newfoundland labrador hydro
a nalcor energy company

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www.nlh.nl.ca

July 31, 2018

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

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon**:**

Re: Newfoundland and Labrador Hydro – 2019 Capital Budget Application

Please find enclosed nine (9) copies, plus the original, of Hydro's 2019 Capital Budget Application (the Application), in two (2) volumes, filed in accordance with the Provisional Capital Budget Application Guidelines issued by the Board of Commissioners of Public Utilities (the Board) in October 2007 and in accordance with the guidelines and conditions for capital budget proposals as outlined by the Board in Order No. P.U. 7(2002-2003). Through this Application, Hydro is seeking approval of $115.9 million in capital expenditures. Hydro is also seeking approval of its 2013 and 2014 average rate base in the amounts of $1,546.9 million and $1,621.0 million, respectively.

The 2019 Capital Budget Application financial schedules include a planned total value of $118.2 million. However, the application seeks approval of $115.9 million as it excludes the 2019 portion of the 2018-2019 Muskrat Falls to Happy Valley Interconnection project ($2.3 million) as approval of this project, which was proposed as part of Hydro's 2018 Capital Budget Application, remains before the Board.

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

Hydro trusts that you will find the enclosed to be in order and satisfactory. Should you have any questions or comments about any of the enclosed, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Michael S. Ladha
Legal Counsel & Assistant Corporate Secretary
MSL/sk

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
Dennis Browne, Q.C. – Browne, Fitzgerald, Morgan & Avis

ecc : Denis J. Fleming – Cox & Palmer
Sheryl Nisenbaum – Praxair Canada
Van Alexopoulos - Iron Ore Company
Senwung Luk - Labrador Interconnected Group
Dean Porter – Poole Althouse
Larry Bartlett – Teck Resources Ltd.
Benoît Pepin - Rio Tinto

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Application

IN THE MATTER OF the *Public Utilities Act*, (the "*Act*"); and

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2019 capital budget pursuant to s.41(1) of the *Act*; (2) its 2019 capital purchases, and construction projects in excess of $50,000 pursuant to s.41(3) (a) of the *Act*; (3) its leases in excess of $5,000 pursuant to s. 41(3) (b) of the *Act*; and (4) its estimated contributions in aid of construction for 2019 pursuant to s.41(5) of the *Act*; and for an Order pursuant to s.78 of the *Act* fixing and determining its average rate base for 2013 and 2014.

TO: The Board of Commissioners of Public Utilities (the Board)

THE APPLICATION OF NEWFOUNDLAND AND LABRADOR HYDRO (Hydro) STATES THAT:

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*.

2. Section A to this Application is Hydro's proposed 2019 Capital Budget in the amount of approximately $115.9 million prepared in accordance with the guidelines and conditions outlined in Order No. P.U. 7(2002-2003) and the Capital Budget Application Guidelines issued October 29, 2007.

3. Section B to this Application is Hydro's proposed 2019 Capital Budget with single and multi-year projects listed separately and prepared in accordance with the guidelines and conditions outlined in Order No. P.U. 7(2002-2003) and the Capital Budget Application Guidelines issued October 29, 2007.

4. Section C to this Application is a list of the proposed 2019 Construction Projects and Capital Purchases for $500,000 and over, prepared in accordance with Order No. P.U. 7(2002-2003) and the Capital Budget Application Guidelines.

5. Section D to this Application is a list of the proposed 2019 Construction Projects and Capital Purchases for $200,000 and over, but less than $500,000, prepared in accordance with Order No. P.U. 7(2002-2003) and the Capital Budget Application Guidelines.

6. Section E to this Application is a list of the proposed 2019 Construction Projects and Capital Purchases in excess of $50,000 but less than $200,000 prepared in accordance with Order No. P.U. 7(2002-2003) and the Capital Budget Application Guidelines.

7. Section F contains no new leases proposed for 2019 in excess of $5,000 per year.

8. Section G to this Application is a Schedule of Hydro's Capital Expenditures, actuals for 2017 and budgeted for 2018 and beyond, for the period 2014 to 2023.

9. Section H to this Application is a report on the current 2018 capital expenditures to June 30, 2018 and any associated variances between the approved budget and the forecasted total budget.

10. Section I sets out the 2013 and 2014 rate base for Hydro.

11. Volume II to this Application contains the supplementary reports referred to in various capital budget proposals greater than $500,000.

12. The proposed capital expenditures for 2019 as set out in this Application are required to allow Hydro to continue to provide to its customers service and facilities which are reasonably safe, adequate and reliable as required by Section 37 of the *Act*.

13. Hydro has estimated the total of contributions in aid of construction for 2019 to be approximately $294,000 for distribution upgrades and service extensions. The information contained in the 2019 Capital Budget (Section A) takes into account this estimate of the contributions in aid of construction to be received from customers. All contributions to be recovered from customers shall be calculated in accordance with the relevant policies as approved by the Board.

14. Communications with respect to this Application should be forwarded to Michael S. Ladha, Legal Counsel and Assistant Corporate Secretary, Telephone: (709) 737-1268, P.O. Box 12400, St. John's, Newfoundland and Labrador, A1B 4K7, Fax: (709) 737-1782.

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

(1) Approving Hydro's 2019 Capital Budget as set out in Section A hereto, pursuant to section 41(1) of the *Act;*

(2) Approving Hydro's 2019 Capital Purchases and Construction Projects in excess of $50,000 as set out in Sections C, D, and E hereto, and its leases as set in Section F, pursuant to section 41(3) of the *Act*; and

(3) Approving the proposed estimated contributions in aid of construction as set out in paragraph 13 hereof for 2019 as required by section 41(5) of the *Act,* with all such contributions to be calculated in accordance with the policies approved by the Board.

(4) Fixing and determining Hydro's average rate base for 2013 and 2014 in the amounts of $1,546,930,000 and $1,620,982,000, respectively, pursuant to section 78 of the Act.

DATED at St. John's in the Province of Newfoundland and Labrador this 31st day of July 2018.

NEWFOUNDLAND AND LABRADOR HYDRO

Michael Ladha,
Counsel for the Applicant
Newfoundland and Labrador Hydro,
500 Columbus Drive, P.O. Box 12400
St. John's, Newfoundland, A1B 4K7
Telephone: (709) 737-1268
Facsimile: (709) 737-1782

IN THE MATTER OF the *Public Utilities Act*, (the "*Act*"); and

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2019 capital budget pursuant to s.41(1) of the *Act*; (2) its 2019 capital purchases, and construction projects in excess of $50,000 pursuant to s.41(3) (a) of the *Act*; (3) its leases in excess of $5,000 pursuant to s. 41(3) (b) of the *Act*; and (4) its estimated contributions in aid of construction for 2019 pursuant to s.41(5) of the *Act*; and for an Order pursuant to s.78 of the *Act* fixing and determining its average rate base for 2013 and 2014.

AFFIDAVIT

I, James R. Haynes, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am President, Newfoundland and Labrador Hydro, the Applicant named in the attached Application.
2. I have read and understand the foregoing Application.
3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador,)
this 31st day of July, 2018,)
before me:)

Barrister – Newfoundland and Labrador

James R. Haynes

2019 Capital Projects Overview

July 2018

newfoundland labrador hydro
a nalcor energy company

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1 Introduction

Pursuant to the provisions of the *Hydro Corporation Act, 2007*, the *Electrical Power Control Act, 1994*, and the *Public Utilities Act*, 1990, Hydro is required to provide reliable service to its customers. The provision of safe, reliable, least-cost supply of electricity requires that Hydro continuously maintain, refurbish, renew, and expand its generation, transmission and distribution assets and other assets that support those systems. Hydro must also address changing environmental and regulatory requirements and challenges that often require the development and integration of new assets or improvements to existing. Hydro's long-term planning initiatives are developed in the context of the following key drivers:

1. The interconnection between Labrador and the Island via the HVdc link (Labrador-Island Link);
2. the interconnection of the Island with Nova Scotia system via the Maritime link;
3. continued load growth on the Avalon Peninsula; and
4. considerations for the impact of forecast increases in electricity rates for customers.

This Overview discusses the material changes made during execution in 2018 that affect current and future projects and the projects proposed for 2019. Discussion of the five-year plan is contained in the section entitled "*2019-2023 Capital Plan*" (Volume I).

2 2018 Execution

Volume I, Section H, of the 2019 Capital Budget Application (2019 CBA) contains the Status Report, including financial tables for capital projects as of June 30, 2018, and project variances and explanations. The explanations include changes that are in progress, but have yet to be reflected in the expenditures forecast. These changes to the plan include:

- The cancellation of the *"Install Breaker Bypass Switch – Howley Project."*
- the removal of scope and budget in the *"Upgrade Circuit Breakers – Various Site Project*," and
- the advancement of the overhaul portion of the *"Turbine Hot Gas Path Level 2 Inspection and Overhaul - Holyrood Gas Turbine"* to the fall of 2018.

These three changes have been incorporated into the 2019 CBA with appropriate adjustments to the 2019 capital plan. Also included in the Status Report is a summary of work completed to-date or in-progress for each of the 2018 In-service Failures projects for the Thermal Generation, Hydraulic Generation, and Terminal Stations.

3 2019 Plan Considerations

Maintaining Hydro's systems in reliable operating condition is accomplished through a combination of 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 lower life cycle costs, improve operational characteristics, increase capacity for load growth, correct reliability criteria violations, improve productivity, and increase efficiency.

The majority of Hydro's installed assets, including the hydroelectric installation at Bay d'Espoir, the Holyrood Thermal Generating Station, the Stephenville Gas Turbine, the Hardwoods Gas Turbine, and much of Hydro's transmission and distribution systems, are more than 40-50 years old.

The sustaining capital proposals, contained in this and previous applications, focus on appropriate maintenance or replacement of existing assets with consideration given to asset age, condition, and performance, as well as availability of more efficient technologies. The cost of Hydro's sustaining capital programs is expected to increase as a result of ongoing condition assessments of aging assets. In other cases, newer, more efficient technologies (e.g. LED lighting) justifies the replacement of equipment.

The age of Hydro's assets also has implications for efficient operating methods. A portion of Hydro's generating plants were constructed at a time when systems and auxiliary equipment were manually operated. With the automation and remote operation of equipment, operating methods have changed, allowing for enhanced safety and efficiency. Included in this Application are proposals to implement automation or improvements in the control and monitoring of equipment. An example is the installation of a recloser remote control for the Rocky Harbour Terminal Station, which allows the Energy Control Centre to remotely de-energize and re-energize the feeders from the station enabling line crews to focus on the issues on-site and reduce the duration of outages.

In the development of a capital proposal, consideration is given to:

- system performance and reliability criteria;
- Hydro’s long-term asset management strategy;
- mandatory criteria (including legislative, Board Orders, safety, or environmental risks);
- load growth and system planning criteria;
- maintenance history;
- condition assessment;
- performance assessment;
- cost efficiencies;
- operating experience;
- changing operating conditions;
- familiarity with equipment;
- operating and maintenance cost; and
- professional engineering and operations judgment.

There are three broad categories of replacement criteria:

- Time and condition based: hours of operation and condition; for example diesel generators (100,000 hours of operation) and vehicles (combination of years and operating hours for some classes);
- Condition based: for example, transmission line wood poles; and
- Technical assessment based: an evaluation of reliability, performance, condition, costs and other factors results in a capital proposal, such as the inspection of fuel tanks and subsequent upgrade, where required.

The 2019 planned capital expenditure totals $118.2[1] million, which includes budgets for previously approved projects, reduced from $146.7M as was submitted in the 2018 CBA for 2019. Hydro continues to advance its processes with respect to asset condition review and is working toward refinement of capital expenditure timelines for its assets.

3.1 Specifically Assigned Assets

A portion of Hydro's asset base is specifically assigned to one of the following industrial customers: Vale Canada Limited, NARL Refining Limited Partnership (NARL), Teck Resources Limited, Corner Brook Pulp and Paper Limited. Specifically assigned assets function to serve a single customer exclusively. The 2019 CBA includes one project that will be specifically assigned to NARL within the Terminal Station Refurbishment and Modernization Project, namely the installation of online dissolved gas analysis (DGA) equipment on the Come By Chance Transformers T1 and T2 to allow for real-time monitoring of dissolved gasses in oil. Continuous monitoring enables Hydro to reduce unplanned outages and lessen the probability of equipment in-service failure. Additional details regarding this project can be found in Volume II, Tab 6: Terminal Station Refurbishment and Modernization Proposal (Section 2.1.4 Refurbish and Upgrade Power Transformers and Table 4) and Overview documents (On-line Oil Analysis section). No other specifically assigned capital projects are included in the 2019 CBA or are currently included in the 5-year Capital Plan. All four industrial customers were contacted by Hydro in May 2018 to discuss the 2019 CBA and the 5-year plan with respect to their specifically assigned assets. Should the DGA project for the Come-By-Chance Transformers T1 and T2 be approved, Hydro will provide cost and schedule updates to NARL during execution on an agreed time frame with respect to the DGA project.

4 2019 Capital Budget

The 2019 CBA contains 54 new projects, as shown in Volume I, Capital Budget. These new projects include the refurbishment of generation facilities, maintenance of gas turbine generation equipment, and modernization and upgrade of terminal stations. The 2019 planned capital

[1] The 2019 Capital Budget Application financial schedules include a planned total value of $118,168,800; however, the application only seeks approval of $115,921,800, and excludes the 2019 portion of the 2018-2019 Muskrat Falls to Happy Valley Interconnection project ($2,247,000) since this project remains before the Board.

expenditure totals $118.2 million, which includes budgets for previously approved projects. The 2019 CBA also includes approximately $322,000 for Front End Engineering and Design (FEED) expended in 2018 to support the development of proposals on a number of projects. All 2019 projects address the need to sustain and/or expand the existing asset base to meet growing customer demand, while improving reliability and adhering to Hydro's principles of safety and environmental responsibility.

Figure 1 shows the 2019 Capital Budget Summary by major area. The categories, other than the Allowance for Unforeseen Items, are discussed further in the following sections.

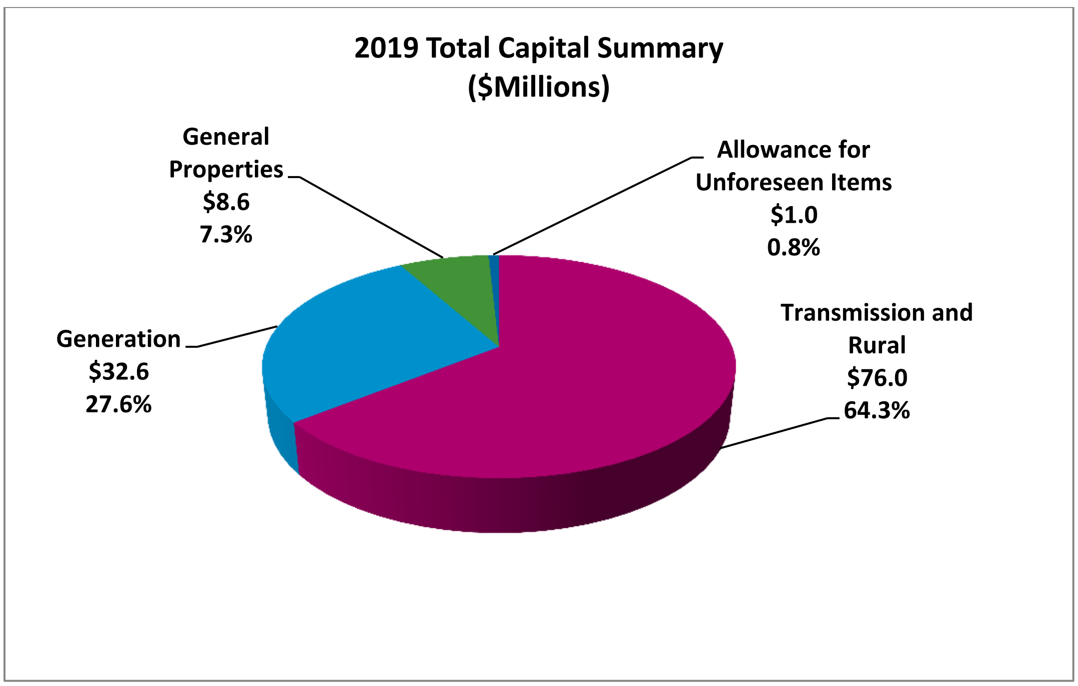

Figure 1: 2019 Capital Budget - Summary

4.1 Generation

On the Island Interconnected System, electricity is provided by Hydro through a mix of hydroelectric and fossil fuel fired generation, supplemented by power purchases.

The planned Generation area expenditures of $32.6 million account for 27.6% of overall expenditures for 2019. The division of the 2019 Capital Budget for the Generation area among Hydraulic Plant, Thermal Plant, and Gas Turbines expenditures is shown in Figure 2. The five-year (2013 to 2017) average capital expenditures for generation are shown in Figure 3.

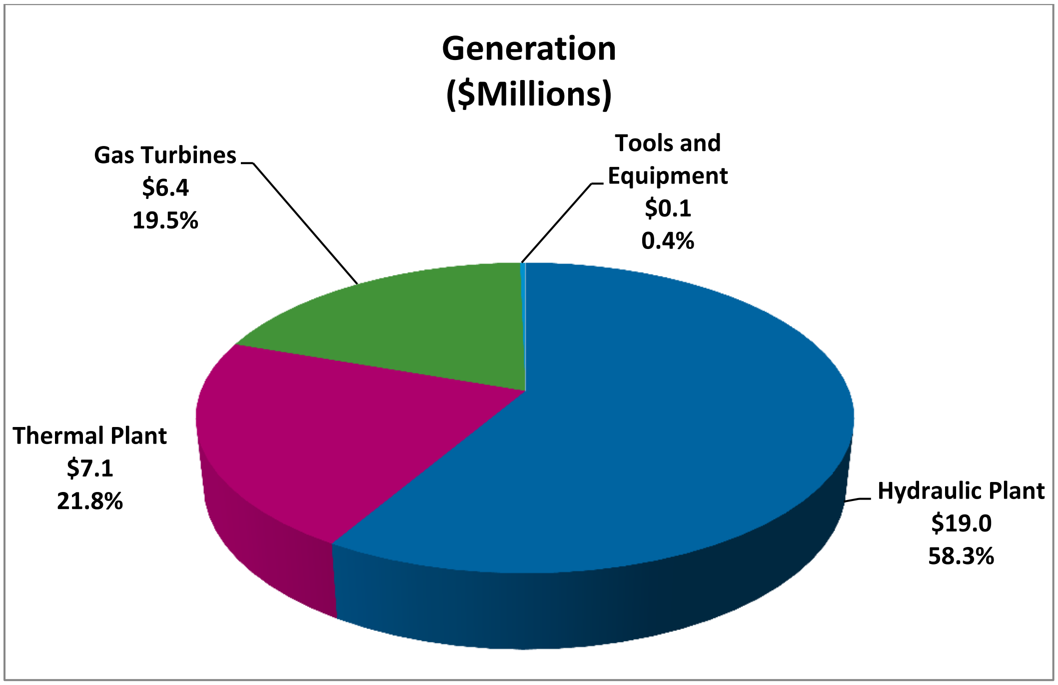

Figure 2: 2019 Capital Budget - Generation

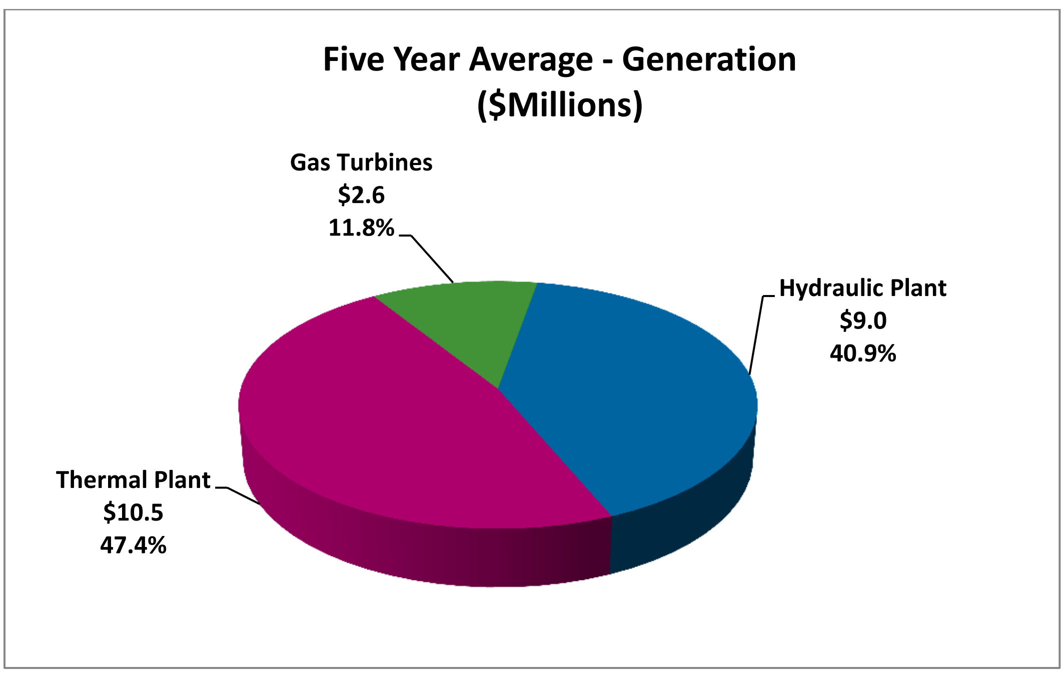

Figure 3: Five-Year Average Capital Expenditures – Generation (2013-2017)

The capital cost for hydraulic plant projects has increased compared with the average over the past five years. As referenced in Section 4.1.1, the increase in hydraulic plant expenditures is primarily a result of the need to refurbish aging assets, particularly at the Bay d'Espoir Hydroelectric Generation Facility (Bay d'Espoir), which was originally constructed in the late 1960s.

