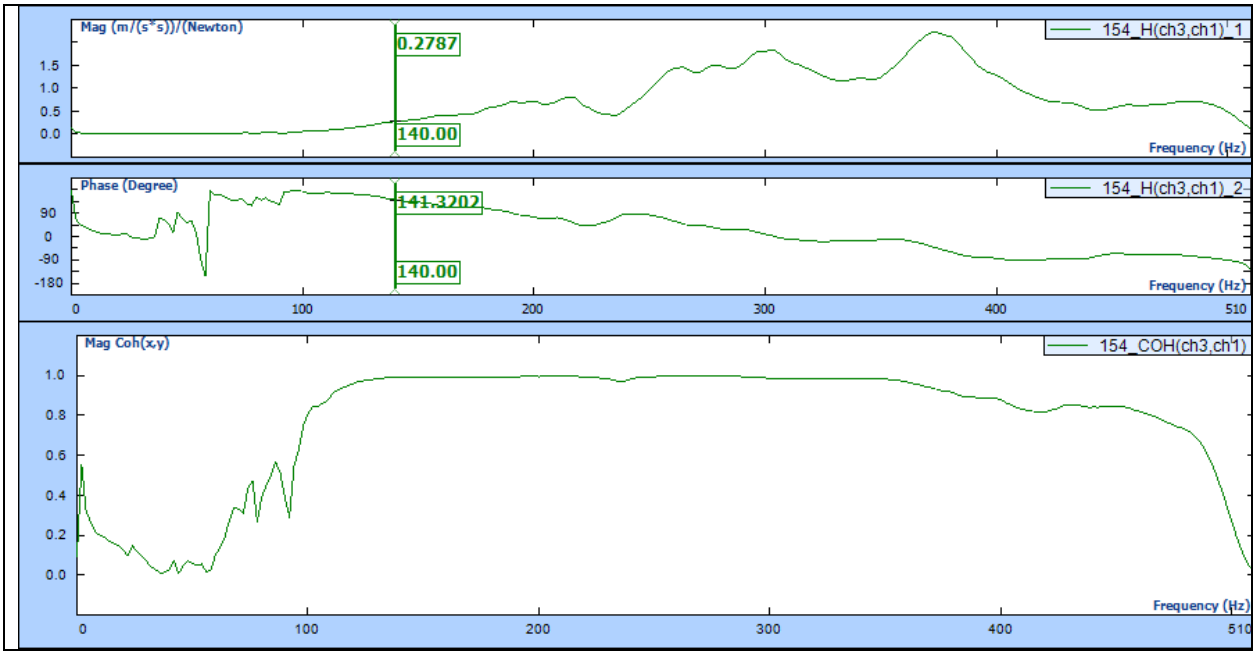
Photograph 151: ***Impact Test Data At 240 Slot Pole Jumper Bottom Radial***



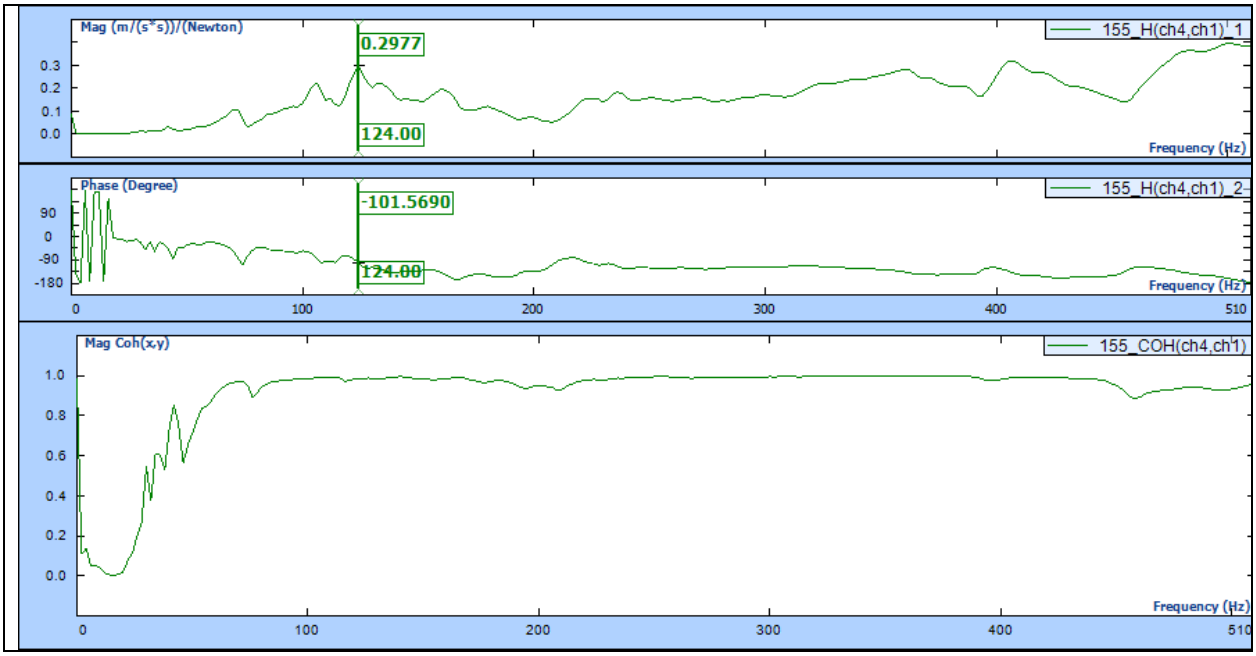
Photograph 152: ***Impact Test Data At 240 Slot Pole Jumper Bottom Tangential***



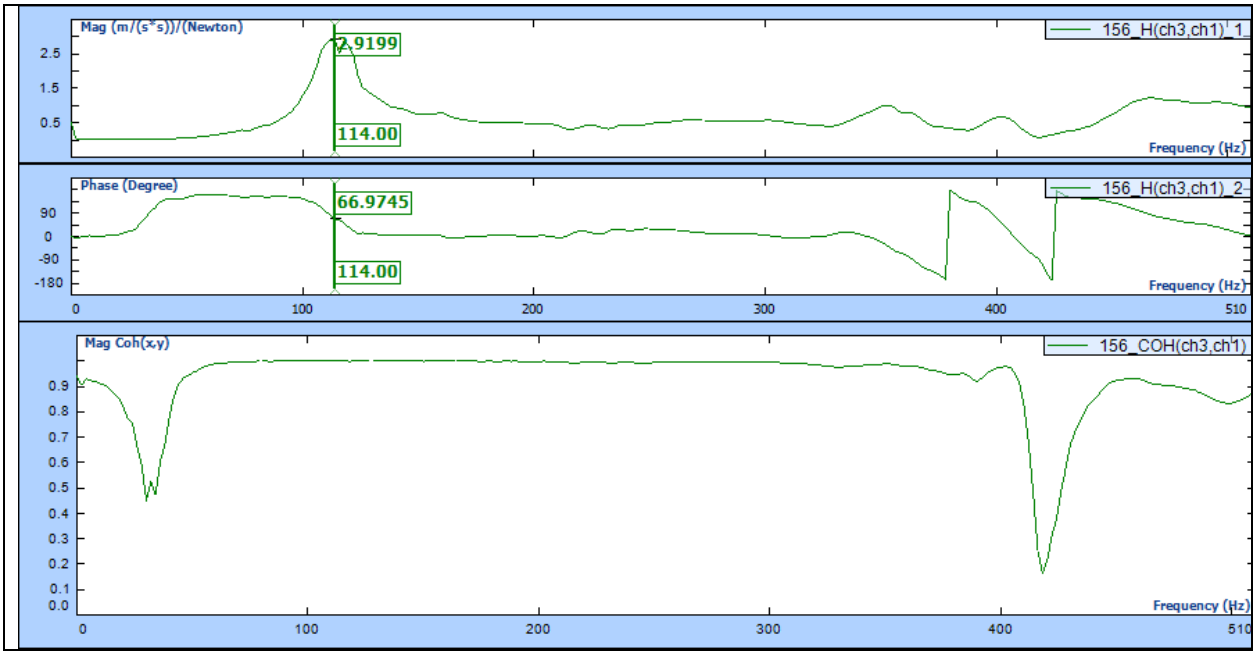
Photograph 153: ***Impact Test Data At 245 Slot Pole Jumper Top Radial***



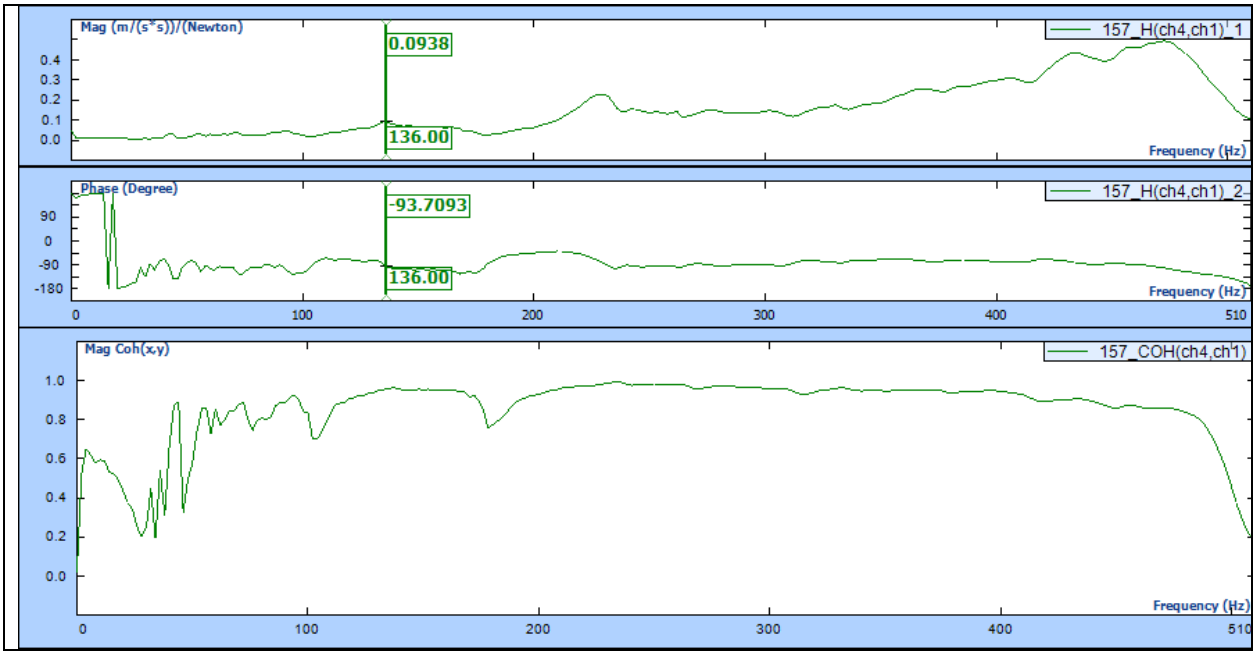
Photograph 154: ***Impact Test Data At 245 Slot Pole Jumper Top Tangential***



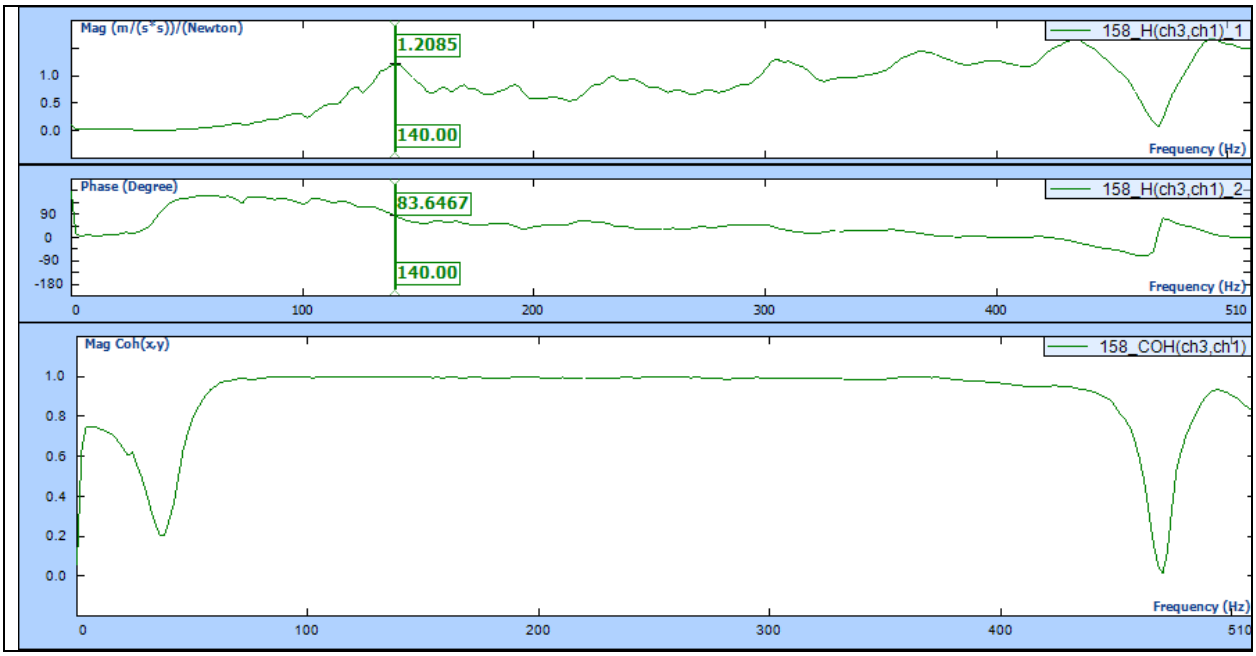
Photograph 155: ***Impact Test Data At 245 Slot Pole Jumper Bottom Radial***



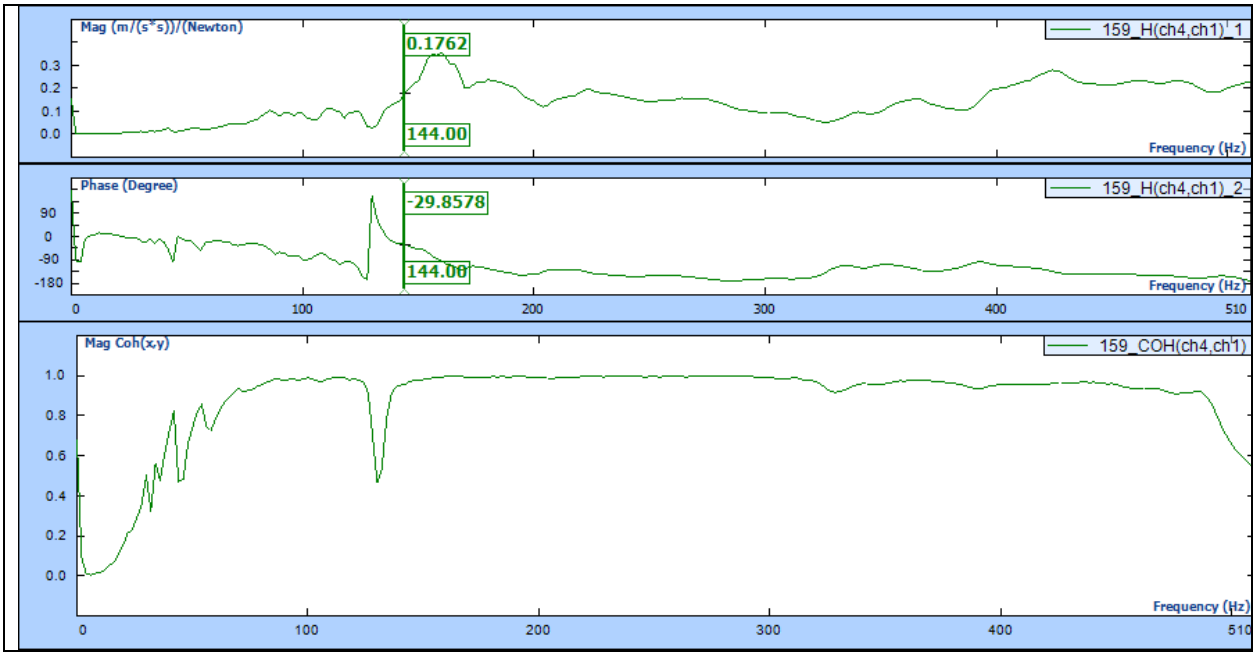
Photograph 156: ***Impact Test Data At 245 Slot Pole Jumper Bottom Tangential***



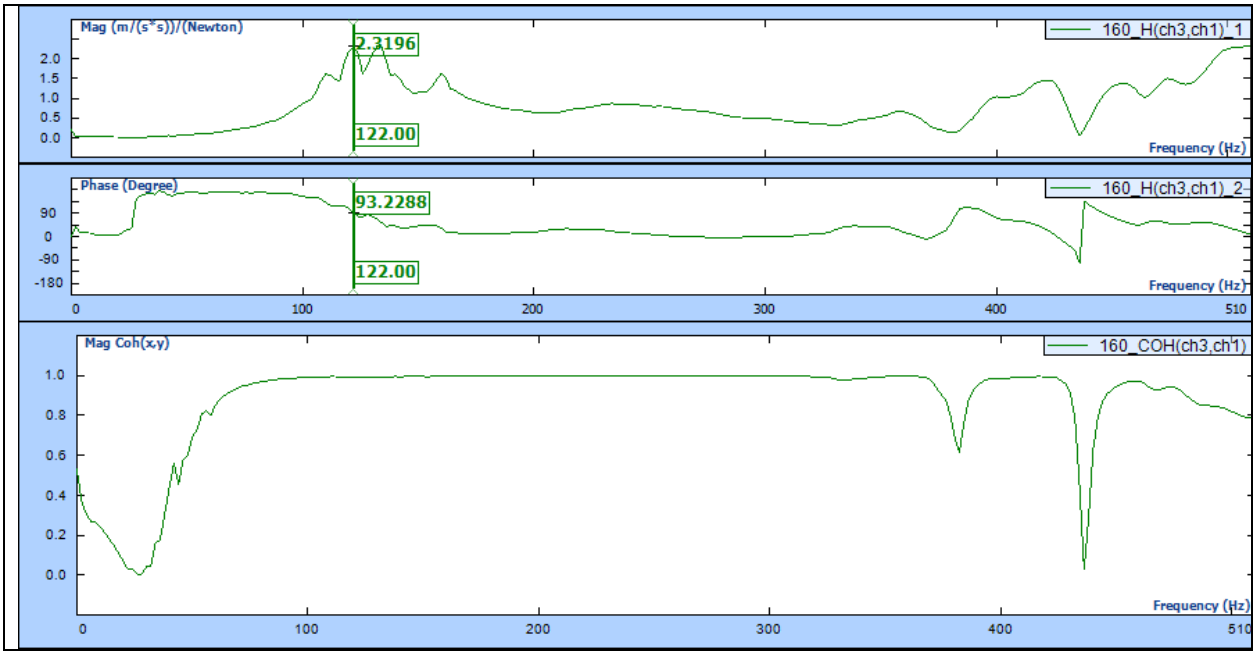
Photograph 157: ***Impact Test Data At 249 Slot Pole Jumper Top Radial***



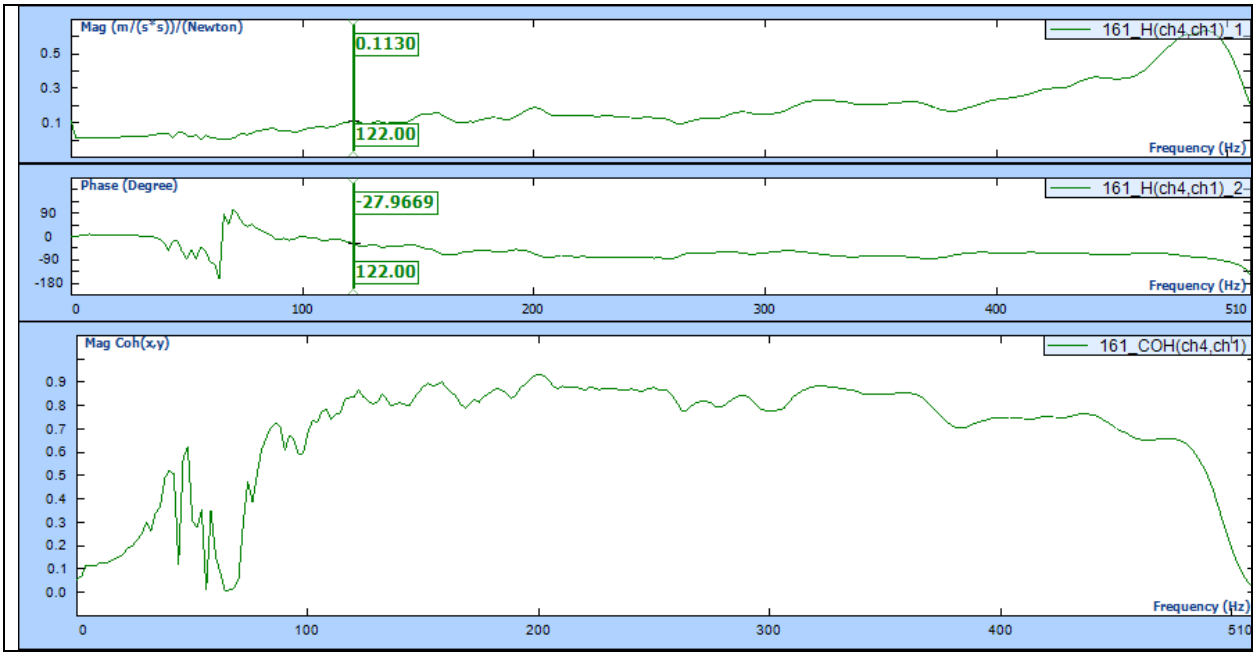
Photograph 158: ***Impact Test Data At 249 Slot Pole Jumper Top Tangential***



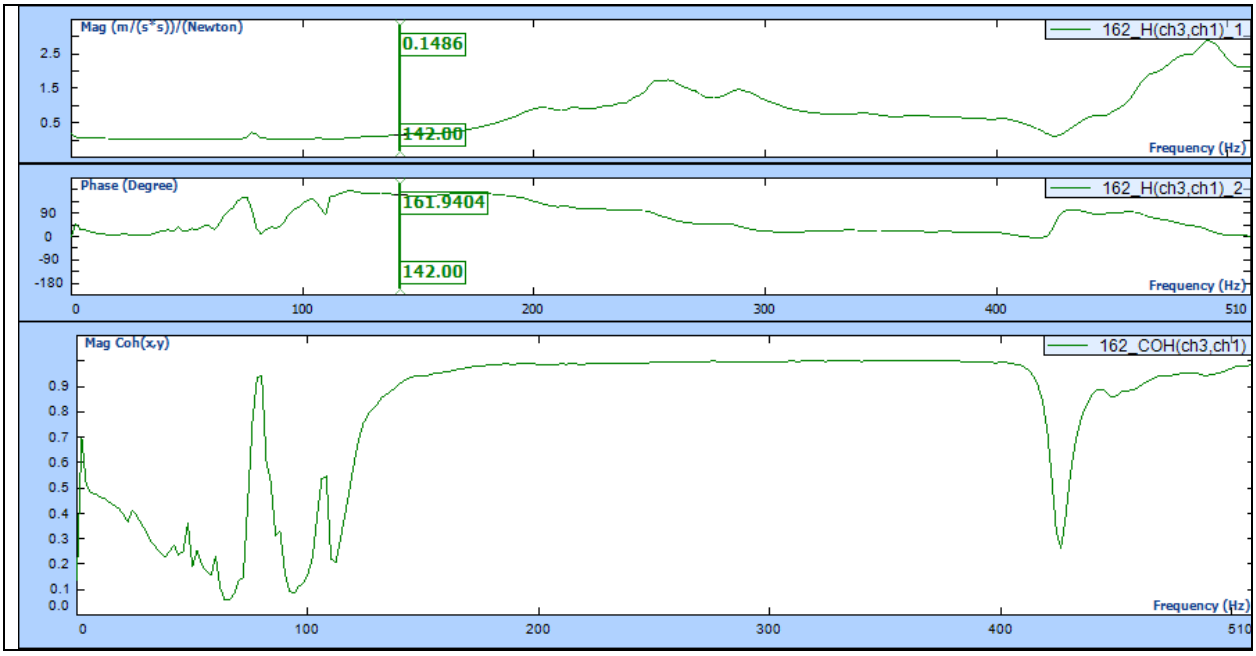
Photograph 159: ***Impact Test Data At 249 Slot Pole Jumper Bottom Radial***



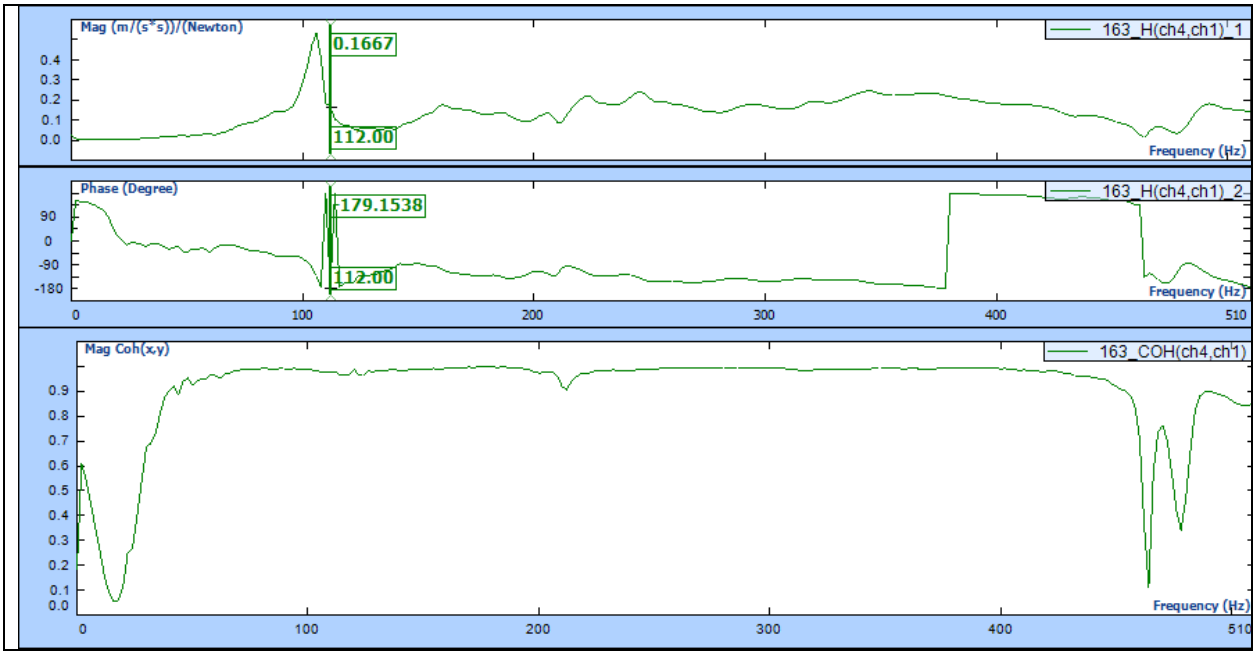
Photograph 160: ***Impact Test Data At 249 Slot Pole Jumper Bottom Tangential***



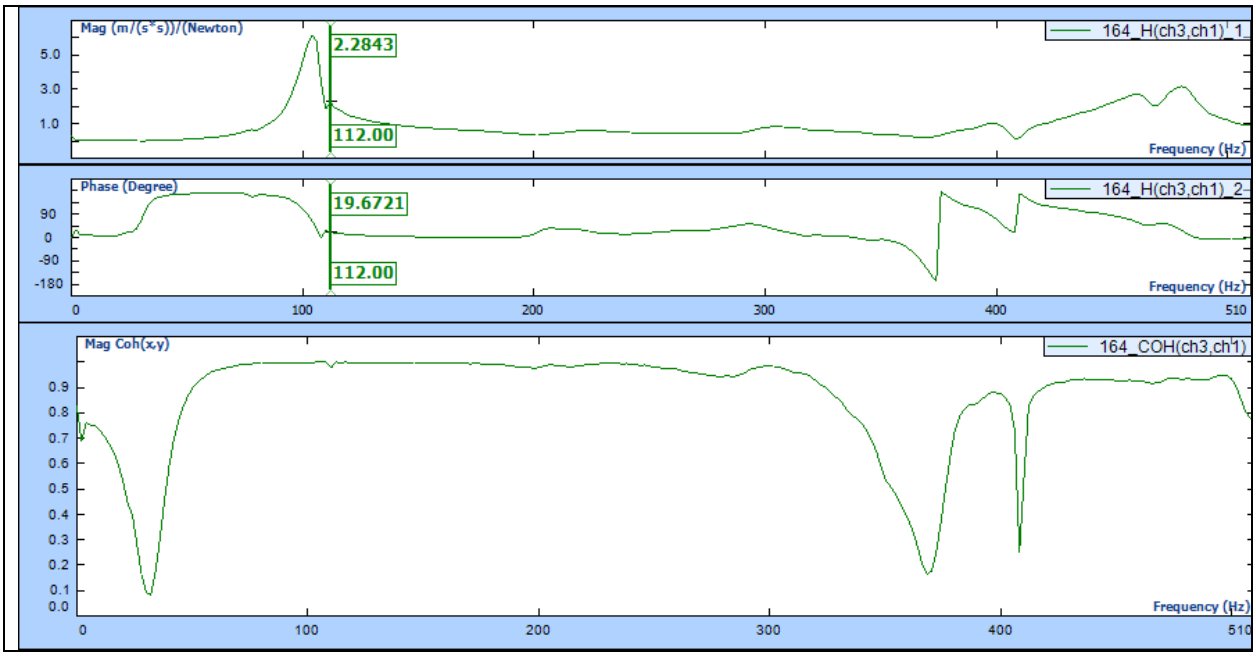
Photograph 161: ***Impact Test Data At 253 Slot Pole Jumper Top Radial***



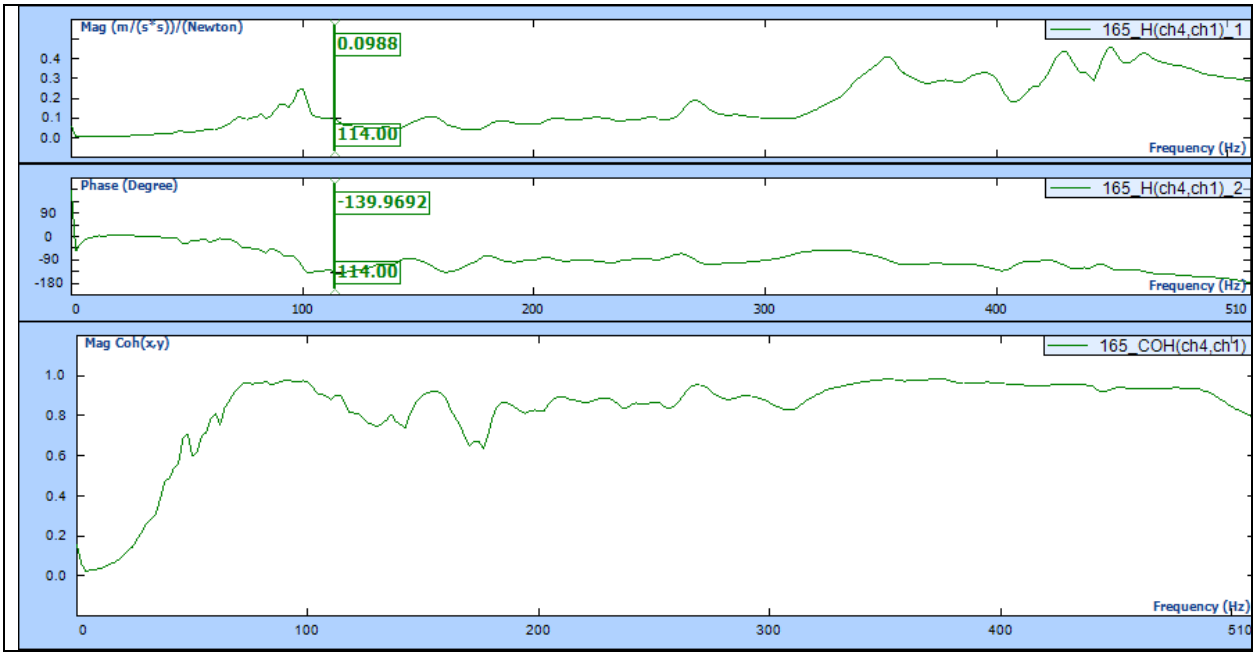
Photograph 162: ***Impact Test Data At 253 Slot Pole Jumper Top Tangential***



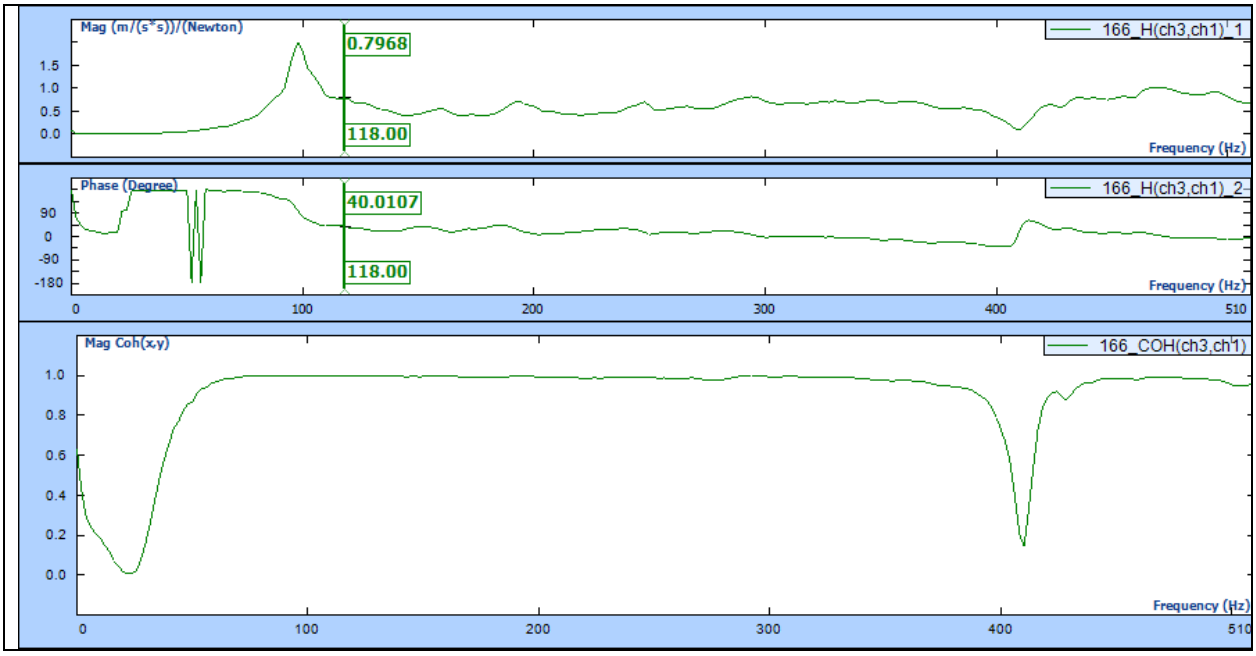
Photograph 163: ***Impact Test Data At 253 Slot Pole Jumper Bottom Radial***



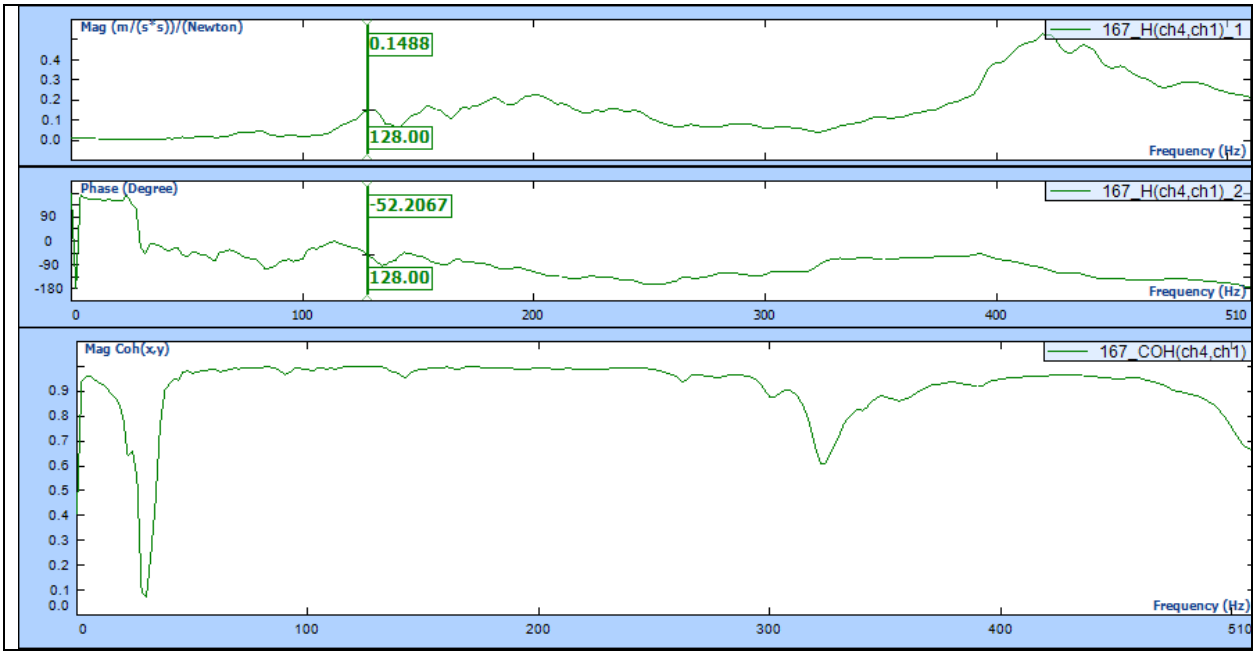
Photograph 164: ***Impact Test Data At 253 Slot Pole Jumper Bottom Tangential***



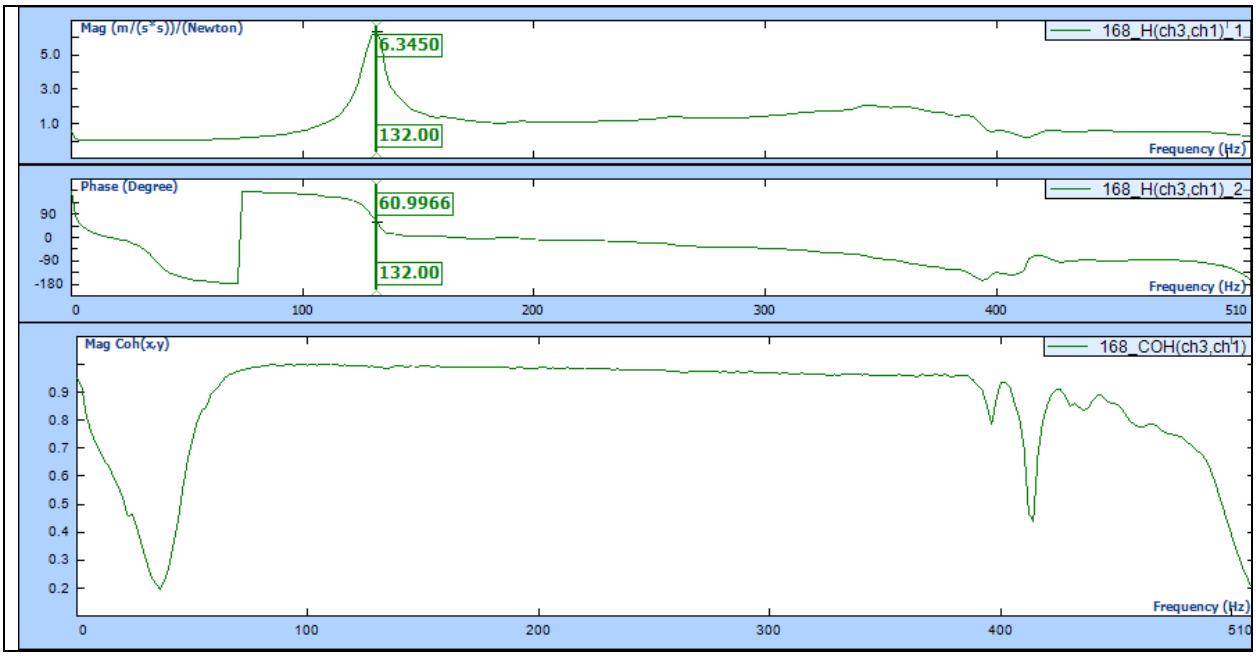
Photograph 165: ***Impact Test Data At 258 Slot Pole Jumper Top Radial***



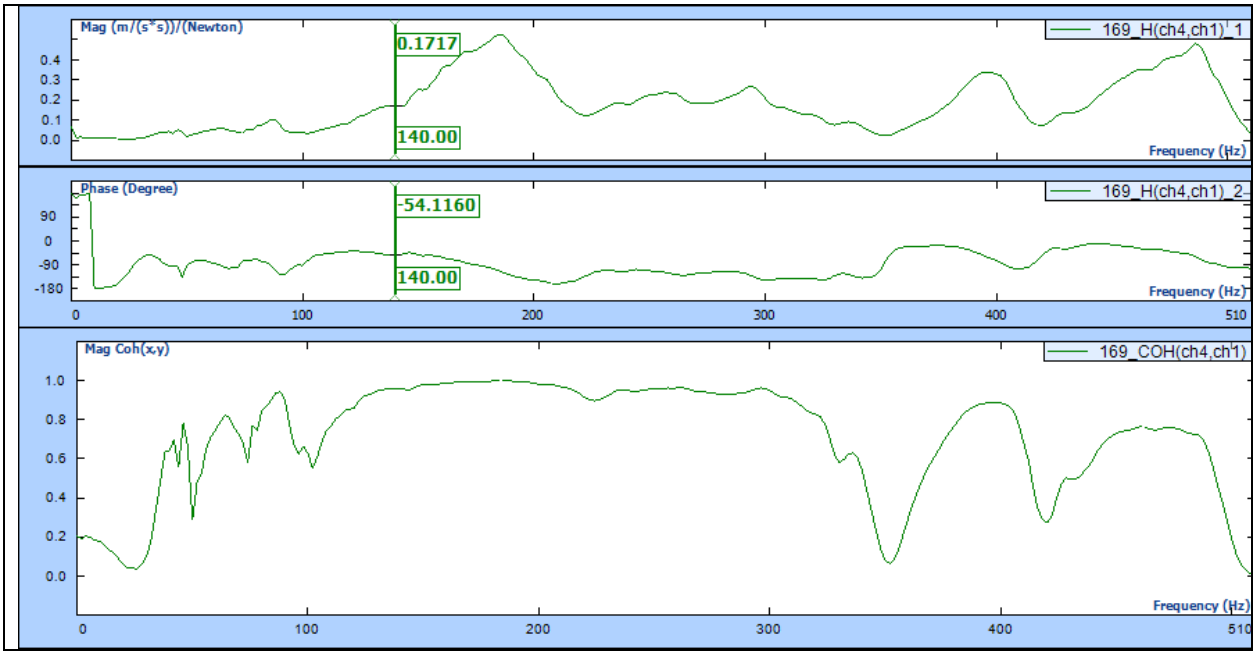
Photograph 166: ***Impact Test Data At 258 Slot Pole Jumper Top Tangential***



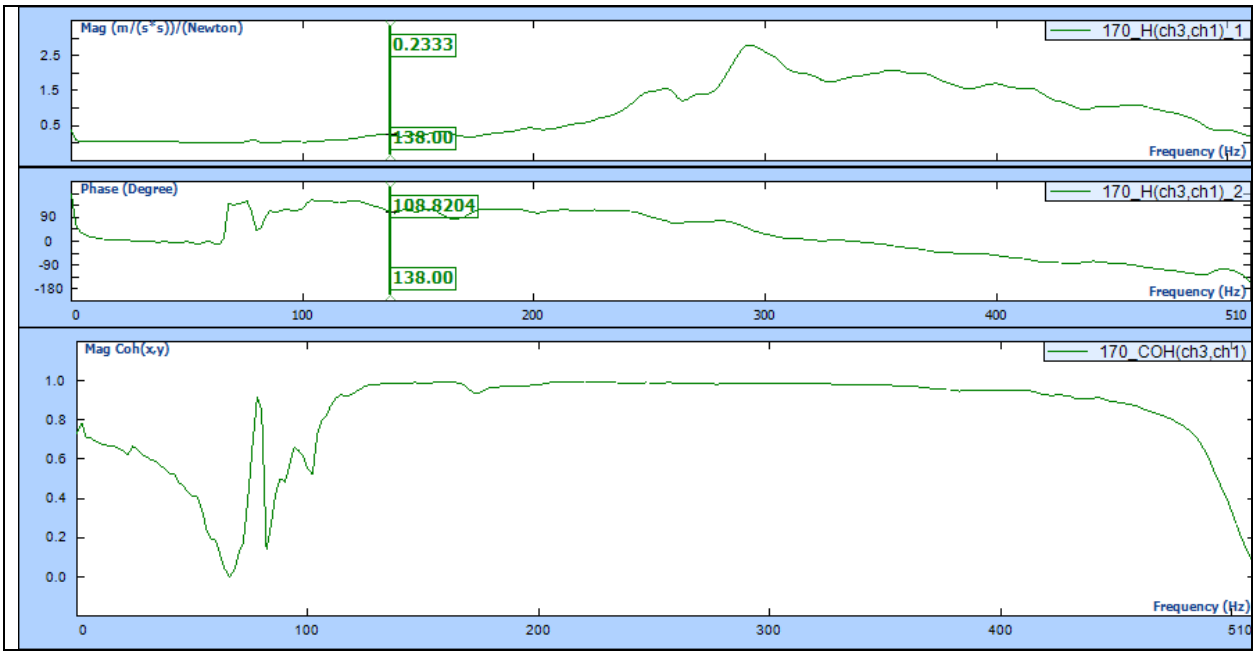
Photograph 167: ***Impact Test Data At 258 Slot Pole Jumper Bottom Radial***



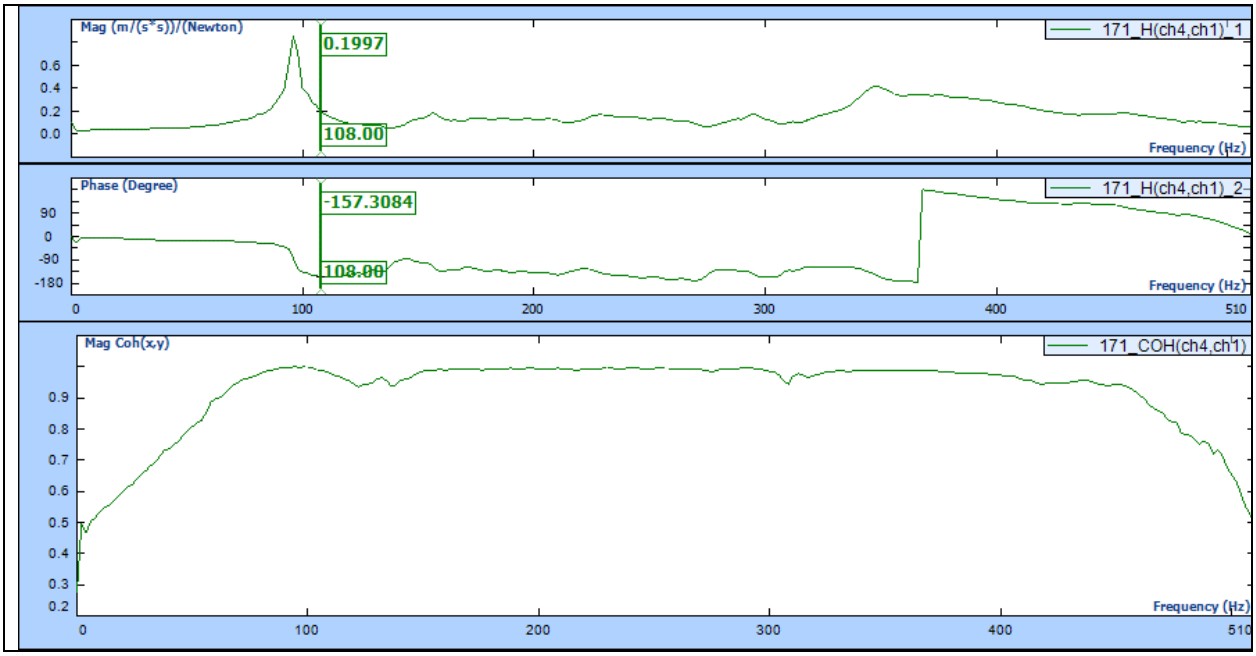
Photograph 168: ***Impact Test Data At 258 Slot Pole Jumper Bottom Tangential***



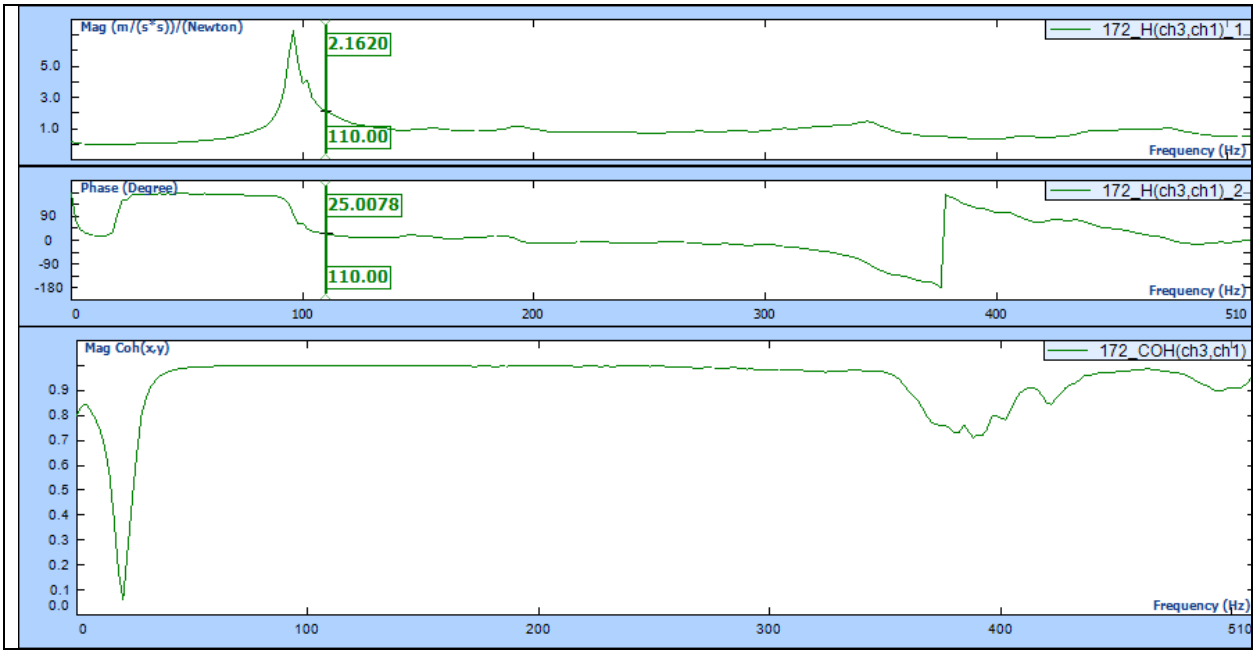
Photograph 169: ***Impact Test Data At 262 Slot Pole Jumper Top Radial***



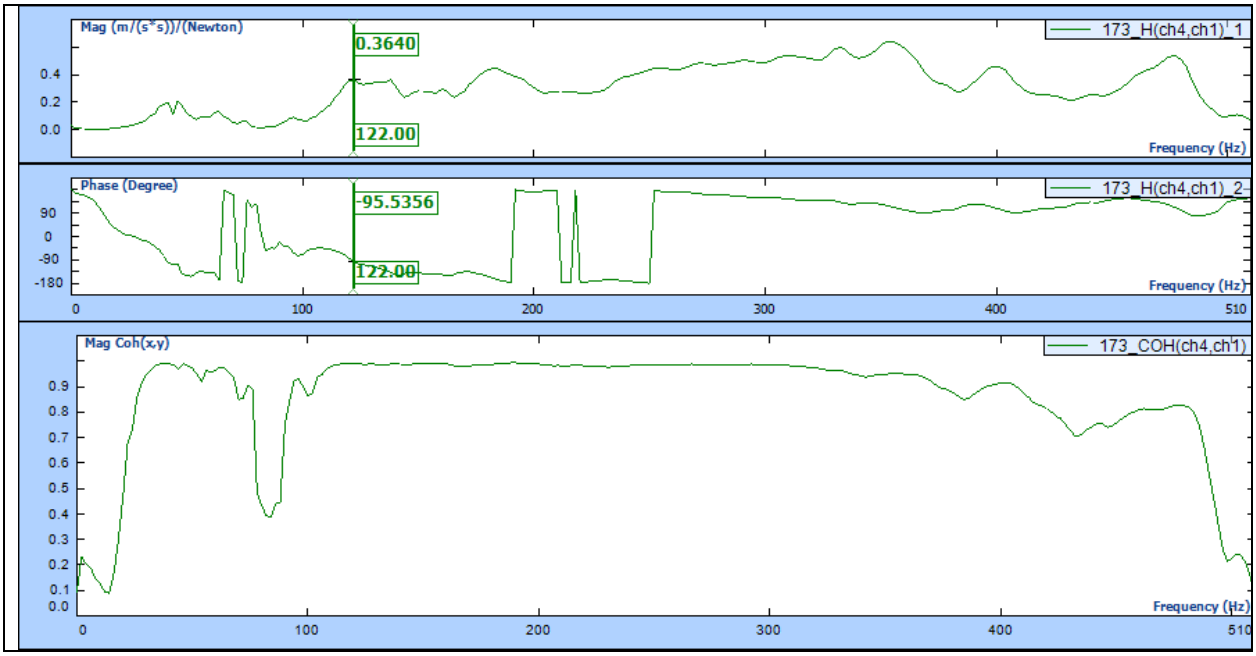
Photograph 170: ***Impact Test Data At 262 Slot Pole Jumper Top Tangential***



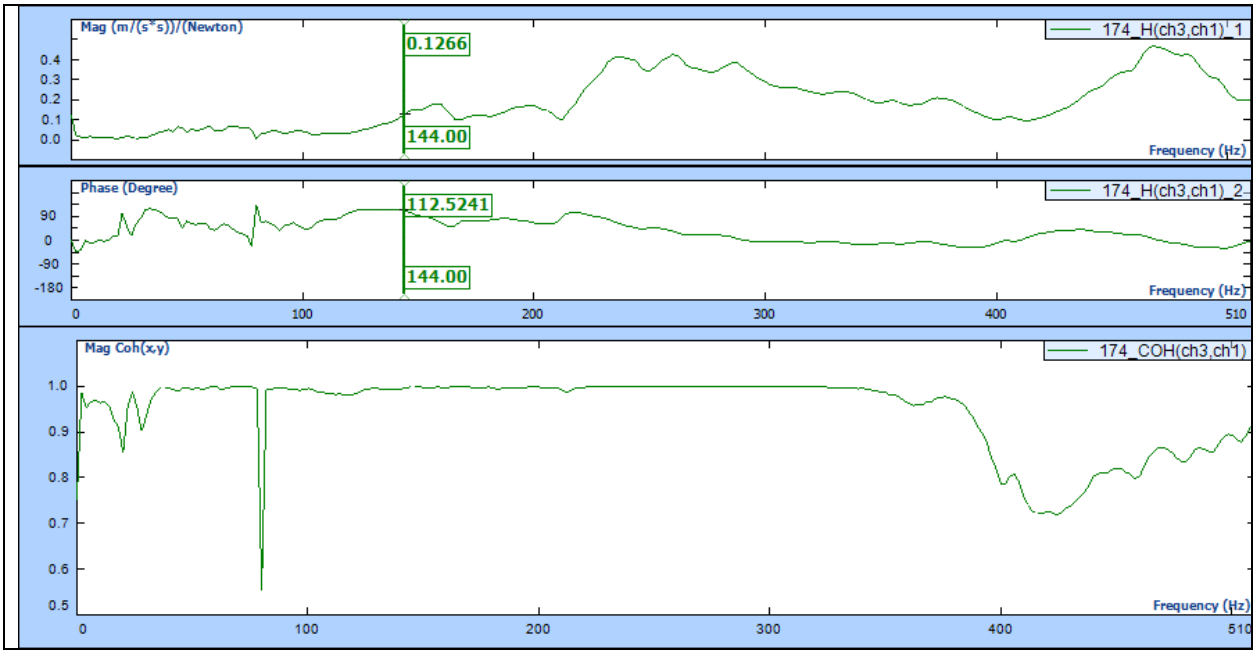
Photograph 171: ***Impact Test Data At 262 Slot Pole Jumper Bottom Radial***



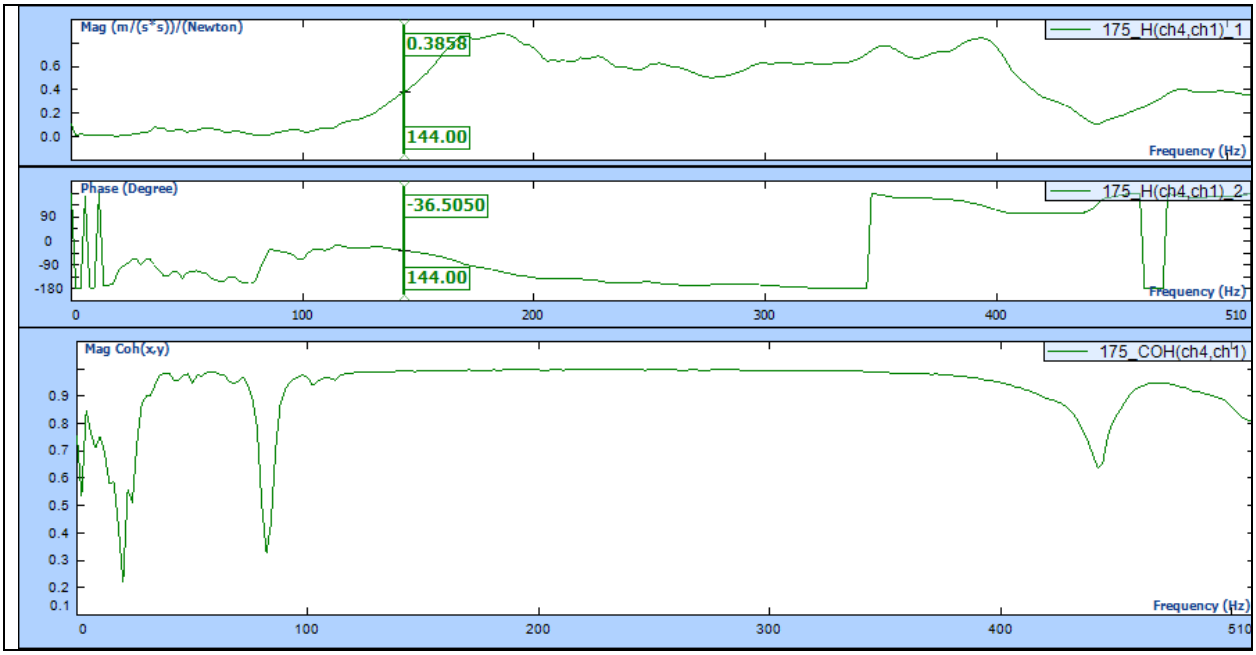
Photograph 172: ***Impact Test Data At 262 Slot Pole Jumper Bottom Tangential***



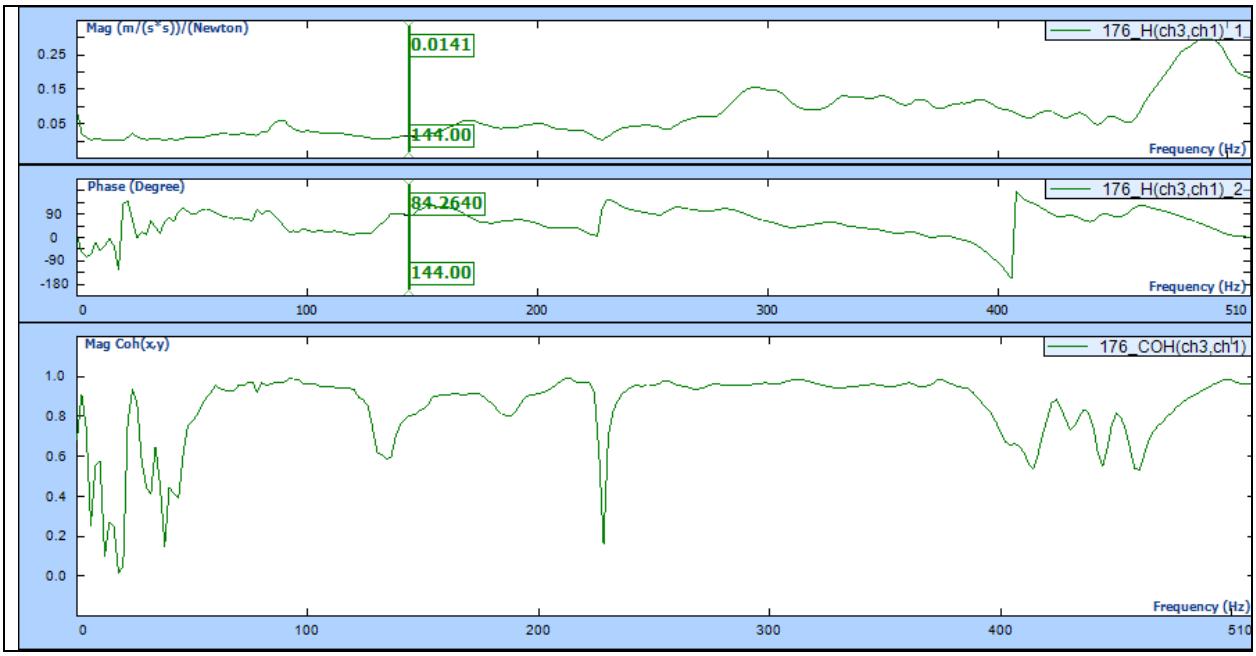
Photograph 173: ***Impact Test Data At 253 Slot Circuit Ring Radial***



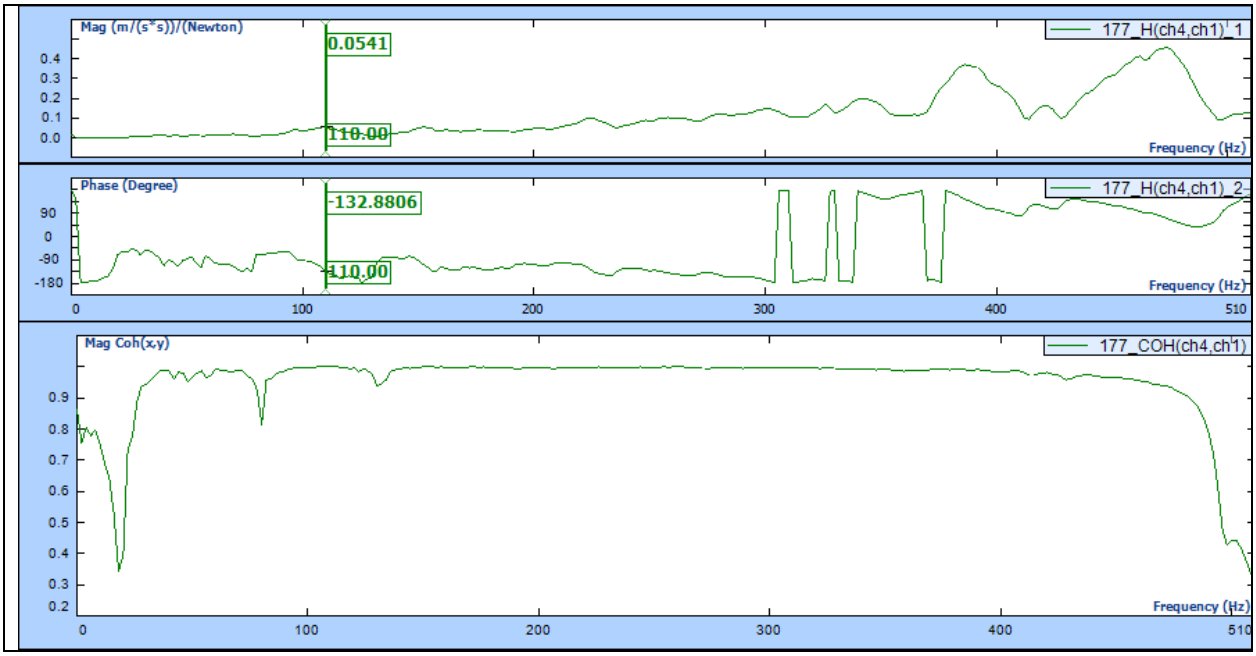
Photograph 174: ***Impact Test Data At 253 Slot Circuit Ring Tangential***



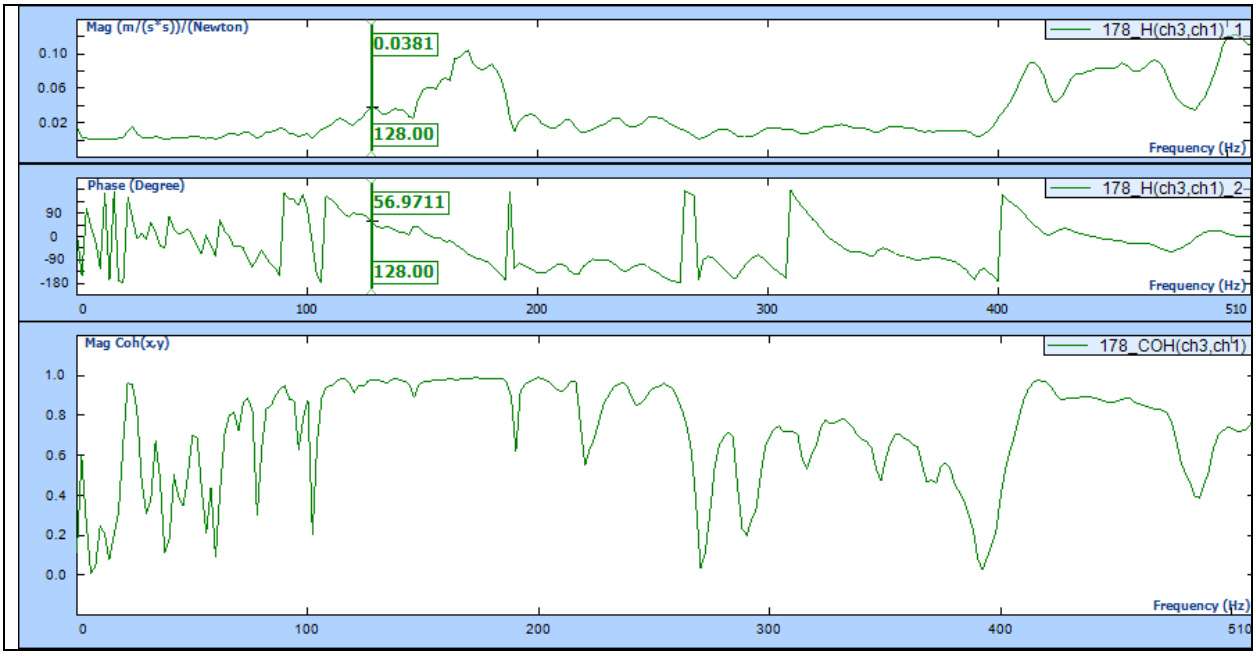
Photograph 175: ***Impact Test Data At 262 Slot Circuit Ring Radial***



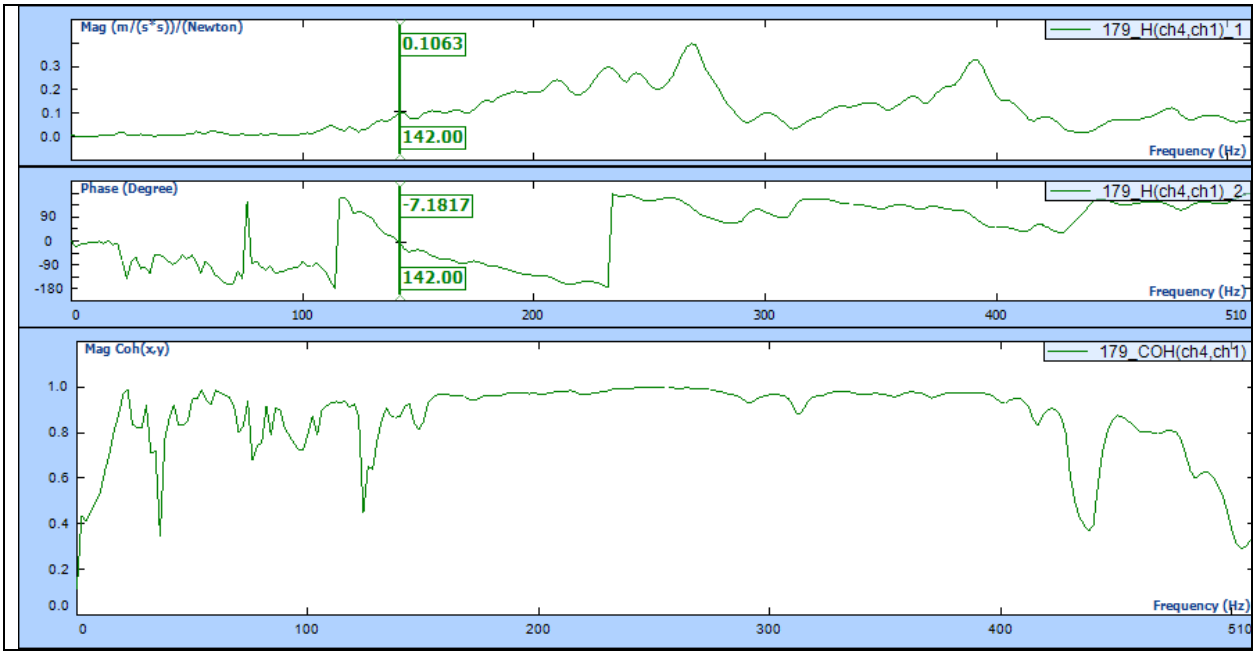
Photograph 176: ***Impact Test Data At 262 Slot Circuit Ring Tangential***



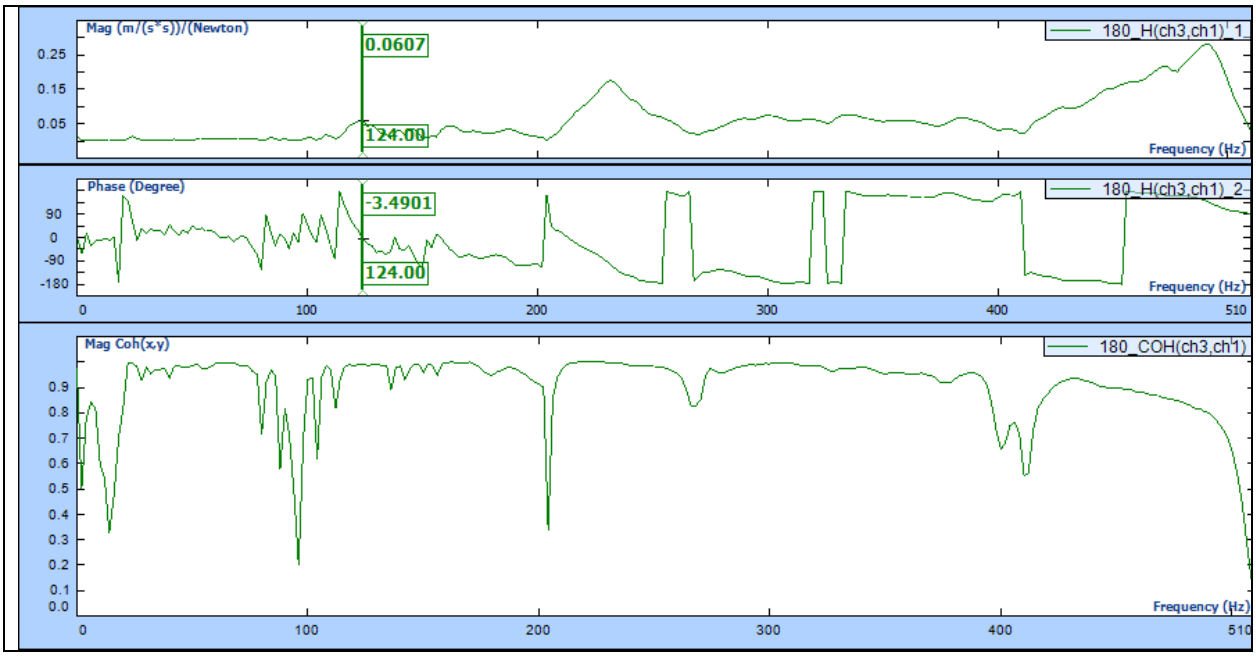
Photograph 177: ***Impact Test Data At 3 Slot Circuit Ring Radial***



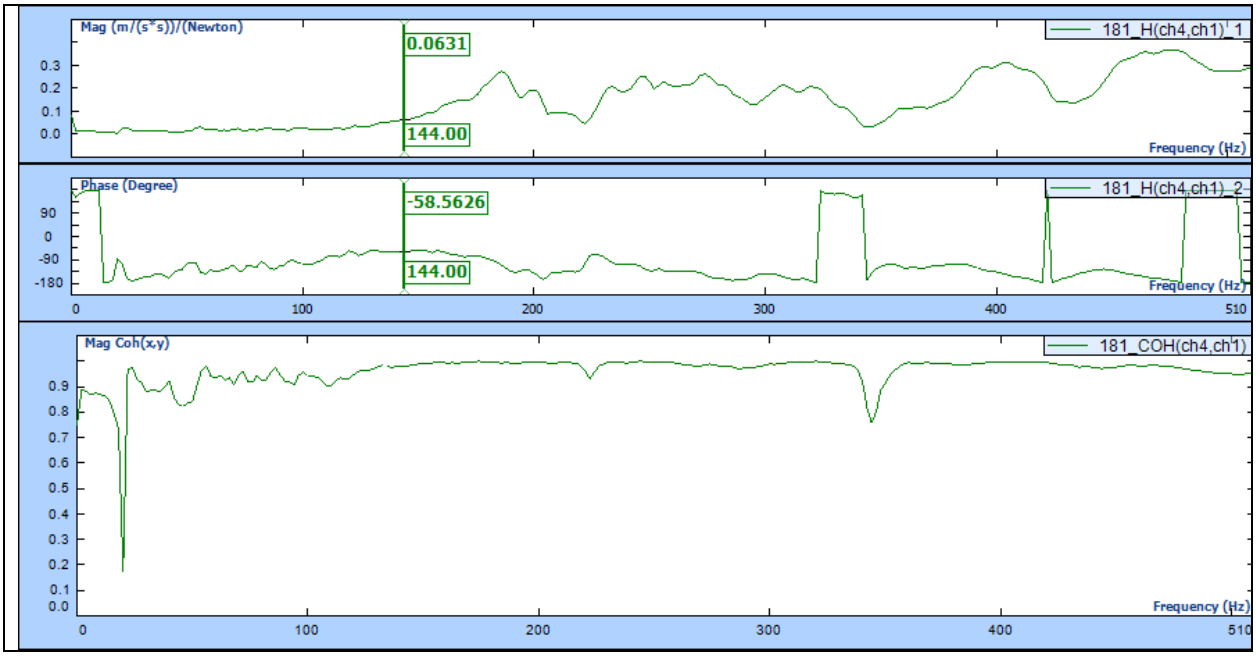
Photograph 178: ***Impact Test Data At 3 Slot Circuit Ring Tangential***



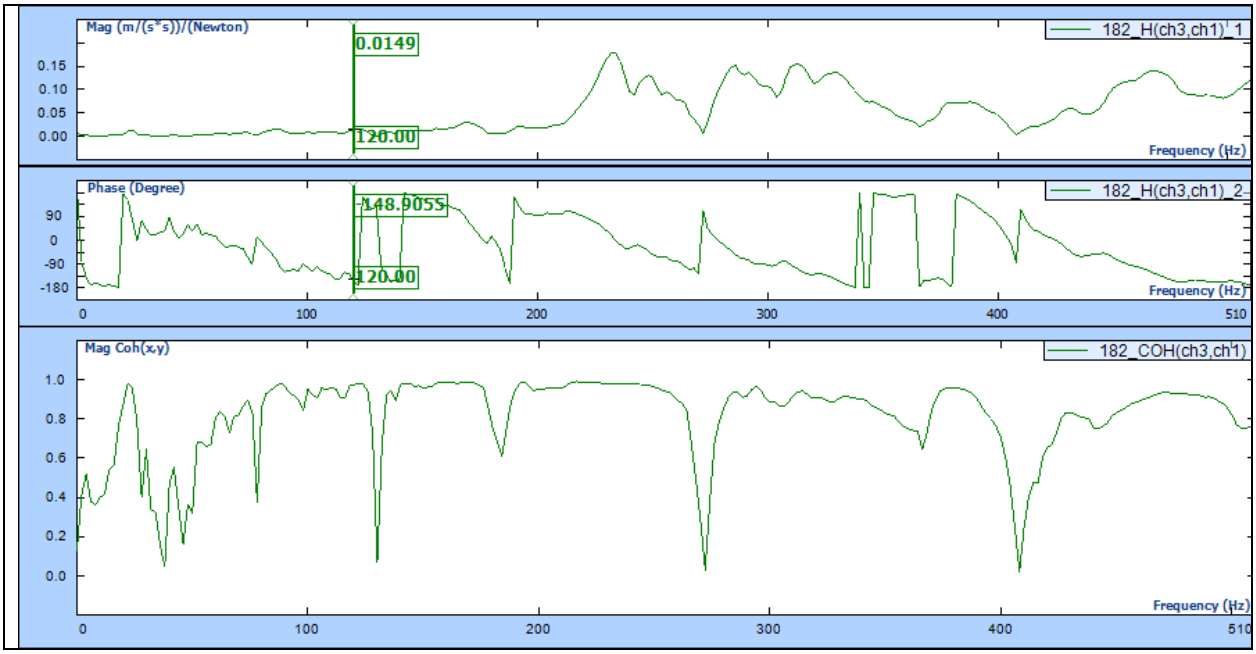
Photograph 179: ***Impact Test Data At 20 Slot Circuit Ring Radial***



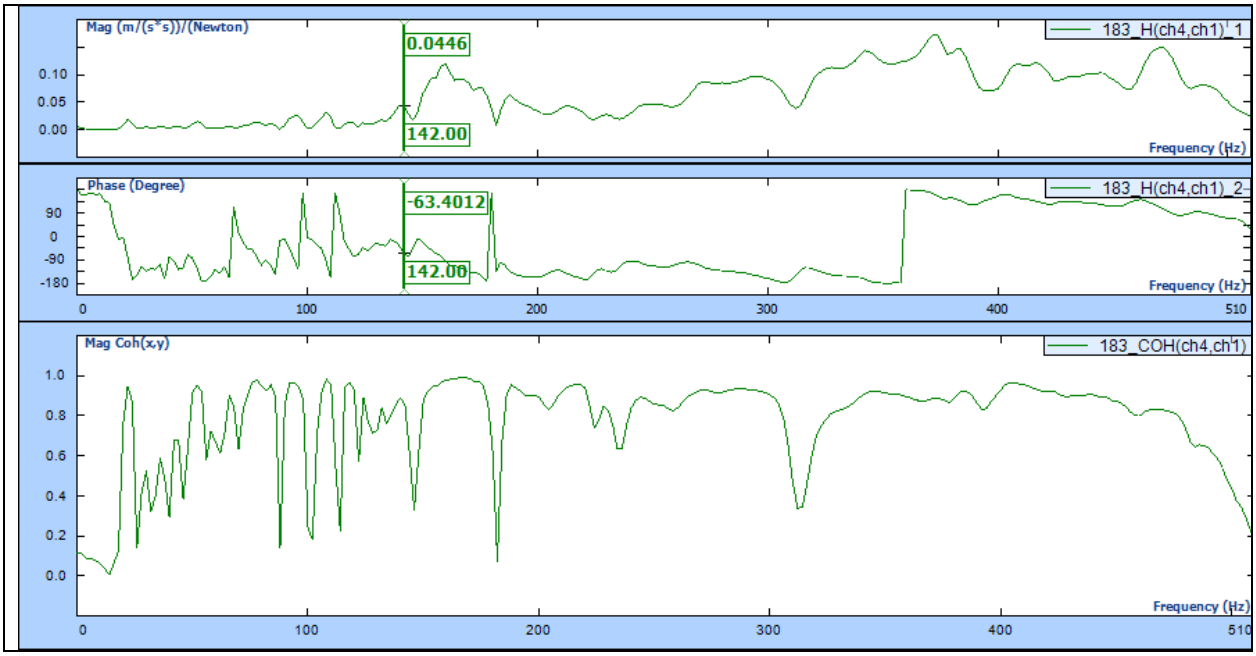
Photograph 180: ***Impact Test Data At 20 Slot Circuit Ring Tangential***



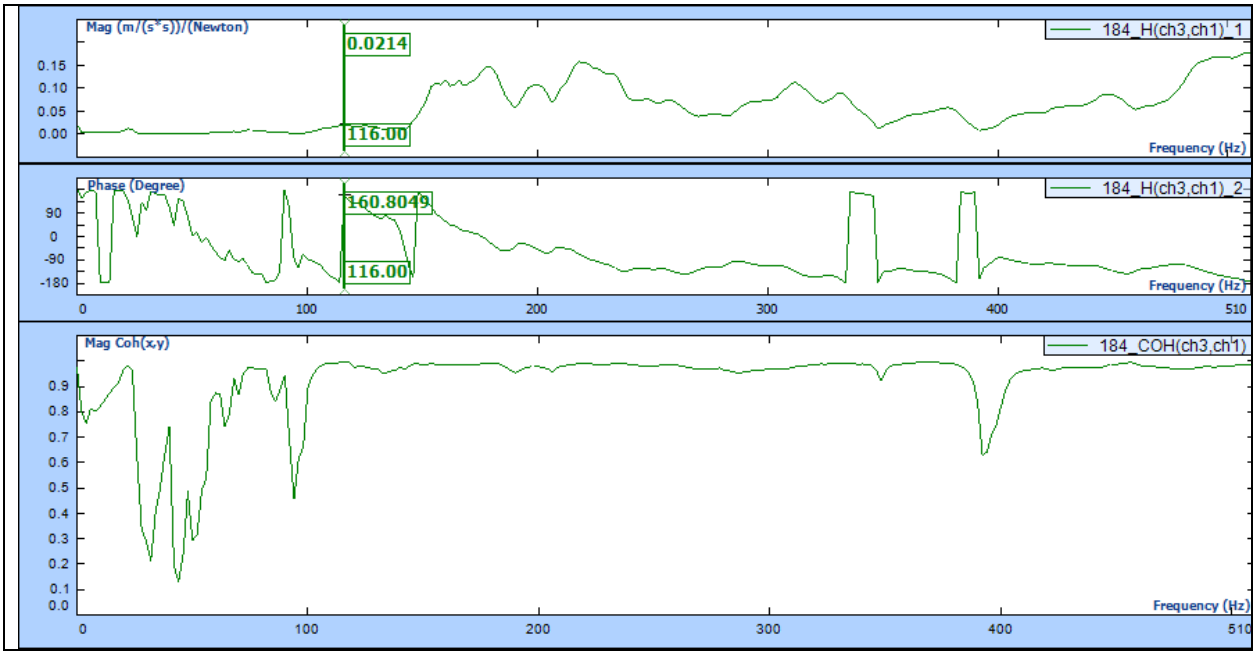
Photograph 181: ***Impact Test Data At 29 Slot Circuit Ring Radial***