2019 thermal plant budget estimates are lower than the five-year average. The thermal plant continues to require major capital expenditures as the majority of the equipment and systems have exceeded their expected life cycle and, in some cases, have undergone life extension. As referenced in Section 4.1.2, expenditures are required to ensure that these important generating assets can continue to operate reliably for customers until they are retired and replaced.

2019 gas turbine expenditures are forecast to decrease compared with the five-year average. Although there is a decrease in Gas Turbine expenditures, as referenced in section 4.1.3, there remains a need to maintain the reliability of the Hardwoods and Stephenville facilities and ensure reliability of the Holyrood gas turbine asset, which was added to Hydro's generation asset fleet in 2015.

4.1.1 Hydraulic Plant

Hydro's major hydraulic generating plants range in age from 15 to 51 years. Capital expenditures are required to ensure their continued reliability and to maximize the useful operating lives of these assets. Many components of the hydraulic generating stations are nearing, or have reached, the end of their expected service lives in the older plants.

In 2019, Hydro is proposing to continue the *"Hydraulic Generation Refurbishment and Modernization Project"* that consolidates planned hydraulic generation-sustaining work into a single project. This project proposal has been materially updated based on feedback from the Board and intervenors during the review of the 2018 CBA in an effort to improve understanding and provide the necessary detail for review of the project. All 2019 activities are focused on sustaining the Hydraulic assets, with no additional standalone projects.

Since 2016, Hydro has executed several unplanned supplemental and allowance for unforeseen items capital projects to refurbish the three penstocks serving Bay d'Espoir Powerhouse 1. Bay d'Espoir Penstock 1 experienced three ruptures between 2016 and 2017, and all three penstocks have had weld refurbishment and plate re-enforcement projects completed since the first rupture in May 2016. Although there are no planned penstock capital projects proposed in the 2019 CBA, Hydro has developed updated plans for the operating and capital work for the penstocks in the system. Please refer to the *"2019-2023 Capital Plan"* (Volume I), Section 4.1 for details on the current and future penstock maintenance plan.

4.1.2 Thermal Plant

The three units of the Holyrood Thermal Generating Station (Holyrood) have now exceeded their generally expected service life of 30 years. Holyrood remains critical to the supply of reliable power to the Island Interconnected System, as it serves the base load of the system and will be required to do so in the short to medium term. No changes are expected in terms of the maintenance strategy for Holyrood, as the plant is expected to produce electricity with a high level of reliability during the extended construction period for the Muskrat Falls Project. Scheduled condition assessments and maintenance will continue to ensure Hydro can reliably meet customer demand.

The long-term operational plan for this facility has been developed in the context of the development of Muskrat Falls with a high voltage direct current (HVdc) transmission link to the Island (Labrador Island Link). Holyrood will remain a critical facility during the construction and commissioning of the Muskrat Falls Project. When the Labrador Island Link goes into service, the Holyrood plant will continue to be an essential component of the Island Interconnected System. Initially, the plant will function as a fully capable standby facility during the early years of operation of the HVdc system. After this initial period, the thermal assets will be decommissioned and the facility will be partially converted to a synchronous condensing facility.

The challenges faced by Hydro are complex as circumstances require that Holyrood operate in a manner quite different than that normally required of a thermal plant. The conventional practice is that a thermal plant is base-loaded throughout its life until it reaches maturity and is then operated as a peaking or standby facility in its final years, operating at a very low capacity factor, often less than 10%. The Holyrood thermal plant has passed the age at which other utilities have performed condition assessment and life extension studies, similar to Hydro's approach, and have either retired their facilities or have initiated major life extension projects. However, until the Muskrat Falls Generating Plant is completed and power is brought to the Island Interconnected System via the Labrador Island Link, the Holyrood plant must continue to operate at or near its historical levels with annual capacity factor in the range of 35% to 45% and at higher levels through the winter period when availability is critical to meet peak demand. The Holyrood capital projects contained in this application are necessary to refurbish and renew assets that are at the end of their useful service lives, and which must be replaced to maintain reliability through to the completion of the Muskrat Falls development.

Please see the Holyrood Overview section for further discussion pertaining to the proposed 2019 Holyrood projects.

4.1.3 Gas Turbines

Located at the Holyrood Thermal Generating Station site, the Holyrood Gas Turbine is a 123.5 MW gas turbine that has been in service since February 2015. It was installed to provide long-term generation capacity for the Island Interconnected System. The 2019 CBA includes one project for the Holyrood Gas Turbine – the upgrade to the compressed air system. This project is required to ensure that the existing system is rated for continuous duty, including compressed air required during unit stand-by.

Hydro's gas turbine plants at Stephenville and Hardwoods are more than 40 years of age, exceeding the generally accepted life expectancy of 25 to 30 years for gas turbine plants. Hydro has included a report on the Hardwoods and Stephenville gas turbine assets in the 2019 CBA within Appendix D of the *"2019-2023 Capital Plan"* (Volume I). Capital proposals in the 2019 CBA for these two facilities are to meet short-term requirements while Hydro completes the Supply Adequacy report, scheduled for submission to the Board in November 2018. All projects included in the 2019 CBA for Hardwoods and Stephenville are single-year projects, and were prioritized and selected to ensure the reliability of these facilities given their age, operating regime, and operational forecast. As the results of the Supply Adequacy report are not yet available, the proposed projects in 2019 are what is necessary to operate the plants and will remain unchanged in the plan regardless of the outcome of the Supply Adequacy study. The results of the study will, however, have a direct impact on the Hardwoods and Stephenville capital plans for 2020 and beyond. Hydro will provide an updated long-term Capital Plan for Hardwoods and Stephenville as part of the 2020 Capital Budget Application.

4.2 Transmission and Rural Operations

Hydro owns and operates 21 isolated rural diesel generation plants throughout Newfoundland and Labrador. Hydro owns and operates almost 4,000 kilometers of transmission lines and more than 50 high voltage terminal stations at voltages of 230, 138 and 69/66 kV. As per P.U. 37 (2016) and P.U. 7(2017), Hydro now owns and operates the Wabush Terminal Station and has long-term subleases on the two 230 kV transmission lines Between Churchill Falls and Wabush, both of which were previously owned by Twin Falls Power Corporation Limited (TwinCo). In addition, Hydro owns and operates approximately 3,400 kilometers of distribution lines, principally in rural Newfoundland and Labrador.

Hydro's Transmission and Rural Operations assets are replaced based on condition, and require ongoing capital expenditures to maintain reliable service, to comply with environmental regulations, and to ensure the safety of employees, contractors, and the general public.

Expenditures in the Transmission and Rural Operations area account for 64.3% of overall expenditures for 2019, totaling $76.0 million. Figure 4 shows the division of the 2019 Capital Budget for Transmission and Rural Operations and Figure 5 provides the five-year average expenditures for this area.

The increase in expenditures for Terminal Stations over the five-year average is largely a result of: the Wabush Terminal Station refurbishment proposal; refurbishment and upgrade of power transformers and the protection, control, and monitoring equipment; and replacement of instrument transformers, disconnect switches, and insulators, which are all encompassed within the *"Terminal Station Refurbishment and Modernization Project".*

The increase in Rural Generation over the five-year average expenditure is primarily attributable to the proposed overhaul and upgrade of diesel generators in multiple communities required for continued reliability and also the continuation of the installation of a secondary fuel containment system liner in Nain for environmental protection.

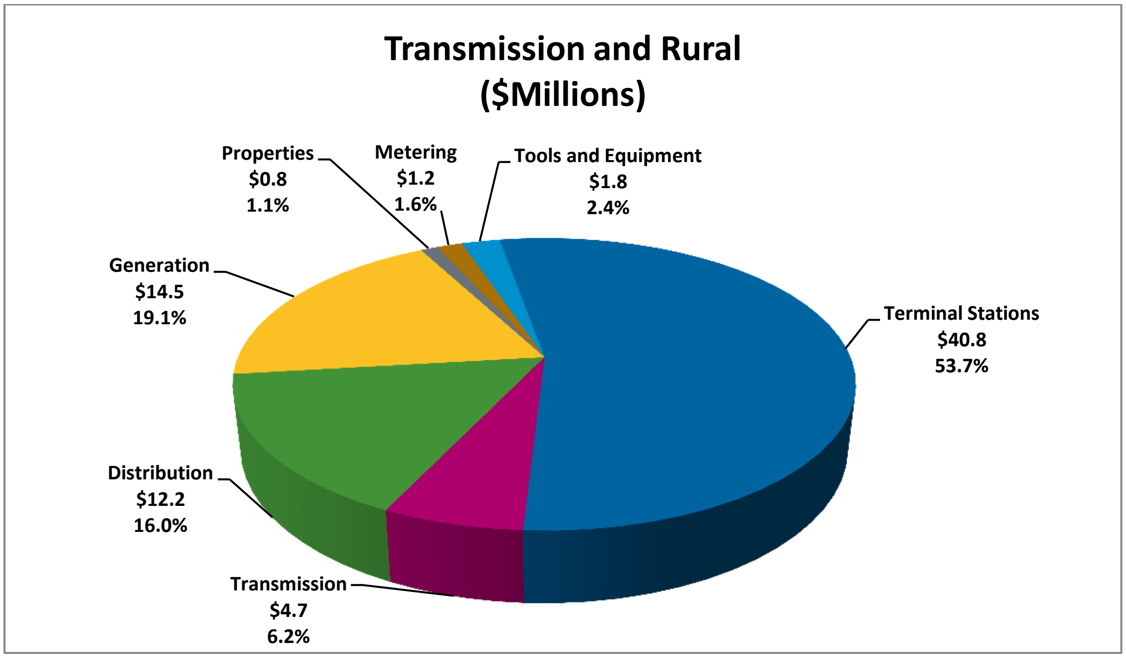

Figure 4: Capital Budget – Transmission and Rural Operations

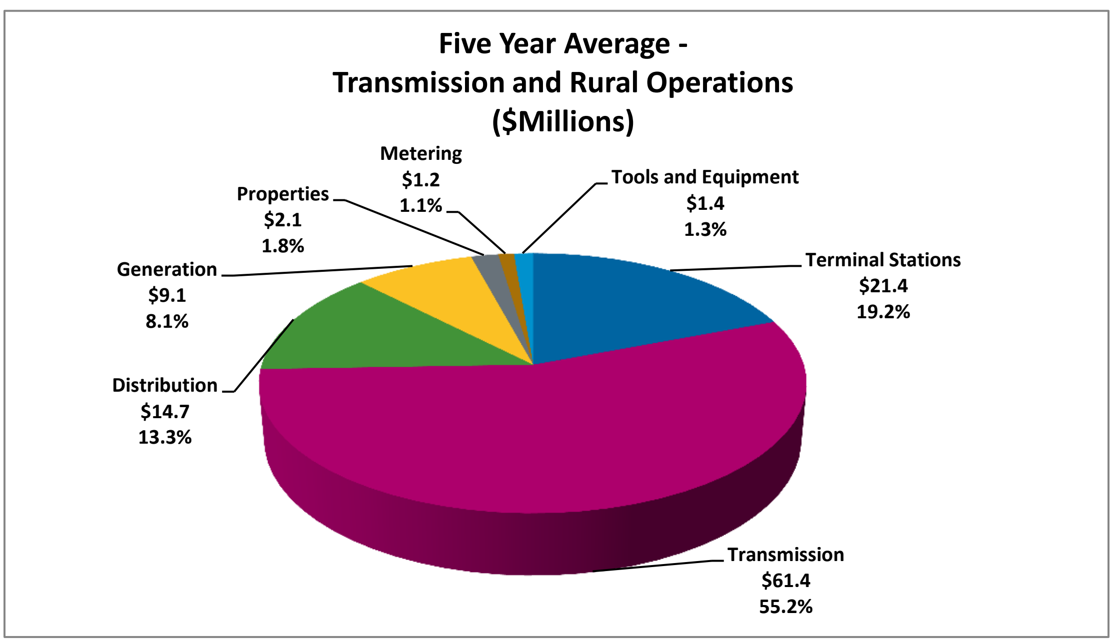

Figure 5: Five-Year Capital Expenditures – Transmission and Rural Operations (2013-2017)

4.2.1 Terminal Stations and Transmission

Many of Hydro's transmission lines and terminal stations were constructed in the 1960s with expected useful lives in the range of 40 years. Reconstruction and general upgrades are needed to ensure that Hydro can continue to provide customers with reliable electrical service. Within the 2019 submission, projects are proposed for the continued upgrade of power transformers and circuit breakers, as well as the replacement of surge arrestors, instrument transformers, and disconnect switches.

In recent years new transmission projects raised the average historical expenditure; however, 2019 does not include any new transmission projects. The only transmission project proposed in the 2019 CBA is the Wood Pole Line Management Program. Hydro has provided a Wood Pole Line Management 2019 update in Appendix C of the *"2019-2023 Capital Plan"* (Volume I).

The *"Muskrat Falls and Happy Valley Interconnection Project (2018-2019)"* was proposed in the 2018 CBA and is with the Board. Given that a decision whether the project will proceed has not yet been provided, this project remains in the capital plan, as proposed. It should be noted that the $2,247,000 included in the plan has not been included in the application amount for the 2019 CBA. This accounts for the 2019 CBA financial schedules include a planned total value of $118,168,800; however, the application only seeks approval of $115,921,800, and excludes the 2019 portion of the Muskrat Falls to Happy Valley Interconnection project.

4.2.2 Distribution and Rural Generation

The 21 remote electrical systems along the coasts of Labrador and on the Island of Newfoundland are primarily served by diesel generation. Providing service to customers in these communities requires that the fuel storage, diesel generating units, facilities, and distribution systems all be kept in safe, reliable, and environmentally responsible working order. This application includes projects specifically directed towards safely meeting load growth requirements, including the additions for customer load growth in isolated communities and the ongoing installation of fire protections systems in diesel plants. In addition, engine overhauls and replacements will be completed in various diesel plants. This Application also includes proposals that target efficiency improvements and other projects focused on the reduction of environmental risks.

Hydro also provides service to residential and general service customers on the Island and Labrador interconnected systems. Hydro has included projects in this Application that are intended to ensure that distribution lines and equipment that require replacement due to condition are replaced prior to failure, thereby reducing the probability of interrupting service to customers. These projects include the upgrade of the distribution systems in various locations. This Application also includes projects to provide service extensions to new customers throughout Hydro's service area.

4.3 General Properties

The General Properties classification's expenditures account for 7.3% of the overall expenditures for 2019, with $8.6 million in proposed capital projects. The General Properties classification includes projects related to Hydro's information systems, where technology is strategically deployed in a wide variety of business applications. This section of the Application also includes proposals for vehicle replacements and telecommunications system replacements, which are all necessary for the provision of reliable and cost-effective service to customers. Figure 6 and Figure 7 show the breakdown of the General Properties Capital Budget for 2019 and the previous five-year average, respectively.

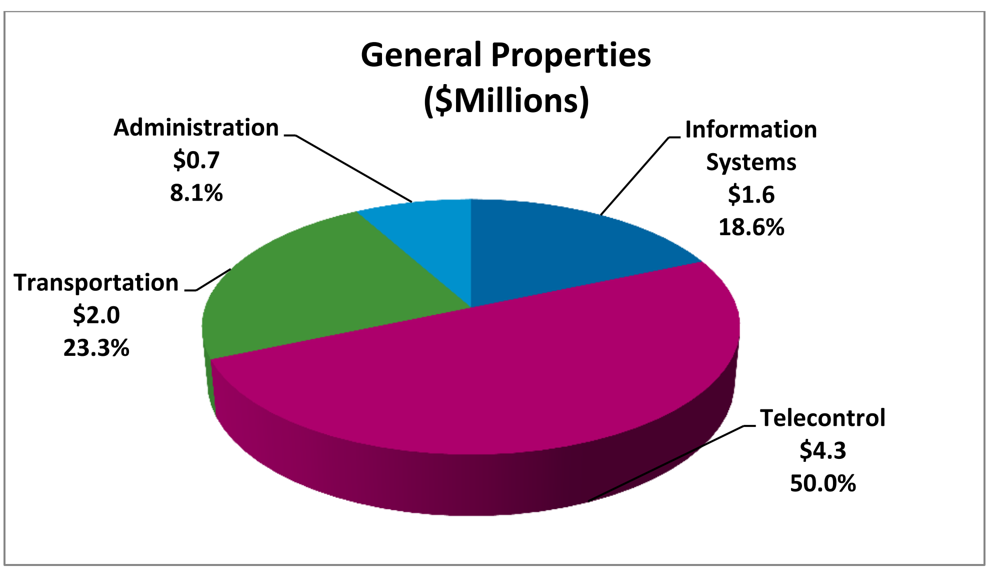

Figure 6: 2019 Capital Budget – General Properties

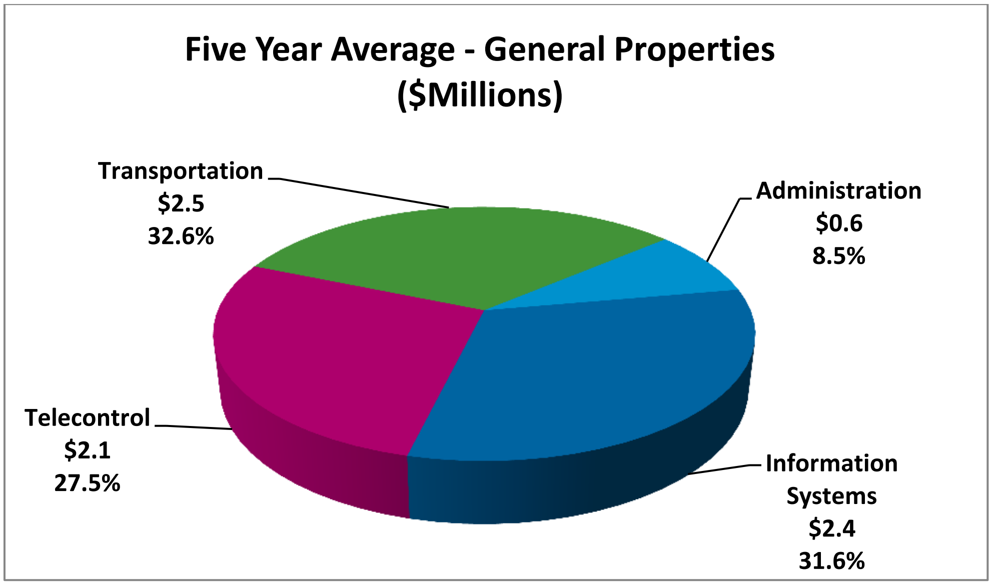

Figure 7: Five-Year Average Capital Expenditures – General Properties (2013-2017)

4.3.1 Information Systems

The Information Systems proposals are directed towards maintaining Hydro's computing capacity and associated infrastructure, ensuring that it remains current and reliable. Projects include upgrades to the software applications used throughout Hydro, upgrades to the energy management system, as well as the replacement of personal computers and peripheral infrastructure.

4.3.2 Telecontrol

Operating an integrated electrical system requires reliable communication systems across Hydro's province-wide facilities both to control equipment and to support employee communications, many of whom work in remote locations. The 2019 capital budget proposals in this area include infrastructure replacements and upgrades, ongoing replacement or refurbishment programs for such items as microwave antenna radomes, network communications equipment, and other equipment that is part of the communications infrastructure.

5 General

5.1 Project Prioritization and Ranking

An overall ranking of 2019 projects is included in this report as Appendix A.

5.2 Projects by Definition and Classification

Table 1 and Table 2 list the 2019 proposed projects by definition and classification, respectively.

Table 1: Projects by Definition

Type	Number	($000)
Clustered	0	0.0
Pooled	48	197,824.2
Other	39	66,671.8
Total	**87**	**264,496.0**

Table 2: Projects by Classification

Type	Number	($000)
Normal	81	246,730.8
Justifiable	5	14,675.6
Mandatory	1	3,089.6
Total	**87**	**264,496.0**

5.3 Phase 1 Engineering Costs

Hydro has tracked the Front End Engineering and Design (FEED) costs specific to each project and these costs form part of the 2019 capital budget submission. Therefore, Hydro's 2019 capital projects include Phase 1 engineering costs that were incurred in association with the related 2019 capital projects and Hydro proposes that the inclusion of these costs be approved.

Hydro has included Phase 1 costs in its capital budget proposals only in those cases where the Phase 1 costs exceed $1,000 for that specific project. Phase 1 costs related to any specific project not receiving Board approval will not be capitalized. The total of these costs included in the 2019 capital budget submission is approximately $322,000.