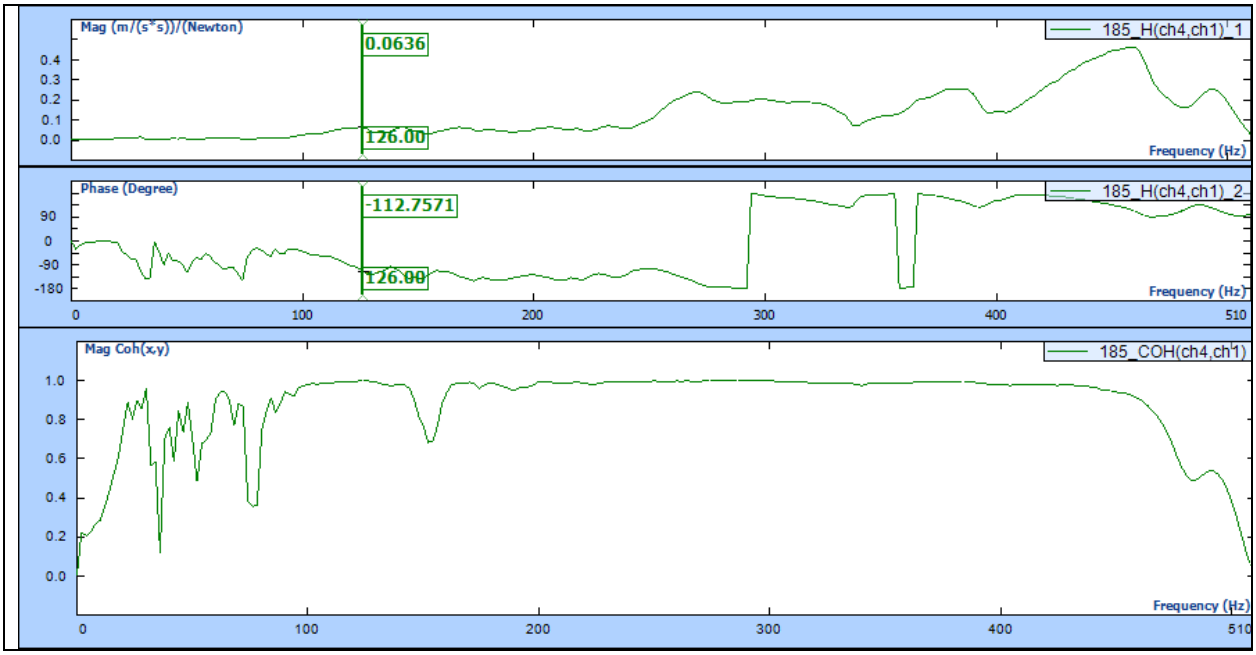
Photograph 182: ***Impact Test Data At 29 Slot Circuit Ring Tangential***



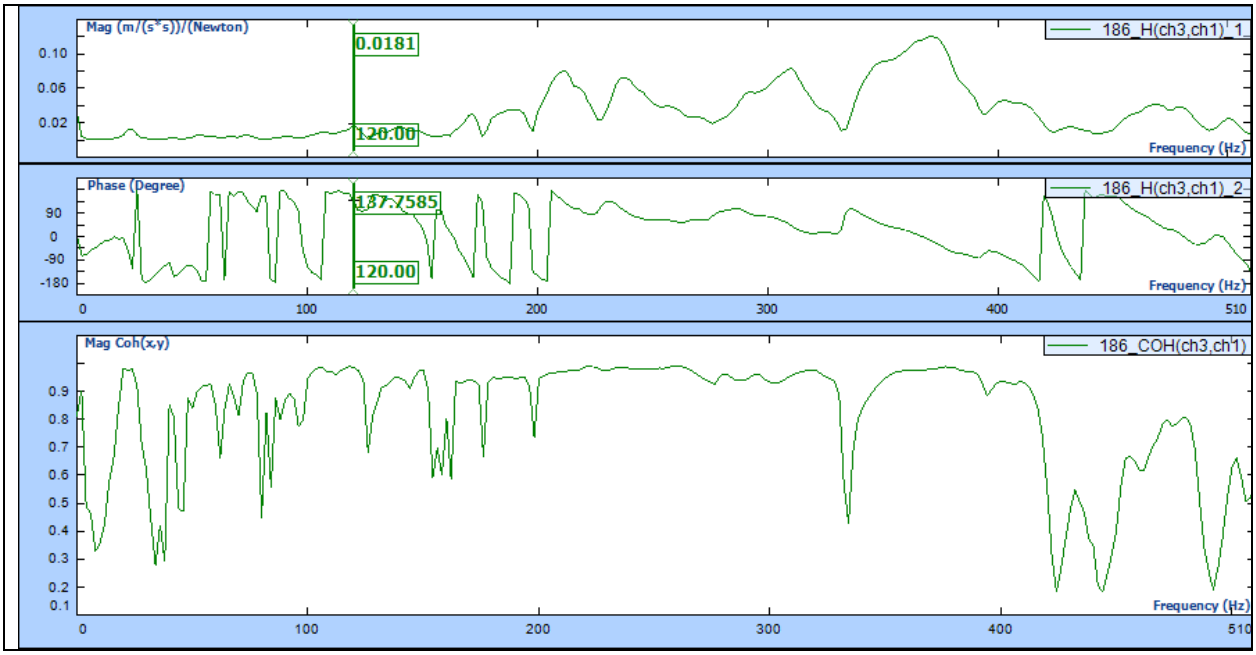
Photograph 183: ***Impact Test Data At 38 Slot Circuit Ring Radial***



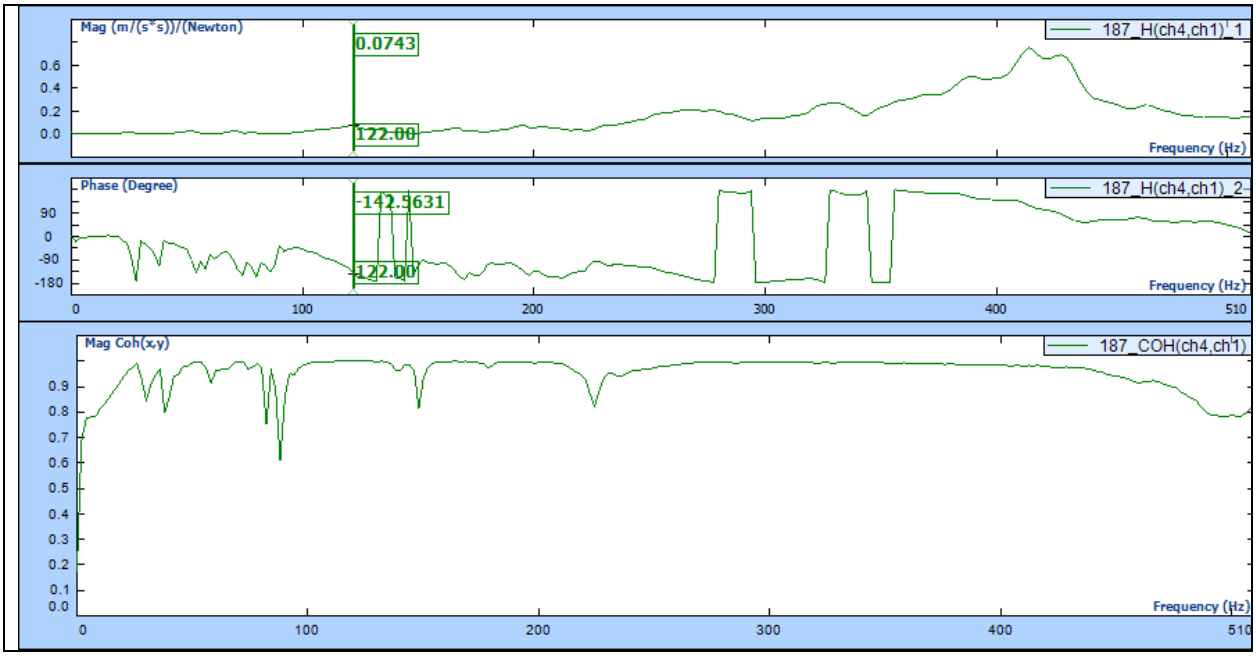
Photograph 184: ***Impact Test Data At 38 Slot Circuit Ring Tangential***



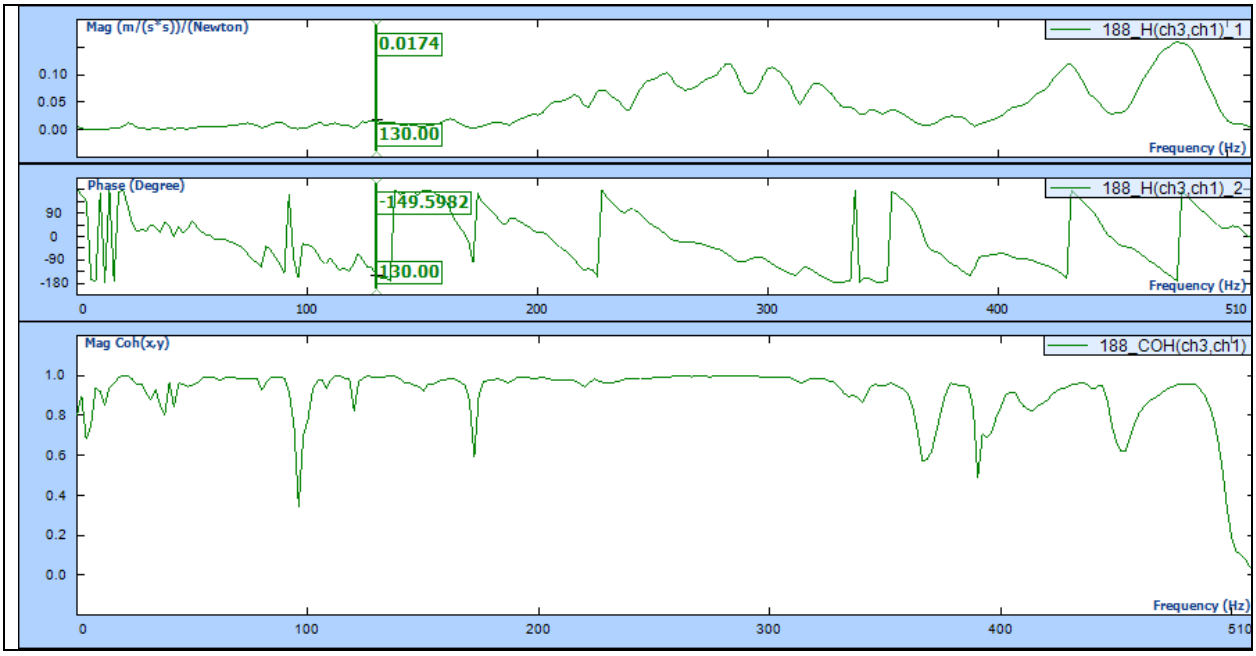
Photograph 185: ***Impact Test Data At 47 Slot Circuit Ring Radial***



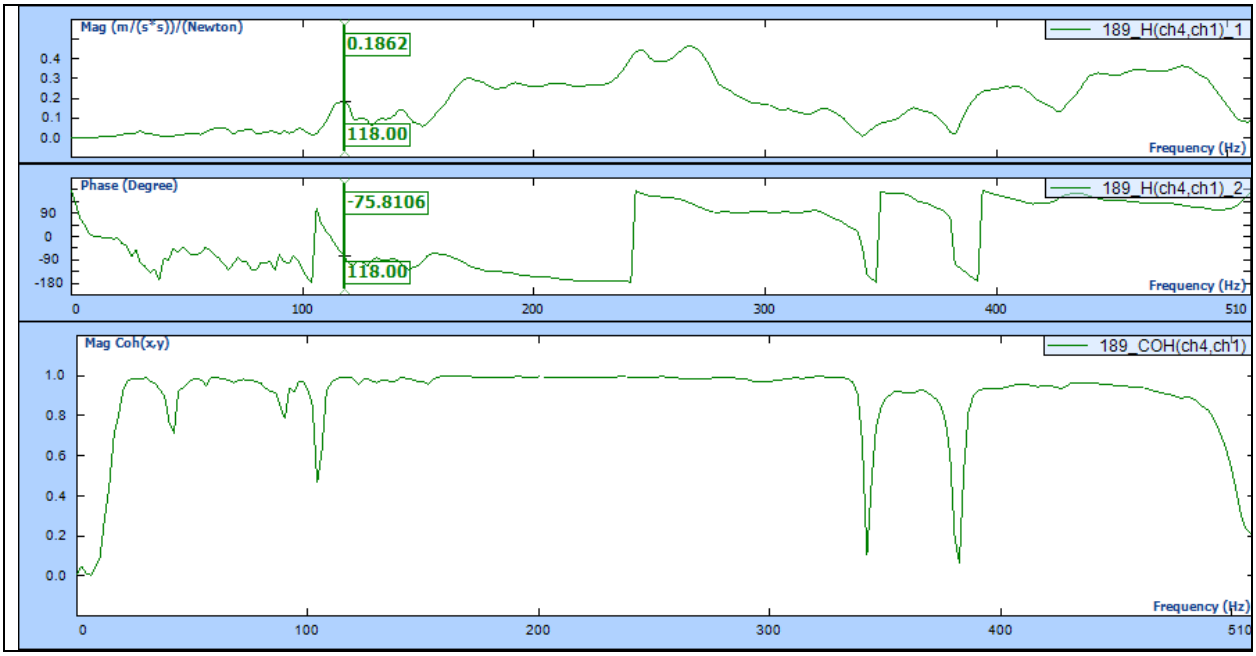
Photograph 186: ***Impact Test Data At 47 Slot Circuit Ring Tangential***



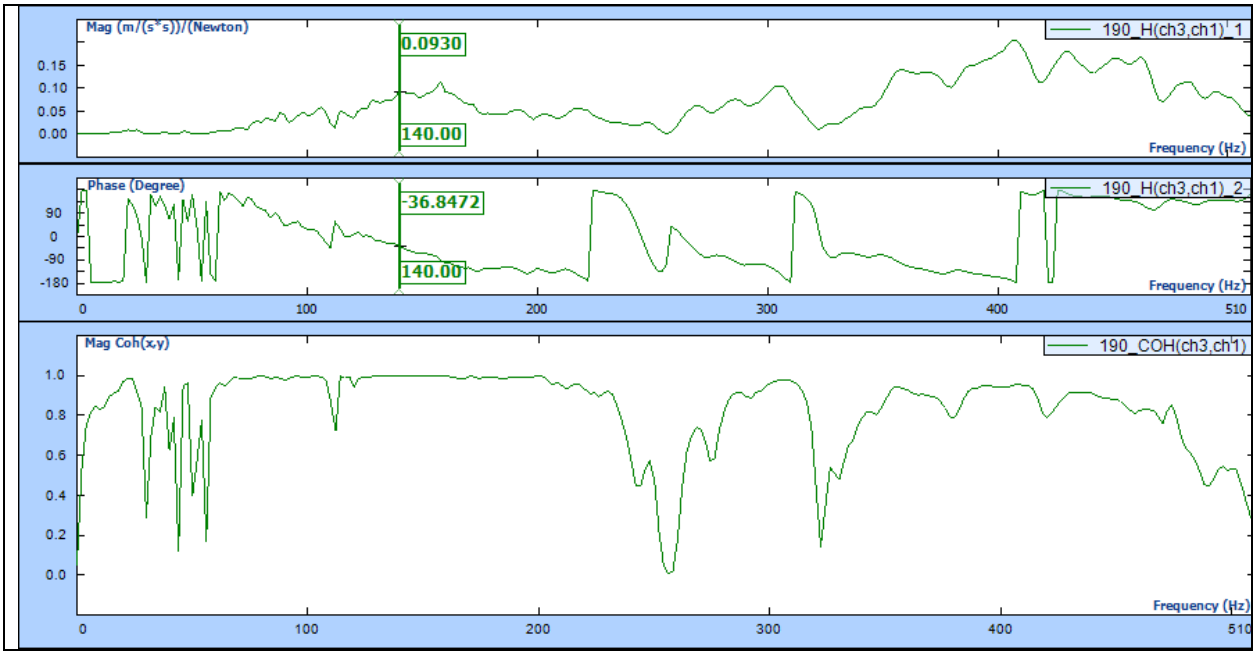
Photograph 187: ***Impact Test Data At 60 Slot Circuit Ring Radial***



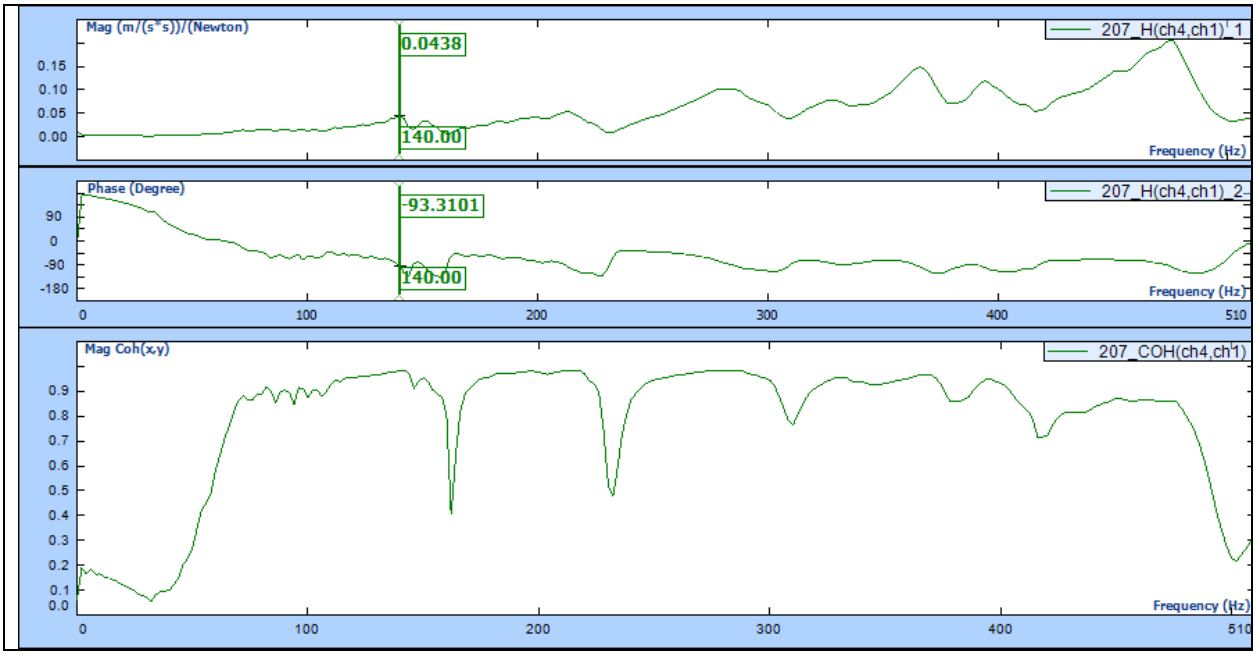
Photograph 188: ***Impact Test Data At 60 Slot Circuit Ring Tangential***



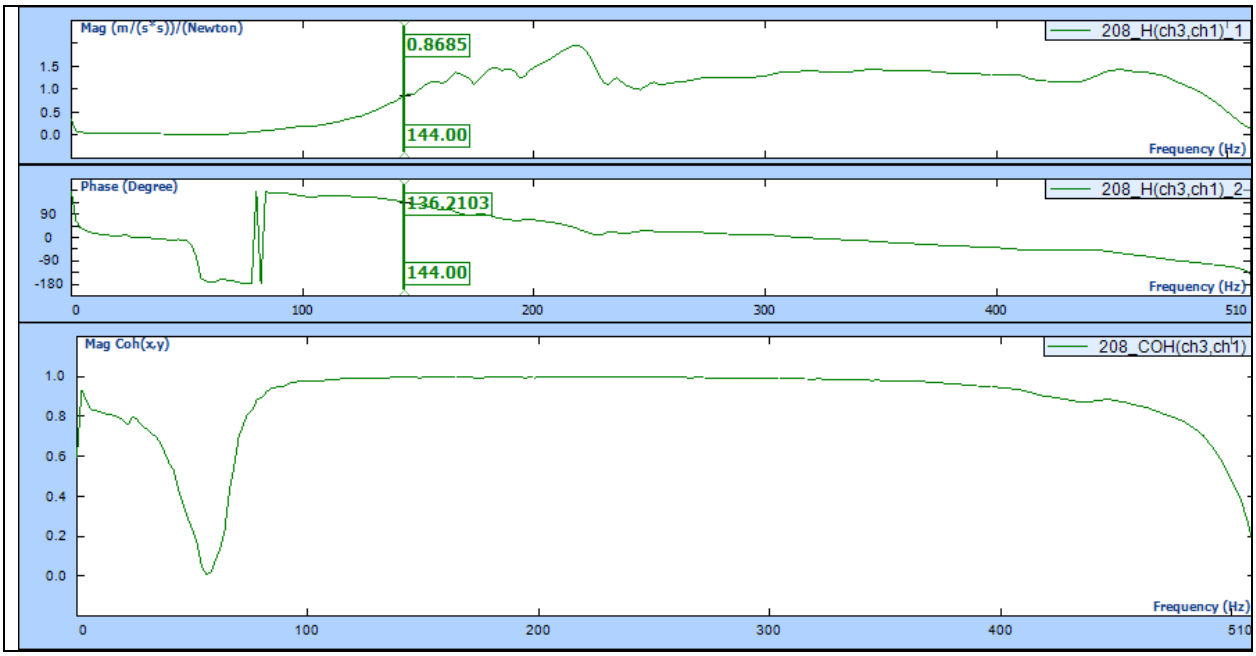
Photograph 189: ***Impact Test Data At 73 Slot Circuit Ring Radial***



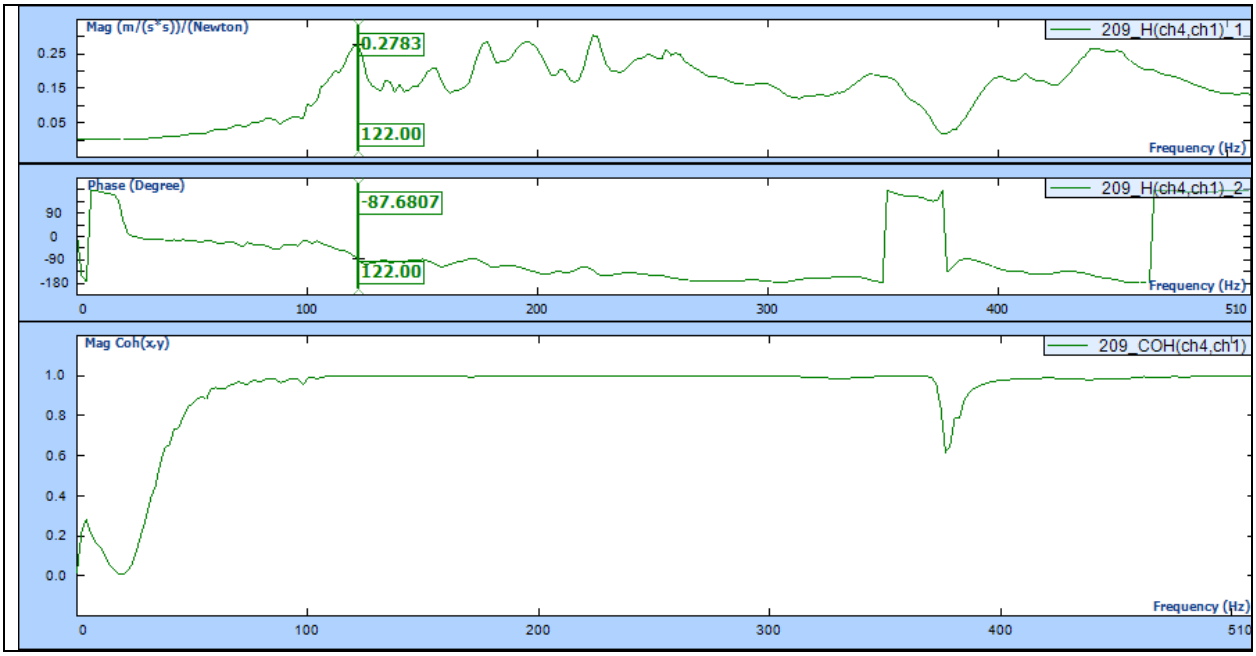
Photograph 190: ***Impact Test Data At 73 Slot Circuit Ring Tangential***



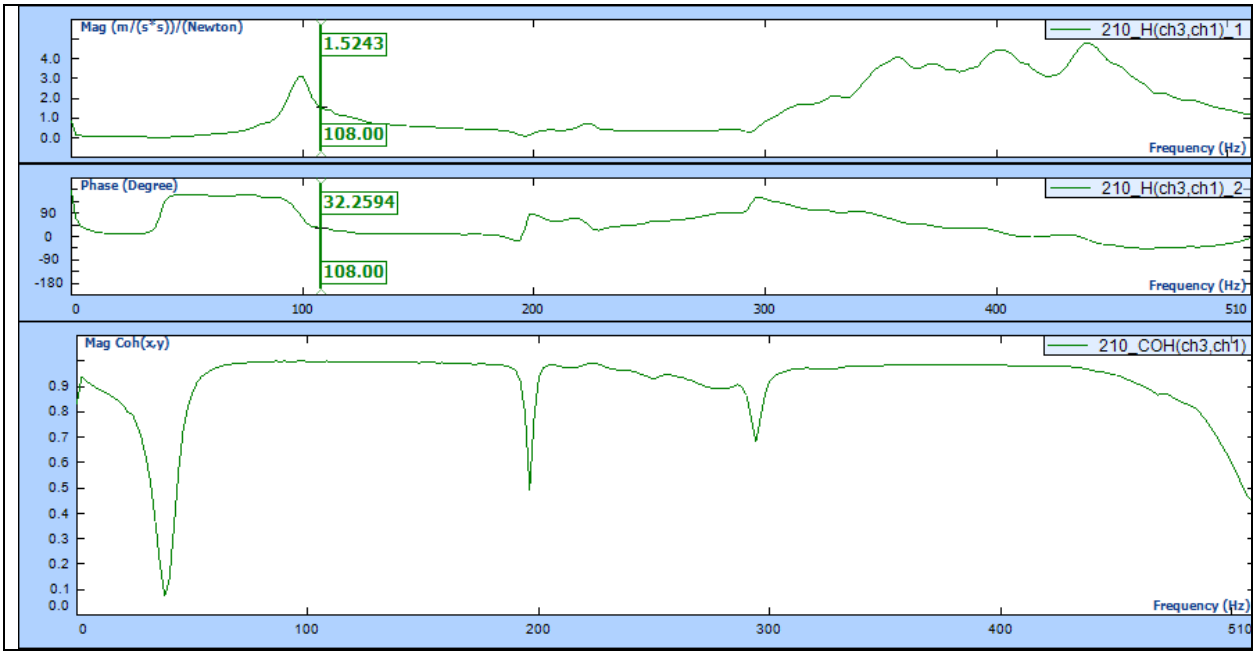
Photograph 191: ***Impact Test Data At 3 Slot Pole Jumper Top Radial***



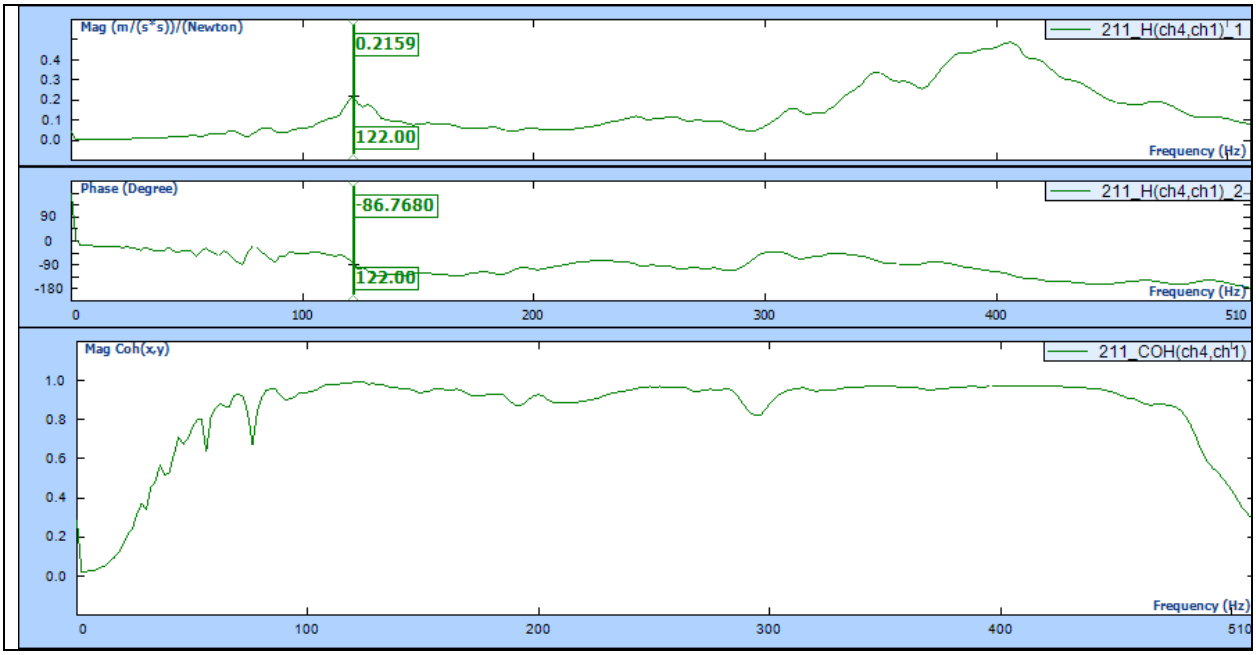
Photograph 192: ***Impact Test Data At 3 Slot Pole Jumper Top Tangential***



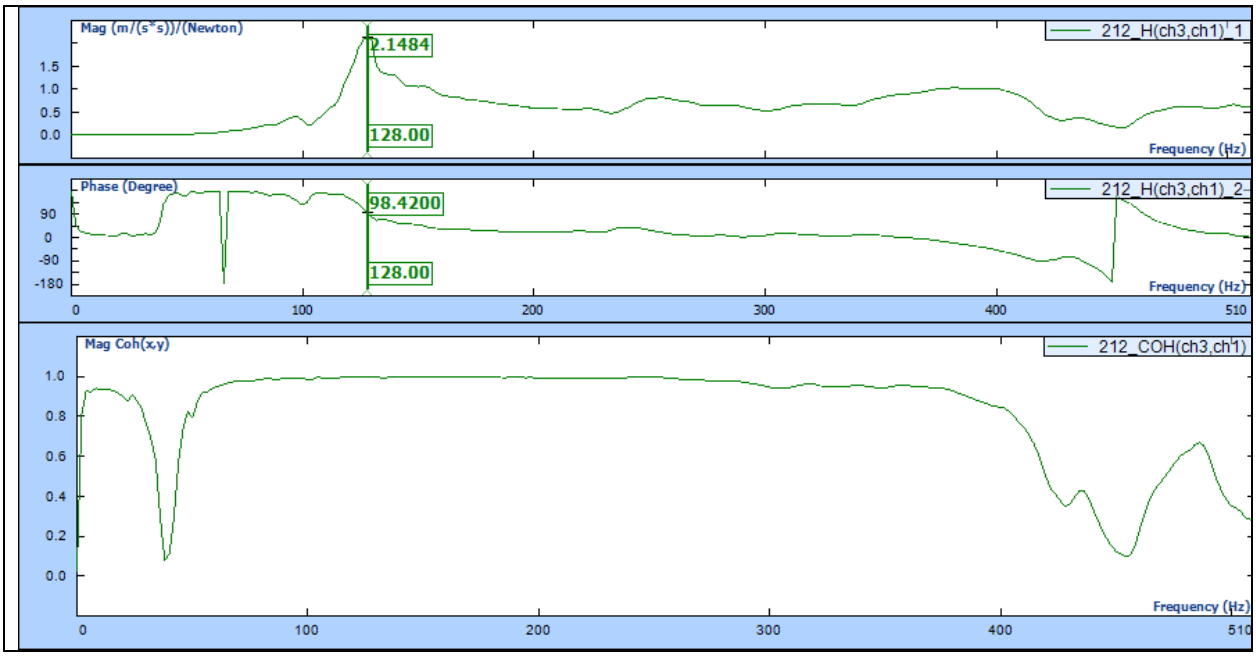
Photograph 193: ***Impact Test Data At 3 Slot Pole Jumper Bottom Radial***



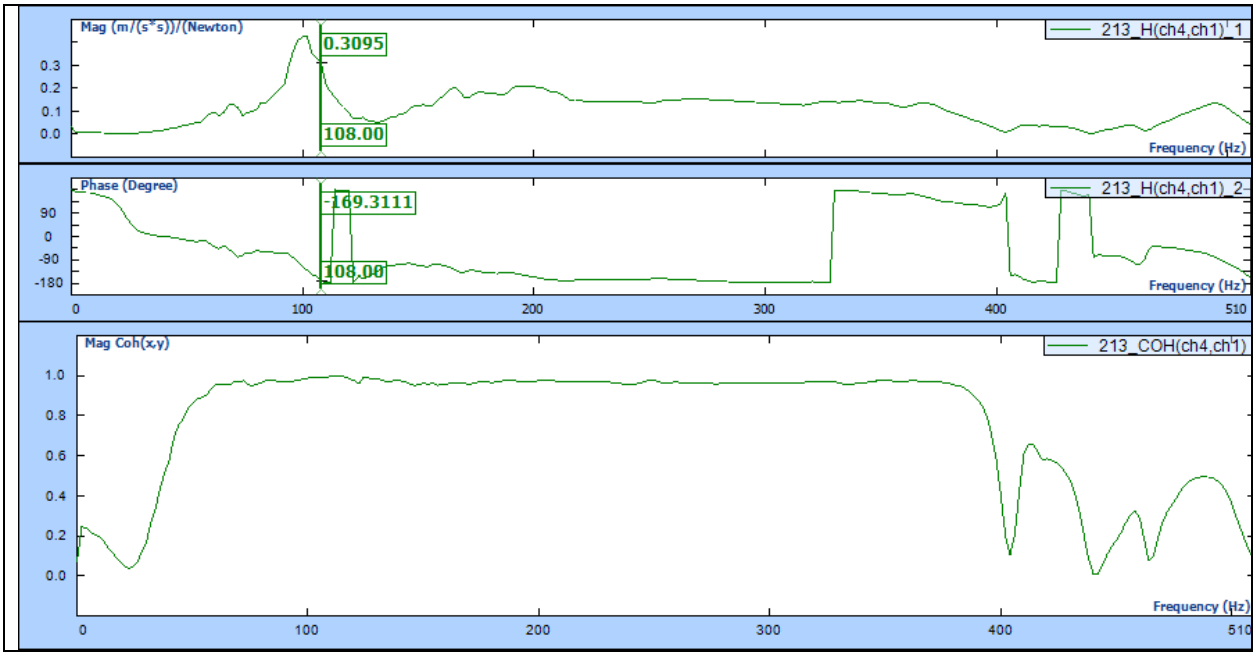
Photograph 194: ***Impact Test Data At 3 Slot Pole Jumper Bottom Tangential***



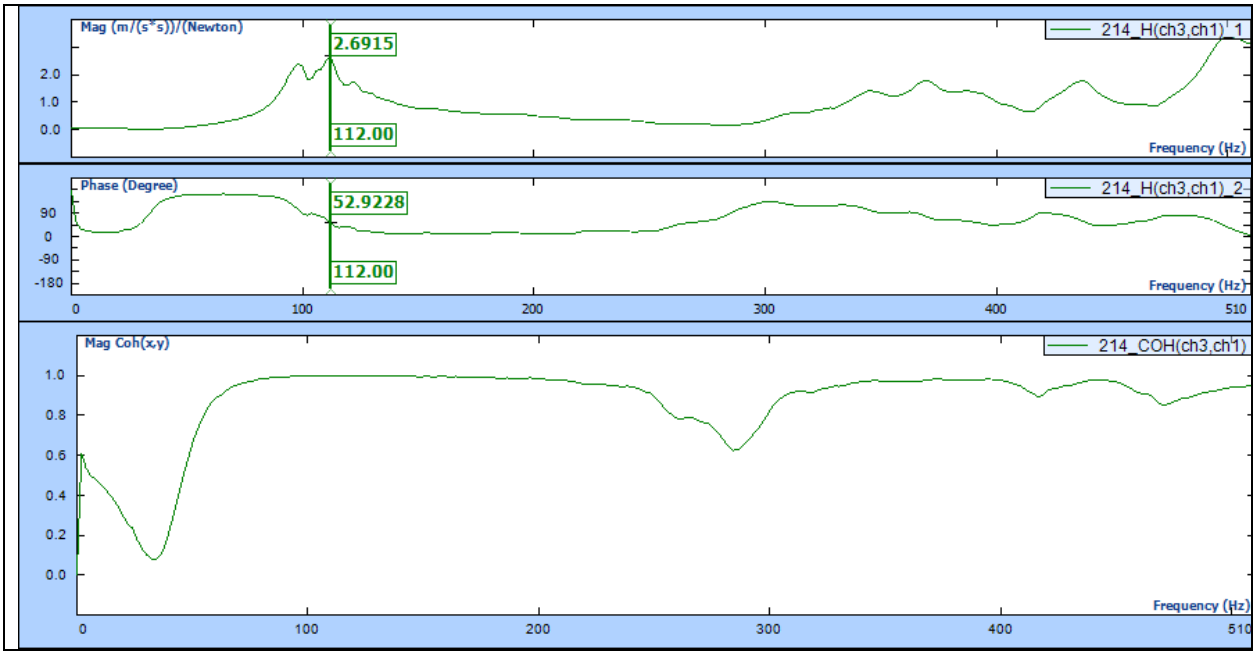
Photograph 195: ***Impact Test Data At 7 Slot Pole Jumper Top Radial***



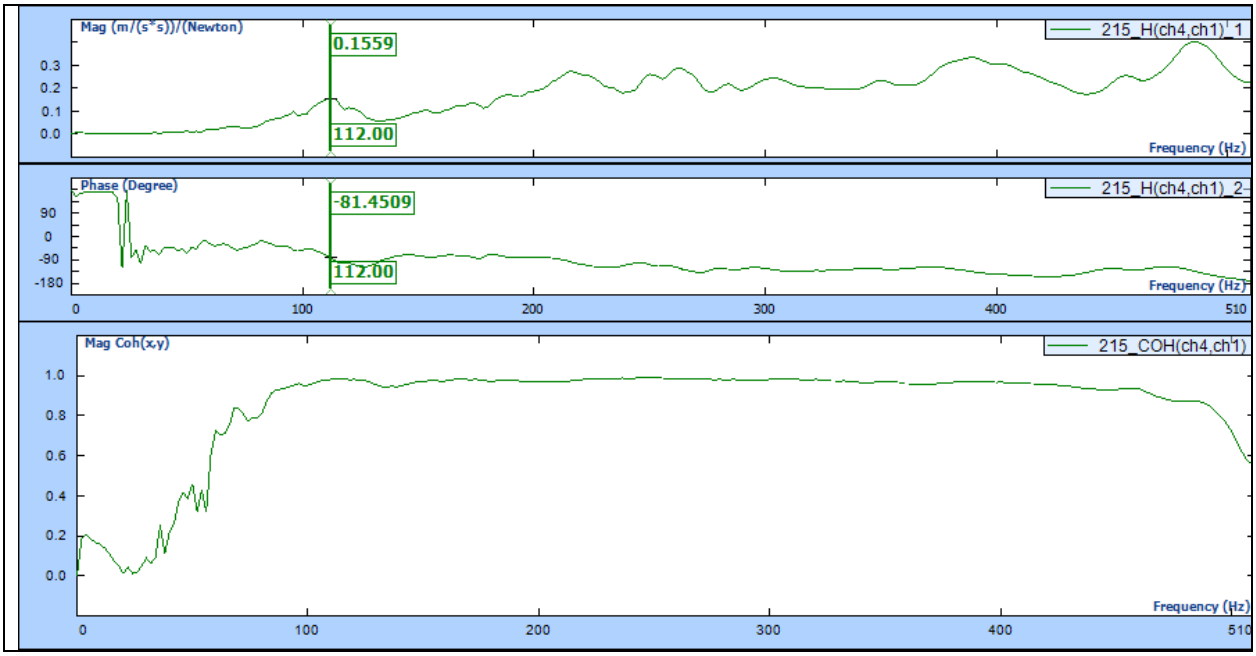
Photograph 196: ***Impact Test Data At 7 Slot Pole Jumper Top Tangential***



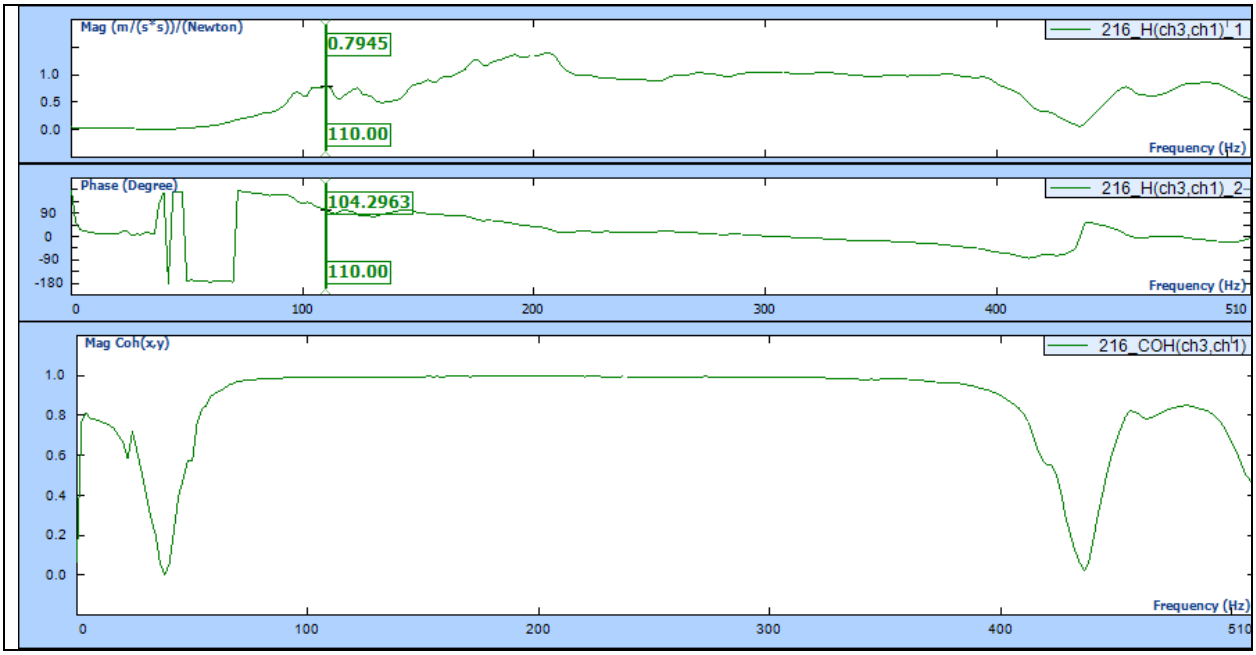
Photograph 197: ***Impact Test Data At 7 Slot Pole Jumper Bottom Radial***



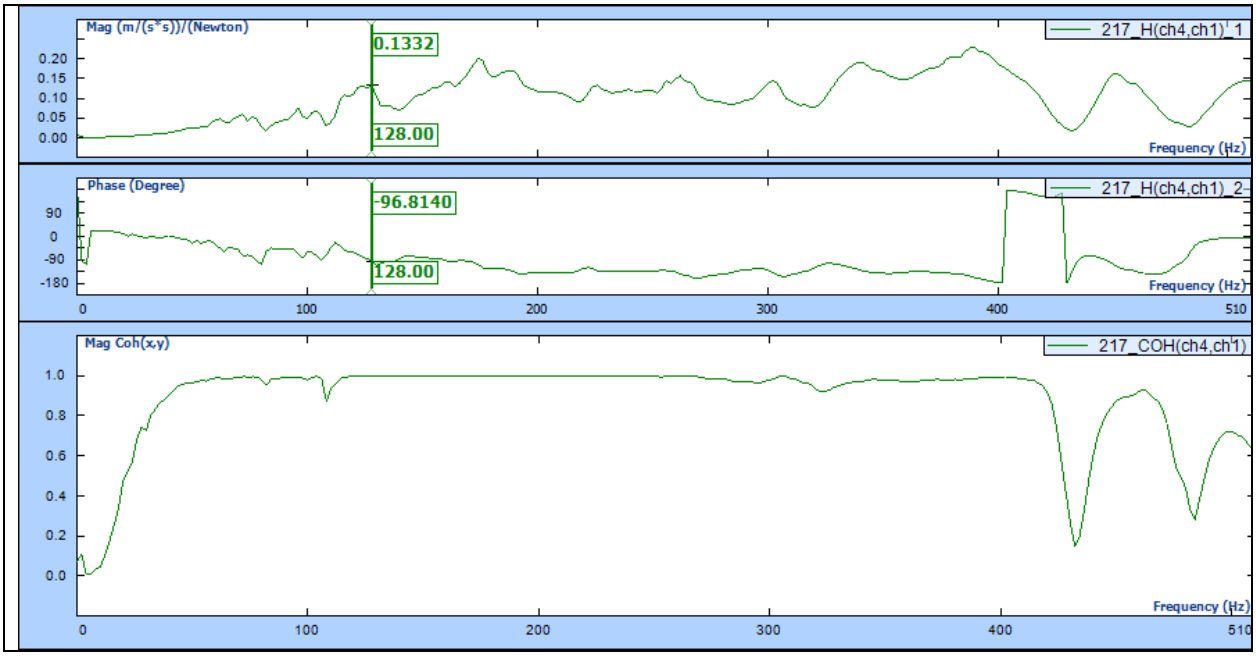
Photograph 198: ***Impact Test Data At 7 Slot Pole Jumper Bottom Tangential***



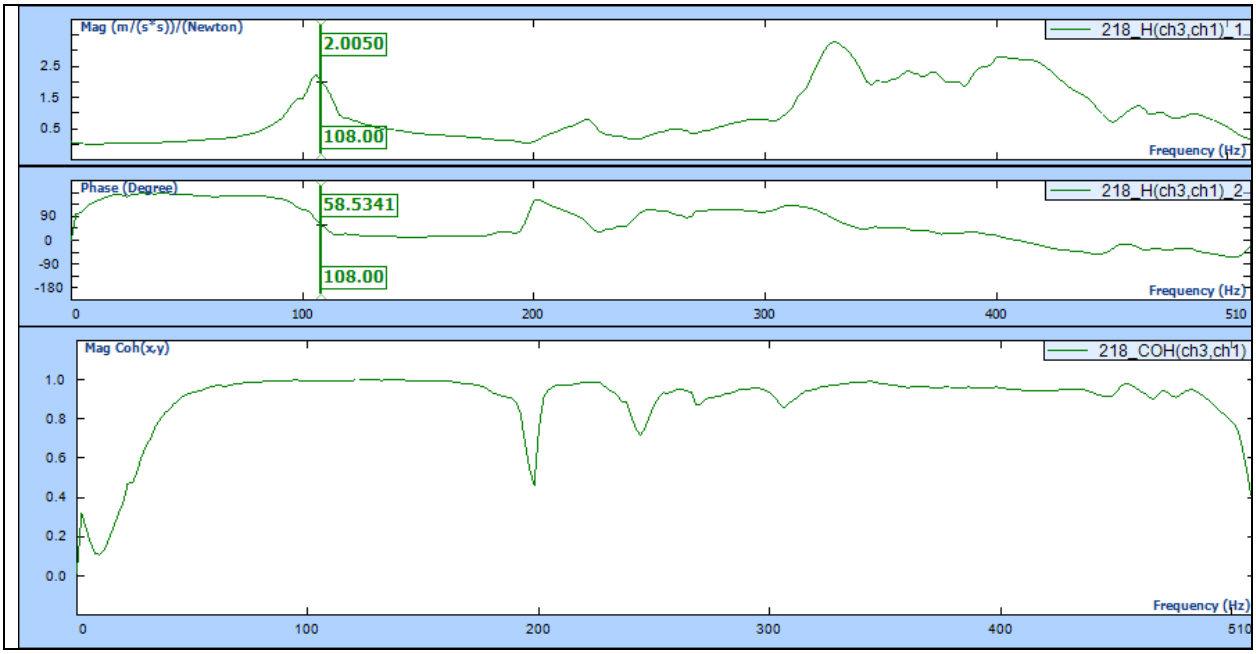
Photograph 199: ***Impact Test Data At 11 Slot Pole Jumper Top Radial***



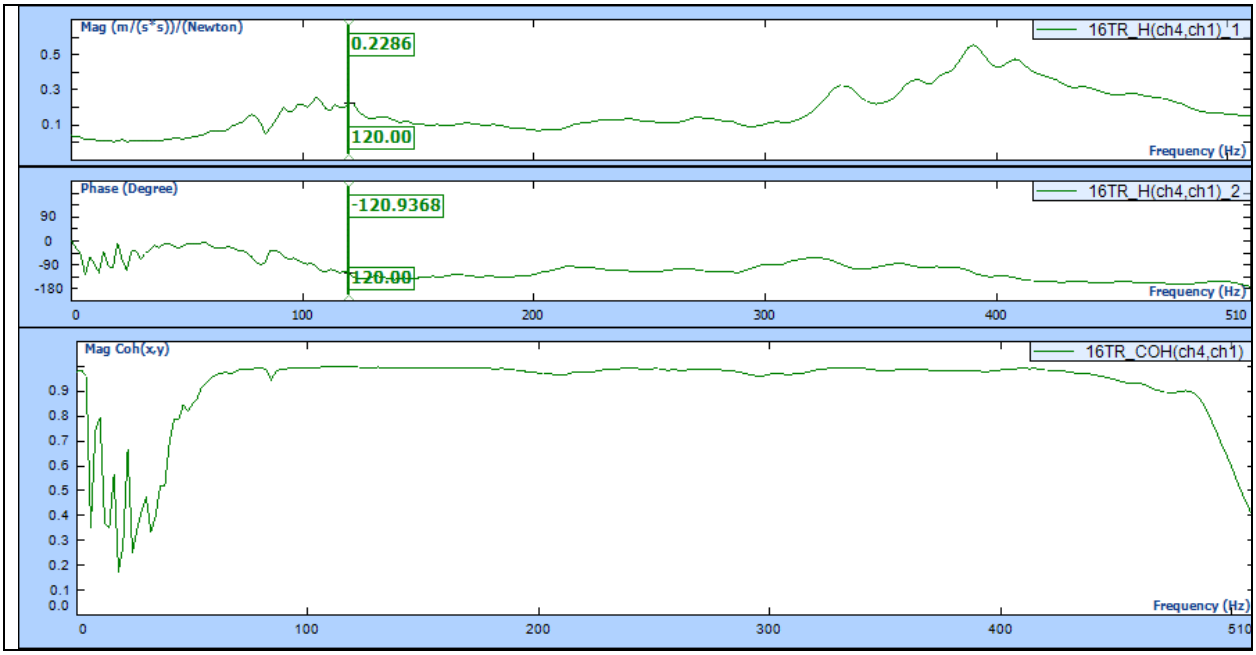
Photograph 200: ***Impact Test Data At 11 Slot Pole Jumper Top Tangential***



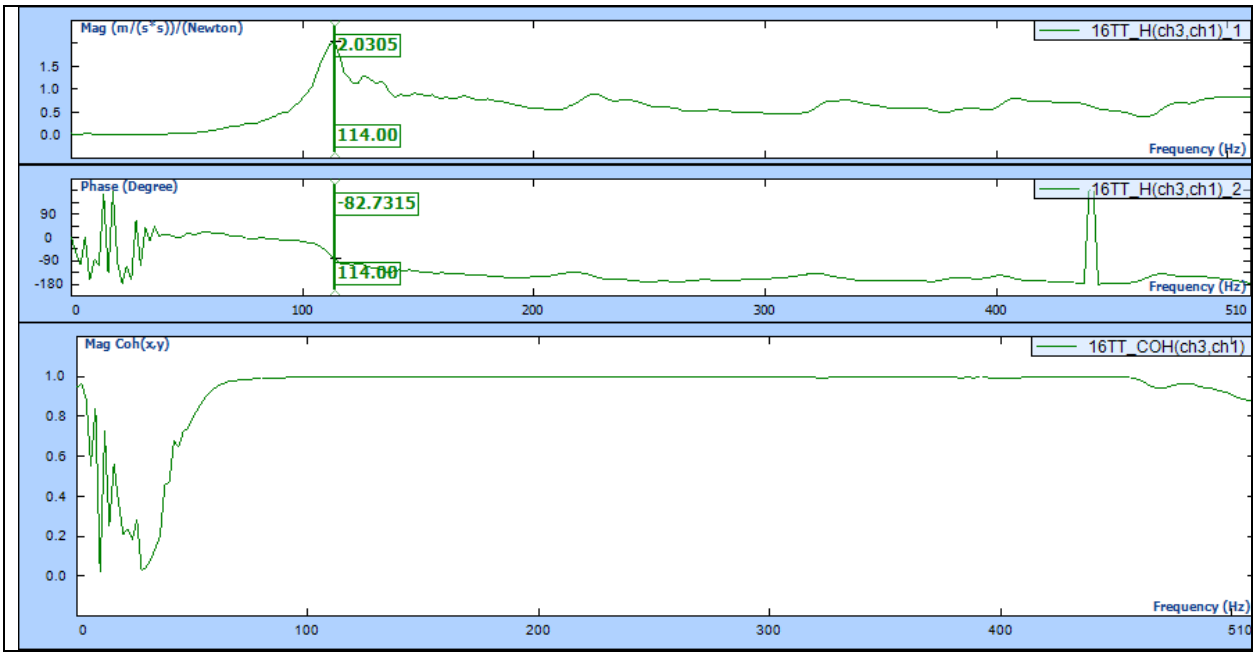
Photograph 201: ***Impact Test Data At 11 Slot Pole Jumper Bottom Radial***



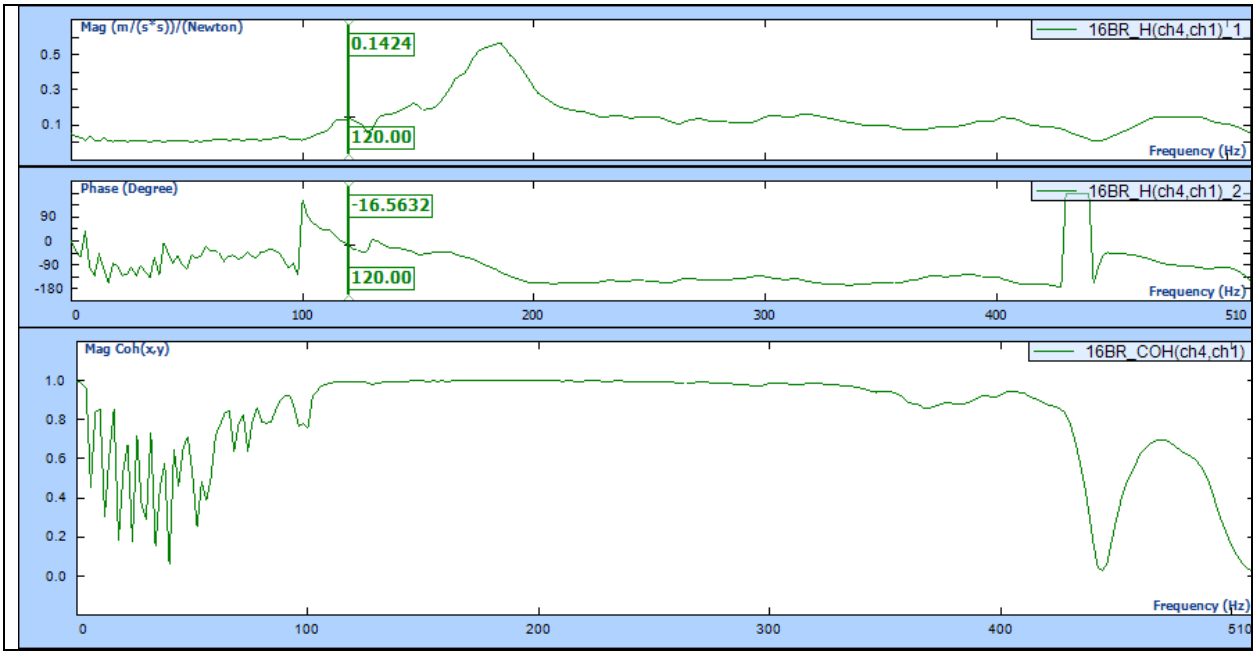
Photograph 202: ***Impact Test Data At 11 Slot Pole Jumper Bottom Tangential***



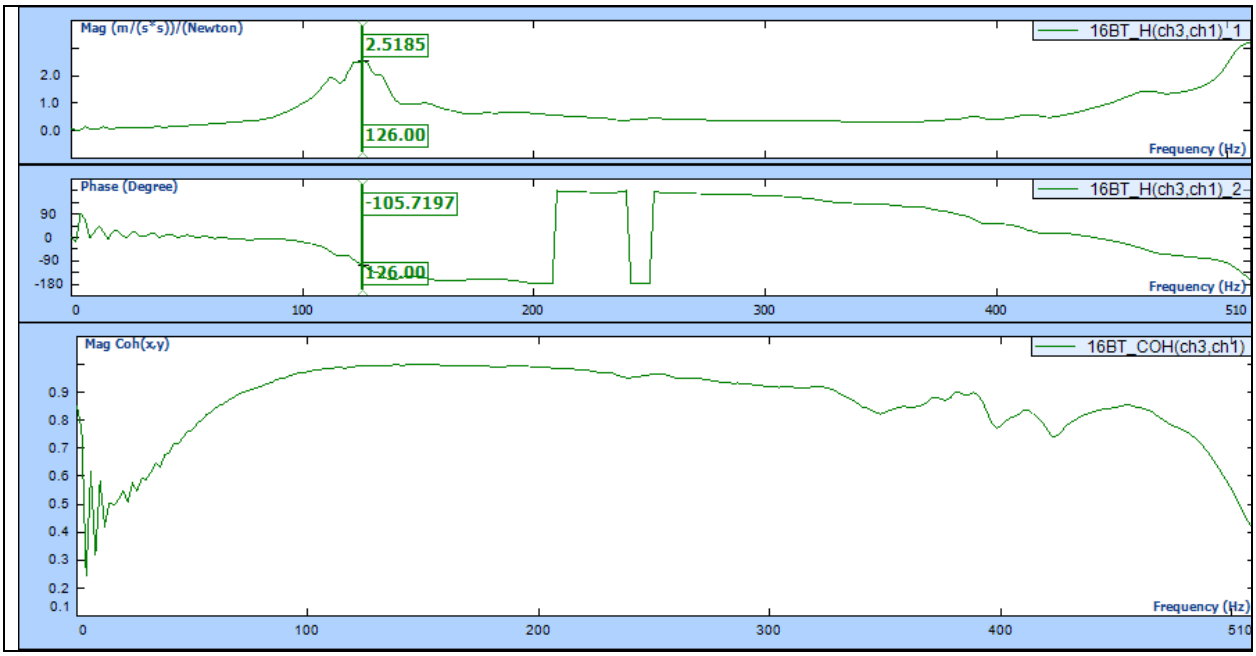
Photograph 203: ***Impact Test Data At 16 Slot Pole Jumper Top Radial***



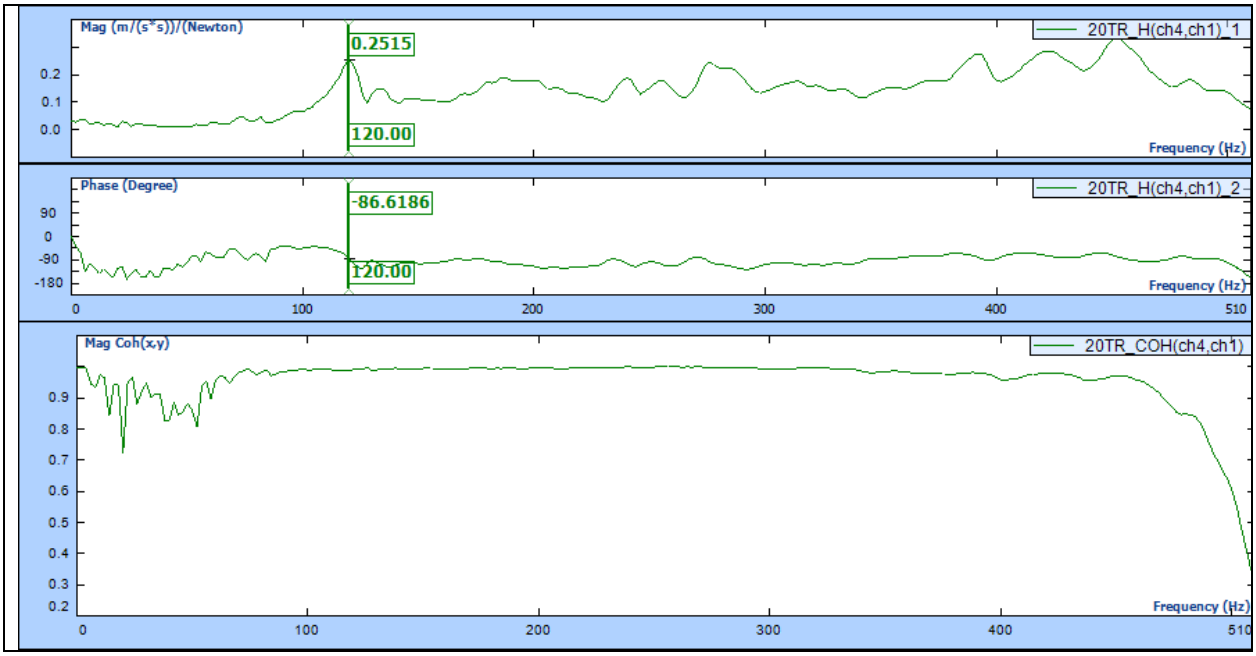
Photograph 204: ***Impact Test Data At 16 Slot Pole Jumper Top Tangential***



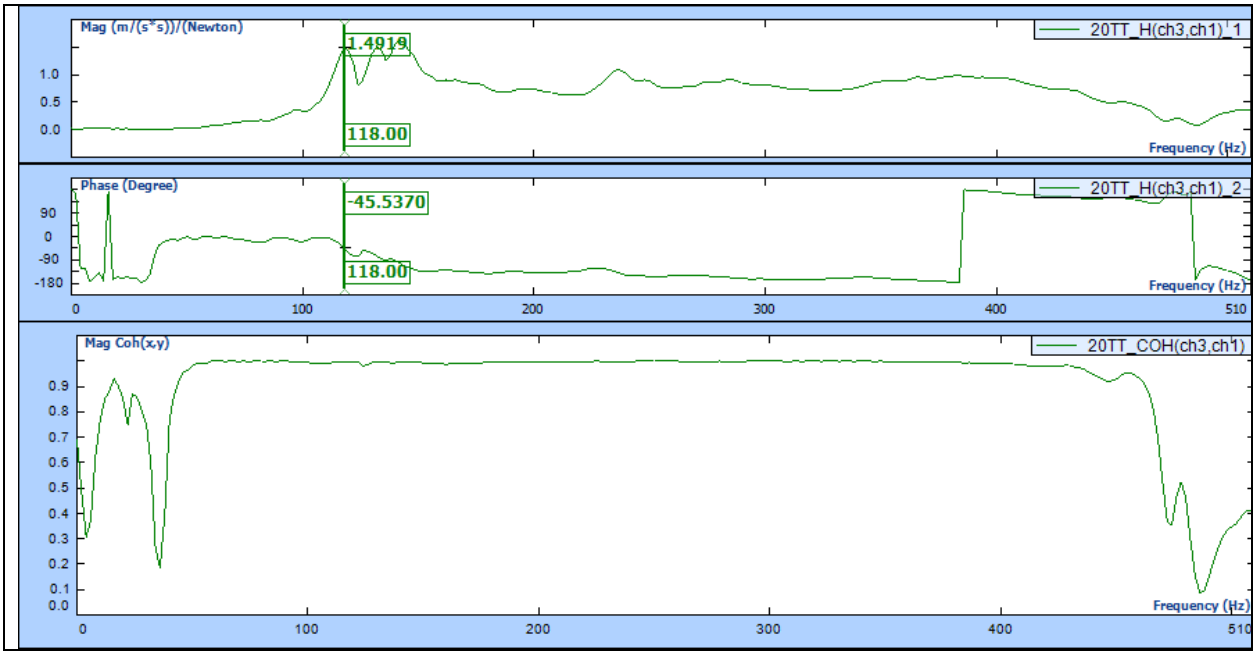
Photograph 205: ***Impact Test Data At 16 Slot Pole Jumper Bottom Radial***



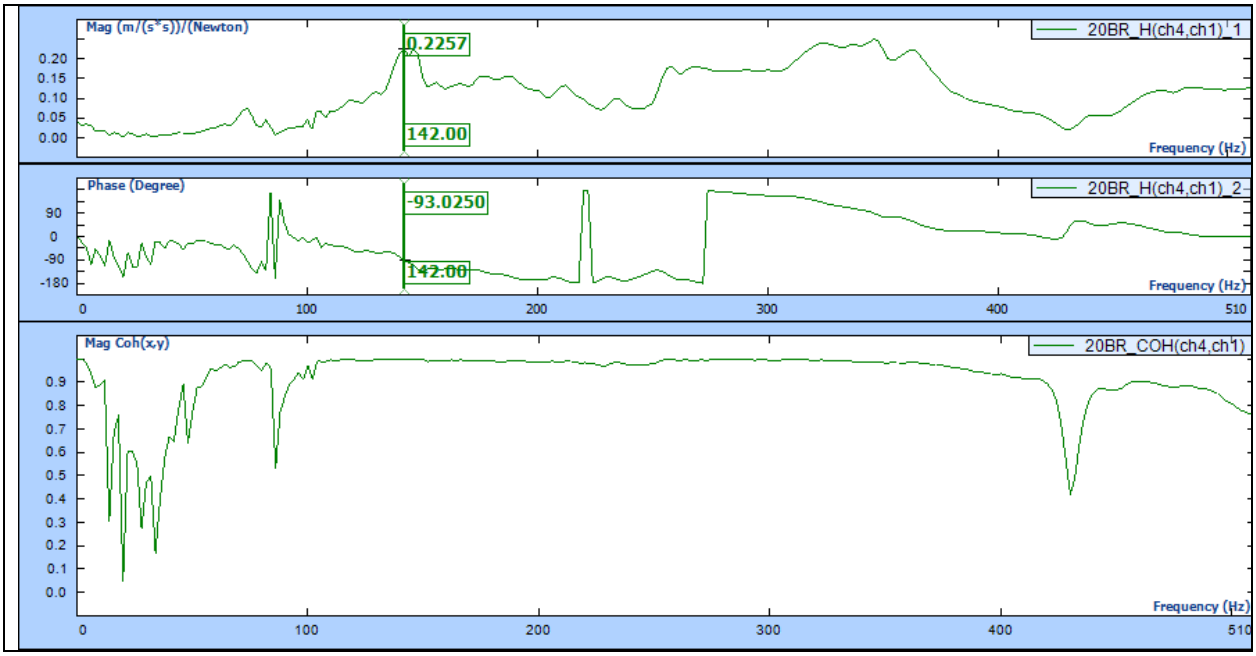
Photograph 206: ***Impact Test Data At 16 Slot Pole Jumper Bottom Tangential***



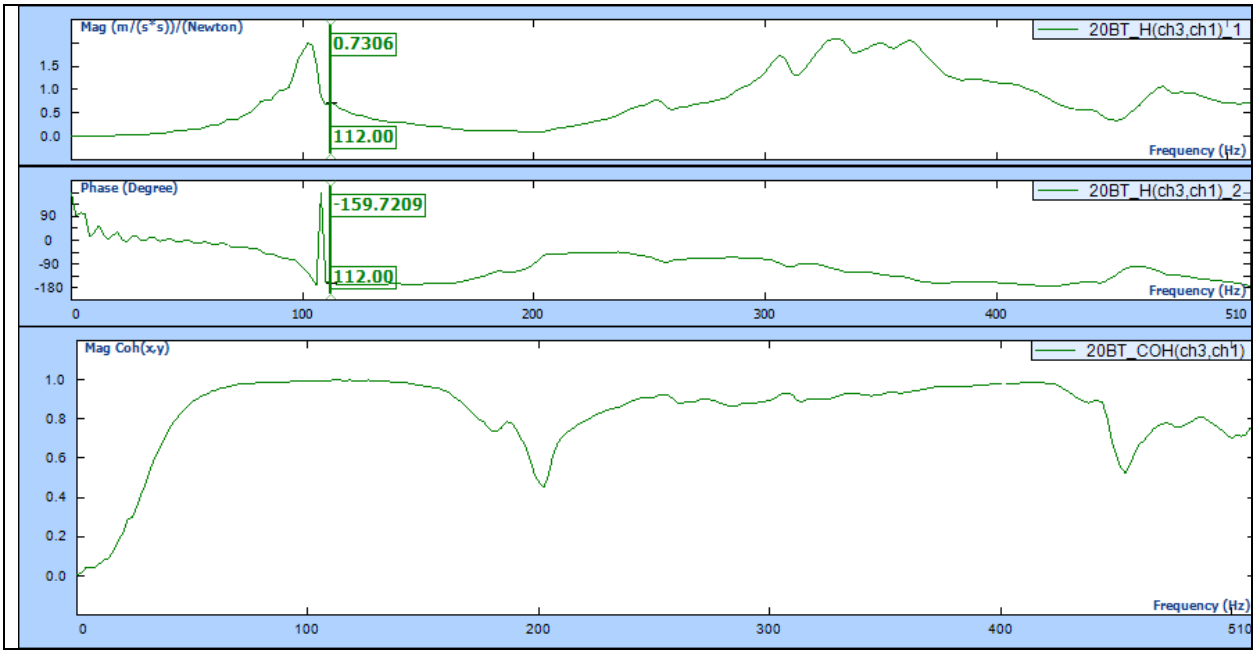
Photograph 207: ***Impact Test Data At 20 Slot Pole Jumper Top Radial***



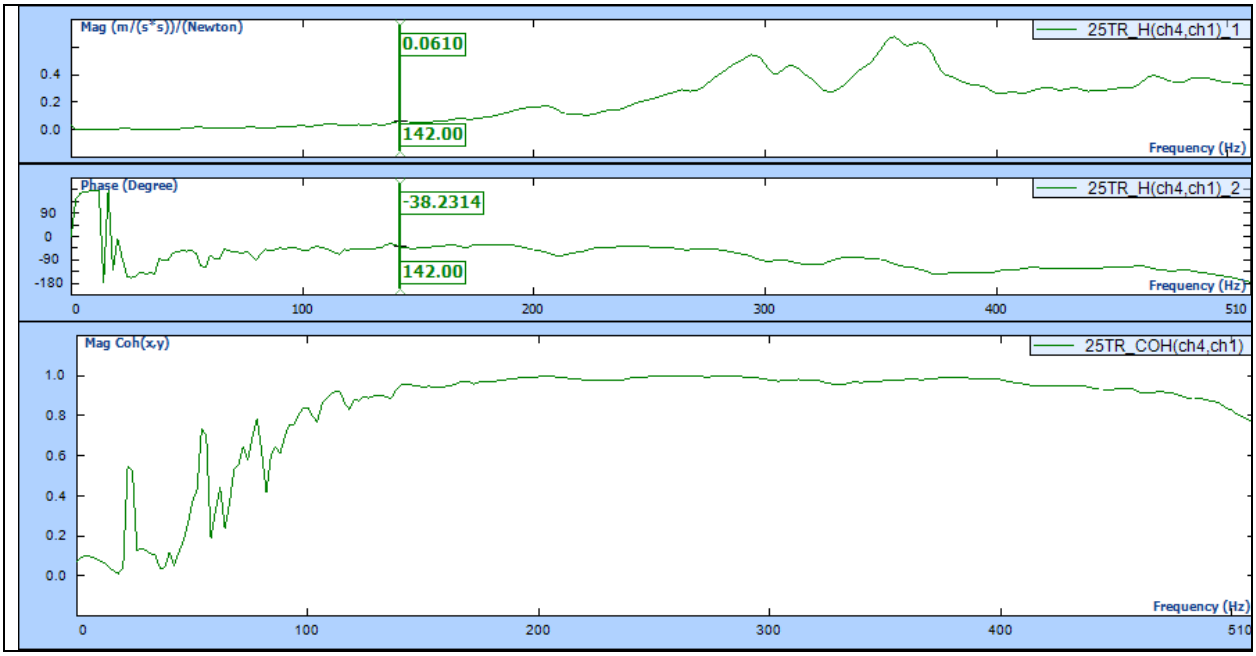
Photograph 208: ***Impact Test Data At 20 Slot Pole Jumper Top Tangential***



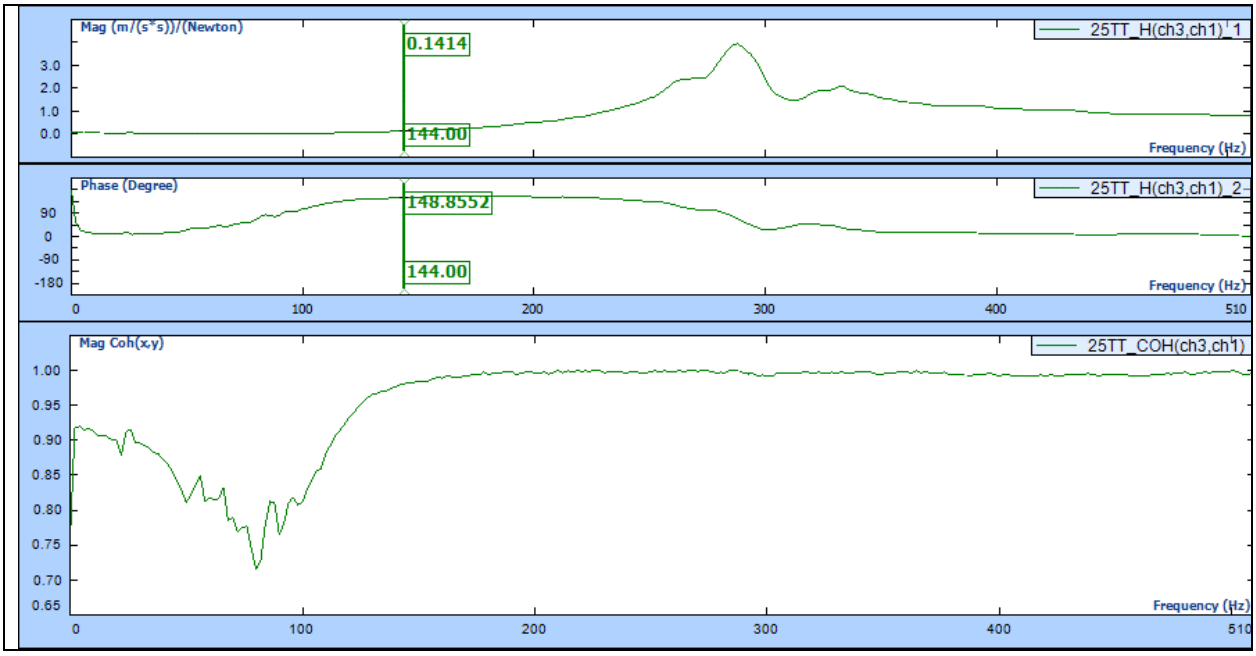
Photograph 209: ***Impact Test Data At 20 Slot Pole Jumper Bottom Radial***



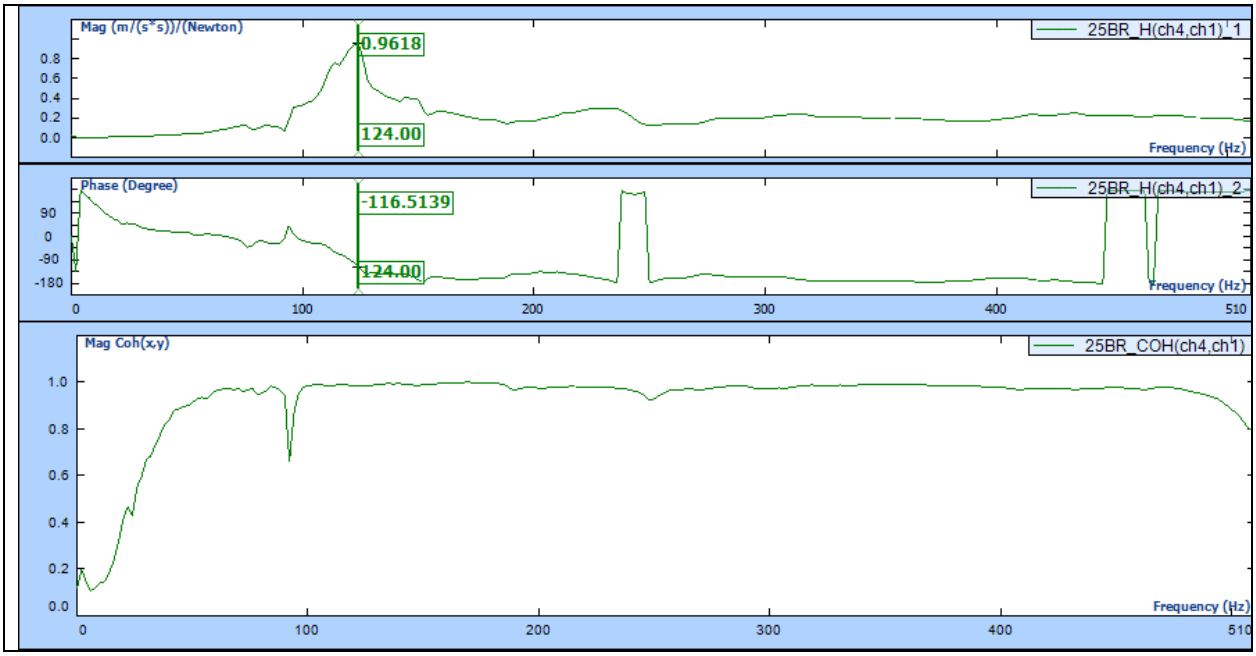
Photograph 210: ***Impact Test Data At 20 Slot Pole Jumper Bottom Tangential***



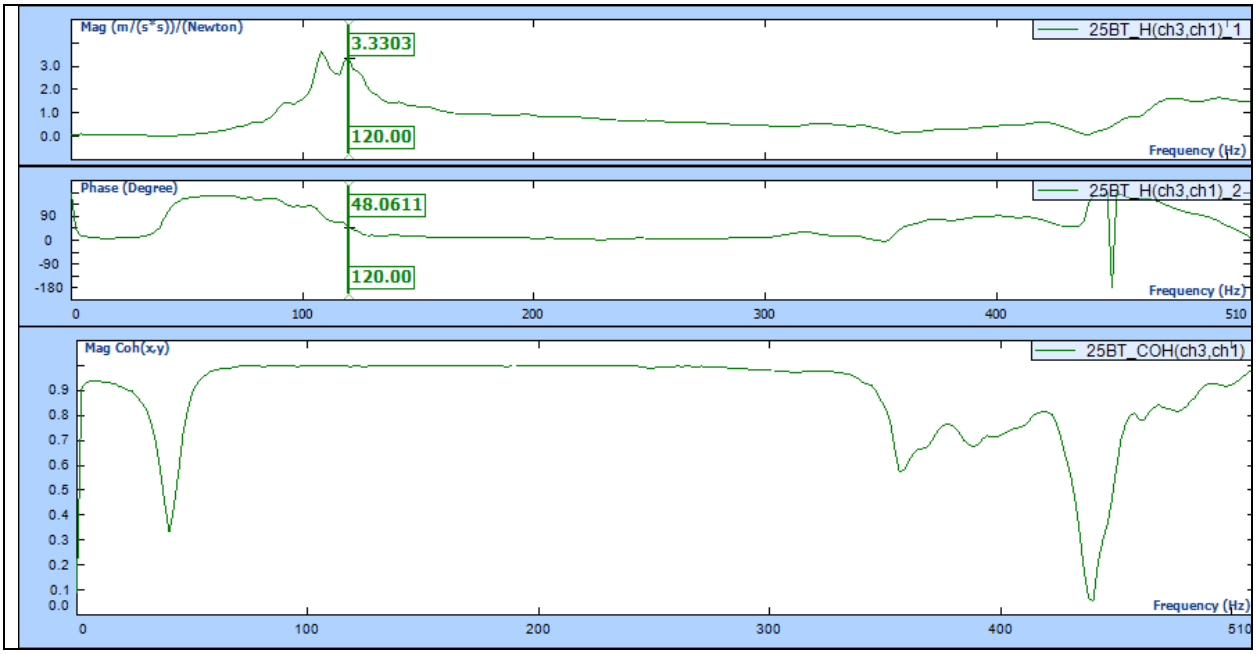
Photograph 211: ***Impact Test Data At 25 Slot Pole Jumper Top Radial***



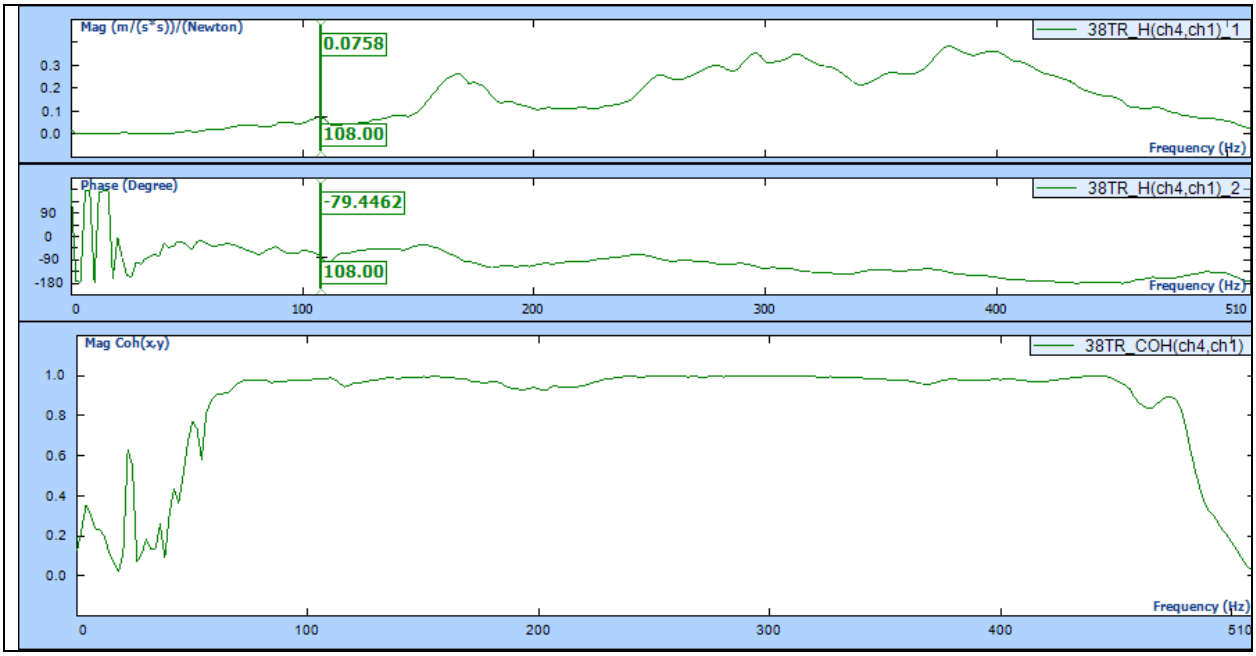
Photograph 212: ***Impact Test Data At 25 Slot Pole Jumper Top Tangential***