Appendix A

2019 Project Prioritization

Prioritization Explanations

Table A1 shows the ranking of Hydro's 2019 capital projects. Rank 1 indicates the projects of the highest importance and in 2019 with no projects with a ranking of more than 29 included in the Application. Projects that received the same score through the prioritization process have the same ranking. The five projects which are classified as Rank 1 are considered high priority projects required to address safety, mandatory, or system load issues. Please note that the non-prioritized projects marked with an "*" in the table are the continuation of multi-year projects.

Table A1: 2019 Project Prioritization

Project Description	2019 Cost ($000)	Rank	Cumulative Project Costs ($000)
Multi-Year Projects (2019 is 2nd or 3rd Year)	60,036.0	*	60,036.0
TRO Service Extensions and Upgrades	8,170.0	*	68,206.0
Transportation	3,457.7	*	71,663.7
Tools and Equipment	802.1	*	72,465.8
Allowance for Unforeseen Items	1,000.0	1	73,465.8
Additions for Load Growth - Distribution Systems	186.7	1	73,652.5
Additions for Load Growth - Isolated Generation Stations	1,523.6	1	75,176.1
Inspect Fuel Storage Tanks - Grey River	203.1	1	75,379.2
Remove Safety Hazards - Various Sites	197.5	1	75,576.7
Condition Assessment and Miscellaneous Upgrades - Holyrood	1,968.8	2	77,545.5
Diesel Plant Fire Protection (2019-2020)	377.2	3	77,922.7
Overhaul Unit 3 Turbine Valve - Holyrood	3,290.5	4	81,213.2
Replace Main Fuel Valves - Hardwoods	404.2	5	81,617.4
Overhaul Olympus Gas Generator - Stephenville	1,666.8	6	83,284.2
Wood Pole Line Management Program - Various Sites	2,467.0	7	85,751.2
Hydraulic Generation Refurbishment and Modernization	9,093.7	8	94,844.9
Terminal Station Refurbishment and Modernization	10,891.1	9	105,736.0
Distribution System Upgrades (2019-2020)	390.8	10	106,126.8
Hydraulic In-Service Failures	1,250.0	11	107,376.8
Thermal In-Service Failures	1,250.0	11	108,626.8
Terminal Station In-Service Failures	1,000.0	11	109,626.8

Project Description	2019 Cost ($000)	Rank	Cumulative Project Costs ($000)
Diesel Genset Replacements (2019-2020)	526.5	12	110,153.3
Overhaul Diesel Units - Various Sites	2,511.3	13	112,664.6
Upgrade Human Machine Interface and Automatic Voltage Regulator – Hardwoods	685.9	14	113,350.5
Install Recloser Remote Control - Rocky Harbour	66.1	15	113,416.6
Upgrade Diesel Plant Building - Ramea	352.5	16	113,769.1
Replace 258 VDC Battery Banks - Holyrood	330.0	17	114,099.1
Upgrade Telecontrol Facilities - Bay d'Espoir Hill and Gull Pond Hill	96.3	18	114,195.4
Upgrade Terminal Station for Mobile Substation - St. Anthony	89.3	19	114,284.7
Replace Human Machine Interface - Cartwright	306.9	20	114,591.6
Replace Teleprotection Bay d'Espoir to Sunnyside - TL202 and TL206	196.8	21	114,788.4
Condition Assessment of Submarine Cables Farewell Head to Fogo	300.1	22	115,088.5
Upgrade Compressed Air System - Holyrood Gas Turbine	70.7	23	115,159.2
Upgrade Line Depots - Roddickton	344.7	24	115,503.9
Install Pole Storage Ramps - Various Sites	301.7	25	115,805.6
Security Improvements - Hydro Place	47.1	26	115,852.7
Computer Technology System Support	1,597.1	27	117,449.8
Construct Heated Storage for Spare Parts and Lube Oil - Hardwoods	49.8	28	117,499.6
Network Services Infrastructure System Support	670.1	29	118,169.7

Table A2 presents the prioritization criteria and the assigned weights used for the 2019 budget.

Table A2: Prioritization Criteria and Weight Factors

Criteria		Factors	Factor Weights
1	Work Classification (maximum weight = 85)	Normal	5
		Justifiable: Payback (70)	15
		Justifiable: Payback (40)	45
		Justifiable: Payback (10)	85
2	Net present Value (maximum weight = 85)	NPV ($0)	0
		NPV (<$100K)	5
		NPV (<$500K)	15
		NPV (<1M)	45
		NPV (>1M)	85
3	Goal 1: Safety (maximum weight = 100)	Minor	10
		Treatment	50
		Lost Time	80
		Disability	100
4	Goal 2: Environment (maximum weight = 100)	None	10
		Minor	50
		Moderate	80
		Significant	100
5	Goals 3-5: Alignment (maximum weight = 65)	None	15
		Maps but no documentation	40
		Maps but with documentation	65
6	Schedule Risk (maximum weight = 65)	External and internal conflicts	10
		Externals affecting completion	20
		No external but internal conflicts	40
		No conflicts	65
7	Continue service to customers (maximum weight = 70)	Can	20
		Can but with high costs	50
		Cannot	70
8	Number of customers impacted (maximum weight = 70)	<100	10
		<1000	30
		<10,000	50
		>10,000	70
9	System Impact: Critical to … (maximum weight = 90)	None specific	5
		System with standby unit	50
		Plant or station	70
		Entire system	90

	Criteria	Factors	Factor Weights
10	Impact intensity (maximum weight = 90)	Minor	4
		Moderate	40
		Significant	70
		High	90
11	Loss Type: Loss of … (maximum weight = 90)	No type	5
		Equipment	40
		Facility	50
		Production	70
		Customer delivery	90
12	Loss mitigation (maximum weight = 90)	Redundant unit	30
		Backup option	60
		Nothing	90
13	Percent Improvement in 5-Year Average SAIDI or SAIFI (maximum weight = 50)	% SAIDI or SAIFI (0)	0
		% SAIDI or SAIFI (<1)	10
		% SAIDI or SAIFI (<2)	15
		% SAIDI or SAIFI (<3)	30
		% SAIDI or SAIFI (>3)	50
14	Estimated Project Cost Range (maximum weight = 50)	N.R.P.	0
		Cost (>$1M)	5
		Cost ($500K - $1M)	15
		Cost ($200K - $500K)	30
		Cost (<$200K)	50

Level 1

Immediate HIGH Priority Projects

Extreme Safety

The project is required to prevent an incident that could cause a fatality or correct a condition that otherwise left unattended may lead to a fatality.

Mandatory

A capital expenditure that Hydro is obliged to carry out as a result of Legislation, Board Order, Environmental or Safety risk.

Load Driven

The project is needed to meet load requirements determined by Hydro’s latest load forecasts. Without the project, Hydro’s firm load and/or reliability criteria will be compromised.

Level 2

Work Classification

Normal

A capital expenditure which is required based on an identified need or historical patterns of repair and replacement.

Justifiable

A capital expenditure which is justified based on a positive cost savings for Hydro. A cost-benefit analysis is required for the project.

Payback (70)

A cost-benefit analysis indicates that the payback period for the project is within 70% of the anticipated life of the project.

Payback (40)

A cost-benefit analysis indicates that the payback period for the project is within 40% of the anticipated life of the project.

Payback (10)

A cost-benefit analysis indicates that the payback period for the project is within 10% of the anticipated life of the project.

Net Present Value

NPV ($0)

The capital proposal generates $0 cost savings to Hydro.

NPV (<$100K)

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of less than $100K for Hydro.

NPV (<$500K)

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of less than $500K for Hydro.

NPV (<$1M)

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of less than $1M for Hydro.

NPV (>$1M)

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of more than $1M for Hydro.

Goal 1: Safety

Minor

The project has no or minor safety issues that are insignificant in impact.

Treatment

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in the need for medical treatment.

Lost Time

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in worker(s) incurring lost time for a short duration.

Disability

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in worker(s) incurring long time leave due to inability to continue working on the job.

Goal 2: Environment

None

The project has no environmental issues.

Minor

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in an environmental impact that:

- Is irreversible within 2 years; and/or
- Will cost more than $10,000 to mitigate; and/or
- Has aspects observed on Hydro's property (at point of impact); and/or
- Is perceived as in conflict with specific individuals in the local community.

Moderate

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in an environmental impact that:

- Is irreversible within 4 years; and/or
- Will cost more than $25,000 to mitigate; and/or
- Has aspects observed within a 1 km radius of Hydro's property (from point of impact); and/or
- Is perceived as in conflict with the local community or other industries.

Significant

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in an environmental impact that:

- Is irreversible within the foreseeable future; and/or

- Will cost more than $50,000 to mitigate and/or
- Has aspects observed at more than 5 km radius of Hydro's property (from point of impact); and/or
- Is perceived as in conflict with the local community and the general public and other industries.

Goals 3-5 Alignment

None

This project does not align with or support any department or corporate goals or objectives.

Maps but no Documentation

This project does align with or support a department or corporate goal or objective but no documentation exists to describe how it maps to the goal or objective.

Maps but with Documentation

This project does align with or support a department or corporate goal or objective and there is documentation that clearly describes how.

Schedule Risk

Externals and Internal Conflicts

The project has external (to Hydro) dependencies that affect the completion of the project on time and on budget and has major interfaces with other internal initiatives. Examples of external dependencies are: non-Hydro projects that interfere with Hydro proceeding with its project; unavailability of external contractors.

Externals Affecting Completion

The project has only external dependencies that affect the completion of the project on time and on budget.

No Externals but Internal Conflicts

The project conflicts with other internal initiatives that affect the completion of the project on time and on budget.

No Conflicts

The project will not encounter any external or internal conflicts that affect its completion.

Continue Service to Customers

Can

Service to customers can continue whether or not this project proceeds. Customers can be defined as either internal or external to Hydro.

Can but with High Costs

Service to customers can continue whether or not this project proceeds but a delay in the project will result in Hydro incurring costs. Customers can be defined as either internal or external to Hydro.

Cannot

Service to customers cannot continue without this project. Customers can be defined as either internal or external to Hydro.

 # Customers Impacted

<100

The project will impact up to 100 customers.

<1000

The project will impact up to 1000 customers.

<10000

The project will impact up to 10,000 customers.

>10000

The project will impact more than 10,000 customers.

System Impact: Critical to...

None Specific

The project is not critical to any particular system.

System with Standby Unit

The project is critical to a system that has a standby unit which could be used to maintain operation or support continued service in the event of failure.

Plant or Station

The project is critical to the proper operation of a generating plant or a terminal station.

Entire System

The project is critical to ensure the reliable operation of the Hydro system.

Impact Intensity

Minor

If this project does not proceed, the repair time is ***less than half*** the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever comes first).

Moderate

If this project does not proceed, the repair time is ***greater than the half but less than 90%*** of the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever is comes first).

Significant

If this project does not proceed, the repair time is ***within plus or minus 10%*** of the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever is comes first).

High

If this project does not proceed, the repair time ***exceeds by more than 10%*** the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever is comes first).

Loss Type: Loss of...

No Type

If the project does not proceed, no loss is expected.

Equipment

If the project does not proceed, there exists a risk of the loss of some equipment.

Facility

If the project does not proceed, there exists a risk of the loss of a facility.

Production

If the project does not proceed, there exists a risk of the loss of production at a Hydro generating plant.

Customer Delivery

If the project does not proceed, there exists a risk of being unable to deliver power to Hydro customer(s).

Loss Mitigation

Redundant Unit

If the project does not proceed the expected loss will be mitigated by a redundant unit present on the system.

Back-up Option

If the project does not proceed the expected loss will be mitigated by a back-up option which ensures that service continues.

Nothing

This project is required because there is no available means to mitigate the expected loss.

Percent Improvement in 5-Year Average SAIDI or SAIFI

% SAIDI or SAIFI (0)

This project will have no effect on the System Average Interruption Duration Index (SAIDI) or System Average Interruption Frequency Index (SAIFI). All non-reliability projects will receive this rating.

% SAIDI or SAIFI (<1)

This project is expected to improve the SAIDI or SAIFI factor by less than one percent.

% SAIDI or SAIFI (<2)

This project is expected to improve the SAIDI or SAIFI factor by less than two percent but greater than five percent is implied.

% SAIDI or SAIFI (<3)

This project is expected to improve the SAIDI or SAIFI factor by less than three percent but greater than ten percent is implied.

% SAIDI or SAIFI (>3)

This project is expected to improve the SAIDI or SAIFI factor by at least three percent.

Estimated Project Cost Range

N.R.P.

This project is a Non-Reliability Project.

Cost (>$1M)

The cost of the project is estimated to be more than a million dollars.

Cost ($500K - $1M)

The cost of the project is estimated to be between five hundred thousand and a million dollars.

Cost ($200K - $500K)

The cost of the project is estimated to be between two hundred and five hundred thousand dollars.

Cost (<$200K)

The cost of the project is estimated to be less than two hundred thousand dollars.

Probability

Not Likely

The risk of the impact is very low if the project does not proceed. It would be surprising that there is an impact.

Low Likelihood

The risk of the impact is low if the project does not proceed. There is about 30% chance of the impact in the proposal year. It's less likely to happen than not.

Likely

The risk of the impact is possible if the project does not proceed. There is about 50% chance of the impact in the proposal year. It's as likely to happen as not.

Highly Likely

The risk of the impact is considerable if the project does not proceed. There is about 75% chance of the impact in the proposal year. It's more likely to happen than not.

Near Certain

The risk of the impact is almost certain if the project does not proceed. There is more than 90% chance of the impact in the proposal year. It would be surprising if the impact did not occur.

Confidence Level

Low

The confidence in the assessment of the impact is low. There are some uncertainties that could significantly change the assessment. The projects risks are not well defined.

Medium

The confidence in the assessment of the impact is uncertain but most likely correct. There are some uncertainties that might moderately change the assessment. The project risks are defined but with some uncertainty.

High

The confidence in the assessment of the impact is very high. The uncertainties will not measurably change the assessment. The project risks are well defined and well controlled.

2019-2023 Capital Plan

July 2018

Table of Contents

Appendices

1 Introduction

Newfoundland and Labrador Hydro (Hydro) is focused on providing safe, reliable, and least-cost service to its customers. Providing a reliable supply of electrical energy depends on maintaining assets in sound condition. Utility assets are kept in safe and reliable working condition by performing routine maintenance and completing refurbishments and replacements as necessary. Asset additions are also determined through analysis of long-term requirements to address future demands for power and energy.

In Order No. P.U. 30(2007), Hydro was directed to file a five-year capital expenditure plan. The Board of Commissioners of Public Utilities (the Board) indicated the plan should focus on strategic spending priorities beginning with the current year of the Capital Budget Application. As well, the capital expenditure plan should identify shifts in spending priorities over the five-year period, the circumstances contributing to these shifts, and alternative approaches under consideration. Additionally, the Board requested specific focus on the Holyrood Thermal Generating Station (Holyrood), which at the time had an uncertain future due to alternative developments under consideration. With the sanction of the Muskrat Falls Project in December 2012, the future of the Holyrood plant has been established. The Holyrood section of this plan addresses Hydro's forecasted maintenance and capital requirements for the plant for the next five years.

As of December 2017, Hydro maintains an asset base of $2.0 billion. Some assets have reached or exceeded their expected service lives and many others are approaching that juncture. Other major assets have not reached their expected service lives but some of their components, auxiliary equipment and systems have or are about to do so. This includes components of major facilities such as the Bay d'Espoir Generating Station (Bay d'Espoir), the Holyrood Thermal Generating Station (Holyrood), the Hardwoods and Stephenville gas turbines, and much of Hydro's transmission and distribution systems. Hydro uses an asset management framework to manage these assets.

Hydro's Five-Year Capital Plan includes details on the costs and timing of asset replacements and refurbishments. The five-year plan is a living document and is revised on an ongoing basis as new asset condition information becomes available, asset management strategies evolve, and demands and priorities change within asset classes. The five-year plan supports Hydro's responsibility to maintain its infrastructure providing safe, reliable and least-cost electricity for customers.

2 Five-Year Plan Overview

Hydro plans to invest $630.1 million in plant and equipment over the 2019 to 2023 period, resulting in an average annual capital expenditure of $126.0 million. Individual year expenditures will range from a low of $118.2 million in 2019[1] to a high of $133.6 million in 2020.

Over the period 2013 to 2017, the average annual capital expenditure was $141.0 million. The levelling of capital expenditures reflects Hydro's shift from the growth in the asset base over the past several years to sustaining the asset base into the foreseeable future. Overall capital expenditures reflect the requirement for projects related to the replacement and upgrade of deteriorating facilities, ensuring compliance with legislation.

Introduced in the 2017 Capital Budget Application (CBA), the "Terminal Station Refurbishment and Modernization Project" consolidates Hydro's asset management philosophies for terminal stations and guides expenditures in the five-year plan, including the replacement of end of service life circuit breakers. In the 2018 CBA, Hydro introduced the "Hydraulic Generation Refurbishment and Modernization Project" which consolidates Hydro's asset management philosophies for Hydroelectric Generation Stations and ensures that equipment is replaced or refurbished in a planned approach. This project proposal has been materially updated based on

[1] The 2019 CBA financial schedules include a planned total value of $118,168,800, however, the application only seeks approval of $115,921,800, and excludes the 2019 portion of the "Muskrat Falls to Happy Valley Interconnection Project."

commentary from the Board and intervenors during review of the 2018 CBA, in an effort to improve understanding and provide the necessary detail for review of the project. This project will also guide expenditures in the five-year plan. The Wood Pole Line Management Program will also continue over the next five years.

The In-Service Failures Projects for Terminal Stations, Hydraulic Generation, and Thermal Generation will ensure that failed equipment is replaced in an expedited manner.

Gas Turbines will continue to be relied upon to provide stand-by and spinning reserve power and (with the exception of the Holyrood Gas Turbine) to function as synchronous condensers to support voltage control on the Island and Labrador Interconnected Systems. As the results of the Supply Adequacy report are not yet available, the 2019 proposed projects reflect necessary requirements to operate the plants and will remain unchanged regardless of the outcome of the Supply Adequacy study. The results of the study will, however, have a direct impact on the Hardwoods and Stephenville capital plans for 2020 and beyond. Although the five-year plan is included in the application, Hydro will provide an updated long-term Capital Plan for Hardwoods and Stephenville as part of the 2020 CBA based on the results of the Supply Adequacy report and the discussions around the future supply options. A two-year "Combustor Inspection Major and Overhaul Project" is also in the five-year plan for the Holyrood unit.

3 Strategic Spending Priorities

Hydro's strategic spending priorities over the next five years address the following areas:

- Mandatory Issues:
  - Ensuring the safety of Hydro personnel, its contractors, and the general public;
  - compliance with legislative and regulatory requirements; and
  - managing environmental risks.
- meeting projected load growth and customer requests;
- applying a consistent asset maintenance philosophy to ensure system reliability and maintain acceptable asset performance as identified by:

- operating experience;
- maintenance history;
- condition assessments; and
- performance evaluation and monitoring.

- achieving cost efficiencies.

Hydro's detailed Five-Year Capital Plan is presented in Appendix A. Over this period, the level of capital expenditure is primarily driven by the age and condition of current infrastructure and assets.

4 Generation

The requirement to invest sustaining capital in generation facilities increased several years ago as parts of Hydro's generating plants approached or surpassed their normal expected service lives. Primary drivers for these projects are the end of service lives for equipment, deterioration causing reductions in reliability or performance, the availability of more efficient technology, and considerations for safety.

4.1 Hydraulic

The condition of key components of Hydro's hydraulic facilities, including auxiliary systems and equipment as well as the water control structures, have deteriorated and some have reached the end of their service lives. Capital investment is required in these areas to ensure the safe reliable operation of the system. The 2019 Capital Plan includes the continuation of the Hydraulic Generation Refurbishment and Modernization project, which consolidates program-based projects into a single project, ensuring that equipment is replaced or refurbished in a planned approach. Hydro has had success in introducing asset management programs and is confident that efficiencies will be realized through the coordination of capital and maintenance work on the hydraulic generation assets.

Since 2016 Hydro has executed several unplanned supplemental and allowance for unforeseen items capital projects to refurbish the three penstocks serving Bay d'Espoir Powerhouse 1. Bay d'Espoir Penstock 1 experienced three ruptures between 2016 and 2017, and all three penstocks have had weld refurbishment and plate re-enforcement projects completed since the first rupture in May 2016. Hydro filed with the Board reports on the two refurbishment projects for Penstock 1 and the refurbishment of Penstock 2. On May 18, 2018, Hydro filed a report on the results of the Bay d'Espoir penstock stress analysis. A recommendation in the stress analysis report was to complete a detailed condition assessment of the penstocks, including the refurbishment areas completed in 2016 and 2017. A supplemental capital project was approved by the Board (P.U. 23(2018)) to complete this condition assessment on penstocks 1 and 2 during the summer 2018 unit outages at Bay d'Espoir. The inspection portion of the condition assessment of Penstock 1, completed on July 17, 2018, indicated that there is no further damage in the area of the refurbished welds. The condition assessments and installation of pressure monitoring equipment will continue into fall 2018, with condition assessment reports filed with the Board by December 15, 2018. The results of the condition assessments will be a driver for future penstock capital projects.