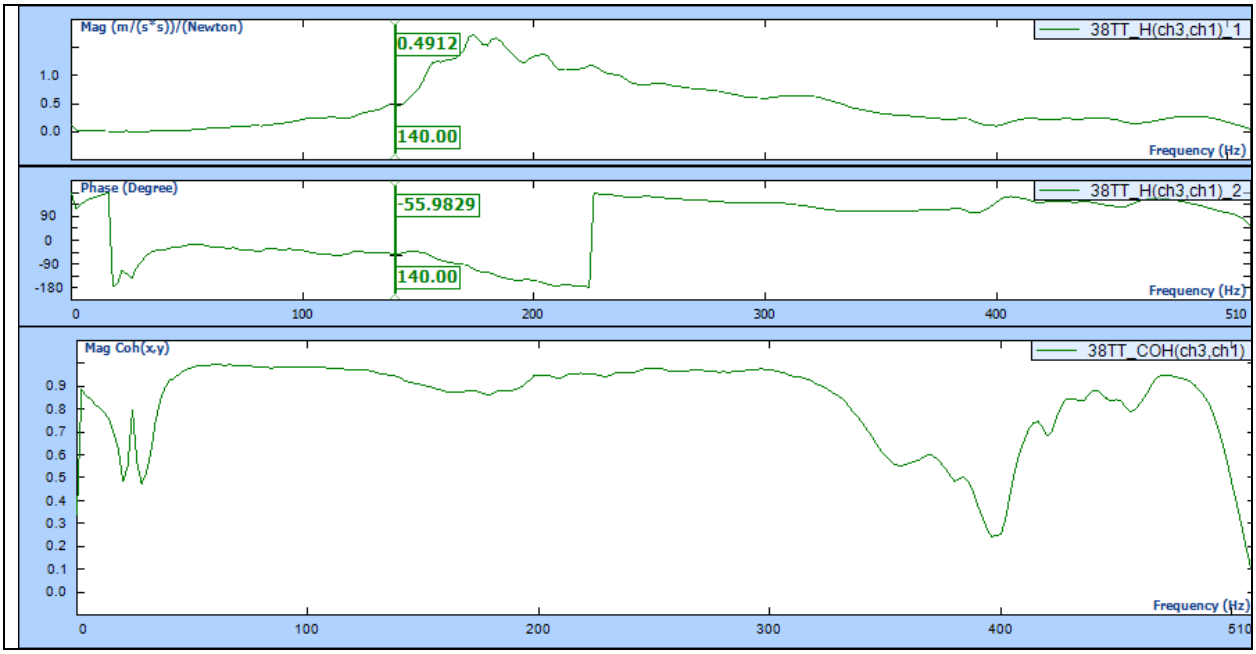
Photograph 213: ***Impact Test Data At 25 Slot Pole Jumper Bottom Radial***



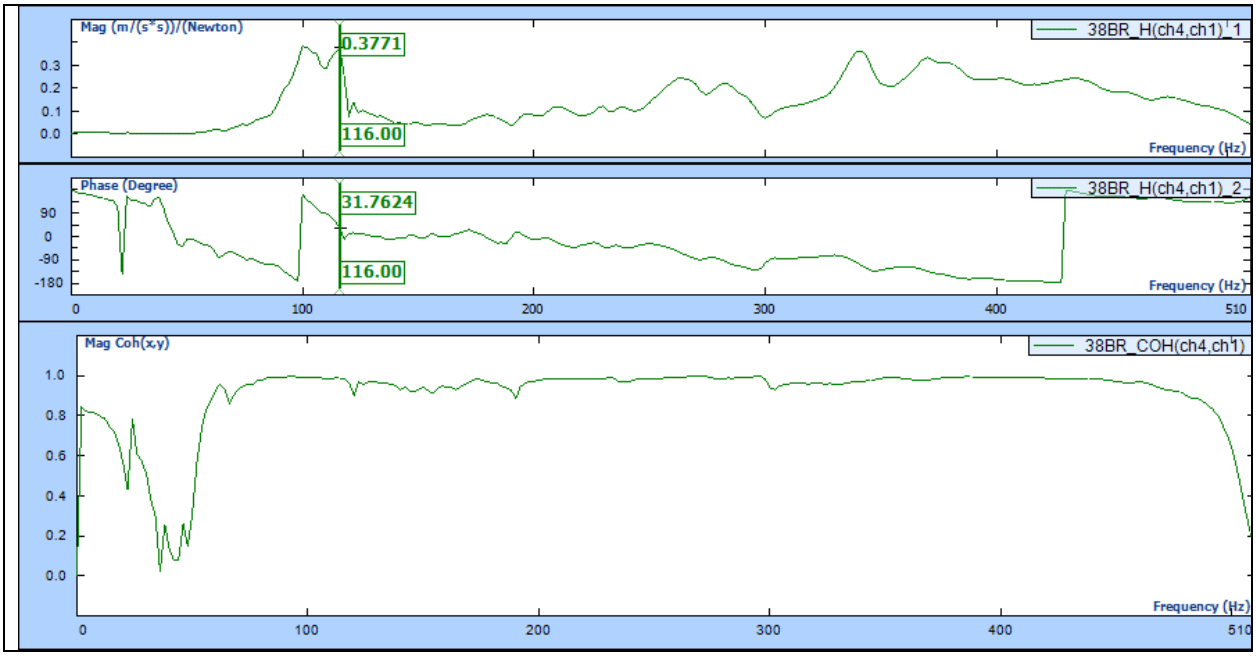
Photograph 214: ***Impact Test Data At 25 Slot Pole Jumper Bottom Tangential***



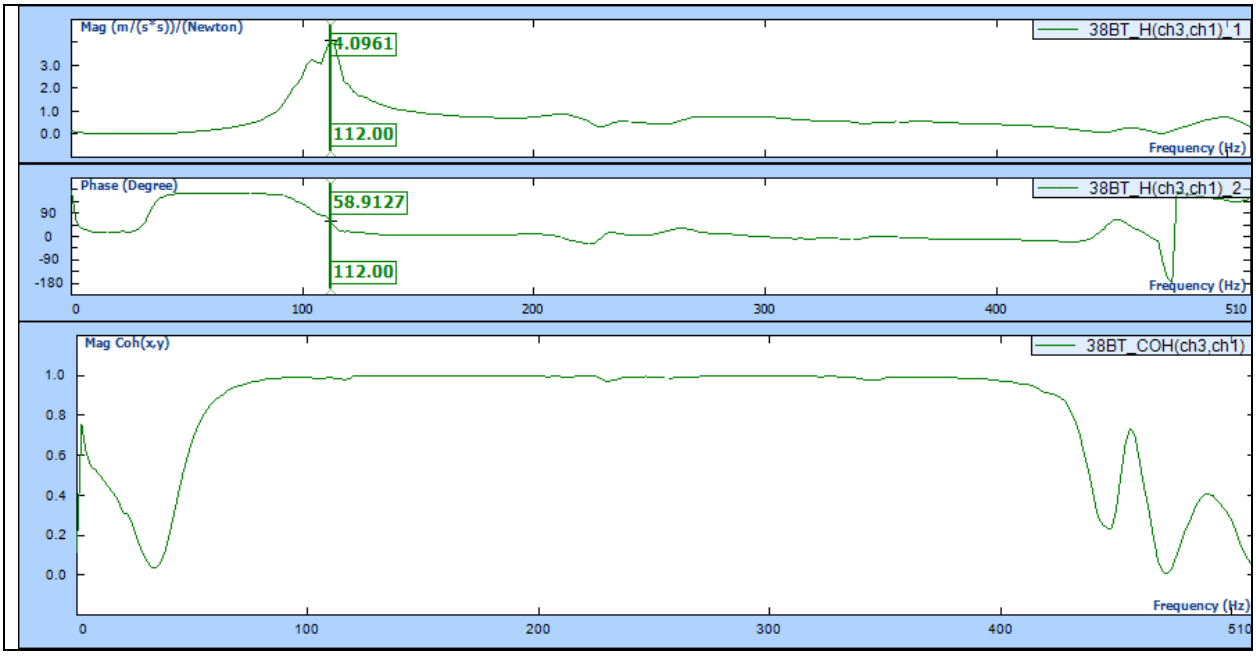
Photograph 215: ***Impact Test Data At 38 Slot Pole Jumper Top Radial***



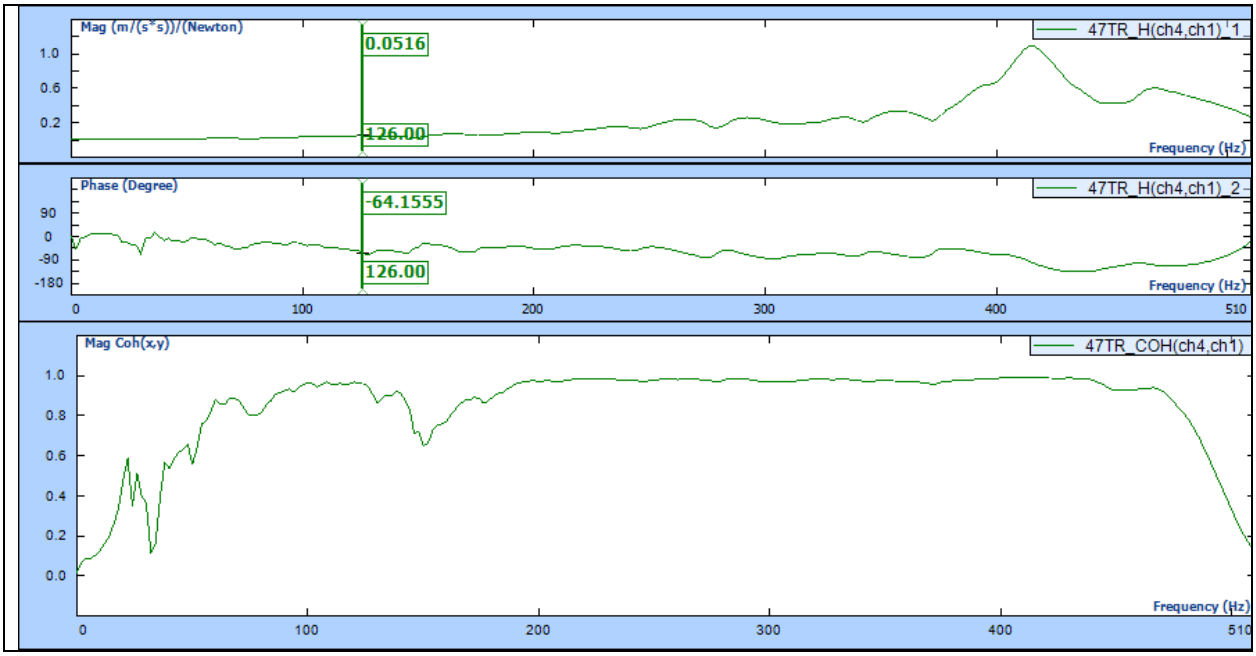
Photograph 216: ***Impact Test Data At 38 Slot Pole Jumper Top Tangential***



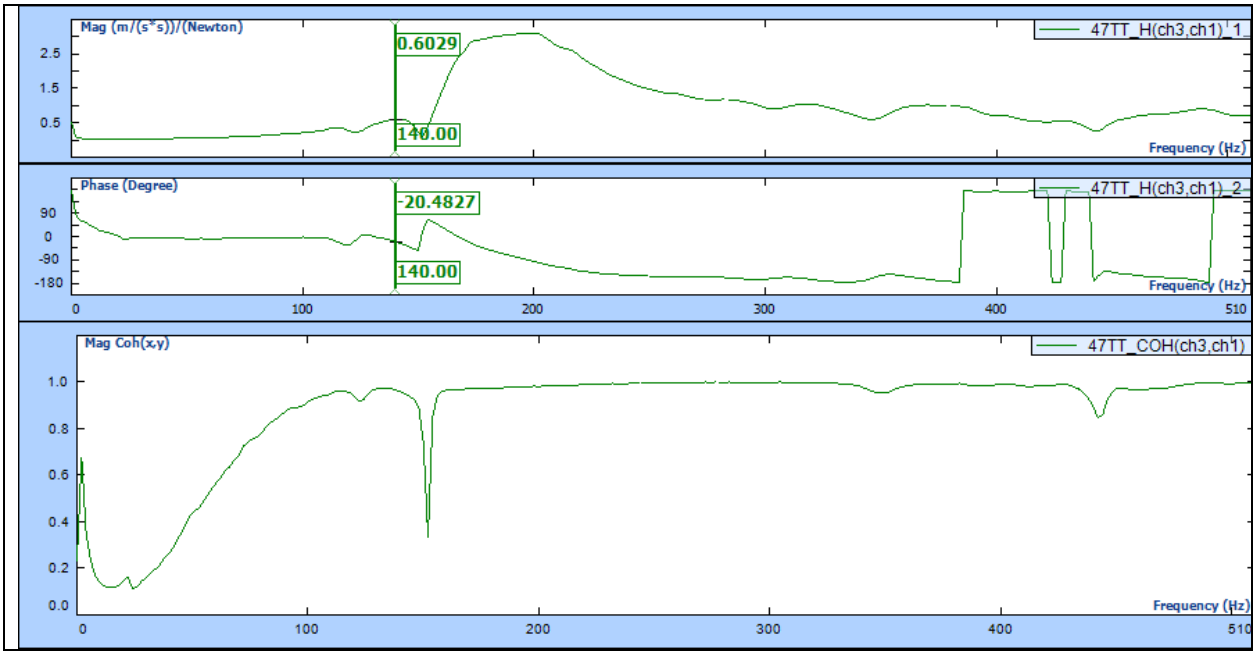
Photograph 217: ***Impact Test Data At 38 Slot Pole Jumper Bottom Radial***



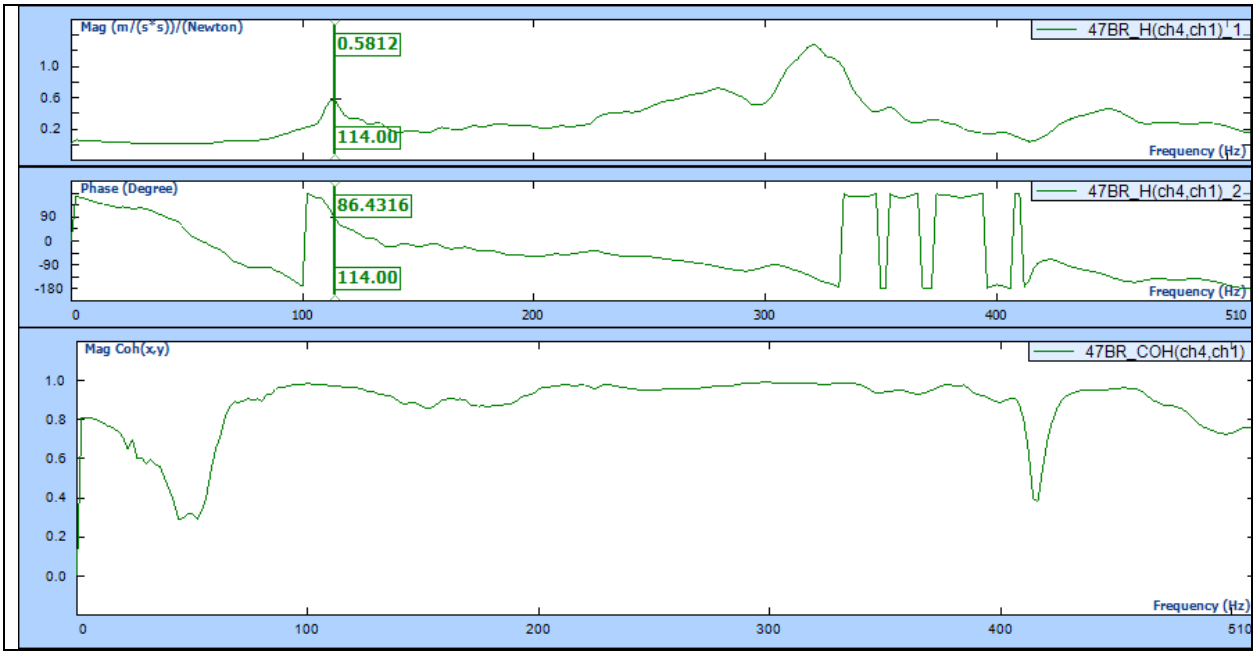
Photograph 218: ***Impact Test Data At 38 Slot Pole Jumper Bottom Tangential***



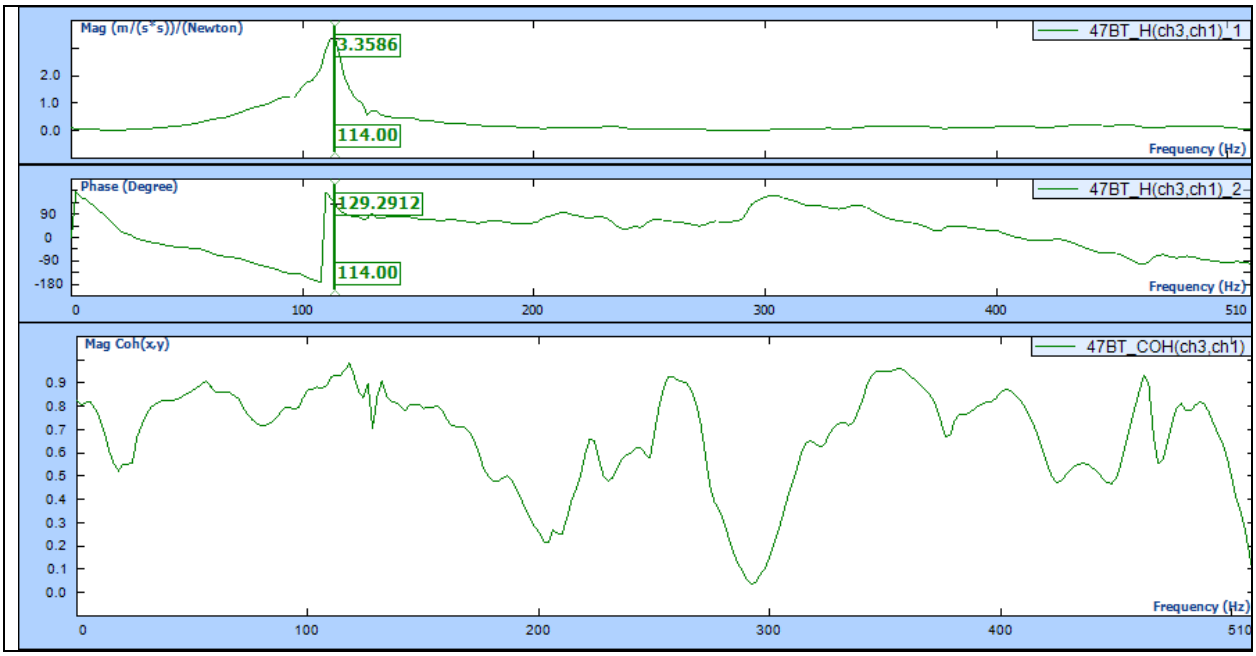
Photograph 219: ***Impact Test Data At 47 Slot Pole Jumper Top Radial***



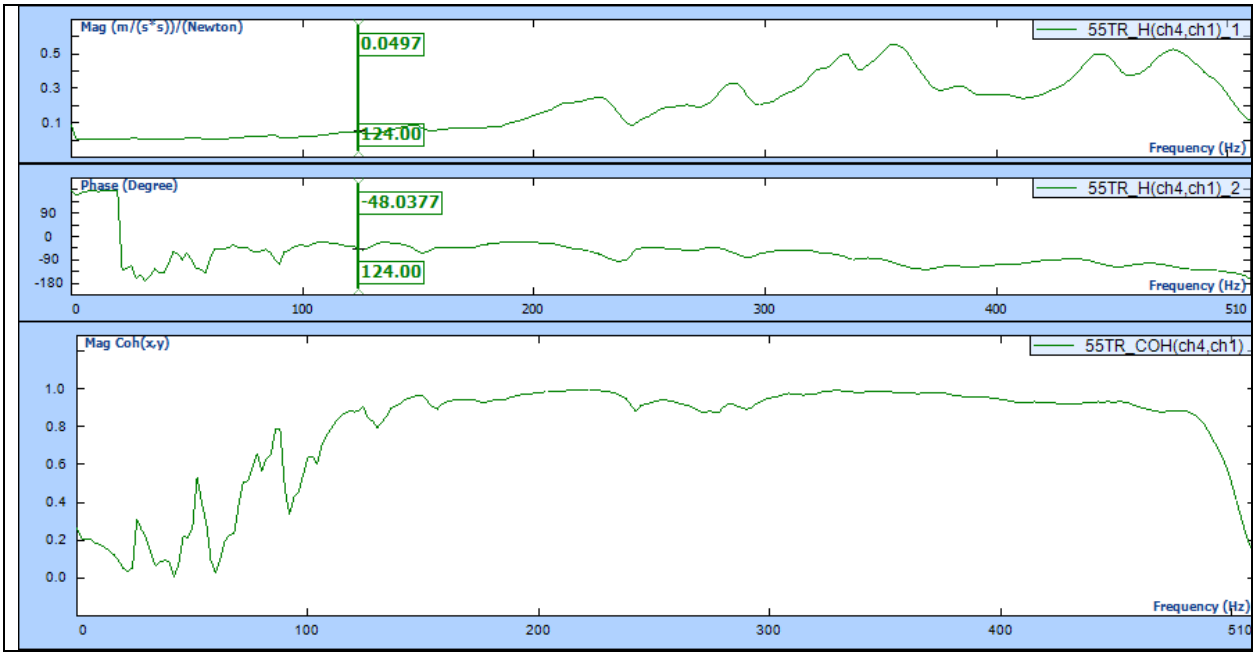
Photograph 220: ***Impact Test Data At 47 Slot Pole Jumper Top Tangential***



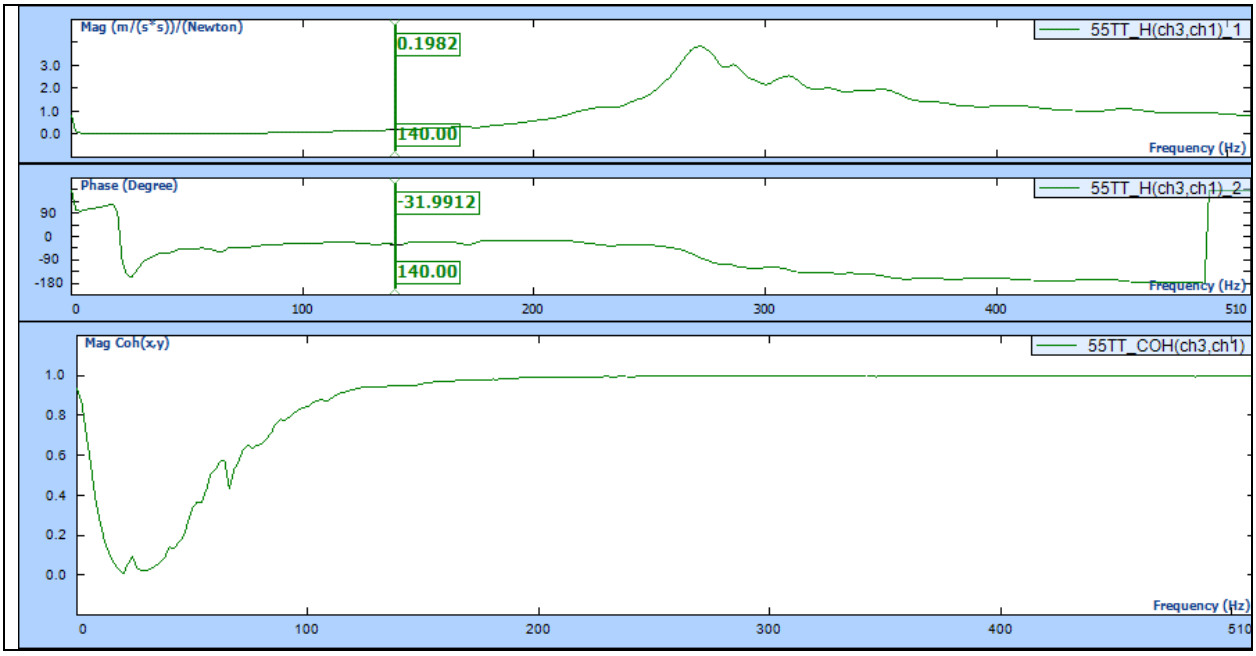
Photograph 221: ***Impact Test Data At 47 Slot Pole Jumper Bottom Radial***



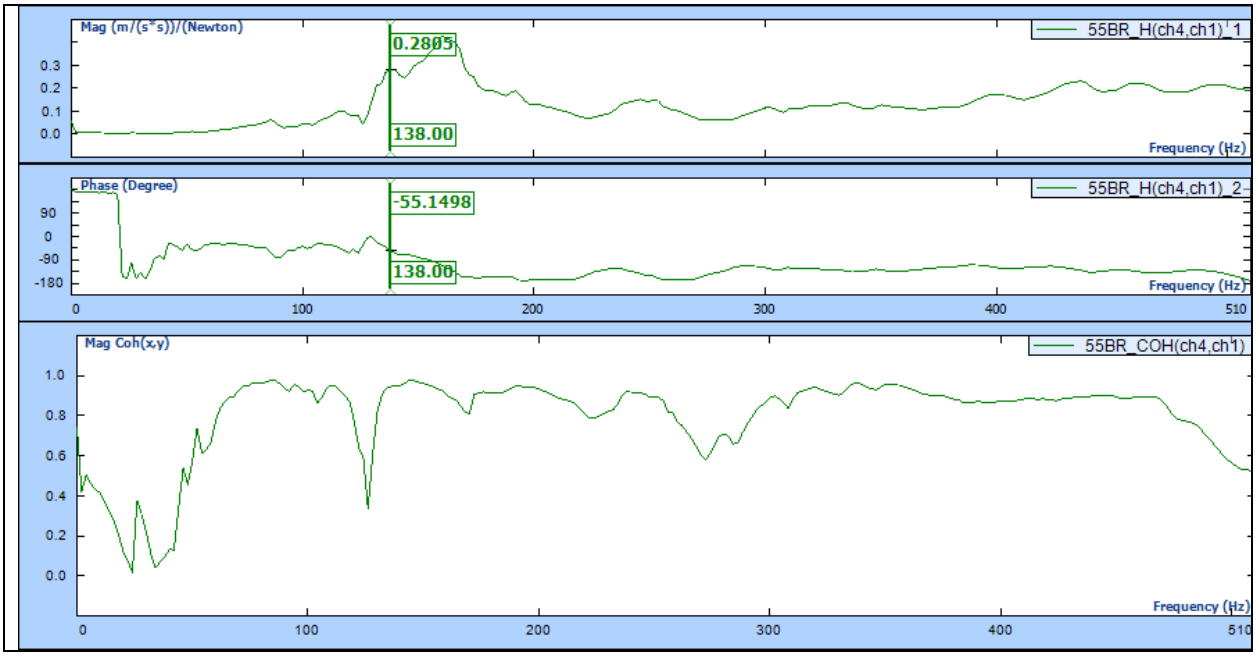
Photograph 222: ***Impact Test Data At 47 Slot Pole Jumper Bottom Tangential***



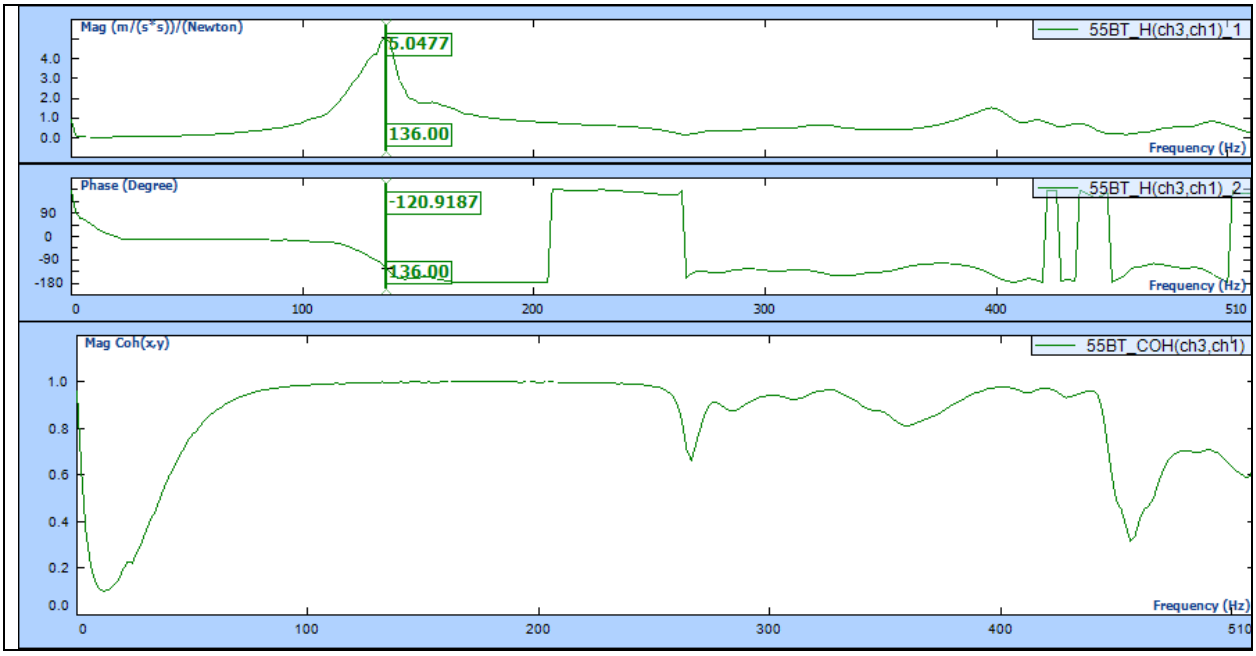
Photograph 223: ***Impact Test Data At 55 Slot Pole Jumper Top Radial***



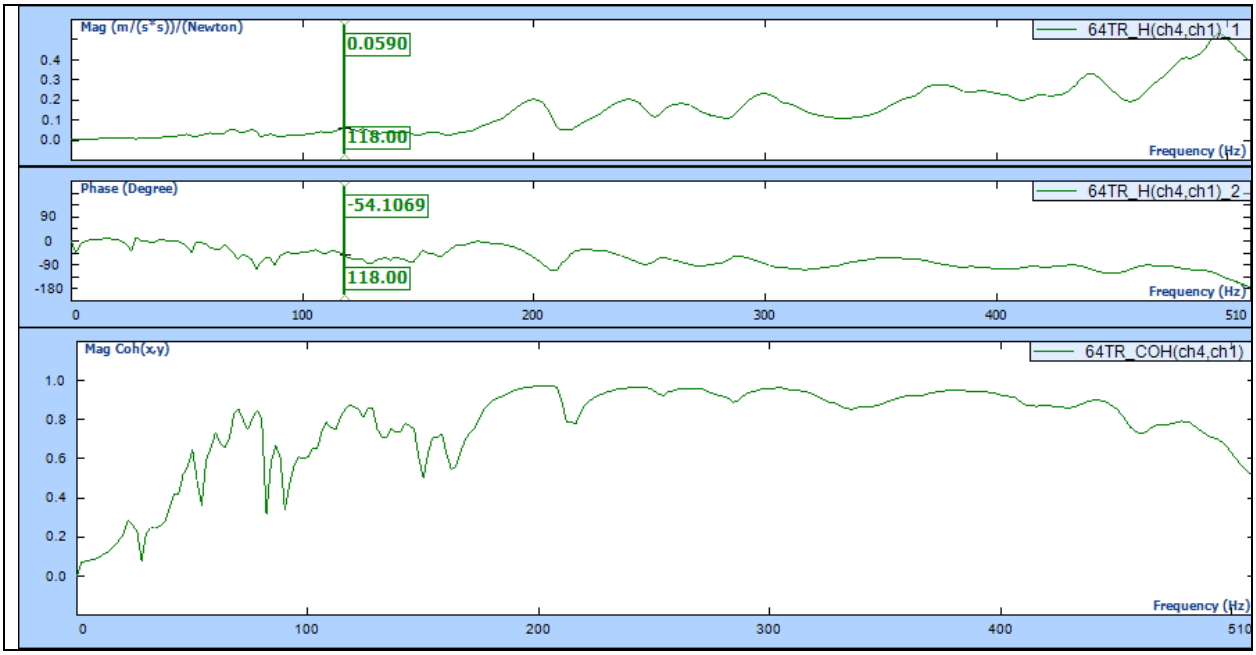
Photograph 224: ***Impact Test Data At 55 Slot Pole Jumper Top Tangential***



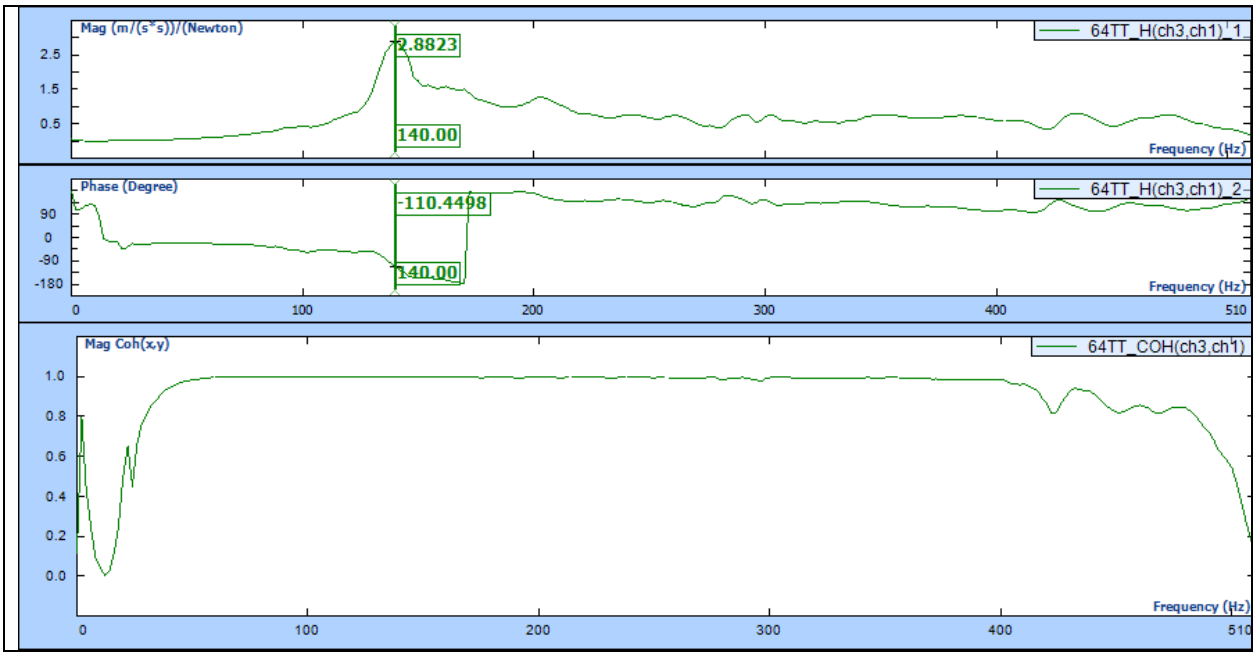
Photograph 225: ***Impact Test Data At 55 Slot Pole Jumper Bottom Radial***



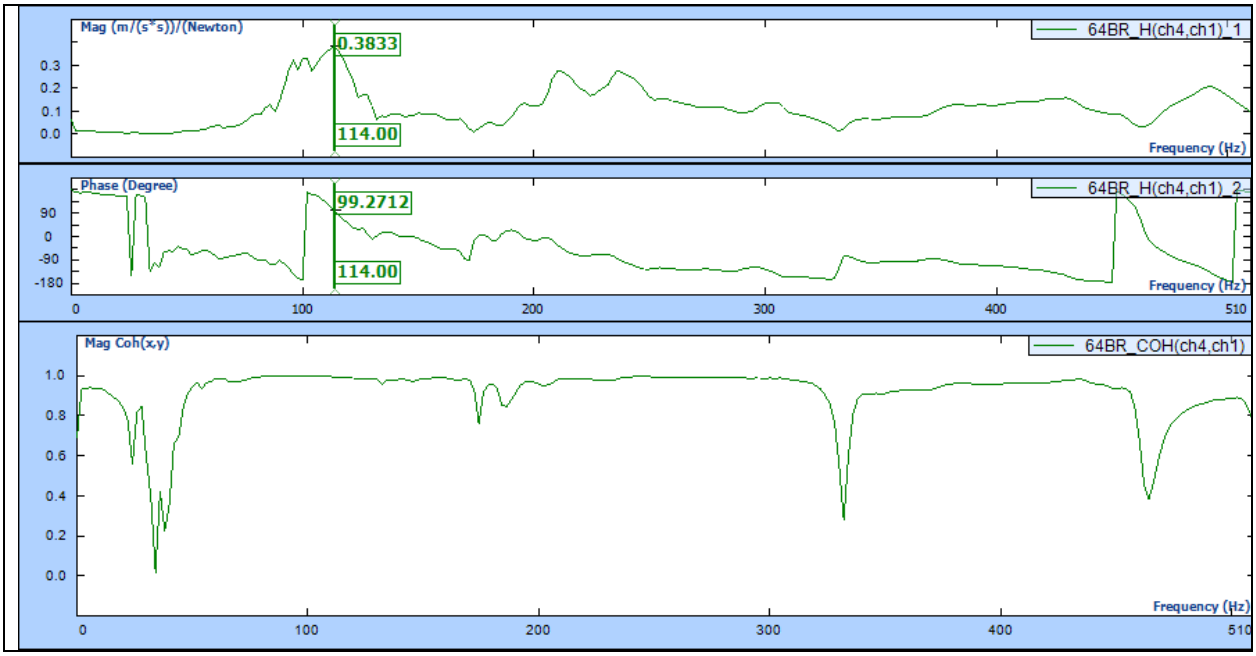
Photograph 226: ***Impact Test Data At 55 Slot Pole Jumper Bottom Tangential***



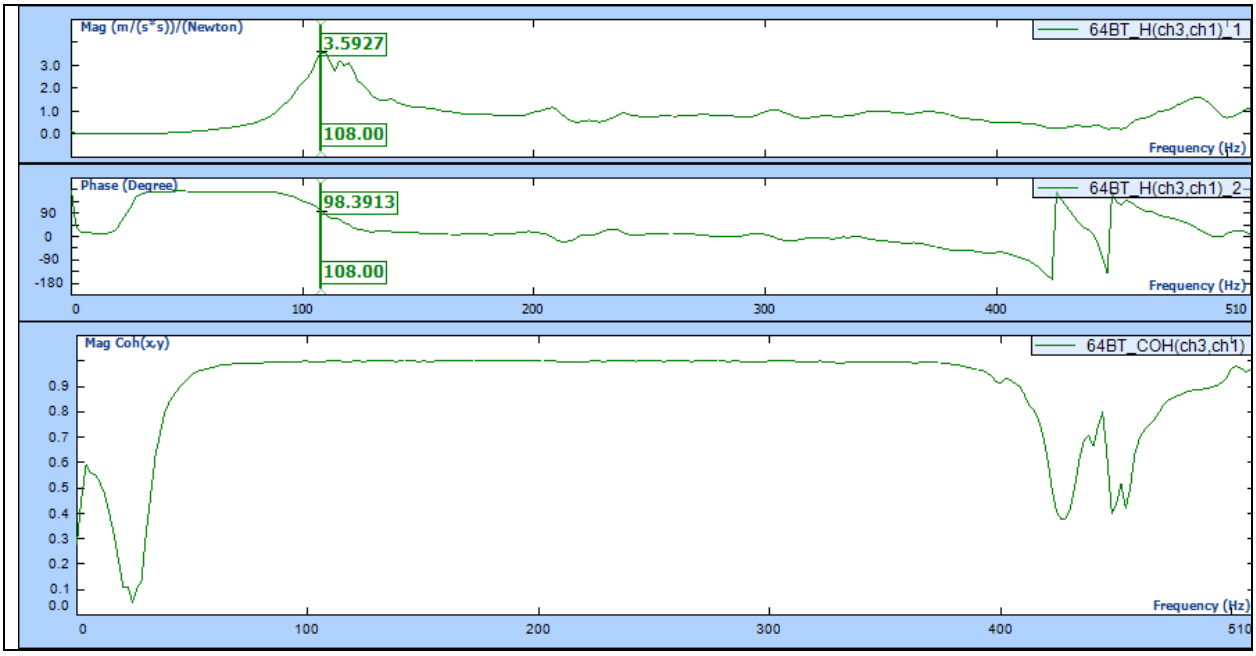
Photograph 227: ***Impact Test Data At 64 Slot Pole Jumper Top Radial***



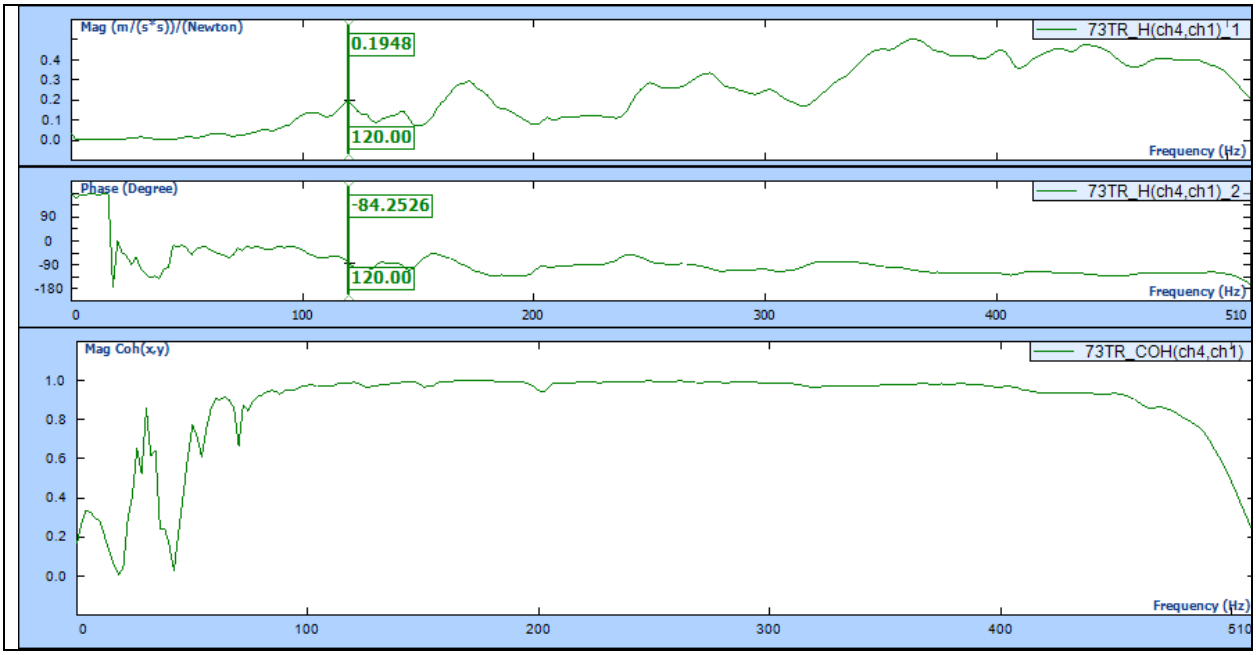
Photograph 228: ***Impact Test Data At 64 Slot Pole Jumper Top Tangential***



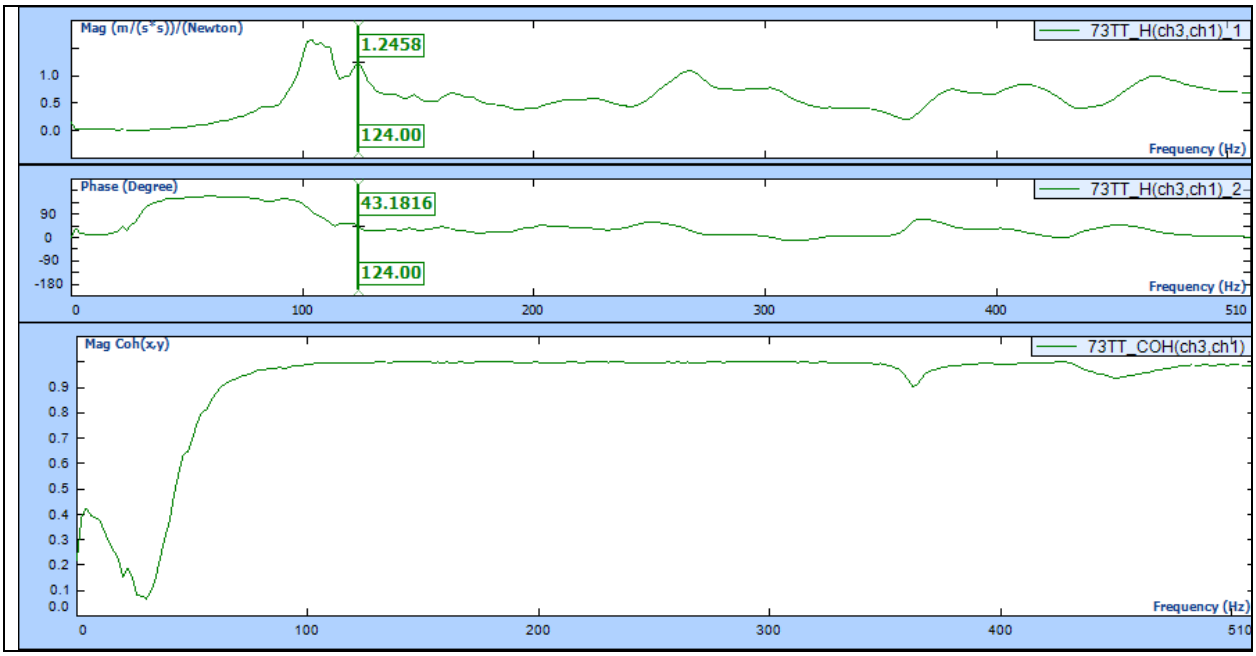
Photograph 229: ***Impact Test Data At 64 Slot Pole Jumper Bottom Radial***



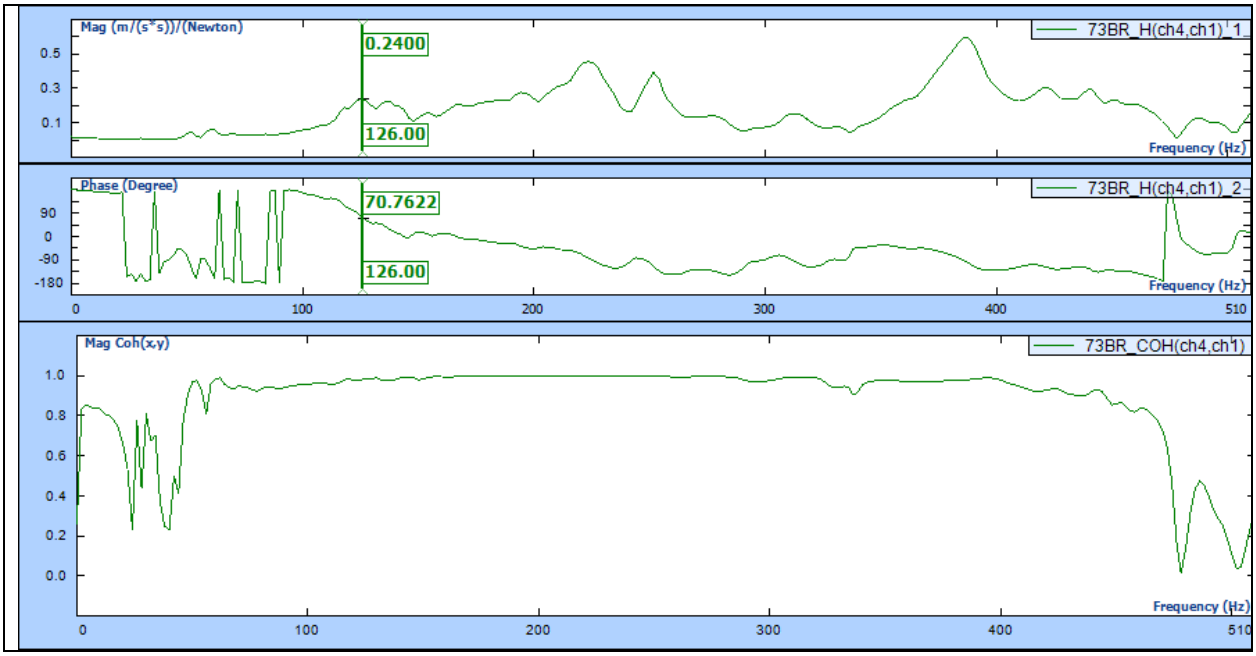
Photograph 230: ***Impact Test Data At 64 Slot Pole Jumper Bottom Tangential***



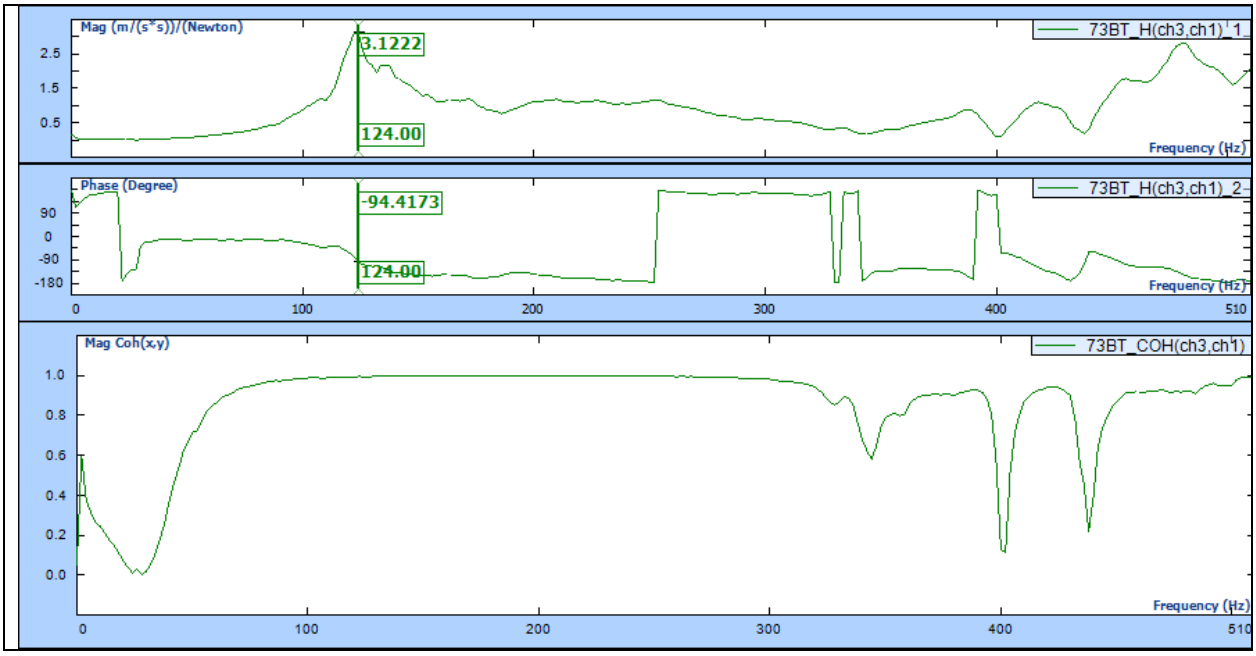
Photograph 231: ***Impact Test Data At 73 Slot Pole Jumper Top Radial***



Photograph 232: ***Impact Test Data At 73 Slot Pole Jumper Top Tangential***



Photograph 233: ***Impact Test Data At 73 Slot Pole Jumper Bottom Radial***



Photograph 234: ***Impact Test Data At 73 Slot Pole Jumper Bottom Tangential***

Attachment 2

Partial Discharge Test Report





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IRIS POWER
A QUALITROL Company

February 12, 2024
Newfoundland & Labrador Hydro

Partial Discharge Test Report

Hinds Lake GS
Unit 1

Attached please find a copy of our Partial Discharge Test Report for the tests carried out on February 01, 2024, for the subject assets at the Hinds Lake GS plant.

The current Partial Discharge test on the subject generator suggests the following condition of the stator winding, partial discharge sources and recommendations:

Asset	PD Levels	PD Source(s)	Recommendations
Unit 1	*High in A-C1, Moderate for B-C1 & C-C1*	Internal voids and slot exit activity	Retest in 6 months

At Iris, we are committed to providing you with superior products and service. We value all input. If you require further information or have any questions, please do not hesitate to contact us.

Sincerely,

Amith Menon

Amith Menon
Manager, Field Service

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Interpretation of Partial Discharge Test Results

PDA Differential

Client:	**NEWFOUNDLAND & LABRADOR HYDRO**
Company:	**NEWFOUNDLAND & LABRADOR HYDRO**
Site:	**Hinds Lake GS**
Asset:	**Unit 1**
Test Date:	**February 01, 2024**

Client Reference	**Credit Card**
IRIS Reference	**50510267**
Issue	**1**
Revision	**0**
Date	**February 07, 2024**
Issuing office	**Toronto, Canada**

Prepared by: **Signature**

Uthpala Siriwardena (Siri) **Date** February 07, 2024

Reviewed by: **Signature**

Howard Sedding **Date** February 10, 2023

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Disclaimer: It is impossible to predict time to failure.

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1 INTRODUCTION

IRIS Power LP was requested by **NEWFOUNDLAND & LABRADOR HYDRO – Hinds Lake GS** to carry out condition assessment of the **Unit 1** stator winding.

This assessment consisted of On-line Partial Discharge measurements. Further information regarding Partial Discharge Interpretation can be found in the attached appendix. These tests were carried out under IRIS Power LP task reference: **50510267.**

2 WINDING COMPARISON

2.1 Statistical Comparison

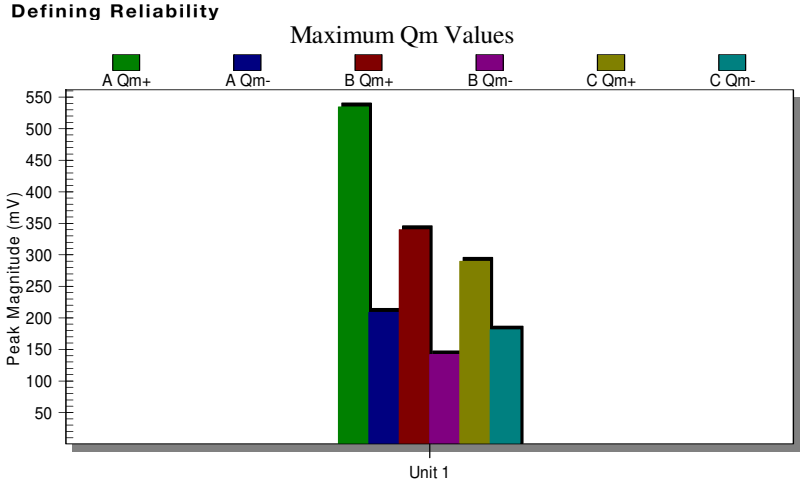
The table below provides a quick summary of relative winding insulation discharge activity when compared to other windings of this voltage class [ref. A-4.2].

Rank	Phase	Concern
Very High		**Moderate concern, should retest in 6 months if stable or in 2-3 months if rising or baseline test. If an upward trend exists, further investigation is recommended.**
High	**Phase A**	
Moderate	**Phase B** **Phase C**	No concern unless an upward trend is present. Retest in 6 months.
Typical		No concern unless an upward trend is present. Retest in 6-12 months.
Low		No concern, retest on regular schedule of 6-12 months.
Negligible		

Disclaimer: The above comparison to the statistical database assumes that the PD couplers are in the optimum location and the standard test method is utilized. If surge capacitors are present at the terminals, a sensitivity check may be needed to ensure that the surge capacitors do not affect the stator winding PD signals. Refer to A-4.2 of the attached Appendix for information regarding impedance mismatches, test method, zone of coverage, and other limitations with statistical ranking.

2.2 Phase Comparison

The plot displays the Q_m+ and Q_m- values for each phase [ref. A-4.3.1].


Maximum Qm Values
A Qm+
A Qm-
B Qm+
B Qm-
C Qm+
C Qm-
Peak Magnitude (mV)
550
500
450
400
350
300
250
200
150
100
50
Unit 1

3 UNIT: Unit 1

3.1 Asset Design

Rated Voltage	*13.8 kV*	Machine Type	*Hydro Generator*
Rated Power	*70.0 MW*	Insulation	
Rated Frequency	*60 Hz*	PD Sensors	*Cable Capacitor (80pF)*
Rated Speed	*360 RPM*	Test Sequence	*5*
Manufacturer	*HITATCHI*	Test Type	*PDA Differential*
Date Manufactured/serial #	*1980 / N/A*	Winding Manufacturer	
Application		Rewind Year	*N/A*
		Data collected by:	*End User*

3.2 Partial Discharge Trends

While the PDView™ plots provide a visual indication of the Partial Discharge patterns in each phase, the summary numbers provide a means to trend and compare results from similar voltage class windings.

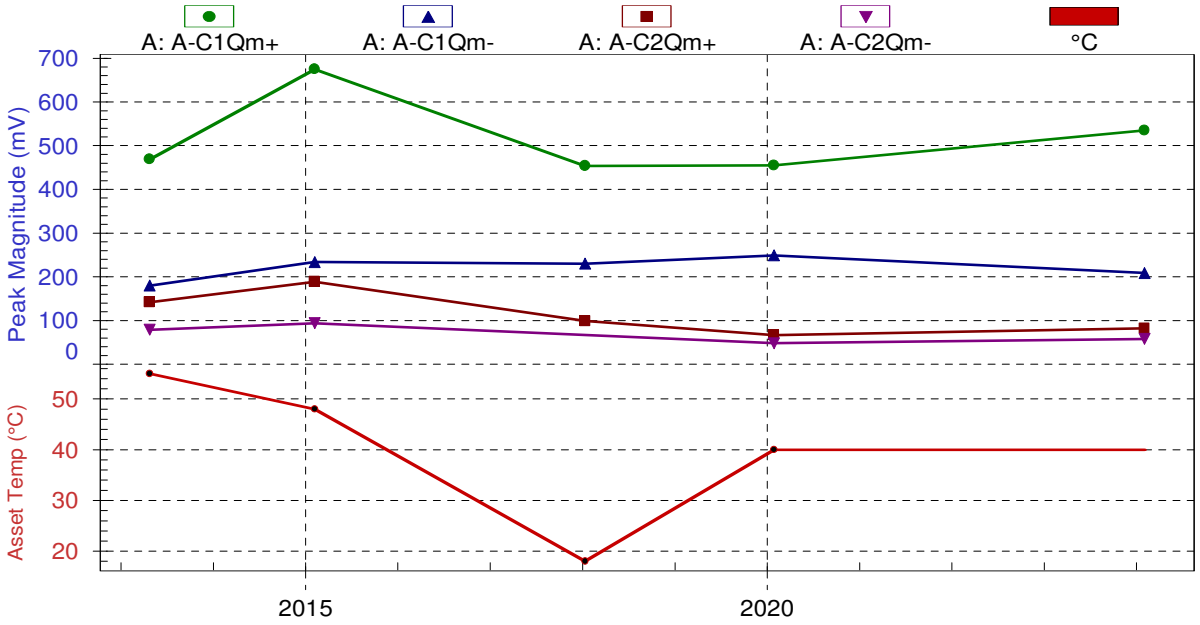
The table below lists the Qm summary numbers from the tests for this machine.

	Power (MW)	Reactive (MVar)	Voltage (kV)	Temp (°C)	Ambient		A-A-C1		A-A-C2		B-B-C1		B-B-C2		C-C-C1		C-C-C2	
					Temp (°C)	RH (%)	Qm+	Qm-	Qm+	Qm-	Qm+	Qm-	Qm+	Qm-	Qm+	Qm-	Qm+	Qm-
Apr 13	65.0	0.0	13.8	55	23	16	469	180	142	79	289	147	224	99	317	172	92	95
Feb 15	65.0	0.0	13.8	48	19	6	675	234	189	94	310	242	241	146	340	219	116	108
Jan 18	70.0	0.0	13.8	18	19	9	454	230	99	-	228	126	149	95	331	169	-	68
Jan 20	65.0	-9.5	13.8	40	28	35	455	249	67	48	446	263	66	49	455	256	69	48
Feb 24	80.0	0.0	13.8	40	29	24	535	209	82	58	340	142	173	99	290	181	75	76

"-" is an indication that the value was not provided, or available at the time of the test.

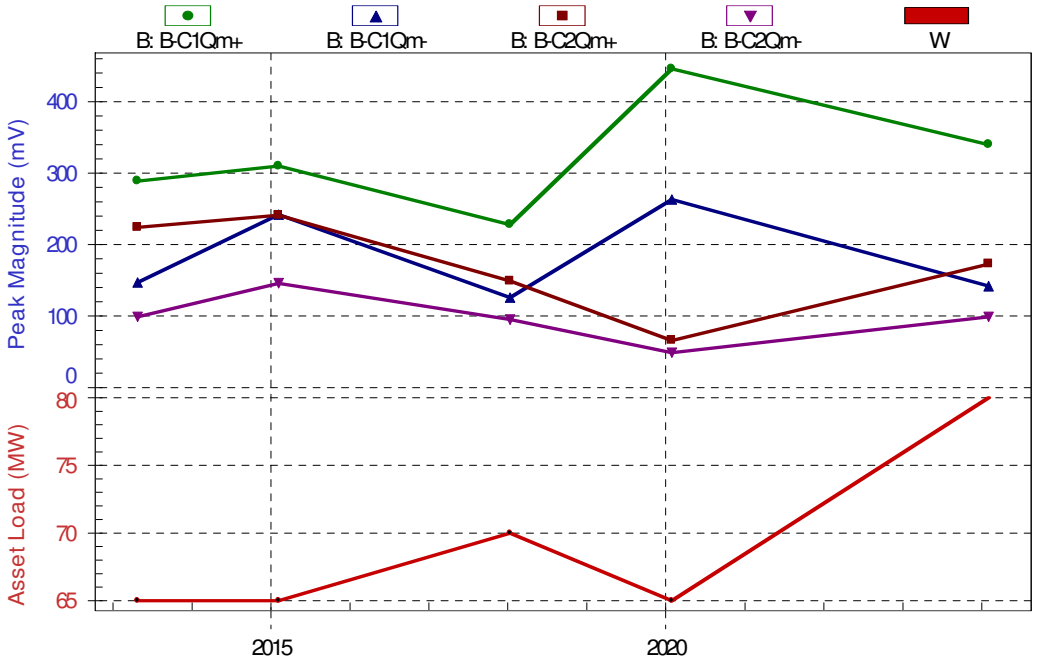
Phase A-A-C1
The Partial Discharge is stable (no more than 25% difference in Peak Magnitudes (+/-Qm), so there is no evidence of a change in winding condition.

Phase A-A-C2
The Partial Discharge is stable (no more than 25% difference in Peak Magnitudes (+/-Qm), so there is no evidence of a change in winding condition.



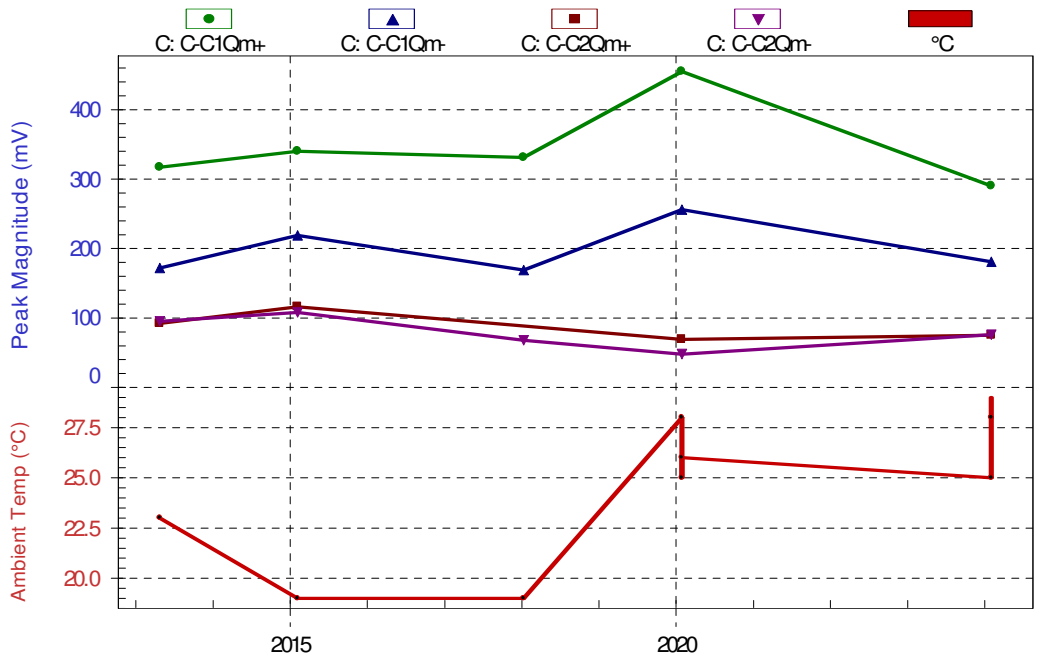
Phase B-B-C1
The Partial Discharge is stable (no more than 25% difference in Peak Magnitudes (+/-Qm), so there is no evidence of a change in winding condition.

Phase B-B-C2
The Partial Discharge is stable (no more than 25% difference in Peak Magnitudes (+/-Qm), so there is no evidence of a change in winding condition.



Phase C-C-C1
The Partial Discharge is stable (no more than 25% difference in Peak Magnitudes (+/-Qm), so there is no evidence of a change in winding condition.

Phase C-C-C2
The Partial Discharge is stable (no more than 25% difference in Peak Magnitudes (+/-Qm), so there is no evidence of a change in winding condition.



3.3 Partial Discharge Results

Phase A	Date	Time	Test Range	K-factor	NQN+	NQN-	Qm+	Qm-
A1 - A-C1	2/1/2024	1:35:11 PM	50.0-850.0 mV	1.00	1113	424	535	209
A1 - A-C2	2/1/2024	1:31:03 PM	10.0-170.0 mV	1.00	149	107	82	58

Phase B	Date	Time	Test Range	K-factor	NQN+	NQN-	Qm+	Qm-
B1 - B-C1	2/1/2024	1:59:53 PM	50.0-850.0 mV	1.00	625	252	340	142
B1 - B-C2	2/1/2024	1:57:49 PM	20.0-340.0 mV	1.00	375	226	173	99

Phase C	Date	Time	Test Range	K-factor	NQN+	NQN-	Qm+	Qm-
C1 - C-C1	2/1/2024	2:18:04 PM	50.0-850.0 mV	1.00	602	328	290	181
C1 - C-C2	2/1/2024	2:13:57 PM	10.0-170.0 mV	1.00	155	159	75	76

3.4 Pulse Phase Analysis Plot

Based on the information known to date, an ABC rotation is assumed. The following plot shows the Linear Pulse density plot with the phases appropriately shifted to make it easier to observe the vertical alignment that occurs when detected pulses are from the same source, as with interphasal and cross-coupled pulses. Should the rotation selected disagree with your documentation, please let us know.

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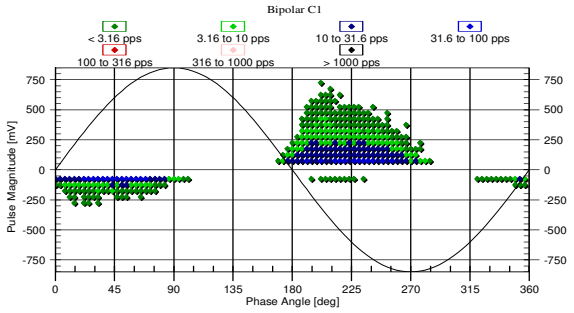
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Pulse Phase Analysis (ABC rotation PRPD)

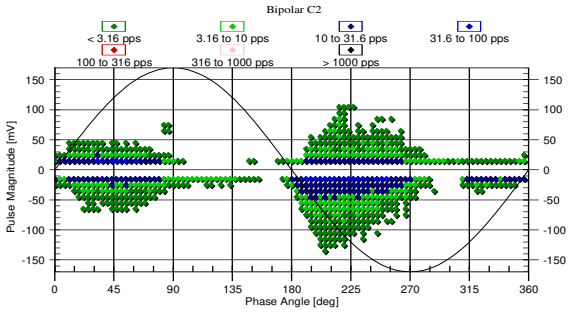
Folder: NEWFOUNDLAND & LABRADOR HYDRO

Asset Name: Unit 1

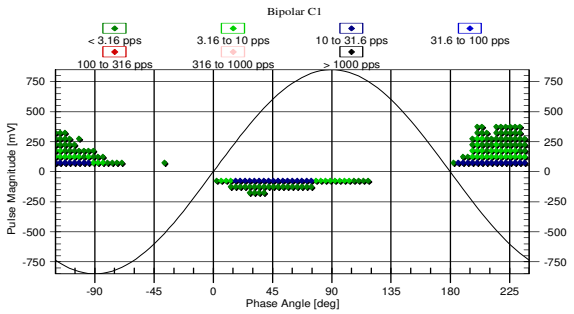
Asset Class: Hydro Generator, Sensor Type: Cable Capacitor (80pF)
Operating load: 80.0 MW, Reactive Load: 0.0 MVar, Operating Asset Temp 40 deg C, Operating Voltage 13.8 kV
Operating Gas Pressure: N/A, Ambient Temp 25 deg C, Ambient Humidity: 24 %, Freq. / Test Duration 60 Hz / 5 s
Manufacturer: HITATCHI, Year of Installation: 1980, Winding Manufacturer: , Re-Wind Year: N/A



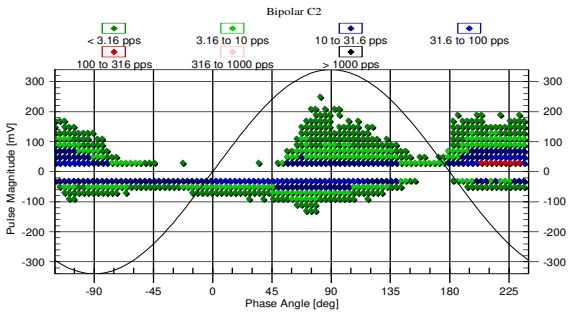
Phase: A, Sensor(s): A-C1,A-C2 Start Time: 2/1/2024 1:35:11 PM
C1: NQN+: 1113, NQN-: 424, Qm+: 535, Qm-: 209, Status OK



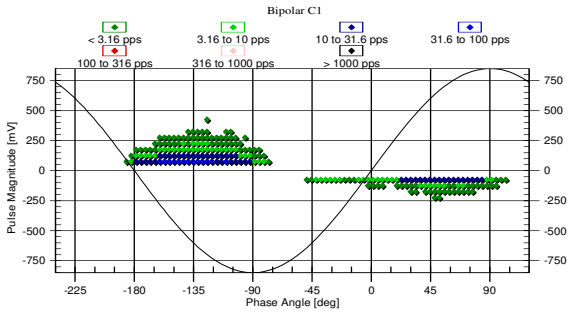
Phase: A, Sensor(s): A-C1,A-C2 Start Time: 2/1/2024 1:31:03 PM
C2: NQN+: 149, NQN-: 107, Qm+: 82, Qm-: 58, Status OVR



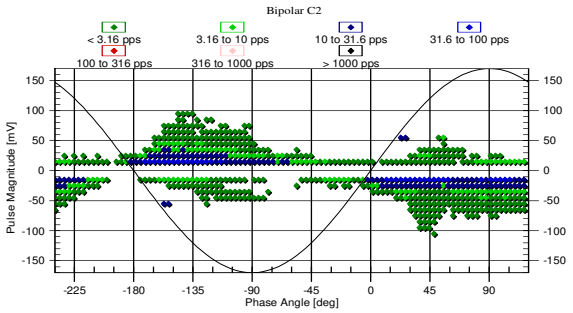
Phase: B, Sensor(s): B-C1,B-C2 Start Time: 2/1/2024 1:59:53 PM
C1: NQN+: 625, NQN-: 252, Qm+: 340, Qm-: 142, Status OK



Phase: B, Sensor(s): B-C1,B-C2 Start Time: 2/1/2024 1:57:49 PM
C2: NQN+: 375, NQN-: 226, Qm+: 173, Qm-: 99, Status OVR



Phase: C, Sensor(s): C-C1,C-C2 Start Time: 2/1/2024 2:18:04 PM
C1: NQN+: 602, NQN-: 328, Qm+: 290, Qm-: 181, Status OK



Phase: C, Sensor(s): C-C1,C-C2 Start Time: 2/1/2024 2:13:57 PM
C2: NQN+: 155, NQN-: 159, Qm+: 75, Qm-: 76, Status OVR

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3.5 Partial Discharge Analysis

The high level of Partial Discharge compared to other windings of this voltage class [ref. A-4.2] means the winding should be carefully monitored during subsequent tests.

The Partial Discharge magnitudes and patterns are not comparable suggesting an isolated problem in the winding, and not a uniform condition.

Appendix Reference	Parameter	Pair	Phase A		Phase B		Phase C	
			A-C1	A-C2	B-C1	B-C2	C-C1	C-C2
PD Trend								
A3.1.2	Comparison to previous measurement	1	Stable (+/-25%)	Stable (+/-25%)	Stable (+/-25%)	Stable (+/-25%)	Stable (+/-25%)	Stable (+/-25%)
A3.1.1	Long Term Trend	1	Stable (+/-25%)	Stable (+/-25%)	Stable (+/-25%)	Stable (+/-25%)	Stable (+/-25%)	Stable (+/-25%)
A3.4	Operating and/or ambient conditions effect	1	Unknown for: All	Unknown for: All	Unknown for: All	Unknown for: All	Unknown for: All	Unknown for: All
PD Comparison								
A3.2	Database comparison	1	High	Low	Moderate	Typical	Moderate	Low
A3.3	Phase comparison	1	Isolated Problem	Uniform	Uniform	Uniform	Uniform	Uniform
A4.2	Polarity predominance	1	Positive	None	Positive	Positive	Positive	None
A3.5	System	1	Negligible		Negligible		Negligible	
PD in Slot		1	Yes	Yes	Yes	Yes	Yes	Yes
A4.2.1	Internal discharge	1	√	√	√	√	√	√
A4.2.1.3	Delamination from conductor	1						
A4.2.2.1	Loose coils	1						
A4.2.2.2	Electrical slot discharge	1	√		√	√	√	
Operating Conditions Effect								
A3.4.1	Load dependence	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
A3.4.2	Stator winding temperature dependence	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
A3.4.3	Hydrogen pressure effect	1	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
A3.4	Operating voltage effect	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
A3.4	Ambient temp. effect	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown

A3.4.4	Ambient humidity effect	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
PD in Endwinding		1	Yes	Yes	Yes	Yes	Yes	Yes
A4.3.2	Inter-Phase	1						
A4.3.1	Stress control interface	1	√	√	√	√	√	
A4.3.2.3	Gap type discharge	1						
A4.5.2	Cross-coupling*	1		√		√		√
A4.5.1	Excitation pulses*	1						
A4.5.4	Severe disturbance*	1						
A4.5.3	Broadband clusters	1						
A4.3.2.1	Contamination	1						
	Peak clusters	1						
Operating Conditions Effect								
A3.4.1	Load dependence	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
A3.4.2	Stator winding temperature dependence	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
A3.4.3	Hydrogen pressure effect	1	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
A3.4	Operating voltage effect	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
A3.4	Ambient temp. effect	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
A3.4.4	Ambient humidity effect	1	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown

* Extraneous pulses: Cross-coupling, excitation pulses, broadband clusters and severe disturbances are not indicative of problems within the asset insulation system; however, their presence may obscure notable winding PD activity. Please refer to Section A-4.5 in the Appendix for more information.

4 STATOR WINDING ASSESSMENTS

4.1 Unit 1

Overall Concern:	Some concern, High to Moderate level of PD and stable levels.
Next Test	Within 6 months

Phase	Pair	C1 Assessment	C2 Assessment
A-Phase	1	Short Term: Stable (+/-25%); Long Trend: Stable (+/-25%); Oper Conditions: Unknown for: All; Ranking: High.	Short Term: Stable (+/-25%); Long Trend: Stable (+/-25%); Oper Conditions: Unknown for: All; Ranking: Low.
B-Phase	1	Short Term: Stable (+/-25%); Long Trend: Stable (+/-25%); Oper Conditions: Unknown for: All; Ranking: Moderate.	Short Term: Stable (+/-25%); Long Trend: Stable (+/-25%); Oper Conditions: Unknown for: All; Ranking: Typical.
C-Phase	1	Short Term: Stable (+/-25%); Long Trend: Stable (+/-25%); Oper Conditions: Unknown for: All; Ranking: Moderate.	Short Term: Stable (+/-25%); Long Trend: Stable (+/-25%); Oper Conditions: Unknown for: All; Ranking: Low.

4.1.1 PD Patterns

- A-3.1.2 SHORT-TERM MOVEMENT: The PD levels of the current test remain similar to the previous results in all six sensor areas, suggesting the stable condition of the subject stator winding. Minor deviations in the PD levels are expected and considered normal.
- A-3.1.1 LONG-TERM TREND: The overall trend has been relatively stable. The minor fluctuations in PD over the years are likely due to variable operating and ambient conditions and not to a change in winding insulation condition. It appears that the positive polarity of PD is affected the most. So, there is no indication of a change in winding condition or PD sources.
- A-3.2 and A-3.3 DATABASE AND PHASE COMPARISON: The PD magnitudes are not similar among the sensors, indicating an isolated problem(s) on the A-C1 sensor. The level of PD is considered HIGH on A-C1, MODERATE in B-C1 and C-C1, and the other sensors are TYPICAL or lower when compared to other similar windings of the same voltage class in the Iris statistical database. The elevated PD levels recorded on this machine indicate some concern and warrant continued monitoring to be aware of any changes concerning PD magnitudes or PD sources.
- A-4.2.2 SLOT PARTIAL DISCHARGE: If the discharge protective coating in the slot section of the stator winding fails to serve its purpose due to various reasons, then the possibility of partial discharge develops here. The resulting PD pattern could then be seen predominantly at the 225° angular position, such as the one shown in the PRPD plot of this report for sensors A-C1, B-C1, B-C2, and C-C1. The activity detected is of great significance and should be investigated further by conducting a load dependence test [A-3.4.1]. The stable level of PD throughout the testing at different loads indicates that there is no looseness in the winding. Hence, there is no cause for immediate concern.

- A-4.3.1 SURFACE DISCHARGE AT VOLTAGE STRESS CONTROL INTERFACE: The narrowly shaped pulse streams at AC reference zero crossings are revealing themselves on all sensor areas except C-C2. This likely suggests isolated locations at near line phase end coils/bars where some localized deterioration of the semiconductive and/or grading voltage stress control coating might be occurring that is beyond the end of the stator slots. This is the main PD source in this machine, and it is a slow deterioration process. Since the level of activity varies with the temperature, testing at stable operating conditions mainly the winding temperature will help for better trending. This is the main PD source in this machine and recoating may eliminate this source of activity temporarily for a few years. Also note that once the surface coating is eroded this may lead to a loosened winding hence the need for continued monitoring and trending.

4.1.2 Recommendations

Though there is no indication of any developing problems with the stator winding insulation assessed here, the high level causes some concern. However, there is no reason to restrict operation, we recommend retesting in similar stable operating conditions in 6 months in order to trend the PD development.

5 LIMITATIONS OF ASSESSMENT

Deterioration due to Partial Discharge is an extremely slow process; however, the prediction of failure is impossible. Eventual failure will occur during a switching surge, poor synchronization, load rejection or some other event causing a breakdown of the weakest point. On-line Partial Discharge tests should be conducted at regular intervals and, where appropriate or indicated, be supplemented with visual inspections and off-line testing. Consistent and regular testing will provide the means to assist plant personnel in determining the overall winding condition. Though some conclusions can be drawn from a single test, the trend at comparable ambient and operating conditions truly evaluates the condition of the winding. Doubling of Partial Discharge over a twelve-months interval often indicates a rapidly deteriorating winding. The plant's history of a machine could be beneficial in deciding the proper course of action.

6 PREVIOUS REPORTS

- Jan 10, 2018 [50362475]

7 ATTACHMENTS

- **Attachment 1 (40 pages)**
  Appendix - Interpretation of PD Results

8 REFERENCES

1) IEEE 1434, "IEEE Guide to the Measurement of Partial Discharges in Rotating Machinery"
2) IEC TS 60034-27-2:2012 Rotating electrical machines - Part 27-2: On-line partial discharge measurements on the stator winding insulation of rotating electrical machines
3) 2021 Iris Power Partial Discharge Severity Tables, available online: https://irispower.com/online-partial-discharge-severity-tables/.

Attachment 3

Hinds Lake Turbine and Generator Condition Assessment





HATCH

Newfoundland and Labrador Hydro

Final Report

For

Hinds Lake Turbine and Generator Condition Assessment

H369389-0000-220-230-0001
Rev. 0
December 9, 2022

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Newfoundland and Labrador Hydro

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Report

Hinds Lake Turbine and Generator Condition Assessment

H369389-0000-220-230-0001





2022-12-09	**0**	**Approved for Use**	**M. Slijepcevic**	**S. Bhan; M. Dodge**	**K. Savoury**	**T. Chislett**
DATE	**REV.**	**STATUS**	**PREPARED BY**	**CHECKED BY**	**APPROVED BY**	**APPROVED BY**

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Appendix A Review of the Inspection Report, Test Records Provided by NL Hydro

Appendix B Turbine Pictures

B.1 Blade Pictures
B.2 Guide Vane Pictures

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1. Introduction

1.1 General

In August 2022 Newfoundland and Labrador Hydro (NL Hydro) engaged Hatch to provide engineering services related to the stator and runner at Hinds Lake Hydroelectric Generating Station.

The objective of this Level I Condition Assessment is to identify deficiencies, provide scope description for restoration/repairs/replacement/removal/recommendations, and enable an accurate cost estimate of such works.

The scope of work for this project generally involves the following:

- Level I Condition Assessment of the current state of the stator and runner.
  - Alternatives, recommendations and timelines to complete a stator re-wedge.
  - Alternatives, recommendations and timelines to complete the runner repairs or upgrades.
  - Review the current runner design and compare to current industry standard.
  - Review current runner condition as well as previous inspection results.
  - Make recommendations on benefits/possibilities of replacing the runner.
- AACE Class 5[1] Capital Cost estimates.
- Recommendations of further analysis or assessment.

1.2 Background

The Hinds Lake Hydroelectric Generating Station is located on the eastern shore of Grand Lake in Newfoundland and Labrador. The plant operates under an average net head of 214 m and has a rated flow of approximately 40 m^3/s. The plant has one unit, and the water conveyance system has one steel lined penstock.

Since its commissioning in 1980, the unit has operated normally, and only routine preventative and corrective maintenance works were performed except for a rotor pole refurbishment in 2019. The runner was repaired several times for cavitation. The generator has operated normally and is inspected regularly. The original turbine manufacturer is NOHAB (acquired by Kvaerner Norway and later by Andritz) and the original generator manufacturer is Hitachi. Generator and turbine characteristics are provided in Table 1-1 and Table 1-2 below.

[1] AACE Class 5 Concept Screening expected accuracy: L: -20% to -50%, H: +30% to +100%.

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Table 1-1: Generator Main Characteristics

Item	Rating
Original OEM	Hitachi Ltd, Japan
Rated capacity	83,300 kVA
Rated voltage	13,800 V
Rated current	3485 A
Continuous maximum rating	100,000 kVA
Rated speed	360 rpm
Rated frequency	60 Hz
Power factor	0.9
Number of phases	3
Commissioning date	1980
Temperature rise: Armature at rated load: Field at rated load: Armature at C.M.R.: Field at C.M.R.:	 60 C 60 C 80 C 80 C

Table 1-2: Turbine Main Characteristics

Item	Rating
Original OEM	NOHAB, Sweden
Rated capacity	77,300 kW
Rated Speed	360 rpm
Rated flow	~40 m^3/s
Average net head	214 m
Average gross head	220 m
Number of stay vanes	19
Number of guide vanes	Unknown
Number of runner blades	16
Crown and band	$2RM^2$ (13% Cr, 6% Ni)
Runner blade material	Uddeholm UHB SS119 (15-17% Cr, 4%-5.5% Ni)
Commissioning date	1980
Runner diameter (D1)	2150 mm

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2. Methodology

For this Level I Condition Assessment, the methodology consisted of a site visit with the intent of collecting any relevant technical documents, an interview with NL Hydro personnel, and a visual inspection of the runner and the generator.

During the site visit, the following documents were available:

- Drawings of the turbine and generator, specifically the runner, stator and rotor.
- Turbine OEM performance curves.
- Weights of major equipment.

Some areas of the Hinds Lake unit had limited access during the outage due to changes in NL Hydro's outage planning. However, all attempts were made to ensure areas that could be entered were assessed thoroughly to provide a quality Level I Condition Assessment.