Hydro has developed an updated maintenance plan for the penstocks on its major generators, with scheduled PM9 (6-year frequency – comprehensive internal inspection), PM6 (annual frequency – external inspection), and PM4 (monthly frequency – external inspection) inspections. Level 2 condition assessments, similar to the project currently being executed for Bay d'Espoir Penstocks 1 and 2, will be executed based on the results of the PM9 inspections and will form the basis of any capital refurbishment requirements included in the 5-year capital plan. Life extension work plans for penstocks outside the assets serving Bay d'Espoir Powerhouse 1 are currently based on age of the interior coating system. Although detailed plans have not yet been developed for any necessary refurbishment of these penstocks, Hydro will complete the PM9 inspections for all penstocks over the next five years to determine the path forward.

4.2 Thermal

On December 17, 2012, the Government of Newfoundland and Labrador announced official sanction of the Muskrat Falls Project, which includes the Labrador Island Link (LIL). Holyrood will be required for power production until the LIL is in service and it is intended that the Holyrood facility will remain fully available for generation in stand-by mode until after March 31, 2021 (post-winter 2021) timeframe. Unit 3 will operate in synchronous condenser mode during this stand-by production phase, with the option to return to full generating mode, if required. Post-winter 2021, Units 1 and 2 and the steam components of Unit 3 at Holyrood will be decommissioned and Unit 3 will continue to operate in synchronous condenser mode, with no generation capability.

Holyrood Units 1 and 2 were commissioned in 1970 and 1971, respectively, and Unit 3 in 1979. The generally accepted life expectancy for thermal plants is 30 years. Holyrood remains critical to the reliable power supply on the Island Interconnected System and especially to the Avalon Peninsula load centre. The capital work contained in this plan is necessary to replace or refurbish assets that are approaching the end of their useful service lives, and to maintain assets that will continue into the future while operating as a synchronous condenser facility.

Please refer to the "*Holyrood Overview*" section (Volume I) of this Application for further discussion pertaining to the five-year plan for Holyrood and the "*Plan of Projected Operating Maintenance Expenditures 2019 – 2028 For Holyrood Generating Station*" (Volume I), for future operational and maintenance expenditure forecasts.

4.3 Gas Turbines

Maintaining the reliability of Hydro's gas turbine assets, which are relied upon to provide stand-by and spinning reserve power and (with the exception of the Holyrood gas turbine) to function as synchronous condensers to help support voltage control on the Island and Labrador Interconnected Systems, is a priority. These facilities accumulate fewer operating hours than other generation sources, but are crucial sources of electricity during emergencies and system peaks and provide voltage support, especially when operating as synchronous condensers.

The 123.5 MW gas turbine located at the Holyrood site has been in service since February 2015 and is part of Hydro's fleet. It was installed to provide long-term generation capacity for the Island Interconnected System. Since being placed in service, the gas turbine has been utilized more frequently and for longer durations than was originally foreseen. To ensure the continued reliability, capital expenditures are required to upgrade the compressed air system for the Holyrood Gas Turbine. A two-year Combustor Inspection Major and Overhaul project for the Holyrood Gas Turbine is scheduled to start in 2020; however, that project is dependent on the usage, which continues to be evaluated. No other capital projects are in the five-year forecast for the Holyrood Gas Turbine.

The 50 MW plants at Hardwoods and Stephenville have required relatively minimal capital expenditure until recent years. As stated in the Capital Overview, Hydro has included a report on the Hardwoods and Stephenville gas turbine assets in the 2019 CBA within this 2019-2023 Capital Plan report as Appendix D. Capital proposals in the 2019 CBA for these two facilities are only to meet short-term requirements while Hydro completes the Supply Adequacy report, scheduled for submission in November 2018. All projects included in the 2019 CBA for Hardwoods and Stephenville are single-year projects and were prioritized and selected to ensure the reliability of these facilities given their age, operating regime, and operational forecast. Given that the results of the Supply Adequacy report are not yet available, the proposed projects in 2019 are those required to operate the plants, and would remain unchanged regardless of the outcome of the Supply Adequacy study. The results of the study will, however, have a direct impact on the Hardwoods and Stephenville capital plans for 2020 and beyond. Hydro will provide an updated long-term Capital Plan for Hardwoods and Stephenville as part of the 2020 CBA.

Hydro's gas turbine plant located at Happy Valley was constructed in 1992. This plant has required only minor upgrades since that time and an overhaul in 2017. The largest expenditures in the five-year plan for Happy Valley Gas Turbine are in 2020 with the replacement of the fire suppression system, an inspection of the generator rotor, and an inspection and refurbishment of the power turbine clutch.

5 Transmission and Rural Operations

The total investment of capital in transmission and rural operations facilities will begin to decrease after 2018, primarily as result of the completion of major transmission projects, (i.e. the upgrade of the transmission line corridor between Bay d'Espoir and Western Avalon (TL 267), which went in service on December 8, 2017, and the continued installation of the transmission line between Soldiers Pond and Hardwoods (TL 266) in 2018). The Muskrat Falls to Happy Valley Interconnection projects remains under review from the 2018 Capital Budget Application.

Other categories of assets are being replaced or refurbished based on condition assessments and a number of components in various facilities have reached or surpassed their normally expected service lives. Projects included in Transmission and Rural Operations address assets that are at, or near the end of, their service lives, improve reliability or performance, improve safety, or implement more efficient technology.

5.1 Terminal Stations

Maintaining reliability is the principal driver for terminal station expenditures over the next five years. Aging equipment is considered when reviewing short-term and long term plans. The five-year plan contains expenditures such as programs to upgrade power transformers, install on-line transformer gas monitoring units, replace circuit breakers, and replace disconnect switches. The plan also contains station-specific projects such as performing site work at various terminal stations to accommodate mobile substations and installing fire protection. Hydro continues with its Terminal Station Refurbishment and Modernization Program, which consolidates

Hydro's asset maintenance philosophies for terminal stations and will guide expenditures over the next five years, including the replacement of aging circuit breakers.

As noted in the Capital Overview, and discussed in "Status Report" (Volume I, Section H), the Upgrade Circuit Breakers – Various Sites project approved scope and budget has been reduced to defer some circuit breakers to after 2020 to help smooth the five-year capital plan. The assessment was made by asset management personnel based on the current condition of the assets. Therefore, there is a new project in 2021 to 2023 to replace these and other circuit breakers. There is also a plan to replace transformers starting in 2022, but this is subject to assessment as the project gets closer.

5.2 Transmission

Transmission investment in the Five-Year Capital Plan reflects the anticipated completion of several major projects early in this five-year period, followed by a focus on improving reliability and sustaining the transmission asset base.

The major project to construct the transmission line between Bay d'Espoir and Western Avalon (TL 267) is in service as of December 6, 2017, with environmental rehabilitation continuing into 2018, and TL 266 between Soldiers Pond and Hardwoods went in service in July 2018. Hydro received approval for TL 267 in Order No. P. U. 53(2014). As part of that approval, Hydro is required to file, with each capital budget application filed until the completion of the project, a report on the construction of TL 267 addressing the work progress, the expenditure and budget status, and an explanation for any deviations from the project scope and budget. The TL 267 update is presented in Appendix B of this 2019-2023 Capital Plan.

In the 2018 CBA, Hydro proposed interconnection between Muskrat Falls and the Happy Valley Terminal Station to increase transfer capacity to address load growth and to improve reliability for the Labrador Interconnected System, specifically Labrador East. Given that this project is still under review by the Board, it remains in the 2019 Capital Plan as proposed. As a result, Hydro is not applying for the 2019 expenditure in this application.

The Wood Pole Line Management Program forms the backbone of Hydro's asset management strategy for its wooden transmission poles, with this strategy in place since 2005. Its effectiveness and value have been tested and demonstrated, as shown in the report "*Review of Current WPLM Program, Interim Report"* (2013 Capital Budget Application, Volume II, Tab 17), enabling Hydro to realize the maximum useful life from these transmission systems. This Program is based on periodic assessment of the wood transmission poles and facilitates their replacement before failure, while extracting the maximum possible reliable life from each pole. Hydro is also continuing to replace insulators and associated hardware on transmission lines, reducing the risk of service interruptions for customers due to insulator failure. An update to the 2013 CBA report on the WPLM program is included in this 2019-2023 Capital Plan as Appendix C.

5.3 Distribution

New customer additions and maintaining reliability are the strategic areas addressed by the Five-Year Capital Plan for distribution assets. Deteriorated portions of distribution assets must be replaced to ensure reliable service. The majority of the distribution system expenditures for the next five years will consist of service extensions and upgrades to distribution systems, distribution pole replacement, and substation upgrading. In 2019 Hydro has proposed a condition assessment on the Fogo Island submarine cable. Hydro will use the results of that condition assessment to forecast appropriate timing integration in the capital plan.

5.4 Rural Generation

The replacement of aging infrastructure is required to ensure reliability for Hydro's 21 isolated electrical systems, which are primarily supplied with electricity by diesel generating sets. Hydro's diesel generating sets have the shortest lives of all its generating assets, requiring overhaul after each 20,000 hours and replacement after approximately 100,000 hours of operation. Figure 1 provides the age distribution of the diesel engines in Hydro's rural generating plants. During the next five years Hydro plans to replace or add generating sets in various isolated diesel plants, with the continuation of the project to replace unit 2059 in Makkovik and the proposed replacement of unit 2052 at Cartwright. These replacements and additions are required to ensure that reliable service is provided to Hydro's isolated rural customers. Many of Hydro's diesel plants will require refurbishment or replacement in the near-term to medium-term. Hydro is continuing with its prioritization process to assist in planning the replacement or modification in a logical sequence. Projects for the replacement and upgrade of diesel plant infrastructure and auxiliary systems are included over the coming five years.

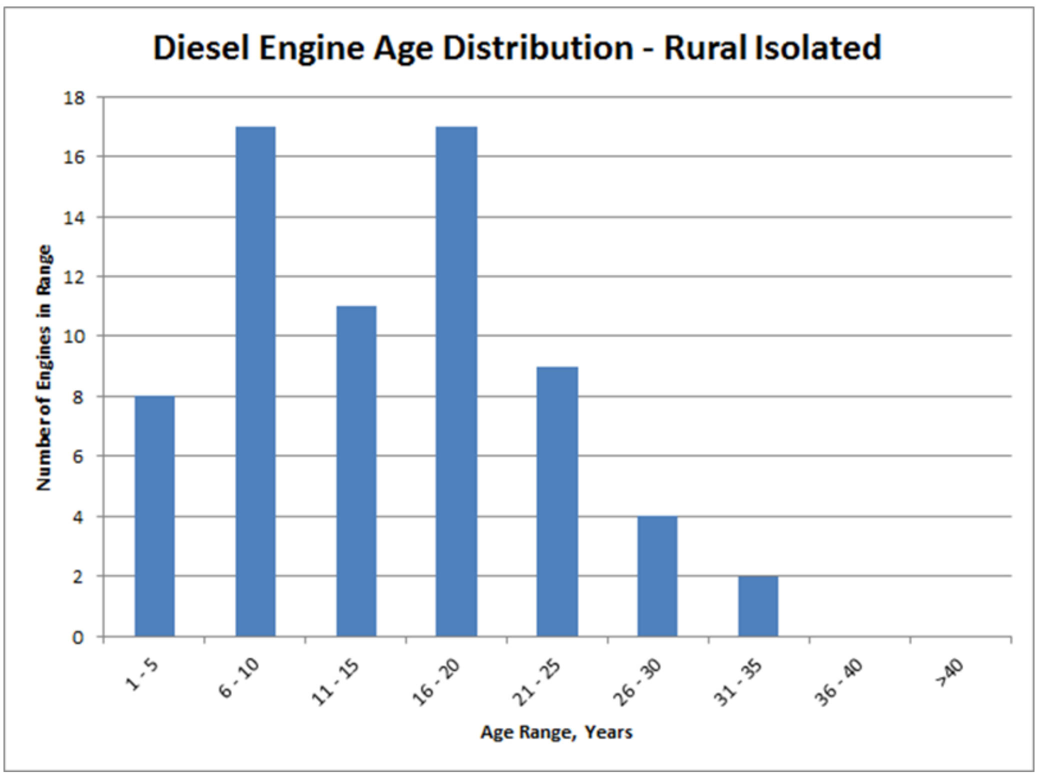

Figure 1: Diesel Engine Age Distribution – Rural Isolated Systems

6 General Property

Hydro's category of general properties is a broad ranging group of assets and includes vehicles, facilities, and information systems infrastructure. Similar to other categories, the assets in general properties require replacement or refurbishment due to deterioration, age, obsolescence, and, at times, due to growth constraints.

6.1 Information Systems

Obsolete technology and aging hardware are the strategic drivers that most significantly contribute to the five-year plan for information systems. Hydro's information systems provide the data required to effectively manage and control the activities of the business. Projects in this category include personal computer and software replacements and this type of replacement is expected to continue over the next five years.

6.2 Telecontrol

Obsolete technology and aging hardware are the most significant contributions to the five-year plan for Telecontrol assets. Hydro's communications network is vital to the operation and control of the power systems. Communications must be reliable and rapid to protect and control the generation, transmission and distribution equipment. The five-year plan contains expenditures in the form of several programs to replace battery banks and chargers, replace air conditioners, refurbish microwave sites, and replace obsolete radio equipment. The plan also includes site-specific projects to replace obsolete teleprotection equipment, upgrade telecontrol facilities, and replace uninterruptable power supply units.

6.3 Transportation

Hydro's vehicles and mobile equipment must continue to be both safe and reliable. Hydro operates a diversified and dispersed fleet of mobile equipment throughout the province that is required to operate and maintain our facilities in sometimes challenging and harsh physical environments. Hydro selects, operates and maintains this equipment in a manner designed to achieve the least life cycle cost and replacements are scheduled in accordance with criteria previously submitted to the Board.

6.4 Administration

Safety, cost efficiencies, reliability and security are the primary drivers of the five-year administration capital plan. Hydro expects to spend $0.95 million annually, on average, over the next five years on items such as office equipment, building auxiliary systems, and building infrastructure.

Appendix A

Five-Year Capital Plan

	Expended to 2018	2019	2020	2021	2022	2023	Total
Generation	25,082.5	32,603.7	38,718.9	43,149.2	33,124.6	24,923.4	197,602.3
Transmission and Rural Operations	64,329.7	75,965.9	86,898.2	78,955.0	81,559.6	91,594.9	479,303.3
General Properties	2,522.8	8,599.2	7,004.4	9,618.6	6,011.9	6,366.4	40,123.3
Allowance for Unforeseen Items	-	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	5,000.0
Total Capital Budget	**91,935.0**	**118,168.8**	**133,621.5**	**132,722.8**	**121,696.1**	**123,884.7**	**722,028.9**

	Expended to 2018	2019	2020	2021	2022	2023	Total
Generation							
Hydraulic Plant	15,174.4	18,995.8	24,879.2	23,345.0	22,945.3	16,225.0	121,564.7
Thermal Plant	80.3	7,139.6	6,948.5	11,185.5	6,890.9	4,559.2	36,804.0
Gas Turbines	9,827.8	6,319.4	6,854.5	8,581.0	3,250.0	4,100.0	38,932.7
Tools and Equipment	-	148.9	36.7	37.7	38.4	39.2	300.9
Total Generation	**25,082.5**	**32,603.7**	**38,718.9**	**43,149.2**	**33,124.6**	**24,923.4**	**197,602.3**
Transmission and Rural Operations							
Terminal Stations	42,063.1	40,772.3	42,951.6	36,737.6	41,755.9	44,976.8	249,257.3
Transmission	17,731.5	4,714.0	4,072.0	3,962.6	4,742.6	5,557.0	40,779.7
Distribution	447.5	12,159.9	15,800.6	17,857.5	16,702.3	19,413.7	82,381.5
Rural Generation	3,694.7	14,527.8	21,420.7	12,758.4	14,576.7	19,146.9	86,125.2
Properties	104.0	765.4	1,245.4	4,619.4	1,865.3	1,376.0	9,975.5
Metering	75.2	1,197.4	197.3	196.8	194.8	193.9	2,055.4
Tools and Equipment	213.7	1,829.1	1,210.6	2,822.7	1,722.0	930.6	8,728.7
Total Transmission and Rural Operations	**64,329.7**	**75,965.9**	**86,898.2**	**78,955.0**	**81,559.6**	**91,594.9**	**479,303.3**
General Properties							
Information Systems	-	1,597.1	925.2	1,298.0	1,321.0	1,485.0	6,626.3
Telecontrol	595.4	4,312.0	1,943.4	5,339.2	1,535.4	1,778.0	15,503.4
Transportation	1,667.2	2,001.8	2,747.9	2,141.3	2,199.7	2,241.9	12,999.8
Administrative	260.2	688.3	1,387.9	840.1	955.8	861.5	4,993.8
Total General Properties	**2,522.8**	**8,599.2**	**7,004.4**	**9,618.6**	**6,011.9**	**6,366.4**	**40,123.3**
Allowance for Unforeseen Items	-	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	5,000.0
Total Capital Budget	**91,935.0**	**118,168.8**	**133,621.5**	**132,722.8**	**121,696.1**	**123,884.7**	**722,028.9**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Hydraulic Plant							
Hydraulic Generation Refurbishment and Modernization (2018-2019)	10,325.4	4,283.1					14,608.5
Refurbish Powerhouse Station Services - Bay d'Espoir	2,886.5	1,460.6					4,347.1
Replace Exciter Controls Units 1 to 6 - Bay d'Espoir	1,040.4	877.0	1,429.6				3,347.0
Install Remote Operation of Salmon River Spillway - Bay d'Espoir	645.9	1,862.5					2,508.4
Energy Efficiency Improvements - Various	276.2	168.9					445.1
Hydraulic Generation Refurbishment and Modernization (2019-2020)		9,093.7	6,745.2				15,838.9
Hydraulic In-Service Failures		1,250.0					1,250.0
Hydraulic Generation Refurbishment and Modernization (2020-2021)			15,454.4	8,819.5			24,273.9
Hydraulic In-Service Failures (2020)			1,250.0				1,250.0
Hydraulic Generation Refurbishment and Modernization (2021-2022)				12,986.2	10,425.0		23,411.2
Hydraulic In-Service Failures (2021)				1,250.0			1,250.0
Refurbish Intake, Main Dam, and Section of Penstock - Snooks Arm				289.3			289.3
Hydraulic Generation Refurbishment and Modernization (2022-2023)					11,270.3	3,400.0	14,670.3
Hydraulic In-Service Failures (2022)					1,250.0		1,250.0
Hydraulic Generation Refurbishment and Modernization (2023-2024)						11,575.0	11,575.0
Hydraulic In-Service Failures (2023)						1,250.0	1,250.0
Total Hydraulic Plant	**15,174.4**	**18,995.8**	**24,879.2**	**23,345.0**	**22,945.3**	**16,225.0**	**121,564.7**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Thermal Plant							
Upgrade Cranes and Hoists - Holyrood	80.3	300.3					380.6
Overhaul Unit 3 Turbine Valve - Holyrood		3,290.5					3,290.5
Condition Assessment and Miscellaneous Upgrades - Holyrood		1,968.8					1,968.8
Thermal In-Service Failures		1,250.0					1,250.0
Replace 258VDC Battery Banks - Holyrood		330.0					330.0
Rewind Unit 3 Stator - Holyrood			1,359.6	5,789.0			7,148.6
Replace Stage II Electrical Distribution Equipment - Holyrood			2,513.2	2,269.6			4,782.8
Thermal In-Service Failures (2020)			1,250.0				1,250.0
Install New Lube Oil / Seal Oil Systems Unit 3 - Holyrood			255.0	765.9			1,020.9
Replace Stage 1 4160V AC Breakers - Holyrood			750.0				750.0
Upgrade Cooling Water System Wet Well Stop Log Unit 3 - Holyrood			300.0				300.0
Upgrade UPS 3 & 4 - Holyrood			266.7				266.7
Upgrade UPS 1 & 2 - Holyrood			254.0				254.0
Thermal In-Service Failures (2021)				1,250.0			1,250.0
Replace One of North or South Instrument Air Receiver System Unit 3 - Holyrood				753.0			753.0
Replace One of North or South Service Air Receivers Unit 3 - Holyrood				308.0			308.0
Upgrade Property Fencing - Holyrood				50.0	50.0		100.0
Overhaul Unit 3 Generator - Holyrood					3,100.0		3,100.0
Replace Unit 3 Generator (slip rings, bushings, bearings, etc.) - Holyrood					1,000.0	1,000.0	2,000.0
Thermal In-Service Failures (2022)					1,250.0		1,250.0
Inspect and Upgrade Light Oil System - Holyrood					100.0	900.0	1,000.0
Replace High Bay Lighting with LED - Holyrood					15.9	609.2	625.1
Upgrade On Site Roads - Holyrood					500.0		500.0
Replace Unit 3 Protective Relaying - Holyrood					500.0		500.0
Upgrade Fire System - Holyrood					275.0		275.0
Upgrade Bio-Green/Sewage Treatment System - Holyrood					100.0		100.0
Thermal In-Service Failures (2023)						1,250.0	1,250.0
Stage 2 Cooling Water Pumphouse Refurbishment - Holyrood						350.0	350.0
Upgrade Plant Heating System - Holyrood						250.0	250.0
Training Centre Upgrades - Holyrood						200.0	200.0
Total Thermal Plant	**80.3**	**7,139.6**	**6,948.5**	**11,185.5**	**6,890.9**	**4,559.2**	**36,804.0**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Gas Turbines							
Increase Fuel and Water Treatment System Capacity - Holyrood Gas Turbine	8,829.9	3,012.7	-	-	-	-	11,842.6
Gas Turbine Equipment and Refurbishment - Hardwoods and Stephenville	997.9	429.3	-	-	-	-	1,427.2
Overhaul Olympus Gas Generator - Stephenville	-	1,666.8	-	1,600.0	-	1,600.0	4,866.8
Upgrade Human Machine Interface and Automatic Voltage Regulator - Hardwoods	-	685.9	-	-	-	-	685.9
Replace Main Fuel Valves - Hardwoods	-	404.2	-	-	-	-	404.2
Upgrade Compressed Air System - Holyrood Gas Turbine	-	70.7	317.7	-	-	-	388.4
Construct Heated Storage for Spare Parts and Lube Oil - Hardwoods	-	49.8	-	-	-	-	49.8
Perform Combustor Inspection - Holyrood Gas Turbine	-	-	2,500.0	2,500.0	-	-	5,000.0
Overhaul Olympus Gas Generator - Hardwoods	-	-	1,600.0	-	1,600.0	-	3,200.0
Upgrade Control System - Stephenville	-	-	100.0	1,531.0	-	-	1,631.0
Replace Fire Suppression System - Happy Valley	-	-	986.8	-	-	-	986.8
Inspect Generator Rotor - Happy Valley	-	-	300.0	600.0	-	-	900.0
Purchase Capital Spares - Gas Turbines (2020)	-	-	300.0	-	-	-	300.0
Install Infrared Scanning Ports - Stephenville	-	-	250.0	-	-	-	250.0
Inspect Power Turbine Clutch A and B - Hardwoods	-	-	100.0	100.0	-	-	200.0
Inspect & Refurbish Power Turbine Clutch - Happy Valley	-	-	200.0	-	-	-	200.0
Refurbish Bus Duct - Stephenville	-	-	150.0	-	-	-	150.0
Replace Fuel Unloading Pumps - Hardwoods and Stephenville	-	-	50.0	50.0	-	-	100.0
Overhaul Gas Turbine End A - Hardwoods	-	-	-	1,100.0	-	-	1,100.0
Replace Lube Oil and Glycol Pumps - Happy Valley	-	-	-	100.0	300.0	-	400.0
Replace Snow Doors - Happy Valley	-	-	-	350.0	-	-	350.0
Inspect Power Turbine - Happy Valley	-	-	-	50.0	250.0	-	300.0
Replace Voltage Regulator - Happy Valley	-	-	-	50.0	250.0	-	300.0
Purchase Capital Spares - Gas Turbines (2021)	-	-	-	300.0	-	-	300.0
Install Infrared Scanning Ports - Happy Valley	-	-	-	250.0	-	-	250.0
Inspect Generator Rotor - Stephenville	-	-	-	-	500.0	1,500.0	2,000.0
Purchase Capital Spares - Gas Turbines (2022)	-	-	-	-	300.0	-	300.0
Replace Lube Oil / Glycol Cooler Radiator Coil - Happy Valley	-	-	-	-	50.0	150.0	200.0
Inspect Generator Rotor - Hardwoods	-	-	-	-	-	500.0	500.0
Purchase Capital Spares - Gas Turbines (2023)	-	-	-	-	-	300.0	300.0
Replace Glycol Cooler Coil - Happy Valley	-	-	-	-	-	50.0	50.0
Total Gas Turbines	**9,827.8**	**6,319.4**	**6,854.5**	**8,581.0**	**3,250.0**	**4,100.0**	**38,932.7**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Tools and Equipment							
Purchase Tools & Equipment Less than $50,000 - Bay d'Espoir & Holyrood (2019)	-	148.9	-	-	-	-	148.9
Purchase Tools & Equipment Less than $50,000 - Bay d'Espoir & Holyrood (2020)	-	-	36.7	-	-	-	36.7
Purchase Tools & Equipment Less than $50,000 - Bay d'Espoir & Holyrood (2021)	-	-	-	37.7	-	-	37.7
Purchase Tools & Equipment Less than $50,000 - Bay d'Espoir & Holyrood (2022)	-	-	-	-	38.4	-	38.4
Purchase Tools & Equipment Less than $50,000 - Bay d'Espoir & Holyrood (2023)	-	-	-	-	-	39.2	39.2
Total Tools and Equipment	**-**	**148.9**	**36.7**	**37.7**	**38.4**	**39.2**	**300.9**
Total Generation	**25,082.5**	**32,603.7**	**38,718.9**	**43,149.2**	**33,124.6**	**24,923.4**	**197,602.3**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Terminal Stations							
Upgrade Circuit Breakers - Various (2016-2020)	33,186.4	6,597.3	11,116.8	-	-	-	50,900.5
Terminal Station Refurbishment and Modernization (2018-2019)	8,170.6	18,625.1	-	-	-	-	26,795.7
Replace Transformer T1 - Buchans	249.0	2,086.1	-	-	-	-	2,335.1
Implement Terminal Station Flood Mitigation - Springdale	186.2	787.8	-	-	-	-	974.0
Purchase Mobile DC Power Systems	270.9	695.6	-	-	-	-	966.5
Terminal Station Refurbishment and Modernization (2019-2020)	-	10,891.1	19,061.8	-	-	-	29,952.9
Terminal Station In-Service Failures	-	1,000.0	-	-	-	-	1,000.0
Upgrade Terminal Station for Mobile Substation - St. Anthony	-	89.3	402.7	-	-	-	492.0
Terminal Station Refurbishment and Modernization (2020-2021)	-	-	7,555.8	10,823.1	-	-	18,378.9
Purchase New Mobile Substation - Bishops Falls	-	-	846.0	3,853.8	-	-	4,699.8
Install Fire Barriers Between T10 & T12 and T10 & T11 - Bay d'Espoir	-	-	161.7	1,207.5	-	-	1,369.2
Upgrade Control Building for Staff Working Spaces - South Brook & Doyles	-	-	453.4	773.5	-	-	1,226.9
Terminal Station In-Service Failures (2020)	-	-	1,000.0	-	-	-	1,000.0
Replace Telecontrol Building and Upgrade Equipment - Daniels Harbour	-	-	57.0	764.0	-	-	821.0
Replace Corroded Junction Boxes - Various	-	-	200.0	200.0	200.0	200.0	800.0
Install Fire Barriers between T1, T2 and T3 and the Substation - Massey Drive	-	-	100.0	400.0	300.0	-	800.0
Install Firewall Between Transformer and Gas Turbine - Stephenville	-	-	146.6	648.7	-	-	795.3
Replace Capacitor Bank C1 - Oxen Pond	-	-	363.6	369.8	-	-	733.4
Upgrade Station Lighting - Various	-	-	200.0	200.0	200.0	-	600.0
Install Drainage to Stop Surface Flooding - Various	-	-	67.8	457.2	-	-	525.0
Install Telephone System - Bottom Waters	-	-	500.0	-	-	-	500.0
Construct Fire Separation Wall between Transformers - Happy Valley	-	-	300.0	-	-	-	300.0
Upgrade Access Road with New Topping - Buchans	-	-	243.4	-	-	-	243.4
Upgrade AC/DC Station Service - Various (2020-2021)	-	-	75.0	75.0	-	-	150.0
Upgrade Reclosing for Circuit Breakers - Various (2020)	-	-	100.0	-	-	-	100.0
Upgrade Circuit Breakers - Various	-	-	-	10,450.0	10,100.0	9,910.0	30,460.0
Terminal Station Refurbishment and Modernization (2021-2022)	-	-	-	4,540.0	7,059.8	-	11,599.8
Terminal Station In-Service Failures (2021)	-	-	-	1,000.0	-	-	1,000.0
Upgrade Drainage to Stop Frost Heaving - Various	-	-	-	200.0	400.0	400.0	1,000.0
Upgrade Station Access Road - Various	-	-	-	400.0	200.0	200.0	800.0
Upgrade Reclosing for Circuit Breakers - Various (2021)	-	-	-	300.0	-	-	300.0
Upgrade AC/DC Station Service - Various (2021-2022)	-	-	-	75.0	75.0	-	150.0
Replace Transformers - Various	-	-	-	-	12,200.0	18,200.0	30,400.0
Terminal Station Refurbishment and Modernization (2022-2023)	-	-	-	-	6,608.6	8,236.5	14,845.1
Modify 230kV Bus Height - Western Avalon	-	-	-	-	2,500.0	-	2,500.0
Install Remote Control Sectionalizer TL251(2)(3) - Hampden	-	-	-	-	437.5	1,691.4	2,128.9
Terminal Station In-Service Failures (2022)	-	-	-	-	1,000.0	-	1,000.0
Upgrade Reclosing for Circuit Breakers - Various (2022)	-	-	-	-	200.0	-	200.0

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Terminal Stations (cont'd)							
Upgrade Station Lighting - Various (2022)	-	-	-	-	200.0	-	200.0
Upgrade AC/DC Station Service - Various (2022-2023)	-	-	-	-	75.0	75.0	150.0
Terminal Station Refurbishment and Modernization (2023-2024)	-	-	-	-	-	4,588.9	4,588.9
Terminal Station In-Service Failures (2023)	-	-	-	-	-	1,000.0	1,000.0
Upgrade Reclosing for Circuit Breakers - Various (2023)	-	-	-	-	-	200.0	200.0
Upgrade Station Lighting - Various (2023)	-	-	-	-	-	200.0	200.0
Upgrade AC/DC Station Service - Various (2023-2024)	-	-	-	-	-	75.0	75.0
Total Terminal Stations	**42,063.1**	**40,772.3**	**42,951.6**	**36,737.6**	**41,755.9**	**44,976.8**	**249,257.3**
Transmission							
Muskrat Falls to Happy Valley Interconnection	17,731.5	2,247.0	-	-	-	-	19,978.5
Wood Pole Line Management Program - Various (2019)	-	2,467.0	-	-	-	-	2,467.0
Wood Pole Line Management Program - Various (2020)	-	-	3,821.2	-	-	-	3,821.2
Conduct LIDAR Surveys (2020) - Various	-	-	250.8	-	-	-	250.8
Wood Pole Line Management Program - Various (2021)	-	-	-	3,381.3	-	-	3,381.3
Upgrade 230 kV L23&L24 - Churchill Falls to Wabush	-	-	-	324.9	649.6	649.5	1,624.0
Conduct LIDAR Surveys (2021) - Various	-	-	-	256.4	-	-	256.4
Wood Pole Line Management Program - Various (2022)	-	-	-	-	2,995.9	-	2,995.9
Construct TL Equipment Off-Loading Areas - Various	-	-	-	-	1,097.1	1,121.2	2,218.3
Wood Pole Line Management Program - Various (2023)	-	-	-	-	-	3,786.3	3,786.3
Total Transmission	**17,731.5**	**4,714.0**	**4,072.0**	**3,962.6**	**4,742.6**	**5,557.0**	**40,779.7**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Distribution							
Distribution System Upgrades (2018-2019) - Various	383.8	2,771.2	-	-	-	-	3,155.0
Install Recloser Remote Control (2018-2019) - English Harbour West and Barachoix	63.7	275.0	-	-	-	-	338.7
Distribution System Upgrades (2019-2020)	-	390.8	5,490.1	-	-	-	5,880.9
Provide Service Extensions - All Regions (2019)	-	4,700.0	-	-	-	-	4,700.0
Upgrade Distribution Systems - All Regions (2019)	-	3,470.0	-	-	-	-	3,470.0
Install Recloser Remote Control (2019-2020) - Rocky Harbour	-	66.1	319.9	-	-	-	386.0
Level 2 Condition Assessment for Submarine Cable Farewell Head to Change Islands	-	300.1	-	-	-	-	300.1
Additions for Load - Distribution System - Wabush	-	186.7	-	-	-	-	186.7
Distribution System Upgrades (2020-2021)	-	-	511.1	6,257.9	-	-	6,769.0
Provide Service Extensions - All Regions (2020)	-	-	4,790.0	-	-	-	4,790.0
Upgrade Distribution Systems - All Regions (2020)	-	-	3,550.0	-	-	-	3,550.0
Replace Burgeo Substation Transformer - Grandy Brook	-	-	204.5	859.2	-	-	1,063.7
Additions for Load - Distribution System (2020-2021)	-	-	535.0	315.0	-	-	850.0
Install Recloser Remote Control (2020-2021) - Various	-	-	50.0	500.0	-	-	550.0
Install Sectionalizing for Cold Load Pickup - Port Hope Simpson	-	-	250.0	-	-	-	250.0
Implement Geographical Information System - Various	-	-	100.0	100.0	-	-	200.0
Distribution System Upgrades (2021-2022)	-	-	-	586.5	6,046.0	-	6,632.5
Provide Service Extensions - All Regions (2021)	-	-	-	4,890.0	-	-	4,890.0
Upgrade Distribution Systems - All Regions (2021)	-	-	-	3,620.0	-	-	3,620.0
Additions for Load - Distribution System (2021)	-	-	-	678.9	-	-	678.9
Install Recloser Remote Control (2021-2022) - Various	-	-	-	50.0	513.3	-	563.3
Distribution System Upgrades (2022-2023)	-	-	-	-	750.0	6,750.0	7,500.0
Provide Service Extensions - All Regions (2022)	-	-	-	-	4,990.0	-	4,990.0
Upgrade Distribution Systems - All Regions (2022)	-	-	-	-	3,680.0	-	3,680.0
Convert L2 to 25kV - Little Bay	-	-	-	-	173.0	1,625.7	1,798.7
Install Recloser Remote Control (2022-2023) - Various	-	-	-	-	50.0	526.0	576.0
Additions for Load - Distribution System (2022)	-	-	-	-	500.0	-	500.0
Provide Service Extensions - All Regions (2023)	-	-	-	-	-	5,090.0	5,090.0
Upgrade Distribution Systems - All Regions (2023)	-	-	-	-	-	3,760.0	3,760.0
Distribution System Upgrades (2023-2024)	-	-	-	-	-	750.0	750.0
Additions for Load - Distribution System (2023)	-	-	-	-	-	500.0	500.0
Convert Nipper's Harbor (L8) to 25kV - Bottom Waters	-	-	-	-	-	387.0	387.0
Install Recloser Remote Control (2023-2024) - Various	-	-	-	-	-	25.0	25.0
Total Distribution	**447.5**	**12,159.9**	**15,800.6**	**17,857.5**	**16,702.3**	**19,413.7**	**82,381.5**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Rural Generation							
Diesel Genset Replacements - Makkovik	604.1	4,703.3	3,592.8	-	-	-	8,900.2
Replace Secondary Containment System Liner - Nain	1,639.2	1,450.4	-	-	-	-	3,089.6
Replace Automation Equipment - St. Anthony Diesel Plant	307.4	1,565.9	-	-	-	-	1,873.3
Diesel Plant Engine Cooling System Upgrades - Various	638.4	671.6	-	-	-	-	1,310.0
Diesel Plant Fire Protection - Postville	505.6	336.4	-	-	-	-	842.0
Diesel Genset Replacements (2019-2020)	-	525.6	3,421.8	-	-	-	3,947.4
Overhaul Diesel Units - Various	-	2,511.3	-	-	-	-	2,511.3
Additions for Load - Isolated Generation Systems	-	1,523.6	658.9	-	-	-	2,182.5
Diesel Plant Fire Protection (2019-2020)	-	377.2	1,540.2	-	-	-	1,917.4
Upgrade Diesel Plant Building - Ramea	-	352.5	-	-	-	-	352.5
Replace Human Machine Interface - Cartwright	-	306.9	-	-	-	-	306.9
Inspect Fuel Storage Tanks - Gray River	-	203.1	-	-	-	-	203.1
Overhaul Diesel Units (2020) - Various	-	-	2,370.3	-	-	-	2,370.3
Additions for Load Growth - Upgrade S/S Transformer & Increase Capacity - Makkovik	-	-	1,853.6	-	-	-	1,853.6
Replace Unit 5056 - St. Brendans	-	-	110.0	1,590.0	-	-	1,700.0
Replace Unit 2039 - St. Lewis	-	-	153.9	1,336.4	-	-	1,490.3
Purchase Mobile Diesel - Bishop's Falls	-	-	1,400.0	-	-	-	1,400.0
Replace Automation Equipment - Various	-	-	261.5	983.7	-	-	1,245.2
Install Fire Protection in Diesel Plants (2020-21) - Paradise River	-	-	100.0	900.0	-	-	1,000.0
Replace Programmable Logic Controllers - Various	-	-	250.0	250.0	250.0	-	750.0
Inspect Fuel Storage Tanks (2020) - Various	-	-	714.8	-	-	-	714.8
Install Unit Fuel Metering - Various	-	-	600.0	-	-	-	600.0
Install Sequence of Events Monitor in Diesel Plants - Various	-	-	281.0	289.1	-	-	570.1
Upgrade Septic System - Nain	-	-	500.0	-	-	-	500.0
Replace Existing Bus with 1,600 Amp Bus - Hopedale	-	-	500.0	-	-	-	500.0
Replace Main Breaker and Extend Plant - Little Bay Islands	-	-	500.0	-	-	-	500.0
Build Roadway for Freight Delivery - Norman Bay	-	-	307.0	-	-	-	307.0
Build Fire Separation Wall Between Transformers - St. Anthony Diesel Plant & L'anse au Loup	-	-	50.0	250.0	-	-	300.0
Replace Human Machine Interface (2020) - Various	-	-	299.5	-	-	-	299.5
Upgrade Water Line to Diesel Plant - Makkovik	-	-	250.0	-	-	-	250.0
Construct Site Fencing - Port Hope Simpson	-	-	250.0	-	-	-	250.0
Purchase and Install Sewage Lift System - Rigolet	-	-	210.1	-	-	-	210.1
Replace Unit Breakers - Port Hope Simpson	-	-	200.0	-	-	-	200.0
Upgrade and Add Site Fencing - L'anse au Loup	-	-	200.0	-	-	-	200.0
Install Automatic Oil Filling System - Various	-	-	200.0	-	-	-	200.0
Install Engine Starting System - Various	-	-	200.0	-	-	-	200.0
Install Waste Oil Storage Tank - Various	-	-	150.0	-	-	-	150.0
Upgrade Fuel Storage - Little Bay Islands	-	-	125.3	-	-	-	125.3