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3. Generator Inspection and Assessment

The team of mechanical and electrical subject matter expert (SME) engineers from Hatch visited the Hinds Lake station on August 30, 2022, with the task to perform inspection of the turbine runner and generator. Access to the generator was provided with the rotor in place, which limited the extent of assessment activities on the generator to inspections of areas that could be accessed.

The rating of the generator is shown in Figure 3-1 below.

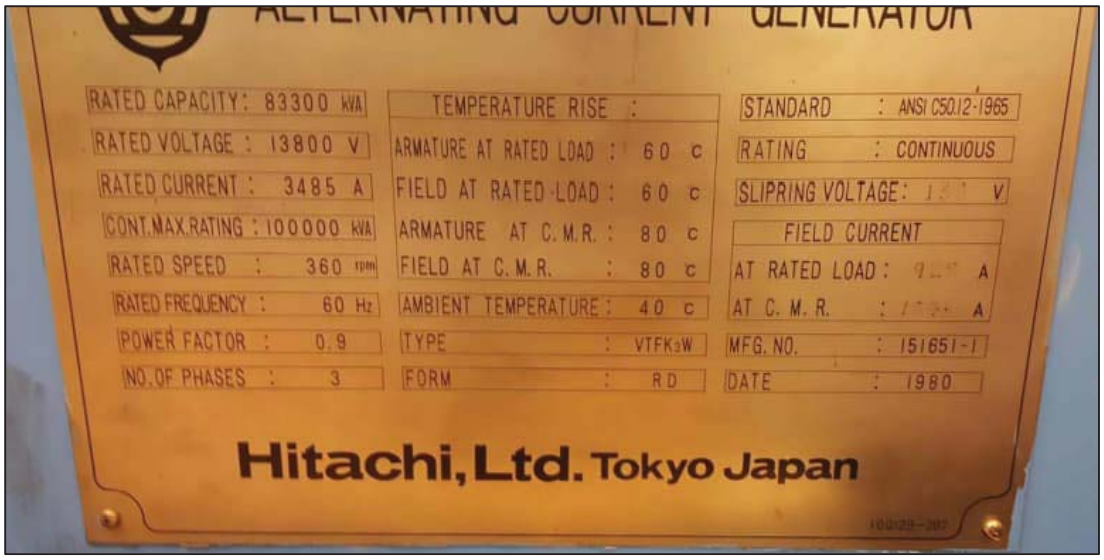


Figure 3-1: Generator Name Plate

During the site visit, NL Hydro provided Hatch with access to review their OEM drawings, as well as previous inspection and test records. They were reviewed to collect data of interest to Hatch for this report. Review of the previous inspections and test records with Hatch comments are attached in separate document H369389-0000-060-0001 (see Appendix A).

With the rotor in place, NL Hydro organized the temporary removal of the one inspection cover at the OD of the frame (to inspect the back of the core) and the one available inspection cover near the main leads' location at the bottom of the unit (to inspect bottom of the stator winding). The inspection of the back of the stator core confirmed that the core is in very good shape, with no wave of looseness on the observed stacked lamination. When inspecting the bottom of the stator winding through the removed cover, the continuously connected damper winding components limited visibility, so even photos taken at the location did not allow a satisfactory view of the slot ends, nor the end of the stator straight part (after the core end) – which is an area that could possibly indicate corona for the 42-year-old winding. Visual inspection at the top of the unit was only possible in the area between adjacent ventilation fans attached between the rotor rim and the ID of the stator core between the adjacent poles. The end of the winding was completely covered with fiber cast end bells

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that redirect cooling air to the air gap (see Figure 3-2 and Figure 3-3). The planned wedge tightness test using an 8 oz ball-peen hammer was not possible with rotor in place.

Considering the above noted restrictions, Hatch's comments on the generator will be based in accordance with review of the previous inspection report, and testing that was done during the outage in 2019 when the rotor was taken out for re-insulation of the field poles (see Appendix A for more details).

Along with unit rating data visible from Figure 3-1, and based on the reviewed OEM drawings, the stator winding has 264 slots with single turn Roebel bars connected with 1 to 7 alternate type jumpers into 2Y star configuration. The coil throw is 1 to 11. All serial or group connections on the top of the unit are encapsulated as are all the bar connections on the bottom. The slot packing is the content of top, center and bottom insulating sticks and slot semiconductive liner only, so no wedge spring is used. The wedges in each slot are secured with Dacron felt (creating the bump by the end of the core) soaked in resin and then left to harden via air during the installation by OEM, which prevents the wedges from moving axially out of the slot.

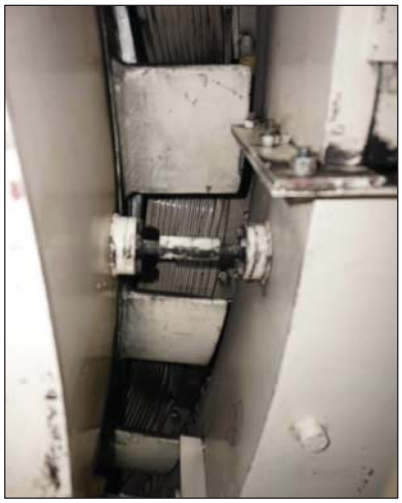


Figure 3-2: View from Top of the Unit



Figure 3-3: View from Bottom of the Unit

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4. Turbine Runner Inspection and Assessment

4.1 Runner and Turbine Design

The NOHAB company philosophy at the time was to create standard hydraulic turbine designs which could be re-used from project to project. Several of the features found on the turbine are typical of Kvaerner / NOHAB technology.

Key features found are:

- Dismantling and removal of the runner through a removable draft tube cone.
- Staged labyrinth seals at the crown and band.
- Maintenance of guide vane bushing by top and bottom access.
- Wear segment installed on facing plate (to prevent leakage in guide vane closed position).

Contrary to later 1990s designs, this turbine has thrust relief holes in the crown and does not appear to be fitted with hydraulic thrust balancing pipes (Hatch did not have drawings confirming pipes connecting the crown chamber to the draft tube). Turbines fitted with thrust relief holes have higher hydraulic thrust than ones designed with hydraulic thrust balancing pipes.

4.1.1 Runner

The runner is of welded construction. The crown and band are cast alloy steel (2RM^2 (13% Cr, 6% Ni) and the blades are made from pressed alloy steel plate (Uddeholm UHB SS119). The runner was fabricated in a workshop and was dynamically balanced. The runner blade design has conventional short blades (not inverted inlet edge relative to outlet edge, similar to X-blade design) which typically has a lower operating range in terms of head and output, and normally has high pressure pulsation. Modern runners tend to have different features, such as a straight inlet and inverted blade toward the outflow. Blade inlets tend to have a larger radius for a broader operating head range without inlet cavitation. Transition weld radius is generally larger by 2 to 5 mm. Surface area is larger due to the inverted blade shape which improves runner cavitation behavior at maximum output. The runner has been designed with proper surface finish and adequate Von Karman chamfers at the discharge edge.

NL Hydro reported cracks at the weld joint between blade outlet and band. Medium to high head runners have generally high dynamic stresses at this location and require high quality welding. Hatch notes that the weld radius of R10 (10 mm) also appears to be too small and would increase stress concentrations in this region of the runner.

The runner cone is made of carbon steel and is bolted to the runner.

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No cracks were found at the inlet of the runner, which indicates the inlet to stay vane distance is sufficient to lower dynamic stress, and that the initial design was adequate to sustain the level of stress of this type of runner.

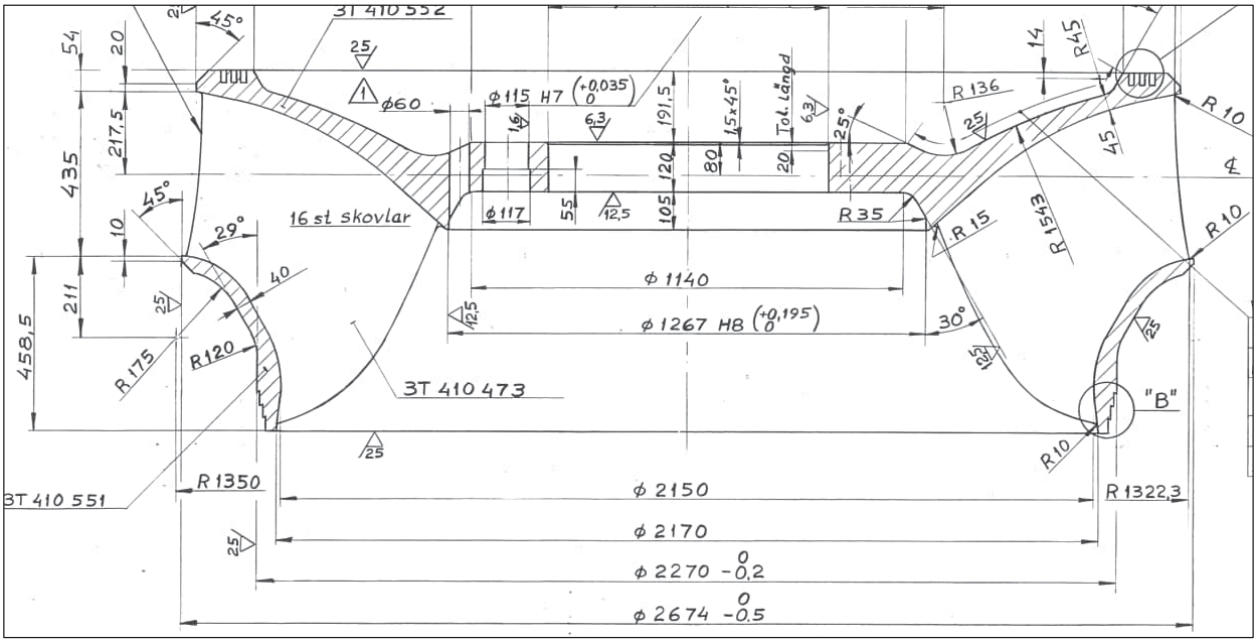


Figure 4-1: Runner Section Drawing

4.1.2 Turbine Distributor

The turbine arrangement is not conventional; it has 16 runner blades, 20 guide vanes, and 19 stay vanes. The stay vanes are unsymmetrical and are not aligned with the guide vanes. The guide vanes are symmetrical type with no end seals on the top and bottom surface. Both stay vanes and guide vanes have been adequately profiled. Stay vanes are made of carbon steel and guide vanes are made of the same material as the runner crown and band (2RM^2 (13% Cr, 6% Ni).

The guide vane top and bottom gap is normally intended to be close to 0 on medium and high head turbines in the closed position as to have no leakage. To achieve this feature, wear segments have been installed on the top and bottom guide vane circle of the stay ring with some compression on the guide vanes.

There was contact between the guide vanes and the facing plates as well as evidence of galling. However, there is no design feature helping to prevent galling in the open position such as bronze segments. Facing plates material appear to be made of stainless steel but the material grade is unknown. Difference in hardness between the guide vane and facing plate is a normal design practice to reduce the probability of gripping and/or galling due to small clearances between the two components (recommended to have a minimum of 50 to 80 BHN or more).

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Bronze segments are also used to reduce the clearances between the top and bottom clearance, but NL Hydro did not report any guide vane leakage issue.

4.2 Runner Inspection and Assessment

The runner was inspected in-place in the turbine pit from the bottom through the draft tube. Overall, the runner (except for cavitation noted below) and adjacent turbine water passages appear to be in good condition.

There was cavitation observed at the inlet suction side (see Figure 4-2, bullet 2), outlet suction side (see Figure 4-2, bullet 3) and on the runner cone itself (see Figure 4-2, bullet 1). Cavitation damage was minimal at outlet on blade 1, 3, 9 and 10. Repairing these blades is recommended. Material loss could not be measured on the inlet of each blade due to limited access to the runner.

Runner observations are summarized in Table 4-1.

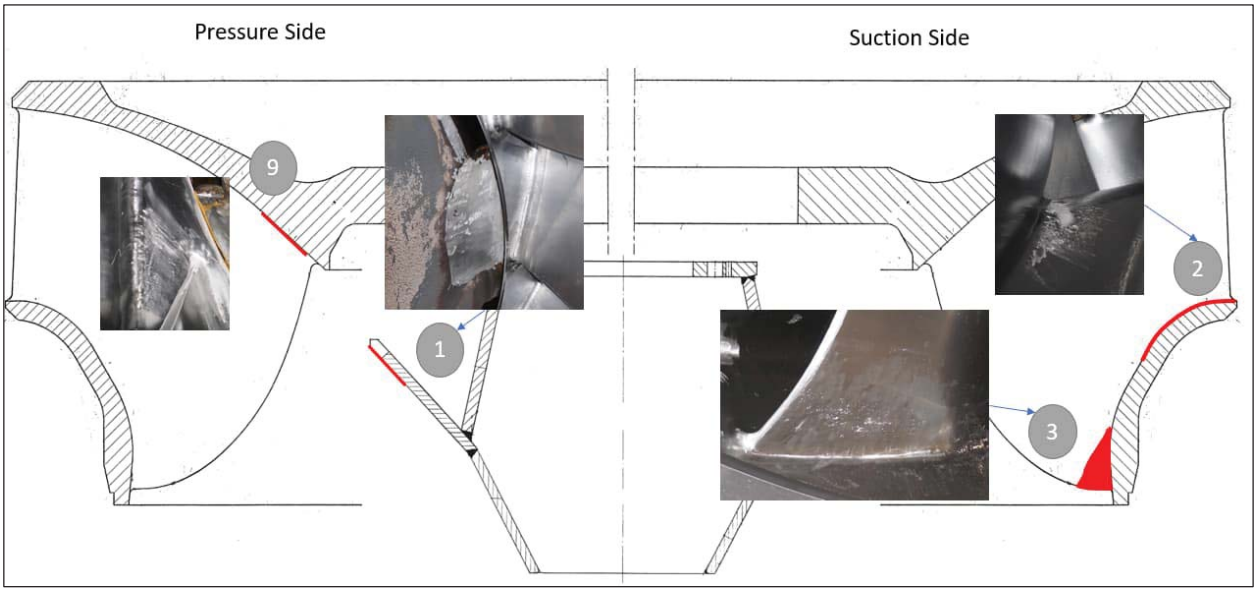


Figure 4-2: Runner Damage Location

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Table 4-1: Runner Condition Observations

Component	Zone	Observation	Potential Cause
Runner cone surface	1	Stainless overlay and traces of rust at junction of base material carbon steel and stainless-steel overlay.	Turbine design; Gap cavitation and inter-blade vortices. Thrust relief holes flow discharge and large openings in the cone design adjacent to the crown.
Inlet blade suction side to band junction surface damage	2	Cavitation erosion. Quantity undetermined.	Turbine design; Operating at high head outside operating zone. Inadequate inlet profile.
Runner blade outlet suction side damage	3	Stainless overlay and workmanship defect. Initial traces of cavitation erosion.	Turbine design; Operating at high output outside operating zone. Inadequate outlet profile.
Crown inter-blade surface	9	Stainless overlay and workmanship defect. Initial traces of cavitation erosion.	Part load operation or extended speed no load operation.

Cavitation on the blade inlet suction side is generally caused when the unit operates at a higher net head than its original design. It should be noted however, that a poor hydraulic design profile could be a contributor to this type of cavitation.

Cavitation on the blade outlet suction side is generally caused when the runner operates beyond its cavitation limit at higher outputs, or when the tailwater level is too low (sigma below sigma incipient).

Cavitation damage observed at the runner cone is likely caused by gap cavitation between the runner cone and runner crown. There is also evidence of grinding at the crown outlet surface, indicating the presence of part-load inter-blade vortices.

It was observed that the blade surfaces were in good condition except for the cavitation noted above. The quality of the Von Karman chamfer were of workmanship poor quality but functioning well.

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Figure 4-3: Picture of Runner from Below

4.2.1 Repair History

At the time of the inspection, the runner had no cracks visible to the naked eye, was in good condition, and did not display extensive material loss, but several areas had incipient cavitation damage and evidence of inadequate grinding.

No cracks were observed during the site visit, but cracks have been previously reported by NL Hydro. The location of these cracks was at the junction of the band and blade discharge, near the weld joint radius. Typically, cracks in early years of operation are caused by high stress or weld defects, or both. Documents reported that “a repair technique applied in the 1980’s using certain electrodes” caused localized brittleness and cracking sensitivity. It was reported to Hatch that the runner blades were less subject to cracks. However, evidence of grinding was found where repairs had been made and the surface finish was at times sometime inadequate due to the difficult working condition and what is likely the use of inadequate tooling for runner grinding and polishing.

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Figure 4-4: Crown Interblade Surface



Figure 4-5: Outlet Suction Side Surface



Figure 4-6: Inlet Suction Side Surface



Figure 4-7: Outlet Pressure Side Surface

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Three different repair procedures were prepared by NL Hydro for the following: double-sided cracks, surface cracks, and cavitation repairs. Records of repair maps were not available. Cavitation repair procedure uses E309 as a base layer for repair with an overlay of cavitation resistant material Cavitec. Double-sided cracks and surface repair procedures also uses E309 as a base layer material and an overlay of cavitation resistant material Cavitec.

Hatch notes that the welding repair procedures are generally acceptable, but that pre-heating and post-welding heat treatment are generally higher for similar material in factory. Also, acceptance criteria for welding are not specified either on drawing or welding procedures. Drawings are available specifying ASME Section VIII, but it is generally recommended to specify NDT requirements in critical high stress area for the runner.

Finally, it is generally a concern that runners that are repaired multiple times over their life may have deteriorated blade profile and altered material properties (base material and filler material). NL Hydro reported less cracks after performing the most recent repairs.

4.2.2 Operating Conditions

Limited information on the operating condition of the unit is available for review. As a minimum, the following information should be available to validate if the unit is operating within its design parameters: number of starts and stops, head water level, tailwater level, flow, power.

Operational data shared with Hatch show the plant operation vary from year to year, or period to period. The plant is either used for base load (few start/stop and high hours of operation) or for peaking operation (high number of start/stop and lower hours of operation). Interestingly, more cracks occurred in the first years of operation when less start/stop occurred. NL Hydro informed Hatch less cracked occurred in the last 10 years since the repair method was revised and improved. Despite a higher number of start/stop than originally intended for this unit, how NL Hydro currently operates the plant should not in the short term influence the life of the runner[2]. However, such assumption should be revised if this runner is operated at speed no load or part load for extended period. Indeed, part load or speed no load operation causes high inter-blade pressure fluctuation and high blade dynamic stress which may cause accelerated fatigue on runners not designed for such condition.

[2] Modern runners are designed for 2 start/stop per day with an expected fatigue life expectancy of a minimum of 50 years, under normal operating conditions between 70 to 100% load.

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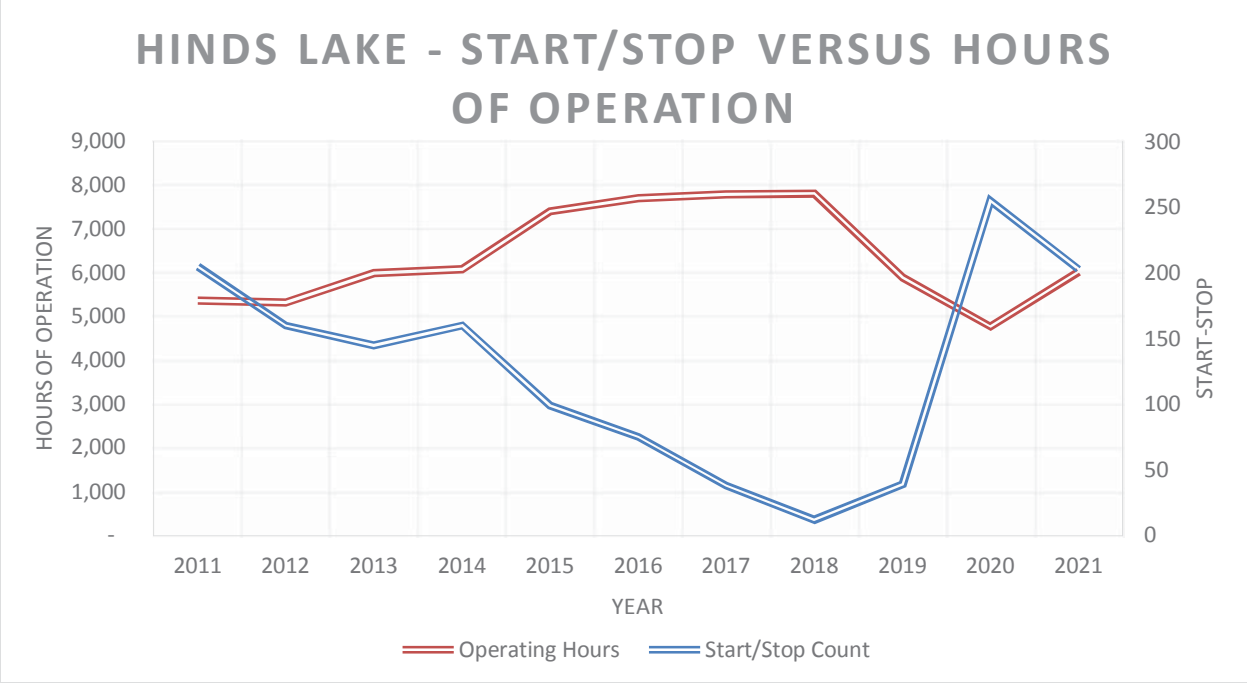


Figure 4-8: Start / Stop vs Hours of Operation

Table 4-2: Operational Data

Hinds Lake Unit Start / Stop and Operational Data			
Year	**Start / Stop Count**	**Operating Hours**	**Notes**
2011	205	5,376	
2012	160	5,331	
2013	145	6,001	
2014	160	6,082	
2015	99	7,408	
2016	75	7,716	
2017	38	7,794	
2018	12	7,815	major outage during the year
2019	39	5,903	major outage during the year
2020	255	4,778	
2021	203	6,026	
2022 YTD Sept	89	4,978	

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Hydraulic conditions were investigated. At the plant, only the hill chart and the critical sigma curve was available. The curves are based on model test and were based on the metric system N11, Q11, P11 (prior to modern IEC60193 definitions based on available energy).

Relevant to this inspection, Hatch notes that these charts do not indicate the cavitation limits where it is safe to operate without any form of cavitation. The reference to critical sigma was generally defined as a reduction in efficiency of 0.2% to 1.0% when lowering the tail water, not incipient cavitation[3]. NL Hydro may wish to clarify with Andritz the exact cavitation limits based on the model test report.

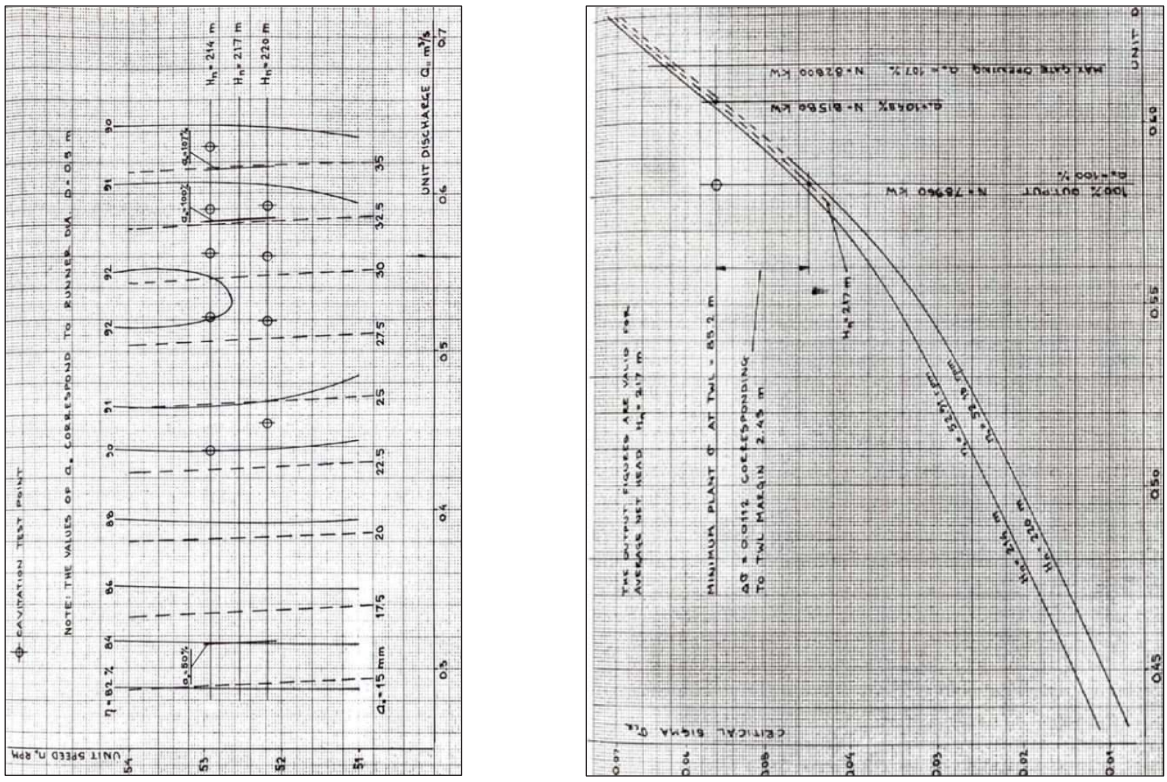


Figure 4-9: Turbine Performance Curves

This means it is very probable that the exact cavitation free operating zone is not known to NL Hydro.

[3] During model testing, sigma break curves are made. In sequence, sigma incipient is defined, then sigma 0.2% efficiency loss, then sigma 1.0% efficiency loss. Generally, runners cavitate when efficiency drops. Sigma critical used to be defined as a specific efficiency drop, and not sigma incipient (apparition of bubbles).

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4.3 Turbine Inspection and Assessment

In addition to the runner, some components of the turbine were inspected during the site inspection. The following components were observed:

- Draft tube cone
- Upper section of the elbow
- Spiral casing
- Stay-vanes
- Guide vanes
- Facing plates.

Areas of concerns are documented in Table 4-3.

Table 4-3: Turbine Inspection Observations

Component	Zone	Observation	Potential Cause
Upper facing plate	4	Initial traces of cavitation erosion. Damaged wear segment. Galling between guide vane and facing plate.	On the downstream side of the facing plate, traces of erosion are present which suggest cavitation or erosion. Gap between guide vane and bottom ring caused damage to facing place (galling) and damage to wear segment. Hydraulic thrust on wicket gate stem.
Lower facing plate	6		
Guide vane	5	Impact marks. Casting defects.	Minor rock impact. Rated velocity at inlet around 11.3 m/s. Suspected casting defects.
Upper draft tube cone	7	Initial traces of cavitation erosion. Damaged wear segment. Galling between guide vane and facing plate.	Original design had upper stainless-steel ring to mitigate gap cavitation between the runner and the draft tube cone. Original paint fell off.
Air admission vents	8	Cavitation.	Geometry causes a low-pressure zone of the cone on carbon steel surface. Area was repaired with stainless overlay.

The location of each of these damages is presented in Figure 4-10.

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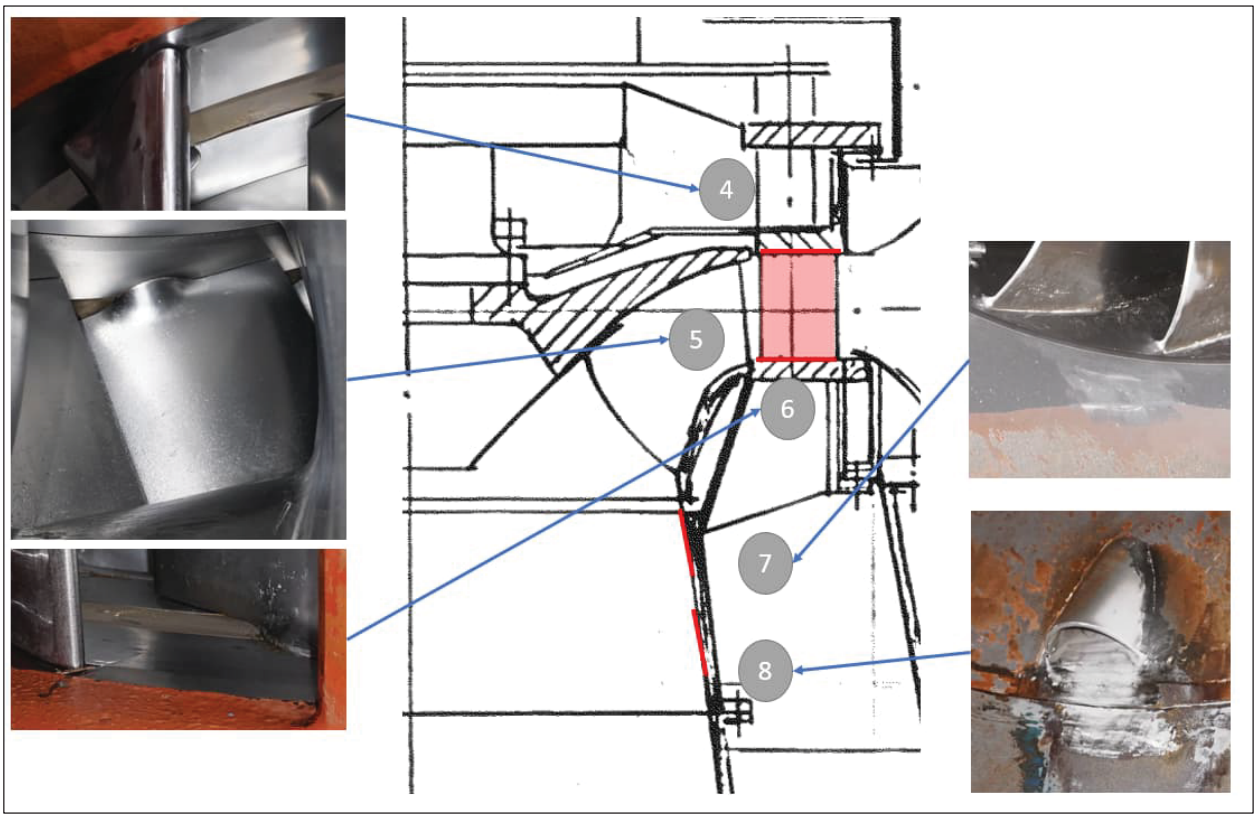


Figure 4-10: Turbine Observations

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5. Assessment

5.1 Runner

The runner that was inspected at Hinds Lake is now 42 years old. The normal design life of such a runner is expected to be 50 years or more. It must be understood that at the time of the design of the runner, advanced numerical flow modelling and calculations were not available.

Hatch was informed that the turbine is operating in the entire operating range, including extensive periods at speed-no-load and part-load, which may affect the life of the runner negatively.

Based on the observations of the runner, it is the opinion of Hatch that the runner is expected to continue operate safely if it is not subjected to an increase in the number of start-stops and is operating near the optimal operating zone. Increasing the number of start-stops and operating at partial load (0 to ~70%) or speed no load increases the frequency and amplitude of mechanical stress on the runner, thus lowering its expected fatigue life expectancy.

5.2 Turbine Upgrade Potential

Hatch has reviewed the hydraulic design of the turbine and estimating based on similar units, considers that Hinds Lake is suitable for upgrade. However, it is necessary to establish the hydrology at the reservoir and downstream of the plant. The water level is not defined with sufficient information. Also, many dimensions of the turbine are missing which limits the potential for analysis.

Based on the limited information for a similar 1980s' turbine, the potential for efficiency upgrades is between 1.5 to 3.0%. We assume that the efficiency hillchart provided for this study is a model hillchart. The current prototype peak should be around 93% where a modern runner would be somewhere above 94.5%.

In terms of output, the existing name plate sets the rating at 77.3 MW and the manufacturer's report set the maximum output at 78.96 MW. Without more information, Hatch estimates the potential for upgrade to be limited to somewhere between 80 to 85 MW.

The upgrade potential is largely dependent on the velocity limit in the spiral casing and draft tube, the tail water level, and the centerline setting. Efficiency gains are also possible through the replacement of the runner and the modification of the guide vanes to add end seals, thus reducing leakage losses at the distributor.

5.3 Generator Assessment

The unit already has a continuous 20% overloading capacity with a 60^0 C temperature rise over 40^0 C cooling air. Considering that the current IEEE 50.12 standard allows the operation of refurbished units at higher temperatures, and rewound winding must have more modern wedging systems with springs, we believe that there is a possibility to increase the output

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power by 5%. Such a possibility should be analyzed in detail on all major components of the generator by the successful bidder when the rewind of the unit is scheduled.

Based on reviewed inspection and test records that NL Hydro provided, this unit has the following issues: corona degradation on bars in slots: 4-5; 30-31; 219-220 and 237-238 at the bottom/top of the unit, high vibration on jumpers, circuit rings, and some bars, as well as widespread loose wedges (if nothing has been repaired since the last outage in 2019).

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6. Recommendations

6.1 Runner

To improve the life of the runner, it is recommended that NL Hydro:

- Equip the plant with adequate instruments to measure water level and flow, if not already present. If instruments are already present, review the plant operational history.
- Equip the plant with accelerometer sensors to detect cavitation and operate inside cavitation free zone.
- Inspect the runner every two or three years and perform necessary cavitation repairs.
- Optimize and operate in cavitation free zone. Request Andritz to complete a model report or consult them to determine the cavitation free zone.

If it is the intent of NL Hydro to operate the plant without restrictions in the operating zone and with an increase in the number of starts and stops, it is recommended to:

- Equip the plant with adequate instruments to measure water level and flow.
- Equip the plant with accelerometer sensors to detect cavitation and operate inside cavitation free zone, and to detect blade failure by cracking.
- Perform a FEA of the runner and evaluate the remaining fatigue life.
- Inspect the runner every year and perform necessary cavitation repairs.
- Order a spare runner with an improved hydraulic and structural design (which can easily be replaced by the draft tube cone).

For either scenario, it is relevant to test the base material of the runner as well as the filler material to understand its properties. Successive generation of repairs have altered the original material and analyzing its properties is part of understanding the remaining life.

6.2 Turbine

The components that were inspected appear to be generally in good condition. For the guide vanes and facing places, the following are recommended:

- Grind and remove defects on the facing plate by polishing, or diamond wire to remove galling between the facing place and the guide vanes.
- Measure and adjust guide vane top and bottom clearance.
- Replace all wear plates with new.

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6.3 Generator

Vibration of the bars in the slot (if present) can be checked by using a borescope through the vents in the core from the back. If a black powder residue is observed along the side of the bars, then the bars are vibrating in the slot due to loose wedges. A re-wedging of the unit would thus be required to prevent further degradation of the ground wall insulation on the bars. Re-wedging of the unit would require a complete removal of the rotor.

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7. Cost Estimates

Hatch offered a wide range of recommendations in Section 6. The following are estimated:

- Runner repair in-situ.
- Install a cavitation detection system using accelerometers.
- Perform a CFD and FEA study on the runner.
- Procurement, supply and installation of a new runner.
- Re-wedge the generator.

7.1 Runner Repair In-situ

Runner repair in-situ is estimated as presented in the table below. The duration for in-situ repair is estimated at 3 weeks.

Table 7-1: Runner Repair in-situ Estimate

Activity	Quantity	Rate $	Subtotal $
Mobilization	1	10,000	10,000
Repair	1,000	120$/h	120,000
Consumables & rentals	1	20,000	20,000
Project Management	250	150$/h	37,500
Demobilization	1	10,000	10,000
Travel / lodging	1	16,800	16,680
Contingency	20%		42,836
		Subtotal	**257,016**

Hatch used a reference for a 4 m diameter runner to scale the estimate. Hatch assumes no engineer is required to carry out the repair since procedures have been developed.

7.2 Vibration and Cavitation Detection System

In absence of accurate information to predict in which operating conditions the runner may cavitate, NL Hydro has the option to upgrade its monitoring system with a more modern vibration system capable of detecting vibration from cavitation.

The system would include the following:

- 4 relative vibration sensors
- 1 key-phaser
- 2 accelerometers (for cavitation)
- 1 distributed vibration system
- 1 vibration analysis software.

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The cost estimate is presented below in Table 7-2.

Table 7-2: Vibration Monitoring System

Activity	Quantity	Rate $	Subtotal $
Specification	1	10,000	10,000
Vibration Monitoring System	1	30,000	30,000
Vendor support	1	10,000	10,000
Installation and commissioning	1	10,000	10,000
Integration/NL Hydro Engineering	1	20,000	20,000
Project Management	80	150$/h	12,000
Travel / lodging	1	10,000	10,000
Contingency	20%		20,400
		Subtotal	**122,400**

7.3 Perform a CFD and FEA Study on the Runner

This work involves scanning the existing runner profile and perform reverse engineering of the existing runner.

Table 7-3: CFD and FEA Study

Activity	Quantity	Rate $	Subtotal $
Specification	1	30,000	30,000
NL Hydro Inspection Support	1	50,000	50,000
In-situ Runner profile scan	1	100,000	100,000
Runner 3D geometry design	120	300$/h	36,000
Water Passage design	120	300$/h	36,000
CFD Analysis	300	300$/h	90,000
FEA Analysis	240	300$/h	72,000
Project Management	120	150$/h	18,000
Contingency	20%		86,400
		Subtotal	**518,400**

The amount presented here is of the same order of magnitude as the effort necessary to perform a new runner design. However, the intent of such study is to understand the existing runner and remaining life.

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7.4 Procurement, Supply and Installation of a New Runner

The runner is now in its 42nd year of operation. NL Hydro can already procure a new runner for storage until proper timing installation. The cost for a runner replacement is presented in Table 7-4.

Table 7-4: Runner Replacement

Activity	Quantity	Rate $	Subtotal $
Specification	1	75,000	75,000
Runner Procurement	1	1,600,000	1,600,000
Mobilization	1	10,000	10,000
Removal and re-installation	400	120$/h	48,000
Commissioning	1	50,000	50,000
Consumables	1	20,000	20,000
Project Management	500	150$/h	75,000
Demobilization	1	10,000	10,000
Travel / lodging	1	25,000	25,000
Engineering services	1	100,000	100,000
Contingency	20%		402,600
		Subtotal	**2,415,600**

The runner is expected to be procured from a tier 1 or tier 2 runner manufacturer with assembly in North America or Europe, but with raw material originating worldwide. Delivery would be FCA St. John's. Only limited supervision is foreseen since it is only for a runner replacement without a complete unit dismantling.

7.5 Re-wedge the Generator

Re-wedging may be required within the next 5 years. The operation requires the procurement of wedges and accessories, the rotor removal, the installation of the generator platform, the removal and re-installation of wedges, the re-assembly of the rotor, and the re-commissioning of the unit which may involve re-alignment. A wedge design may be required if the OEM is unable to supply such parts. The cost estimate is presented below.

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Table 7-5: Generator Stator Re-wedging Estimate

Activity	Quantity	Rate $	Subtotal $
Specification	1	30,000	30,000
Wedge Procurement	1	50,000	50,000
Mobilization	1	10,000	10,000
Rotor removal, re-wedge, re-assembly	720	120$/h	86,400
Commissioning	1	25,000	25,000
Consumables	1	10,000	10,000
Project Management	120	150$/h	18,000
Demobilization	1	10,000	10,000
Travel / lodging	1	20,000	20,000
Contingency	20%		51,880
		Subtotal	**311,280**

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8. Conclusions

Hatch inspected the runner, the turbine, and the generator at Hinds Lake. While the access to the unit was somewhat limited, and original OEM had not provided all technical and operational data for their design, the following conclusions have been drawn:

- The turbine and the runner that were inspected are generally in acceptable condition with no immediate risk of failure. Within 1 or 2 years, NL Hydro should plan to repair new cavitation and existing cavitation on outlet of blade 1, 3, 9 and 10. During this future outage, it is recommended to lower the runner and perform work in the erection bay to have access to the inlet and improve access to the runner for better workmanship.
- Operating the turbine and runner outside its optimal setting may lead to premature end of life of the runner. Instrumenting the plant may help in operating the unit within optimal settings.
- Because drawings and information are not sufficient, it is not possible to precisely estimate the upgrade potential. However, based on comparable technology, Hatch estimate the possible efficiency gain to be a minimum of 1.5% and output gain to be a minimum of 5%.
- NL Hydro should perform a borescope inspection of the sides of the bars (at both the high and low voltage sides) in the slot by using the vents of the stator core from the back of the core (as accessible through inspection windows on OD of the frame). If a black powder residue along the side of the bar is observed, then there is bar vibration in the slot.
- Cost of the following major recommendations were estimated:
  - Runner Repair in-situ.
  - Installation of a cavitation detection system using accelerometers.
  - Runner a CFD and FEA study on the runner.
  - Procurement, supply and installation of a new runner.
  - Re-wedge the generator.

These cost aim to provide guidance to NL Hydro in their short term and long-term capitalization plan to extend the life of the unit as well as replace major components.

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Appendix A
Review of the Inspection Report, Test Records Provided by NL Hydro

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NL Hydro - Hinds Lake, U1 Review of the inspection report, test records provided by NL Hydro

H369389-0000-21A-060-0001

Component	Subcomponents	Report Date	Report Provided By	Review of the Inspection and Test Records Provided by NL Hydro	Hatch Comments	
Generator				**The generator of U1 is supplied by Hitachi rated for 83.3 MVA / 100 MVA max, 13.8 kV, 0.9 pf, 360 rpm with static excitation.**		
	Stator / rotor	13-Nov-2020	EnerServ	1. A mandatory inspection was performed after rotor rebuild. Collection of the carbon contaminant on rotor pole connectors leading edges after short period of time - one year only. 2. Stator winding phase jumpers, main and neutral bus lashes are loose with signs of corona, that might lead to premature failure.	1. Investigate with OEM effectiveness of the carbon dust sealing within the collector rings compartment. The ventilation system for collector rings is separate from the generator ventilation system (see drawing 10P069-625), so it might be required to implement dust collection system. 2. It is not known to us if anything was done regarding the looseness of the existing lashings to prevent further degradations.	
	Stator winding	29-Oct-2019	Qualitrol_Iris Power LP	1. Impact (bump) test was performed. The calibrated force is used on 64 jumpers on NDE, circuit rings close to the main leads and some stator bars near slot exit as those components are prune to more vibration and then measured its overall response in high magnitude accelerance (m/s^2)/N. It has been found that frequency respond function (FRF) at over 12 locations are greater than 0.85 at the frequency of interest. Some of them are in the area of 5 to 8 m/s^2/N, that coincide with location where the lashings on the jumpers or circuit rings are loose.	1. It is not known to us if anything was done regarding the looseness of the lashings to prevent further degradations. When we reviewed stator coil drawing 10P071-070 and assembly of the stator coil connection of generator drawing 10P078-825, we noticed that heavy 1 to 7 jumpers are quite high above core end and they are lashed together only while main and neutral leads are supported by lashing them to light steel structure. Such arrangement for both are possibly destined for vibration, so it would be required to re-address this issue at first scheduled rewind of the unit.	
	Stator winding	31-Oct-2019	Qualitrol_Iris Power LP Partial Discharge Test	Higher PD activity are recorded on phase A (T1) at the 45^0 / 225^0 phase positions - indicative of the phase to ground voltage dependent PD sources in a slot portion of the stator winding), vs moderate PD activity on other two phases. Trending of the readings from 2013 to 2015 to 2018 did show some variations up and down on Qm+ and Qm-, but not dramatic increase upward.	Perform next PD reading on more sensitive scale of HydroTrac.	
	Stator winding	15-Nov-2019	Doble Test	PF and Tip-up test was performed by NL Hydro. Recorded values are in the area expected for epoxy-mica insulation system. Visual inspection listing in the report seems to be standard, without marking what was observed on this machine and to what extent.		
	Staor winding	13-Nov-2019	Wedge detector test	NL Hydro performed wedge tightness test during the outage for field poles reinsulation on 2019 by using Iris wedge detector. The mapping show that majority of the wedges are very loose, recomending that rewedging of the stator winding should be done at earlier possible opportunity.	Due to limited access to the ID of the stator with rotor in place, Hatch inspector could not even reach the area of the end wedges by hand from the bottom or top of the unit. The OEM stator coil drawing 10P071-070 shows that semiconductive liner is used only with other fillers in the slot, so tightness of the wedges are relaying on slot packing shrinkage over the 40 years of unit operation. There is no wedge spring in this OEM design, neither the special wedges axialy as an access to measure the spring tightness, so when we sum all data the conclusion is leading to possible bar vibration in the slot which can lead to the ground fault failure. Records of wegde mapping, bump test vibration, high PD activity, visual corona by the end of the core on the bars in slots 4-5; 30-31; 237-238 and 219- 220 are supporting above conclusion. Once the rewind of the unit would be scheduled, this OEM design should be reviewed to implement more modern stator wedging system with a spring.	

	Stator / Rotor	21-Sep-2019	Electrical inspection report	1. NL Hydro performed IR, PI and DC hipot test on stator winding with results all acceptable when the rotor was taken out for field poles re-insulation. It has been observed a severe corona activity in four zones from the core ends toward the coil diamond at the bottom and top of the unit, that are lining up with slot numbers: 4-5; 30-31; 237-238 and 219- 220 with recommendation that those coils shall be repaired before end of the outage. 2. Observation of the rotor rim movement at the top of the unit a few millimeters in relation to the bottom of the rim stack, could be a sign that rotor rim shrink is lost.	1. It's not known to Hatch if recommendation of the corona repair is done or not on those coils. When such degradation is in the area of interface of other corona protection (OCP) and end corona protection (ECP) which is high stress area, then corona activity is likely present in the core slot as well. The same slots have the high voltage coils which are close to the main leads (majority belongs to phase A (T1)) have loose wedges as well, so vibration of the coils in the slots are likely present. This can be confirmed by using the borescope trough vent plate from the back of the core to see if any residue of abrasion from OCP is present. Once the contact between bar OCP surface and the core slot surface is lost by degradation of the OCP, the corona would progress into the ground wall insulation much faster leading to the ground fault in the slot. Such fault can severely damage the stator core lamination as well as melt the bar off. 2. It is not known to Hatch from available OEM drawings if we have floating rim or rim shrink design on this machine, but this observation should be further investigated.	

Appendix B
Turbine Pictures

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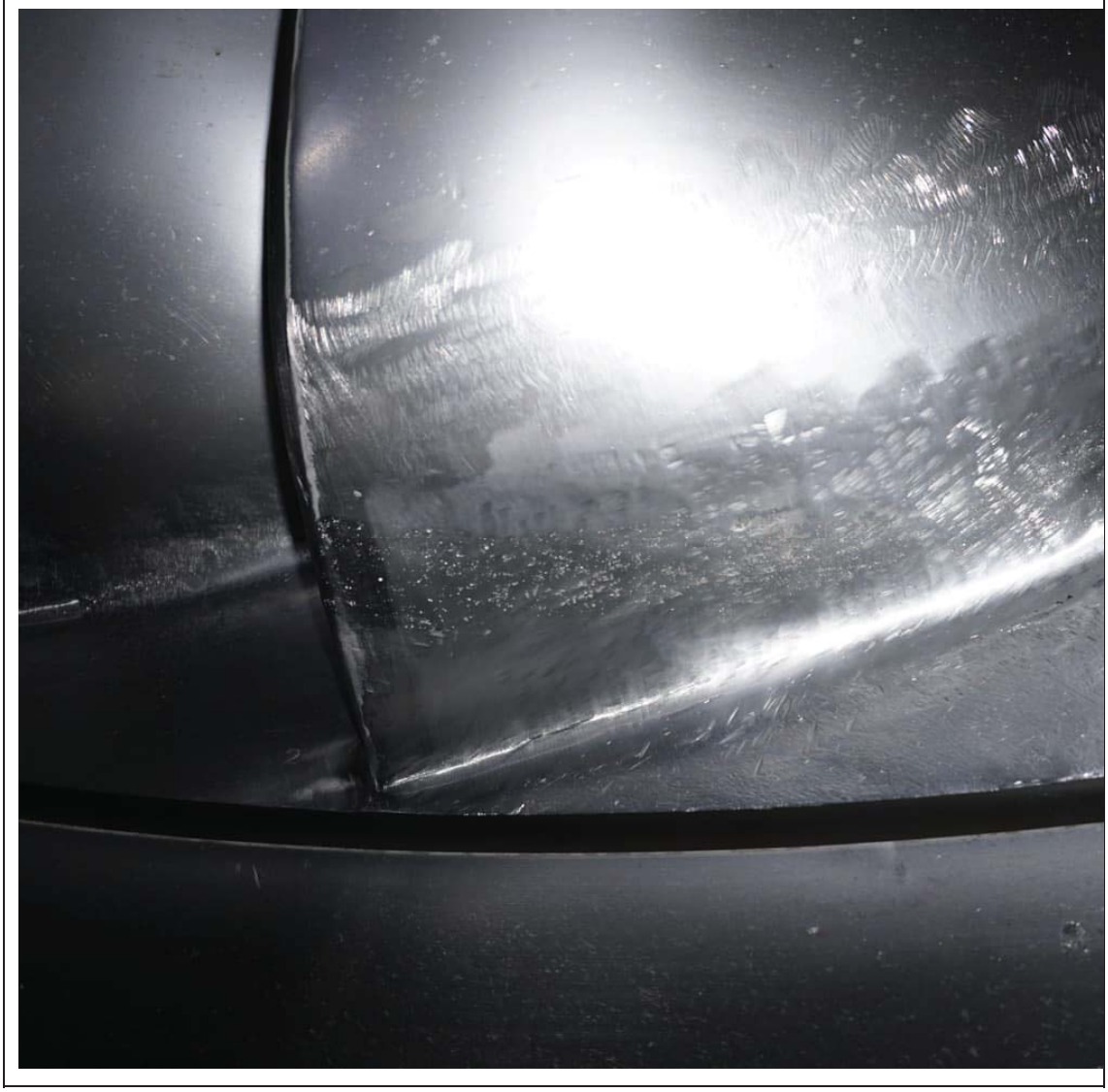
B.1 Blade Pictures

Blade 1



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Blade 2



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Blade 3



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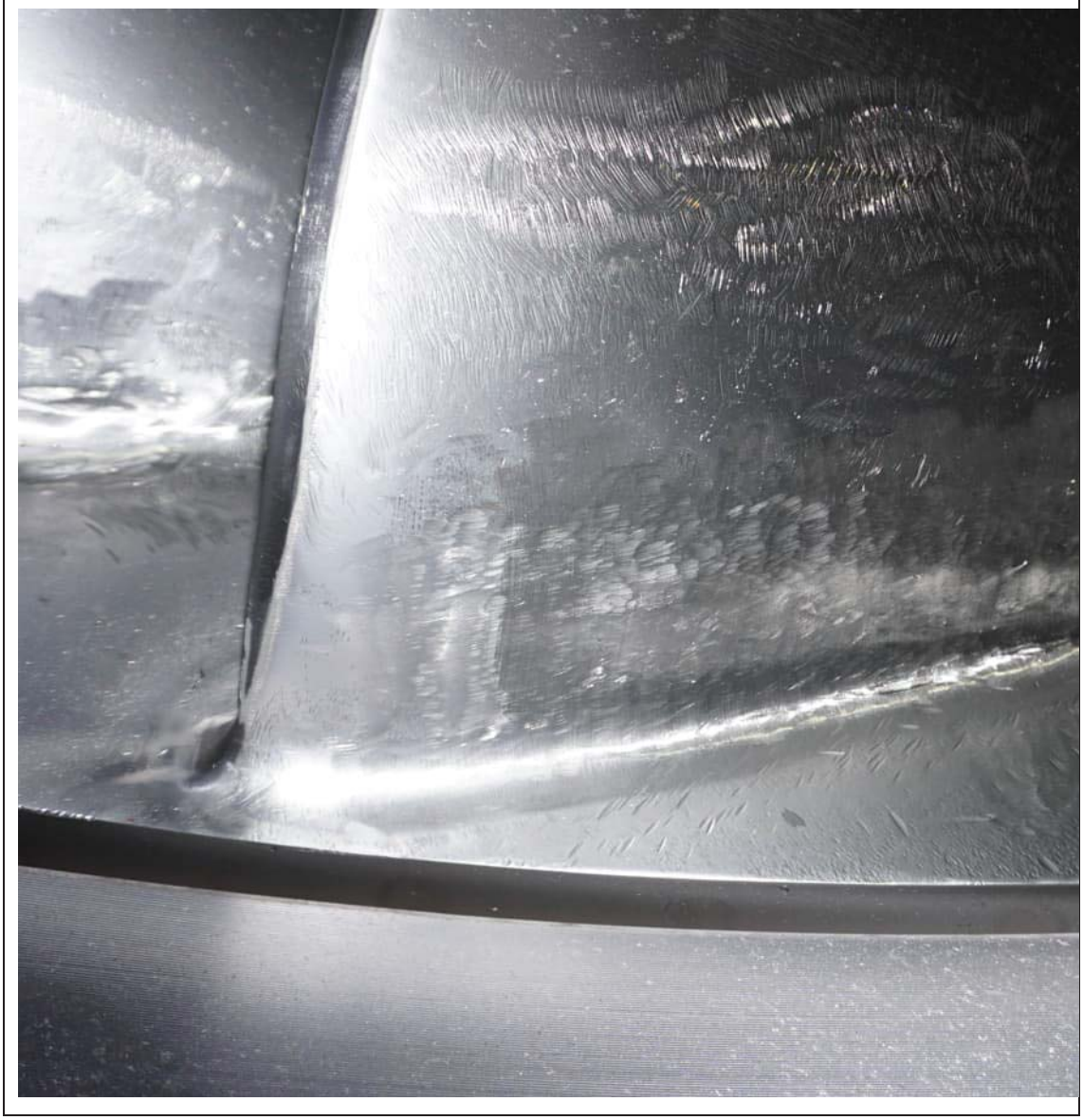
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Blade 5



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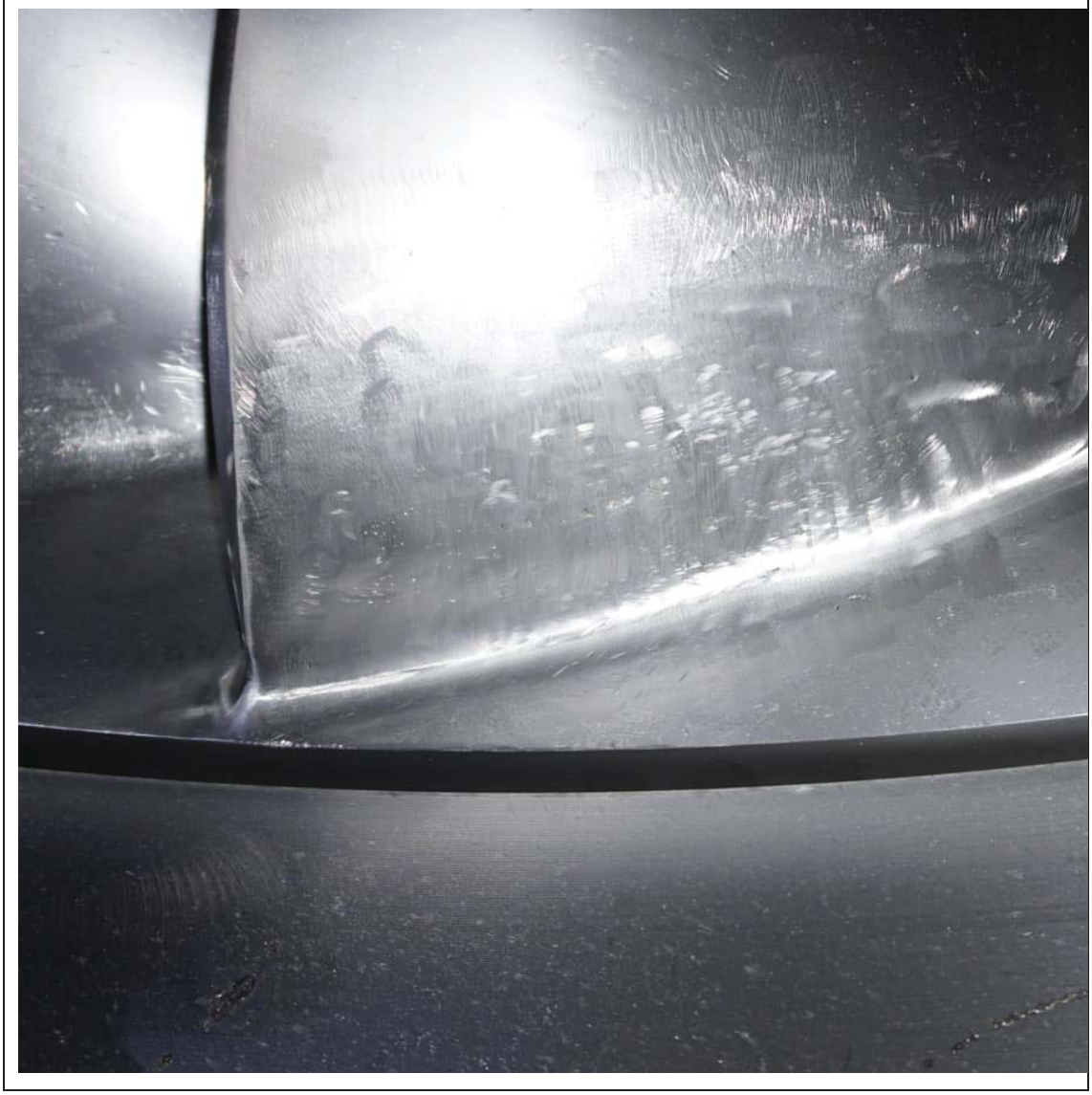
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Blade 7



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Blade 8



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Blade 9 – Incipient Cavitation on Blade Surface



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Blade 10 - Incipient Cavitation on Blade Surface



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Blade 16



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B.2 Guide Vane Pictures

Guide Vane Pressure Side



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Guide Vane Suction Side



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B.2.1 Runner and Draft Tube

View of Entire Runner



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View of Upper Draft Tube Cone Liner



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View of Air Vent and Draft Tube Cone Surface



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$1,000,000 to $5,000,000

Refurbish Intake 2

2025–2026

Bay d’Espoir



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Attachment 1: Cancellation of Previously-Approved Capital Projects at Bay d'Espoir

Attachment 2: Bay d'Espoir Hydroelectric Development – Intake #1 Inspection – April 2016

Refurbish Intake 2 (2025–2026)

Location: Bay d'Espoir

Investment Classification: Renewal

Asset Category: Hydraulic Plant

Cost: $3,353,751

1.0 Introduction

The Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir") 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.

Bay d'Espoir 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. Bay d'Espoir Units 3 and 4, fed through Intake 2 and Penstock 2, are major hydroelectric units in the Bay d'Espoir generating fleet that are operated to meet system load requirements on the Island Interconnected System. 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.

The refurbishments of the Bay d'Espoir intakes were originally proposed as two-year projects within Hydro's Hydraulic Generation Refurbishment and Modernization Program, filed as part of its annual capital budget application ("CBA")—Intake 1 (2018 CBA),[1] Intake 2(2019 CBA),[2] and Intake 3(2020 CBA).[3] 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, project scope changes and delays related to the COVID-19 pandemic

[1] "2018 Capital Budget Application," Newfoundland and Labrador Hydro, rev. October 3, 2017 (originally filed July 27, 2017), vol. II, tab 1, approved in Board Order No. P.U. 5(2018).
[2] "2019 Capital Budget Application," Newfoundland and Labrador Hydro, rev. October 9, 2018 (originally filed July 31, 2018), vol. II, tab 1, approved in Board Order No. P.U. 46(2018).
[3] "2020 Capital Budget Application," Newfoundland and Labrador Hydro, August 1, 2019, vol. II, tab 1, approved in Board Order No. P.U. 6(2020).

resulted in missing the outage window required to replace Intake Gate 2. As such, in 2021, Hydro filed correspondence with the Board of Commissioners of Public Utilities ("Board") to cancel the refurbishments of Intakes 1 and 2.[4] Hydro noted in this correspondence that the work on Intake 3 would continue, while proposals would be developed for the refurbishments to Intakes 1 and 2 following analyses to determine the appropriate timeframe for execution.[5] The Refurbish Intake 1 Project (2024–2025) was proposed and approved in the 2024 CBA.[6,7]

Intake 2 has been in service since 1967 and has performed well; however, some components are approaching the end of their service life, which can threaten the reliability of the powerhouse and penstock if not addressed. As such, the Intake 2 refurbishment work is required in 2025 to maintain the safe and reliable operation of Intake 2.

2.0 Project Description and Justification

The scope of this project is to refurbish the Bay d'Espoir Intake 2, including the replacement or refurbishment of several main components: the intake gate, embedded parts, superstructure, and hoist.

This project is required to maintain the reliable operation of the Bay d'Espoir Intake 2. 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, such as when Intake Gate 2 failed to close due to a side roller issue in 2013. 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 critical for Hydro to maintain the reliable operation of the Bay d'Espoir Intake 2. Due to operational constraints, delays related to the COVID-19 pandemic, and project scope changes[8] Hydro was not able to execute the planned refurbishment of Intake 2 in 2020; however, the condition of

[4] Please refer to Attachment 1.
[5] Work proceeded on Intake 3 in 2021; the intake was refurbished, and the gate was successfully replaced.
[6] "2024 Capital Budget Application," Newfoundland and Labrador Hydro, rev. December 15, 2023 (originally filed July 12, 2023), sch. 6, proj. 2, approved in Board Order No. P.U. 35(2023).
[7] As the approved Bay d'Espoir Penstock 1 Life Extension Project would result in an extended outage to the associated assets in 2025, Hydro determined it would be most efficient to cluster the Refurbish Intake 1 (2024–2025) – Bay d'Espoir Project to be completed during this time. While it is expected that Penstock 2 will require similar refurbishment in the future, the Intake 2 work cannot be delayed any further to align with the potential refurbishment of Penstock 2.
[8] Originally, Hydro proposed to replace Intake Gate 1 and refurbish the existing Gate 1 for use on Intake 2. However, after the completion of a cost-benefit analysis, it was determined that the least-cost option was to proceed with the replacement of all gates instead of refurbishment.

Intake 2 has continued to deteriorate since that time, and Hydro proposes to proceed with this project in 2025–2026.

3.0 Asset Overview

3.1 Asset Background

The Bay d'Espoir Intake 2 was commissioned in 1967 and supplies water to Penstock 2. Penstock 2 transports water to Units 3 and 4, which have a combined generation capacity of 153 MW.

As shown in Figure 1, Intake 2 is comprised of many moving and embedded parts that together control the water flow into the penstock. The main component of Intake 2 is the gate, which is formed by a welded steel frame with a downstream skin plate and concrete ballast. Each gate has four pre-loaded side rollers and 12 main rollers. The gate is operated with a cable hoist attached to a single central lifting point.

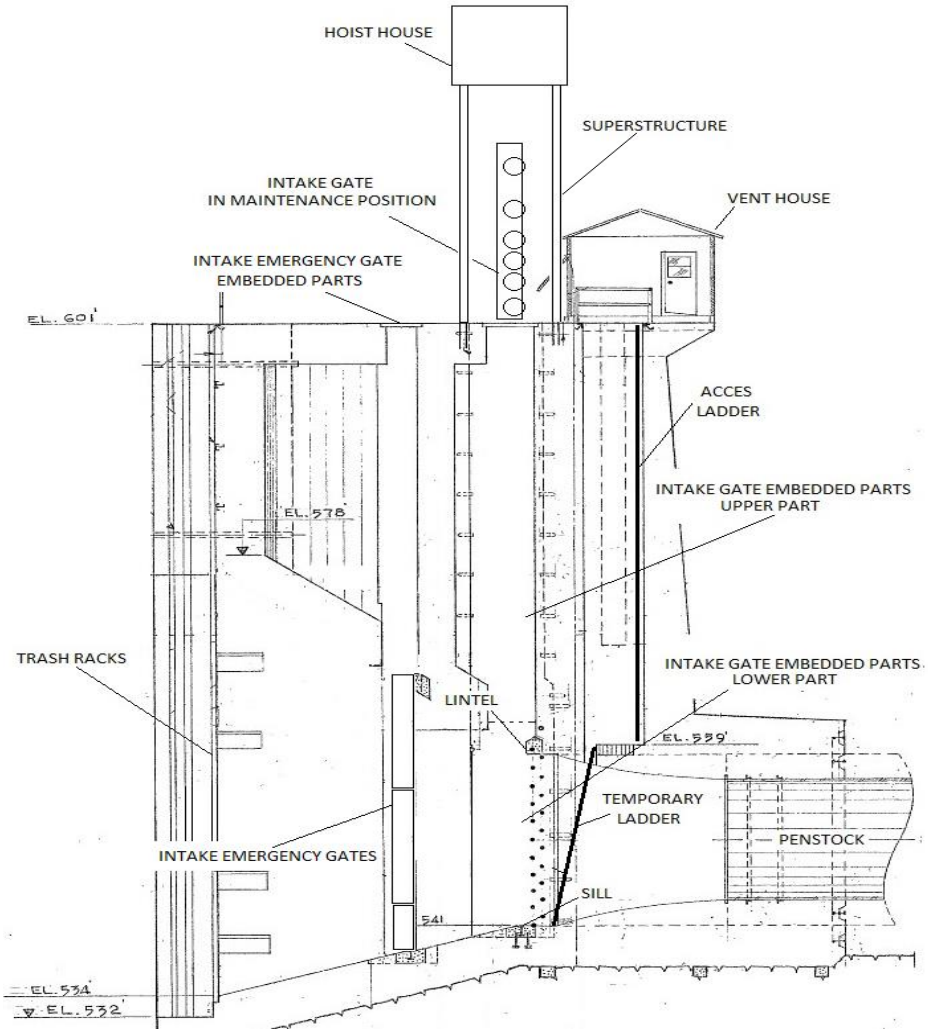


Figure 1: Bay d'Espoir Intake Structure

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.[9]

[9] Bay d'Espoir 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[10] 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 2013, Intake Gate 2 failed to close due to issues related to seized side rollers on the gate. In the past 30 years, Hydro has experienced two other major incidents at 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 2 has performed well over its 57-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 2016 condition assessment indicated varying levels of deterioration, particularly in submerged and embedded components, which included concrete erosion and corrosion on embedded parts and gate components.[11] As recommended in the 2016 condition assessment, Hydro has assumed that Intakes 1, 2, and 3 are in similar condition, as all three intakes are of similar design, age, and operation. This assumption was confirmed during the execution of the Intake 3 refurbishment in 2020–2021, as critical components that were deteriorated included main rollers, roll paths, side rollers, and seals, as seen from the original condition assessment in Figure 2 and Figure 3. As such, Hydro has assumed the pre-refurbishment condition of Intake 3 to be the current

[10] 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 the control gate to elevate differential pressure, allowing the emergency gates to be removed.

[11] Please refer to Attachment 3 of Hydro's response to PUB-NLH-018, Revision 1 of its 2018 CBA proceeding.

condition of Intake 2, in addition to the deterioration experienced given its continued operation since 2021.



Figure 2: Intake 1 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. The Bay d'Espoir Intake Gate 2, which is 57 years old, is showing deterioration and will reach the end of its service life by 2026.

4.0 Analysis

4.1 Evaluation of Alternatives

The proposed alternatives for this project include:

- Deferral;
- Refurbishment of intake structure and gate; and
- Refurbishment of intake structure with gate replacement.

4.1.1 Deferral

Intake 2 is an integral part of Bay d'Espoir; it provides water control for Units 3 and 4, which have a combined generation capacity of 153 MW.

Hydro decided to defer this project in 2021 in light of the prioritization of other critical work on the system and delays associated with the COVID-19 pandemic; however, this work cannot be delayed further. This work is required to maintain the safe and reliable operation of Intake 2. Further deferral poses a safety hazard and risks the operation of Units 3 and 4. 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.

4.2 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.[12] The lowest-cost option is the gate replacement.

Table 1: Least-Cost Evaluation Summary ($000)

Alternatives	CPW[13]	CPW Difference between Alternative and the Least-Cost Alternative
Gate Replacement	501	-
Gate Refurbishment	562	61

4.3 Recommended Alternative

Based on the least-cost evaluation, it is recommended to proceed with the refurbishment of the Intake 2 structure with gate replacement.

4.3.1 Risk of Asset Stranding

Bay d'Espoir 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 Bay d'Espoir; therefore, Hydro considers the risk of asset stranding to be low.

[12] 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.
[13] Cumulative Present Worth ("CPW").

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025–2026 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-Implementation	5	3	**15**
Post-Implementation	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 2025.

In 2025, 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 2026, the scope includes:[14]

- 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.

[14] This approach is similar to the execution strategies developed during the rehabilitation of Intake 3 in 2020–2021. The replacement of Intake Gate 2 will utilize the same design as that of Intake 3.

5.1 Project Budget

The estimate for this project is shown in Table 3.

Table 3: Project Estimate ($000)[15]

Project Cost	2025	2026	Beyond	Total
Material Supply	0.0	122.9	0.0	**122.9**
Labour	138.7	398.5	0.0	**537.2**
Consultant	100.0	132.0	0.0	**232.0**
Contract Work	0.0	1,928.1	0.0	**1,928.1**
Other Direct Costs	8.1	39.2	0.0	**47.3**
Interest and Escalation	12.9	186.7	0.0	**199.6**
Contingency	24.7	262.1	0.0	**286.7**
Total	**284.4**	**3,069.4**	**0.0**	**3,353.8**

5.2 Project Schedule

The schedule for this 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 2025	May 2025
Procurement Consultant engineering, procure materials, and replacement parts.	February 2025	May 2026
Construction Perform the refurbishment and required replacements.	June 2026	September 2026
Commissioning Commission new equipment.	September 2026	September 2026
Closeout: Document closeout and lessons learned completion.	October 2026	November 2026

[15] Numbers may not add due to rounding.

6.0 Conclusion

The Bay d'Espoir Intake 2 is approaching the end of its service life and requires major refurbishment. This project is required to ensure the future reliable operation of Units 3 and 4 at Bay d'Espoir. Unit 3 and Unit 4 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 at Bay d'Espoir



newfoundland labrador hydro
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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**
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Senwung Luk, Olthuis Kleer Townshend LLP
Julia Brown, Olthuis Kleer Townshend LLP

Attachment 2

Bay d'Espoir Hydroelectric Development – Intake #1 Inspection – April 2016

RD Énergie

newfoundland labrador hydro
a nalcor energy company

RD ÉNERGIE

Project no: 160304-NLH

Bay d'Espoir Hydroelectric Development

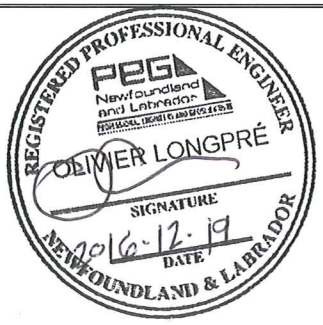
Intake #1 Inspection

April 2016

Prepared by: O. Longpré, P. Eng. 2016-12-16
Olivier Longpré, P. Eng. Date

Verified by: P. Eng 2016-12-16
Simon Rousseau, P. Eng. Date

Rev.	Date	Description	Seal
0	2016-06-30	Draft	
1	2016-11-18	Revised for comments	
2	2016-12-16	Final	



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2. Appendices

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3. Glossary of Terms

BDE: Bay d'Espoir Generating Station

Deck: Floor level at the top of the concrete structure of the intake. It refers to the elevation 601' for the BDE hydroelectric development.

Downstream: In the direction in which a stream, river, etc., flows.

Embedded Parts: Equipment connected to the concrete, bearing the gate. In this report the embedded parts refers to the intake gate embedded parts.

Emergency Gates: Gates which main function is to allow the emptying of the conduit for maintenance purposes and access to the main equipment (intake gate embedded parts for instance). The emergency gates are operated in balanced pressure of water only.

First Stage Concrete: Consists of the first concrete poured during the construction of a dam, forming all the structure of the dam, except the niches surrounding the embedded parts.

Hoist House: Insultated steel shelter covering the wire rope hoist at the intake

Intake: Four penstock entrances, intakes #1 to #4 equipped with intake gates and trash racks.

Intake Gate: Gate located at the intake enabling or disabling the passage of water through the penstock. The intake gate is the ultimate safety device for the turbine and its main function is to close in an emergency situation.

Left: Refers to the shore on the left when looking downstream.

Right: Refers to the shore on the right when looking downstream.

Superstructures: Four steel structures above the intake concrete dam of BDE. The superstructure supports the wire rope hoist and hoist house. It also guides the intake gate when it is lifted above the concrete deck.

Second Stage Concrete: Concrete used after the first stage concrete to fill the space between the embedded parts and the first stage concrete. This process allows the attainment of precise tolerances for the alignment of the embedded parts.

Upstream: Direction toward the source of a stream, a river, etc.

Vent house: House located downstream of the intake gate at BDE, more precisely over the ventilation shafts. It shelters the controls for the wire rope hoist.

Wire Rope Hoist: Lifting equipment use to raise or lower a load with lifting cables.

1. Executive Summary

RD Énergie proceeded with the inspection of Intake 1 between the 16th and the 20th of April 2016 in order to provide detailed information to NL Hydro on the condition of the intake structures.

The hoist components located in the hoist house and superstructure are considered well preserved. Maintenance work to the intake has been ongoing and is present in the observations made.

However, the inspection revealed issues, mostly coming from the deterioration of submerged components due to corrosion. Deterioration of critical components such as the gate main rollers, roll paths, side-rollers and seals directly affect the gate capacity for proper operation and can be a threat to the safety of the power house and penstock if not addressed. This report identified that the intake gate lowering force has diminished significantly, putting its capacity at risk to lower properly in an emergency situation.

Furthermore, deterioration of submerged components is overloading the hoist. Additionaly, the hoisting rope and bottom sheave block were found in very poor condition, diminishing the hoist lifting safety factor. For these reasons, cracking the gate should be avoided until the intake gate main rollers, seals, sheave block and wire rope rehabilitations have been performed. Replacement of the hoisting rope shall be performed as soon as possible.

In the short-term, recommendations are made to rehabilitate the gate and its embedded parts in order to stabilize deterioration and improve the intake gate safety and operability. The costs for these works are particularly significant and close to a gate complete replacement and embedded parts reconstruction. New equipment would have a better life expectancy compared to the rehabilitated ones and could be beneficial for NL Hydro in the long-term. The construction options should be reviewed before starting the rehabilitation process.

Costs estimates for the rehabilitation works established in this report are as follows for one intake:

$127 568 Immediate works to address direct safety issues;

$1 318 487 (short-term 1-3 years) to stabilize and maintain structural integrity and operability of the intake;

$194 100 (medium-term 5-10 years) to stop further deterioration and assure safe and durable operations.

2. Introduction

2.1 Scope of Work

Since the construction of Bay d'Espoir site in 1965, the intake gates and associated equipment have not undergone a thorough investigation to determine the condition of the overall structure and its components. An engineering study done by Hatch in 2008-2009 also identified the need to perform a detailed inspection of the intake gate and its main components.

RD Énergie was instructed to complete a detailed inspection of the Intake 1 in order to provide detailed information to NL Hydro on the condition of the intake structures.

The scope of the inspection included the following main components:

- Gate;
- Embedded Parts;
- Superstructure;
- Hoist;
- Emergency gates.

The objectives were to:

- Inspect and assess in detail the condition of Intake 1;
- Write a detailed inspection report;
- Recommend short-term, medium-term and long-term solutions;
- Produce cost estimates based on recommendations.

The inspection took place between the 16th and the 20th of April 2016 with the assistance of NL Hydro project and operation teams.

NL Hydro proceeded with the dewatering of the penstock using the emergency gates and dogged the intake gate to its maintenance position before the arrival of inspectors. A aerial lift platform was available to inspect the intake gate and the superstructure.

Access to the embedded parts was performed by using the access ladder and additional temporary ladders.

NL Hydro supervised and coordinated the work on the site. Figure 1 shows an overview of the inspected intake. Figures 2, 3 and 4 show general pictures taken during the inspection.

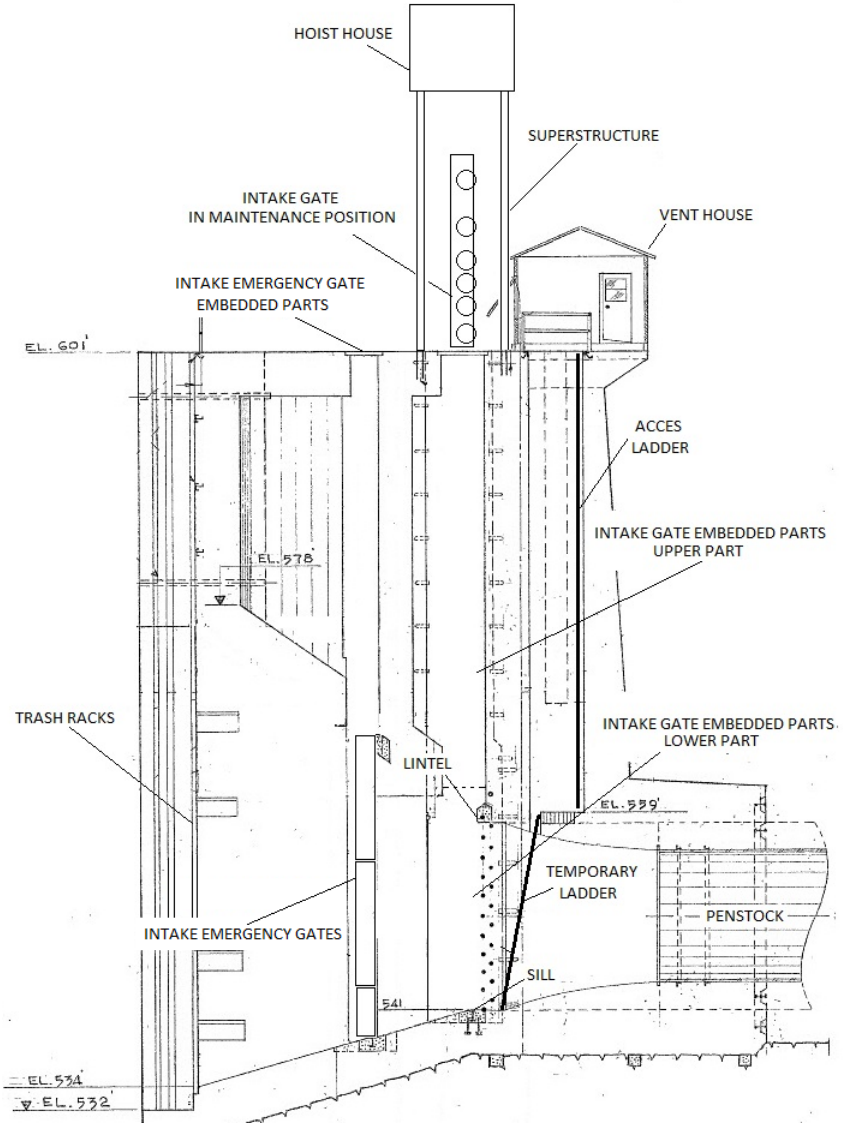


Figure 1: Bay d'Espoir intake structure #1



Figure 2: Access to the embedded parts from the vent house using ladders



Figure 3: Intake #1 at the time of the inspection



Figure 4: Intake #1 dewatered using the emegency gates

2.2 Intake Characteristics

The BDE Hydroelectric Development is located 10 km northeast of Milltown-Head of Bay d'Espoir. The site was built in 1965 by ShawMont Engineering Newfoundland Limited. The generating station has seven (7) Francis turbines, four (4) penstocks and a hydraulic head of 176 m (577ft) for a total capacity of 604 MW.

The intake is equipped with four (4) independent intake gates. Intakes #1, #2 and #3 were designed by Dominion Bridge Co. The fourth intake was installed afterwards and information about its design was not reviewed in this scope of work. Gates #1, #2 and #3 are made of a welded steel frame with a downstream skin plate and concrete ballasts. Each gate has four (4) preloaded side rollers and twelve (12) main rollers. The gate is operated with a cable hoist attached to a single central lifting point.



Figure 5: Intake gate #1 in maintenance position

The intake gate main purpose is to cut the water flow to the powerhouse for emergency or maintenance purposes. The gate must be able to lower under its own weight in case of an emergency and the cable hoist must be able to crack open the gate under full water pressure in order to slowly fill the penstock. The BDE generating station uses the intake gate as a third control device to manage the water flow. The wicket gates and the penstock spherical valve are the two main control systems.

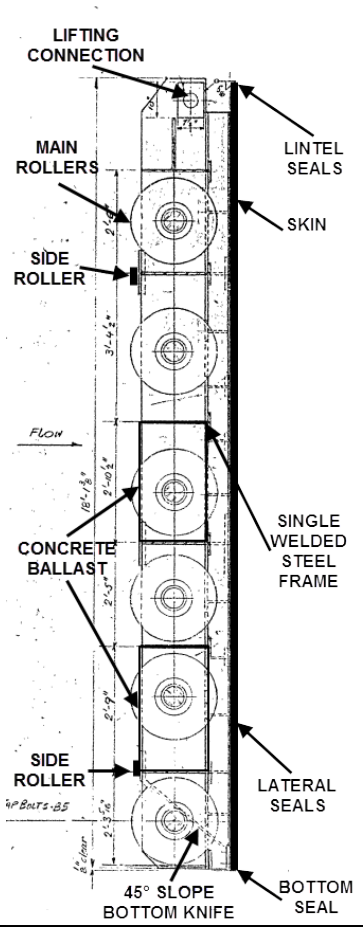
The intake gate can be dewatered for maintenance and inspection purposes using the intake emergency gates. Six (6) emergency gates are needed to completely seal an intake (2 sets of 3 gates). The two (2) bottom gates are only used at the intake while the others can be also used as draft tube gates at the power house. The two (2) gates at the top are equipped with valves in order to refill the void between the emergency gates and control gate to alleviate differential pressure, allowing the emergency gates to be removed. The emergency gates are installed using a master log and a mobile crane.

3. Pre-Inspection Assessment

3.1 Intake Gate General Information

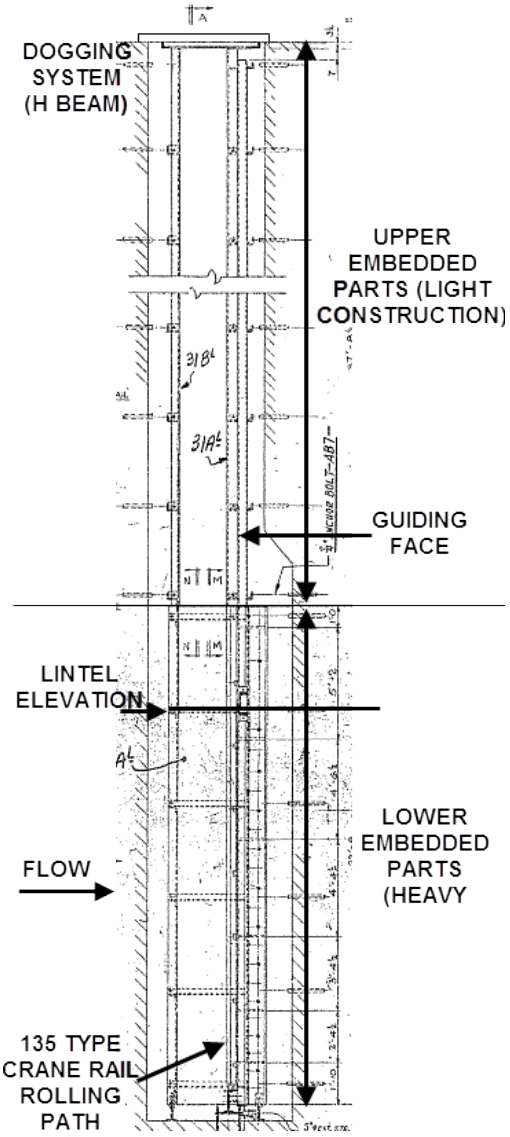
The intake gate is completely submerged most of the time and is rarely used. The gate open position must remain as close as possible to the penstock opening in order shorten the distance for emergency closing situations. The gate is operated minimally once a year, in accordance with the preventive maintenance program.

The main components of the intake gate system include:

Intake Gate o Single welded steel frame with downstream skin plate and seals; o 11mm (7/16'') skin plate; o 5309mm sealed width, 5232mm sealed height; o Twelve (12) 610mm main rollers on *Lubrite* bushings and eccentric shafts; o J-seals on sides and linte l with anti-friction coating; o 6mm precompression of side and lintel seals; o 5mm compression of sill seal; o Guiding system with four (4) preloaded side rollers; o Approx. weight without ballast: 14 510 kg (in air); o Approx. weight with concrete ballasts: 24 490 kg (in air); o 45 ° sloping bottom knife.	