	Expended to 2018	2019	2020	2021	2022	2023	Total
Rural Generation (cont'd)							
Construct Lube Oil Ramp For Waste Oil - Nain	-	-	120.0	-	-	-	120.0
Construct Site Fencing - Norman Bay	-	-	50.0	-	-	-	50.0
Plant Improvements (2021-2022) - Various	-	-	-	1,039.1	2,076.0	-	3,115.1
Overhaul Diesel Units (2021) - Various	-	-	-	2,424.2	-	-	2,424.2
Replace Unit 577 - Postville	-	-	-	113.1	1,636.0	-	1,749.1
Install Fire Protection in Diesel Plants (2021-2022) - Charlottetown	-	-	-	100.0	923.4	-	1,023.4
Replace PLCs and Software - Various	-	-	-	300.0	300.0	300.0	900.0
Replace Fuel Lines and Control Valves to Bulk Storage.- Various	-	-	-	250.0	250.0	250.0	750.0
Replace PML 3800 Series Mini RTUs - Various	-	-	-	250.0	250.0	250.0	750.0
Inspect Fuel Storage Tanks (2021) - Various	-	-	-	700.0	-	-	700.0
Replace Unit Breakers - Various	-	-	-	150.0	200.0	200.0	550.0
Additions for Load Growth - Isolated Generation Stations - Various (2021)	-	-	-	500.0	-	-	500.0
Install Infrared Scanning Ports - Various	-	-	-	150.0	150.0	150.0	450.0
Replace Human Machine Interface (2021) - Various	-	-	-	307.8	-	-	307.8
Replace Bulk Storage Piping - Black Tickle	-	-	-	300.0	-	-	300.0
Replace DSLC and MSLC - Various	-	-	-	100.0	100.0	100.0	300.0
Upgrade Fuel Piping Bulk Tanks to Units - Grey River	-	-	-	200.0	-	-	200.0
Replace Radiator Stands - Black Tickle	-	-	-	50.0	150.0	-	200.0
Increase Plant Storage - Various	-	-	-	150.0	-	-	150.0
Install Electric Trolly on Jib Crane - Various	-	-	-	75.0	75.0	-	150.0
Replace Diesel Engine - Various	-	-	-	-	3,300.0	2,200.0	5,500.0
Overhaul Diesel Units (2022) - Various	-	-	-	-	2,500.0	-	2,500.0
Replace Unit 2054 - Hopedale	-	-	-	-	150.0	2,250.0	2,400.0
Replace Unit 2073 - Port Hope Simpson	-	-	-	-	150.0	2,250.0	2,400.0
Perform Plant Improvements as Per 2012 FEED Project (2022-2023) - Various	-	-	-	-	250.0	2,134.0	2,384.0
Replace Unit 2058 - Little Bay Islands	-	-	-	-	100.0	1,700.0	1,800.0
Install Fire Protection in Diesel Plants (2022-2023)	-	-	-	-	500.0	1,055.5	1,555.5
Automate Diesel Plant (2022-23) - Postville	-	-	-	-	100.0	995.0	1,095.0
Additions for Load Growth - Isolated Generation Stations - Various (2022)	-	-	-	-	500.0	-	500.0
Replace Human Machine Interface (2022) - Various	-	-	-	-	316.3	-	316.3
Upgrade Old Diesel Plant For Storage Area - Nain	-	-	-	-	250.0	-	250.0
Inspect Fuel Storage Tanks (2022) - Various	-	-	-	-	100.0	-	100.0
Overhaul Diesel Units (2023) - Various	-	-	-	-	-	2,500.0	2,500.0
Upgrade Auxiliary System - Various	-	-	-	-	-	500.0	500.0
Install Fire Protection in Diesel Plants (2023-2024)	-	-	-	-	-	500.0	500.0
Additions for Load Growth - Isolated Generation Stations - Various (2023)	-	-	-	-	-	500.0	500.0
Replace Diesel Plants (2023-2024) - Various	-	-	-	-	-	400.0	400.0
Replace Human Machine Interface (2023) - Various	-	-	-	-	-	324.7	324.7
Plant Improvements (2023-2024) - Various	-	-	-	-	-	250.0	250.0
Replace Unit 2053 - Hopedale	-	-	-	-	-	137.7	137.7
Inspect Fuel Storage Tanks (2023) - Various	-	-	-	-	-	100.0	100.0
Automate Diesel Plant (2023-2024)	-	-	-	-	-	100.0	100.0
Total Rural Generation	**3,694.7**	**14,527.8**	**21,420.7**	**12,758.4**	**14,576.7**	**19,146.9**	**86,125.2**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Properties							
Install Energy Efficiency Lighting in Diesel Plants - Various	104.0	119.0	122.2	-	-	-	345.2
Upgrade Line Depots - Roddickton	-	344.7	-	-	-	-	344.7
Install Pole Storage Ramps - Wabush	-	301.7	-	-	-	-	301.7
Upgrade Fire System - Bishop's Falls	-	-	113.0	887.4	-	-	1,000.4
Upgrade Line Depots (2020-2021) - Various	-	-	377.4	607.3	-	-	984.7
Construct Storage Building - Springdale	-	-	132.8	730.0	-	-	862.8
Upgrade Office Facilities (2020) - Various	-	-	300.0	-	-	-	300.0
Replace Roof on Garage - Bishop Falls	-	-	100.0	-	-	-	100.0
Upgrade HVAC System - Stephenville	-	-	100.0	-	-	-	100.0
Upgrade Outside Property - Various	-	-	-	650.0	405.9	-	1,055.9
Upgrade Line Depots (2021-2022) - Various	-	-	-	387.7	624.2	-	1,011.9
Replace In-Floor Drains and Sanitary Lines - Bishop's Falls	-	-	-	746.7	-	-	746.7
Upgrade Office Facilities (2021) - Various	-	-	-	307.9	-	-	307.9
Upgrade Classroom and Boardroom in Main Office - Bishop's Falls	-	-	-	179.4	-	-	179.4
Upgrade Outside Property - Deer Lake	-	-	-	123.0	-	-	123.0
Upgrade Line Depots (2022-2023) - Various	-	-	-	-	398.5	640.9	1,039.4
Upgrade Office Facilities (2022) - Various	-	-	-	-	316.7	-	316.7
Upgrade Outside Property - Happy Valley	-	-	-	-	120.0	-	120.0
Upgrade Line Depots (2023-2024) - Various	-	-	-	-	-	409.4	409.4
Upgrade Office Facilities - Various	-	-	-	-	-	325.7	325.7
Total Properties	**104.0**	**765.4**	**1,245.4**	**4,619.4**	**1,865.3**	**1,376.0**	**9,975.5**
Metering							
Install Automated Meter Reading (2018-2019) - Bottom Waters	75.2	1,001.0	-	-	-	-	1,076.2
Purchase Meters and Metering Equipment- Various (2019)	-	196.4	-	-	-	-	196.4
Purchase Meters and Metering Equipment- Various (2020)	-	-	197.3	-	-	-	197.3
Purchase Meters and Metering Equipment- Various (2021)	-	-	-	196.8	-	-	196.8
Purchase Meters and Metering Equipment- Various (2022)	-	-	-	-	194.8	-	194.8
Purchase Meters and Metering Equipment- Various (2023)	-	-	-	-	-	193.9	193.9
Total Metering	**75.2**	**1,197.4**	**197.3**	**196.8**	**194.8**	**193.9**	**2,055.4**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Tools and Equipment							
Replace Off Road Track Vehicle Unit No. 7239 & 7954 - Bishop Falls & Bay d'Espoir	213.7	986.3	-	-	-	-	1,200.0
Replace Light Duty Mobile Equipment - Various (2019)	-	469.6	-	-	-	-	469.6
Purchase Tools & Equipment Less than $50,000 - Central (2019)	-	171.2	-	-	-	-	171.2
Purchase Tools & Equipment Less than $50,000 - Labrador (2019)	-	109.2	-	-	-	-	109.2
Purchase Tools & Equipment Less than $50,000 - Northern (2019)	-	92.8	-	-	-	-	92.8
Replace Off Road Track Vehicle Unit No. 7974 - Stephenville	-	-	8.8	741.2	-	-	750.0
Replace Light Duty Mobile Equipment - Various (2020)	-	-	484.4	-	-	-	484.4
Replace Off Road Track Vehicle Unit No. 7698 - Stephenville	-	-	8.8	455.2	-	-	464.0
Replace Off Road Track Vehicle Unit No. 7565 - Stephenville	-	-	14.0	441.9	-	-	455.9
Replace Off Road Track Vehicle Unit No. 7799 - Springdale	-	-	200.0	-	-	-	200.0
Replace Back Hoe Unit No. 9813 - Holyrood	-	-	173.0	-	-	-	173.0
Purchase Tools & Equipment Less than $50,000 - Central (2020)	-	-	166.5	-	-	-	166.5
Purchase Tools & Equipment Less than $50,000 - Northern (2020)	-	-	94.9	-	-	-	94.9
Purchase Tools & Equipment Less than $50,000 - Labrador (2020)	-	-	60.2	-	-	-	60.2
Replace Light Duty Mobile Equipment - Various (2021)	-	-	-	620.6	-	-	620.6
Purchase Tools & Equipment Less than $50,000 - Central (2021)	-	-	-	148.7	-	-	148.7
Replace Excavator Unit No. 7063 - Bay d'Espoir	-	-	-	92.0	-	-	92.0
Replace Excavator Unit No. 7064 - Springdale	-	-	-	92.0	-	-	92.0
Replace Excavator Unit No. 7065 - Bay d'Espoir	-	-	-	92.0	-	-	92.0
Purchase Tools & Equipment Less than $50,000 - Northern (2021)	-	-	-	77.6	-	-	77.6
Purchase Tools & Equipment Less than $50,000 - Labrador (2021)	-	-	-	61.5	-	-	61.5
Replace Off-Road Track Vehicles V7067, V7601, V9829	-	-	-	-	802.7	-	802.7
Replace Light Duty Mobile Equipment - Various (2022)	-	-	-	-	625.0	-	625.0
Purchase Tools & Equipment Less than $50,000 - Central (2022)	-	-	-	-	152.0	-	152.0
Purchase Tools & Equipment Less than $50,000 - Northern (2022)	-	-	-	-	79.4	-	79.4
Purchase Tools & Equipment Less than $50,000 - Labrador (2022)	-	-	-	-	62.9	-	62.9
Replace Light Duty Mobile Equipment - Various (2023)	-	-	-	-	-	630.0	630.0
Purchase Tools & Equipment Less than $50,000 - Central (2023)	-	-	-	-	-	155.2	155.2
Purchase Tools & Equipment Less than $50,000 - Northern (2023)	-	-	-	-	-	81.1	81.1
Purchase Tools & Equipment Less than $50,000 - Labrador (2023)	-	-	-	-	-	64.3	64.3
Total Tools and Equipment	**213.7**	**1,829.1**	**1,210.6**	**2,822.7**	**1,722.0**	**930.6**	**8,728.7**
Total Transmission and Rural Operations	**64,329.7**	**75,965.9**	**86,898.2**	**78,955.0**	**81,559.6**	**91,594.9**	**479,303.3**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Information Systems							
Software Applications							
Upgrade Energy Management System - Hydro Place (2019)		271.7					271.7
Upgrade Software Applications - Hydro Place (2019)		110.4					110.4
Refresh Security Software - Hydro Place (2019)		90.7					90.7
Perform Minor Enhancements - Hydro Place (2019)		47.1					47.1
Upgrade Energy Management System - Hydro Place (2020)			371.5				371.5
Upgrade Software Applications - Hydro Place (2020)			100.0				100.0
Refresh Security Software - Hydro Place (2020)			60.0				60.0
Perform Minor Enhancements - Hydro Place (2020)			50.0				50.0
Upgrade Energy Management System - Hydro Place (2021)				381.5			381.5
Upgrade Software Applications - Hydro Place (2021)				100.0			100.0
Refresh Security Software - Hydro Place (2021)				60.0			60.0
Perform Minor Enhancements - Hydro Place (2021)				50.0			50.0
Upgrade Energy Management System - Hydro Place (2022)					391.0		391.0
Upgrade Software Applications - Hydro Place (2022)					100.0		100.0
Refresh Security Software - Hydro Place (2022)					60.0		60.0
Perform Minor Enhancements - Hydro Place (2022)					50.0		50.0
Upgrade Energy Management System - Hydro Place (2023)						400.0	400.0
Upgrade Software Applications - Hydro Place (2023)						100.0	100.0
Refresh Security Software - Hydro Place (2023)						60.0	60.0
Perform Minor Enhancements - Hydro Place (2023)						50.0	50.0
Total Software Applications	**-**	**519.9**	**581.5**	**591.5**	**601.0**	**610.0**	**2,903.9**
Computer Operations							
Replace Personal Computers - Hydro Place (2019)		496.0					496.0
Upgrade Core IT Infrastructure - Hydro Place (2019)		359.4					359.4
Replace Peripheral Infrastructure - Hydro Place (2019)		221.8					221.8
Replace Peripheral Infrastructure - Hydro Place (2020)			142.2				142.2
Upgrade Core IT Infrastructure - Hydro Place (2020)			125.0				125.0
Replace Personal Computers - Hydro Place (2020)			76.5				76.5
Replace Personal Computers - Hydro Place (2021)				371.2			371.2
Replace Peripheral Infrastructure - Hydro Place (2021)				210.3			210.3
Upgrade Core IT Infrastructure - Hydro Place (2021)				125.0			125.0
Replace Personal Computers - Hydro Place (2022)					380.0		380.0
Replace Peripheral Infrastructure - Hydro Place (2022)					215.0		215.0
Upgrade Core IT Infrastructure - Hydro Place (2022)					125.0		125.0
Replace Personal Computers - Hydro Place (2023)						490.0	490.0
Replace Peripheral Infrastructure - Hydro Place (2023)						260.0	260.0
Upgrade Core IT Infrastructure - Hydro Place (2023)						125.0	125.0
Total Computer Operations	**-**	**1,077.2**	**343.7**	**706.5**	**720.0**	**875.0**	**3,722.4**
Total Information Systems	**-**	**1,597.1**	**925.2**	**1,298.0**	**1,321.0**	**1,485.0**	**6,626.3**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Telecontrol							
Network Services							
Replace PBX Phone Systems - Various	91.7	1,150.6	-	-	-	-	1,242.3
Replace MDR 6000 Microwave Radio - Various	64.0	1,137.0	-	-	-	-	1,201.0
Replace Battery Banks and Chargers (2018- 2019) - Various	382.1	555.8	-	-	-	-	937.9
Replace Teleprotection - TL261	57.6	459.8	-	-	-	-	517.4
Upgrade Telecontrol Facilities - Gull Pond Hill and Bay d'Espoir Hill	-	96.3	577.6	-	-	-	673.9
Replace Radomes - Various	-	263.5	-	-	-	-	263.5
Replace Teleprotection - TL202 & TL206	-	196.8	-	-	-	-	196.8
Replace Network Communications Equipment (2019)- Various	-	189.5	-	-	-	-	189.5
Upgrade Remote Terminal Units - Various	-	167.7	-	-	-	-	167.7
Upgrade Site Facilities - Various	-	49.4	-	-	-	-	49.4
Purchase Tools & Equipment Less than $50,000 (2019)	-	45.6	-	-	-	-	45.6
Replace Battery Banks and Chargers - Various (2020)	-	-	475.1	-	-	-	475.1
Upgrade Telecontrol Facilities - Godfathers Cove	-	-	48.0	350.0	-	-	398.0
Replace Network Communications Equipment (2020) - Various	-	-	185.0	-	-	-	185.0
Replace Radomes (2020) - Various	-	-	185.0	-	-	-	185.0
Replace Air Conditioners (2020) - Various	-	-	150.0	-	-	-	150.0
Upgrade Access Roads (2020) - Microwave Sites	-	-	127.2	-	-	-	127.2
Replace RTUs (2020) - Various	-	-	100.0	-	-	-	100.0
Upgrade Site Facilities (2020) - Various	-	-	49.1	-	-	-	49.1
Purchase Tools & Equipment Less than $50,000 (2020)	-	-	46.4	-	-	-	46.4
Replace VHF Mobile Radio System - Various	-	-	-	2,800.0	-	-	2,800.0
Replace SCADA Communications Equipment (Peters Barren to Hawke's Bay) - TL221	-	-	-	666.0	-	-	666.0
Replace Battery Banks and Chargers - Various (2021)	-	-	-	485.7	-	-	485.7
Replace Back-up Generator - Microwave Sites (Blue Grass Hill)	-	-	-	200.0	200.0	-	400.0
Replace Network Communications Equipment (2021) - Various	-	-	-	180.0	-	-	180.0
Replace Radomes (2021) - Various	-	-	-	180.0	-	-	180.0
Replace Air Conditioners (2021) - Various	-	-	-	150.0	-	-	150.0
Upgrade Access Roads (2021) - Microwave Sites	-	-	-	132.0	-	-	132.0
Replace RTUs (2021) - Various	-	-	-	100.0	-	-	100.0
Upgrade Site Facilities (2021) - Various	-	-	-	48.0	-	-	48.0
Purchase Tools & Equipment Less than $50,000 (2021)	-	-	-	47.5	-	-	47.5
Replace Battery Banks and Chargers - Various (2022)	-	-	-	-	496.8	-	496.8
Replace Network Communications Equipment (2022) - Various	-	-	-	-	180.0	-	180.0
Replace Radomes (2022) - Various	-	-	-	-	180.0	-	180.0
Replace Air Conditioners (2022) - Various	-	-	-	-	150.0	-	150.0
Upgrade Access Roads (2022) - Microwave Sites	-	-	-	-	132.0	-	132.0
Replace RTUs (2022) - Various	-	-	-	-	100.0	-	100.0
Purchase Tools & Equipment Less than $50,000 (2022)	-	-	-	-	48.6	-	48.6
Upgrade Site Facilities (2022) - Various	-	-	-	-	48.0	-	48.0

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Network Services (cont'd)							
Replace Battery Banks and Chargers - Various (2023)	-	-	-	-	-	508.3	508.3
Replace Back-up Generator - Microwave Sites (Bay d'Espoir Hill)	-	-	-	-	-	200.0	200.0
Replace Network Communications Equipment (2023) - Various	-	-	-	-	-	180.0	180.0
Replace Radomes (2023) - Various	-	-	-	-	-	180.0	180.0
Replace Air Conditioners (2023) - Various	-	-	-	-	-	150.0	150.0
Replace Network Management Tools - Various	-	-	-	-	-	140.0	140.0
Upgrade Access Roads (2023) - Microwave Sites	-	-	-	-	-	132.0	132.0
Replace RTUs (2023) - Various	-	-	-	-	-	100.0	100.0
Replace Power Line Carrier - TBD (2023-2024)	-	-	-	-	-	90.0	90.0
Purchase Tools & Equipment Less than $50,000 (2023)	-	-	-	-	-	49.7	49.7
Upgrade Site Facilities (2023) - Various	-	-	-	-	-	48.0	48.0
Total Telecontrol	**595.4**	**4,312.0**	**1,943.4**	**5,339.2**	**1,535.4**	**1,778.0**	**15,503.4**
Transportation							
Replace Vehicles and Aerial Devices - Hydro System (2018-2019) - Various	1,667.2	753.7	-	-	-	-	2,420.9
Replace Vehicles and Aerial Devices - Hydro System (2019-2020) - Various	-	1,248.1	594.9	-	-	-	1,843.0
Replace Vehicles and Aerial Devices - Hydro System - Various (2020-2021)	-	-	2,153.0	745.0	-	-	2,898.0
Replace Vehicles and Aerial Devices - Hydro System - Various (2021-2022)	-	-	-	1,396.3	799.7	-	2,196.0
Replace Vehicles and Aerial Devices - Hydro System - Various (2022-2023)	-	-	-	-	1,400.0	816.9	2,216.9
Replace Vehicles and Aerial Devices - Hydro System - Various (2023-2024)	-	-	-	-	-	1,425.0	1,425.0
Total Transportation	**1,667.2**	**2,001.8**	**2,747.9**	**2,141.3**	**2,199.7**	**2,241.9**	**12,999.8**

Project Description	Expended to 2018	2019	2020	2021	2022	2023	Total
Administration							
Upgrade Exterior of Building - Hydro Place	260.2	405.7	-	-	-	-	665.9
Remove Safety Hazards - Various	-	197.5	-	-	-	-	197.5
Security Improvements - Hydro Place	-	47.1	48.0	-	-	-	95.1
Purchase Office Equipment (2019)	-	38.0	-	-	-	-	38.0
Replace Transfer Switch - Hydro Place	-	-	437.2	-	-	-	437.2
Pave Middle Parking Lot & Replace Curb & Drainage - Hydro Place	-	-	320.2	-	-	-	320.2
Remove Safety Hazards (2020) - Various	-	-	214.2	-	-	-	214.2
Replace Elevator Motors and Controls Equipment - Hydro Place	-	-	200.0	-	-	-	200.0
Refurbish Stairways, Railings and Entrance Ways - Hydro Place	-	-	129.4	-	-	-	129.4
Purchase Office Equipment (2020)	-	-	38.9	-	-	-	38.9
Replace Roof on Office Building - Bishop's Falls	-	-	-	300.0	-	-	300.0
Remove Safety Hazards (2021) - Various	-	-	-	219.6	-	-	219.6
Upgrade HVAC System - Bishop's Falls and Whitbourne	-	-	-	200.0	-	-	200.0
Purchase Office Equipment (2021)	-	-	-	70.5	-	-	70.5
Replace Warehouse Ramps - Postville	-	-	-	50.0	-	-	50.0
Replace Lower East Parking Lot Curbs, Catch Basins and Drainage - Hydro Place	-	-	-	-	500.0	-	500.0
Remove Safety Hazards (2022) - Various	-	-	-	-	220.0	-	220.0
Replace Domestic Water Valves - Hydro Place	-	-	-	-	100.0	-	100.0
Replace Cabinets in Kitchenettes - Hydro Place	-	-	-	-	60.0	-	60.0
Purchase Office Equipment (2022)	-	-	-	-	40.8	-	40.8
Replace Overhead Doors - Hydro Place	-	-	-	-	35.0	-	35.0
Replace Upper East Parking Lot Curbs, Catch Basins and Drainage - Hydro Place	-	-	-	-	-	500.0	500.0
Remove Safety Hazards (2023) - Various	-	-	-	-	-	220.0	220.0
Refurbish Leak Detection System - Hydro Place	-	-	-	-	-	100.0	100.0
Purchase Office Equipment (2023)	-	-	-	-	-	41.5	41.5
Total Administration	**260.2**	**688.3**	**1,387.9**	**840.1**	**955.8**	**861.5**	**4,993.8**
Total General Properties	**2,522.8**	**8,599.2**	**7,004.4**	**9,618.6**	**6,011.9**	**6,366.4**	**40,123.3**
Total (Including Allowance for Unforeseen Items)	**91,935.0**	**118,168.8**	**133,621.5**	**132,722.8**	**121,696.1**	**123,884.7**	**722,028.9**

Appendix B

TL 267 Project – 230 kV Transmission Line – Bay d'Espoir to Western Avalon Annual Report

TL 267 Project – 230 kV Transmission Line

Bay d'Espoir to Western Avalon

Annual Report

July 2018

newfoundland labrador hydro
a nalcor energy company

Summary

The Board of Commissioners of Public Utilities (the Board) approved the Newfoundland and Labrador Hydro Upgrade of Transmission Line Corridor (the Project) on December 12, 2014, with a total capital expenditure of approximately $291M and an in-service date of May 1, 2018. As TL 267 has a material impact on system reliability and eliminates system constraints relating to power flow to the Avalon Peninsula, the schedule was accelerated to be in service before winter of 2017.