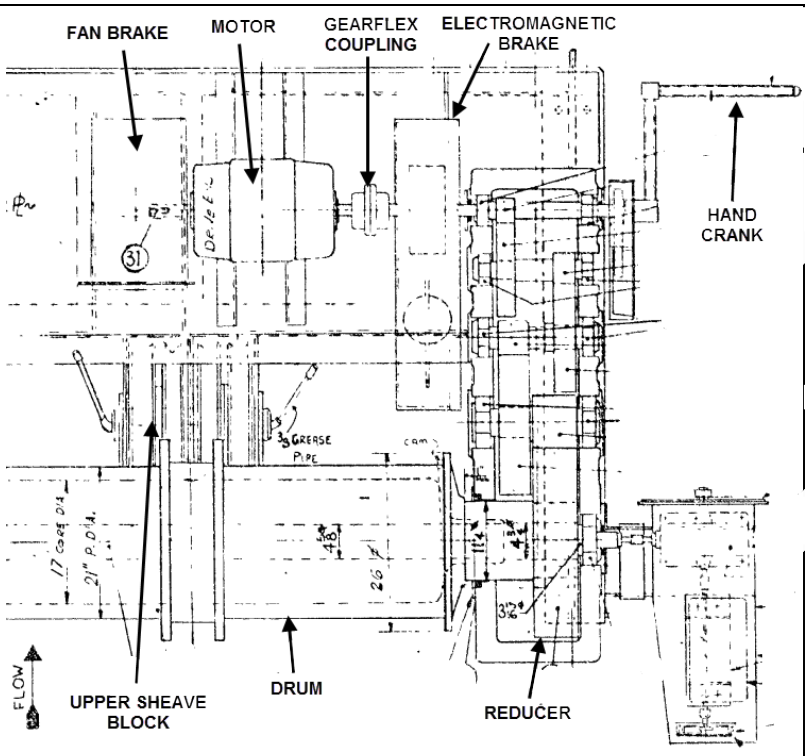
Embedded Parts

- Lateral sections have two different configurations, one for its upper section and one for its lower section;
- The lower section is made of a heavier construction using a 135 type crane rail rolling path with rail clip holders;
- The upper section is made of a ligther construction using channels and angles
- 5715 mm span between rails;
- No heating;
- Machined stainless steel seal faces (sill, sides and lintel);
- H-beams dogging system for fully open position.



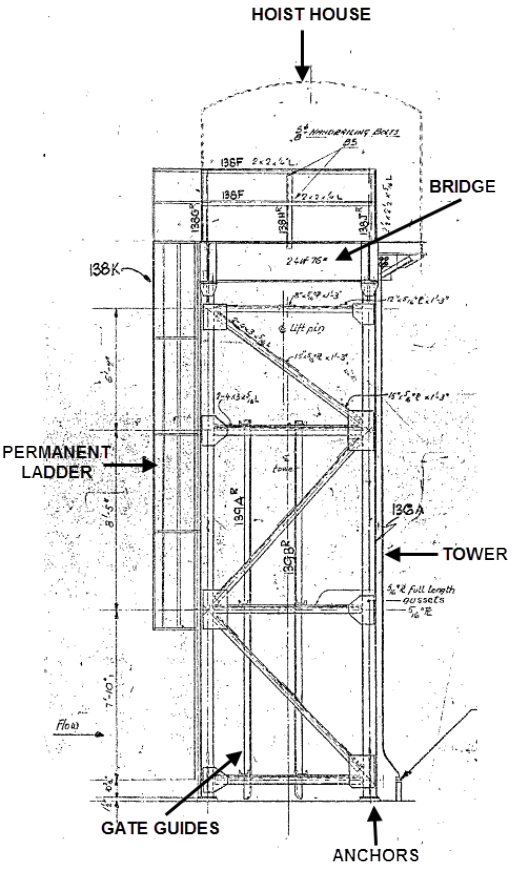
Gate Hoist

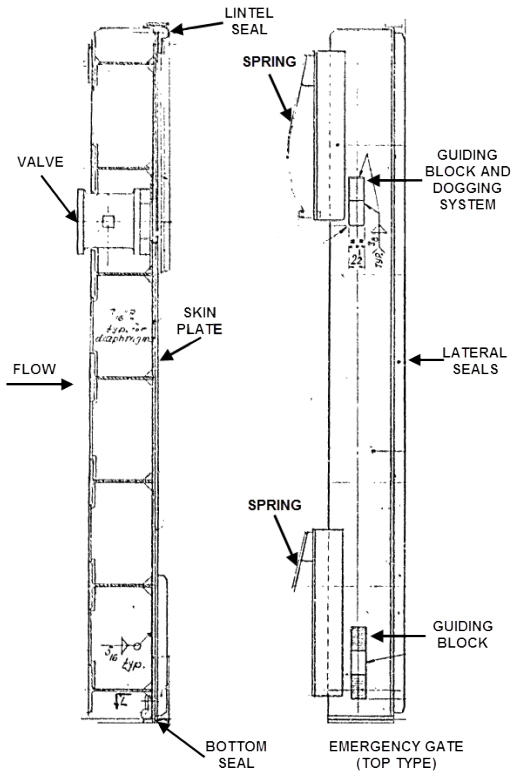
- Single lifting point wire rope hoist;
- Single drum with double winding;
- 40 770 kg (90 000 lbs) hoist capacity;
- 29.3mm/s (5.76 f.p.m) lifting speed;
- 55.9mm/s (11 f.p.m) max dropping speed (lowering on fan brake);
- Powered by a 550V electric motor 20 hp and 1120 rpm;
- Equipped with electromagnetic brake, fan brake and manual emergency operations;
- 7/8" wire rope IPS galvanized;
- 27 200 kg (60 000 lbs) bottom sheave block capacity on *Lubrite* bushings (based on information ref. drawing A-2546-E1) ;
- Four (4) stages helical Dominion Bridge gearbox.



Intake Superstructure

- Welded and bolted assembly of two towers, a bridge, a hoist house and an access;
- 11.51 m high by 2.29 m wide by 6.55 m long;
- Anchored by eight (8) anchor bolts;
- Access by fixed ladder;
- Heated hoist house covered with #11 gage steel flashing and fiberglass insulation.



Emergency gates o Welded steel frame with downstream skin plate and seals o Rubber J-seals on sides, lintel and bottom of gates; o Springs and steel guiding bars; o Two sets of three (3) different emergency gate types are required to completely seal an intake (two bottom ones, two middle ones and two top ones for a total of six (6) emergency gates); o Top emergency gate equipped with watering up valve; o Operated with a master log and mobile crane.	

Key elevations and other design specifications regarding the intake 1, 2 and 3:

- Sill elevation: EL – 541' (164.9 m);
- Lintel elevation: EL – 558' (170,1m);
- Deck level: EL - 601' (183.2 m)
- Full supply water level: EL – 593' (180.7m)
- Low supply water level: EL – 579' (176.5m)

Intake gate drawing list is presented in Appendix A.

The intake gate designed by Dominion Bridge is generally following the industry best practices known at the time in terms of material quality and design principles.

For instance, BDE intake gates have downstream skin plate and seals, which is considered the most reliable configuration for emergency closing operation since it is not subject to catapulting forces when filling the penstock. Figure 6 shows how pressure can form at the back of an intake gate with upstream skin plate and push the gate upward in the gate shaft.

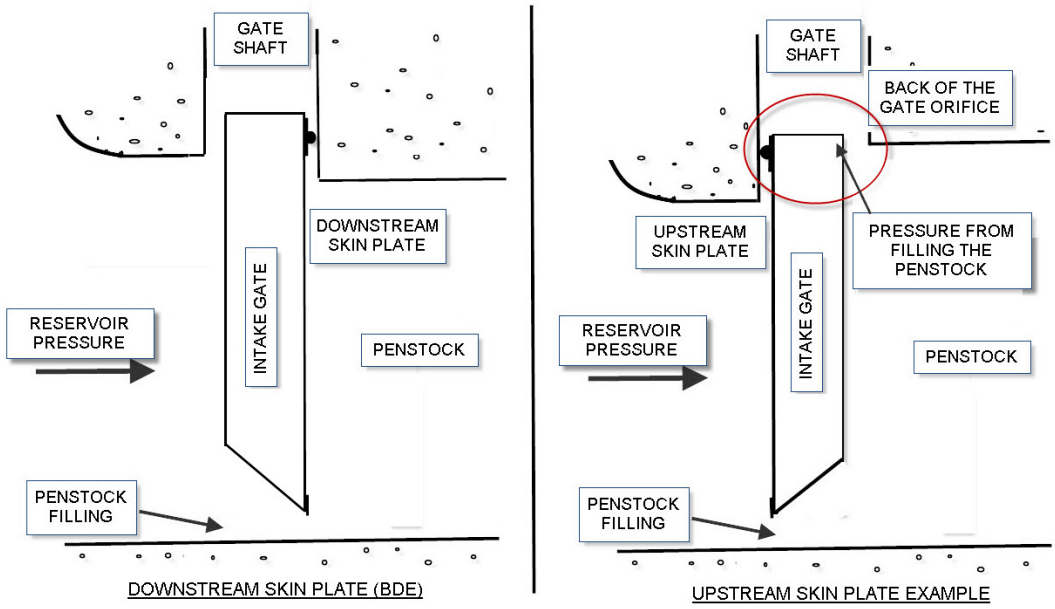


Figure 6: Upstream vs downstream skin plate for intake gate

For intake gates having downstream skin plate and seals, downpull is always an important consideration and particular attention is given to the design of the gate bottom and lintel in order to reduce the hydraulic forces to a minimum. The downpull forces occur with the gate partly open when a part of the head is converted into kinetic energy. The 45° sloping bottom is the optimized design to reduce the magnitude of these downpull forces.

Some concerns in the intake design were identified during the pre-inspection assessment:

- Single flange lintel seal on the intake gate
    - Single flange lintel seals tend to flip over when their anti-friction coating has deteriorated increasing the risks to get torn (Figure 7);

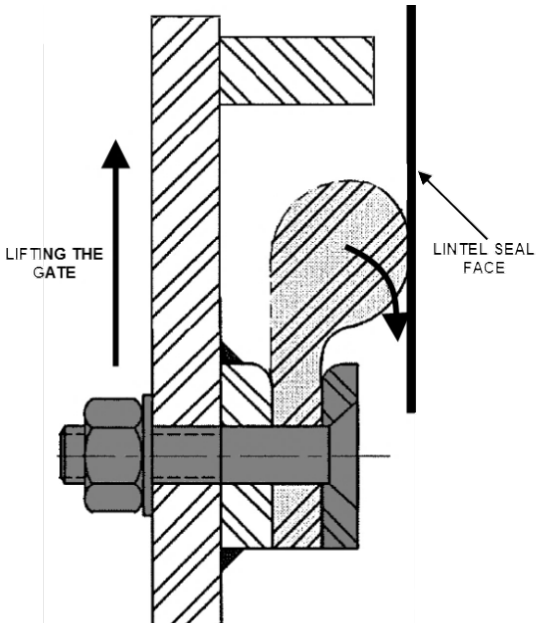


Figure 7 : Single flange lintel can flip over

- *Lubrite* bushings and steel shafts in main roller assemblies
    - Since the shaft is not made of stainless steel, corrosion will develop progressively on the mating surface with the bushing, thus, causing additional friction to the gate motion or even seizing;
- Single lifting point
    - Having a single lifting point increases the risk of gate jams. In this particular case, the gate has a small width/height ratio (below 1), which is considered acceptable to reduce the risks of gate jams;
- Bottom sheave block
    - Based on the original drawing A-2546-E1, the bottom sheave block has less capacity than the hoist (27 200 kg vs 40 770 kg) , making it a potential weak point in the lifting system.
- Unbraced superstructure
    - The superstructure is unbraced in the left/right direction making it weak in that direction against seismic, wind loads or gate jamming in the superstructure.

3.2 Previous Inspections and Major Intake Issues

NL Hydro experienced two major incidents at BDE intake within the past 20 years. The two incidents were of similar nature and happened at the intakes #2 and #4 during a penstock water-up. The analysis revealed that the intake gates had traveled past their prime positions and the penstock filled too quickly which created a pressure wave that wast sent back through the penstock and ultimately resulted in the destruction of the vent house. Safety measures were implemented to address the issue, such as the implementation of an automated filling procedure involving the use of a PLC controlled in real time by the pressure monitored in the penstock.

A report was issued by Hatch in 2009 regarding the life expectancy of the BDE intake. The testing and detailed inspection of the intake gates was not part of their study. Below is a summary of the recommendations made by Hatch:

- Upgrade the intake electrical controls;
- Upgrade the intake power distribution panels;
- Replace hoist motors, starters and control panels;
- Replace gate limit switches;
- Rehabilitate gate rollers;
- Install proper heating system to the hoists brake;
- Preventive maintenance to the hoisting rope every two years;

3.3 Residual Lifting and Closing Force Study

Since the gate must close under its own weight, a residual lifting weight study was performed by RD Énergie to establish the design reaction forces applied while lowering and lifting the gate. This residual gate weight study considers two (2) lifting cases:

- Case #1: Emergency drop and gate cracking under full water pressure;
- Case #2: Emergency drop and gate cracking in non-flowing water;

The lifting cases are calculated with the full water supply level and ballasted gate.

Table 1: Residual lifting and closing force study					
Cases	Lifting force (at start)		Closing residual force on sill		Closing force ratio*
	kg	(lbs)	kg	(lbs)	%
Case #1: Emergency drop and cracking full water pressure	37 400	(82 364)	4 800	(10 479)	22.6
Case #2: Drop and cracking in non-flowing water	18 431	(40 624)	17 775	(39 176)	98.2

The details of the calculations are shown in Appendix B.

The results for flowing water conditions (Case #1) are in accordance with expectations. A residual closing force ratio over 20% is considered adequate for this application[1]. This gives some margin to compensate for the deterioration of the gate's rolling and sealing which will increase friction forces. The capacity of the cable hoist is sufficient considering the lifting force obtained in this study.

According to the results of this evaluation, the gate should close easily in non-flowing water conditions (Case #2).

[1] Erbisti, *Design of Hydraulic Gates*, 2004

3.4 Study of the Hoist's Capacity

The cable hoist's capacity is rated at 40 770 kg (90 000 lbf).

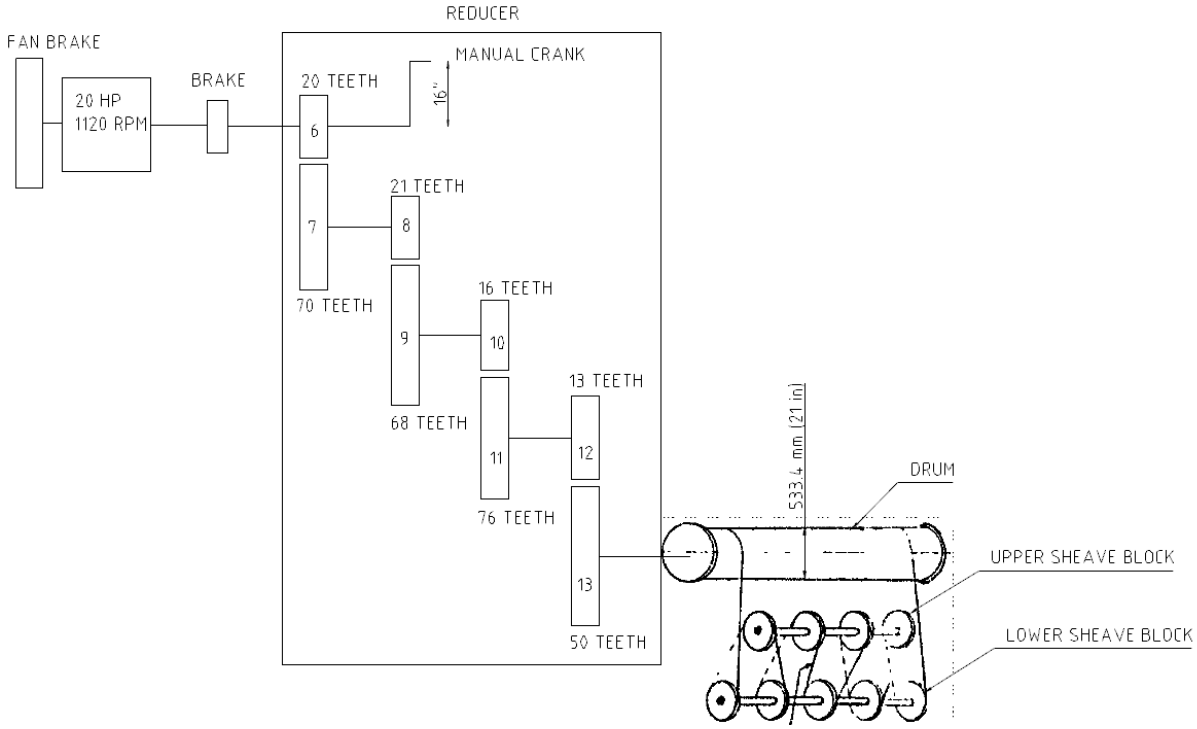


Figure 8: Hoist drive train showing the different reduction ratios

RD Énergie has reviewed the hoist's capacity and the rated capacity of 90 000 lbs was thereby confirmed. Details of the calculations are presented in Appendix C. Below are the main specifications and the results of these calculations:

Motor power: 20 HP
Motor speed: 1120 RPM
Motor nominal torque: 127.16 N*m (94 ft*lbs)
Drive train reduction ratio: 200
Drive train efficiency: 92%
Reeving reduction ratio: 5
Reeving efficiency: 85%
Nominal load to wire rope: 4.81 metric tons (10 607 lbf)
Wire rope load limit (5:1, standard Ø7/8 wire rope): 5.65 metric tons (12456 lbf)
Lifting capacity: 40 770 kg (90 002 lbf)
Lifting speed: 30.21 mm/s (5.948ft/min)
Hoist global efficiency: 78%
Force required at hand crank to crack open the gate: 304 N (69 lbf)

Time required to lift from sill to deck elevation: 10.25 min

The bottom sheave block has a rated capacity (267 kN) which is lower than the hoist capacity (400 kN). This is not considered to follow the lifting standards or best industry practices. The sheave block capacity should be at least equal or over the hoist lifting capacity[2].

The motor is a design D, which means that it has a high breakdown torque. Its rated breakdown torque can be up to 300% of its nominal torque (Figure 9). Considering applications where the load is guided, design C motors should be used in order to limit the breakdown torque in case of load jams. The motor should be calibrated with 190 % to 210 % breakdown and starting torque specifications. The intent is to have sufficient intrinsic safety factors on the hoist mechanical components.

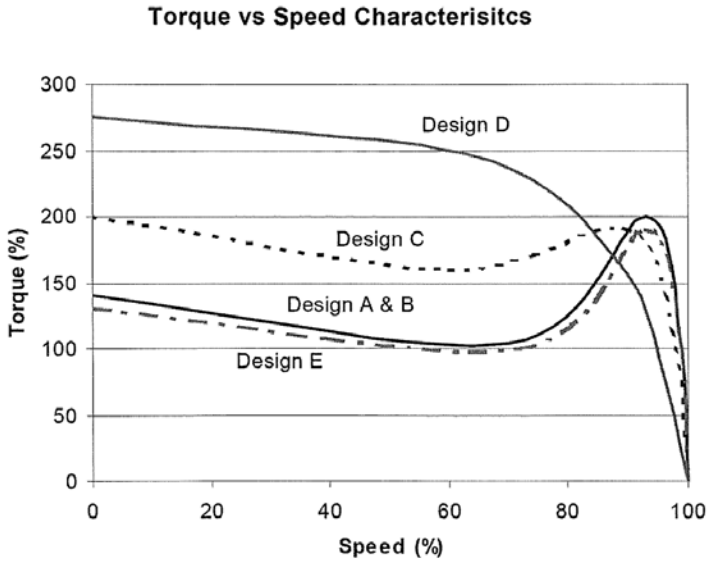


Figure 9: Torque vs speed characteristics (NEMA Designs)

The motor duty cycle is 30 minutes, which gives enough time to complete the 10.25 min travel from sill to deck level without stopping. Best industry practices recommend using continuous duty cycle motors.

[2] CMAA 70, *Specifications for Top Running Bridge & Gantry Type Multiple Girder Electric Overhead Traveling Cranes*, 2004

4. Observations and Assessment

The detailed inspection sheets are presented in Appendix D.

4.1 General

The inspected components of the intake #1 above water level were in good condition considering the age of the equipment. Preventive maintenance has limited the equipment deterioration.

A visual inspection of the components related to intake #1 structure was conducted and there were no major defects detected on the steel handrails, the gratings or the vent house structure.

4.2 Intake Gate #1 Observations

4.2.1 Operations

Several descents and rises of the gate were performed in the de-watered intake. No abnormal friction or problems were observed.

The emergency activation was not tested because of the permits in place in order to ensure worker protection during the inspection. Cracking of the gate was performed after RD Énergie departure, the operation was achieved successfully with emergency gates removed.

4.2.2 Steel Frame

The gate's frame is well preserved considering the presence of bio-corrosion in this area. The gate's frame remains mainly untouched and measurements of the residual thickness show no significant loss of material. As well, the protective coating is still in good condition.

No damage or deformation was observed on the gate's frame or on the skin plate. However, one area remains of concern and is located at the connecting point between the sheave block and the gate top beam. The hardware used in the lifting point bolted connection is corroded (Figure 12). Photos of the gate frame inspection are shown below.



Figure 10: Gate's structure upstream side



Figure 11: Intake gate's skin plate (downstream side)



Figure 12: Corroded hardware at the lifting point connection

4.2.3 Main Rollers

All twelve (12) main rollers were inspected. The majority of them were turned by hand. An average hardness of 400 HB was measured on the rolling face of the rollers. The following table details the observations made:

Table 2: Intake Gate #1 Main Rollers Observation				
Roller Nuber	Overall Condition	Rolling Condition	Other Remarks	Pictures
LW#1	Average	Rolling by hand	Corroded (pits up to 1mm)	
LW#2	Average	Rolling by hand	Corroded (pits up to 1mm)	
LW#3	Deteriorated	Rolling by hand	Highly corroded (pits up to 3mm)	#202 to 206
LW#4	Deteriorated	Rolling by hand	Highly corroded (pits up to 3mm)	#207 to 214
LW#5	Deteriorated	Rolling by hand	Highly corroded (pits up to 3mm)	#215 to 224
LW#6	Deteriorated	Rolling by hand	Highly corroded (pits up to 3mm) Shaft alignment issue	#236 to 240
RW#1	Average	Rolling by hand	Corroded (pits up to 1mm)	
RW#2	Acceptable	Rolling by hand		
RW#3	Deteriorated	Not rolling by hand	Highly corroded (pits up to 5mm)	#262
RW#4	Deteriorated	Rolling by hand	Highly corroded (pits up to 5mm)	#263 to 266
RW#5	Acceptable	Rolling by hand		#267, 268
RW#6	Deteriorated	Rolling by hand	Highly corroded (pits up to 3mm)	#275 to 279

LW refers to the wheels on the left side and RW refers to the wheel on the right side.

Pictures of the main rollers can be found in Appendix J.

The majority of rollers are deteriorated because of pitting corrosion to their rolling faces (Figure 13). The corrosion covers almost all the rolling surface. The pits on the surface have an approximate depth of up to 3 mm. The rollers condition is in general considered poor.



Figure 13: Pitting corrosion to rolling face main roller (pic #206)

All the keeper plates that hold the eccentric shafts in place are highly corroded. The keeper plate of the main roller #6 on the left side of the gate is so corroded that its shaft has rotated and changed the main roller adjustment (Figure 14).



Figure 14: Shaft has shifted at LW#6 Roller

4.2.4 Guiding System

Four (4) side rollers guide the gate. Two of these are at the bottom and the other two are at the top. They are preloaded with springs in order to keep the gate centered. The following table details the observations made:

Table 2: Intake Gate #1 Side Rollers Observation

Roller No.	Overall Condition	Rolling Condition	Other Remarks	Pictures
LB (left bottom)	Failed	Not rolling	Seized, organic corrosion. Severe corrosion to adjustment system. No more compression in spring.	-
RB (right bottom)	Failed	Rolling	Highly corroded. Severe corrosion to adjustment system. No more compression in spring.	-
LT (left top)	Failed	Rolling	Organic corrosion. Severe corrosion to adjustment system. Nuts of spring are stripped. No more compression in spring.	#225 to 235
RT (right top)	Failed	Rolling	Surface highly corroded. Severe corrosion to adjustment system. No more compression in spring.	#269-274

Pictures of the side rollers can be found in Appendix J.



Figure 15: Side roller overview

Corrosion has damaged the side rollers adjustment system to the point where they had to be welded on-site during the inspection to prevent the side rollers from falling off the gate. The adjustment nuts were welded to the adjustment screws on all side rollers (Figure 16).



Figure 16: Example of damage on side rollers adjustment system

4.2.5 Seals

The anti-friction coating of the lateral and the lintel J-seals is worn (Figure 17). The wear is more significant in the lower part of the lateral seals and there are areas where it is discoloured and others where it is completely removed. The coating is an important feature of the gate and it must be in good condition to reduce friction and ensure the gate emergency closing. The anti-friction coating reduces up to 10 times the seal friction coefficient. The deterioration of the coating can also create an overload of the hoist.

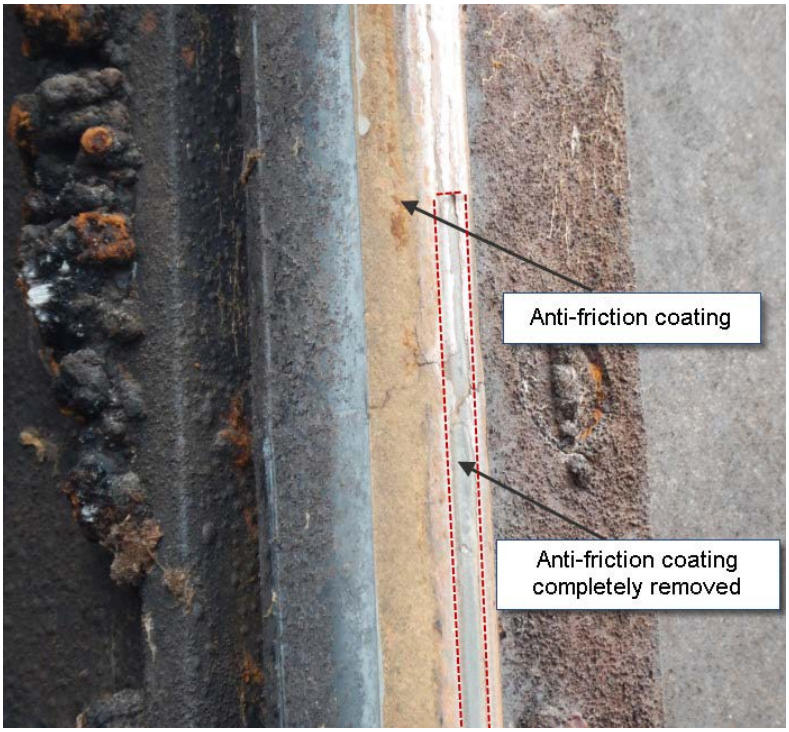


Figure 17: Wear of the seal's anti-friction coating

Precompression of the J-seals seemed to be adequate (approximately 6mm) and the sill seal appeared to be in good condition.

The nuts used to clamp the seals are highly corroded (Figure 18). It may be difficult to unscrew them. The clamp bars were found with some corrosion but in working condition (Figure 19) .



Figure 18: Corrosion to seal's nuts



Figure 19: Clamp bars with some corrosion

4.3 Intake Gate #1 Assessment

The intake gate frame is generally well preserved. No deformations or significant material loss on its steel members was observed. Our team believes the defects observed will not jeopardize the gate structural integrity. On the other hand, some issues found have a direct impact on the gate operability and can reduce its capacity to lift and close properly. Functional tests performed in air showed no anomalies. The emergency drop in full water pressure was not be tested during the inspection.

Here are the main assessment findings:

a. The main rollers overall condition is in general poor. The rollers are deteriorated due to pitting corrosion on their rolling face. This condition increases the rolling friction which affects the gate capacity to lift and close properly. This situation also increases the lifting load and can create overloads to the hoist.
b. The anti-friction coating on the J-seals has been removed in some areas. Based on seal manufacturers specifications, the friction force can be up to 10 times higher when there is no anti-friction coating. This could prevent the gate from closing properly during an emergency drop. The deterioration of the coating can also create an overload of the hoist. The seals are considered to have reached the end of their useful life.
c. The spring in the four (4) side rollers are broken, this prevents the proper guiding of the gate in its embedded parts. The four (4) side rollers can no longer be adjusted due to corrosion. The side rollers are no longer functional and can lead to improper positioning of the gate, particularely when closing under water load.
d. The protective coating is in good condition. Some small areas exhibit corrosion nodules.
e. The bolts, nuts and washers at the gate connection with the upper sheave are corroded. Their condition is considered poor.

4.4 Hoist Observations

Since the hoist is used only in emergencies or during maintenance operations, it is most of the time in a standby mode. A periodic inspection is performed yearly in accordance with NL Hydro's preventive maintenance program and it includes functional tests, lubrication, maintenance and visual inspection.

The hoist controls were improved in recent years with the addition of a PLC, penstock pressure monitoring, a travel limit switch, a slack rope limit switch and a position indicator. The purpose was to enhance safety during a penstock filling operation.

There is limited space in the hoist house. It is difficult to move around the hoist.

4.4.1 Operations

The hoist motor has no reverse function and can only lift the gate. The lowering of the gate is performed by releasing the electromagnetic brake. For testing purposes this operation was done manually during the inspection. The gate was then dropped on the fan brake as part of the manual operation.

4.4.2 Components Condition

The hoist was inspected with the penstock de-watered. A visual inspection of its main components was performed. Table 3 summarizes the observations made during the inspection:

Table 3: Hoist Main Observations

Hoist Systems	Parts Inspected	Ok	Not OK	N /A	Comments
1. Controls	Position indicator			X	As part of NL Hydro isolation, this limit could not be tested
	Up limit			X	As part of NL Hydro isolation, this limit could not be tested
	Slack rope limiter			X	As part of NL Hydro isolation, this limit could not be tested
	Overload limiter			X	Not included by designer
	Stop Switch	X			Accessible in hoist house
	Main Control	X			New PLC in operation
2. Electrical Power	Power cables	X			
	Loose connectors	X			
	Cabinets in hoist house		X		Missing front free space[(3)]

Table 3: Hoist Main Observations					
Hoist Systems	Parts Inspected	Ok	Not OK	N /A	Comments
	Motor elect. protection 40amps		X		See main issue section 4.3.3
3. Motor	Electrical insulation (40MΩ ≈ 30sec)	X			
	Amerage readings:				
	102AMPS at start	X			< 5 x time nominal[(4)]
	50-80AMPS rising		X		See main issue section 4.3.3
	20,5AMPS out of water		X		See main issue section 4.3.3
	Anchoring bolts tightened	X			
	Noise, vibration or heat	X			Tested out of water only
	Paint		X		Rust to casing and bolts
	Labelled, service class	X			
4. Ventilator Brake	Louvers adjustement (45°)	X			
	Louvers fixation	X			
	Anchoring bolts tightened	X			
	Operation, vibration or noise	X			
	Labelled	X			
	Lowering speed ≈11 ft/min	X			
	Paint	X			
5. Flex. Coupling	Overall condition	X			
	Noise, vibration or heat	X			
6. Electromag. Brake	Operation, no vibrations or noise	X			
	Braking capacity	X			
	Pads condition	X			
	Pads adjustment	X			
	Springs condition	X			
	Paint		X		Rust to components
	New 125W heater		X		Too close to power cable
7. Gearbox	Noise, vibration or heat	X			
	Lubricant condition		X		See main issue section 4.3.3
	Oil level		X		See main issue section 4.3.3
	Defects to gears	X			
	Cracks or defects to casings	X			
	Heater			X	Not originaly provided
	Breather			X	Not originaly provided
	Magnetic catcher			X	Not originaly provided
	Bearing	X			Potential lead presence
	Leaks		X		See main issue section 4.3.3
8. Hand crank	Operation			X	As part of NL Hydro isolation, this limit could not be tested

Table 3: Hoist Main Observations					
Hoist Systems	Parts Inspected	Ok	Not OK	N /A	Comments
	Manual mode protection		X		No device to protect from inadvertent reenergization
	Mechanical brake			X	As part of NL Hydro isolation, this limit could not be tested
	Overall condition	X			
9. Drum	Noise, vibration or heat	X			
	Cracks or defects to the drum	X			
	Rope fleet angle	X			
	Rope not overlapping	X			Unless in maintenance pos.
	Minimaly two remaining wraps			X	Could not be confirmed
10. Upper Sheave	Rope fleet angle	X			
	Deformation	X			
	Corrosion	X			
	Attachment	X			
	Wear level	X			
	Lubrication		X		Loose grease tube
11. Bottom Sheave	Rope fleet angle	X			
	Deformation	X			
	Corrosion		X		See main issue section 4.3.3
	Attachment		X		Heavy corrosion
	Wear level		X		Heavy corrosion
	Lubrication		X		Corrosion
12. Hoisting Rope	Overall condition		X		See main issue section 4.3.3
	Attachment to drum	X			
13. Support Frame	Deformations	X			
	Paint	X			Some rust
	Bolted connections	X			

[3] CSA C22.1-12 *Electrical Code*, Section 2

[4] CSA C22.1-12 *Electrical Code*, Section 28

4.4.3 Main issues observed

Operations

No major anomalies were observed during the hoist operation. The cable rubs against the steel frame of the upper guard section. This situation happens when the gate is lifted to its maintenance position outside its embedded parts (and the hoisting rope reaches to the drum extremities). It is believed that the hoisting rope is rubbing against the steel structure since the commissioning of the hoist. Rubbing marks to the steel frame can be found on both sides of the steel frame (left and right) (Figure 20).



Figure 20: Rubbing mark to upper wire rope protective guard

Amperage readings and motor electrical protection

Amperage readings are higher then expected. Based on calculations presented in Appendix C, the expected amperage value for lifts outside water is approximately 16.8 amps. The corresponding amperage readings were approximately of 20.5 amps indicating potential deterioration of the hoist mechanical efficiency.

The amperage readings of 50 to 80 amps made during the cracking of the intake gate are two to three times over the nominal 24 amps of the motor. This is an abnormal situation which is overloading (heavily) the hoist. The deterioration of the rolling contact between the rolling path and the main rollers, deterioration of bushing sliding contact in the main roller assemblies, deterioration of seal anti-friction coating and deterioration of the bottom sheave block are considered as the main potential causes.

There is a discrepancy with the current measured on site (50 to 80 amps) during gate operation and the fuse capacity specified on drawing 2105-E-002 (40 amps).

Lubrication Condition

An oil sample from the gearbox has been analyzed to determine the condition of the equipment and lubricant. This analysis took place at the "Hydraulique EP" laboratory. The detailed data and results are available in Appendix E. The analysis revealed two main issues; the first is a very high lead concentration. Lead is not believed to be coming from the original lubricant formula, and after reviewing the gearbox drawings, it is believed the Timken bearings are the most probable source of the high lead concentration. The second main issue is the oil viscosity. The sample tested at 768 Centistoke which is many times thicker than the expected oil viscosity for this type of equipment (about 150 Centistokes). See Figure 21 and Figure 22 for more details.



Figure 21: High oil viscosity in the gearbox

ISO Grade	Equivalent SAE Grade	Viscosity			
		Centistokes		10^{-6} reyns (lb s/in^2)	
		40 °C	100 °C	104 °F	212 °F
32	10W	32	5.4	4	0.6
46	20	46	6.8	5.7	0.8
68	20W	68	8.7	8.5	1.1
100	30	100	11.4	12.6	1.4
150	40	150	15	19	1.8
220	50	220	19.4	27.7	2.4

Figure 22: Oil viscosity and oil grade example[5]

[5] http://www.engineeringtoolbox.com/iso-grade-oil-d_1207.html

The lubricant specifications should be in accordance with the original equipment manufacturer recommendations. If the information is no longer available (could be found in maintenance records or operator's manuel for instance), AGMA 9005-E02 standard can be used to get a suggested viscosity grade.

Oil Level

The gauge currently installed does not show clearly the high and low oil level in the gearbox and can create confusion when reading. The maximum and minimum oil level should be clearly identified on the indicator. The minimum and maximum levels should be in accordance with the original equipment manufacturer recommendations. If the information is no longer available (could be found in maintenance records or operator's manuel) we recommend that the gear (not the pinion) having the highest velocity dips into the oil (Figure 23). The oil level was considered low at the time of the inspection since the first gear train was missing lubrication.

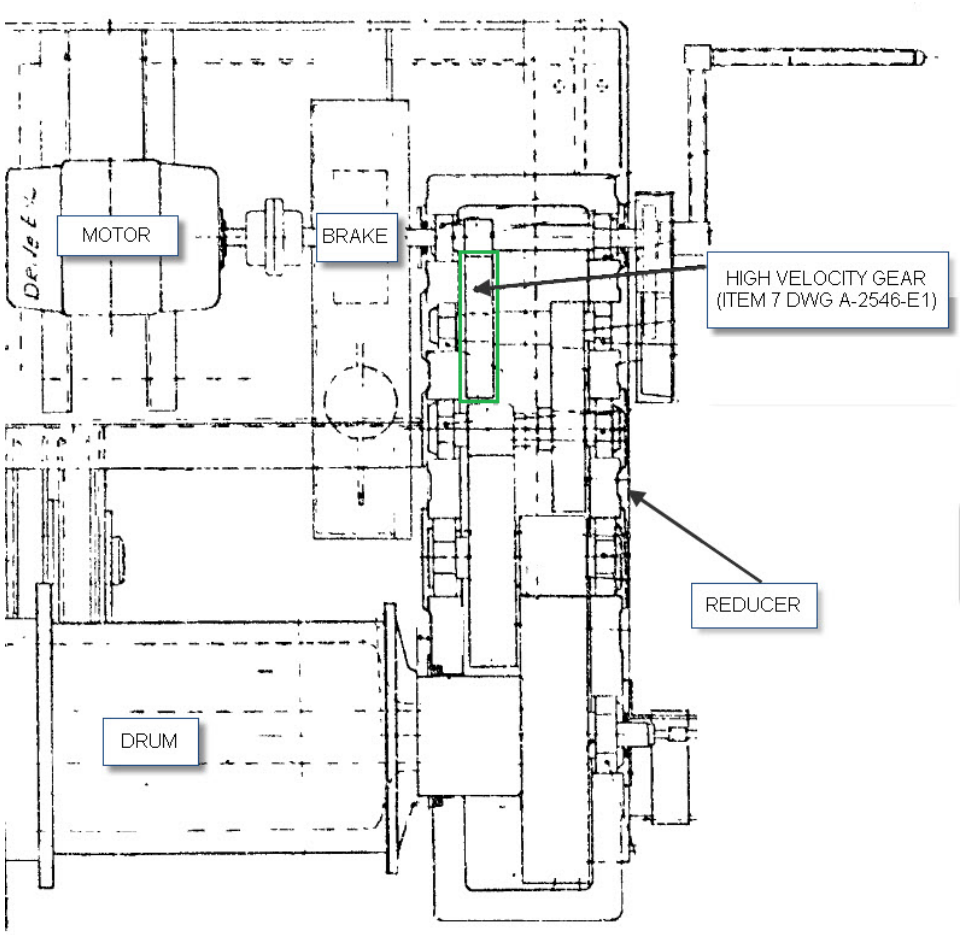


Figure 23: High velocity gear location in reducer

Hoisting Rope

The hoisting rope is rusted and corrosion nodules were found to it. No material loss could be observed on the outer surface of the cable. The area where the hoisting rope shows the most nodules is at the bottom sheave (Figure 24).

The hoisting rope is in very poor condition. Rust was found on large sections of it and corrosion nodules could be seen at the central pulley of the bottom sheave block.

Corrosion is difficult to evaluate and is a serious cause of degradation. Usually, corrosion appears because of a lack of lubrication. It will often occur internally before there is any visible external evidence on the rope surface. Corrosion of the rope core not only effects the metal wires, but also prevents the rope's component parts from moving smoothly as it flexes. Undetected corrosion may lead to a sudden and unexpected rope failure. To prevent corrosion, the wire rope should be kept well lubricated.



Figure 24: Rust and corrosion nodules found to lifting cable

Bottom Sheave Block

The overall condition of the sheave block is considered poor. It is still functional, but corrosion has deteriorated its subcomponents. No anomalies were observed during operations (no vibrations, abnormal sounds or blocking). Pitting corrosion was found on components such as pulleys, shaft, thrust washers, hoisting rope and steel frame (Figure 25). The corrosion was more critical on the central pulley where the cable crosses over. Besides corrosion, no damages or deformations were observed.

In comparison to the bottom sheave block, the upper sheave block is considered in good condition.



Figure 25: Bottom sheave block overall condition

Leaks

A leak was observed at the output shaft on the gearbox. The grease tube is perforated at its connection with the casing (Figure 24). The leak prevents the proper greasing of the *Clipper* split seal.



Figure 26: Leakage to the output shaft bearing on the gearbox

4.5 Hoist Assessment

The following points were noted during the assessment:

a. The hoisting rope is rubbing against the protective guards steel frame at the connection with the hoist bridge. This is an abnormal situation and corrective actions to address the issue will be developed in the recommendation Section 6.
b. No mechanical safety device protects the hoist's motor from stalling. The motor type (design "D") can stall up to 300% of its nominal rated torque. Electrical fuses cannot effectively protect the hoist mechanical components against motor stalling.
c. The amperage readings for the motor are very high, indicating a deterioration in the system efficiency. Some amperage readings are particularly worrisome such as the ones made during the cracking of the gate. The readings show the hoist is overloaded heavily probably due to the deterioration of the gate main rollers, seals and sheave block. The cracking operation is considered to be over the hoist capacity. This operation should be avoided.
d. The amperage readings for the motor are over the motor electrical protection specified of 40 amps. The fuse size and type should be verified. The motor electrical protection should comply with CSA C22.1-12 *Electrical Code*.
e. The hoisting rope is rusted and corrosion nodules are found on it. The hoisting rope is considered to have lost some of its capacity and is deteriorating rapidly. The hoisting rope overall condition is considered very poor and should be replaced as soon as possible. In the meantime, cracking operations or drops in full water pressure should be avoided as much as possible.

   A maintenance program should be put in place to prevent the wire rope from deteriorating and to prevent hazardous lifting operations. In similar applications, wire ropes life expectancy ranges approximately from 5 to 15 years;
f. The bottom sheave is affected by pitting corrosion. Corrosion has spread to important components such as pulleys, steel frame, pin, bolts and shaft. Overall condition is considered poor and prevent the sheave block from properly operating (squeezing risks and internal friction). However, we believe the structural capacity of the sheave is not in jeopardy at this time.
g. A grease tube is perforated at the output shaft on the gearbox preventing the seal to be greased properly. The tube should be replaced or repaired and the seal should be greased.
h. Lubricant used in the gearbox has a high viscosity and lead contaminant issues limiting its capacity to lubricate properly. Lubricant is considered to have reached the end of its life expectancy.

i. The lubricant filling level in the gearbox should be clearly indicated on the gauge as the lubricant level was considered low at the time of the inspection. The minimum and maximum levels should be in accordance with the original equipment manufacturer recommendations.

4.6 Embedded Parts Observations

Only the lower section of the embedded parts was inspected (Figure 27). Since the inspection was performed using ladders, the upper section of the embedded part was out of reach. No damages or rubbing from gate operations could be observed on the upper section.

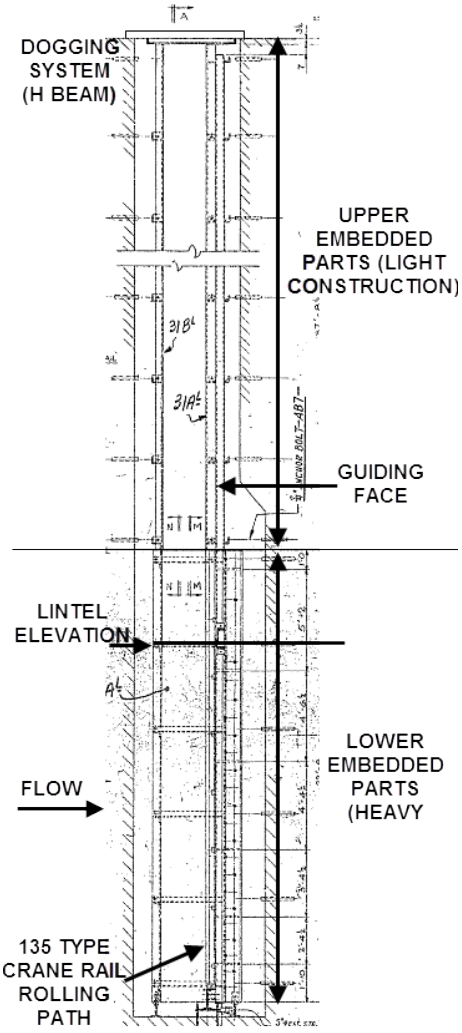


Figure 27: Lower and upper embedded parts

Traces (bright marks on the stainless seal faces) of the intake gate seals on the embedded parts could be observed. This confirmed an adequate positioning of the gate in closed position (Figure 28). Seal faces were found in good condition.

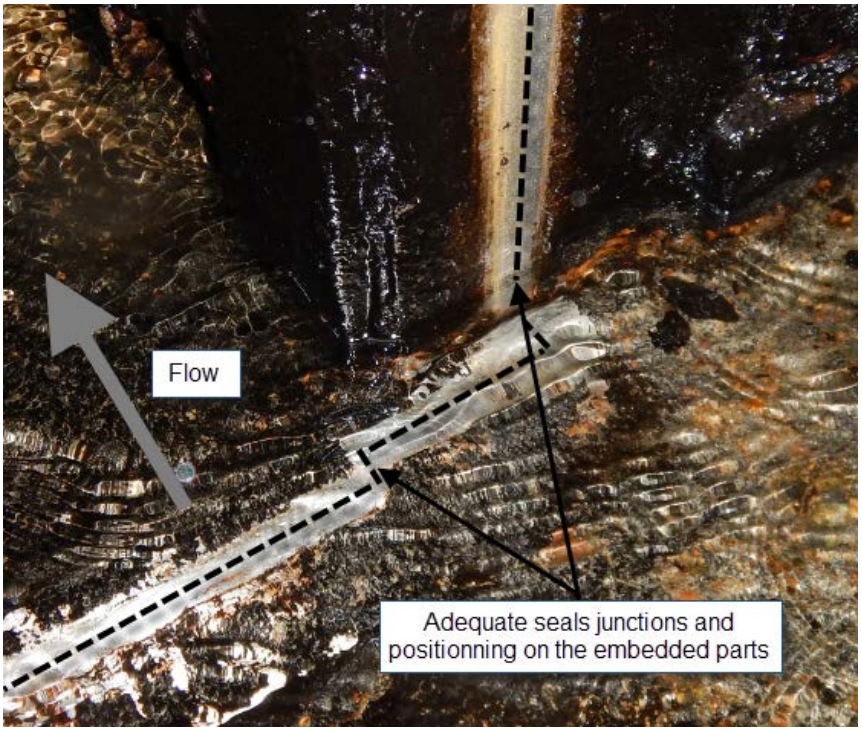


Figure 28: Seal junction at sill and lateral guide

4.6.1 Main Issues Observed

Second stage concrete damage

Issues in second stage concrete were found downstream of the rolling face on the right side lateral guide (Figure 29). The holes are approximately 250 mm deep. It could not be confirmed if water could leak through the holes since no links were found with the upstream side of the embedded parts.

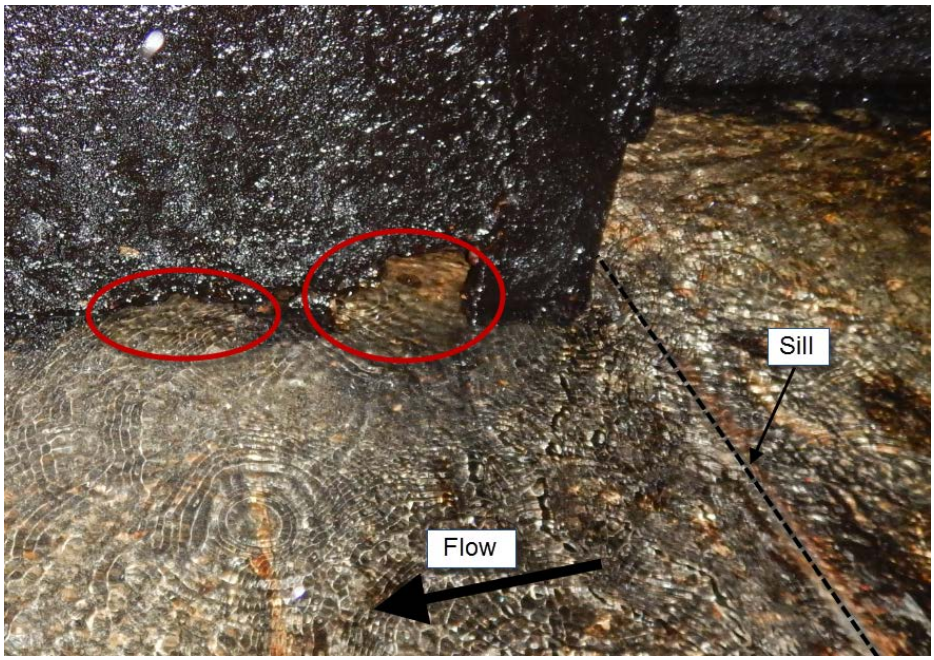


Figure 29: Holes (2) to second stage concrete

A soft area in the second stage concrete was also found downstream of the right lateral guide about 1m above sill. The soft area has an approximate diameter of 250mm and extends more than 200mm deep (Figures 30 and 31).

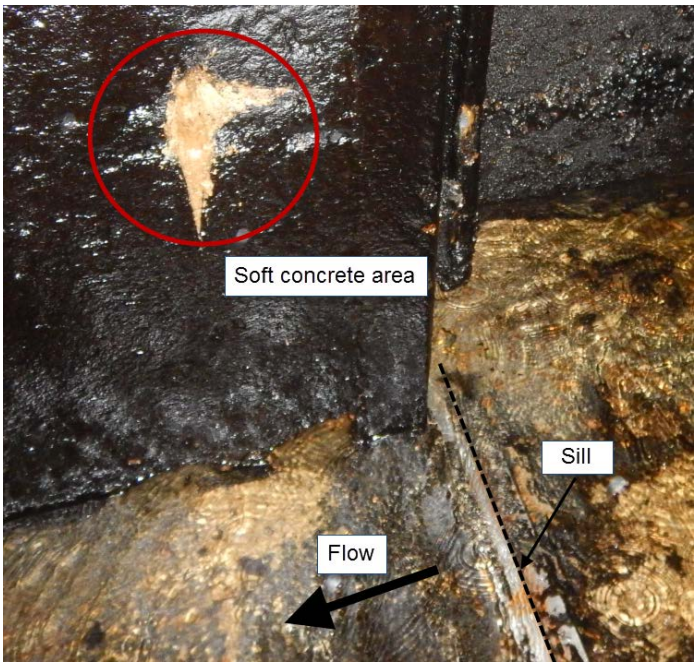


Figure 30: Soft second stage concrete issue

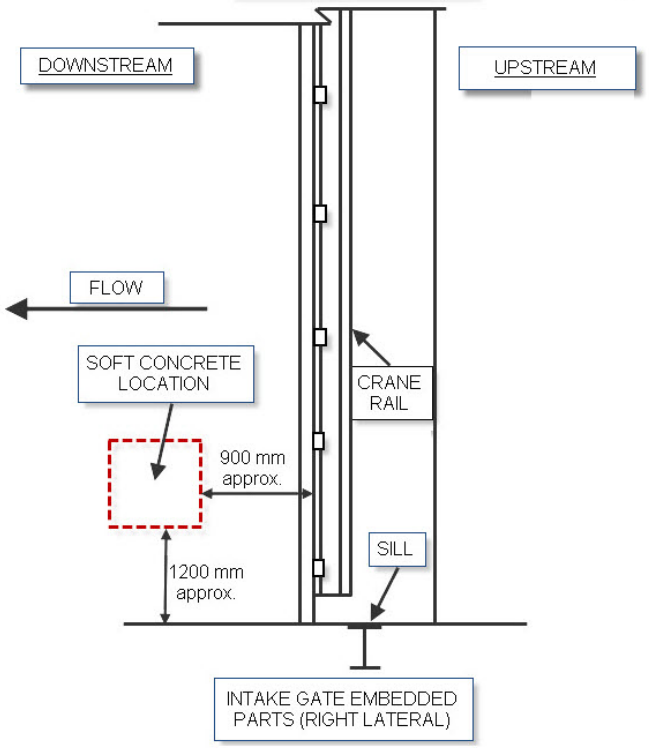


Figure 31: Soft concrete location

Corrosion to main rolling paths

The rolling paths are in a deteriorated condition. Heavy pitting corrosion with pits up to 3mm deep were observed on the rolling path (Figure 32). The corrosion has spread over the two main rolling paths and covers most of the surface.



Figure 32: Pitting corrosion to the rolling path

Access ladders to the embedded parts

The permanent ladder allowing access to the upper part of the embedded parts and the upstream side of the gate is out of service. The second access ladder located in the vent house was used for the inspection of the sill and lower lateral embedded parts. The ladder was found to have heavy pitting corrosion to some of its horizontal bars located in the submerged portion of the ladder (up to 3mm pits). No pictures of this issue are available.

4.6.2 Lateral Guides and Rolling Path Measurements

Verticality and horizontality checks were performed using a *Leica Lino L360* level laser, a machinist ruler and measuring tape (precision +/-1.5mm on verticality and horizontality). Figure 33 shows the different surfaces that were measured.

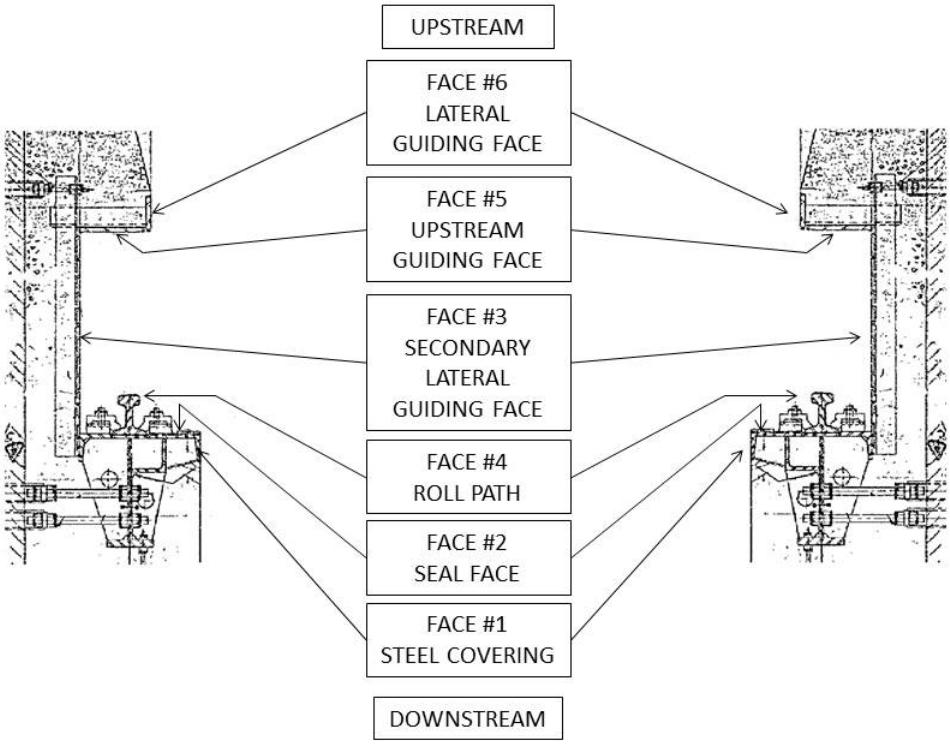


Figure 33: Surfaces measured

Besides the sealing surfaces (Face #2), all measurements were performed on heavily pitted surfaces due to corrosion.

The detailed measurements can be found in Appendix F.

Sealing surfaces (Face #2)

The two vertical seal surfaces were found to have a maximum straightness deviation of 3 mm over their entire length (Figure 34). The sill sealing surface was found to be straight and the lintel could not be measured due to access limitations. The straightness deviations found are inside the work limits of the J-seals and are not believed to be affecting the gate sealing capacity.

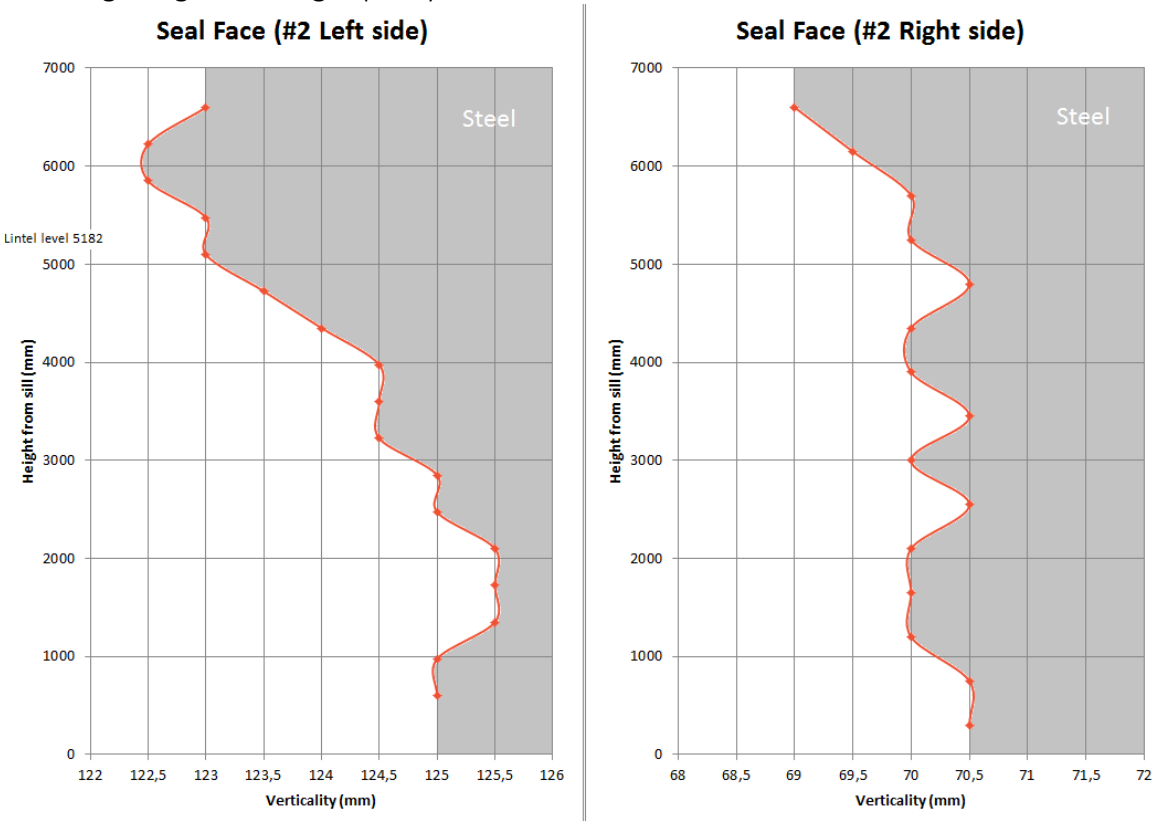


Figure 34: Seal faces straightness (Face #2)

Guiding surfaces

The guiding faces #3, face #5 and face #6 are affected by pitting corrosion. Maximum pits depth of 3 mm were observed. The gate is primarily guided by the preloaded side-rollers rolling against Face #6. Faces #3 is designed to limit the gate's maximum lateral movements and Face #5 limit the gate's upstream travel.

Rubbing traces on both lateral guiding faces (Face #3) were observed (Figure 35). The rubbing is coming from the buffers (Figure 36) welded to the sides of the gate. It is believed that the gate is guided by Face #3 and steel buffers instead of face #5 since the side rollers are not in operation anymore.

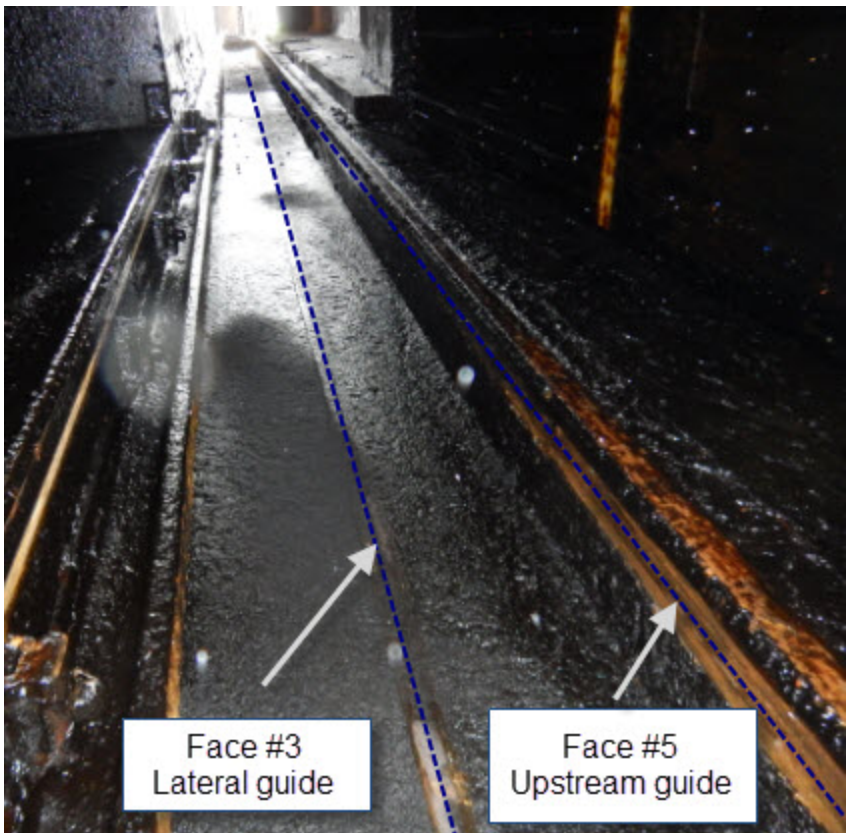


Figure 35: Rubbing trace to lateral guides (Face #3)

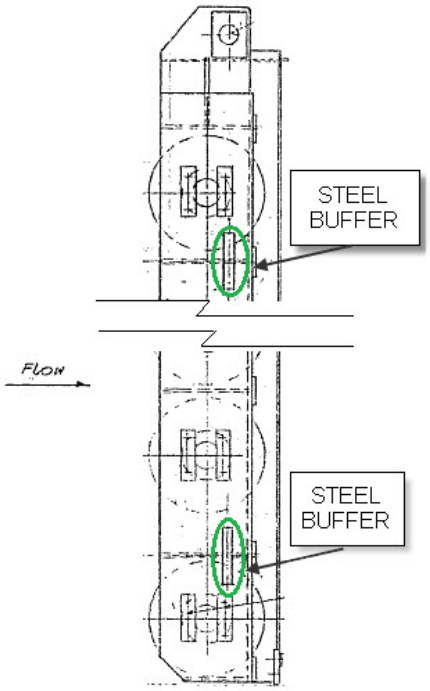


Figure 36: Steel buffers rubbing against Face #3

The rubbing traces on the upstream guiding face (Face #5) are considered normal since the gate has been operated in equilibrated water pressure or in air. The space measured between Face #5 and the rolling face is considered acceptable.

A deviation of approximately 3 mm is measured to the left guiding face (Face #6) see Figure 37 below:



Figure 37: Guiding face straightness measurement

Rolling face

A deviation was found in the 3000 mm to 7000 mm portion of the left side rolling face (Figure 38). The rolling face seems to be closing in by 3 mm. Deviations can overstress rollers, gate structure and overload the hoist.

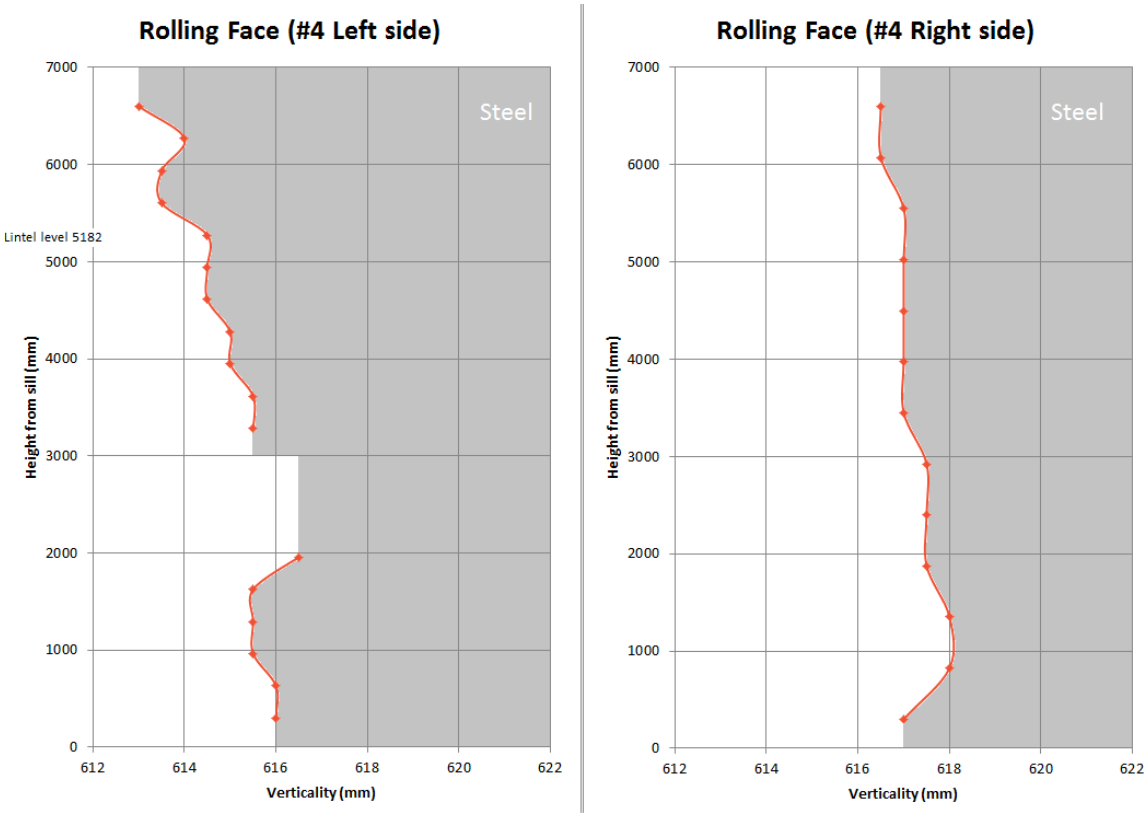


Figure 38: Rolling face straightness measurements

4.7 Embedded Parts Assessment

The following points were noted during the assessment:

a. The two (2) lateral sealing faces were found to have some deviation to their straightness. This is not believed to cause sealing issues. The original verticality tolerance of the lateral seal faces is +/- 0.4 mm (+/- 1/64 in) over the fullheight. The sill was found to be straight;
b. Heavy pitting corrosion with pits up to 3 mm deep was observed to the rolling paths. The poor condition of the rolling faces can be a threat to the gate capacity to achieve the emergency drop. This situation is also increasing the lifting load and can overload the hoist.
   Verticality and straightness measures revealed important deviations which are outside original installation tolerances of +/- 0.4 mm (+/- 1/64 in) over the fullheight. Deviations can overstress rollers, gate structure and overload the hoist.
   The rolling paths have reached the end of their useful life. The clamps used to fix the rails in place were in fair condition;
c. Guiding faces #3, #5 and #6 are made of exposed steel. Pitting corrosion was observed with pits up to 3 mm deep. Straightness deviations are not considered to limit the capacity of the gate to be properly guided;
d. Material loss due to corrosion is not believed to jeopardize the structural integrity of the steel members at this moment. Besides the rolling paths, corrosion has spread over limited areas;
e. Second stage concrete around the embedded parts was found damaged in some locations. Two voids were found downstream of the right lateral embedded parts, as well as an area of soft concrete. The soft concrete could be removed by hand;
f. Downstream fixed ladder located in the vent house to access the embedded parts is corroded in limited areas. Deterioration rate will increase since no more protection against corrosion is active. Its overall condition is considered fair but should be reassessed yearly;
g. The fixed ladder located on the upstream side of the intake gate embedded parts is out of service. The ladder should be tagged accordingly until its replacement.

4.8 Superstructure and First Stage Concrete Observations

The superstructure is generally well preserved. Detailed inspection sheets are available in Appendix D. No problems were noted regarding the gate operating inside the superstructure guides.

4.8.1 Main Issues Observed

Deformation or damages to steel members and structural components

An anchor point was found to be heavily damaged by corrosion (Figure 39). The anchor point is used as a lifting lug to install the protective guards located around the hoisting rope under the hoist bridge. The use of this anchor point should be prohibited until its replacement.

Permanent deformations to the protective guard's anchor points were also noted (Figure 40).



Figure 39: Damaged anchor point



Figure 40: Protective guards deformed anchor points

Anchoring

The grout used to support the superstructure has rotten. Parts of it can now be easily removed (Figure 41). The issue was found to all four (4) tower bases.



Figure 41: Grout found soft at tower bases

Anchor bolts were installed without lock nuts, but no nuts were found untightened.

Corrosion is established on the nut of the anchor bolt located on the right downstream side of the superstructure (Figure 42).



Figure 42: Corrosion to the anchor bolt nut

Electrical Ground

In general, electrical grounds wires have some strains broken (Figure 43).



Figure 43: Strains broken to ground wire

Access

The fall arrest wire installed to the access ladder is rusted (Figure 44). The ladder inspection log was not reviewed in the current scope of work.



Figure 44: Rusted fall arrest steel wire

Protection against corrosion

The paint system applied to the superstructure was found to be effective. No significant loss of material could be measured to the structure. Areas such as bolted connections and weldings were exhibiting rust and signs of corrosion (Figure 45).



Figure 45: Damage to superstructure paint system

Hoist house

The hoist house protects the hoist against the weather. No trace of leakage was apparent inside. No deformations could be found to its structure. The paint system protecting the cladding is still in working condition. Some paint was peeling on the hoist house floor. Some insulation panels were removed.

Protective guards

The paint system applied inside the protective guards of the hoist wire rope was found to be peeling in some areas and deteriorating (Figure 46).



Figure 46: Paint peeling inside protective guards

Concrete

Most of the concrete does not show any significant cracking or damages. Some areas on the deck exhibited surface delamination and local cracking (Figure 47).



Figure 47: Deck concrete delamination

4.9 Superstructure Assessment

In general, the superstructure is well preserved. No deformations, anomalies or significant material loss to its steel members were observed.

The following points were noted during the assessment:

a. The grout support at the tower bases is in poor condition. Rotten grout must be repaired. This is not believed to jeopardize the structural integrity of the superstructure at this moment. Deterioration rate will increase based on weather conditions and seasonal change.
b. The paint system applied to the superstructure has reached the end of its life expectancy. Rust has started to spread in some areas and spots of corrosion was found at bolted connections and weldings.
c. The paint system applied to the wire rope protective guards is peeling. Rust has started to spread in some areas and spots of corrosion could be found. The paint has reached the end of its expected life.
a. An anchor point welded under the superstructure bridge is used to lift the wire rope protective guards. It was found to be significantly weakened by corrosion. The anchor point is considered to have reached the end of its life expectancy and could lead to hazardous lifting operation if used;
b. The protective guards anchor points should not be used to lift sideways. Some anchor points have been permanently deformed. Their use could lead to hazardous lifting operations;
d. The fall arrest wire running up the access ladder is rusted and prevents the personnel from trusting its capacity to properly arrest a fall. The wire is believed to have reached the end of its useful life.
e. Ground wires have broken strains. Their grounding capacity was not tested or assessed in the current inspection scope.
f. Concrete delamination and small cracks were found in some areas at the intake concrete deck. The damages observed are considered minor.

4.10 Emergency Gates Inspections

A visual inspection of some emergency gates was performed at the draft tube with the gates in the dogged position. The sealing condition of some emergency gates could also be observed while installed in intake #1.

4.10.1 Main Issues Observed

Sealing

The emergency gates sealing capacity was found to be poor at the time of the inspection. Cinders were required to reduce the flow in order to give a secure access to the intake gate well for the inspection. It is believed that the leakage could be coming from debris and sediment deposit in the embedded parts or from the emergency gate sealing system (to be validated).

The inspection of one emergency gate located at the draft tube revealed deteriorated seals and clamping bars. Some sections of seals were not flexing anymore due to damages found at their clamping location (Figure 48). The gaps created by the lack of flexing will create leakage. The clamping bars are corroded and deformed in some areas.



Figure 48: Seal gap on lintel portion of an emergency gate

Paint

The paint is peeling in some areas exposing the gate structure to the environment (Figure 49). Rust and corrosion were found on the gate frame. No significant loss of material was observed.



Figure 49: Emergency gate paint condition

4.11 Emergency Gates Assessment

The following points were noted during the assessment:

a. Seals and clamping bars were found to be in poor condition. They are considered to have reached the end of their life expectancy;
b. The paint system applied is peeling and showing signs of aging. The paint system has reached the end of its life expectancy.

5. Analysis

5.1 Intake Operability

Deterioration of critical components such as the gate main rollers, roll paths, and seals directly affect the gate capacity for proper operation. A second analysis of the intake gate residual lifting and closing forces was performed in order to get an idea of the magnitude of the impact of deterioration on the hoist and intake gate functionality.

Here are the results:

Table 3: Residual lifting and closing force analysis in full water pressure

Cases	Lifting force (at start)		Closing residual force on sill		Closing force ratio
	kg	(lbs)	kg	(lbs)	%
Case #1: Considering current gate condition	41 600	(91 630)	500	(1 212)	2,6
Case #2: Considering fully removed coating to seals	52 000	(114 572)	-9 900	(-21 729)	-46,8

Details regarding the calculations are presented in Appendix G.

Case #1 is based on the current gate condition including damages to the rolling surfaces and seals coating. The closing force ratio is close to 0% and reveals potential issues with the gate lowering capacities. The risks are mostly below the gate 5% open position and could affect the emergency lowering and prime positioning of the gate for penstock refill. The lifting force also exceeds the hoist lifting capacity of 90 000 lbs.

Case #2 is a hypothetical situation (for reference only) considering a complete deterioration of the J-seals anti-friction coating. This case shows how important the coating is for the gate proper operating capacities. If the coating is completely removed the gate cannot lower under its own weight. The gate could still be moved in equilibrate water pressure (downstream pressure = upstream pressure).

5.2 Downpull

Downpull has not been considered in the calculations made in Section 5.1 but will be acting during the emergency lowering. The reason why the downpull forces were not taken into account is because they are not acting significantly when the gate is close to the sill (less than 1.5% opening). Figure 50 shows an example of a downpull curve using a 45° sloping bottom knife for gate similar to inake gate #1. The forces shown are arbitrary.

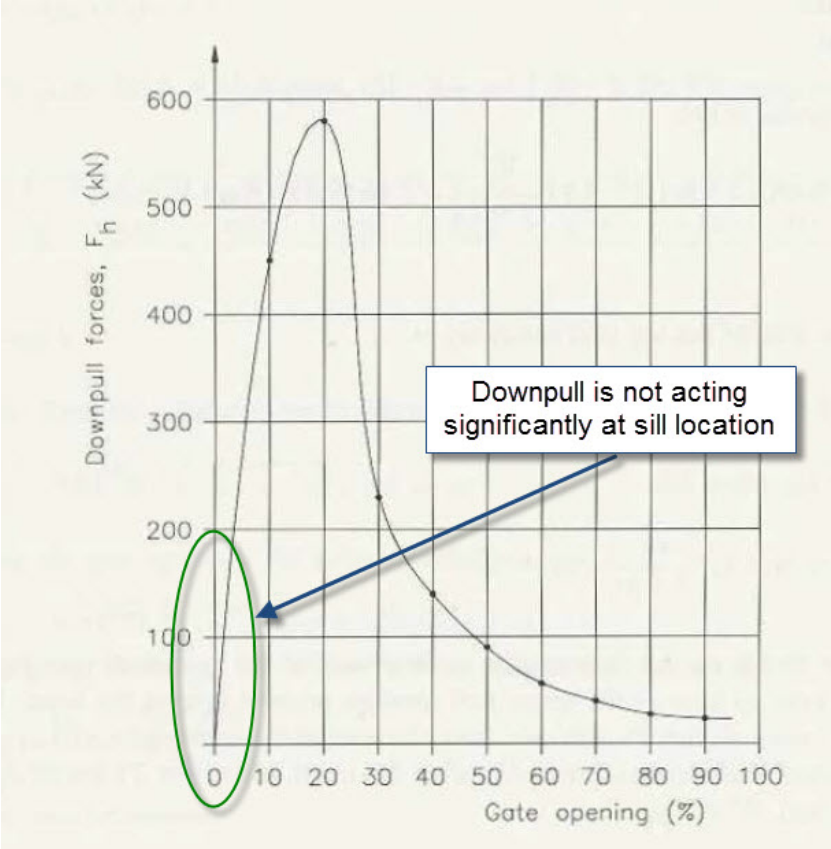


Figure 50: Typical downpull curve based on gate opening (%) [1]

The hoist is not designed to lift the gate over its penstock filling position. The additional load coming from the downpull forces would exceed the hoist rated capacity and could be a threat to the structural and mechanical components integrity (and would be hazardous for the powerhouse, penstock and vent house).

[1] Erbisti, *Design of Hydraulic Gates*, 2004

5.3 Corrosion Type

The corrosion found to the submerged components is of an organic type known as biological fouling. Biological fouling is the accumulation of microorganisms on wetted surfaces. Microscopic organisms tend to settle nonuniformly on metal surfaces. These microorganisms may contain bacteria which oxidize iron. They also may contain other types of bacteria that modify the local chemistry (acid-producing) and render it more corrosive to the metals. Bacterial colonies and deposits form elevated areas called nodules.

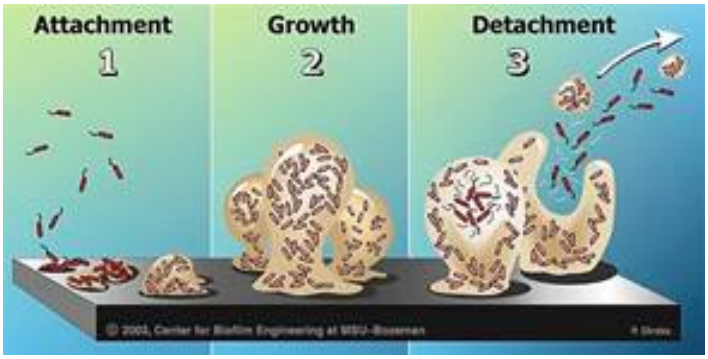


Figure 51: Conceptual model of bacterial colonization[2]

The deterioration of a metal as a result of the metabolic activity of microorganisms is also known as microbiological influenced corrosion (MIC). Positive identification of microbiologically influenced corrosion requires chemical, biological and metallurgical analysis of the water and the metal nodules.

An important step in preventing biocorrosion is to start with a clean system and to keep it clean. The most common approach to maintain a system free of biocorrosion involve the use of coatings, cathodic protection and biocides.

The application of a cathodic current (sacrificial anode for instance) changes the pH at the metal surface making it more basic due to the production of hydroxyl ions. An increase in pH above 9 to 10 is considered detrimental to many marine microorganisms.

The biocides shall be in compliance with local autorities and NL Hydro. Biocides should be used once during rehabilitation works to treat the steel surfaces and could then be mixed into the paint system such as an anti-fouling paint. Specialized contractors or supplier should be used in order to determine the best approach and products.

[2] https://shuthalles.wordpress.com/

6. Recommendations

6.1 Inspection Results: Abstract

The hoist components located in the hoist house and superstructure are considered well preserved. Maintenance work to the intake has been ongoing and is present in the observations made.

However, the inspection revealed issues, mostly coming from the deterioration of submerged components. Deterioration of critical components such as the gate main rollers, roll paths, side-rollers and seals directly affect the gate capacity for proper operation and can be a threat to the safety of the power house and penstock if not addressed (we identified in this report that the intake gate lowering force has diminished significantly, putting its capacity at risk to lower properly in emergency situation). We recommend reviewing BDE power house safety assessment with this information in order to establish the risk level on the equipment and operators in case the intake does not close completely in emergency situation. Some details on risks and consequences can be found in Section 6.2 and more details on the analysis made are available in Section 5.1 and 5.2.

Furthermore, deterioration of submerged components (such as gate main rollers, roll paths, seals and bottom sheave block) is overloading the hoist. Additionaly, the hoisting rope and bottom sheave block were found in very poor condition diminishing the hoist lifting safety factor. For these reasons, cracking the gate should be avoided until the intake gate main rollers, seals, sheave block and wire rope rehabilitations have been performed. Replacement of the hoisting rope and bottom sheave block shall be performed as soon as possible.

Intake #2 and #3 are of similar age and design. The assessments made in this report can be used as guideline for these two other intakes.

6.2 Risk Analysis

The following table summarizes the risks associated with the assessments made:

Comp.	Causes	Risk description	Direct consequences
Gate	a. Main rollers deteriorated condition	Overload to hoist	Mechanical wear to hoist
			Electrical wear to hoist
			Hazardous operation/Worker safety
		Failing emergency drop	Leakage to power house in emergency situation
			Hazardous operation/Worker safety
		Failing penstock prime positonning	Overload to penstock
			Excessive air blow to vent house
			Hazardous operation/Worker safety
	b. Main rollers loose eccentric shafts	Overload to the rollers	Main rollers deterioration
		Overload to gate structure	Gate structure deformation
		Overload to rolling path	Rolling path deterioration
	c. Wear to seals coating	Overload to hoist	Mechanical wear to hoist
			Electrical wear to hoist
			Hazardous operation/Worker safety
		Failing emergency drop	Leakage to power
			Hazardous operation/Worker safety
		Failing penstock filling positonning	Overload to penstock
			Excessive air blow to vent house
			Hazardous operation/Worker safety
	d. Damage to guiding system	No adjustement possible	Leakage
			Gate rubbing
		Misalignment of gate	Leakage
			Gate rubbing
			Jamming of the gate
			Hazardous operation/Worker safety

Comp.	Causes	Risk description	Direct consequences
Gate	e. Corrosion to bottom sheave critical components and bolted connection	Increased friction	Increase wear to hoist
			Increase wear to lifting wire rope
		Failing emergency drop	Leakage to power house in emergency situation
			Hazardous operation/Worker safety
		Failing penstock filling positonning	Overload to penstock
			Excessive air blow to vent house
			Hazardous operation/Worker safety
		Structural failure	Dead load drop
			Hazardous operation/Worker safety
	f. Bottom Sheave block low rated capacity	Structural failure	Dead load drop
			Hazardous operation/Worker safety
	g. Damage to painting system	Material loss	Component failure
			Leakage
Hoist	h. Hoisting rope rubbing	Strands deformation	Accelerated wear to hoisting rope
			Strands break
		Damage to steel structure	Accelerated wear
	i. No mechanical safety device against overloads	Component failure	Unit shutdown
			Hazardous operations/Worker safety
	j. High amperage to motor	Overload to hoist	Mechanical wear to hoist
			Electrical wear to hoist
	k. Corrosion to hoisting rope	Hoisting rope failure	Unit shutdown
			Hazardous operations/Worker safety
			Dead weight drop
	l. Perforated grease tube	No lubrication to gearbox seal	Accelerated wear to seal
	m. Deteriorated gearbox lubricant	No lubrication to gears and pinions	Accelerated wear to gears and pinions
			Material loss by corrosion
	n. Low gearbox lubricant level	No lubrication to gears and pinions	Material loss by corrosion

Comp.	Causes	Risk description	Direct consequences
Embedded Parts	o. Pitting corrosion to rolling paths	Overload to hoist	Mechanical wear to hoist
			Electrical wear to hoist
			Hazardous operations/Worker safety
		Overload to rollers	Main rollers deterioration
		Failing emergency drop	Leakage to power house in emergency situation
			Hazardous operation/Worker safety
		Failing penstock filling positonning	Overload to penstock
			Excessive air blow to vent house
			Hazardous operations/Worker safety
	p. Pitting corrosion to guiding faces	Damage to side rollers	Side rollers deterioration
		Gate misalignment	Leakage
	q. Damage to second phase concrete	Damage to the embedded parts	Leakage
	r. Paint at end of useful life	Corrosion to steel components	Material loss by corrosion
	s. Pitting corrosion to access ladder	Structural failure	Hazardous access/Worker safety
Superstructure	t. Painting system reached its end of life	Material loss	Reduction of structural capacity
	u. Damaged grout to the superstructure anchors	Diminished support	Loss of anchoring capacity
			Damage to first stage concrete
			Overload to tower structure
	v. Rusted fall arrest wire	Limit means of access to hoist house	Use of alternative and less appropriate fall arrest systems/Worker safety
	w. Damaged anchor points	Anchor point failure	Dead load drop
			Hazardous operations/Worker safety
	x. Broken strains to ground wire	To be assessed	To be assessed
	y. Unbraced laterally	Lack of lateral stability	Weak against seism, high wind and gate jamming
	z. Concrete delamination	Uneven grounds	Trips and falls/Worker safety
		Reduction of rebar protection	Reduction of deck lifespan

Comp.	Causes	Risk description	Direct consequences
Emerg. Gates	aa. Deteriorated seals	Leakage	Extensive emergency gate installation work
	bb. Painting system reached its end of life	Material loss	Leakage/Worker safety
			Reduction of structural capacity

6.3 Detailed Recommendations (for 15-25 years intake life extension)

Recommendations are separated into three categories: *Immediate works* which are developed to address direct safety issues; *Short term repairs (1-3 years)* are the minimum required to stabilize and maintain structural integrity and operability; *Medium term (5-10 years) repairs* are recommended to stop further deterioration and assure safe and durable operations of intake #1.

Additional details regarding the repair or maintenance recommendations are presented in Section 6.4.

6.3.1 Immediate works

Based on the assessment of intake #1 at BDE, the following recommendations are provided to address direct safety issues found during the inspection:

1. Superstructure: The fall arrest wire running up the access ladder is rusted and prevents the personnel from trusting its capacity to properly arrest a fall. We recommend replacing the wire with a new one based on the manufacturer's specifications.
2. Superstructure: Complete risk management analysis regarding the hoist house access if it has not been already completed.
3. Superstructure: An anchor point used to lift the gate wire rope protective guards was found to be dangerously weakened by corrosion. The anchor point shall not be used until it is removed. A beam clamp anchor point could be used for replacement.
4. Superstructure: Some gate wire rope protective guards anchor points are deformed. The anchor points shall be removed and shall not be used until then. The lifting procedure shall be studied in order to determine if a new anchor point design is required to prevent its deformation.
5. Hoist: The hoisting rope is in very poor condition and loosing its lifting safety factor (rust and corrosion presence). Its replacement shall be planned as soon as possible. The worst section is at the crossover at the bottom sheave block. Consider replacing the bottom sheave block at the same time with a sheave block of equal or greater capacity then the rated hoist capacity of 40 770 kg (90 000 lbs). Consider a design with modern self-lubricating bushings and corrosion resistant components.

   Greasing the total length of the new hoisting rope periodically is recommended in order to reduce rust and corrosion forming in the submerged portion of the hoisting rope. This implies to lift the gate out of the water.

6. Hoist: (This is not a direct safety issue) Perforated grease tube at the output shaft of the gear box shall be repaired or replaced during the next hoist maintenance operation.
7. Hoist: Verify the fuse size and type installed for the motor electrical protection. If required, replace the fuses with new fuses of type and size in compliance with the motor circuit design and CSA C22.1-12 *Electrical Code.* Do not oversize the fuses.
8. Hoist: (This is not a direct safety issue) Replace the gearbox lubricant with new during the next hoist maintenance operation.
9. Embedded parts: Tag the upstream access ladder with a danger sign or equivalent to notify it is out of service until its removal is done. Plan to remove or replace the access ladder in the short term.

6.3.2 Short Term Repairs (1-3 years)

Actions stated in the *Immediate work* section 6.3.1 should be acknowledged.

The short term repairs recommended here are mainly required to stabilize deterioration and improve the intake gate safety and operability.

This scenario considers inspection and maintenance programs to be in place.

The following recommendations are provided to address deterioration issues found to the intake:

1. Gate: The main rollers shall be replaced, including keeper plates, bushings and shafts. This will improve the gate closing capacity and reduce load to the hoist components.
2. Gate: The J-seals shall be replaced, including their bolting hardware and clamp bars. This will improve the gate closing capacity and reduce load to the hoist components. The sill seal should be replaced at the same time, including its bolting hardware and clamp bars.
3. Gate: The four (4) side rollers are too deteriorated to function, they shall be completely replaced, including their bolting hardware.
4. Gate: Repaint the intake gate. Use of biocides may be required in order to treat the steel surface against biocorrosion before applying a paint system.
5. Gate: If the bottom sheave block has not already been replaced, it shall be replaced with a bottom sheave block of equal or greater capacity then the rated hoist capacity of 40 770 kg (90 000 lbs). Consider a design with modern self-lubricating bushings and corrosion resistant components.

6. Gate: The bolts nut and washers at the connection between the gate and the bottom sheave block shall be replaced by new.
7. Hoist: The hoisting rope is rubbing against the steel structure. A steel spacer of about 20 mm shall be added to the drum extremities in order to limit the hoisting rope to travel pass its rubbing position.
8. Hoist: Replace the Nema design "D" motor with an equivalent but of Nema design "C" instead. This will diminish the motor breakdown torque rating in case of a gate jam and increase the safety factors to the hoist mechanical components.
9. Embedded parts: The two rolling paths have reached the end of their expected life and shall be replaced by two new 135 lbs crane rails including associated fastening clamps.
10. Embedded parts: Damages found to second phase concrete shall be repaired. Softened and damaged concrete shall be removed and surface shall be prepared for re-grouting using non-aggregate, non-shrink grout.
11. Embedded parts: Guiding faces #6 shall be reconstruct using putty and machined afterward.
12. Embedded parts: Replace the access ladder and replace its anchoring system with stainless steel anchors.
13. Embedded parts: Repaint all exposed steel surfaces (no paint to the stainless steel surfaces)
14. Embedded parts: Plan for minor repairs to the upper embedded parts sections, such as grout injection, concrete surface reparation and repainting of the steel parts.
15. Superstructure: Clean and regrout all tower anchor points. Existing grout shall be completely removed and regrouted. Care shall be taken to keep the superstructure level from moving.
16. Superstructure: Paint touch-ups (or overall repainting) should be applied to the structure in locations where corrosion or rust has appeared in order to increase the lifespan of the paint system.
17. Superstructure: Structural analysis to assess the structural capacity of the superstructure shall be performed to confirm if additional bracing is required.
18. Emergency gates: The seals, clamping bars and hardware of the emergency gates shall be replaced by new.
19. Emergency gates: Repaint the emergency gates;

Based on the extent of the work required on the gate, a complete gate replacement can be considered.

6.3.3 Medium Term Repairs (5-10 years)

Actions stated in the *Immediate Work* Section 6.3.1 and *Short Term Repairs* Section 6.3.2 should be acknowledged.

The medium term repairs recommended here are mainly required to limit further deterioration and assure safe and durable operations of intake #1 for 15-25 years.

This scenario considers inspection and maintenance programs are in place.

The following recommendations are provided to address deterioration issues found to the intake:

1. Hoist: New technologies exist in regards to lightning strike protection. These technologies act on people and equipment safety. They prevent lightning strikes from hitting in critical areas and will block voltage from entering by grounding the equipment. This recommendation would improve safety and equipment reliability (if not already in place).
2. Hoist: Improve manual lifting system (hand cranck) by implementing a safety device to protect against inadvertent reenergization of the hoist motor.
3. Superstructure: Repaint the superstructure and hoist house. When the paint system has reached the end of its expected life or when touch-up works is considered too extensive, the superstructure shall be repainted. Rust (reddish color) and paint discoloration shall be checked periodically to assess the paint quality. Corrosion (black color) shall not appear on the superstructure.
4. Superstructure: Plan for reinforcing the superstructure against lateral loads. Additionnal bracing is to be considered.
5. Concrete repairs: Remove the damaged concrete in the locations where delamination or cracking has occured.
6. Hoist house: Improve the electrical layout in the hoist house in order to assure adequate free space in front of cabinets.

6.4 Rehabilitation Considerations

The rehabilitation works to the intake gate are extensive and we consider that performing them at a factory could be a likely alternative. It would require the gate to be moved from the intake to a local machine shop. The work on the rollers, seals, side-rollers and structure (paint) could then be performed. This alternative would also provide a safer work environment for the embedded parts works which would probably be happening at the same time under the gate.

It may be possible to rotate the gate to a flat position on the upstream side of the deck using the hoist and rollers.

6.5 Repair or Maintenance Details

The details shown in this section are intended to give additional information to the repair and maintenance works described in the recommendation section in order to better define the extent of the work. The details are not exhaustive.

Materials

Unless specified to the drawings, the materials shall comply with the standards below:

Structural steel (weldable)	CSA 44W, 50W
Structural bolts (over or equal to 15.9mm dia)	ASTM A325
Nuts (over or equal to 15.9mm dia)	ASTM A563DH
Washers (over or equal to 15.9mm dia)	ASTM F436
Stainless bolts	A320 B8
Stainless washers	AISI 304
Stainless nuts	A194 Grade 8

Paint touch-ups

All surfaces to be coated must be clean, dry and free from contamination. Prepare areas of corrosion by mechanical cleaning in order to obtain a SSPC SP3 surface preparation or hydroblast the surface to SSPC SP12. Remove all oil, grease and soluble contaminants. Abrade surrounding intact area, feather the edges and capture all debris. Submerged areas should be treated with biocides. See Appendix I for information regarding surface preparation standards.

Confirm with a paint representative that the existing paint can be matched with the new paint touch-ups. We would recommend that an adhesion test be performed.

We would recommend a two component epoxy coating. Application method, surface preparation and paint type shall be recommended by your paint representative.

Repaint (Overpaint)

Fresh water wash to remove all dirt and contaminants. Oil or grease should be removed in accordance with SSPC-SP1: solvent cleaning. Abrasive blast clean to SSPC-SP10 or hydroblast (*Geoblaster* for instance) to your paint representative standards. Submerged areas should be treated with biocides. See Appendix I for information regarding surface preparation standards.

Confirm with a paint representative that the existing paint can be matched with the new paint. We would recommend that an adhesion test be performed.

We would recommend a two components epoxy coating or cold metallization (Rust-Anode primer). Application method, surface preparation and paint type shall be recommended by your paint representative.

Gearbox lubricant

Synthetic gear oil would be best suited for the intake hoisting operation in our opinion. Synthetic oil can function despite water or contaminants presence which were observed at site. It also has a better resistance to temperature change.

Replacing the gearbox oil will require the casing to be cleaned to ensure that there will be no more contaminants at the bottom of it. If the inside portion of the gearbox is not accessible, a pump and filtering system in closed loop can be used. Be careful, the used oil is expected to have high lead concentrations.

Oil should be sampled once a year and the results of the analysis should be compiled in order to create a long term trend analysis.

Grout repairs superstructure tower bases

Grout to all tower bases should be removed and re-grouted with non-aggregate, non-shrink grout with 50 MPa minimum compressive strength. The grouting method shall include provisions to hold the superstructure load and avoid level changes during the grout removal and grouting operation.

Concrete repairs at the intake deck level

Determine the area to be repaired where cracks or delamination are apparent. Remove the damaged concrete until sound concrete is reached (up to 6 inches deep maximum), and then by adding freeze-thaw resistant concrete. Apply concrete without over thickness. It is important to ensure the quality of the link between the old and the new concrete. This is done by making sure the new concrete has a grip on the existing reinforcing bars by covering them. Also, the material on which the reparation is done should be saturated with water and the surface should be dried to maximize the adhesion.

Bottom sheave replacement

The sheave block shall be completely removed and replaced by a new one of 40 770 kg rated capacity. Corrosion resistant shafts (17-4 PH stainless steel) and modern self-lubricated bushings are to be used. Special care shall be taken in order to protect the other sheave components from corroding. Field machining is to be expected in order to fit the new pin to the gate.

Figure 52 shows an overview of the bottom sheave block replacement:

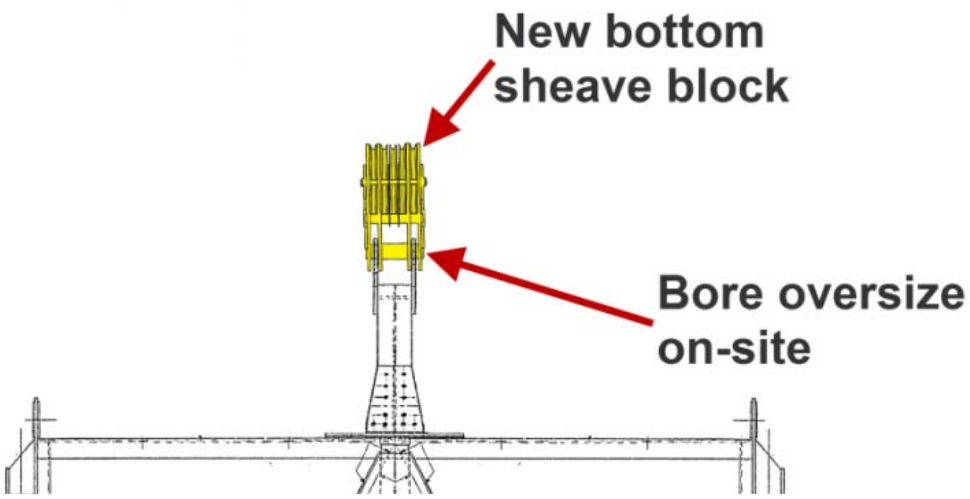


Figure 52: Bottom sheave block replacement sketch

Steel spacer to hoist drum

In order to prevent the hoisting rope from rubbing against the steel structure, we recommend installing a steel spacer to the hoist drum. Figure 53 shows an overview of the work required:

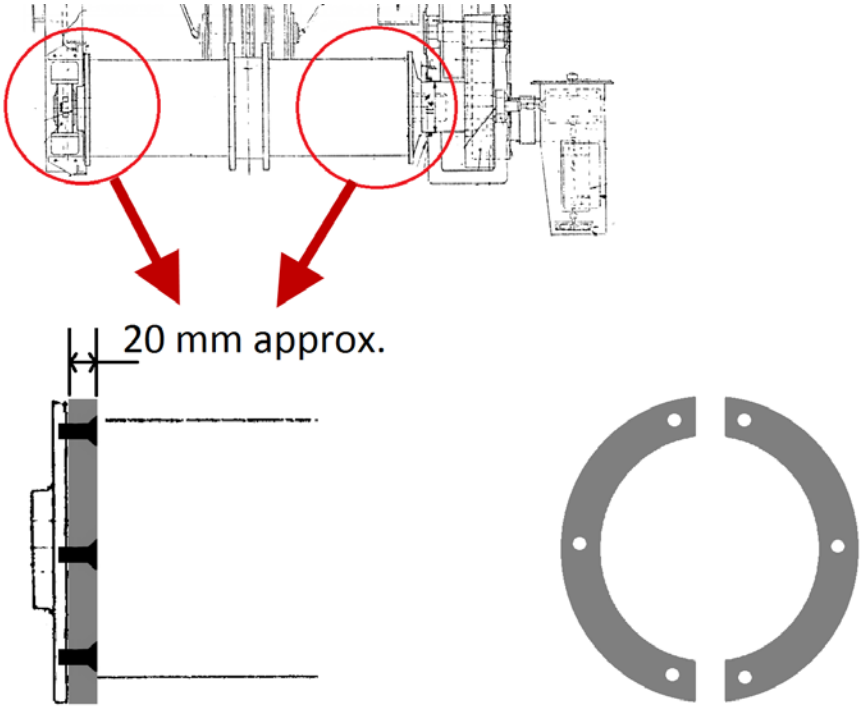


Figure 53: Steel spacer to hoist drum

Intake gate seal replacement

The J-seal shall be replaced with a new vulcanized and anti-friction coating J-seal with a double flange lintel seal. Hardware shall be replaced with stainless steel fasteners. The clamp bars shall be replaced using stainless steel material and old clamp bars as templates. Replace at the same time the sill seal, including its bolting hardware and clamp bars. An additional seal face and clamp bar will have to be installed at the gate lintel in order to receive the double flanged J-seal (Figure 54).

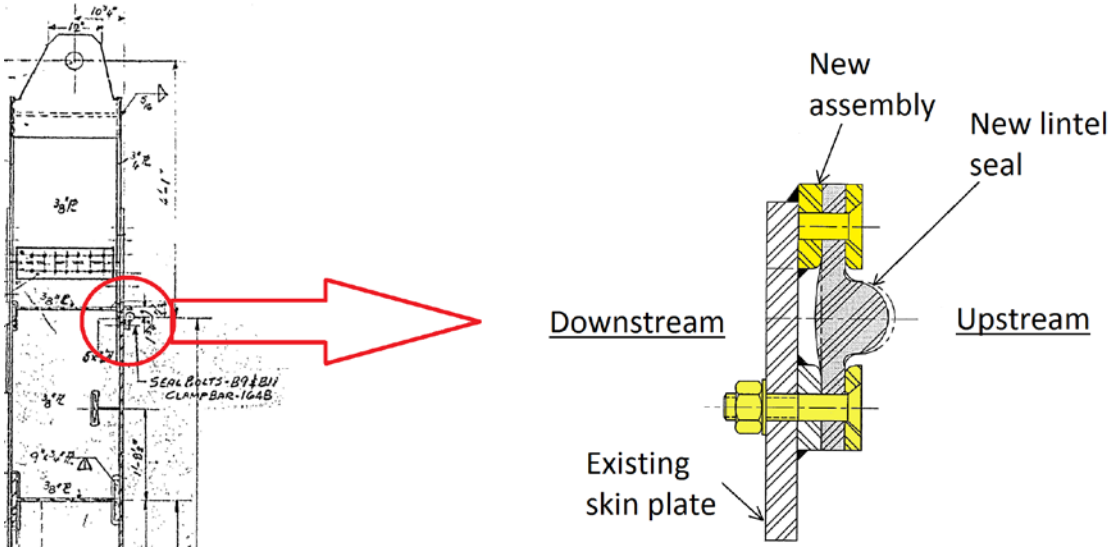


Figure 54: Seal replacement sketch

Main roller replacement

All twelve (12) main rollers shall be replaced with the same specifications as the previous ones. We recommend upgrading the shaft with 17-4 PH stainless steel material. The replacement work could take place on site with the gate in maintenance position or at the factory. It will be required to machine the gate structure in order to rebore the main roller supports. Some possibilities exist to replace the *Lubrite* bushing with an equivalent material (*Orkot* or *Tordon* material for instance) to reduce its costs. Detailed engineering would be required in order to confirm an adequate replacement material. Precise adjustment of the rollers would be made vertically or horizontally. Twelve (12) new keeper plates will be required to fix the adjustment. Figure 55 shows an overview of the replacement work.

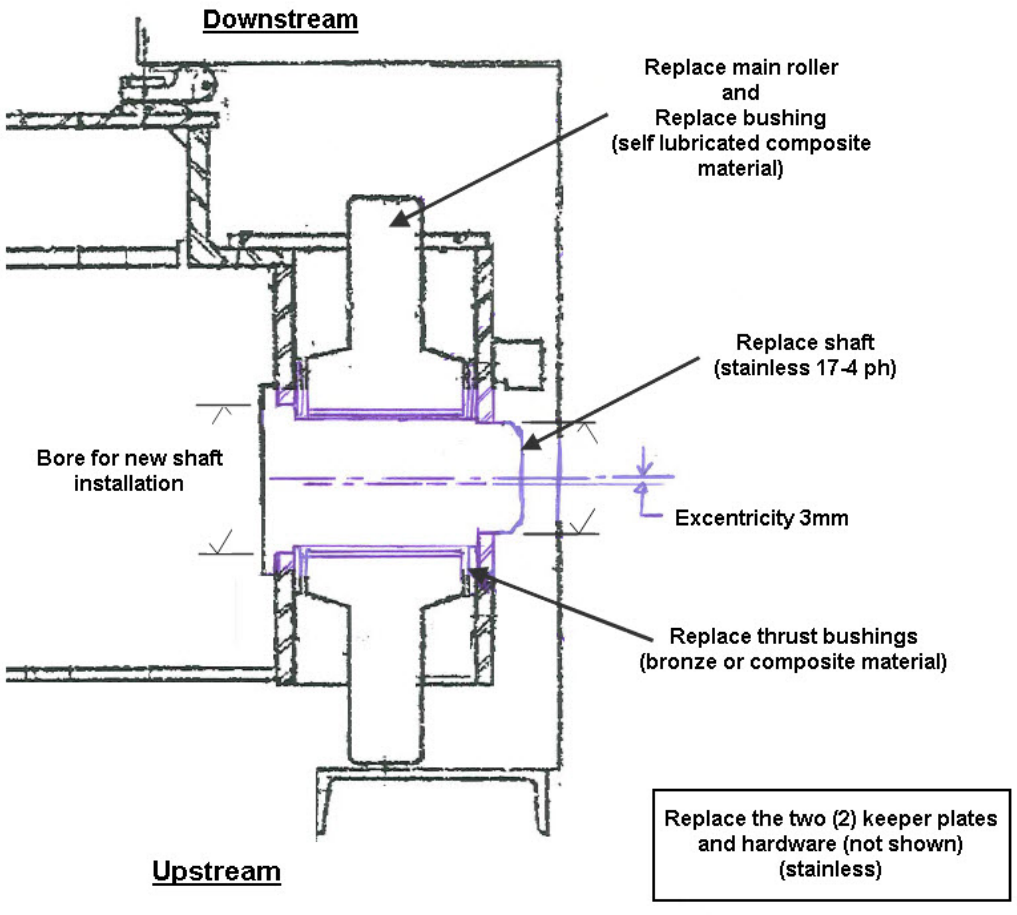


Figure 55: Main roller replacement work overview

Side roller replacement

All four (4) side rollers shall be replaced. We recommend upgrading all subassemblies with stainless steel materials. Figure 56 shows an overview of the replacement work.

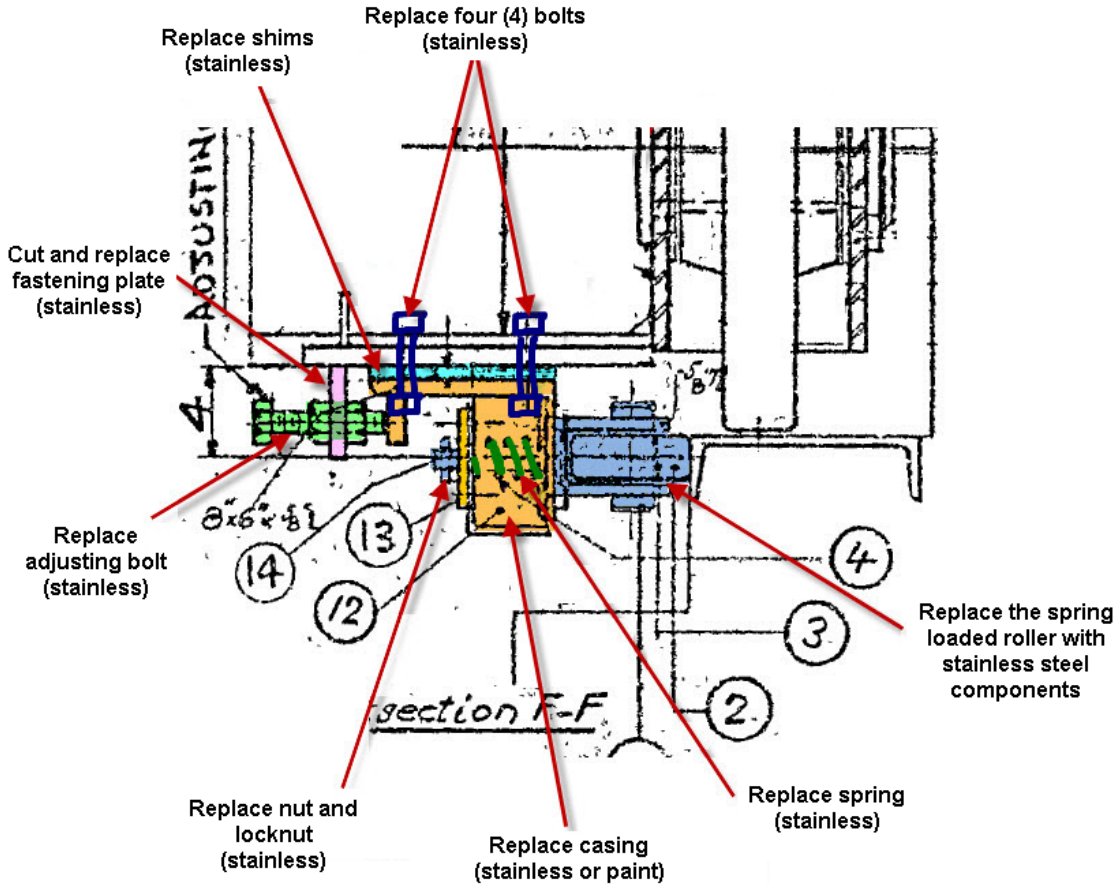


Figure 56: Side roller replacement sketch

Guiding face repairs (Face #6)

- Prepare the guiding surface by a blast cleaning (*Geoblaster*) to SSPC-SP5 and biocide treatment;
- Apply an epoxy based composite putty (*Belzona, Devcon Titanium* putty or equivalent) to fill the corrosion damages or straightness deviations as required;
- Machine the epoxy based composite to nominal measurement;
- Apply a protective coating to the machined surface;

Rolling path repairs

Replace the two rolling paths with new 135 lbs crane rails including associated fastening clips. The rolling surface of the rails shall be hardened to 250 BHN min. Figure 57 shows an overview of the replacement work.

The proposed rehabilitation sequence of the rolling paths is as follow:

- Dispose the used rails and clamps;
- Prepare the surface with a blast (*Geoblaster*) cleaning and biocide treatment;
- Assess the rail support surface texture and verticality. Apply an epoxy based composite (*Belzona* or *Devcon Titanium* putty) to fill the corrosion damages or straightness deviations as required;
- Machine the surface with the epoxy based composite to nominal measurement;
- Weld the new clips;
- Apply a protective coating to the machined surface (Rust Veto or equivalent);
- Paint the exposed surfaces with two components epoxy paint, see Repaint paragraph p.70;
- Install the new rails, confirm their positioning and verticality;
- Bolt the stainless hardware in order to fix the rails in place using the clips;

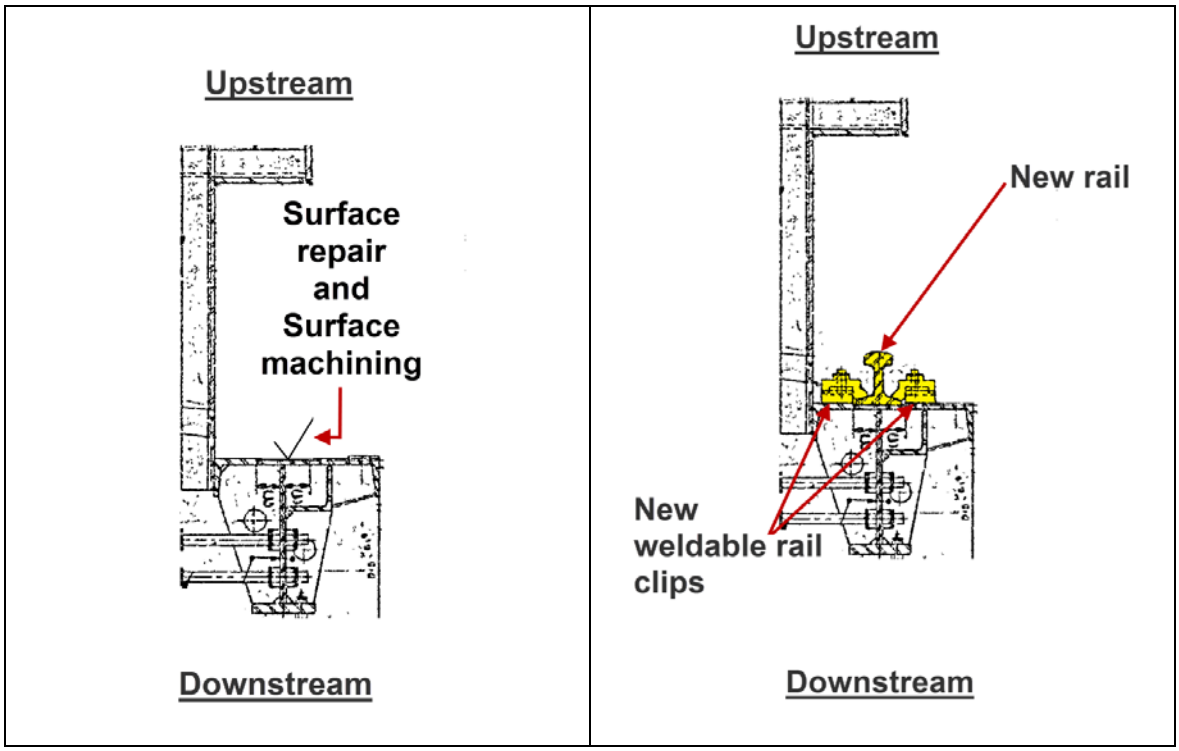


Figure 57: Rolling path replacement sketch

7. Estimations

The estimate below is at conceptual level and therefore, an imprecision level of about 30% is to be considered.

7.1 Parameters for the Estimates

- The estimates are based on the work for one intake gate;
- The estimates consider the access road is practicable for mobile crane without additional work;
- The estimates do not consider the preparation work that could be required for mobile crane mobilization at the intake;
- Costs due to loss of production are excluded;
- Surveillance costs are excluded;
- Training costs are excluded;
- Average workers rate is established at 90$/hour;
- Inflation is excluded;
- A 25% contingency is applied.

Estimation details are in Appendix H.

7.2 Costs Estimate Summary

The tables below summarize the estimates for the different scopes of work for one intake:

Immediate Works	
Engineering	20 000.00 $
Preparatory Works	15 000.00 $
Bottom Sheave Block Replacement	59 220.00 $
Lifting Points Replacement	3 290.00 $
Hoist Maintenance	4 085.00 $
Superstructure Fall Arrest System	460.00 $
Total	**102 055.00 $**
Contingence (25%)	**25 513.75 $**
Grand total	**127 568.75 $**

Short-term Works	
Engineering	132 000.00 $
Preparatory Works	72 800.00 $
Gate Refurbishment Works	318 940.00 $
Hoist Refurbishment Works	27 600.00 $
Embedded Parts Refurbishment Works	333 400.00 $
Superstructure Refurbishment Works	41 550.00 $
Total	**926 290.00 $**
Emergency Gate Refurbishment Works (6 gates)	128 500.00 $
Contingence (25%)	**263 697.50 $**
Grand total	**1 318 487.50 $**

Mid-term Works	
Engineering	25 000.00 $
Preparatory Works	21 800.00 $
Hoist refurbishment Works	18 520.00 $
Superstructure Refurbishment Works	75 660.00 $
Concrete Repair Works	14 300.00 $
Total	**155 280.00 $**
Contingence (25%)	**38 820.00 $**
Grand total	**194 100.00 $**

7.3 Costs Level and Rehabilitation Strategy

The costs covered in the short-term works are particularly important. For instance, the costs level for gate refurbishment works and embedded parts refurbishment works are close to the costs of new equipment. The life expectancy of new equipement is about 50 to 60 years compared to the 15 to 25 years life expectancy with the proposed refurbishment works. Going for new equipment could be beneficial for NL Hydro in that project.

Refurbish Marine Terminal

2025–2026

Holyrood



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Appendix A: Holyrood Marine Terminal 10 Year Life Extension

Appendix B: HTGS Marine Terminal Boardwalk Structural Inspection

Refurbish Marine Terminal (2025–2026)

Location: Holyrood

Investment Classification: Renewal

Asset Category: Thermal Plant

Cost: $2,486,452

1.0 Introduction

The Holyrood Thermal Generating Station ("Holyrood TGS") includes three thermal generating units that provide a total capacity of 490 MW and is an essential part of the Island Interconnected System. These thermal generating units are operated with No. 6 (Bunker C) fuel oil, supplied to the Holyrood TGS by sea tankers. A piping system pumps the fuel to a tank farm until the fuel is required for the thermal generating units.

The Holyrood Marine Terminal Facility is an integral component of the fuel oil handling system and is the single point of entry for all the fuel oil utilized by the Holyrood TGS. The assets that comprise the marine terminal include the shoreline boardwalk, shore-link bridge, berthing jetty, loading arms, capstans, 450 mm fuel pipeline, concrete gravity fenders, and the concrete-filled circular steel piles that support the berthing jetty and shore-link bridge.

As per the "Reliability and Resource Adequacy Study – 2022 Update,[1] the Holyrood TGS shall remain available for a Bridging Period while Hydro seeks to develop new long-term sources of supply. At this time, capital investment related to the generation function of the Holyrood TGS is necessary to support system reliability and maintain Hydro's ability to meet customer demand during peak periods. These assets require refurbishment to extend their service life and to maintain the safe and reliable operation of the marine terminal to enable fuel deliveries to the Holyrood TGS.[2]

[1] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.
[2] This project is required to enable the Holyrood Marine Terminal Facility to continue to be used for fuel supply delivery to Units 1, 2, and 3 at the Holyrood TGS, as required and is the basis for this proposal. However, marine terminal access at Holyrood in support of future combustion turbine fuel supply is a strategic consideration discussed in the *Reliability and Resource Adequacy Study Review* proceeding.



Figure 1: Holyrood TGS Marine Terminal

2.0 Project Description and Justification

The scope of this project entails the refurbishment of the marine terminal at the Holyrood TGS as shown in Figure 1. The scope was derived through the completion of an independent life extension study[3] and reflects the minimum refurbishment and condition assessments required to extend the service life of the assets. The refurbishments include a section of the shoreline boardwalk, gravity fender bumpers, and capstan gearboxes. Level 2 condition assessments will be completed on the jetty steel piles, bollards and the gravity fender mechanical linkage arms to refine refurbishment scopes for these components.

Tankers offload about 220,000 barrels of fuel with each delivery and are the only fuel supply option for the Holyrood TGS. The Holyrood Marine Terminal Facility is an integral component of the fuel oil handling system and the single point of entry for all No. 6 fuel oil utilized by the Holyrood TGS. The inability of a tanker to safely dock at the marine terminal could disrupt fuel supply and ultimately result in generation outages. The proposed refurbishments to the marine terminal must be completed to ensure the continued safe, reliable operation of the asset.

Hydro recommends completion of this project to ensure the continued operation of the Holyrood Marine Terminal Facility.

[3] Hatch Limited performed a Life Extension Condition Assessment for Holyrood assets in 2021.

3.0 Asset Overview

3.1 Asset Background

The marine terminal at Holyrood TGS was initially constructed in 1969 and consists of a 125-metre shore arm link that bridges the jetty to the adjacent land, as outlined in Figure 2. The jetty is approximately 74 metres long by 12 metres wide and supports the fuel oil offloading arms and associated pipeline and controls related to the fuel oil offloading process. Both the shore arm link and jetty consist of a concrete superstructure supported on concrete-filled circular steel piles, as shown in Figure 5 of Appendix A. The berthing jetty structure is 242 feet long by 39 feet wide; and, also supports the gravity fender system that absorbs the forces created from the vessels as they approach the marine terminal. The vessels are secured to the marine terminal using four mooring dolphins and four motorized capstans located on the shore, and mooring bollards located on the jetty superstructure. The four motorized capstans are only accessible by the shoreline boardwalk.

When the vessel is secured at the marine terminal, fuel oil is offloaded from the vessel into the fuel oil offloading arms located on the jetty, and pumped through a pipeline into the fuel oil storage facility, located approximately one kilometre from the marine terminal.

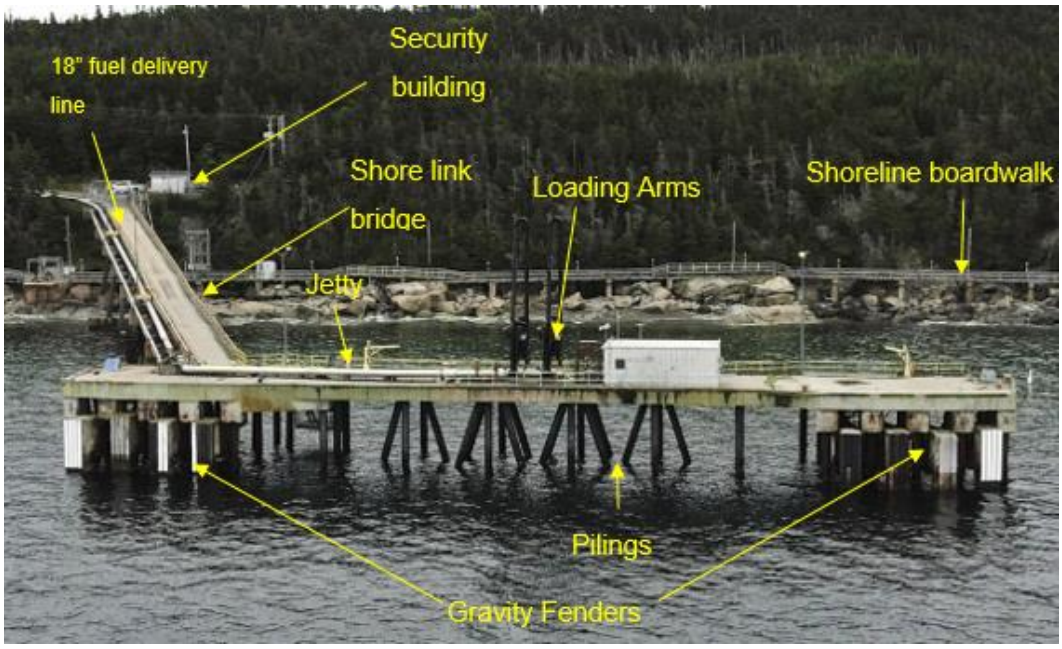


Figure 2: Holyrood TGS Marine Terminal

3.2 Historical Reliability

Hydro has addressed asset deterioration to prevent failures as they are discovered, primarily through the Thermal In-Service Failures Program,[4] which has been increasing since 2018. A condition assessment completed by Wood Canada Limited in November 2023 ("November 2023 Assessment") is provided as Appendix A to this report and includes a synopsis of recent upgrades and maintenance work completed on the marine terminal jetty within Sections 8.0 and 9.0.

3.3 Asset Condition

The November 2023 Assessment was completed on the structures and equipment that comprise the marine terminal. This project addresses, in detail, only the infrastructure and equipment that require refurbishment at this time.

Components of the marine terminal jetty which are proposed for refurbishment and/or level 2 condition assessment under this project include the concrete-filled steel piles, 70-tonne concrete gravity fenders on the berthing structure, shoreline boardwalk and the capstans. The condition of each component is described below.

The concrete-filled steel piles were evaluated during the 2023 condition assessment, which found that the remaining life of the sacrificial anodes varied from 0–100%. Some anodes on the north end of the jetty showed signs of damage due to ice contact, and a number of piles were noted to have visible corrosion present at the 'splash zone.' A follow-up inspection was recommended for completion within the next five years.

Along the jetty's berthing structure, there are eight 70-tonne concrete gravity fenders equipped with a timber bumper and plastic rubbing strips. The timber bumpers for numbers 2–6 require replacement of missing timbers. The concrete gravity fenders shown in Figure 3 are mounted to the jetty by a mechanical linkage system that swings and retracts to absorb the forces exerted by the tanker during berthing.

[4] A synopsis of the work completed under the Thermal In-Service Failures Program each year is provided within Hydro's annual Capital Expenditures and Carryover report, most recently filed with Board of Commissioners of Public Utilities ("Board") on April 1, 2024 and provided as Attachment 1 to Schedule 5 of this application. Reports since 2018 are available on the Board website. http://www.pub.nl.ca/indexreportspages/capitalexpenditure.php

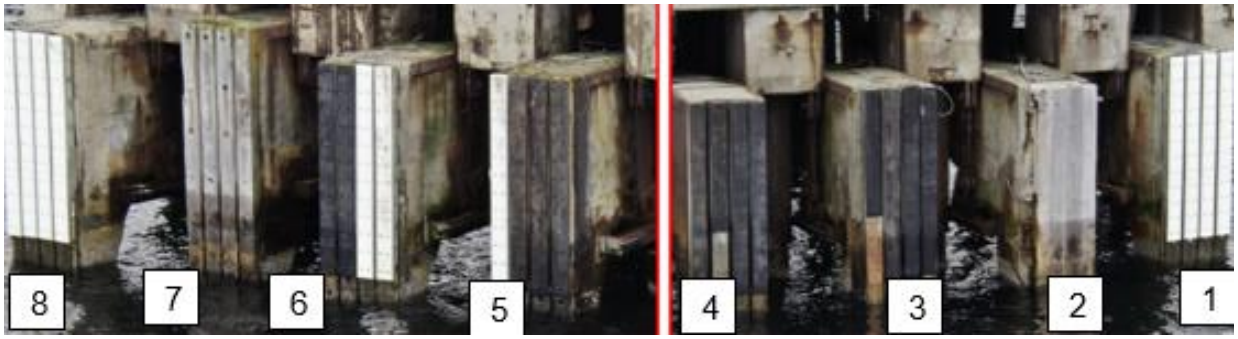


Figure 3: **Concrete Gravity Fender Individual Locations**

To monitor their condition and ensure that they remain in reliable operating condition, a condition assessment is completed on the concrete gravity fenders mechanical linkage system every five years with refurbishment completed as required. Concrete gravity fender number 2's linkage system is original and measurements indicated its progression towards failure; as such, it is recommended that its replacement be completed within the next five years. If failure of these linkage arms occurs, the concrete gravity fender could detach from the dock and fall into the ocean below.[5]

The shoreline boardwalk is constructed primarily of timber founded on steel, timber, and concrete supports which rest atop the natural coastal bedrock. Sections of the boardwalk that are of original construction are showing signs of deterioration and have undergone partial refurbishments since 2021, as shown in Figure 4. Additional boardwalk refurbishments are required to ensure safe access to four motorized capstans.

The motorized capstans are used to secure the tanker for fuel offloading and their gearboxes and motors require overhauls every five to seven years to decrease potential failure and delay of tanker delivery. The three capstans which have been identified for overhaul within this project were last overhauled in 2019.

[5] Such a failure did occur in 2008 on number 4 concrete gravity fender.



Figure 4: **2022 Boardwalk Replacement – Rotted Timber Stringers**

4.0 Analysis

4.1 Evaluation of Alternatives

The alternatives considered for this project include:

- Deferral; and
- Like-for-like refurbishment of the marine terminal.

4.1.1 Deferral

Deferral of the proposed refurbishments presents an unacceptable risk to the reliable operation of the Holyrood TGS. Docking a sizeable oil tanker could also present a significant environmental risk if the dock were to fail unexpectedly. At 54 years of age, the marine terminal is nearing the end of its useful service life and, in recent years there has been an increase in required corrective maintenance to address the failure of critical components.

The Holyrood Marine Terminal Facility is the single point of entry for all of the fuel oil utilized by the plant, and maintaining its integrity is imperative to the reliable operation of Holyrood TGS. For this reason, deferral of this project is not a viable option.

4.1.2 Like-for-Like Refurbishment of the Marine Terminal

This alternative involves the completion of refurbishments to the marine terminal. The identified refurbishment scopes will include like-for-like refurbishment to the shoreline boardwalk, concrete gravity fenders and mechanical linkages, and capstan gearboxes.

Completion of this work will ensure the safe and reliable operation of the Holyrood Marine Terminal Facility.

4.2 Least-Cost Evaluation

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

4.3 Recommended Alternative

Hydro recommends proceeding with like-for-like replacement/refurbishment of the marine terminal components. This alternative will extend the service life of the asset and ensure the continued safe and reliable operation of the marine terminal.

4.3.1 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]

Further, marine terminal access at Holyrood in support of future combustion turbine fuel supply is a strategic consideration discussed in the *Reliability and Resource Adequacy Study Review* proceeding. Marine terminal access at the Holyrood TGS has strategic importance to mitigate future fuel supply risk for existing and any potential new thermal generating assets. While Hydro's current operation involves the supply of combustion turbine fuel by truck, continuing shifts in the global supply chain may drive requirements for deliveries from alternative sources. Therefore, marine terminal access at the Holyrood TGS would be critical.

[6] Due to the extension of the Holyrood TGS through the Bridging Period, Hydro submitted an application to the Board to extend the Holyrood Accelerated Depreciation Deferral Account. The Board approved the extension of the account and related amendments in Board Order No. P.U. 1(2024). Hydro also was directed to file a report on the account in its next general rate application.

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for this 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-Implementation	5	4	**20**
Post-Implementation	5	2	**10**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**4.0**

5.0 Scope of Work

This project involves the refurbishment of the marine terminal at the Holyrood TGS. The scope of work includes:

Year 1 (2025)

- Shoreline boardwalk refurbishment of approximately 10 metres (30 feet) of boardwalk and installation of boardwalk structural supports to a 15 metre (50 foot) section;
- Jetty refurbishment for the gravity fender bumpers (number 5 and number 6);
- Overhaul of two capstan gearboxes;
- Procurement of mechanical linkage for gravity fender number 2; and
- Completion of condition assessment for the jetty (including the steel piles, bollards, and fender mechanical linkages numbers 5–8).

Year 2 (2026)

- Jetty refurbishment for the gravity fender bumpers for numbers 2–4;
- Installation of gravity fender number 2 mechanical linkage system;
- Overhaul of one capstan gearbox; and,
- Condition assessment of the fender mechanical linkages for numbers 1–4.

5.1 Project Budget

The estimate for this 2025–2026 project is shown in Table 2

Table 2: Project Estimate ($000)[7]

Project Cost	2025	2026	Beyond	Total
Material Supply	100.0	0.0	0.0	**100.0**
Labour	189.4	139.9	0.0	**329.3**
Consultant	174.0	254.0	0.0	**428.0**
Contract Work	575.0	670.0	0.0	**1,245.0**
Other Direct Costs	2.8	2.6	0.0	**5.4**
Interest and Escalation	45.5	122.5	0.0	**168.0**
Contingency	104.1	106.6	0.0	**210.8**
Total	**1,190.8**	**1,295.6**	**0.0**	**2,486.5**

5.2 Project Schedule

The proposed scope of work will be executed as a multi-year project. The project is planned to start in 2025 and to be completed by the end of 2026. The schedule for this project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Budget review, scope statement, schedule development, risk assessment.	January 2025	May 2025
Design:		
Completion of the tender package–Year 1.	February 2025	April 2025
Procurement:		
Procure mechanical linkage for concrete gravity fender number 2.	May 2025	December 2025
Commissioning:		
Commissioning – Year 1.	July 2025	September 2025
Commissioning – Year 2.	July 2026	September 2026
Closeout:		
Construction contract closeout – Year 1.	October 2026	December 2026
Construction contract closeout – Year 2.	October 2026	December 2026
Project completion, interest cut-off, lessons learned, as-built drawings.		

[7] Numbers may not add due to rounding.

6.0 Conclusion

The Holyrood Marine Terminal Facility enables the safe and reliable transfer of fuel from tankers to the Holyrood TGS tank farm. The marine terminal's condition has deteriorated and many of its components, including the shoreline boardwalk, concrete gravity fenders, and the capstans require refurbishment.

The proposed refurbishments are required to restore the asset, extend its service life and ensure Holyrood TGS can continue to safely and reliably receive fuel for the generation of electricity.

Appendix A

Holyrood Marine Terminal 10 Year Life Extension





Holyrood Marine Terminal 10 Year Life Extension

wood.

Holyrood Marine Terminal 10 Year Life Extension

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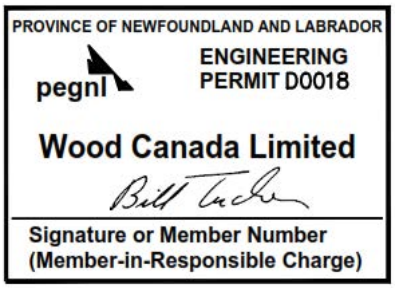
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Prepared by:

Wood Canada Limited
133 Crosbie Road
St. John's, NL AIA 3C1





REV.	DATE	REVISION(S)	PREPARED BY	CHECK	APP	CLIENT
C	2023-11-24	Issue for Use	BT	AH	BT	
B	2023-11-10	Issue at 90% Completion	BT	AH	BT	
A	2023-10-18	Issue at 50% Completion	BT	AH	BT	

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Appendix A Site Visit Photos

1.0 Introduction

1.1 Summary

The Holyrood Marine Terminal facility, initially constructed in 1969, receives fuel oil from tankers delivering to the Holyrood Thermal Generating Station (TGS) Tank Farm to be used for steam production.

Wood was retained by Newfoundland and Labrador Hydro (NLH) to perform a study to extend the Marine Terminal's life for another ten (10) years. The study includes:

- identifying capital upgrade requirements;
- reviewing preventative maintenance practices and inspection/overhaul frequencies;
- recommending future assessments that may be required to confirm the service life.

2.0 Scope of Study

The following items are included in the scope of work for this study:

- Review the 2018 Marine Terminal 10-year Life Extension Study
- Review recent upgrades and maintenance activities. These include;
    - Timber fender replacements;
    - Replaced linkage arms on the concrete gravity fenders;
    - Mechanical loading arm overhauls;
    - Upgrades to the shoreline boardwalk;
    - Replacement of capstan access platforms;
    - Replacement of the 4-inch fuel oil pump-out pipeline;
- Review recent inspection reports, including;
    - Shoreline boardwalk structural assessments
    - Annual expansion joint survey
    - Fender inspections
    - Pile inspections
    - Loading arm inspections
- Complete a Level 1 site assessment;
- Identify components requiring further investigation or level 2 condition assessments;
- Evaluate overhaul/inspection frequencies;
- Provide suitable measurements for expansion joints for annual comparisons;

3.0 References

3.1 Drawings

The following drawings were reviewed by Wood for the Marine Terminal Life Extension Study. Some of these drawings were contained in previous life extension studies and inspection documents.

Table 1 Reference Drawings

Ref.	*Doc. Number*	*Rev*	*Description*	*Issued*	*Comments*
3.1.1	A-1	1	Jetty Bumper Timbers	2022-11	Baysteel
3.1.2	A-1		Concept Drawing Typical Support	2021-10	Baysteel
3.1.3	Figure 4	A	Jetty Head Existing Breasting Mooring Arrangement	2011	From 3.2.2
3.1.4	Figure 5	A	Proposed Mooring Upgrades	2011	From 3.2.2
3.1.5	H337965-M-A3-001	A	Loading Arm Layout	2011-03-22	Hatch
3.1.6	H331421-M-D-001-1	1	Temporary Support Details for Gravity Fenders 3,5&6	2008-11-07	Hatch
3.1.7	H331421-M-D-002	0	Temporary Support Details for Fenders 5&6	2008-11-13	Hatch
3.1.8	238-05-4004-055	1	Marine Terminal Upgrading of Fenders 2,3,4,5&6	1999-04-15	NL Hydro
3.1.9	238-05-4004-05	0	Jetty Head - Piling Layout	1981-08-18	NL Hydro
3.1.10	238-05-4004	1	Shore Arm - General Arrangement	1970-02-04	Shawmont
3.1.11	238-05-4004-004	2	Details of Piling	1970-03	Shawmont
3.1.12	238-05-4004-026	R1	Marine Terminal Gravity Fenders Arrangement & Details	1970-11-30	Shawmont
3.1.13	238-05-4004-027	R1	Marine Terminal Gravity Fenders Detail of Front Suspension Bracket	1970-05-07	Shawmont
3.1.14	238-05-4004-056	2	Marine Terminal Boardwalk Mooring Dolphin # 1 Repairs New Plan	2023-06-20	JewerBailey
3.1.15	238-05-4004-057	2	Marine Terminal Boardwalk Mooring Dolphin # 1 Repairs New Plan	2023-06-20	JewerBailey
3.1.16	238-05-4004-058	2	Marine Terminal Boardwalk Mooring Dolphin # 1 Repairs Details"	2023-06-20	JewerBailey
3.1.17	238-05-4004-059	2	Marine Terminal Boardwalk Mooring Dolphin # 1 Repairs Details	2023-06-20	JewerBailey
3.1.18	238-05-4004-063		Holyrood Marine Terminal Repairs Alternate No.1 Sections	1983-06-23	Mid Ocean Engineering Ltd
3.1.19	238-05-4004-064		Holyrood Marine Terminal Repairs Pile Splice and Expansion Joint Details	1983-06-23	Mid Ocean Engineering Ltd

Ref.	Doc. Number	Rev	Description	Issued	Comments
3.1.20	238-05-4004-065		Holyrood Marine Terminal Repairs Details	1983-06-23	Mid Ocean Engineering Ltd
3.1.21	238-05-4004-066		Holyrood Marine Terminal Repairs Alternate No.2 Sections	1983-06-23	Mid Ocean Engineering Ltd
3.1.22	238-05-6111-002		Holyrood Marine Terminal Repairs Site Plan	1983-06-23	Mid Ocean Engineering Ltd

3.2 Life Extension Studies

The planned date for decommissioning the Holyrood Thermal Generating Station has been extended several times and previous studies for life extension of the Marine Terminal have been completed.

Table 2 References: Life Extension Studies

Ref.	Doc. Number	Rev	Description	Issued	Comments
3.2.1	H353306-00000-240-230-0001	0	Holyrood Marine Terminal 10-Year Life Extension Study	2018-03-21	Hatch
3.2.2	H337965-0000-50-124-0001	0	Holyrood Marine Terminal 10 Year Life Extension Study	2011-04-29	Hatch

3.3 Pile Inspections

The following documents contain information related to inspections of the concrete filled steel piles that support the trestle and loading platform of the marine terminal.

Table 3 References: Pile Inspections

Ref.	Doc. Number	Rev	Description	Issued	Comments
3.3.1	N.A.		Pile Inspection	2021	
3.3.2	H353306-00000-240-230-0001	0	Holyrood Marine Terminal 10-Year Life Extension Study	2018-03-21	Hatch
3.3.3	H344177-0000-10-124-0001	A	HTGS Jetty and Shore Arm Pile Inspections	2013-12-12	Hatch

3.4 Fender Inspections and Work Orders

The following documents contain information related to of the swinging concrete fenders on the loading platform of the marine terminal.

Table 4 References: Fender Inspections

Ref.	*Doc. Number*	*Rev*	*Description*	*Issued*	*Comments*
3.4.1	21-114-03	Rv 0	Marine Terminal Gravity Fender Inspection	2022-05-25	AAE
3.4.2			Fender Timber Bumper Drone Inspection	2022-05-30	NL Hydro
3.4.3	N.A.		3 and 9 Arm Photos	2021-07-26	
3.4.4			Fender Arm Measurements (2016 vs. 2021)	2021-07-27	Hatch
3.4.5	H361253-00000-240-024-0001	0	Letter: HTGS - Marine Terminal Fender visual inspection	2019-11-19	Hatch
3.4.6	H358307-00000-240-024-0001	A	Letter: HTGS - Marine Terminal Fender visual inspection	2018-12-03	Hatch
3.4.7	H348376-00000-100-024-0001	0	Letter: HTGS - Marine Terminal Fender visual inspection	2014-12-22	Hatch
3.4.8	Project No: 12962103		Work Request to Replace Failed Jetty Bumper Timbers on 3	2021-10-20	NL Hydro
3.4.9	Project No: 12962201		Work Request to Replace Failed Jetty Bumper Timbers on 1, 5, 6 and 8	2022-09-06	NL Hydro

3.5 Shoreline Boardwalk Inspections

The following documents contain information related to inspections of the boardwalk structure and the concrete deck of the approach trestle.

Table 5 References: Boardwalk Inspections

Ref.	*Doc. Number*	*Rev*	*Description*	*Issued*	*Comments*
3.5.1	N.A.		2023 Marine Terminal Shoreline Boardwalk Inspection	2023-11-16	NL Hydro
3.5.2	N.A.		HTGS Marine Terminal Boardwalk Structural Inspection	2023-02-03	JBC
3.5.3	N.A.		Work Request for Walkway and Capstan Work	2022	NL Hydro
3.5.4	N.A.		Marine Shoreline and Concrete Walkway Inspection	2020-01-28	NL Hydro
3.5.5	N.A.		Marine Shoreline and Concrete Walkway Inspection	2017	NL Hydro
3.5.6	N.A.		Marine Shoreline and Concrete Walkway Inspection	2016-10-06	NL Hydro

3.6 Other Documents

The following documents contain information related to other components of the terminal.

Table 6 References: Other Documents

Ref.	*Doc. Number*	*Rev*	*Description*	*Issued*	*Comments*
3.6.1	N.A.		2021 Marine Terminal Loading Arm Overhaul	2021	NL Hydro
3.6.2	N.A.		Boland Marine Report on Loading Arm Work	2021	Boland Marine
3.6.3	N.A.		Jetty Gap Measurements (spreadsheet)		NL Hydro

4.0 Description of Marine Terminal Infrastructure

4.1 General

The following sections give a brief description and photographs of the main components of the Marine Terminal infrastructure, to provide context for this study. The Holyrood Thermal Generating Station (TGS) is in the Town of Holyrood bordering Conception Bay South on the Avalon Peninsula of Newfoundland and Labrador. The Marine Terminal facility, initially constructed in 1969, receives fuel oil from tankers delivering to the Holyrood TGS Tank Farm to be used for steam production in the plant. The following figure shows a satellite view of the Marine Terminal (circled in white), tank farm and TGS.



Figure 1 Satellite View of Thermal Generating Station, Tank Farm and Terminal

The purpose of the Holyrood Marine Terminal is to offload No. 6 fuel oil for the Holyrood Generating Station from incoming tankers. It was designed and constructed in 1969 to meet the standard practices and vessel sizes of the day. An aerial view of the terminal is shown in the following figure.

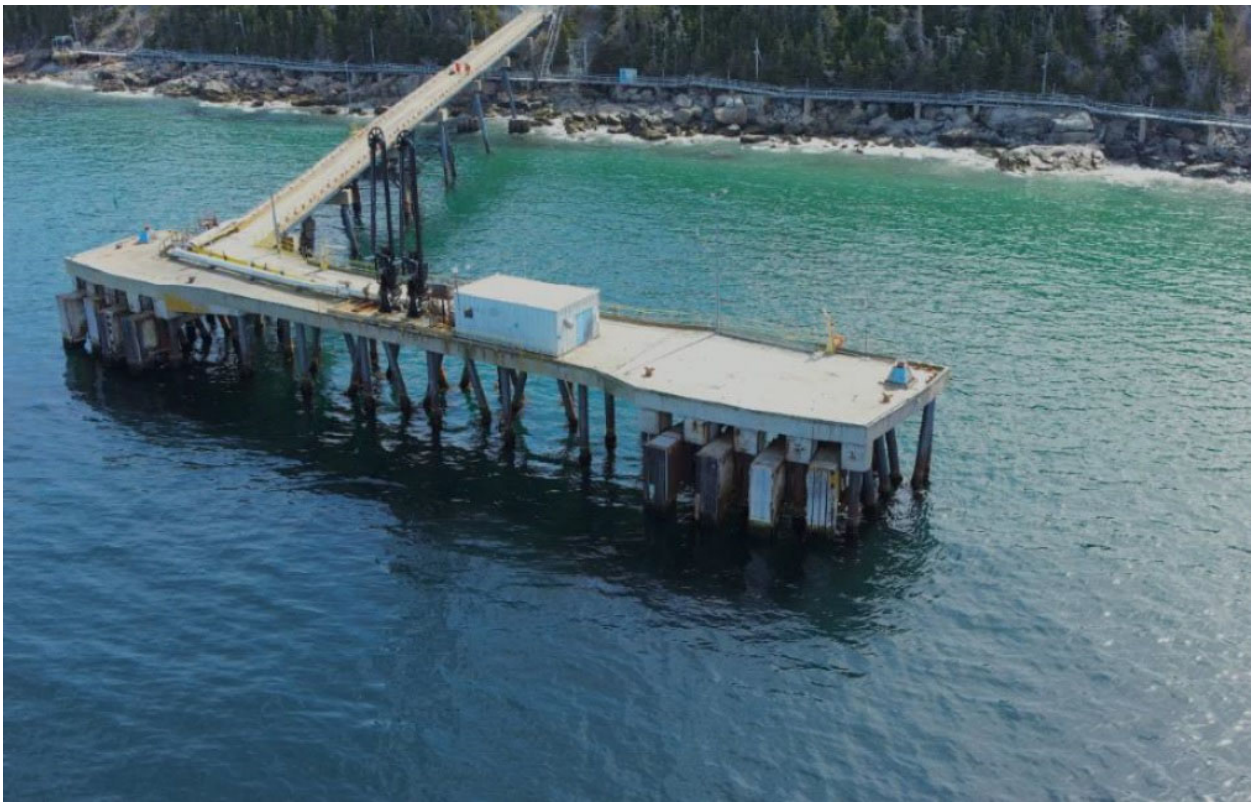


Figure 2 Marine Terminal Aerial View

4.2 Approach Trestle.

The approach trestle (referred to on the original drawings as the 'shore arm') is approximately 410ft in length with a 20.6ft wide concrete deck. It is supported on eight (8) pile bents.



Figure 3 Approach Trestle

The following extract from the original drawing of the trestle indicates the numbering of the bents. The bents are numbered from Bent 1, closest to the platform to Bent 8, which is on shore.

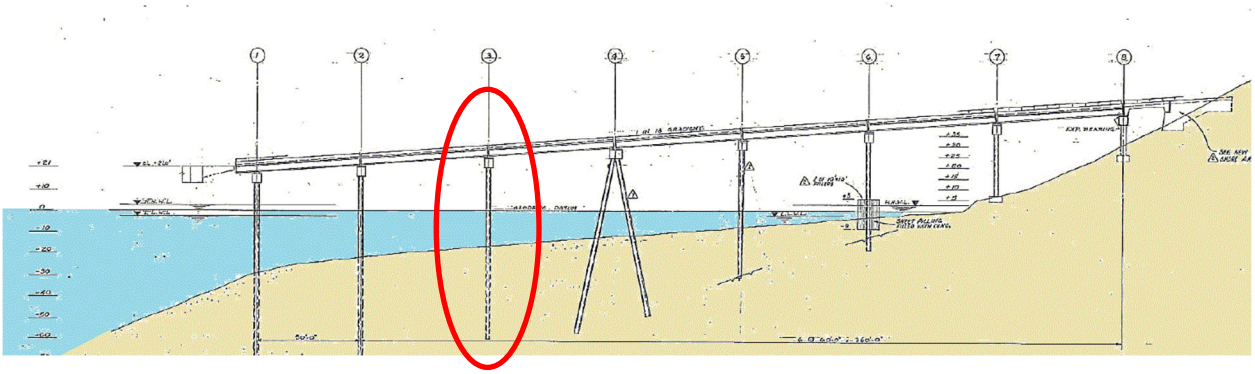


Figure 4 Bent Numbering

Note: Bent 3, shown above from the original design drawing, was modified in 1983 following ice damage, as can be seen in the photograph in Figure 3. Reference drawings 3.1.14 to 3.1.18 show details of the repairs.

4.3 Platform.

The combined Breasting Structure/Loading Platform is 241.7ft long by 39.4ft wide with a concrete top slab that varies from 2 to 3.5 feet in thickness. It is supported on eighty-two (82) 600mm diameter steel pipe piles filled with concrete. The breasting portions of the platform have eight 70 tonnes swinging concrete gravity fenders. Fenders 8,7,6 and 5 are located at the North end of the platform (closest to the trestle) and Fenders 4, 3, 2, and 1 are located at the South end of the platform as shown in the following figure. Only fenders 6, 5, 4 and 3 are used by vessels at the berth. Fenders 1 and 7 are seized in place (Ref. [3.2.2]) and fenders 2 and 8 are functional but not used. The photos below were extracted from Ref. [3.4.1] and were taken in 2022 using a UAV.

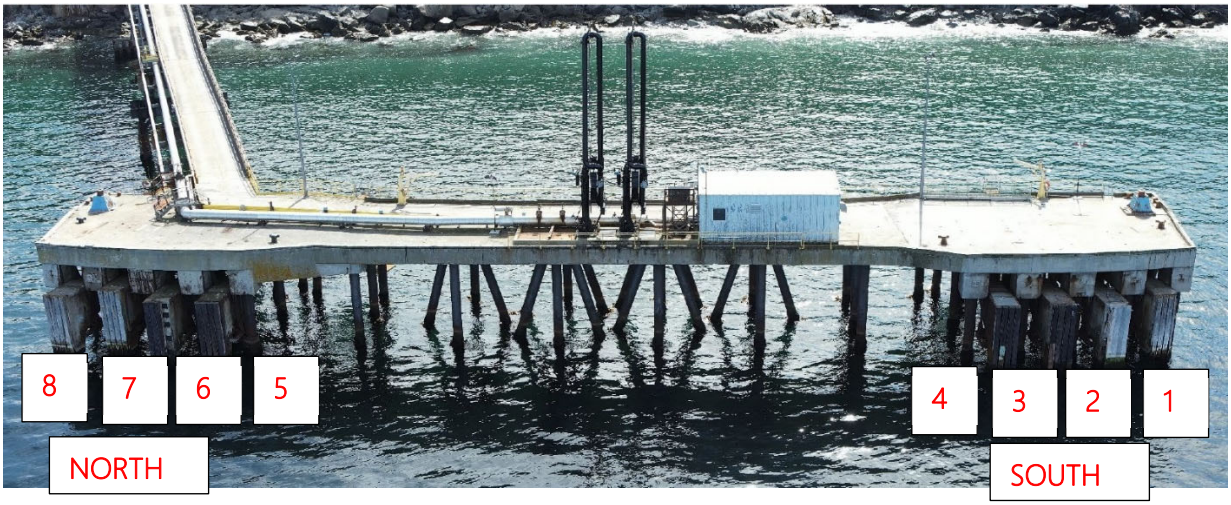


Figure 5 Platform showing Fender Arrangement



Figure 6 North Fenders (8, 7, 6, 5)



Figure 7 South Fenders (4, 3, 2, 1)

4.4 Mooring Structures

There are four mooring structures, connected by a boardwalk, located along the shoreline. The shoreline consists of boulders and exposed granite bedrock. Each mooring structure has two bollards and one capstan. A satellite view showing the mooring structures (numbered 1 to 4) and the boardwalk (shown by yellow line) is given in the following figure.



Figure 8 Mooring Structure Locations

4.5 Mechanical Infrastructure

The mechanical systems at the terminal include;

- Two loading arms;
- 18-inch fuel delivery line;
- 2.5-inch pump-out pipeline;
- Pipeline supports.

5.0 History of Incidents

5.1 General

The table gives a history of incidents that resulted in equipment replacement, refurbishment and in some cases, emergency work. It is compiled from the information provided by NL Hydro. There may be other incidents as well, but the ones cited provide examples of past damage that give an indication of types of possible future damage.

5.2 Summary Table

Table 7 History of Upgrades or Failures

No.	Description of Damage and Repairs	Date	Project
1	North portion of platform required major repairs after a vessel impact	1972	
2	Several of the trestle piled support bents (in particular, Bent 3), required a major repair because of pack ice damage. Although the trestle deck did not collapse, it was very close to failure near the expansion joint at the jetty end.	1983 See Note	
3	Fender No. 4 detached from the supporting deck structure and fell to the seabed. Fender No. 3 was replaced. Temporary repairs, completed in Dec. 2008, were made to the front support arms of Fenders No. 5 and 6. Permanent repairs and replacement of Fender 4 completed in 2013.	2008	
4	Overhaul Loading Arms	2018	Condition Assessment and Misc Upgrades
5	Marine Terminal Jetty Pump-out Line and Break Away Valve	2018	Thermal In-Service Failures (TISF)
6	Capstan Grating Replacement	2019	TISF
7	Replace Failed Timbers	2019	TISF
8	Fender Timber Replacement	2019	TISF
9	Marine Terminal Boardwalk Refurbishment	2020	TISF
10	Overhaul Loading Arms	2021	TISF
11	Marine Terminal Safety Upgrades	2021	Remove Safety Hazards
12	Refurbish Capstan Gearbox	2021	TISF

No.	Description of Damage and Repairs	Date	Project
13	Refurbish failed timbers on Jetty Fender No.3	2021	TISF
14	Replace Jetty Fender NO. 3 & 8 Suspension System	2021	TISF
15	Replace South Marine Terminal Loading Arm Swivel Joint	2021	TISF
16	Marine Terminal Boardwalk Failure	2022	TISF
17	Replace Failed Jetty Fender Timbers	2022	TISF
18	Refurbish Marine Terminal Shoreline Boardwalk	2023	TISF

6.0 Operational Issues

6.1 General

This life extension study provides recommendations for actions required to provide a 10-year life extension to the Marine Terminal based on its current operational usage. This study does not include recommendations related to opportunities for improvement of the terminal. Given the age of the facility, some aspects of the terminal may not follow current best practice. Note that vessel traffic at the Marine Terminal is relatively infrequent, typically consisting of 6 to 8 vessels per year, generally from early Spring to late Fall. Increasing the efficiency of the offloading operations for this volume of traffic would not warrant large capital investments considering the limited timespan of the life extension.

As noted, this is beyond the scope of this study, but some operational aspects of the terminal are briefly discussed in the following section to provide context, as they have been discussed in previous reports and studies.

6.2 Berth Characteristics

Since the original construction of the jetty, there have been some changes to the operational characteristics of the berth. Based on the review of information provided, the following sections provides Wood's understanding of the current berthing requirements and limitations. It is assumed that these same requirements will carry forward through the 10-year life extension period. The information below has been extracted from the reference documents, but specific items should be confirmed based on current service agreement(s) between the terminal and its users.

6.2.1 Vessel Size

The original design was for a 35,000 DWT vessel but the size of vessels using the facility has since increased. The 2011 life extension study (Ref. 3.2.2), states that the size of vessels using the berth is as follows:

Typical Smallest Vessel

Kandilousa – 600 ft LOA (overall length) – 105.6 ft Beam – 40,000 Maximum Assigned DWT

Typical Largest Vessel

Aris – 611.5 ft LOA (overall length) – 105.6 ft Beam – 53,000 Maximum Assigned DWT

6.2.2 Vessel Approach to Berth

The fenders are aligned on an arc. The exterior fenders #1, #2, #7 and #8 are set back from the berthing face while interior fenders #3, #4, #5 and #6 are aligned with the berthing face. In the original design, the exterior fenders were intended to absorb energy if impacted as the ship approached the berth, and to direct the ship into an orientation parallel to the berth. However, fenders #1 and#7 are stuck in the retracted position (Ref. 3.2.1) and therefore won't contact the vessel. A vessel approaching at high speeds risks damaging the berth. This happened in 1972, requiring major repairs. Current berthing practice has not been reviewed in detail but uses tugs and bow thrusters to position the vessels parallel to the berth. Under this docking procedure, vessels do not contact fenders #1, #2, #7 and #8. Contact occurs with the interior fenders #3, #4, #5 and #6

6.2.3 Vessel Ballasting

For larger double hulled vessels, the vessel must be ballasted properly to ensure the reach of the loading arms is not exceeded.

6.3 Mooring Arrangement

The distance from the berthing face to the mooring structures located on shore is larger than for a typical mooring arrangement. This requires more time to secure the lines to the mooring structures. It has also been noted that some vessels do not have long enough lines to reach the bollards and must use shore tether lines. In addition, longer lines are more flexible, meaning that the vessel is not secured as tightly to the berth. During heavier seas, this may be a problem, and the vessel may have to leave the berth. Ref.[3.2.2], the 10 Year Life Extension Study performed in 2011, gives a more detailed discussion of mooring issues and includes a concept layout for new offshore mooring dolphins. However, since no action has been taken, it is assumed that the current arrangement, despite its limitations has been deemed acceptable by the users of the berth.

6.4 Loading Arm Reach

Current double hulled vessels have a higher deck elevation, and the current loading arms do not have sufficient reach under certain conditions, depending on the tides and the vessel ballasting. Ref. 3.2.2 recommended adding pedestals to raise the height of the loading arms. However, since no action has been taken, it is assumed that the current arrangement meets the operational requirements.

6.5 Combined Berthing / Loading Platform

Ref. [3.2.2] notes that placing the breasting fenders on the loading platform is not considered to be current best practice, since a vessel contacting the fenders at excessive speed could potentially damage the infrastructure on the loading platform. However, since the amount of infrastructure on the loading platform is limited, and because measures are in place to limit the speed at which the vessel contacts the berth, it is assumed the current configuration meets operational requirements.

6.6 Fendering

The gravity type fenders used on the platform do not have as much energy absorption capacity as conventional fenders. Ref. [3.2.2] indicated that the support piles of the loading platform would be overstressed by a vessel approaching the berth at an angle of 11 degrees. However, current practice is for the vessel to be tug assisted so that it is parallel to the berth before making contact. Under this scenario, the fact that fenders 1 and 7 are seized in place, and essentially do not absorb energy is not relevant, since they do not contact the vessel. If the current usage is operationally acceptable, then modifications are not required during the expected 10-year service life extension.

7.0 Review of Previous Marine Terminal Life Extension Study

7.1 General

The previous life extension studies for the Marine Terminal are listed in Section 3.2. The first 10-year life extension study was conducted in 2011. The most recent study was performed in 2018. The study concluded '*with yearly monitoring, the marine facilities should operate satisfactorily for an additional 10 years*.'

The 2018 study noted that the following recommendations from the 2011 study had been implemented:

- Installation of emergency evacuation platforms (*note: not currently used)*.
- Installation of light fixtures with improved accessibility for maintenance.

It also noted that the following recommendations from the 2011 study had not been implemented:

- Addition of pedestal to base of loading arms to increase their operational envelope.

7.2 Recommendations of 2018 Life Extension Study

This life extension study made recommendations based on the assumption that the Marine Terminal would be decommissioned sometime between 2021 and 2027. The recommendations are summarized in the table below.

Table 8 Recommendations from 2018 Life Extension Study

No.	Item	Recommendation	Follow-up
1	Fenders	Measure pin to support and pin to pin every 5 years.	
2	Expansion Joints	Measure gaps at expansion joint yearly or based on ice conditions	Measurements have been made. See review in Section 9.2.
3	Piles	Anodes do not need to be replaced. No repairs required to piles.	Review if this recommendation still applies if decommissioning is in 2032.
4	General	Yearly inspections required for structural components.	Annual inspections have been made of boardwalk structure and marine fenders.
5	Piles	Perform diving inspection of piles and concrete by 2022.	Inspection conducted in 2021 but did not include UT thickness measurements.

7.3 Inspection Data given in 2018 Life Extension Study

The 2018 Life Extension Study included the following inspection reports. Section 9.0 discusses the inspection findings in more detail.

No.	Inspection Data	**Section**
1	Piles – Ultrasonic Testing Data	Appendix A. See Section 9.0 for summary of findings.
2	Fenders – Support Arm Measurements	Appendix B. See Section 9.4 for summary of findings.

8.0 Review of Recent Upgrades and Maintenance

8.1 Fender Timber Replacements

Ref. [3.1.1] is a shop drawing issued in 2022 that shows the bumper timber details. The work performed is described in the work order requests Ref. [3.4.8] for fender #3 in 2021 and [3.4.9] for fenders #1, #5, #6, and #8 in 2022.

8.2 Fender Arms

The table below shows the most recent upgrades performed on the fender arms.

Fender	Most Recent Upgrades
#1	Original. Note: currently stuck in retracted position.
#2	Original
#3	Full replacement of front arms in 2008 and again in 2021
#4	Fell from dock an into the ocean in 2008, but not replaced until 2013
#5	Temporary repairs to front arms in 2008, full replacement of front arms in 2013
#6	Temporary repairs to front arms in 2008, full replacement of front arms in 2013
#7	Original. Note: currently stuck in retracted position.
#8	Full replacement of front arms in 2021

8.3 Mechanical Loading Arm Overhauls

The last major overhaul of the loading arms was performed in 2021 as described in Ref. [3.6.1]. Boland Marine & Industrial LLC is the maintenance contractor (OEM) for the loading arms and have serviced them every three years since their installation in 1969.

The most recent overhaul included:

- Replacement of the riser joint on the south loading arm;
- Purchase of three critical spare parts, and;
- Replacement of the apex joint on the North loading arm.

8.4 Shoreline Boardwalk Upgrades

A work request in 2022 (Ref. [3.5.3]) identified four locations where the supports for the boardwalk had been undermined. A concept drawing by Baysteel (Ref. 3.1.2) shows a replacement support consisting of W4 cross beam to support the boardwalk stringers, supported by two 4-inch square HSS posts with a base plate that is doweled into the rock. The repairs at these four locations have been completed. Two more locations have been completed in 2023.

8.5 Capstan Access Platform Replacements

New Access Platforms have been installed on the seaward side of each mooring structure. The platforms are steel members with knee braces supported from the existing concrete, with a serrated galvanized grating walking surface. These platforms can be seen in Photographs 9, 11, 12 and 13 of Appendix A. Given their recent construction, they should function as designed for the next 10 years.

8.6 Fuel Oil Pump-out Pipeline Replacement

In 2018/2019, a new 2.5" fuel oil pump-out line was installed to replace the original 4" line. The new line runs along the top of the concrete upstand for ease of installation and access, rather than on the structural pipe supports where the original line was located.

9.0 Review of Recent Inspection Reports

9.1 Shoreline Boardwalk Structural Assessments

A summary of the most recent inspection reports and findings is given below:

Table 9 Boardwalk Inspections

	Year	Reference	Summary of Boardwalk Condition
1	2022	3.5.1	Report by outside consultant listed several deficiencies in the boardwalk structure and made recommendations for general maintenance, repairs to be carried out in the next 1-3 years, and repairs requiring action.
2	2022	3.5.2	This is a work requisition rather than an inspection report but shows photos of 3 undermined boardwalk supports to be repaired.
3	2020	3.5.3	Recent storm surge had washed away many areas of the embankment where boardwalk is located. Some timbers washed away, handrailing detached and some uprooted trees were washed onto boardwalk. Damage to safety railing and platforms at mooring structures. Recommended repair of all storm damage.
4	2017	3.5.4	Boardwalk overall good condition. Broken board. Recommended to remove overgrowth and replace broken board.
5	2016	3.5.5	Boardwalk generally good condition, some minor repairs ongoing. Recommended to remove overgrowth.

9.2 Expansion Joint Survey

In the original trestle configuration, Bent 4 was considered to be fixed (it was supported on batter piles to make it stiffer than the other bents). Expansion joints were located at the ends of the trestle, adjacent to the platform and adjacent to the shore. However, in recent years, there does not appear to be significant movement at the original expansion joints. Movement has been observed at joints in the deck which are adjacent to Bent 3. The steel pipe piles supporting this bent were damaged by pack ice, and a steel frame was placed around this bent as a repair. However, the ice damage also displaced the bent, causing a misalignment with the centerline of the trestle. The gaps between the deck slabs are regularly monitored, A summary of the most recent inspection reports and findings is given below. Note that the measurements of the gaps at the joints were often included in the same inspection report with the shoreline boardwalk.

Table 10 Gap Measurements

Date	#1 [inches]	#2 [inches]	#3 [inches]	#4 [inches]	Ref.
Oct-16	3.25	4.50	5.25		3.5.6
Oct-17	3.25	4.75	5.25		3.5.5
Dec-17	3.25	4.50	5.50		3.5.5
Oct-19	3.20	4.60	5.80	7.20	3.5.4
Jun-21	3.10	4.50	5.50	7.30	3.6.3
Sep-21	3.50	4.50	5.50	7.00	3.6.3
May-23	3.10	4.50	5.70	7.50	3.6.3

Notes:

1. Gaps 1, 2 and 3 are located on the South side of the trestle roadway.
2. Gap 4 was identified later and is on the North side of the trestle roadway.
3. The 'Gap' dimensions are the measured center to center distance of the pins. However, some pins are broken off, but measurements can still be made to center. Based on the photos in the inspection report, on Gaps 1, 2 and 3, the pins were set back approximately 1" from the edge of concrete, so the physical gap is the indicated value minus 2". On Gap 4, the pins were set back approximately 2" from the face of concrete, so the physical gap is the indicated value minus 4". However, for purposes of monitoring relative movement, the 'gap' measurement between center of pins is suitable and should be maintained for comparison of historical values.

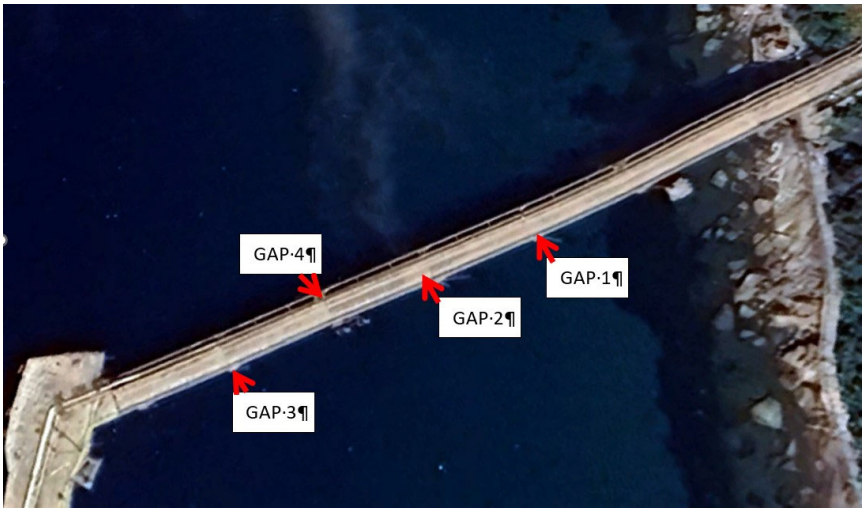


Figure 9 Gap Measurement Locations

The gap measurements in inches are plotted in the figure below. It indicates that the gaps between the deck panels have remained fairly constant.

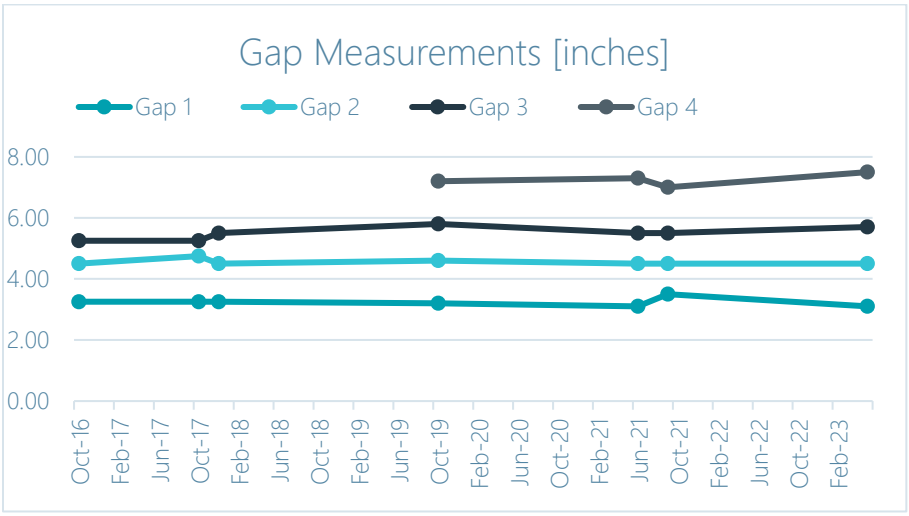


Figure 10 Historical Gap Measurements

9.3 Pile Inspections

The 2011 Life Extension report (Ref. [3.2.2]) included a methodology for inspecting the piles.