The project includes expansion of the Bay d'Espoir (BDE) Terminal Station, expansion of the Western Avalon (WAV) Terminal Station (located in Chapel Arm), and construction of 188 km of 230 kV transmission line.

The transmission line and terminal station components of the project are now substantially complete, and the line was successfully energized and placed in service on December 6, 2017.

Work to be completed in 2018 includes: re-termination of the TL 208 line at Western Avalon Terminal station to the new station expansion; environmental reclamation work along the right of way and access roads and addressing any other deficiencies along the line; environmental monitoring; material reconciliation and establishing spare parts inventory; as-built submittals; and project close out documentation.

Cost expenditure is tracking as planned, with expenditure to date of approximately $277M.

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1 Introduction

The Board of Commissioners of Public Utilities (the Board) approved the Project on December 12, 2014. The Project, now known as TL 267, involves design and construction of 188 km of 230 kV steel tower transmission line, as well as station expansions at Bay d'Espoir and Western Avalon Station (Chapel Arm). The approved capital expenditure is $291,658,000. As directed by the Board as part of the release of the Project, an annual report shall be filed with each capital budget application until completion of the Project.

2 Project Description

On April 30, 2014, Hydro filed an application for approval to construct a 230 kV transmission line between Bay d'Espoir (BDE) Hydroelectric Generation Station and Western Avalon Terminal Station (WAV) at Chapel Arm, including upgrades at both stations to accommodate the new infrastructure. The Project was justified based on maintaining system reliability and meeting the long-term power requirements of the Island Interconnected System. It provides additional capacity, enhances resiliency to system faults, and relieves congestion on the existing transmission system. Based on the information supplied by Hydro as part of the Project review process, the Board released Board Order P.U. 53(2014) on December 12, 2014, approving the Project as described.

The Project is comprised of three distinct projects, and two sub-projects. The three distinct projects are:

1. The addition of portions of an air insulated breaker and one half station diameter at Bay d'Espoir Terminal Station 2, including:
   a. Two circuit breakers and associated disconnect switches; and
   b. Electrical and protection and control (P&C) equipment.
2. The addition of gas insulated switchgear (GIS) ring bus in Western Avalon Terminal Station at Chapel Arm; and
3. A new 230 kV transmission line 188 km in length linking the two stations.

The two sub-projects are:

1. Modifications to Bay d'Espoir Terminal Station 2 to allow for independent isolation of TL 206, converting the existing ring bus to a breaker and one half scheme; and
2. Modifications to Western Avalon Terminal Station to connect TL 208, which currently services the Vale site, to the new station expansion.

Given limited outage opportunities, the two sub-projects are being executed as second priority to TL 267 and are being completed as outage coordination and limitations permit.

The transmission line and terminal station components of the project are now substantially complete, and the line was successfully energized and placed in service on December 6, 2017. Work to be completed in 2018 includes: re-termination of the TL 208 line at Western Avalon Terminal station to the new station expansion; environmental reclamation work along the right of way and access roads and addressing any other deficiencies along the line; environmental monitoring, material reconciliation and establishing spare parts inventory; as-built submittals, and project close out documentation.

3 Engineering

The Project, including all station modifications and line designs, utilizes all of the latest industry standards, practices, and design criteria currently in use by Hydro. Modifications to the terminal stations include the latest electrical and protection and control equipment.

Transmission line design utilized Hydro's operational experience and design criteria applicable along the existing corridor to ensure a reliable addition to the Island Interconnected System. The design involved the creation of a new tower family capable of structurally maintaining reliable service with the inclusion of shield wires for lighting outage protection. The transmission line design was completed in 2016.

Detailed design for the terminal stations is also complete, including the design for the TL 208 re-termination, and the re-termination project is in the tendering phase.

4 Environmental Assessment

Given the size and nature of the Project, registration for environmental assessment (EA) under the Environmental Protection Act was required. The EA Registration Document for this project was an enhanced registration document, which included baseline studies for key environmental components such as caribou, avifauna, historic resources, rare plants, and an assessment of the effects of the Project on these components.

As consultation is a cornerstone of the EA process, Hydro consulted with key stakeholders and held open house sessions in June 2015 in select communities including Bay d'Espoir, Come By Chance, and Chapel Arm to inform stakeholders about the new line and to have meaningful discussions and identify concerns.

The Project was submitted for registration as an undertaking under Part 10 of the Provincial *Environmental Protection Act* on July 16, 2015. The release from further Environmental Assessment was subsequently issued by the Department of Environment and Conservation on June 15, 2016.

The preparation of a Decommissioning Plan was a requirement of the Project EA Release. The Decommissioning Plan addresses concerns specific to Hydro's operations and assets constructed adjacent to the Bay du Nord Wilderness Reserve (the Reserve). The plan details what assets are to be decommissioned as well as plans for limiting and discouraging illegal public access to the Reserve. The Decommissioning Plan also details the proposed methods for rehabilitating quarries, borrow areas, roads, and trails following the completion of construction on the Project.

The Decommissioning Plan is currently with the Environmental Assessment Division for review to establish the required scope of the environmental reclamation work along the right of way and access roads. The required environmental reclamation work will be completed during the 2018 construction season.

5 Procurement

Procurement activities are substantially complete with the remaining activities focusing on the reconciliation of construction spares with capital spare requirements.

6 Construction

Construction started with the commencement of the transmission line clearing in June 2016. Transmission line construction subsequently began in August 2016, followed closely by construction in the Western Avalon and Bay d'Espoir Terminal Stations in September 2016.

The transmission line and terminal station components of the project are now substantially complete, and the line was successfully energized and placed in service on December 6, 2017.

Construction work to be completed in 2018 includes: re-termination of the TL 208 line at Western Avalon Terminal station to the new station expansion; and environmental reclamation work along the right of way and access roads and addressing any other deficiencies along the line.

The TL 208 re-termination work is scheduled to take place in August and September 2018 and is being coordinated with and is dependent on required equipment and customer outages. Environmental reclamation and other work is scheduled to take place between June and October 2018. The final scope and start date for this work is dependent on receipt of approval from the Environmental Assessment Division of the Decommissioning Plan.

7 Cost

The bulk of the project expenditure occurred in 2016 and 2017, with a smaller fraction of spend forecasted to occur in 2018 for the scope described in Section 2. The expenditures are summarized as follows: $2.1M (2015), $59.3M (2016), $213.6M (2017), and $16.6M (2018). Expenditures over the last 12 months covered by this annual report primarily include engineering, material procurement, and construction-related costs.

The project S-Curve (Figure 1) reflects expenditures to the end of April 2018. Overall, $277M has been expended on the project to date and the project remains forecasted to be on budget at $291,658,000.

With respect to the major construction contracts, the transmission line construction contract is complete and has been closed out. The Bay d'Espoir Terminal Station construction contract is complete and has been closed out, and the Western Avalon Terminal Station contract is in the final closeout stage.

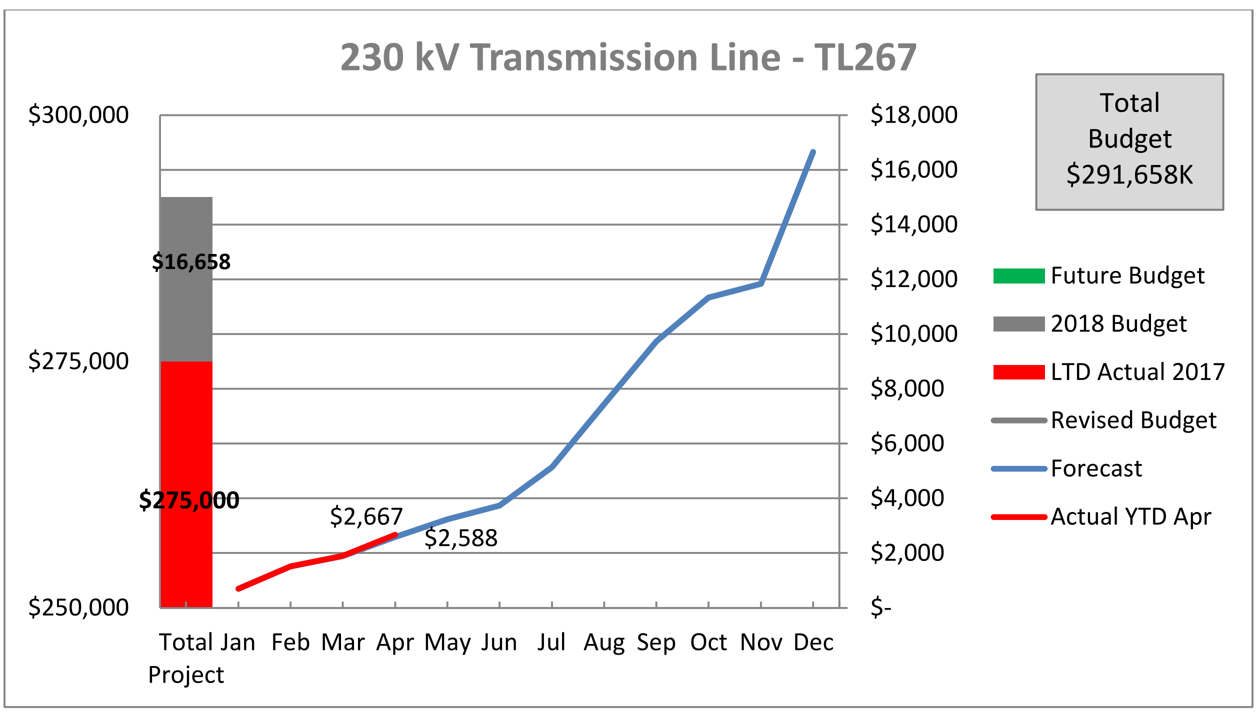

Figure 1: Project S-Curve

8 Schedule

The TL 208 re-termination work is scheduled to take place in August and September 2018 and is being coordinated with and is dependent on required equipment and customer outages. Environmental reclamation and other work is scheduled to take place between June and October 2018. The final scope and start date for this work is dependent on receipt of approval from the Environmental Assessment Division of the Decommissioning Plan.

Appendix C

Progress Report #2 (2012-2017) Review of the Current Wood Pole Line Management (WPLM) Program

Progress Report #2 (2012-2017)

Review of the Current Wood Pole Line Management (WPLM) Program

July 2018

newfoundland labrador hydro
a nalcor energy company

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1 Introduction

Newfoundland and Labrador Hydro (Hydro) maintains approximately 2,500 km of wood pole transmission lines operating at 69, 138 and 230 kV voltage levels. The pole plant asset includes approximately 26,000 transmission size poles. Figure 1 presents the overall Island Interconnected System transmission line network.

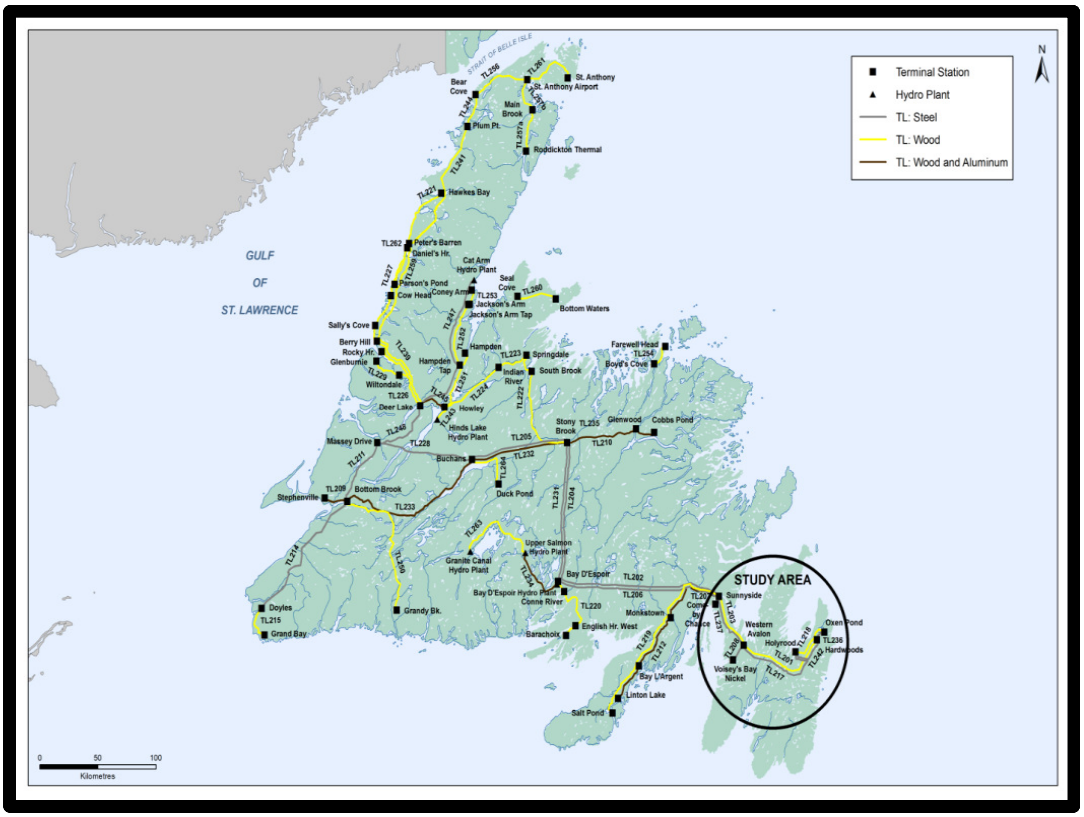

Figure 1: Island Map showing all High Voltage Transmission Lines and Study Area

Hydro first initiated the Wood Pole Line Management (WPLM) Program as a pilot study in 2003. Under this pilot study, Hydro completed the inspection of poles on the Avalon Peninsula. After the pilot study, Hydro determined that the program should continue as a long term asset management and life extension program. The program was presented to the Board of Commissioners of Public Utilities (the Board) in October 2004 as part of Hydro's 2005 Capital Budget Application. The proposal was supported in the application by the Hydro Internal Report titled *"Wood Pole Line Management Using RCM principles".* The program was approved by Board Order P.U. 53(2004). The emphasis was to support a planned shift from a time based to a condition-based maintenance program. Based on data collected to date, the WPLM Program has improved the reliability, extended the life of the pole plant asset and reduced the total cost of ownership over the complete life of the poles. It should be noted that the results reported in this study consider only the pole inspection data since 1998, and excludes data such as line failure under extreme wind and ice conditions, or any other poles replaced previous to the initiation of the WPLM program.

1.1 Basic Facts of the WPLM Program

- Identification of "danger poles (non climbable)" that require immediate replacement to avoid safety hazards.
- Inspections conducted to identify poles that need to be replaced to maintain structureal integrity and reliability.
- Long-term maintenance of accurate pole plant asset data.
- Streamlining of capital budgeting process based on condition data.
- Treatment of poles to protect against decay and ant attacks thus extending the life of the asset.
- Extension of asset life.
- Life extension also provides an opportunity to reduce environmental footprint because Hydro replaces less poles.
- Reduction of total ownership costs.

2 Scope of WPLM Program

The objectives of the WPLM Program were to address four specific items as follows:

1. inspect poles and associated line components such as conductor, hardware and insulators;
2. treat all poles;

3. develop and implement an electronic data collection system to facilitate field data collection and subsequent data analysis; and
4. make data based, optimized decisions to rehabilitate, or replace poles and associated hardware.

The aim of the program is to ensure that deteriorated poles are identified and retreated for life extension, and identify in a timely manner poles requiring replacement before in-service failures occur, thereby avoiding more expensive repairs, service outages and danger to line workers.

3 Report Scope

As stated in Board Order P.U. 2(2012) *"This report should provide evidence of, for example, results of non-destructive testing, undertaken to date, whether the program has met the stated objectives of deferring replacement of assets, if the program has resulted in improved reliability of the system, and what the current best practice is in other jurisdictions with respect to wood pole asset management."*

In order to provide evidence with specific examples to show what Hydro has accomplished so far with the WPLM program, the following areas are presented in this progress report to show the validity and the justification of continuing such a program in the future.

- improved reliability of the system
- current industry's best practice in other jurisdictions
- demonstrated evidence of the actual and expected long term benefits

The analysis presented in this report primarily considers the data for two of the lines in the Avalon Peninsula transmission line system. These lines were chosen because they are exposed to the most severe environmental conditions representing the worst case scenario, and it has data available for multiple inspection years. The first comprehensive Progress Report (Interim Report) was submitted to the Board in the 2013 Capital Budget Application in 2012.[1]

4 Improved System Reliability

Figure 2 illustrates the transmission reliability improvement of the Island Interconnected System. It shows the total forced outage hours due to structural failures on wooden transmission lines before and after implementation of the WPLM program. The pilot project on WPLM started in 2003 with a two year duration. The full program was launched in 2005.

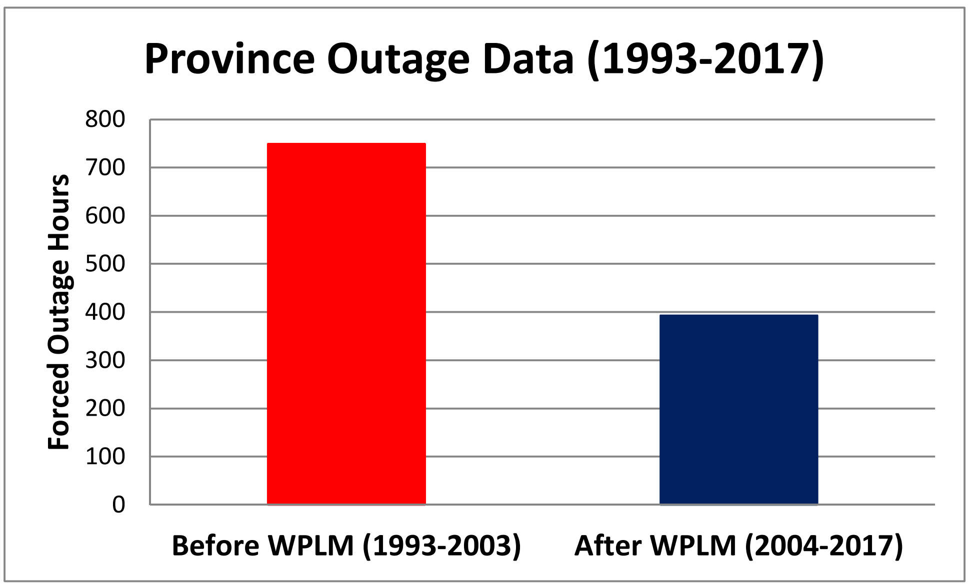

Figure 2: Outage Data for the Province

[1] Please refer to http://www.pub.nf.ca/applications/nlh2013capital/files/application/NLH2013Application-WoodPoolLineMgt.pdf.

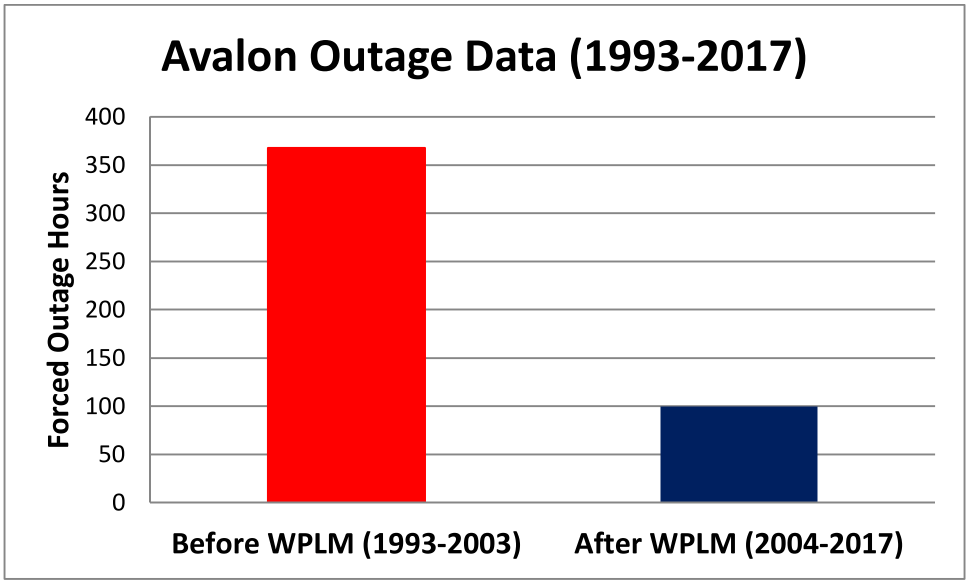

Figure 3: Outage Data for Avalon Peninsula

As shown in Figure 2 and Figure 3, the outage data demonstrates that there has been a material improvement on the Avalon Peninsula since the WPLM Program was launched in 2003. During this same period, the Avalon has experienced severe wind and ice storm events. The improvement on the Avalon Peninsula is over 70 percent, and the province-wide improvement is close to 50 percent.

5 Industry Best Practice

Two benchmarking criteria were used to compare Hydro's WPLM Program data with industry best practice. The first considers the annual cost of maintenance with respect to the replacement asset value (RAV). Based on Avalon Peninsula pole plant asset data, the ratio of average annual maintenance cost over RAV is 0.10%, well below the generally accepted industry best practice of one to four percent.