- Pile numbering to follow drawings A1-238-05-4004-005 and AD 239-05-4004-25
- Inspect all 82 piles above and below water (visual inspection)
- Ultrasonic thickness measurements for 14 selected piles.

Table 11 Pile Inspections

	Year	Reference	Pile Inspection Findings
1	2021	3.3.1	Anodes: Average not calculated, but values are similar to previous inspection. Ultrasonic Thickness Measurements: were not taken.
2	June 2017	3.3.2	Anodes: Average 42% remaining, with considerable variation between anodes. Ultrasonic Thickness Measurements: Average 96.5% of thickness remaining. Lowest % remaining was 84%.
3	2013	3.3.3	Anodes: Average 41.4% remaining, with considerable variation between anodes. Ultrasonic Thickness Measurements: Average 92% of thickness remaining. Lowest % remaining was 80%.

9.4 Fender Inspections

Visual inspections of the fenders are carried out periodically. The reports reviewed for this study are given in the table below.

Table 12 Fender Visual Inspections

	Year	Reference	Fender Inspection Findings
1	2023	3.4.1 (AAE) 3.4.2 (NLH)	UAV visual inspection: noted damaged or missing timbers on fenders (Pg 8 of Ref. 3.4.1), some spalling of concrete on fenders with exposed rebar.
2	2022	3.4.9	Replacement of timbers on Fender #1, 5, 6 and 8 – some inspection performed during this work.
3	2021	3.4.8	Replacement of timbers on Fender #3 – some inspection performed during this work, but no formal report.
4	2019	3.4.5	Wire rope tethers attached to wooden wear panels corroded away. Missing/damaged timbers on several fenders.
5	2018	3.4.6	Similar observations as 2019 inspection.
6	2014	3.4.7	Missing rubbing strip and loose timbers

Since Fender Number 4 detached and fell to the seabed in 2008, measurements have been taken of the support arms to monitor the amount of wear of the pins and support brackets.

Table 13 Fender Support Arm Measurements

	Year	Reference	Support Arm Measurements
1	2021	3.4.4	Comparison of support arm measurements made in 2008, 2013 and 2021. Fenders 1 and 7 are retracted and no measurements were made. Fenders 2 and 8 aren't in contact with vessel under current berthing procedures, but there may still be wear on the components due to wave action and steel corrosion. Fender 3 support arm was replaced in 2008. Fenders 4, 5 and 6 support arms were replaced in 2013.
2	2016	3.2.1	The 2016 measurements are given in the 2018 Life Extension Report
3	2008	3.2.2	The 2008 measurements are given in the 2011 Life Extension Report

9.5 Loading Arm Inspections

An OEM performs an overhaul of the loading arms every 3 years. They perform the dismantling and

inspection of all components and replace them as needed. All components are reassembled and inspected before they are returned to service. See Ref. [3.6.1] for a description of the most recent overhaul in 2021.

10.0 Level 1 Site Assessment

This report is based on the methodology of a "Level 1" assessment, which includes:

1. Visual Walk-Through Inspection.
2. Life Cycle Status;
3. Review of Past Maintenance and Inspections;
4. System for Condition Assessment;
5. Action Plans;
6. Technical and Safety Risk;
7. Additional Assessment Requirements;
8. Recommendations;
9. Capital Investment.

These items are covered in the following Sections.

10.1 Walk Through Inspection

Wood inspectors Bill Tucker and Andrew Haglund visited the Marine Terminal on July 21st, 2023. They were accompanied on site by Joanne Norman, the NL Hydro Civil Engineer for the HTGS. Photographs to document the condition of the facility on this date are given in Appendix A.

The inspection provided a frame of reference for the review, assessed whether the condition of any infrastructure components had significantly changed since previous inspections, and provided general information about items not explicitly covered by previous inspection reports. Some items noted during the inspection are discussed below.

10.1.1 Damaged Pile Bent

Trestle Pile Bent 3 (the third one from the loading platform) was damaged by ice in 1983. The repair consisted of a rectangular frame supported on H-piles. Initially, the support transferring the weight of the pier to the support frame (circled in white on the following photograph), appeared to less substantial than required. However, on further inspection, the support that was added on the right (circled in red on the following photograph) can support the pier.



Figure 11 Pile Bent 3 South Side (looking towards loading platform)



Figure 12 Pile Bent 3 on North Side (looking towards shore)

The support on the north side of the bent appears to not be in contact with the pier (see preceding figure), but on this side the original circular pipe pile still supports the pier, so the built-up support is not actually required. It may have been installed when levelling the pier as part of the original repair.

The Bent 3 repair is based on the repair Alternate No. 2 shown in Ref. [3.1.18]. The damaged pile on the north side was removed and the new support frame with H-piles now supports the weight on that side.

There appears to be some subsequent deformation of the support frame. So, perhaps subsequent ice damage to this bent occurred following the original repair in 1983. However, the bent appears stable, and no further investigation is recommended.

10.1.2 Ice Protection at Base of Piles

On some of the trestle support piles close to shore, there is ice protection at the base of the pile. The protection consists of steel sheet pile, filled in with concrete around the bent support pile.



Figure 13 Ice Protection around Support Pile P9 on Bent 6

The condition of the ice protection around the south pile on Bent 6 (S8) is similar. Although the steel sheet pile is mostly corroded away, and pieces of the concrete are missing, there is still enough concrete remaining to protect the support pile from direct loading from ice. The ice protection serves no other structural purpose so its condition is not a concern, although if it deteriorates to such an extent that the support pile is exposed to ice loads, then refurbishing the protection should be considered.

For Bent 5 (piles P8 and S7), in deeper water, it appears that ice protection was installed for the pile on the north side (S7) consisting of a concrete filled corrugated pipe near the waterline, but not on P8. The protection on S7 has effectively deteriorated as shown in the following photograph. However, as some piles on other bents have ice protection, and others don't, there is not a clear indication how effective the ice protection is, and what degree of protection it provides. Therefore, the piles should continue to be

monitored but no remedial action is currently recommended.

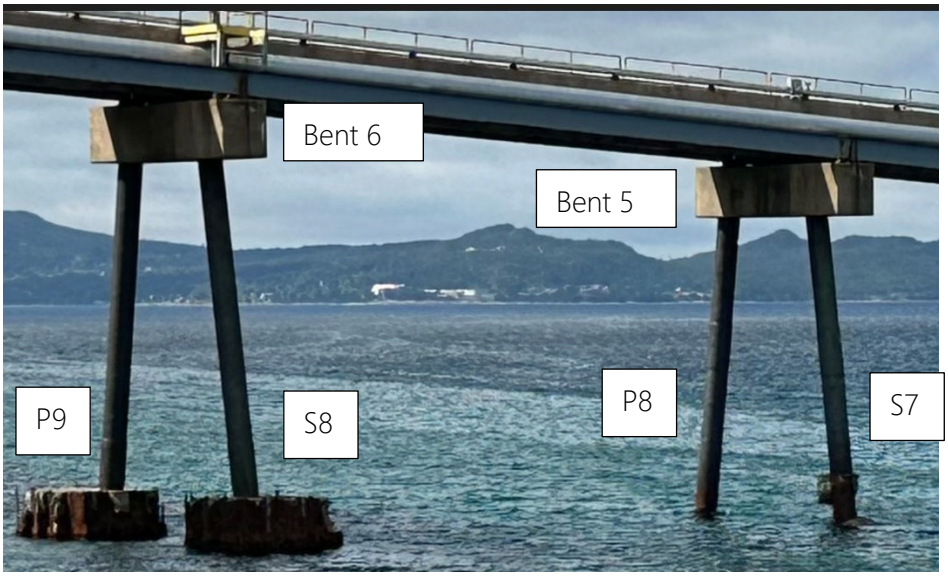


Figure 14 Bents 6 and 5

10.2 Life Cycle Status

The Marine Terminal is nearing the end of its planned service life. Under the current NL Hydro asset management plan, the HTGS will continue in service until 2030 and be decommissioned by 2033. If the service life is extended past this date, then this service life extension study should be updated as needed.

The Terminal was built in 1969 and therefore has been in service for more than 50 years. However, even though it is approaching the end of its useful service life, the concrete filled steel pipe piles which are the main load bearing elements that support the trestle and platform have retained most of their original steel wall thickness, based on the most recent measurements available. Therefore, providing that the other infrastructure components are maintained and repaired or replaced if damaged, the terminal is capable of functioning for the next 10 years.

10.3 Review of Past Maintenance and Inspection

Section 8.0 describes recent maintenance activities and upgrades at the Jetty. Section 9.0 describes recent inspection reports.

10.4 System for Condition Assessment

The following table summarizes the existing system for condition assessment of the Jetty infrastructure.

Table 14 System for Condition Assessment

	Item	Inspection	Frequency
1	Shoreline Boardwalk	Visual inspection.	Annually or after major storm. Last four were 2023, 2022, 2021 and 2020, although report from 2021 is not available. (reports are not always generated, but findings are captured through the preventative maintenance program).
2	Expansion Joints	Measurement of gaps in trestle roadway panels.	Annually, although for some years, gap measurements are only compared with previous year and aren't recorded.
3	Structural Piles	Visual inspection above and below water (82 piles), UT thickness (12 piles), anodes	5-year intervals (approx.). Last three 2021, 2017 and 2013.
4	Fenders	Visual inspection	Annually (although reports are not always available). Most recent reports 2023, 2022, 2021, 2019, 2018 and 2014. This is now done using a drone with camera.
5	Fender Arms	Measurements	Now being done at 5-year intervals (approx.). Last three 2021, 2016 and 2008.
6	Loading Arms	Inspection/refurbishment is combined.	3-year intervals (approx.) by OEM.

The methodology and frequency of these condition assessments appears to be appropriate, as the terminal has met its functional requirements for the past 10 years. Recommendations for the methodology and frequency during the 10-year life extension period are given in Section 0

10.5 Action Plans

Action plans for the Marine Terminal should be developed based on the recommendations from the most recent inspection reports for the infrastructure components.

10.6 Technical and Safety Risks

Recommendations on safety upgrades made in the 2011 Life Extension report (Ref. 3.2.1) have been installed on the platform (evacuation, improved lighting). The present study is focused on the Marine Terminal Infrastructure does not cover operational procedures. Therefore, no recommendations are made concerning safety risks relating to the terminal's operation.

For technical risks, reviewing the history of past incidents requiring repair, given in Section 5.0, provides a guide to possible future risks.

10.6.1 Damage from Vessel Impact

Vessels now use tug assistance to approach parallel to the berth, and therefore do not pose a risk to the platform from vessel impact. However, as indicated in the 2011 Life Extension Report (Ref. [3.2.1]), analysis of a vessel approaching at an 11-degree angle indicates that the platform piles would be overstressed. This conclusion remains valid.

10.6.2 Pile Damage caused by Pack Ice

The trestle pile bents closest to the shoreline have a concrete encasement to protect them from pack ice. However, this can't be implemented on the deeper water piles for practical reasons. The deeper water piles are potentially subject to overstress if sheet ice makes contact at the water line, and then wind or wave action causes the ice to push against the pile, bending or displacing it. Major damage due to ice loading occurred in 1983. In 2022, there was some ice damage to the ice protection around the inshore piles, but not to the piles themselves. Major pile damage due to pack ice is considered as an accidental load case (i.e., a rare event). It would not be practical to reinforce the piles sufficiently to resist this accidental load case. Therefore, NL Hydro should have a contingency plan in the case one of the trestle bents is damaged by pack ice.

10.7 Inspection Requirements

The recommendations for inspection requirements in the 10-year life extension period are given in the table below.

Table 15 Recommended Inspections

	Item	Recommendation
1	Shoreline Boardwalk	Annually (before tanker season) or after major storm following current practices.
2	Expansion Joints	Annually.
3	Structural Piles	Every five years. If upgrades are performed in 2025 and 2026, the next pile inspection could be performed in 2025 and any findings for remediation could take place in 2026. This should be sufficient, for the terminal to meet the service life extension requirements.
4	Fenders Timbers	Annually (before tanker season). The most recent inspection used a drone and photographs taken are very high quality, so it is assumed inspections will continue based on this approach.
5	Fender Arms	Measurements within a 5-year time frame. As for the piles, next inspection could be performed in 2025 and any remediation could take place in 2026. Note that most recent replacements were in 2021 (#3 and #8), 2013 (#4, #5 and #6) and 2008 (#3).
6	Loading Arms	Refurbish as per current schedule (twice in next 10 years).
7	Mooring Structures	See discussion below.

The rationale for these inspection requirements and some additional context is provided below.

10.7.1 Shoreline Boardwalk

The boardwalk is in the wave affected zone of the shoreline. Past storms have caused undermining of supports, broken handrails and deck timbers. Therefore, the boardwalk should be inspected early in the spring of each year, prior to the tanker season, for any signs of damage.

The 2022 inspection report (Ref.[3.5.2]), by a consultant, contained a detailed list of recommended replacements and repairs. In 2023 during work to replace a section of the boardwalk, an additional 30 feet was found to be rotted and required replacement before the 2023-2024 winter operating season. The 2022 structural assessment initially found this section in relatively good condition; however, the removal of the covering wood decking exposed the true condition.

The 2023 inspection report identified some rotted timbers that hadn't previously been observed because they were hidden by the wooden decking. The report describes the recent work that has been completed and provides recommendations for the remaining actions required to extend the service life of the boardwalk.

10.7.2 Gaps between Joints of Trestle Walkway Slabs

The gaps between some of the trestle walkway slabs were created when trestle Bent #3 was damaged by pack ice in 1983. The gaps have been measured since 2016.

Given the length of the trestle a temperature change of 25 degrees could lead to a change in length of 1 to 2 inches. Changes in the gaps that are less than this, and don't progressively increase over time would not be a cause for concern. Any larger changes or progressive widening should be assessed.

10.7.3 Fender Timbers

Currently, timbers are annually inspected for damage using a drone survey. This inspection routine should be maintained.

10.7.4 Fender Linkages

The inspection and measurements of the support arms and clevis assemblies are currently done every 5 years and should continue, unless progressing slotting is discovered that would require an increase in the inspection frequency.

10.7.5 Mooring Structures

A previous life extension study recommended that bollards be pull tested for their rated capacity of 70 tonnes. However, given the non-optimum mooring configurations present at the terminal, it is unlikely that vessels would remain on the berth during high wind conditions. Therefore, the bollards are not likely to experience their maximum pull force.

However, the condition of the anchors that attach the bollards to the concrete cannot be easily assessed using a visual inspection. Therefore, a Level 2 inspection, consisting of a vibration test (which will indicate if any of the anchors are no longer effective, is recommended early in the life extension period, so that any anchors that need to be replaced can be identified.

10.7.6 Fuel Oil Pump Out Line

"The original fuel oil pump out line failed and has been replaced with a new line. The design of the new line hasn't been reviewed as part of this study.

10.8 Recommendations

The recommendations for future inspection requirements are given in Section 10.7. Recommendations for refurbishment or replacement of existing infrastructure is summarized in the following table.

Item	Recommendation
Shoreline Boardwalk	Continue refurbishment as recommended in recent inspection reports. Work performed on the boardwalk over the last few years has indicated that the main timbers supporting the original spans may appear to be only weathered on the exterior but have extensive interior rot. For this reason, recommend planning to replace the remaining 8 original spans.
Gaps at Joints on Trestle	The joints in the trestle appear be stable based on recent measurements of the gaps. They should be monitored as per the inspection recommendations, but no remedial work is currently indicated
Structural Piles	Due to history of ice damage to piles, a contingency budget should be available for emergency repairs in case of future ice damage. Thickness measurements were not taken in the 2021 inspection, so a future inspection should include thickness measurements for comparison with previous inspection findings. At the same time, missing anodes on the piles should be replaced.
Fenders Timbers	Since timbers are subject to damage due to interaction with vessel, they should be replaced any time significant damage is identified in the annual inspections. New details that have been proposed to improve the service life of the timbers should be implemented. Other measures such as using a more durable wear material could also be considered.
Fender Arms	The linkage arm for fender #2 dates from the original construction. Given the issues encountered on other fenders, replacement of this fender during the life extension period should be anticipated. Fenders #1 and #7 have not been measured in recent inspections since they are no longer functional. But they should be assessed, to determine if they are at risk of detaching due to corrosion during the service life extension period. The other fenders (#3, #4, #5, #6 and #8) have had new linkages installed in the last 10 years and should continue to function over the service life extension period. The arms for fenders #3, #4, #5, #6 and #8 have been replaced within the last 10 years. Fender #2 linkage arm dates from the original construction and the most recent inspection report recommends that it be replaced. Fenders #1 and #7 are stuck in a retracted position and are therefore no longer functional and measurements to determine condition have not been taken in recent inspection reports. However, a Level 2 assessment should be made on whether they are at risk of failing due to general

Item	Recommendation
	corrosion.
Loading Arms	Overhaul every 3 years as per current schedule. Assume overhauls in 2024 and 2027 since the last one was performed in 2021.
Mooring Structures	Recommend vibration testing of bollards to determine if the anchorage into concrete is sound (the concern, given their age is that anchors may be extensively corroded). New anchors may be recommended for some bollards, depending on the test results.

10.9 Capital Investment.

The general approach to capital investment will be to only perform as much refurbishment as necessary to keep the terminal fully operational during the life extension period.

The table below shows a possible budget for expenditures during the 10-year life extension period, based on the current condition of the terminal. It assumes that a capital investment project will be approved for 2025-2026 in which the majority the planned work will be carried out as indicated below. Actual costs will vary depending how work is packaged, budgets available and NL Hydro's internal priorities and approval process. Costs are shown to 2030 since from 2031-2033 the terminal will be in decommissioning phase However, if a further life extension required, the costs should be re-assessed.

Year 1 (2025)

- Boardwalk: Replace 5 of 9 original sections of the shoreline boardwalk;
- Boardwalk: Install new structural supports to failing and undermining areas;
- Fenders: Replace fenders no. 2,3 & 4 timber bumpers with a new design;
- Fenders: Replace fenders no. 4 side bumpers;
- Steel Piles: Level 2 condition assessment (visual and UT thickness measurements);
- Bollards: Level 2 assessment (vibration testing).

Year 2 (2026)

- Boardwalk: Replace remaining 4 sections of the shoreline boardwalk;
- Boardwalk: Install remaining new boardwalk supports and foundations to failing and undermining areas;
- Fenders: Replace fenders no. 5,6 & 7 timber bumpers with a new design;
- Fenders: Replace fenders no. 5 & 6 side bumpers;
- Fenders: Refurbish concrete gravity fenders mechanical linkage system as identified from level 2 assessment;
- Bollards and Piles: Upgrades identified from the level 2 assessment of the bollards and steel piles.

Table 16 Budget Estimates

Item	2024	2025	2026	2027	2028	2029	2030
Shoreline Boardwalk		$ 350,000	$ 350,000				
Structural Piles		$ 100,000	$ 100,000				
Fenders Timbers		$ 450,000	$ 450,000				
Fender Arms		$ 400,000					
Loading Arms	$ 350,000			$ 350,000			
Mooring Structures		$ 50,000					
Total	**$350,000**	**$1,350,000**	**$900,000**	**$350,000**	**$-**	**$-**	**$-**

10.9.1 Basis of Cost Assumptions and Comments:

1. **General.** Costs are shown in 2023 dollars with no adjustment for inflation. Costs do not include engineering or project management. Costs are based on planned replacement of infrastructure components that have reached the end of their useful service life. The cost magnitudes are based on the anticipated extent of work required and historical costs that reflect mobilization and access costs for this site (for example, costs of scaffolding required to do work on the fenders). Wood also recommends that a contingency amount be set aside for certain components to cover the possibility of accidental load cases (such as unusually severe pack ice, vessel impact or unusually severe storms) causing damage that requires emergency repairs.
2. **Shoreline Boardwalk.** Work performed on the boardwalk over the last few years has indicated that the main timbers supporting the original spans may appear to be only weathered on the exterior but have extensive interior rot. For this reason, should plan for replacing the remaining 9 original spans. The proposed time frame is 2025 and 2026, i.e., relatively early in the life extension period, so that they don't fail in service. After replacement of all original spans, the boardwalk should continue to be inspected before the tanker season for damage caused by wave or ice loads. A contingency amount could be carried to cover any required repairs, but no further replacement of the main boardwalk structure would be planned.
3. **Structural Piles**. The most recent inspection report in 2021 did not include ultrasonic thickness measurements. These measurements should be taken to verify that current thickness of piles is adequate to provide 10 additional years of service. Sacrificial anodes that were identified as missing during the previous inspection should be replaced to ensure that corrosion rates remain acceptably low.
4. **Fender Timbers.** The timbers on fenders #2 to #7 need to be replaced and costs show work packaged over two years, 2025 and 2026. A modified attachment detail has been developed, which should extend the service life of the timbers.
5. **Fender Linkage Arms.** Fenders #3, #4, #5, #6 and #8 have had new linkages installed within the last

10 years. Fender #2 linkage arm dates from the original construction and the most recent inspection report recommended that it be replaced. Fenders #1 and #7 are stuck in a retracted position and are therefore no longer functional and not subject to wear and tear from vessel berthing. However, a Level 2 assessment should be made on whether they are at risk of failing due to general corrosion, as previously one of the gravity fenders failed and sank to the seabed.

6. **Loading Arms.** A detailed assessment of the loading arms was not performed for this report, since they are overhauled on a 3-year cycle by an equipment supplier. The costs shown are based on the most recent overhaul, but actual cost will depend on what is found during the next planned mobilizations in 2024 and 2027.

7. **Mooring Structures.** The cost shown is for a recommended Level 2 vibration analysis which will indicate whether the anchorage of the bollards to the concrete mooring structures are still intact. (The Level 1 visual inspection confirmed that the bollards are still functional but could not assess the condition of the anchors within the concrete.

APPENDIX A: SITE VISIT PHOTOGRAPHS

PHOTOGRAPHS

Client: NL Hydro
Project: 258543
Data For: Site Visit July 21, 2023
Prepared By: BT Checked By:
Date: 21-Jul-2023
Work Order: 258543
FileNo: 4.1.4



Photo 1 Boardwalk from MS3 looking towards Trestle
(2023-07-21_09h-46m.jpg)



Photo 2 Boardwalk from MS4 looking towards Trestle
(2023-07-21_09h-53mA.jpg)



Photo 3 Boardwalk between MS3 and MS4
(2023-07-21_09h-57m.jpg)



Photo 4 Boardwalk from MS2 looking toward Trestle
(2023-07-21_10h-14m.jpg)

PHOTOGRAPHS

Client: NL Hydro
Project: 258543
Data For: Site Visit July 21, 2023
Prepared By: BT Checked By:
Date: 21-Jul-2023
Work Order: 258543
FileNo: 4.1.4



Photo 5 Boardwalk from MS2 looking toward MS1
(2023-07-21_10h-14mA.jpg)



Photo 6 Boardwalk from MS1 looking towards Trestle
(2023-07-21_10h-16mA.jpg)



Photo 7 Mooring Structure 3 Capstan
(2023-07-21_09h-32m.jpg)



Photo 8 Mooring Structure 3 Capstan
(2023-07-21_09h-32mC.jpg)

PHOTOGRAPHS

Client: NL Hydro
Project: 258543
Date: 21-Jul-2023
Data For: Site Visit July 21, 2023
Work Order: 258543
Prepared By: BT Checked By:
FileNo: 4.1.4



Photo 9 Mooring Structure 3 Bollards
(2023-07-21_09h-32mD.jpg)



Photo 10 Mooring Structure 4 Capstan
(2023-07-21_09h-49m.jpg)



Photo 11 Mooring Structure 4 Bolllards
(2023-07-21_09h-49m_.jpg)

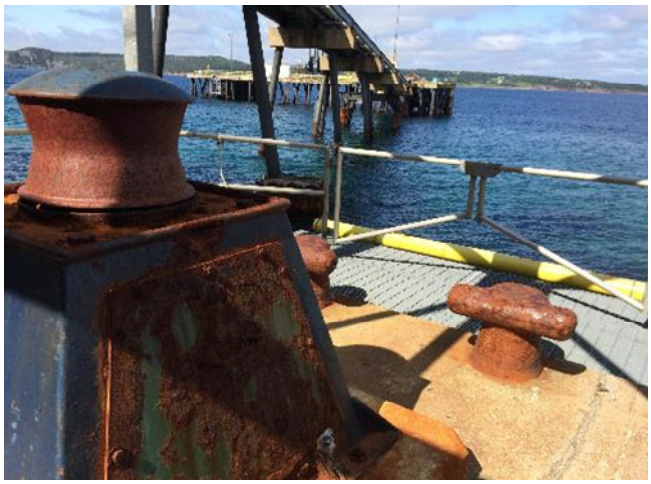


Photo 12 Mooring Structure 2
(2023-07-21_10h-12m.jpg)

PHOTOGRAPHS

Client: NL Hydro
Project: 258543
Data For: Site Visit July 21, 2023
Prepared By: BT Checked By:
Date: 21-Jul-2023
Work Order: 258543
FileNo: 4.1.4



Photo 13 Mooring Structure 1 Bollard
(2023-07-21_10h-18m.jpg)

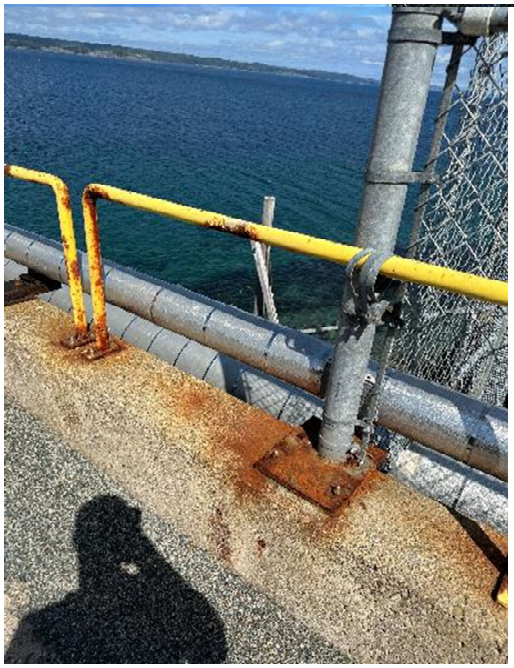


Photo 14 New Pump Out Fuel Line
(2023-07-21_10h-43mB.jpg)



Photo 15 Trestle Roadway
(2023-07-21_10h-44m.jpg)



Photo 16 Trestle Roadway
(2023-07-21_10h-44m_.jpg)

PHOTOGRAPHS

Client: NL Hydro
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Data For: Site Visit July 21, 2023
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FileNo: 4.1.4

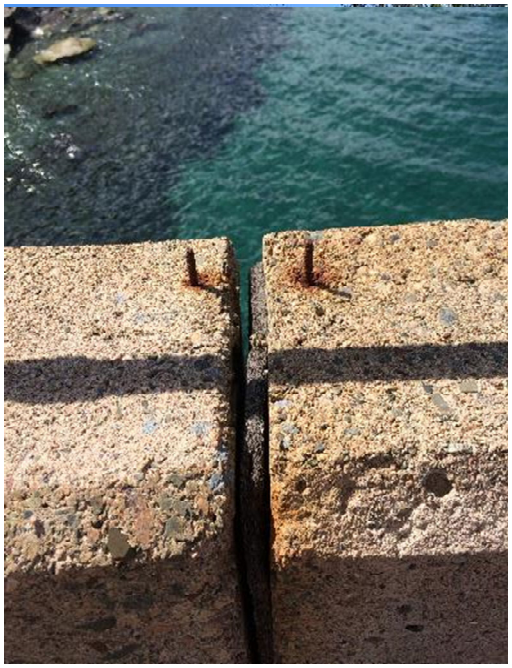


Photo 17 Trestle Joint
(2023-07-21_10h-45m.jpg)

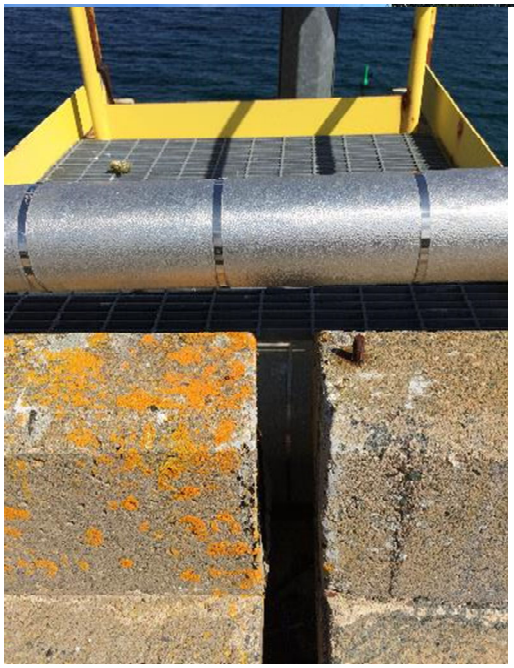


Photo 18 Trestle Joint
(2023-07-21_10h-47m.jpg)



Photo 19 Trestle from LP
(2023-07-21_10h-53m.jpg)



Photo 20 Trestle Joint
(2023-07-21_11h-02m.jpg)

PHOTOGRAPHS

Client: NL Hydro
Project: 258543
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Prepared By: BT Checked By:
Date: 21-Jul-2023
Work Order: 258543
FileNo: 4.1.4

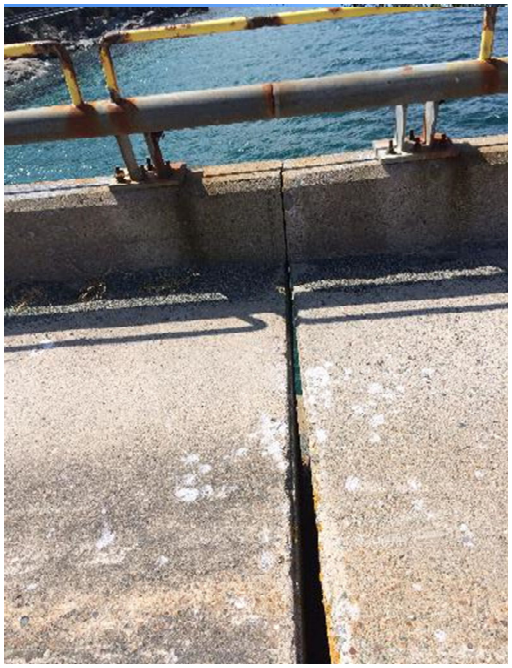


Photo 21 Trestle Joint
(2023-07-21_11h-03m.jpg)



Photo 22 Trestle Joint
(2023-07-21_11h-03mA.jpg)



Photo 23 Bent 7 North Pile
(2023-07-21_09h-31m.jpg)



Photo 24 Bent 7 South Pile
(2023-07-21_09h-31mA.jpg)

PHOTOGRAPHS

Client: NL Hydro
Project: 258543
Date: 21-Jul-2023
Data For: Site Visit July 21, 2023
Work Order: 258543
Prepared By: BT Checked By:
FileNo: 4.1.4

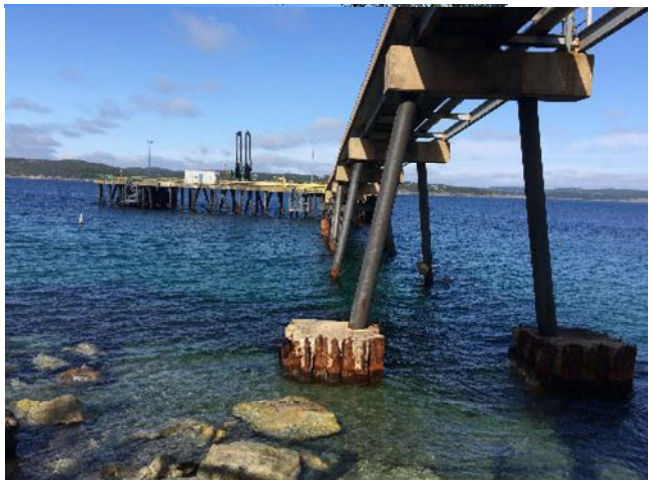


Photo 25 Bent 6
(2023-07-21_09h-32m_.jpg)

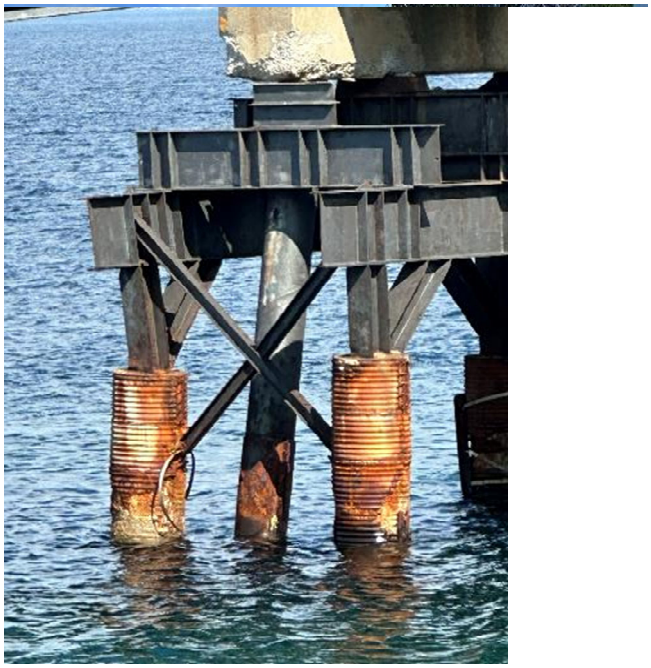


Photo 26 Bent 3
(2023-07-21_10h-09m.jpg)



Photo 27 Loading Platform
(2023-07-21_10h-50m.jpg)



Photo 28 Loading Platform Shoreward Side
(2023-07-21_11h-04m.jpg)

Appendix B

HTGS Marine Terminal Boardwalk Structural Inspection



HTGS MARINE TERMINAL BOARDWALK STRUCTURAL INSPECTION

Holyrood, NL

Prepared for:
Rising Edge Group
64 Airport Road
St. John's, NL
A1A 4Y3

Prepared by:
Jewer Bailey Consultants ULC
75 Tiffany Lane
St. John's, NL A1A 0L1

JBC Project No.
22-C-142

Client Project No.
12962201

Date
February 03, 2023

JEWER BAILEY CONSULTANTS
STRUCTURAL · MECHANICAL · ELECTRICAL

HTGS Marine Terminal Boardwalk

Structural Inspection

For

Rising Edge Group

PROVINCE OF NEWFOUNDLAND AND LABRADOR
PEG Newfoundland and Labrador PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
PERMIT HOLDER
This Permit Allows
JEWER BAILEY CONSULTANTS ULC
MIRC:
To practice Professional Engineering in Newfoundland and Labrador.
Permit No. as issued by PEG N0540 which is valid for the year 2023.

REGISTERED PROFESSIONAL ENGINEER
Newfoundland
R.T. BAILEY
SIGNATURE
2023.02.03
DATE
PROVINCE OF NEWFOUNDLAND

ENGINEERING REPORT REVISION INDEX

Issue Code	Revision				Pages Revised	Remarks
	By	Reviewed	Approved	Date (dd/mm/yy)		
C	RB	RB	RB	03/02/2022		Final
B	RB	RB	RB	06/12/2022		Draft Re-issued for Review
A	RB	RB	RB	06/12/2022		Draft -Issued for Review

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1.1 Introduction 1
2 FACILITY DESCRIPTION 2
3 WORK COMPLETED 3
4 INSPECTION FINDINGS 5
5 RECOMMENDATIONS 6

Appendices

APPENDIX "A" – Repair Work Photographs

APPENDIX "B" – Inspection Photographs

NOTICE TO READERS

This document contains the expression of the professional opinion of Jewer Bailey Consultants ULC as to the matters set out herein, using its professional judgment and reasonable care. It is to be read in the context of the agreement (the "Agreement") between Jewer Bailey Consultants ULC and Rising Edge Group (the "Client"), and the methodology, assumptions, procedures, and techniques used and the circumstances and constraints under which its mandate was performed. This document is written solely for the purpose stated in the Agreement, and for the sole and exclusive benefit of the Client, whose remedies are limited to those set out in the Agreement. This document is meant to be read as a whole, and sections or parts thereof should thus not be read or relied upon out of context.

The services performed and outlined in this report were based, in part, upon visual observations at the site. Due to site conditions limited inspections of site structures were conducted by the consultant's personnel in preparation of this report. The opinions expressed herein cannot be extended to portions of the site that are unavailable for direct observation reasonably beyond the control of Jewer Bailey Consultants ULC.

Jewer Bailey Consultants ULC disclaims any liability to the Client and to third parties in respect of the publication, reference, quoting, or distribution of this report or any of its contents to and reliance thereon by any third party.

The conclusions and recommendations of this report are based in part, on the limited available site information. The possibility remains that unexpected conditions may be encountered at the site in locations not specifically investigated. Should such an event occur, Jewer Bailey Consultants ULC must be notified in order that we may determine if modifications to the conclusions presented herein are necessary.

CONFIDENTIALITY

This document is the property of and contains information proprietary to Rising Edge Group. Without authorization, the contents hereof shall not be duplicated, transmitted, used or disposed, directly or indirectly, for any purpose.

1 GENERAL

1.1 INTRODUCTION

Jewer Bailey Consultants ULC (JBC) has been retained by Rising Edge Group to perform a structural inspection of the Holyrood Thermal Generating Station (HTGS) Marine Terminal Boardwalk due to concerns over the condition of the timber deck/stingers and supporting concrete piers.

The purpose of this investigation was to inspect the condition of the boardwalk, identify deficiencies and recommend upgrading/repairs. The inspection was limited to a visual inspection only and testing and intrusive investigations were not conducted as part of this inspection.

Due to safety concerns access to the underside of the boardwalk was limited and restricted to those areas that had safety barriers installed.



Figure 1.1: Boardwalk Layout.

2 FACILITY DESCRIPTION

The marine facilities at the Holyrood Thermal Generating Station were constructed and put into service circ. 1970.

The existing boardwalk system is used to access the four (4) capstans/mooring bollards used for the berthing of tankers delivering fuel oil for the thermal generating station.

As noted in Figure 1 the four (4) mooring platforms are located along the immediate shoreline behind the berth. Access to the platforms is along the approximately 400 m long boardwalk.

The superstructure of the boardwalk consists mainly of 3” x 8” and 3” x 6” deck boards, 10” x 10” stringers, 4” x 4” handrail posts and 2”x4” handrails.

The substructure consists of concrete piers varying in size from 300 mm dia. sono-tubes to substantial concrete piers.

The boardwalk elevation varies along its length and is accessible by the use of ramps at strategic locations.

Unfettered access to the mooring platforms by maintenance crews is critical to the operation of the marine terminal. Crews typically push a tool cart to the platforms in carrying out repair and maintenance activities. The cart can weight upwards of 1000 lbs although the exact weight has not been verified.

3 WORK COMPLETED

At the time of the inspection Rising Edge Group were completing repairs to the deficient boardwalk areas previously identified by NL Hydro.

The areas of repair are concentrated on the boardwalk sections between mooring platforms #1 and #2 and mooring platforms #2 and #3 as indicated in Figures 3.1 and 3.2.



Figure 3.1: Repair work areas.



Figure 3.2: Repair work areas.

In general, the repairs consisted of installing new steel beams and columns at strategic locations along the boardwalk to support the boardwalk timber framing. New footings were also installed as part of the work. Where required the timber stringers and decking were also replaced to match the existing construction.

Photographs of the repair work can be found in Appendix A

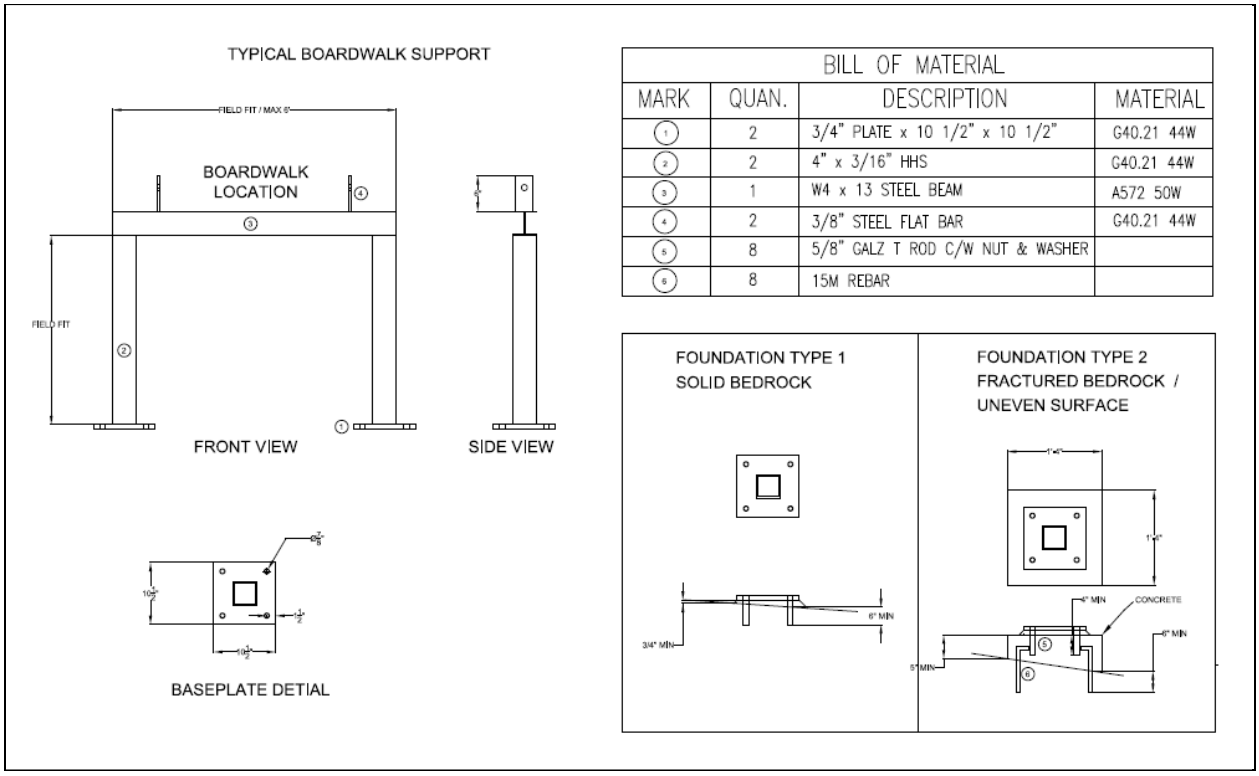


Figure 3.3: Typical Boardwalk Support Details.

Based on the repair work that has been carried out to date it is our professional opinion that the boardwalks in the areas of repair have been restored to their original capacity and can continue use under normal operating conditions.

4 INSPECTION FINDINGS

On November 18, 2022, Mr. Ray Bailey of Jewer Bailey Consultants ULC (JBC) visited the boardwalk for the purposes of completing an inspection of the boardwalk system. Mr. Bailey was accompanied on the visit by Robert Lacey, Project Manager with Rising Edge Group.

During the site inspection work was ongoing for repairs previously identified by NL Hydro.

Photographs of the inspection can be found in Appendix B.

Based on this site inspection the following observations were noted:

1. Many of the concrete piers supporting the boardwalk system are deteriorated to varying extends.
2. Undermining of the concrete piers was evident in several locations.
3. Some piers appear to be founded on loose rock.
4. Timber deck, beams and handrails all appear worn, but this wear for the most part, appears to be surface wear. The original boardwalk timbers are coated with creosote however when prodded with a knife revealed sound timber immediately below the surface.
5. Several deck and handrail timbers showed signs of decay.
6. Nails were “popped” from the surface on many of the deck boards.
7. Several of the ramps require a toe board to provide a smooth transition between the various boardwalk levels.
8. A section of boardwalk immediately east of mooring platform #2 is sagging on the shoreside and requires repair.
9. Access stairs are stable but are skewed to one side.
10. New timber stringer requires a splice plate.
11. Beams/stringers supported on the 4”x4” handrail posts should have a minimum of two (2) bolts. Some were observed to have only one (1) bolt.
12. Angle supporting the boardwalk tie-in to mooring platform #4 is severely corroded.
13. The span on the last two long spans before mooring platform #4 are long and have a noticeable spring in them. However, they appear in good condition.

5 RECOMMENDATIONS

Based on the site observations the following actions are recommended. The action items fall into three categories; 1) General Maintenance, 2) Repairs that should be carried out within the next 1-3 years, 3) Repairs requiring action this year.

The recommended future repair work is based on current conditions however events such as usage, climatic conditions etc. can reduce the timelines for repair. Given the age of the boardwalk it is not possible to give an accurate timeline as to when specific portions of the boardwalk will require repair or upgrades.

Until such time as the repairs recommended to be carried out this year are completed it is recommended that only pedestrian traffic be allowed on the boardwalk section immediately adjacent to mooring platform #4 (corroded support angle).

The area of the sagging deck appears stable and does not appear in any danger of collapse. Moving a tool cart along across the section of boardwalk is acceptable however the boardwalk should be inspected prior to imposing any heavy load as storm events could cause further shifts in the supporting structure.

All other sections of the boardwalk can operate as normal (pedestrian and tool cart access).

If it becomes necessary to bring the tool cart onto the boardwalk prior to the repairs being carried out a detailed review can be conducted to determine the allowable load on the boardwalk structure from the tool cart.

GENERAL MAINTENANCE

The noted deficiencies should be monitored on a routine schedule (monthly, semi-annual etc.) and repaired as necessary. Such work would include:

1. Timber deck, beams and handrails all appear worn, but this wear for the most part, appears to be surface wear. The original boardwalk timbers are coated with creosote however when prodded with a knife revealed sound timber immediately below the surface.
2. Several deck and handrail timbers showed signs of decay.
3. Nails were “popped” from the surface on many of the deck boards and should be “hammered in”.
4. Several of the ramps require a toe board to provide a smooth transition between the various boardwalk levels.
5. Access stairs are stable but are skewed to one side.

REPAIRS THAT SHOULD BE CARRIED OUT WITHIN THE NEXT 1-3 YEARS.

The noted deficiencies should be monitored on a routine schedule (monthly, semi-annual etc.) and repaired as necessary. It appears the undermining issues may have existed for several years and while the undermining may not pose an immediate threat it should be monitored especially after storm events which may cause addition undermining and erosion.

1. Many of the concrete piers supporting the boardwalk system are deteriorated to varying extends.
2. Undermining of the concrete piers was evident in several locations. These should be monitored and repaired as required.
3. Some piers appear to be founded on loose rock. These should be monitored and repaired as required.
4. New timber stringer requires a splice plate.
5. Beams/stringers supported on the 4”x4” handrail posts should have a minimum of two (2) bolts. Some were observed to have only one (1) bolt.
6. The span on the last two long spans before mooring platform #4 are long and have a noticeable spring in them. However, they appear in good condition.

REPAIRS REQUIRING ACTION

The noted deficiency should be repaired this year.

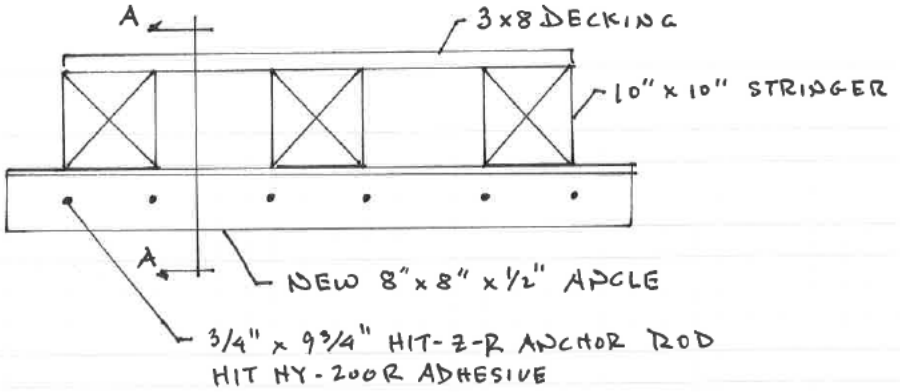
1. A section of boardwalk immediately east of mooring platform #2 is sagging on the shoreside and requires repair. It appears that the supporting post has shifted however the structure appears stable.

   The repairs can be completed using details currently employed at the site to repair other boardwalk areas.
2. The angle supporting the boardwalk tie-in to mooring platform #4 is severely corroded and should be replaced/repaired. Without a more detailed investigation it is not possible to determine the structural capacity of the deck support or its longevity. The span is approximately 10-12 ft so alternatively, a new section of boardwalk can be built over the existing. The new section would have to ramp up/down to the platform level.

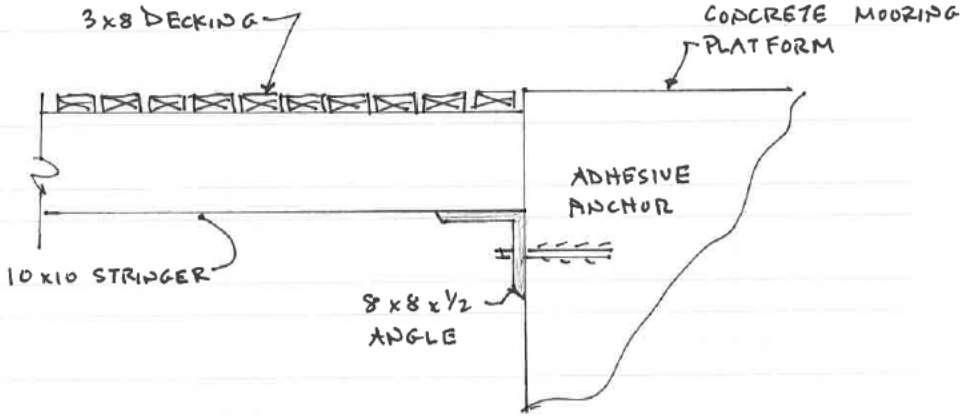
   Proposed repair options are shown below. Option A entails replacing the existing angle with a new angle and anchoring the new angle to the existing concrete abutment. Option B entails constructing a new ramp over the existing boardwalk.

JEWER BAILEY CONSULTANTS

PROJECT:	HTGS Marine Terminal Boardwalk		
PROJECT #	22-C-142	PHASE :	
ITEM:	OPTION - A		
PREPARED BY:	RTB	CHECKED BY:	
DATE:	DEC 6/22	PAGE	of

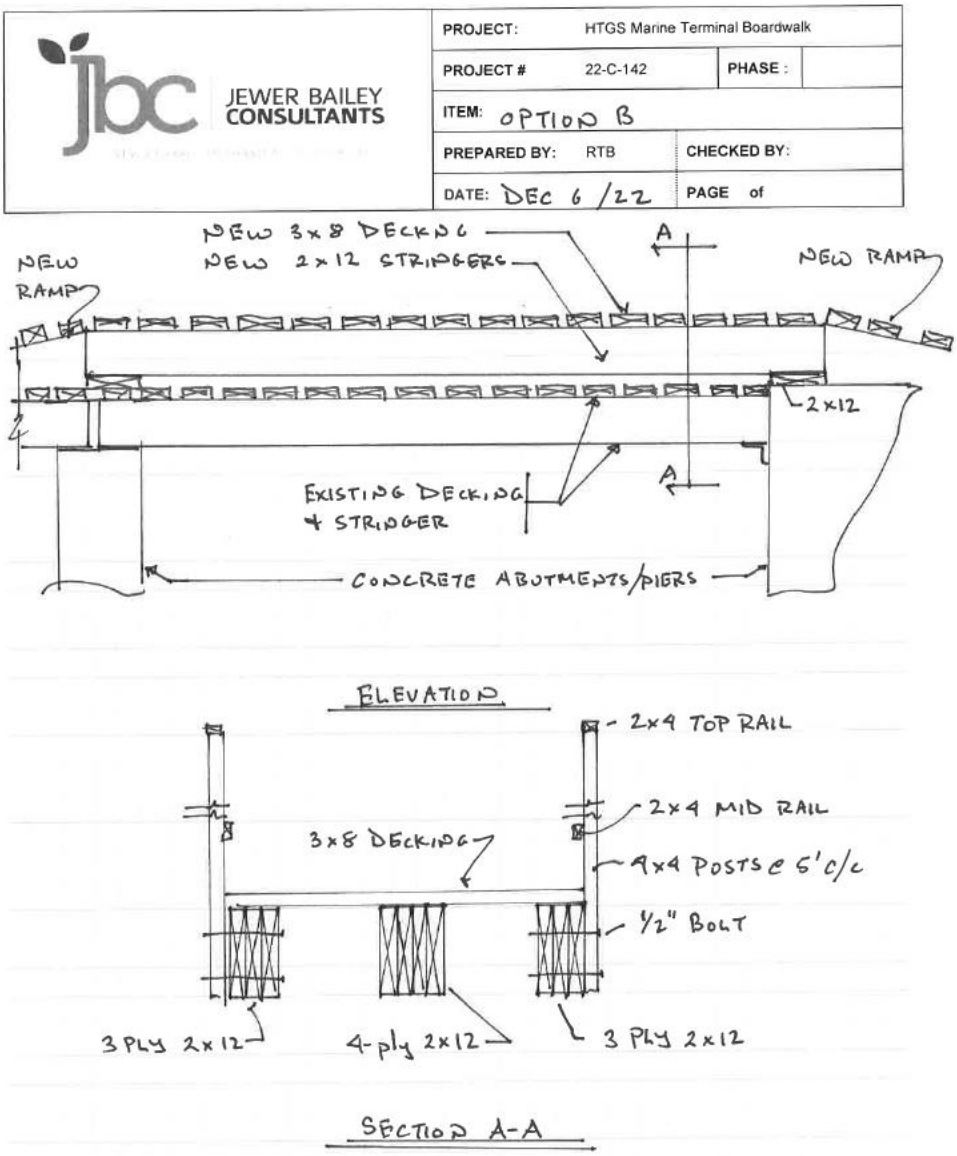


ELEVATION



SECTION A-A

Option A – New angle.



Option B – New ramp section

APPENDIX A

REPAIR WORK PHOTOGRAPHS



Photo #A-1: Typical post and beam support system.



Photo #A-2: New post and beam supporting existing stringer & deck system.



Photo #A-3: New boardwalk decking at ramps.



Photo #A-4: New support for shelter.



Photo #A-5: New post on concrete wall.



Photo #A-6: New deck for shelter.



Photo #A-7: New concrete footing.



Photo #A-8: Typical base plate.



Photo #A-9: Typical support.



Photo #A-8: Typical ramp framing.



Photo #A-9: New support work.



Photo #A-10: Existing piers doweled into new footings.

APPENDIX B

INSPECTION PHOTOGRAPHS



Photo #B-1: Corroded angle under boardwalk at mooring platform #4.



Photo #B-2: Area of sagging boardwalk.

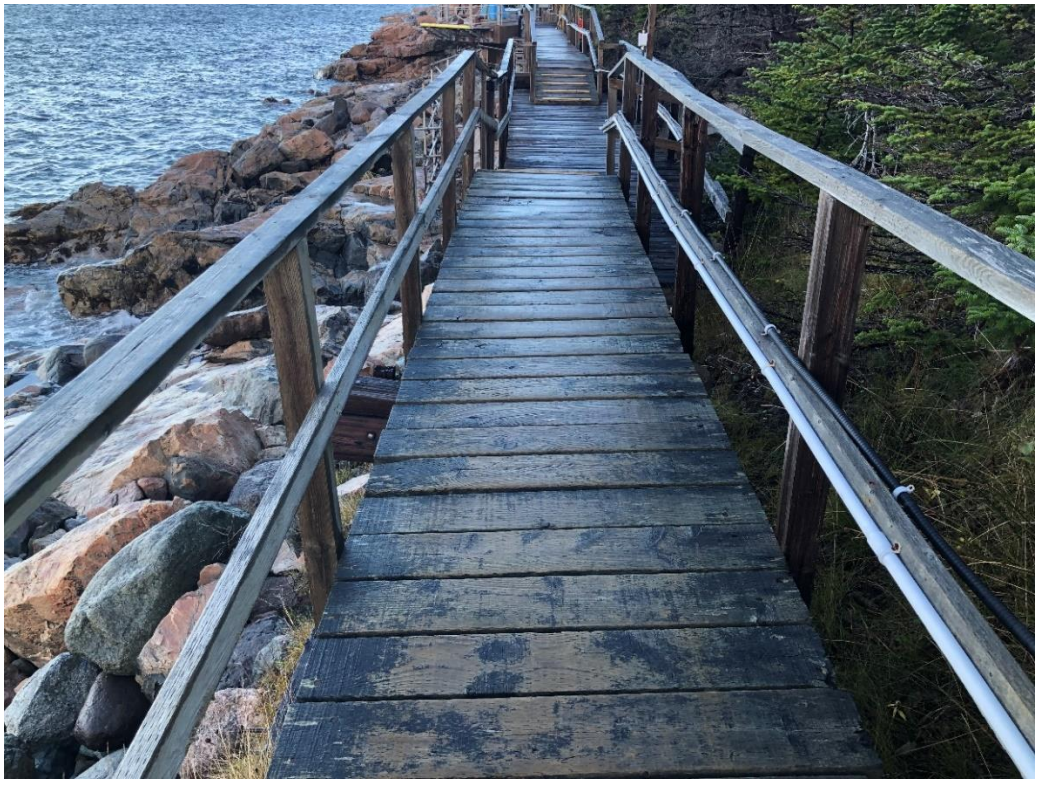


Photo #B-3: Typical boardwalk with ramps at elevation changes.



Photo #B-4: Access stairway.



Photo #B-5: Missing nosing piece on ramp.



Photo #B-6: Typical sono-tube pier founded on loose rock.

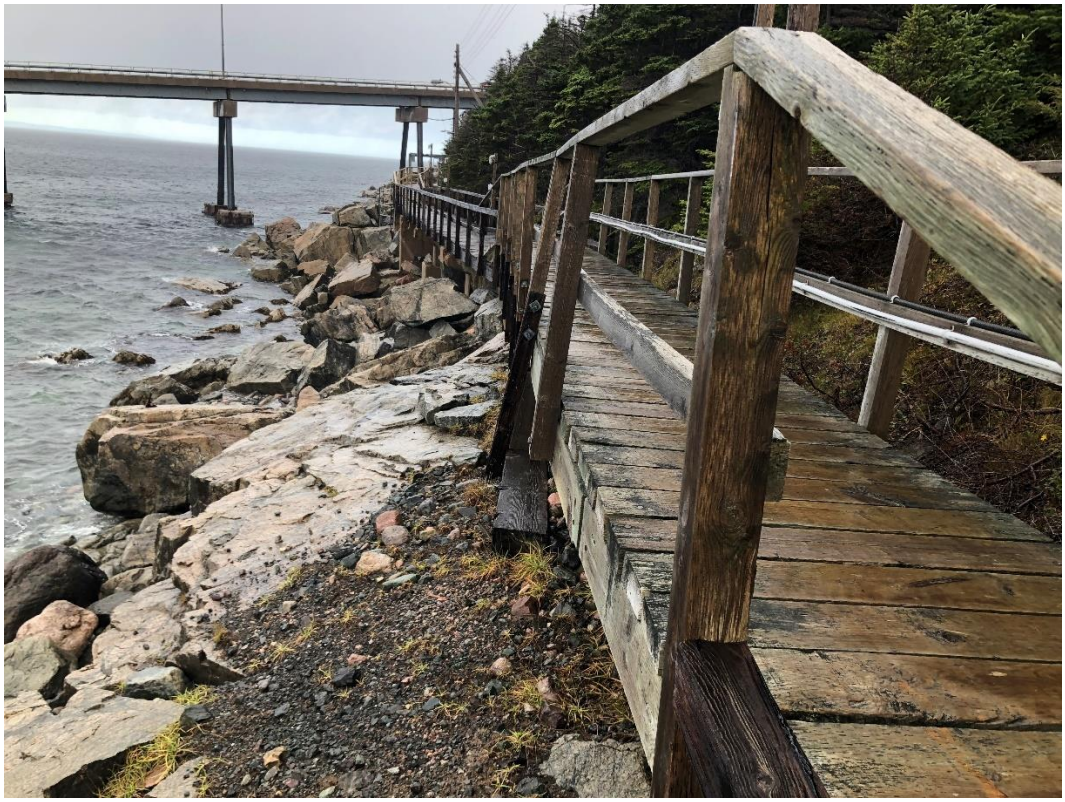


Photo #B-7: Handrails out of alignment.



Photo #B-8: Typical boardwalk supports.



Photo #B-9: New support work.



Photo #B-10: Boardwalk supported on concrete wall and timber blocks.



Photo #B-11: Long spans before platform #4.



Photo #B-12: Boardwalk tie into platform #4.

Replace Emergency Diesel Genset

2025–2027

Cat Arm

newfoundland labrador hydro

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Replace Emergency Diesel Genset (2025-2027)

Location: Cat Arm

Investment Classification: Renewal

Asset Category: Hydraulic Plant

Cost: $1,601,264

1.0 Introduction

The Cat Arm Hydroelectric Generating Station ("Cat Arm") is located on the Northern Peninsula of the Island portion of the province, in close proximity to the nearby community of Jackson's Arm. The generating station houses two vertical Francis Units capable of producing 63.5 MW of power each, for a total plant output of 127 MW or 680 GWh annually. Cat Arm relies on the use of station service power to maintain plant operations; without station service, generation is not possible. The main source of station service power is supplied by one of the generating units, with backup service power from a 12.5 kV overhead transmission line from the nearby community of Coney Arm, as well as a 450 kW emergency diesel genset.[1] The emergency diesel genset was installed in 1984 and is original to the commissioning of the generating station. Obsolescence of spare parts required for corrective maintenance has become an issue and replacement of the genset is required.

2.0 Project Description and Justification

This project will replace the emergency diesel genset at Cat Arm, including engineering, procurement, and installation of a replacement unit of equivalent size.

This project is required to ensure the reliable operation of Cat Arm. The existing emergency 450 kW genset is a critical source of emergency power supply for Cat Arm. The genset is obsolete and sourcing replacement parts is difficult. The genset cannot be overhauled due to obsolescence and must be replaced.

[1] All of Newfoundland and Labrador Hydro's ("Hydro") hydraulic generation facilities have transmission, hydraulic units, and backup gensets to supply station service. This is a critical system to provide the safe and reliable generation of electricity.

3.0 Asset Overview

3.1 Asset Background

The emergency diesel genset was installed during the original commissioning of Cat Arm in 1984 and has accumulated an excess of 2,000 hours of operation since installation. The 450 kW emergency diesel genset undergoes regular preventative maintenance ("PM"), which includes documenting the unit's operating hours. Replacement parts have become increasingly difficult to source and further overhauls are not feasible due to unit obsolescence.

3.2 Historical Reliability

The diesel genset has operated more than 2,000 hours since installation, has undergone regular PM and has been a relatively reliable source of emergency backup power for Cat Arm. However, due to the age of the asset, equipment malfunctions are at a heightened risk and repairs are becoming increasingly difficult due to part obsolescence.

3.3 Asset Condition

The emergency diesel generator was forced out of service in late 2023 due to radiator failure. A direct replacement radiator could not be sourced due to unit obsolescence and the leak could not be repaired on-site; therefore, the radiator was sent to a third-party maintenance facility for repair. The repair required a full radiator core replacement, leading to a prolonged period in which the diesel generator could not be used.

3.4 Condition-Based Remaining Life

The emergency genset is obsolete and has reached the end of its useful service life. Replacement parts are not available and life extension is not feasible.

4.0 Analysis

4.1 Evaluation of Alternatives

Hydro has evaluated the following alternatives:

- Deferral;
- Upgrade life extension; and

- Like-for-like replacement.

4.1.1 Deferral

Deferral is not an option for this project, as this genset is a backup power source for supply to the powerhouse's station service, used to maintain continued operation under emergency circumstances. Without the emergency diesel generator, station service system reliability is comprised due to a decrease in redundancy. The current genset is over 40 years old, and is no longer able to be maintained due to obsolescence. Deferral of this project presents an unacceptable risk of loss to station service at Cat Arm.

4.1.2 Upgrade Life Extension

Due to the age of this unit, replacement parts are difficult to source and the unit has reached the end of its useful life. As such, the alternative to pursue an upgrade life extension is not feasible for this project.

4.1.3 Like-for-Like Replacement

This alternative involves like-for-like replacement of the diesel genset at Cat Arm with a unit of equivalent size.

4.2 Least-Cost Evaluation

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

4.3 Recommended Alternative

The recommended alternative is the like-for-like replacement of the diesel genset at Cat Arm, which requires the procurement and installation of a 450 kW emergency diesel genset to supply backup power to the powerhouse station services in the event of an outage. Hydro recommends completing the proposed genset replacement to ensure the reliable operation of Cat Arm.

4.3.1 Risk of Asset Stranding

This genset is a backup power source for supply to the powerhouse's station service, used to maintain the continued operation of Cat Arm under emergency circumstances. Cat Arm is required to provide reliable power to the Island Interconnected System, and there are no plans to decommission this plant. As such, Hydro believes the risk of asset stranding is low.

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	4	3	**12**
Post-Implementation	4	2	**8**
		Risk Mitigated	**4**
		Risk Mitigated per $1 Million	**2.5**

5.0 Scope of Work

This project will replace the existing 450 kW genset, with a new diesel genset of the same size. The scope of this project includes the design, procurement, and installation of a new genset, exhaust, radiator fan, after cooler, switchgear with breaker and all other equipment necessary to facilitate the proper function of the new unit. Upgrades to some existing protection and control ("P&C") equipment will be required for interconnection of the new unit, including additions to the Programmable Logic Controller ("PLC") Cabinet, modifications to engine PLC cabinet, diesel control panel with engine PLC cabinet, and modification and testing of PLC logic.

5.1 Project Budget

The estimate for this 2025–2027 budget is shown in Table 2.

Table 2: Project Estimate ($000)[2]

ProjectCost	2025	2026	Beyond	Total
Material Supply	23.6	554.7	0.0	**578.3**
Labour	201.4	392.3	38.7	**632.3**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	14.0	0.0	**14.0**
Other Direct Costs	10.8	75.6	0.0	**86.4**
Interest and Escalation	14.1	90.2	72.8	**177.0**
Contingency	16.4	94.4	2.4	**113.2**
Total	**266.2**	**1,221.2**	**113.9**	**1,601.3**

5.2 Project Schedule

The project schedule is presented in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules.	January 2025	March 2025
Engineering: Site visit, design/specification development for tender/procurement.	March 2025	July 2025
Procurement: All the required material's for genset and P&C upgrade.	April 2025	April 2026
Construction: Remove old genset, electrical and P&C equipment.	September 2026	September 2026
Commissioning: Run up the new genset; P&C equipment to confirm operation and release to operations.	September 2026	October 2026
Closeout: Close work order, complete all documentation and complete lessons learned.	January 2027	June 2027

[2] Numbers may not add due to rounding.

6.0 Conclusion

The backup diesel genset at Cat Arm is a 450 kW unit and has been in service since commissioning in 1984, and has reached the end of its useful service life. This model is obsolete, as many parts are discontinued and no longer available. An overhaul of this unit is not possible, and replacement is the only viable option. Without the availability of the diesel generator to supply station service, redundancy in this critical system is diminished, which will directly impact generating plant reliability. Hydro is proposing this project to replace the original genset to ensure the continued reliable operation of Cat Arm.

Project 5

Install Mid-Span Structures
TL220

2025–2026

newfoundland labrador hydro

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Install Mid-Span Structures – TL220 (2025–2026)

Location: TL220 (Bay d'Espoir to Barachoix)

Investment Classification: Service Enhancement

Asset Category: Transmission

Cost: $1,110,609

1.0 Introduction

Transmission line TL220 is a 69 kV wooden pole transmission line that runs from the Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir") to the Barachoix Terminal Station for a distance of approximately 63 kilometres as shown in Figure 1.

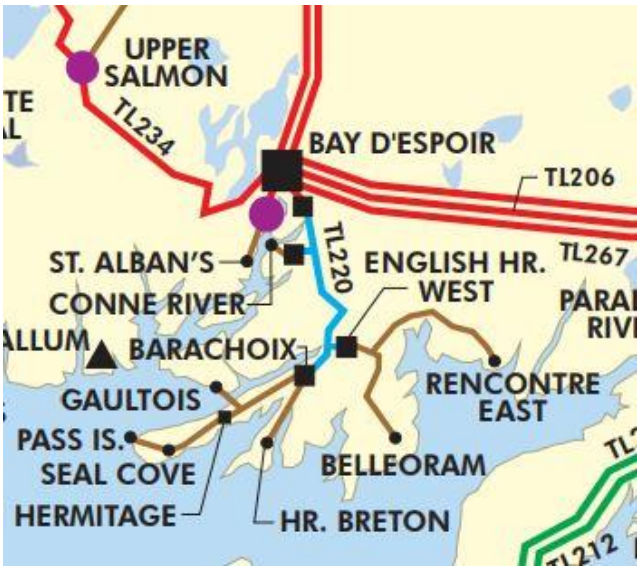


Figure 1: TL220 Location

In light of recently discovered conductor clearance violations under ice loading, Newfoundland and Labrador Hydro ("Hydro") proposes to install 11 mid-span structures on TL220 to improve public safety.

2.0 Project Description and Justification

During the winter of 2020, significant ice accumulation in the area resulted in the conductor on TL220 sagging to the ground between Structures 68 and 69, resulting in a fault that caused an unplanned outage to approximately 2,600 customers. Figure 2 is a photograph taken by Hydro personnel while

investigating the cause of the fault; the imprint left in the snow by the conductor is circled in red. In October 2020, a mid-span structure was installed to rectify the low clearance issue at this location as shown in Figure 3.

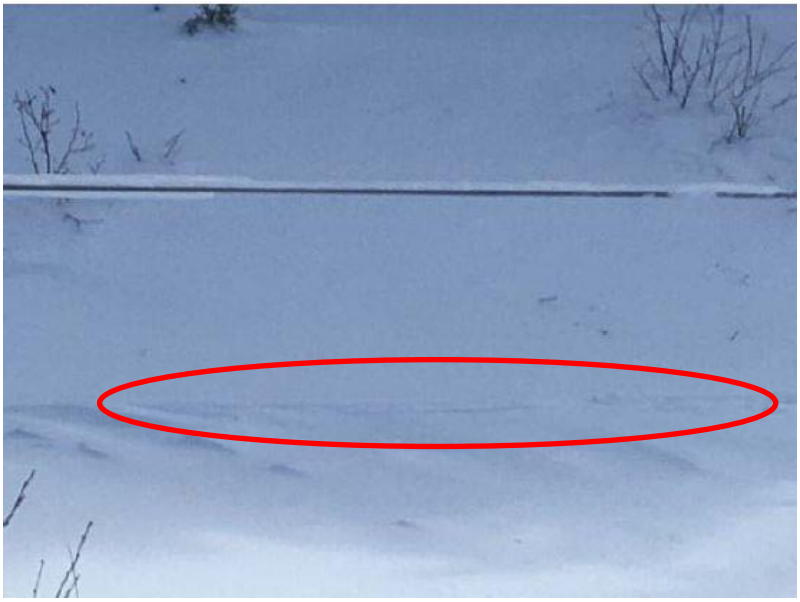


Figure 2: Ice Laden Conductor between Structures 68 and 69



Figure 3: New Mid-Span Structure 68-1

As a result of this incident, a clearance assessment was conducted in 2022 on TL220 to identify any additional clearance issues on the line. This assessment determined that 11 other spans violated the Canadian Standards Association ("CSA") clearances under the required design ice load.[1,2] Table 1 lists the locations of these violations and the minimum clearances determined. As these locations are accessible by snowmobile, Hydro proposes to construct 11 mid-span structures to rectify these violations and improve public safety.

Table 1: TL220 Clearance Violations under Required Design Ice Load

Span (Structure to Structure)	Minimum Clearance (ft.)
3–4	13.0
9–10	8.8
19–20	6.4
38–39	8.6
45–46	3.0
51–52	9.0
52–53	11.6
55–56	10.8
60–61	6.9
70–71	12.8
72–73	5.5

3.0 Asset Overview

3.1 Asset Background

Originally constructed in 1970, TL220 is a 69 kV wood pole transmission line approximately 63 kilometres long, located between Bay d'Espoir and the Barachoix Terminal Station. Due to failures resulting from ice storms, approximately 35 kilometres of TL220 was re-routed and upgraded in 1999. The clearance violations discussed herein are located in the original section of the line, which was not upgraded.

[1] For areas accessible by snowmobile, CSA clearance standards require more than 13 ft. between the ground surface and the lowest point of the conductor under the required design ice load. Current clearances at these 11 spans under extreme ice conditions are extremely low compared to Hydro standards, which are typically higher than the CSA minimum requirements.
[2] The required design ice load for this line is a radial ice loading of 1 inch.

TL220 is a radial transmission line connecting the Connaigre Peninsula to the electrical grid; it is expected to remain in service for the foreseeable future. It is currently maintained under Hydro's Wood Pole Line Management Program.

3.2 Historical Reliability

The fault caused by the low sagging conductor resulted in TL220 being out of service for over ten hours, affecting approximately 2,600 customers on the Connaigre Peninsula. No other outages have been caused by low-sagging conductors in recent history. Table 2 summarizes the outage frequencies and durations on TL220 from 2017 to 2023. The additional 7.85 hours of outage duration in 2020 were due to a terminal station transformer issue (approximately 5.80 hours), a lightning strike (approximately 1.65 hours) and an emergency repair of deteriorated hardware on a wood pole structure (approximately 0.4 hours)

Table 2: TL220 Outage Summary

Year	Number of Outages	Total Forced Outage Duration (Hours)
2017	0	0
2018	0	0
2019	1	0.02
2020	3	17.85
2021	1	0.05
2022	0	0
2023	0	0

4.0 Analysis

4.1 Evaluation of Alternatives

Hydro has evaluated the following alternatives:

- Deferral;
- Upgrade life extension;
- Like-for-like replacement; and
- Install mid-span structures.

4.1.1 Deferral

Deferral is not a viable alternative for this project. Due to the 11 clearance violations observed on TL220, Deferring this work and maintaining the status quo would result in an unacceptable risk to public safety. Additionally, the high likelihood of electrical fault reoccurrence and cable failure on this line would also result in reduced reliability for the customers serviced through this line.

4.1.2 Upgrade Life Extension

As there are no existing mid-span structures installed for the 11 clearance violations, Hydro has not identified any upgrade life extension options for this project.

4.1.3 Like-for-Like Replacement

As there are no existing mid-span structures installed for the 11 clearance violations, Hydro has not identified any like-for-like replacement options for this project.

4.1.4 Install Mid-Span Structures

Based on the magnitude of the clearance violations, there are no viable alternatives to the installation of mid-span structures to rectify the clearance violations on TL220.

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 installation of 11 mid-span structures to rectify the TL220 clearance violations.

4.3.1 Risk of Asset Stranding

TL220 is a radial line connecting the Connaigre Peninsula to the electrical grid. It is expected to remain in service indefinitely; therefore, the risk of asset stranding associated with this project is low.

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for this 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 3.

Table 3: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	5	2	**10**
Post- Implementation	5	1	**5**
		Risk Mitigated	**5**
		Risk Mitigated per $1 Million	**4.5**

5.0 Scope of Work

The scope of this project is to construct 11 mid-span structures on TL220, similar to the structure depicted in Figure 3, within the spans listed in Table 1Table 4. This work includes engineering design to determine the optimum location for structure installation within these spans, material procurement, tendering, contract management, construction, and project closeout.

For this project, two of the 11 mid-span structures will need to be constructed in wetlands and will therefore require foundation cribbing. They will be built in the winter months of 2026 to minimize environmental impacts and reduce costs associated with environmental mitigation.

It is anticipated that TL220 will remain energized during construction to minimize potential customer outages. It is possible; however, that weather and/or site conditions may inhibit the use of live-line techniques for some structures. In this case, outages may be required for periods of construction.

5.1 Project Budget

The estimate for this project is shown in Table 4.

Table 4: Project Estimate ($000)

Project Cost	**2025**	**2026**	**Beyond**	**Total**
Material Supply	88.0	0.0	0.0	**88.0**
Labour	194.7	43.7	0.0	**238.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	297.0	100.0	0.0	**397.0**
Other Direct Costs	153.7	38.2	0.0	**191.9**
Interest and Escalation	64.3	26.6	0.0	**90.9**
Contingency	83.6	20.8	0.0	**104.4**
Total	**881.3**	**229.3**	**0.0**	**1,110.6**

5.2 Project Schedule

This project is expected to start in January 2025 and conclude in the first quarter of 2026 as shown in Table 5.

Table 5: Project Schedule

Activity	Start Date	End Date
Planning:		
Resource planning.	January 2025	March 2025
Design:		
Engineering design.	January 2025	February 2025
Procurement:		
Order materials.	February 2025	February 2025
Tendering.	February 2025	April 2025
Construction:		
Construct 9 mid-span structures.	July 2025	August 2025
Construct 2 mid-span structures (in wetlands).	February 2026	March 2026
Closeout:		
Complete closeout documentation.	March 2026	March 2026

6.0 Conclusion

As a result of significant ice accumulation in the area, a span of conductor on TL220 sagged to the ground, causing an electrical fault on the system that ultimately resulted in an unplanned outage to approximately 2,600 customers. A subsequent clearance assessment was conducted by Hydro, through which 11 additional spans have been identified as violating clearance standards under the required design ice load. Hydro proposes to rectify these violations to mitigate risk to public safety and system reliability through the construction of 11 mid-span, wooden pole structures.

Replace Interconnect Microwave Radios

2025



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Replace Interconnect Microwave Radios (2025)

Location: Various

Investment Classification: General Plant

Asset Category: Telecontrol

Cost: $1,102,964

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") operates and maintains a private telecommunications transport system which provides critical connectivity to terminal stations and generating stations. This connectivity is primarily used by the following functional networks:

- Hydro's Supervisory Control and Data Acquisition ("SCADA") network, which provides the Newfoundland and Labrador System Operator's Energy Control Center ("ECC") with remote visibility[1] and control[2] of the power system;
- Teleprotection[3] network, 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 telecommunications transport system is comprised of network elements of various vintages including microwave radio and fibre-optic multiplexors. The existing microwave radio platform installed at Hydro's sites in the interconnection portion is obsolete and are discontinued by the manufacturer. In the event that a microwave radio was to fail in this interconnection portion, then Hydro's private telecommunications transport network would be impacted. Hydro proposes the replacement of these obsolete microwave radios to ensure reliable service is maintained on its telecommunications transport system.

[1] The ECC collects real-time data from remote sites in order to monitor the health of the grid.
[2] The network gives the ECC the ability to control remote devices such as circuit breakers, transformers, reclosers, etc.
[3] 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.

2.0 Project Description and Justification

This project will replace the functionality of the interconnect radio system and upgrade available bandwidth by establishing a new fibre-optic transport link between the eastern and western microwave radio systems on fibres contained in the Labrador-Island Link ("LIL") Optical Ground Wire ("OPGW") cable. This work is required to ensure continued reliable operation of Hydro's private telecommunication transport network, in order to provide critical connectivity to stations and plants and to provide sufficient performance for applications and end users.

The current radio platform is obsolete and has been discontinued by the manufacturer. Hydro has a service contract in place with the manufacturer that will expire on December 31, 2025, and cannot be renewed. After that time, Hydro will be unable to receive support or spare parts to operate these radios. Further to this, without a bandwidth upgrade, the interconnect radio link will become a traffic bottleneck in Hydro's transport network, limiting the bandwidth that can be utilized between the eastern microwave radio backbone and western microwave radio backbone (to be upgraded in 2024–2025 as part of another, approved project) to approximately one-third of the available 450 Mbps on each system. If bandwidth is not increased and network paths become congested, applications will see reduced performance or may cease to function entirely.

In the event that a radio on the interconnect system were to fail, either through a failure of the radio itself or as a result of failed support equipment, Hydro's transport network would be impacted. In the case of the interconnect radio system, this would cause a loss of connectivity between the eastern and western microwave systems, resulting in a loss of primary connectivity. Some traffic would revert to backup circuits and teleprotection would revert to single link operation. This would leave the network in a vulnerable state. An additional failure would cause widespread communications outages, leading to a loss of SCADA, teleprotection, and administrative network services.

Figure 1 shows Hydro's microwave network connections. The locations of the radios to be replaced are highlighted in yellow.

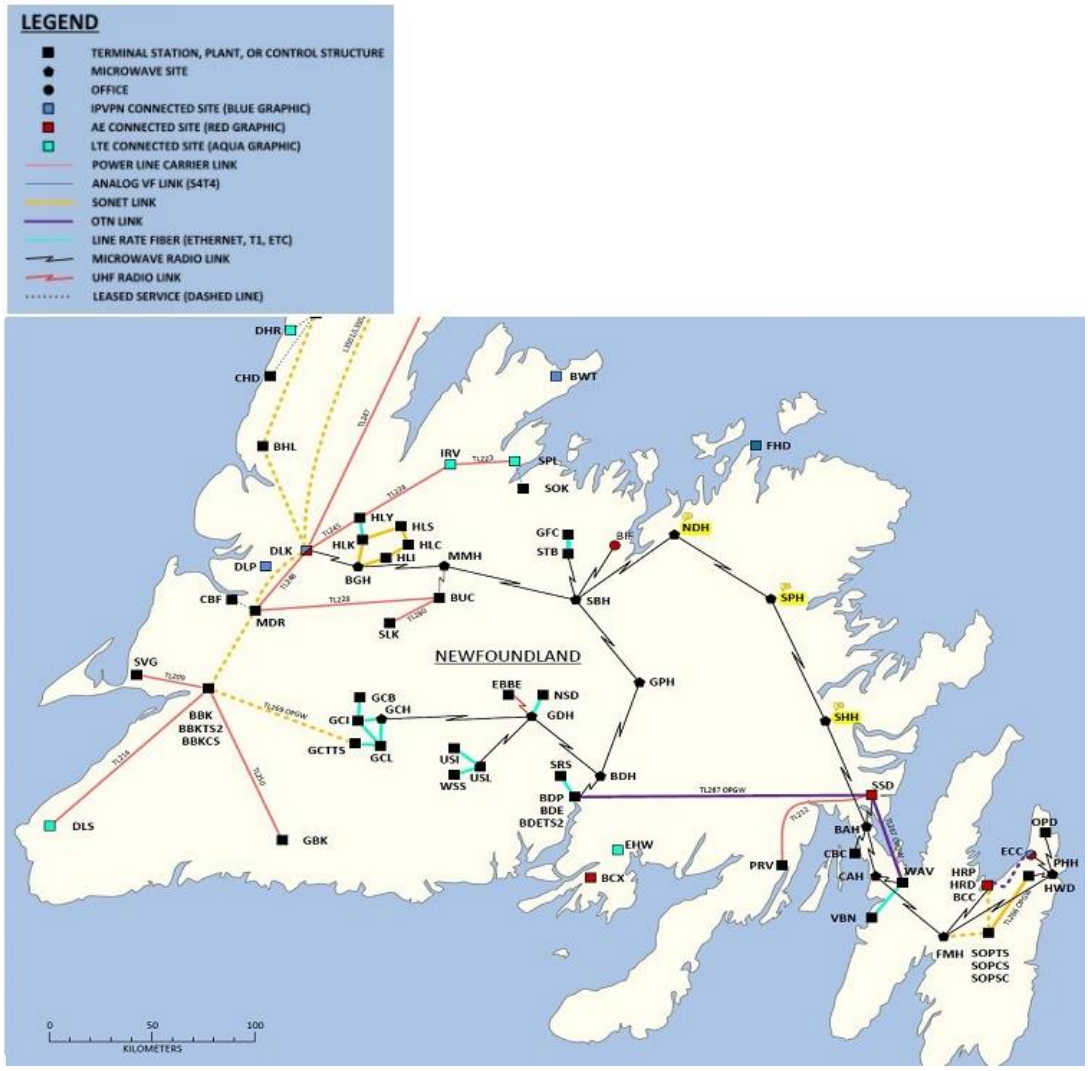


Figure 1: Microwave Network View

1 3.0 Asset Overview

2 3.1 Asset Background

3 Hydro currently has 25 microwave radio hops[4] in its network. Of these hops, four were replaced with the
4 newer version of the microwave radios in 2017; seven were replaced in 2019; and another ten are

[4] A hop is a link connecting two sites.

currently undergoing replacement in 2024–2025.[5] The remaining four hops currently use the obsolete version of the microwave radio and 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 this 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 advancements 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. However, for the three specific sites for this proposal, many of the dedicated building operational systems required to run the microwaves are also obsolete and will presently require replacement/refurbishment.

[5] One of the ten hops undergoing replacement in 2024–2025 is being replaced by a fibre-optic link.

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[6]

Hop	Year Installed	Age (Years)
BAH-SHH	2003	21
SHH-SPH	2003	21
SPH-NDH	2003	21
NDH-SBH	2003	21

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.[7]

Due to regular preventive, corrective maintenance practices, 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] Bull Arm Hill ("BAH"); Shoal Harbour Hill ("SHH"); Square Pond Hill ("SPH"); Notre Dame Hill ("NDH"); Sandy Brook Hill ("SBH").
[7] 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;
- Like-for-like replacement; and
- Fibre-optic transport link.

4.1.1 Deferral

The existing microwave radio technology is obsolete and must be replaced by 2025. The four hops proposed for replacement constitute the last remaining obsolete microwaves radios in Hydro's network. As these assets are part of a connected communications system, these hops require replacement at the same time and deferral on a hop-by-hop basis is not viable.

Further, the deferral of the replacement of the four proposed microwave radios beyond 2025 would result in the loss of the service contract with the manufacturer.[8] 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.

4.1.2 Upgrade Life Extension

As spare equipment and manufacturer support are no longer available for the interconnect radio system, an upgrade to the existing equipment is not a viable alternative.

[8] 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.

4.1.3 Like-for-Like Replacement

The existing microwave radio platform installed for Hydro's interconnect microwave system 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. Other dedicated building operational systems needed to run the microwave radio system are also obsolete and presently require replacement/refurbishment. Additional work required to support replacement with a comparable microwave radio platform includes the following:

- Propane generators and associated controllers are in need of overhaul/refurbishment;
- Rectifiers are discontinued by the manufacturer and at the end of their useful service life;
- Batteries are at the end of their useful service life;
- Fire suppression systems are at the end of their useful service life;
- Administrative network equipment has reached the end of its useful service life;
- Microwave antennas have to be inspected for potential replacement;
- Microwave antenna radomes have to be inspected for potential replacement; and
- HVAC[9] systems are at the end of their useful service life.

Therefore, like-for-like replacement of the existing system is not a viable option.

4.1.4 Fibre-Optic Transport Link

This alternative involves replacing the functionality of the interconnect radio system and upgrading the available bandwidth by establishing a new fibre-optic transport link between the eastern and western microwave radio systems on fibres contained in the LIL OPGW cable.

4.2 Least-Cost Evaluation

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

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

4.3 Recommended Alternative

Hydro recommends the replacement of the interconnect microwave radio link with a fibre-optic transport link as the least-cost option for this work. The fibre-optic link also provides a more reliable communication medium with increased bandwidth and less potential equipment failure points.

4.3.1 Risk of Asset Stranding

There is no risk of asset stranding for the proposed equipment due to the fact that Hydro's administrative and operational networks will remain a requirement for the foreseeable future. The proposed fibre-optic links will also provide enough bandwidth to meet Hydro's current projected network requirements throughout the useful life of the proposed equipment.

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the 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-Implementation	5	4	**20**
Post-Implementation	5	2	**10**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**9.1**

5.0 Scope of Work

This project involves the replacement of four interconnect microwave radio links with a fibre-optic transport link. The scope of work will include the following:

- Site visits and front-end engineering design;
- Fibre-optic equipment procurement;
- Tender for fibre-optic build;
- Optical transport equipment configurations and work package creations;

- Fibre-optic cable and transport equipment installation; and
- Installation, commissioning, and testing of fibre-optic links.

5.1 Project Budget

The estimate for this 2025 project is shown in Table 3.

Table 3: Project Estimate ($000)

Project Cost	2025	2026	Beyond	Total
Material Supply	406.5	0.0	0.0	**406.5**
Labour	213.6	0.0	0.0	**213.6**
Consultant	76.5	0.0	0.0	**76.5**
Contract Work	239.2	0.0	0.0	**239.2**
Other Direct Costs	10.1	0.0	0.0	**10.1**
Interest and Escalation	47.3	0.0	0.0	**47.3**
Contingency	109.8	0.0	0.0	**109.8**
Total	**1,103.0**	**0.0**	**0.0**	**1,103.0**

5.2 Project Schedule

The schedule for this project is shown in Table 4.

Table 4: Project Schedule

Activity	Start Date	End Date
Planning:		
Project kickoff/planning/design phase.	January 2025	March 2025
Design:		
Detailed design work for communications, civil, and T&D, including tender developments.	February 2025	April 2025
Procurement:	February 2025	March 2025
Configuration:		
Equipment configuration.	April 2025	June 2025
Construction:		
Installation and commissioning.	June 2025	October 2025
Closeout:		
Engineering drawings/documentation/closeout.	November 2025	December 2025

6.0 Conclusion

This project is required to replace the obsolete and discontinued microwave radios used in Hydro's interconnect system. Hydro recommends replacement of the interconnect microwave radio link with a fibre-optic transport link. The fibre-optic link is the least-cost option for this project, and will deliver the required increase in bandwidth to meet Hydro's increasing network demands, while also providing a more reliable communication medium with less potential equipment failure points.

$750,000 to $1,000,000

Upgrade Work Protection Code Application

2025–2026

newfoundland labrador hydro

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Upgrade Work Protection Code (2025–2026)

Location: Various

Investment Classification: General Plant

Asset Category: Information Systems

Cost: $901,407

1.0 Introduction

Newfoundland & Labrador Hydro ("Hydro") must upgrade its current Work Protection Code ("WPC") application, which has reached the end of its useful life. At its operating sites across the company, Hydro uses ESMII[1] software to meet WPC requirements. The Newfoundland and Labrador System Operator ("NLSO") currently utilizes a WPC system developed in-house, which is a standalone software and does not connect with ESMII. This system is actively supported by the Operational Technology ("OT") department, but does not contain many of the features currently available in ESMII.

Hydro's current version of WPC presents risks to cyber-security, compliance with work protection requirements, and work execution and safety. As a result, Hydro requires a more modernized, web-based version, which will allow for a standardized system across the company and provide greater accessibility, security, and performance. Additionally, this application will also be deployed to the NLSO, allowing for one standardized application across the company to provide internal efficiencies and system integration.

As the WPC application is an OT and is used across the company, this project will be executed by Regulated Hydro using the shared services model. It will utilize the approved Intercompany Transaction Costing Guidelines[2] to share costs between entities appropriately. The Board of Commissioners of Public Utilities ("Board") has previously accepted this approach for sharing costs amongst entities in Board Order No. P.U. 27(2022), indicating that where information sharing is required in the context of the corporate structure, the shared-services approach is preferable to a standalone model.

[1] Equipment Status Monitoring II ("ESMII").
[2] "2017 General Rate Application," Newfoundland and Labrador Hydro, rev. July 4, 2018 (originally filed July 28, 2017), vol. II, exh. 5.

2.0 Project Description and Justification

Hydro's WPC is a critical, complex group lockout program utilized to ensure electrical equipment is isolated[3] prior to beginning work, which was adopted from Ontario Power Generation ("OPG").[4] Work protection is essential for the safe and effective coordination of work activities in complex high voltage electrical work environments, where there is a high risk of worker injury and equipment damage. The WPC ensures that Hydro meets Occupational Health & Safety ("OHS") regulatory requirements to ensure the safety of workers and equipment.

At its operating sites, Hydro uses ESMII software to meet WPC requirements. Should Hydro's ESMII fail, operational departments would be forced to revert to paper permits for equipment isolation. The resulting impact of ESMII failure to work scheduling would be significant and would introduce numerous safety risks to both operations and personnel. ESMII provides efficient methodologies to reduce human error and introduces computerized automation of isolation and de-isolation procedures for improved worker and equipment safety.

ESMII provides near-real-time interaction with status and configuration control processes, making this a full-service module for Operations staff to manage equipment and support maintenance activities. Personnel have rapid access to the status of work protection packages with coverage of the entire electronic life cycle, which is adaptable to organizational processes and other regulatory requirements. Isolations and de-isolations can be pre-templated for maximum reusability and to align with any existing preventative maintenance program, allowing for efficiencies and full integration with work management processes.[5] In addition to operating sites, the upgraded version will also be deployed to the NLSO, allowing for one standardized WPC across the company. Both the current version of ESM and the application used by the NLSO have surpassed end-of-life are dependent on other applications that have been depreciated by the vendor, which can increase security risk.

The upgrade of the ESM software was originally included within the 2021 Capital Budget Application as part of the Software Upgrades and Minor Enhancements capital program; however, the project was cancelled in late 2022 due to cost increases from the vendor for customization required for Hydro's

[3] Electrical isolation is the process of disconnecting a piece of electrical equipment or circuit from its power source.
[4] The original ESMII version is per OPG design and implementation, with enhancements and customizations to complement Hydro's own unique work protection governance and procedures.
[5] In 2023, 1,562 work permits were created across the company, and 4,497 associated switching orders were executed for various operational activities.

work protection procedures. Through 2023, while mitigating the risk associated with deferral, Hydro re-assessed the project scope and execution, while maintaining required functionalities.

3.0 Asset Overview

3.1 Asset Background

Hydro's original WPC framework, which was paper-based, was adopted from OPG in the early 1990s. In 2007, ESMII, the WPC software used by OPG, was implemented in Holyrood. Since that successful implementation, Hydro has deployed the software across all plants within the company, both in the regulated and non-regulated business, including Exploits System, Bay d'Espoir Hydroelectric Generating Station, Churchill Falls Hydroelectric Generating Station, and the Muskrat Falls Hydroelectric Generating Station, as well as the Labrador-Island Link ("LIL").

Prior to the introduction of ESMII to the operating sites, an in-house WPC solution was developed for the Energy Control Centre (now the NLSO) in 2006. The custom-built Microsoft access database is maintained separately by the OT department and lacks integration with ESMII and the key functionalities that ESMII provides.

WPC software provides a high degree of safety and compliance to work protection and execution; failure of the NLSO or ESMII software would significantly impact Hydro's ability for timely and efficient work execution, and introduce numerous safety risks.

3.2 Historical Reliability

ESMII's work protection module provides efficient methodologies to reduce human error and introduce computerized automation of isolation and de-isolation procedures for improved worker and equipment safety. Over the lifetime of this software, Hydro has executed capital projects to improve its functionality; however, it has since reached the end of its useful life.

The WPC database utilized by the NLSO has been maintained to the best of the ability of the OT department since 2006; however, it has also reached the end of its useful life.

In their current state, both systems present a cyber-security risk for Hydro.

3.3 Asset Condition

The WPC applications are at the end of life, pose cybersecurity risks, utilize out-of-date frameworks, and cause significant issues for users. In addition to upgrading the software, it is Hydro's intent to provide a single, centralized software solution across the company, including the NLSO, to improve operational efficiency and systems integration.

3.4 Condition-Based Remaining Life

As previously noted, the current software relies on a web browser and infrastructure that has already surpassed its end-of-life and is therefore considered in a 'run-to-failure' state. Reaching the end of its useful service life means this software is no longer supported, and security vulnerabilities increase.[6]

4.0 Analysis

4.1 Evaluation of Alternatives

Hydro evaluated the following alternatives:

- Deferral;
- Upgrade life extension;
- Like-for-like replacement; and
- Alternative strategies.

4.1.1 Deferral

Hydro has deferred the upgrade since 2022; however, additional deferral of this project is not a viable option as it would significantly increase risks related to cybersecurity, software failure, and personnel safety. The current ESMII WPC application is utilizing a web browser and framework that have surpassed the end of their useful service life, with associated infrastructure moved to an isolated environment to reduce impact on the OT infrastructure in case of failure. Hydro has taken steps to mitigate the risks and issues introduced by using unsupported software; however, these continue to increase.

[6] Until the system is upgraded, Hydro has isolated the servers and software to mitigate the impact of any cybersecurity breaches on other infrastructure; however, this is not a long-term solution and does not extend the life of the existing system.

4.1.2 Upgrade Life Extension

The current ESMII software version requires the use of depreciated and unsupported legacy browser, applications that can no longer be updated which creates security vulnerabilities, and requires customization that prevents the ability to secure the system. This increases the likelihood of a cybersecurity incident, and as a result upgrade life extension is not a viable alternative.

4.1.3 Like-for-Like Replacement

This project allows Hydro to upgrade its current, end-of-life WPC applications with an updated application that will (i) address cybersecurity and other risks within the existing systems; (ii) enable Hydro to continue the safe and effective coordination of work activities; and, (iii) ensure that Hydro meets OHS regulatory requirements to ensure the safety of workers and equipment.

4.1.4 Alternative Strategies - Clustering

Hydro has identified the opportunity to cluster the upgrade of the ESMII WPC application with the replacement of the in-house built NLSO WPC database. The replacement for ESMII will also be deployed to the NLSO, allowing for one standardized application across the company.

4.2 Least-Cost Evaluation

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

Hydro is pursuing this capital project as part of the shared services model versus a standalone system, if each line of business had to acquire and implement its own WPC system, the duplication of effort would result in higher costs to Hydro's customers than participation in a shared services approach. Given that Hydro's customers ultimately pay for the allocation of the WPC costs to Hydro's regulated operations and the allocation to the Muskrat Falls project entities,[7] the efficiencies resulting from a single WPC program for the entire company will provide a lower overall cost for its customers.

4.3 Recommended Alternative

Hydro's current WPC solution is a critical application that allows the safe execution of work, protecting Hydro employees and equipment; however, the current applications have reached the end of their useful service life and require upgrading. Hydro is recommending proceeding with the like-for-like replacement of the ESMII and clustering this project with the replacement of the current NLSO WPC

[7] Including Muskrat Falls and LIL.

software system, which will provide a standardized WPC software solution across the company, improving operational efficiency and system integration.

4.3.1 Risk of Asset Stranding

WPC is a vital application, critical to the successful and safe execution of maintenance; therefore, the risk of asset stranding is extremely low and highly unlikely.

4.3.2 Risk Mitigation

WPC is vital to the protection of personnel and equipment safety. Software failure could increase the safety risk and likelihood of human injury, as well as damage to equipment.

Hydro assessed the pre- and post-implementation risk of the scope of work for the 2025-2026 project in accordance with Hydro's Capital Risk Assessment process, as outlined in Section 7.0 of Schedule 1.0. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	5	5	**25**
Post-Implementation	5	2	**10**
		Risk Mitigated	**15**
		Risk Mitigated per $1 Million	**16.6**

5.0 Scope of Work

This project will include planning, design, and implementation of the new software.

5.1 Project Budget

The estimate for this project is shown in Table 2. The project cost will be split using Hydro's intercompany guidelines and allocated based on users. Hydro will be responsible for 40% of the total cost (approximately $361,000), while Muskrat Falls and Churchill Falls will each be responsible for 30% of the total cost (approximately $270,000 each).

Table 2: Project Estimate ($000)

Project Cost	2025	2026	Beyond	Total
Material Supply	200.0	340.0	0.0	**540.0**
Labour	202.0	54.0	0.0	**256.0**
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	9.8	16.0	0.0	**25.8**
Contingency	40.2	39.4	0.0	**79.6**
Total	**452.0**	**449.4**	**0.0**	**901.4**

5.2 Project Schedule

The schedule for this project is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Planning.	January 2025	March 2025
Design:		
Design and implementation.	March 2025	October 2026
Closeout:		
Closing.	November 2026	December 2026

6.0 Conclusion

Hydro's current WPC solution is a critical application that allows the safe execution of work, protecting Hydro employees and equipment. The current software ESMII presents a cyber-security risk, which has reached the end of its useful service life, and requires upgrading. The new software will provide a standardized WPC solution across the organization, including the NLSO, to improve operational efficiency and system integration.

Perform Level 2 Condition Assessment Stage 1 & 2 Cooling Water Sump Structures

2025

Holyrood



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Appendix A: Hatch Floor Assessment Report

Perform Level 2 Condition Assessment Stage 1 & 2 Cooling Water Sump Structures (2025)

Location: Holyrood

Investment Classification: Renewal

Asset Category: Thermal Plant

Cost: $891,919

1.0 Introduction

The Holyrood Thermal Generating Station ("Holyrood TGS"), which includes three thermal generating units that provide a total capacity of 490 MW, is an essential part of the Island Interconnected System. The thermal generating units utilize an open cycle circulating water system to regulate the temperature of the units during operation. The Stage 1 Pumphouse was constructed in 1969 and supplies cooling water to thermal Units 1 and 2. The Stage 2 Pumphouse followed in 1979 and supplies water to thermal Unit 3.

Deterioration of the reinforced concrete beams, which support the floor slab for each pumphouse, has compromised their integrity resulting in a restriction of floor loading to foot traffic only. This has limited Newfoundland and Labrador Hydro's ("Hydro") ability to complete prescribed maintenance on the assets that are housed within the buildings, thus, placing their reliable operation at risk. This impacts the safe operation of the Holyrood TGS.

As per "Reliability and Resources Adequacy Study – 2022 Update" ("2022 Update"),[1] 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 is proven, and generation reserves are met. As the compromised floor structure's integrity and associated load restrictions will continue to limit Hydro's capacity to complete necessary asset maintenance until the

[1] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.

cooling water sump beams are refurbished and the pumphouse floor structure's design load capacity is reinstated, mitigation is required.

2.0 Project Description and Justification

The proposed project is required to perform a Level 2 Condition Assessment of the reinforced concrete support beams for the floor structure in Stage 1 Pumphouse and Stage 2 Pumphouse.

Deterioration of the concrete support beams has progressed to the point where their structural integrity is compromised. Subsequent load restrictions, imposed on the floors, have limited the pumphouses to pedestrian traffic only. The inability to bring equipment into the pumphouses limits Hydro's ability to complete prescribed asset maintenance and places their continued, reliable operation at risk.

If left unattended, the concrete deterioration will continue to progress. This progression will inevitably result in further access restrictions and could ultimately result in the structural failure of the floor slab. The pumphouses must remain in safe operating condition until they are decommissioned upon the retirement of Holyrood TGS. Given the complex nature of the work area and the requirement to complete the work under a unit outage, the proposed level II condition assessment is necessary to accurately define the concrete's condition, develop the refurbishment scope, and plan for its execution.

3.0 Asset Overview

3.1 Asset Background

The generating units at the Holyrood TGS are equipped with a circulating water system that provides cooling water to the turbine condenser, and a closed auxiliary cooling water system serving the generator hydrogen coolers, turbine generator lubricating oil coolers, turbine hydraulic power unit fluid coolers, boiler feed water pumps lubricating oil cooler, and the mechanical vacuum pumps.

The Stage 1 Pumphouse was constructed in 1969 and supplies circulating water to thermal Units 1 and 2. The Stage 2 Pumphouse followed in 1979 and supplies water to thermal Unit 3. The circulating water consists of seawater that is drawn from a nearby pond into the sump chambers of each pumphouse; the ceilings of these intake sumps form the floor slab of the pumphouses, where workers access

components of the system for overhauls and maintenance work. The water is ultimately pumped to the powerhouse where it serves to regulate the operating temperature of the thermal generating units.

3.2 Historical Reliability

The Stage 1 and 2 Cooling Water Sumps have remained in reliable operation since their original installation. This is due, in large part, to the regularly prescribed corrective and preventive maintenance to which they have been subject throughout their service life.

Historically, the sumps have undergone a thorough cleaning and inspection every five years with corrective maintenance performed as required. These inspections are not only critical for the operation and reliability of the sumps but also to ensure the reliable operation of the thermal generating unit's cooling water system.

Deterioration of the concrete members has resulted in safety concerns related to sump access and the implementation of load restrictions for the pumphouse floors. The inability to safely access the sumps has resulted in the discontinuation of their regular cleaning and inspecting, while the floor load restrictions impede Hydro's ability to conduct critical maintenance for the assets housed within the pumphouses.

While there have been no disruptions to system reliability attributed to the condition of the cooling water sumps thus far, their current condition hinders the completion of asset maintenance and, places the reliable operation of the thermal generating unit's cooling water system at risk.

3.3 Asset Condition

The seawater contained in the pumphouse sump chambers creates a highly corrosive, moisture-laden environment. Throughout their service life the reinforced concrete beams, which support the floor slabs in each pumphouse, have deteriorated to the point in which their structural integrity is compromised.

Corrosion of the steel reinforcing members has resulted in significant spalling and delamination of the concrete members, as shown in Figure 1 and Figure 2.[2]



Figure 1: Concrete Delamination along Structural Beam



Figure 2: Concrete Delamination along Structural Beam

The condition of the concrete structural components has resulted in the imposition of floor loading restrictions within the pumphouses. The loading restrictions, originally implemented for a single sump in 2017, were expanded to encompass the entire floor area following the completion of a 2022 Floor Load Assessment by Hatch Ltd. which is included as Appendix A.

[2] Spalling is the deterioration of steel-reinforced concrete and is characterized by the appearance of cracks and red rust. Delamination is the process which occurs when the top layer of a concrete slab separates from the rest of the slab's body.

Presently, the floor loading for both pumphouses is restricted to foot traffic, which limits the ability to perform preventive and corrective maintenance for the circulating water system's components.

3.4 Condition-Based Remaining Life

The cooling water sump concrete is consistently exposed to a moisture-laden, salt-rich environment, which leaves the concrete surface exposed to contaminants. These contaminants promote corrosion of reinforcing steel and, ultimately, could lead to the failure of the concrete in the form of delamination and spalling.

Subsequently, the pumphouse floor structures have deteriorated to the point in which their structural integrity has been compromised, requiring the implementation of load limits on the concrete floor. While it is difficult to predict the remaining life of the concrete, it is certain that the noted deterioration will continue to progress.

4.0 Analysis

4.1 Evaluation of Alternatives

Hydro evaluated the following alternatives for the continued safe and reliable operation of the Stage 1 and 2 Cooling Water Sumps:

- Deferral; and
- Perform Level 2 Condition Assessment.

4.1.1 Deferral

Deferral and continued use of the current mitigation strategy, which consists of an imposed load restriction for the pumphouse floors, is not a viable alternative for this project due to the operational and safety risk presented by the concrete deterioration of the pumphouse floors. It is certain that the noted deterioration will continue to progress, which limits the ability to complete prescribed maintenance and further compromises the structural integrity of the floor, resulting in additional effort to restore the sumps to an acceptable condition, the implementation of enhanced load restrictions, and ultimately the potential structural failure of the floor.

4.1.2 Perform Level 2 Condition Assessment

Deterioration of the concrete members has resulted in safety concerns related to sump access, and the implementation of load restrictions for the pumphouse floors. The inability to safely access the sumps has resulted in the discontinuation of their regular cleaning and inspections, while the floor load restrictions impede Hydro's ability to conduct critical maintenance for the assets housed within the pumphouses. The inability to complete asset maintenance places the reliable operation of the thermal generating unit's cooling water system at risk.

This alternative involves the completion of a Level 2 Condition Assessment of the reinforced concrete support beams. This assessment will serve to define the required concrete refurbishment scope and plan the execution of the work.

4.2 Least-Cost Evaluation

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

4.3 Recommended Alternative

Mitigation measures are necessary to ensure the safety of personnel and to affirm that the appropriate work is performed relative to the assets' remaining service life. As noted in the 2022 Update, Holyrood TGS is required to remain available through the Bridging Period. Hydro has determined that continued reliance on the current mitigation strategy, which consists of an imposed load restriction for the pumphouse floors, is no longer viable and that the proposed Level 2 Condition Assessment must be completed to define the required concrete refurbishment scope and plan the execution of the work.

4.3.1 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).[3]

4.3.2 Risk Mitigation

Hydro assessed the pre- and post-implementation risk of the scope of work for the project in accordance with Hydro's Capital Risk Assessment process, as outlined in Section 7.0 of Schedule 1.0. The outcome of this assessment is provided in Table 1.

Table 1: Risk Scoring Pre- and Post-Implementation

	Impact	Likelihood	Score
Pre-Implementation	5	3	**15**
Post-Implementation	5	1	**5**
		Risk Mitigated	**10**
		Risk Mitigated per $1 Million	**11.2**

5.0 Scope of Work

This project involves performing a Level 2 Condition Assessment of the reinforced concrete support beams for the floor structure in Stage 1 Pumphouse and Stage 2 Pumphouse at the Holyrood TGS. The scope of work will be executed as a single-year project, and will include:

- Procurement of stop logs;[4]
- Dewatering and cleaning of the sumps;
- Erection of access scaffold; and
- Level 2 Condition Assessment of the reinforced concrete support beams.[5]

[3] Due to the extension of the Holyrood TGS through the Bridging Period, Hydro filed an application with the Board of Commissioners of Public Utilities ("Board") to extend the Holyrood Accelerated Depreciation Deferral Account. The Board approved the extension of the account and related amendments in Board Order P.U. 1(2024). Hydro also was directed to file a report on the account in its next general rate application.

[4] The procurement of stop logs will be required to permit sump dewatering to complete the assessment.

[5] Should the assessment findings support the urgency, Hydro will file a supplemental application to begin the execution of the refurbishment scope ahead of the next capital budget application.

5.1 Project Budget

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2025	2026	Beyond	Total
Material Supply	150.0	0.0	0.0	**150.0**
Labour	214.3	0.0	0.0	**214.3**
Consultant	199.0	0.0	0.0	**199.0**
Contract Work	204.0	0.0	0.0	**204.0**
Other Direct Costs	14.9	0.0	0.0	**14.9**
Interest and Escalation	38.5	0.0	0.0	**38.5**
Contingency	71.2	0.0	0.0	**71.2**
Total	**891.9**	**0.0**	**0.0**	**891.9**

5.2 Project Schedule

The proposed scope of work will be executed as a single-year project. The schedule for this 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.	January 2025	February 2025
Procurement:		
Procure stop logs.	February 2025	May 2025
Tender condition assessment contract.	February 2025	March 2025
Engineering:		
Complete assessment Pumphouse 1.	May 2025	June 2025
Complete assessment Pumphouse 2.	June 2025	July 2025
Final condition assessment report.	July 2025	September 2025
Closeout:		
Project completion, interest cut-off, lessons learned, and as-build drawings.	October 2025	December 2025

6.0 Conclusion

The reinforced concrete beams, which support the floor slabs in each pumphouse, have deteriorated to the point in which their structural integrity has been compromised. If left unattended, the concrete deterioration will continue to progress. This progression will inevitably result in further access restrictions and could ultimately result in the structural failure of the floor slab. The pumphouses must remain in safe operating condition until they are no longer required for operation of the Holyrood TGS.

The proposed Level 2 Condition Assessment will serve to identify the concrete refurbishment scope required to extend the service life of the sumps, providing a safe working environment for the remaining life of the assets.

Appendix A

Hatch Floor Assessment Report





Exhibit A - Disclaimer (Structural safety reports)

IMPORTANT NOTICE TO READER

This report was prepared by Hatch Ltd. ("**Hatch**") for the sole and exclusive use of Newfoundland and Labrador Hydro (the "**Principal**") for the sole purpose of assisting the management of the Principal to make decisions with respect to the use and maintenance of the Stage 1 and Stage 2 Pumphouse floor slabs (the "**Structure**"), and must not be used for any other purpose, or provided to, relied upon or used by any other person. Any use of or reliance upon this report by another person is done at their sole risk and Hatch does not accept any responsibility or liability in connection with that person's use or reliance.

This report contains the opinion of Hatch using its professional judgment and reasonable care based upon observations of the condition of the Structure made at the time of preparation of this report, and information made available to Hatch by the Principal or by certain other parties (the **"Principal or Other Information**").

The use of or reliance upon this report by the Principal is subject to the following:

(1) this report is to be read in the context of and subject to the terms of the relevant services agreement and signed proposal between Hatch and the Principal (the "**Hatch Agreement**"), including any methodologies, procedures, techniques, assumptions and other relevant terms or conditions specified in the Hatch Agreement;

(2) this report is meant to be read as a whole, and sections or parts of the report must not be read or relied upon out of context;

(3) unless expressly stated otherwise in this report, Hatch has not verified the accuracy, completeness or validity of the Principal or Other Information, makes no representation regarding the accuracy of such information and does not accept any responsibility or liability in connection with the Principal or Other Information; and

(4) the condition, stability and safety of the Structure may change over time (or may have already changed) due to natural forces or human intervention, and Hatch does not accept any responsibility for the impact that such changes may have on the accuracy or validity of the opinions, conclusions and recommendations set out in this report.

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Project Memo

H369543

December 14, 2022

To: Joanne Norman, P. Eng. From: Anne Stapleton, P. Eng.

cc: D. McDonald, C. Seymour, S. Routledge

Newfoundland & Labrador Hydro
Holyrood TGS, Circulating Water Pumphouses - Stage 1 and 2 Floor Load Assessment

Floor Load Assessment - Phase 1 Summary

1. Introduction

Dear Ms. Norman,

Hatch was engaged by Newfoundland & Labrador Hydro (NL Hydro) to structurally assess the existing floor structure within the south units (1 to 4) of the Holyrood Thermal Generating Station (HTGS) Stage 1 and 2 Pumphouses. The floor area inspected is displayed in Figure 1. This area of the structure is utilized by NL Hydro for ongoing maintenance activities within the pumphouses.

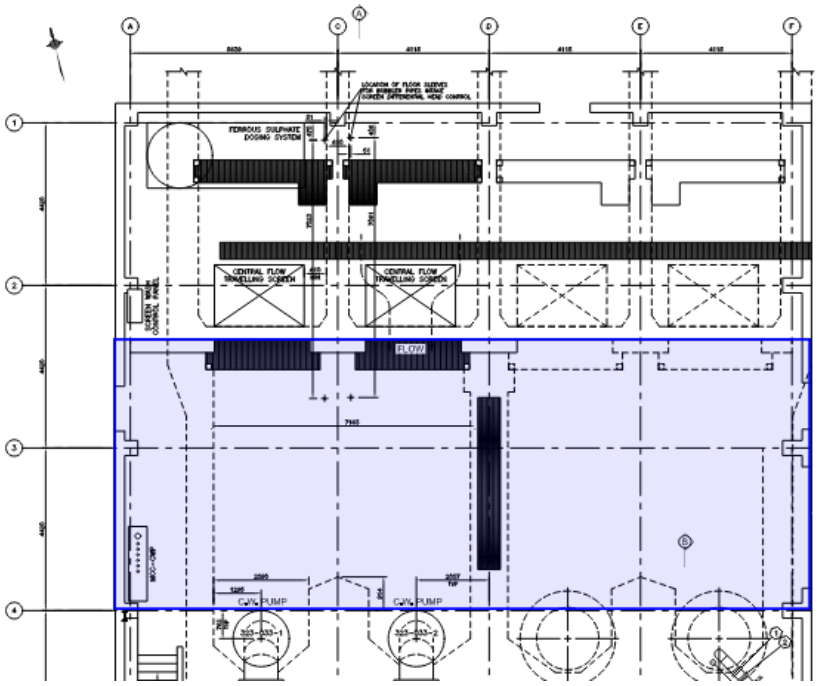


Figure 1: Inspection areas for pumphouse 1 and 2 (T/slab EL. 11.17')

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This memo addresses Phase 1 of the structural assessment. Phase 1 consists of a high-level analysis of the floor area in Figure 1, based on site inspection results and review of existing drone inspection data, to recommend a safe uniformly distributed load for the floor slab. Requirement to proceed to Phase 2, which encompasses review of the equipment loads that can be supported on the floor slab, is dependent on the results of Phase 1.

Upon review of previous site inspection and drone inspection reports, it is our understanding that the concrete floor slab spanning the sump pit and its associated support beams have experienced deterioration over time. Additionally, Hatch visited both pumphouse sites on September 21, 2022 to inspect the top of the floor slab. From this site investigation, the slab area generally appeared to be in fair condition, however, localized cracking was noted throughout where the slab contains embedded steel (i.e., along edges of manways and trenches). No visible signs of deflection were observed in the floor slab.

Hatch personnel were not able to directly access the underside of the slab, but based on review of the drone inspection reports, the following conditions were identified. The underside of slab shows some signs of corrosion, cracking, and concrete spalling, though it was primarily localized around the floor trenches and sump manways. Slab support beams located along gridlines C & E (green box, Figure 2) appeared to be in fair condition. Support beams that frame the floor trench and divide the South units (red box, Figure 2) show significant longitudinal cracking, signs of corrosion, and loss of concrete cover. Hatch's phase one structural analysis focused on these beams due to the noted deterioration level and their criticality in supporting the floor slab.

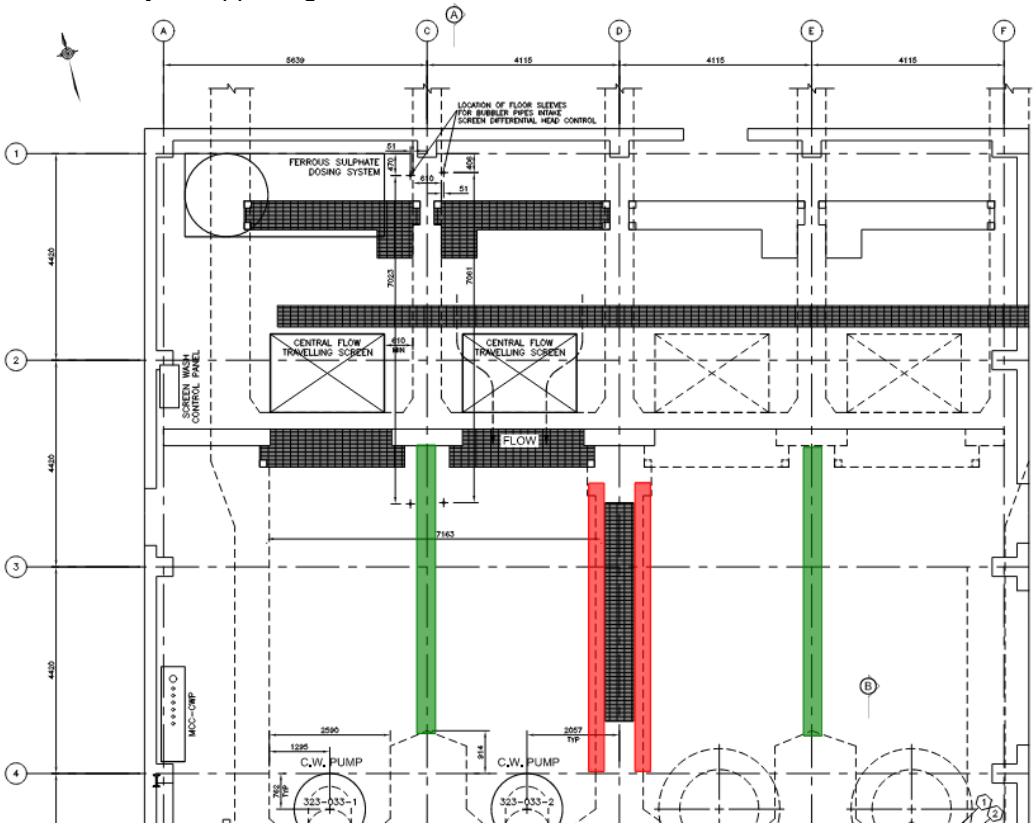


Figure 2: Slab support beam layout

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2. Beam Analysis

Upon review of the original structural drawings, both pumphouses appear to have a similar layout and concrete reinforcement design. Given the similarity, only analysis of pumphouse 1 is presented in this memo. The analyzed beams are located from gridlines D-2 to D-4 and support both the slab and frame the open floor trench. Each beam is 1ft (300mm) wide x 2ft (610mm) deep with a clear span of 14.5ft (4420mm), as shown in Figure 3. The existing reinforcement consists of 2-#8 top reinforcement, 3-#10 bottom reinforcement and #4 transverse shear reinforcement.

Concrete core testing was completed in October 2017 and results were available to Hatch for this assessment. Based on this data, a concrete compressive strength of 20 MPa was used for structural analysis.

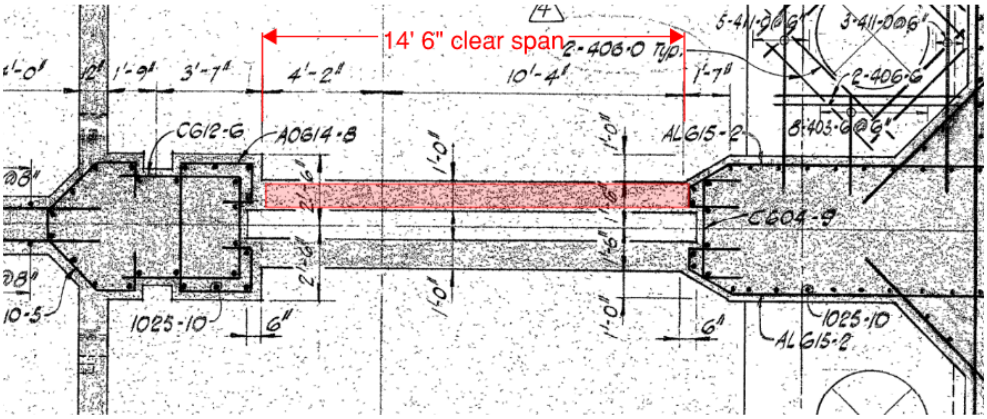


Figure 3: Support beam plan location and dimensions

The significant cracking parallel with the length of the beam is consistent with corrosion of the bottom longitudinal beam reinforcing (see Figure 4). This reinforcing steel and its bond to the concrete is what provides the main resistance to bending from applied loads. Given that we cannot measure the extent of bar corrosion, and the fact that these beams are exposed to a damp, salt-rich environment, analysis does not consider contribution from the bottom steel reinforcing or concrete below this steel.

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Figure 4: Drone inspection photos (Pumphouse 2, Unit 4 South)

Additionally, the top of the beam has a notch for embedded steel at the trench cover. From the recent visual inspection, there is a significant crack running parallel to the edge of the trench at approximately 3” (75mm) from the steel. Given the beam is only 12” wide, we did not consider concrete above the top of the embedded steel (1.75” (44mm) deep) as contributing to the cross-sectional area of the concrete. See Figure 5.

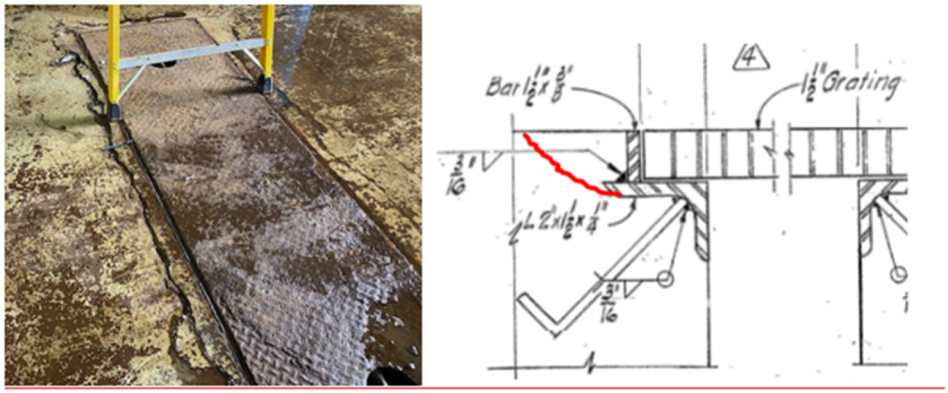


Figure 5: Crack running parallel to floor trench and embedded steel detail

In summary, the structural analysis assumes a reduced section size with no longitudinal reinforcement. The overall section depth was reduced by approximately 5.5” (140mm) to account for longitudinal cracking along the bottom and top of beam (Figure 6).

For the initial analysis, it was also assumed that the beam is “simply supported” (ie. it’s end supports are “pinned”). This aligns with analysis results of the original beam that confirmed that it had sufficient capacity to resist design loads when analyzed with “pinned” end supports.

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Assuming the beam ends are “pinned” is a conservative approach, as concrete beams will have some inherent rigidity at their connection to concrete columns. In reality, the end supports will be somewhere between 100% “pinned” and 100% “fixed”. We therefore also analyzed a second case with the beam ends represented as approximately 50% “fixed”. Fixity affects the amount of bending moment seen at the beam mid-span and end supports.

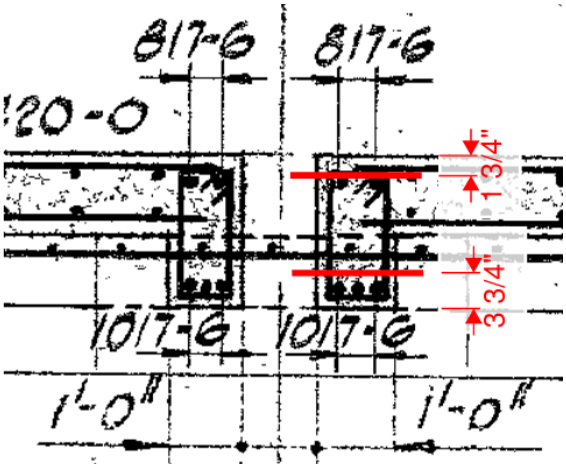


Figure 6: Existing reinforcement section and reduced section size assumption

3. Analysis Results and Conclusions

Analysis of the current concrete beam(s), with the above noted assumptions, gave the following results:

- With “pinned” end conditions, the beam capacity was not sufficient to support the dead load (ie. the self-weight of the floor slab).
- With a 50% “partially fixed” end condition, the beam capacity was sufficient to support the dead load however there was very limited additional capacity for live load.

As stated above, analysis with a “pinned” end condition is likely conservative, particularly when considering that some percentage of the steel reinforcement is still present and likely contributing to the beam capacity. Hatch therefore believes that the “partially fixed” end condition is reasonable for analysis of the beam, though the actual percentage of fixity cannot be determined.

Based on this, Hatch recommends that the beams and slabs be refurbished to their original condition or that new beams be installed directly beneath the existing beams to re-establish the original capacity. In addition, Hatch recommends that the use of the floor slab, in certain areas, be limited to **foot traffic only as necessary** until such refurbishments can be made.

As requested by NL Hydro, Hatch has included a pumphouse floor plan in Appendix A outlining zones in which live load capacity is reduced. It is not recommended to support equipment on the floor structure or use it as an assembly area.

If refurbishments are not able to be completed at this time, regular inspections (annually at minimum) should be performed to ensure that further deterioration has not occurred. The results of these inspections shall

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be reviewed by a competent structural engineer. Until such time that refurbishments are performed, the use of the floor in these areas shall be limited to the conditions described above. A significant change in condition could further impact the structural capacity of the floor in these or other areas and therefore affect the potential operation of the plant. Hatch is unable to comment on the operational limitations due to these load restrictions or the operational risks resulting from an unplanned shutdown and/or need for refurbishment. These restrictions and risks should be assessed by NL Hydro.

It should also be noted that some of the beams located along grid 4, which help in supporting the main pumps, also appear to have longitudinal cracking visible in the drone photos. While these beams do not govern support of the floor slab, further structural analysis is recommended to determine if the capacity to support the pumps has been reduced. Alternatively, these beams could be refurbished to their original condition concurrently with other restoration work.

Please note that this analysis is based on inspection data available at the time of this memo. Given the significant cracking and corrosion observed and the highly corrosive environment, restoration should be done in a timely manner since deterioration is likely to be progressive.

Sincerely,

Anne Stapleton, P.Eng.

AS:dm
Attachment(s)/Enclosure



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References

- Advanced Access Engineering, 21-114-04 - Pumphouse 1 Sump Inspections
- Advanced Access Engineering, 22-114-04 - Pumphouse 2 Sump Inspections
- H354367-00000-240-066-0001 - Holyrood 2017 Condition Assessment Report (June 19, 2018)
- H365408-00000-210-066-0001 - HTGS Condition Assessment and Life Extension Study (March 30, 2022)
- Pumphouse 1 drawings:
    - 238-06-0110-008, Rev 4 - PUMPHOUSE - BASESLAB & SECTIONS - CONCRETE OUTLINE
    - 238-06-0110-009, Rev 5 - PUMPHOUSE - SECTIONS - CONCRETE OUTLINE
    - 238-06-0110-010, Rev 6 - PUMPHOUSE - ELEVATED FLOOR PLAN - CONCRETE OUTLINE
    - 238-06-0110-011, Rev 2 - PUMPHOUSE - ELEVATED FLOOR PLAN - REINFORCEMENT - EQUIPMENT BASES
    - 238-06-0110-012, Rev 4 - PUMPHOUSE - BASE SLAB & SECTIONS - REINFORCEMENT
    - 238-06-0110-013, Rev 4 - PUMPHOUSE - SECTIONS - REINFORCEMENT
- Pumphouse 2 drawings:
    - E-320-C006, Rev 7 - NEW PUMPHOUSE - FLOOR SLAB, SECTIONS & REINFORCEMENT
    - E-320-C007, Rev 0 - NEW PUMPHOUSE - CONCRETE SECTIONS & MISCELLANEOUS STEEL ITEMS
    - E-320-C008, Rev 2 - NEW PUMPHOUSE - WING WALLS
    - E-320-C037, Rev 3 - NEW PUMPHOUSE - SUBSTRUCTURE FORMLINE LAYOUT & DETAILS
    - E-320-C038, Rev 4 - NEW PUMPHOUSE - CONCRETE SECTIONS & EMBEDDED COMPONENT DETAILS
    - E-320-C041, Rev 4 - NEW PUMPHOUSE - FOUNDATION SLAB REINFORCEMENT
    - E-320-C046, Rev 3 - NEW PUMPHOUSE - REINFORCEMENT - FLOOR SLAB
    - B1-1403-323-M002, Rev 6 - HOLYROOD GENERATING STATION CIRCULATING WATER PUMPHOUSE, GENERAL ARRANGEMENT - PLAN

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Appendix A:
Pumphouse 1 and 2 Plan Views

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PUMPHOUSE #1

238-06 0110 - R6

For details of Bases A to G incl. see Dwg. 238-06-0110-011 (B omitted)

10" Fire-fighting mains to be laid by others. Inv. elev. inside Pumphouse 4.0'

Drainage Pit. Low invert 3'8". For Typ. det. see dwg 238-07-0136-027 Pit No. 1. N.T.S.

Diesel Fire Pump Base A

Chlorinator Base B

Base C Elect. Fire Pump

Base E Booster Pump

Base F

Base H

Chlorinator

Wall footings Chlorinator

Provide temporary capping at ends of cable conduits during construction. Typ.

Conduits to project 12" above finished floor, parallel to & against wall

Isolation joint

Removable handrail

Concrete thrust block

Utilidor

For details of utilidor and associated stairs, see Dwg. 238-06-0110-021

Grounding det see

Total of 9 x 4 = 36 Trash racks req'd. thus

2-Units req'd. thus

3-Units req'd. thus

For cast-in anchor bolts at steel col's see Dwg. 238-06-0110-108 R1.

LEGEND

Area limited to foot traffic only

Ex. grid lines

NTS

REMOVABLE HANDRAIL DETAIL
G - Req'd. thus

ANCHOR BOLT - TYPE X3

ANCHOR BOLTS							
MK NR.	NR. REQ'D	SLEEVE DIM. DIA.	SLEEVE DIM. LENGTH	BOLT DIM. TYPE	BOLT DIM. DIA.	BOLT DIM. LENGTH	BOLT DIM. PROJ.
MK-6	48	2"	1'-4½"	X3	1"	1'-10½"	4½"

NOTES:

1. Concrete in powerhouse shall be 3500/1½. Concrete in utilidor shall be 3000/1½.
2. Removable handrail: Rails: 1½" ϕ std. pipe. Posts: 1½" ϕ E.H. pipe
3. Waterproofing for utilidor: 3-Ply membrane waterproofing shall be applied as specified by the manufacturer. Material shall be the following type supplied by Domtor Constr. Material Ltd. or equal. Bitumen - Foundation coating fibrated. Membrane reinforcing - Glass fab.
4. Water stops: Water stops shall be B. F. Goodrich Koroseal 4500 Type 600-A.
5. Concrete cover: 3" for all formed surfaces, (Walls & base slab) 4" for base slab & unformed surfaces.
6. Concrete cover: 1" Clear for elevated slab. 1½" " " beams & grade slabs.
7. For details of grounding cables to be incorporated in the slab see Grounding Plan - Dwg. 238-13-0810-115.
8. All embedded metal parts to be hot dipped galvanized.
9. All concrete surfaces shall receive a F3 finish.
10. Floors & Stairs: Master plate metallic aggregate or an approved equal shall be applied to the floors & stairs at a rate of .75 lb. per square foot in accordance with the manufacturers instructions.
11. Water stops are to be provided for construction joints up to El. 8.00'.
12. Floor loading: Floors designed for 300 lb/ft² L.L.
13. Paint to be in accordance with clause 4.12.08.03 of Specification. (Trash racks).

REFERENCES:

Dwg. 238-06-0110-006 - Excavation plan circulating water piping, pumphouse & utilidor, seal pit.
- 238-06-0110-008 - Pumphouse - Base slab & Sections - Conc. outline.
- 238-06-0110-009 - Pumphouse - Sections - conc. outline.
- 238-06-0110-011 - Pumphouse - Elevated floor plan - Reinforcement.
- 238-06-0110-012 - Pumphouse - Base slab & sections - Reinforcement.
- 238-06-0110-013 - Pumphouse - Sections - Reinforcement.
- 238-13-0310-115 - Pumphouse Grounding

rev no	date	revision	by	chk	app
R6	Nov. 16.69	Bases A to H deleted	WE		WE
R5	30.10.69	Trash rack details, manhole cover & Stoplog cover details added.	R.S.	J.H.	
R4	26 Sept. 69	Grade slab & details added	R.S.	J.H.	
R3	18 Sept. 69	Details added	R.S.	J.H.	
R2	26 Aug. 69	Released for wall construction	R.S.	J.H.	
R1	1 Aug. 69	General Revision; Former Dwg. Nr. 238-06-0110-008 P.	R.S.	J.H.	

CONSTRUCTION ISSUE

NEWFOUNDLAND AND LABRADOR POWER COMMISSION

HOLYROOD GENERATING STATION

PUMPHOUSE - ELEVATED FLOOR PLAN - CONC. OUTLINE.

SHAWMONT RESOURCES JOINT VENTURE

1047 YONGE STREET, TORONTO 5, ONTARIO

Civil	Mech.	Elect.

Struct. Dept.	Mech. Dept.	Elect. Dept.	Instr. Dept.

scale 1/4" = 1'-0"
date 2 MAY 1969
designed K.H. drawn I.B. / R.S.
checked approved

J. K. RILEY — LICENCE TO PRACTICE

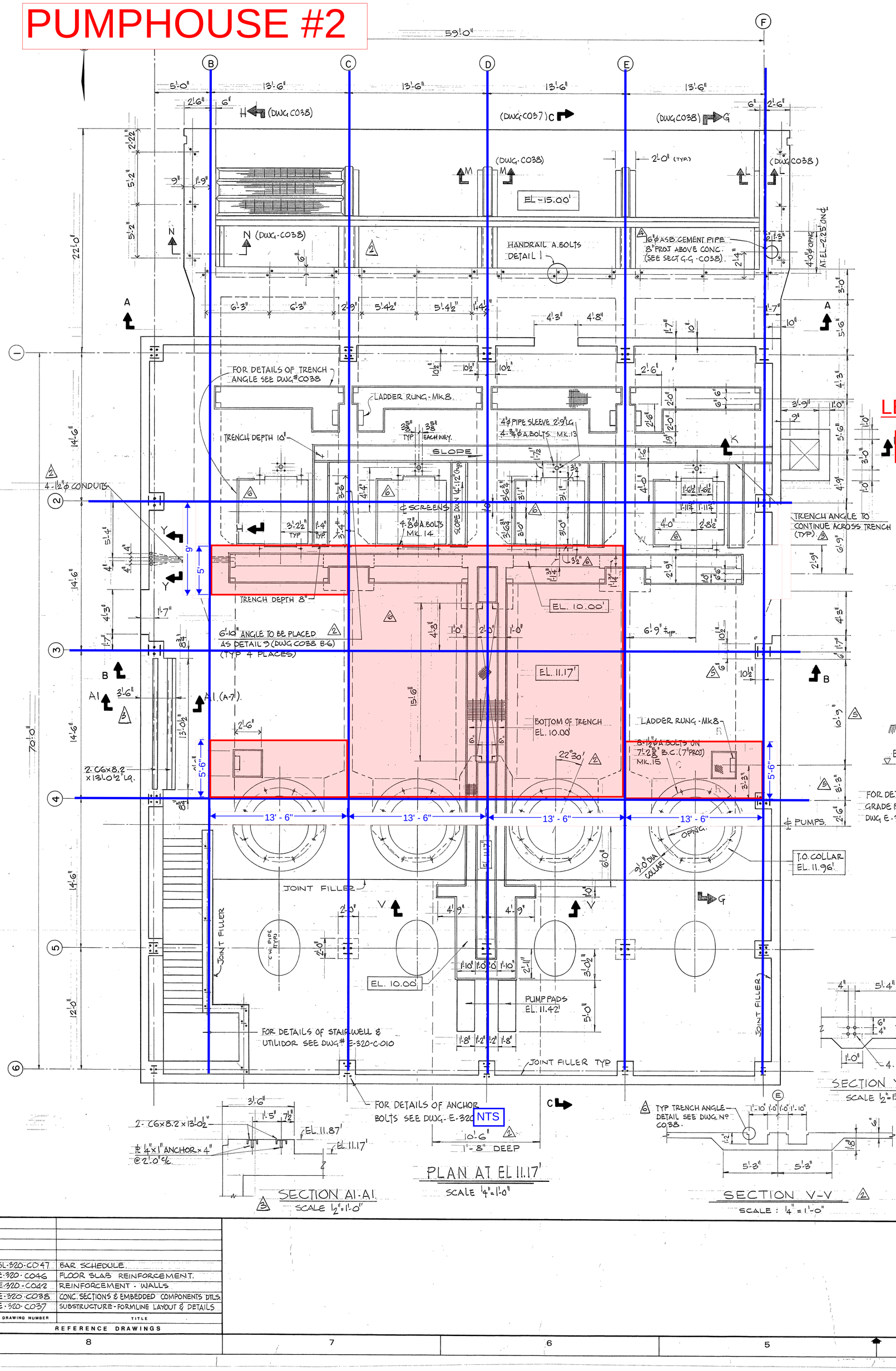
238-06 0110

010 - R6

Perform Level 2 Condition Assessment Stage 1 & 2 Cooling Water Sump Structures (2022) – Holyrood
Appendix A, Page 10 of 13

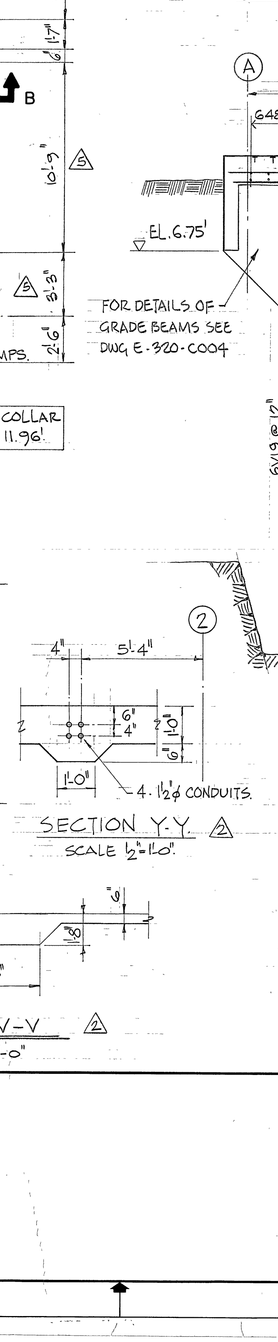
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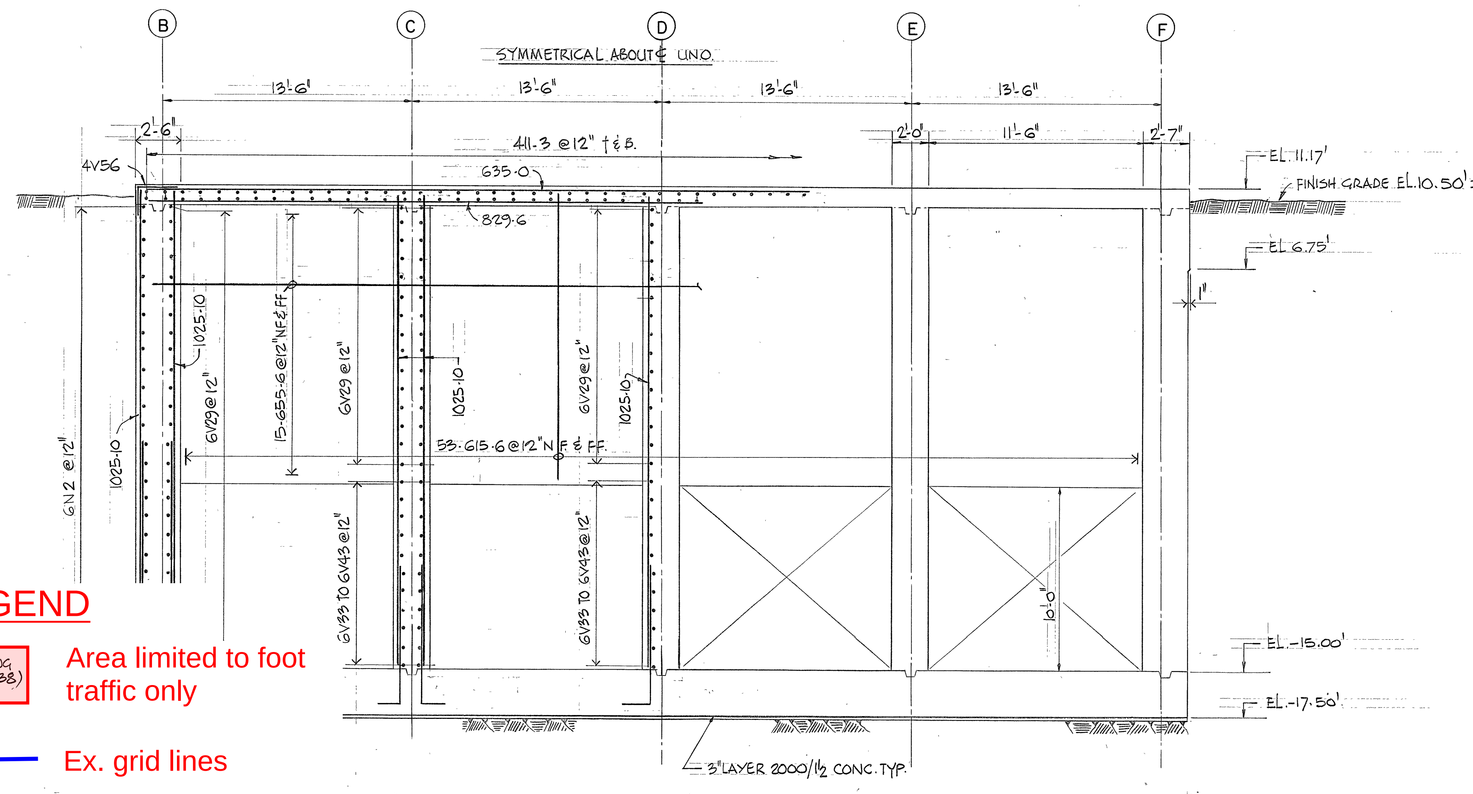
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PLAN AT EL 11.17'

SCALE 1/4"=1'-0"





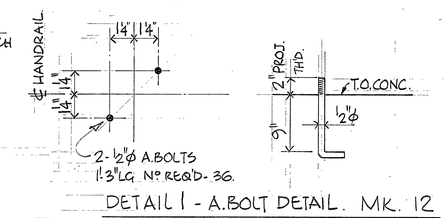
SECTION B-B

SCALE 1/4"=1'-0"

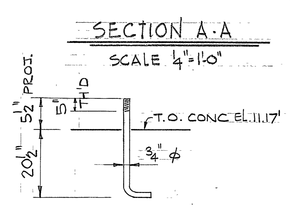
LEGEND

(DWG. C038) Area limited to foot traffic only

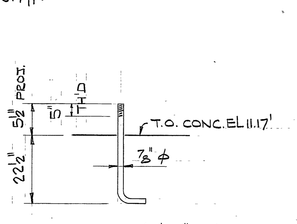
Ex. grid lines



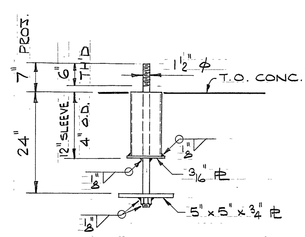
DETAIL 1 - A.BOLT DETAIL. MK. 12



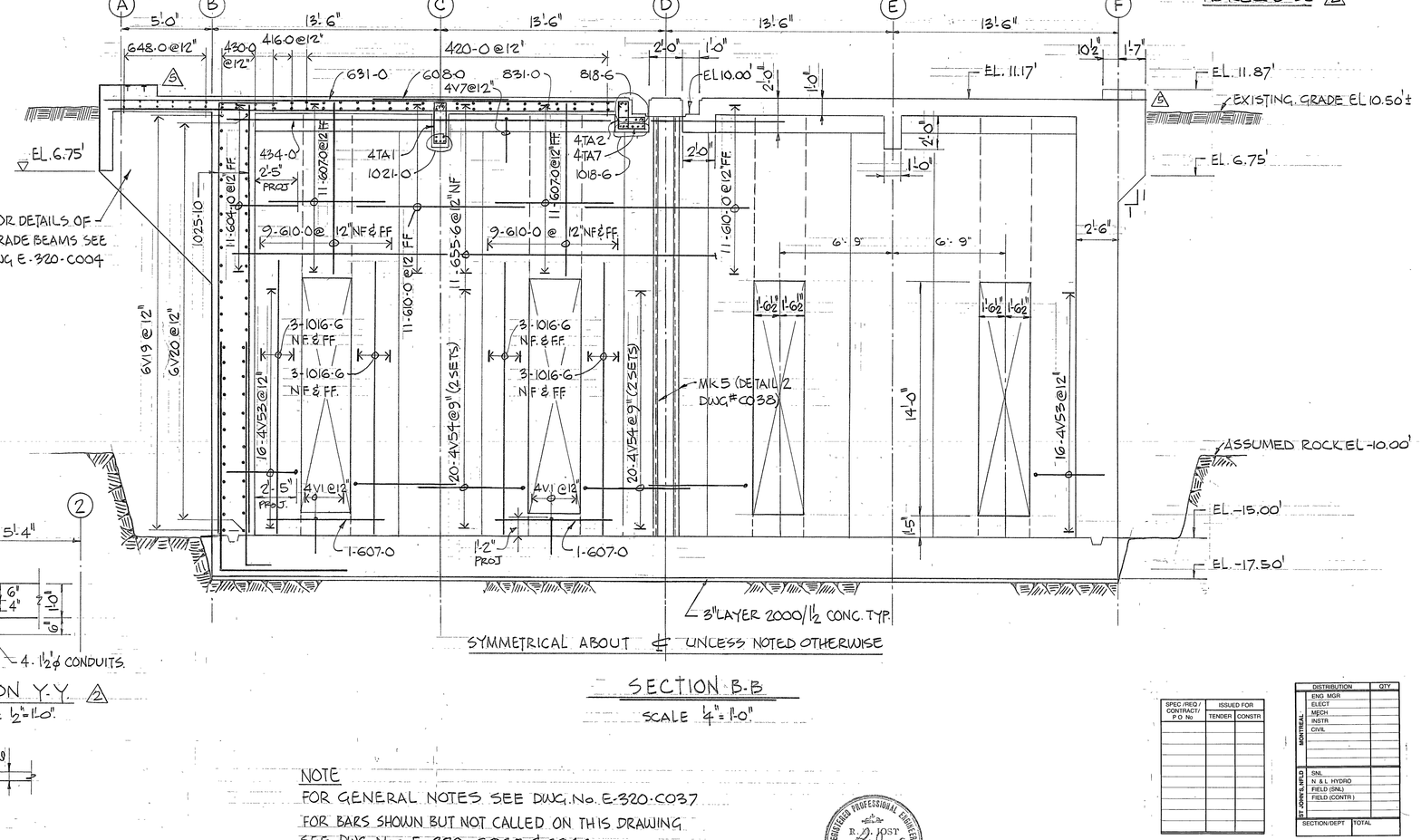
A. BOLT MK. 13 (2'-6" LG.) No REQ'D 16



A. BOLT MK. 14 (2'-8" LG.) No REQ'D - 16



A. BOLT MK. 15 No REQ'D-32



SECTION B-B

SCALE 1/4"=1'-0"

NOTE

FOR GENERAL NOTES SEE DWG. No. E-320-C037

FOR BARS SHOWN BUT NOT CALLED ON THIS DRAWING SEE DWG. Nos E-320-C042 & C046.

SPEC. REQ / CONTRACT / P.O. No	ISSUED FOR TENDER	ISSUED FOR CONSTR

DISTRIBUTION	QTY
ENG. MGR.	
ELECT.	
MECH.	
INSTR.	
CIVIL	
CONSTRUCTION	
CIVIL	
N. & L. HYDRO	
FIELD (SNL)	
FIELD (CONTR.)	
SECTION/DEPT	TOTAL

DRAWING NUMBER	TITLE
REFERENCE DRAWINGS	
E-320-C047	BAR SCHEDULE.
E-320-C046	FLOOR SLAB REINFORCEMENT.
E-320-C042	REINFORCEMENT - WALLS
E-320-C038	CONC. SECTIONS & EMBEDDED COMPONENTS DTLS.
E-320-C037	SUBSTRUCTURE - FORMLINE LAYOUT & DETAILS

NO	DATE	LOCATION	DESCRIPTION	MADE BY	CIVIL	ELECT.	MECH.	I & C	CONST.	CLIENT
REVISIONS					APPROVED					
7	79/5/24		AS BUILT		JP	JED				
6	86-1-28	D-28,3 E-3,4	SCREEN OPGS REVISED, PADS REMOVED 4 PLACES	R.K.						
5	82-11-17	C-5	LARGE DOOR OPENG REVISED	R.K.						
4	17-11-77	E-5	A.S.B. PIPE ADDED	R.K.						
3	28-10-77		TENDER ISSUE CONTRACT 3923							
		C-8, A-7, D-5	CONC. PEDESTAL ADDED TRENCH ANGLE REVISED	R.K.						
2	19-10-77		CONDUITS ADDED & GEN. REV.	R.K.						
1	26-7-77		ISSUED FOR CONSTRUCTION.	J.H.						
0	1-11-76		ISSUED FOR TENDER.	J.H.						

APPROVED FOR CONSTRUCTION
SEP 20 1977
APPROVED BY: V.M. Parrish
MANAGER, ENGINEERING

PASSED

DESIGNED
DRAWN R. H. H.
CHECKED J.H.
RECOMMENDED

WORK ORDER 1403

HYDRO — CONSTRUCTION ISSUE AS BUILT

NEWFOUNDLAND AND LABRADOR HYDRO

HOLYROOD GENERATING STATION - STAGE II

ENGINEERING AND DESIGN BY SHAWMONT NEWFOUNDLAND LIMITED ST. JOHN'S, NEWFOUNDLAND

NEW PUMPHOUSE FLOOR SLAB, SECTIONS & REINFORCEMENT

SCALE	DATE	DWG NO	REVISION
AS SHOWN	1 NOV. 76	E-320-C006	7

Autodesk Docs://E-320 Columbia Substation Shop Drawings/E-320-C006.dwg 2022-05-11

Programs and Projects under $750,000

Programs and Projects

Under $750,000



Description of Newfoundland and Labrador Hydro ("Hydro") Proposed Programs and Projects Under $750,000 by Investment Class ($000)

General Plant			
Title	**Total Spend**	**Project/Program**	**Description**
Upgrade Core OT Infrastructure (2025)	674.3	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 Energy Management System ("EMS") servers and storage infrastructure to ensure Hydro has a reliable and secure environment to support EMS operations. These upgrades to core Operating Technology ("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.
Install Electric Vehicle Chargers (2025–2026) – Hydro Sites	656.1	Program	To support the continued integration of electric vehicles ("EV") into its fleet, Hydro is proposing to install additional EV chargers at Hydro-owned sites across the province. The installation of EV chargers will ensure that Hydro fleet EVs can be readily charged and available. Hydro intends to install 20 Level 2 EV chargers at 6 Hydro-owned sites across the province.
Install Fire Protection in 230 kV Stations (2025–2026) – Come by Chance	586.2	Project	The Come by Chance Terminal Station 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 Come by Chance 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.
Replace GPS Clocks (2025–2026)	580.7	Project	Hydro uses Global Positioning System ("GPS") clocks at its operational sites. These systems are critical for providing precision time reference to communications equipment to maintain synchronization and timestamping of events. The clocks Hydro is currently using to provide time reference are reaching their end of service life and are no longer supported by the manufacturer. This project includes the replacement of GPS clocks with currently supported models to prevent issues with post incident analysis and time reference in modern equipment.

General Plant (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Purchase Personal Computers (2025)	575.6	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 2025 to maintain adequate service levels for business continuity and ensure electronic business data is secure.
Replace 48 V Battery Banks and Chargers (2025)	559.1	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. The Uninterruptable Power Supply battery banks at Hydro Place are also reaching end of life and require replacement under this program. 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 operational sites including generating plants, terminal stations, microwave repeater sites, and control structures, 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.
Upgrade Energy Management System (2025–2026)	472.9	Program	This program proposes an 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. This upgrade is planned for implementation in 2026, in line with the established two-year upgrade cycle; however, the planning and design stages of the program must begin in 2025 to meet required timelines.

[1] Volts direct current ("Vdc").

General Plant (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Install Power Canal Public Safety Boom (2025) – Upper Salmon	463.8	Project	Hydro has a responsibility to manage public safety risks that could be caused by their dams and related water retaining structures, and the operation of those structures. This project includes the installation of a public safety boom to address public safety risks at the Upper Salmon Power Canal. The public safety boom will prevent access to high velocity zones in waterways, acting as a control measure to prevent harm to the public. The boom was identified as a control measure in a public safety risk assessment to help treat the public safety risk associated with the Upper Salmon Power Canal, along with signage and fencing, which has since been installed in previous years.
Install CCTV Systems (2025)	440.1	Project	To address physical security concerns, Hydro currently operates Internet Protocol based Closed Circuit Television ("CCTV") systems at some operating sites. This project is required to expand Hydro's coverage of CCTV systems to 12 additional Hydro sites. These systems are required to improve physical security at Hydro's sites and to enable the ability to detect and/or deter unauthorized access and theft. These activities represent a safety risk to public and personnel, and financial risk to Hydro and its customers; installation of such equipment will mitigate these risks.
Replace Network Communications Equipment (2025)	413.2	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 41 switches with functionally-equivalent devices based on their criticality and operational impact.

General Plant (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Implement SCADA Points Application (2025–2026)	385.3	Project	Supervisory Control and Data Acquisition ("SCADA") points are critical components of the EMS, providing supervisory control and data acquisition of field devices to manage, monitor and control the interconnected power system. Hydro currently manually maintains a collection of spreadsheets, which are stored in a web-based collaborative platform to manage approximately 30,000 SCADA points across 75 sites. Each spreadsheet manages sensitive and critical information on network devices across all sites. This project will see the creation of a custom application that will assist with the management of field point additions, modifications, removals, development, testing and commissioning more securely, efficiently, and reliably.
Purchase Surveying Software and Equipment (2025)	316.4	Project	Hydro has an internal team of geomatics technologists who complete surveys and collect geographic data to support capital work. Survey data is required to meet a standard of accuracy and precision to support the monitoring of dams and hydraulic structures, transmission and distribution projects, topographic land data, and general site development, where required. The surveying equipment and software currently in use is considered obsolete by industry standard, and is experiencing an increase of failures, resulting in extended downtime for repairs. Under this project, Hydro is proposing to replace the surveying equipment and software in line with industry standard in order to restore equipment reliability, reduce down time associated with equipment maintenance, and provide personnel with equipment.
Upgrade Remote Terminal Units (2025)	238.4	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 Energy Control Center, 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 2025, 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.

General Plant (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Replace Peripheral Infrastructure (2025)	205.4	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 2025, the program will replace approximately 40 printing devices, one plotter, and three display units.
Modify Office Buildings and Procure Furniture, Fixtures and Equipment (2025)	178.5	Program	Hydro is required to perform office retrofits and purchase office furniture, tools and equipment to support operations at its office facilities. Existing furniture and equipment assets have a short average lifespan of approximately five years; as such, unanticipated failures and deterioration of these assets are likely to occur. Office retrofits are typically driven by changes in the organizational structure, which requires spatial changes in the physical environment, or unforeseen requests to accommodate departmental or individual employee needs. This program allows for the immediate capital refurbishment and replacement work required in such cases, with the 2025 scope focusing on Hydro Place. Purchases may include new equipment to address in-service failures, or purchases of capital spares. Any delay of replacing existing equipment that has failed or is under performing, or accommodating the needs of the changing business, has the potential to disrupt business operations or performance levels.

General Plant (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Perform Level 2 Condition Assessment – Powerhouse Slope (2025) – Cat Arm	169.4	Project	The Cat Arm Hydroelectric Generation Station ("Cat Arm") powerhouse was constructed at the base of a rock face slope, which is in close proximity to the powerhouse on three sides. Rock and debris can regularly be found at the base of the rock face and, occasionally, in close proximity to the Cat Arm powerhouse. The impact of rock falls near the powerhouse creates concern for the safety of workers in the area, as well as, the reliable operation of the nearby powerhouse and associated equipment. This project involves the completion of a Level 2 Condition Assessment of the Cat Arm powerhouse slope rock faces. The assessment will include recommendations for any required remediation measures, which can then be used to develop detailed engineering documents to complete such work. The condition assessment will start the process of ensuring the reliable operation of Cat Arm by protecting the sites essential infrastructure and the safety of its employees.
Refurbish Meteorological Stations (2025)	167.8	Project	Hydro operates several meteorological measurement stations in the Bay d'Espoir and Cat Arm reservoirs which measure and log various environmental parameters such as precipitation, temperature, humidity, wind, and elevation/water level. Each station regularly transmits this data back to Hydro's EMS where it is used to make critical decisions related to hydrology and reservoir operations and system production. Current meteorological data logging equipment at six of Hydro's meteorological sites are at the end of their useful life and contain obsolete equipment that cannot be appropriately maintained to ensure consistent and reliable data reporting. This project involves the refurbishment of the equipment at these sites with modern devices that are calibrated to ensure accurate data collection.

General Plant (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Perform Security Improvements (2025)	160.7	Project	This project involves the installation of new access control systems on all of the stairwell doors at Hydro Place, as well as the switchboard/receptionist door. The access control system includes a card reader, electronic door contact, a request to exit button at each door, and a controller at each floor level. There are 17 access-controlled doors in total. The scope of work also includes installation of two card access controlled key cabinets. Card access lock hardware and controls for the internal stairwells and switchboard/reception room will improve security access for both staff and contractors who need to access Hydro Place after hours. In addition, card controlled key lock boxes will provide efficient access to fleet vehicle keys in Hydro Place after hours.
Purchase Mobile Devices (2025)	160.2	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.
Update Cyber Security Infrastructure (2025)	115.6	Program	Hydro's computer systems and network infrastructure require continuous protection from cyber threats. In 2025, this program will refresh Hydro's cybersecurity infrastructure by implementing multi-factor authentication for critical network devices and completing cyber asset inventory. Hydro proposes this program to ensure it has adequate cybersecurity tools to mitigate security threats to 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**
Telecommunications In-Service Failures (2025)	94.1	Program	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.
Mandatory			
Title	**Total Spend**	**Project/Program**	**Description**
Purchase Meters and Metering Equipment (2025–2026)	724.6	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.
Inspect Fuel Tanks (2025) – Holyrood	608.0	Project	Inspection of the four fuel oil storage tanks, identified as Tanks 1, 2, 3 and 4, at the Holyrood Combustion Turbine ("Holyrood CT") is required to ensure compliance with regulatory requirements, identify necessary maintenance and repair items, and maximize forecasted remaining asset service life. Fuel storage Tanks 1 and 2 have reached their ten-year service life and, in accordance with the terms and conditions of the Certificate of Approval ("COA"), they must undergo their initial out-of-service inspection in 2025. Failure to complete the inspection will violate the terms and conditions of the COA and could result in the cessation of generating activities at the Holyrood CT.

Renewal			
Title	**Total Spend**	**Project/Program**	**Description**
Inspect Fuel Tanks (2025) – Stephenville	676.9	Project	Inspection of fuel storage tanks is required to ensure compliance with regulatory requirements, identify necessary maintenance and repair items, and maximize forecasted remaining asset service life. In 2025, Hydro will inspect the fuel oil storage tanks at the Stephenville Gas Turbine. The fuel storage tanks at the Stephenville Gas Turbine have exceeded their ten-year inspection interval; failure to complete the proposed inspections presents an unacceptable risk to the continued reliable operation of the unit. The completion of the proposed inspections will highlight internal tank defects, enable the completion of identified refurbishments, and extend the service life of the assets. Failure to complete the proposed inspections could result in the development of fuel leaks; which may necessitate environmental remediation, result in reduced plant fuel storage capacity, and potentially impact the availability of the generating unit.
Install Breaker Failure Protection (2025–2027) – Holyrood	665.2	Project	Breaker failure protection is a form of protective relaying, in which the failure of a breaker to open and interrupt current will cause the surrounding breakers to open, to ensure the system is appropriately isolated. This includes tripping adjacent breakers in the same station as well as adjacent stations, as required. The 230 kV breaker failure relaying at the Holyrood Terminal Station ("Holyrood TS") is at the end of its useful service life, has condition concerns, and is not compliant with Hydro's current standards. The upgrade of the 230 kV breaker failure protection at the Holyrood TS is necessary to maintain the reliability of the power system protection.

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Perform Major Inspection – Synchronous Condenser 2 (2025–2026) – Wabush	595.6	Program	This program supports the reliable operation of synchronous condensers through optimal timing of condition assessment and refurbishment. The Level 2 Condition Assessment requires the synchronous condensers to be partially dismantled to complete electrical testing and the inspection of bearings, resistance rings, stators, rotors, and other internal components. It also requires the rotor to be pulled from the unit for a thorough inspection. These activities on synchronous condensers are required to identify equipment, environmental, safety, and reliability deficiencies. To support the continued safe and reliable operation of the Wabush Terminal Station, Hydro recommends completing the scope of Synchronous Condenser 2 Level 2 Condition Assessment and Refurbishment Program in 2025 and 2026. Preparation of contract documentation and technical conditions will take place in 2025, with the assessment and refurbishment activity occurring in 2026.
Gas Turbine In-Service Failures (2025)	500.0	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.
Perform Level 2 Condition Assessment – Intake 4 and Unit 7 Draft Tube (2025) – Bay d'Espoir	471.5	Project	Bay d'Espoir Intake 4 was installed in 1976 and supplies water to Bay d'Espoir Unit 7 through a buried steel penstock. An assessment completed on Bay d'Espoir Intake 1 in 2016, which is of similar vintage to Intake 4, indicated that there were varying levels of deterioration, particularly in the submerged and embedded components. This project involves the completion of a Level 2 Condition Assessment of Intake 4 and the Draft Tube, including embedded parts and draft tube gates. This information will aid Hydro in the development of a plan to refurbish Intake 4 and the draft tube at an appropriate time to to extend their service life and ensure the safe and reliable operation of Bay d'Espoir Unit 7.

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Replace Instrument Transformers (2025–2026)	468.9	Program	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. Under this program, five instrument transformers will be replaced. Two of these units are being replaced due to age and poor condition and three of these units are being 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.
Replace Terminal Station Battery Banks and Chargers (2025–2026)	438.5	Program	Battery banks and chargers are used to supply dc[2] power to critical terminal station components (such as circuit breakers, protection and control relays, and disconnect switch motor operators) and provide ac[3] 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.
Replace Roof (2025) – Grey River	390.8	Project	The Grey River Powerhouse roofing system is comprised of a flat, steel roof deck, topped with an inverted roof assembly, and has exceeded its service life. The powerhouse roof is no longer able to provide an adequate level of weather tightness; and in recent years the formation of leaks in the facility have increased in frequency. These leaks disrupt operations and pose a risk to the sensitive equipment that is housed within the facility. The continued formation of leaks and ingress of water could result in equipment damage and result in a plant outage. Hydro is proposing the replacement of the existing powerhouse roofing system to restore its integrity, prevent the reoccurrence of leaks, and mitigate the risk of water infiltration.

[2] Direct current ("dc").
[3] Alternating current ("ac").

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Upgrade Data Alarm Systems (2025–2026) – Hardwoods	372.7	Project	The Hardwoods Terminal Station ("Hardwoods TS") data alarm system provides alarm notifications based on station abnormalities. Primary system equipment and protection relays trigger the data alarm system when anomalies and/or alarms occur. The existing local window main annunciator of the Hardwoods TS data alarm system has exceeded its useful service life. Module failure could lead to long-term deficiencies with the annunciator operation; impacting Hydro's ability to effectively respond to equipment issues at the Hardwoods TS as the level of alarm granularity is reduced. Due to the existing annunciator reaching obsolescence, and the fact that Hardwoods TS will remain one of the critical 230 kV terminal stations for the foreseeable future, it requires a reliable means of monitoring the alarm state of the terminal station. This project will upgrade the existing data alarm system at the Hardwoods TS to support the continued reliable operation of the station.
Replace 250 Vdc Battery Bank (2025-2026) – Stephenville	369.9	Project	The 250 Vdc battery bank at the Stephenville Gas Turbine is used to supply DC power to critical components (such as DC auxiliary fuel forwarding pump, auxiliary lube pump, generator hydraulic jacking pumps, governor hydraulic pumps, and emergency lighting). This battery bank is recommended for replacement based on age, as this asset is nearing the end of its serviceable life. Failure to replace this asset could result in a loss of dc power and the inability to start the unit in a black start scenario; resulting in a forced outage until the battery bank is replaced, or until primary ac station service is restored.
Replace Human-Machine Interface (2025) – Stephenville	277.0	Project	The Stephenville Gas Turbine Human-Machine Interface ("HMI") consists of hardware and software components that control and monitor plant equipment. Software installed on the HMI provides control, setpoint adjustments, alarms, trip actions, and historical information collection of connected equipment. The HMI is a critical component of operations for the Stephenville Gas Turbine, which has exceeded its service life for several years as the asset had been planned for decommissioning. As communicated in Hydro's 2024 Resource Adequacy Plan,[4] Hydro is supporting the continued operation of the unit beyond 2024; thus it is now prudent to complete the upgrade.

[4] "2024 Resource Adequacy Plan: An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, July 9, 2024.

Renewal (Cont'd)			
Title	**Total Spend**	**Project/Program**	**Description**
Replace Circuit Breaker Reclosing Controllers (2025–2026) – Cow Head and Massey Drive	269.0	Project	The existing reclosing controllers for the 230 kV rated circuit breaker B1L48 at Massey Drive Terminal Station and the 66 kV rated circuit breaker B1L27 at Cow Head Terminal Station have reached the end of their useful life, have condition concerns, and do not comply with Hydro's P&C standard. This project proposes to upgrade these two controllers with two modern microprocessor-based reclosing controllers. This will further improve the dependability, security, and service continuity of power transmission of the 230 kV line TL248 and 66 kV line TL227 in the event of a fault experienced by these lines.
Transmission In-Service Failures (2025)	184.3	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.
Update Flame Scanners – Unit 3 (2025) – Holyrood	140.6	Project	Flame scanners are instruments that are used to detect the presence of flame on a burner inside of the boiler, and sends that information back to the Burner Management System. In the event of a burner flameout, the flame scanner will detect the absence of flame and the system will cut fuel to that burner to avoid buildup of non-combusted fuel that could create a dangerous explosive environment inside the boiler. Unit 3 has nine flame scanners, one for each burner. This project will upgrade the existing flame scanner system on Unit 3, which is obsolete and no longer being supported by the original equipment manufacturer. Without upgrading the flame scanners there is a risk to the operation of Unit 3, and a risk that the available capacity of the unit will be decreased.

Service Enhancement			
Title	**Total Spend**	**Project/Program**	**Description**
Remove Safety Hazards (2025)	203.3	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*.
Perform Minor Telecommunications Enhancements (2025)	99.8	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.