The second criterion uses other utilities' replacement rate data obtained from various sources. Hydro's current WPLM program is in line with many utilities' best practices within North

America. A CEATI survey conducted in 2012[2] by the Wind and Ice Storm Mitigation Interest Group indicated that most utilities have:

- regular inspection program;
- preventive treatment program; and
- realized life extension.

The comparison of Hydro's replacement rate and the expected mean life is also in line with other utility data when one considers the variability in climatic conditions. Hydro's comprehensive inspection and maintenance program enables measurement and comparison on an ongoing basis to ensure the program continues to deliver against stated objectives.

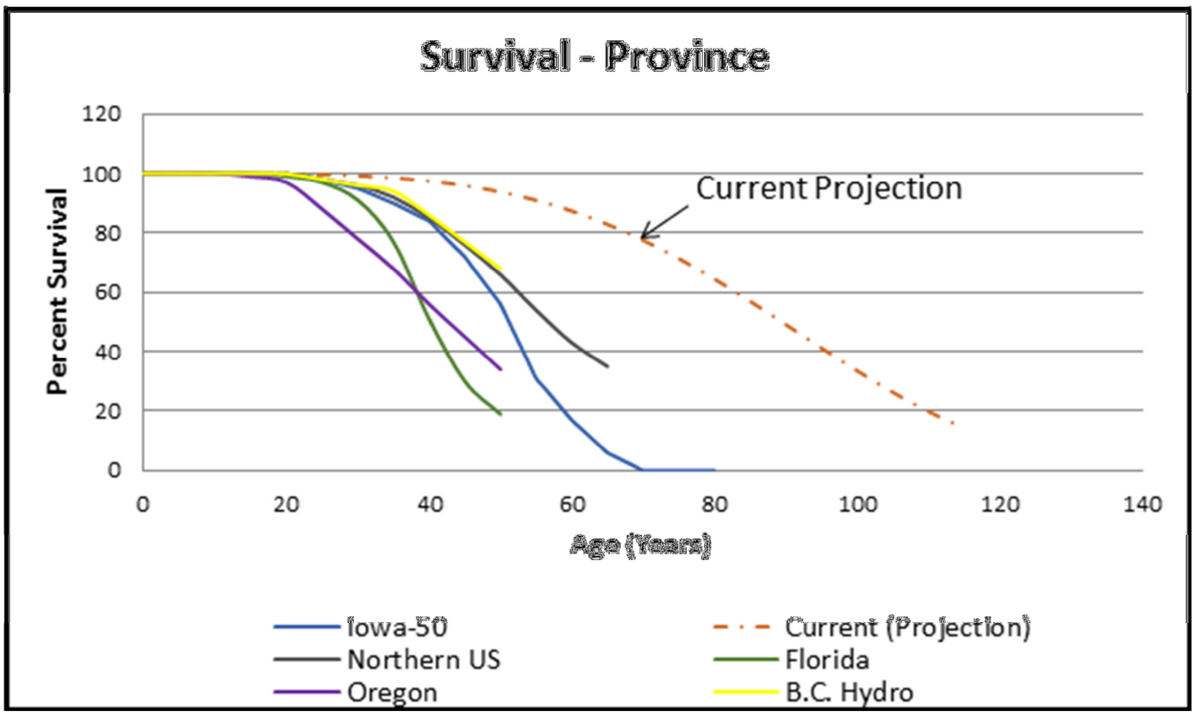

Figure 4: Comparison with Other Utilities

Figure 4 compares typical wood pole plant survival rates and indicates demonstrable value from the WPLM Program as compared to other North American utilities.

[2] Goel, 2012.

The comprehensive inspection and maintenance program of the WPLM Program provides the basis to ensure investment on the appropriate assets in a timely manner. Hydro's pole replacement rate is 0.36% per year for the Avalon and 0.10% per year for the province compared to the published data of 0.5 percent to 0.7 percent per year for the west coast of North America. The continued collection and analysis of field data through the WPLM Program is critical to extracting this demonstrated value.

6 Program Benefits

6.1 Reliability Improvements

The outage data shows that there has been an Island wide step change reduction in failures since the WPLM Program was launched despite the line system experiencing severe ice storm events in 2008 and 2010 and a number of wind storms including Hurricane Igor in 2010 and the wind storm of March 2017. This improved performance is attributable to the on-going inspection and preventive treatment program that Hydro has carried out since 2005.

6.2 Asset Life Extension

A standard 50-year IOWA curve was used for this study as a reference base case. The 50-year curve shown in Figure 5 indicates that 50 percent of pole plant asset is typically replaced by the time the asset age has reached 50 years. Figure 5 also illustrates the survival curve for the pole plant asset for the Island Interconnected System.

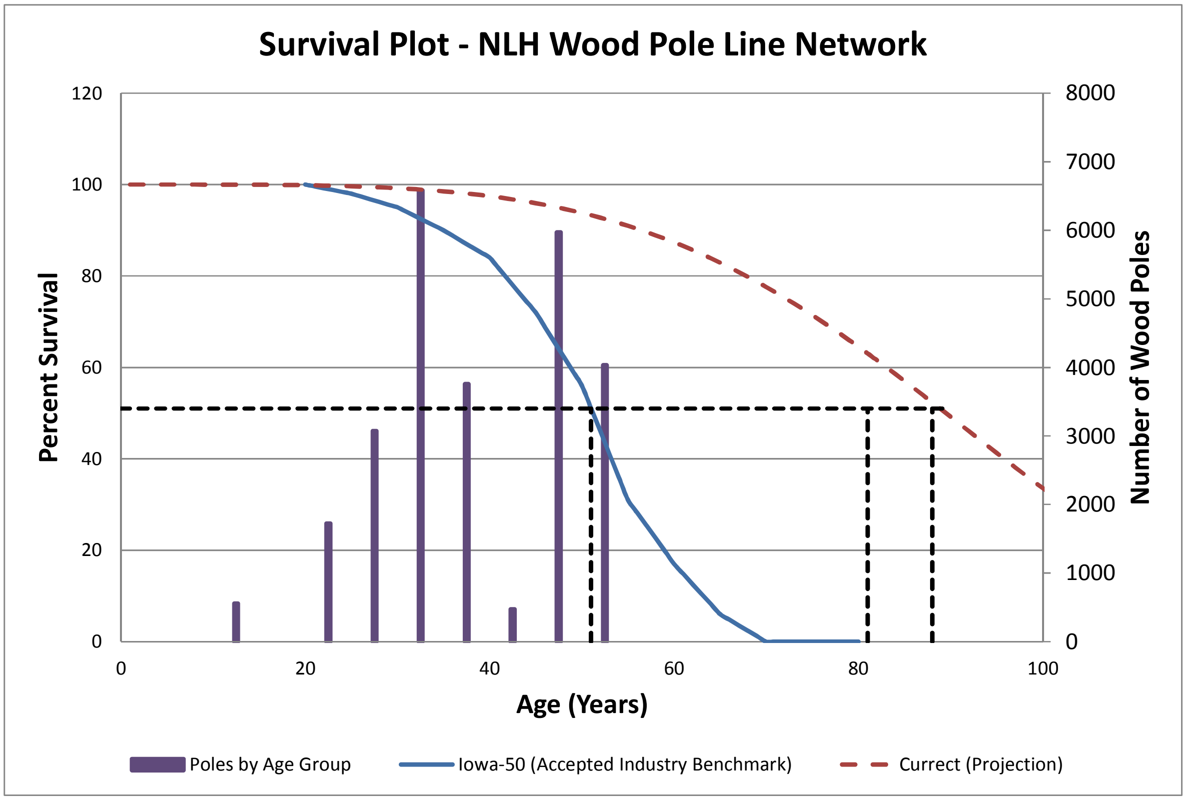

Figure 5: Survival Curves for the Pole Plant Asset (Island Interconnected System) and the Asset Age Distribution

Data analysis from the first fourteen years of the WPLM Program is aligned with an incremental increase in effective average pole life. This gain in the expected asset life of the entire pole plant asset can be achieved through the successful continuation of the WPLM Program.

Figure 6 utilizes the data from four inspection cycles (1985, 1998, 2005, 2015-2017) for the Avalon Peninsula pole system. Hydro's original data closely follows the IOWA curve. Furthermore, it is expected that the pole treatment program will extend the life of the pole plant asset. This is shown by the solid blue curve. Based on the current projection (solid red curve), the expected mean life is approximately 80 years[3], which is significantly higher than the

[3] The 80 year projected life determined in this study is greater than the approximately 60 year estimated useful life derived in the 2015 depreciation study. The difference is primarily because this study considers only the pole

conventional economic life of 40 years historically used in the industry.[4] This projection will be further refined as more data is collected, but it can be seen that life extension is being recognized through execution of this project. The typical IOWA curve assumes an expected asset life of 50 years. Analysis of data shown in this report indicates that the asset life of the pole plant asset on the Avalon Peninsula is 30 years longer than the benchmark IOWA.[3] Hydro has revised its asset depreciation of pole life from an estimated useful life of 53 years to an average life of approximately 60 years,[3] which is reflective of the life extension now being realized.

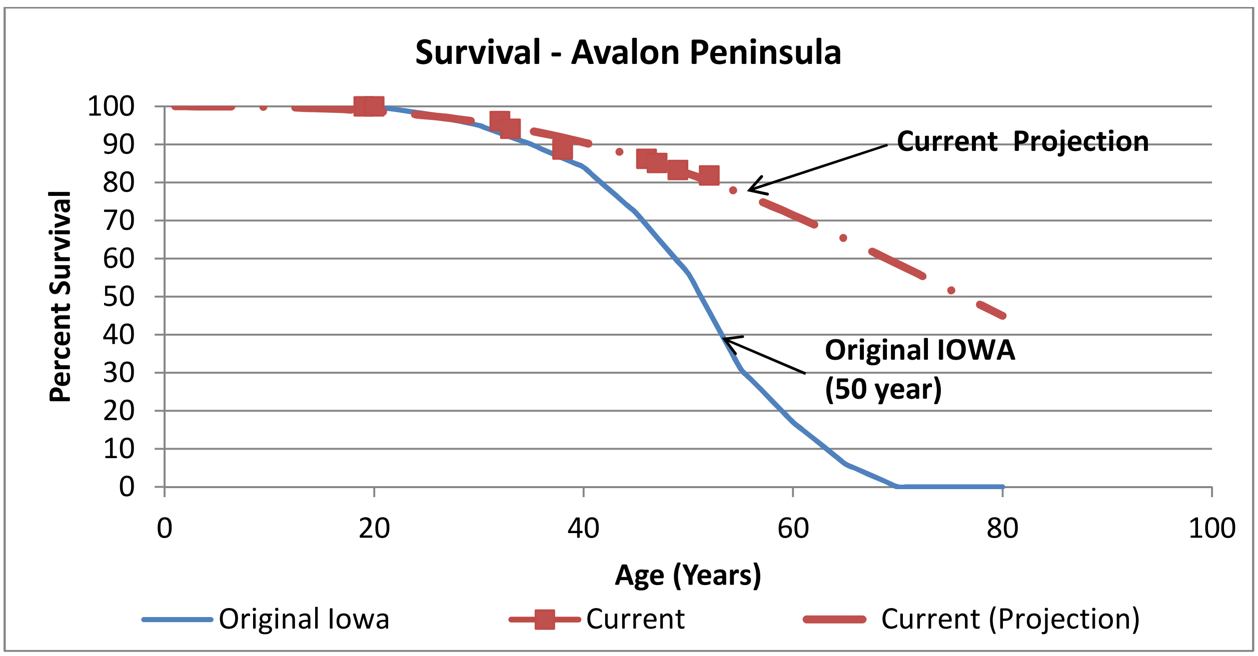

Figure 6: Survival Curves for Avalon Pole Plant Asset

6.3 Reduced Total Cost of Ownership (Net Present Value Analysis and Results)

Based on Hydro's cost data, Figure 7 compares the unplanned replacement cost versus planned replacement cost of a pole.

inspection data since 1998, and excludes data such as line failure under extreme wind and ice conditions, or any other poles replaced previous to the initiation of the WPLM program.

[4] Mankowski, Hansen and Morrell, 2002.

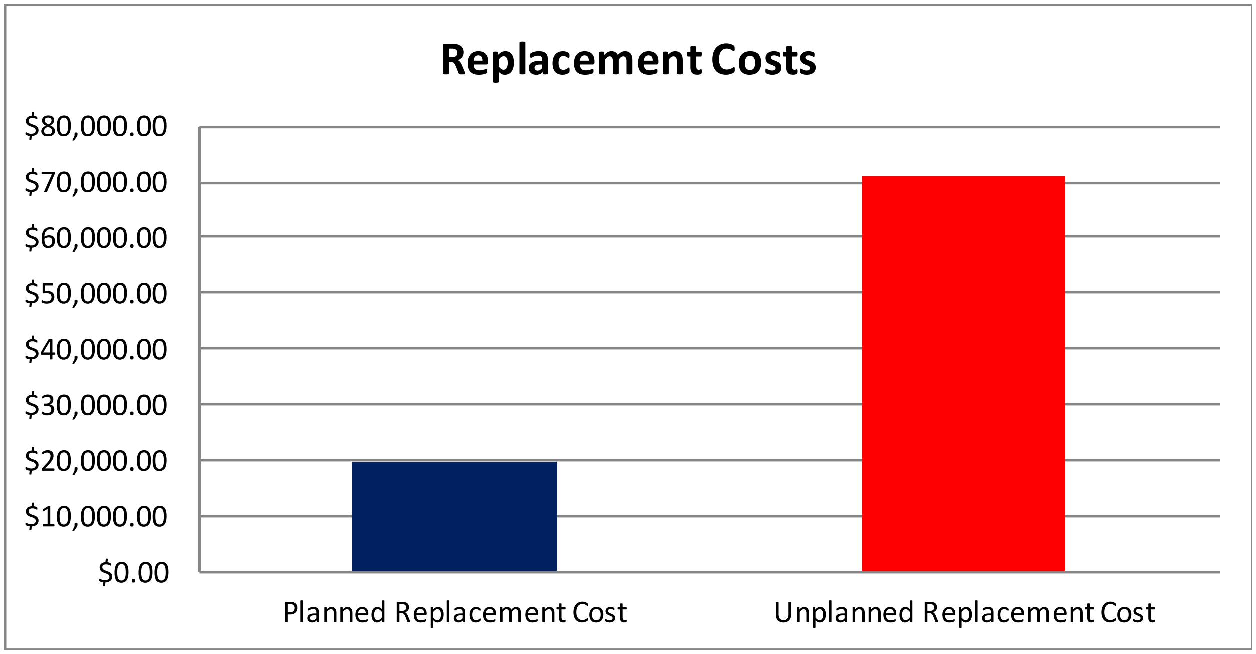

Figure 7: Comparison of Costs – Planned versus Unplanned

6.3.1 Optimum Inspection/Maintenance Interval –Justification (Haldar,2018)

A Weibull probability distribution model was developed and the analysis of a line on the Avalon system provides an optimum maintenance (inspection) interval where the cost of maintenance (inspection) is balanced against the future replacement (failure) cost. Based on Hydro's cost data, results show that the model predicted inspection interval (Figure 8) is in line with several utilities' best practices.[5] Freeman and Ragon (2010) also reported a typical inspection cycle as 8 -12 years for wood pole lines. Their study was based on the following inspection techniques: visual, sound and bore, full excavation and treatment for achieving 99% efficiency.

[5] Murkowski, Hansen and Morrell, 2002

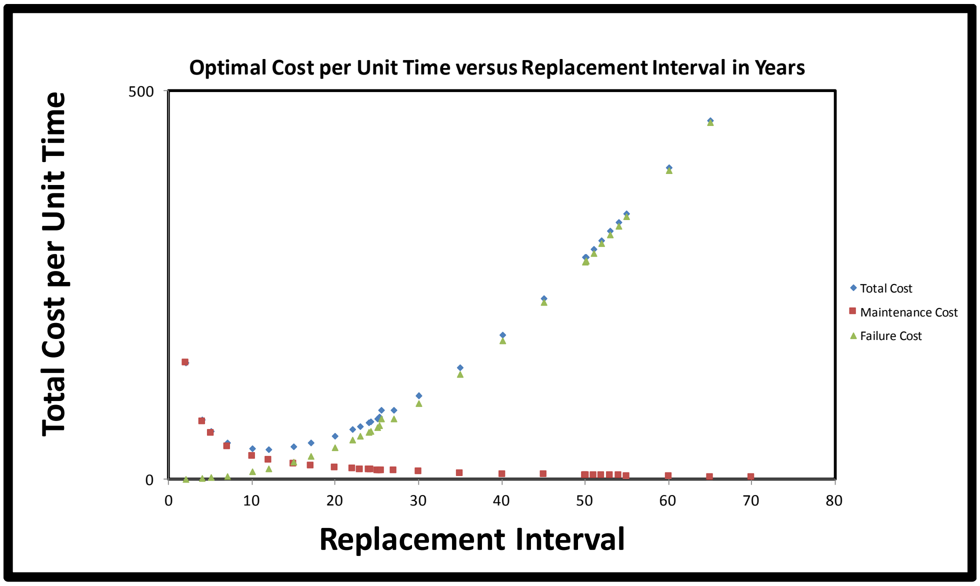

Figure 8: Optimum Inspection/Maintenance Interval

6.3.2 NPV Analysis of Cost Deferral – Maintenance of Existing Line Asset versus Building New Line Asset

By maintaining the asset health in good condition, Hydro will be able to defer the cost of replacing the pole plant asset (i.e. building new lines). Figure 9 shows the net present value of the asset replacement cost for a service life of 50 years calculated for the 10-year period of 2018-2027. This cost is compared with the maintenance cost under the WPLM program during the same period. The customer will benefit from cost avoidance by not replacing the Avalon Peninsula pole line system in 2018 because the lines can be maintained for an incremental 10-year period until 2027 and potentially beyond 2027 depending on what Hydro finds during the next five-year inspection cycle.

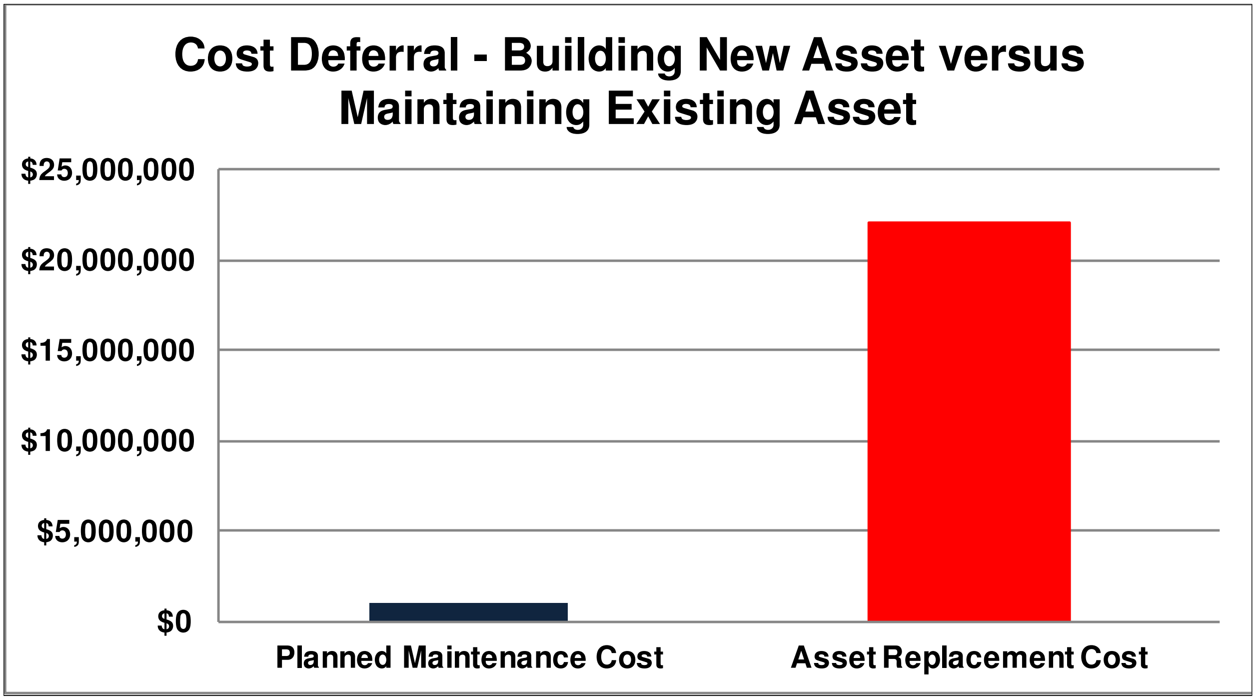

Figure 9: Benefit of WPLM Program – Cost Deferral for New Asset

7 Non-destructive Tests

Hydro's WPLM program is a comprehensive pole inspection, test and treatment program. It consists of two 10-year cycles initiated in 2005. Under this program poles are inspected by sounding, boring and visual means. Poles are then internally treated with preservative where appropriate, and identified for scheduled repair, or replacement if deemed necessary. A limited number of full scale tests are also done periodically to validate the field data. Figure 10 presents the summary of defects found during the inspection of Island Interconnected System.

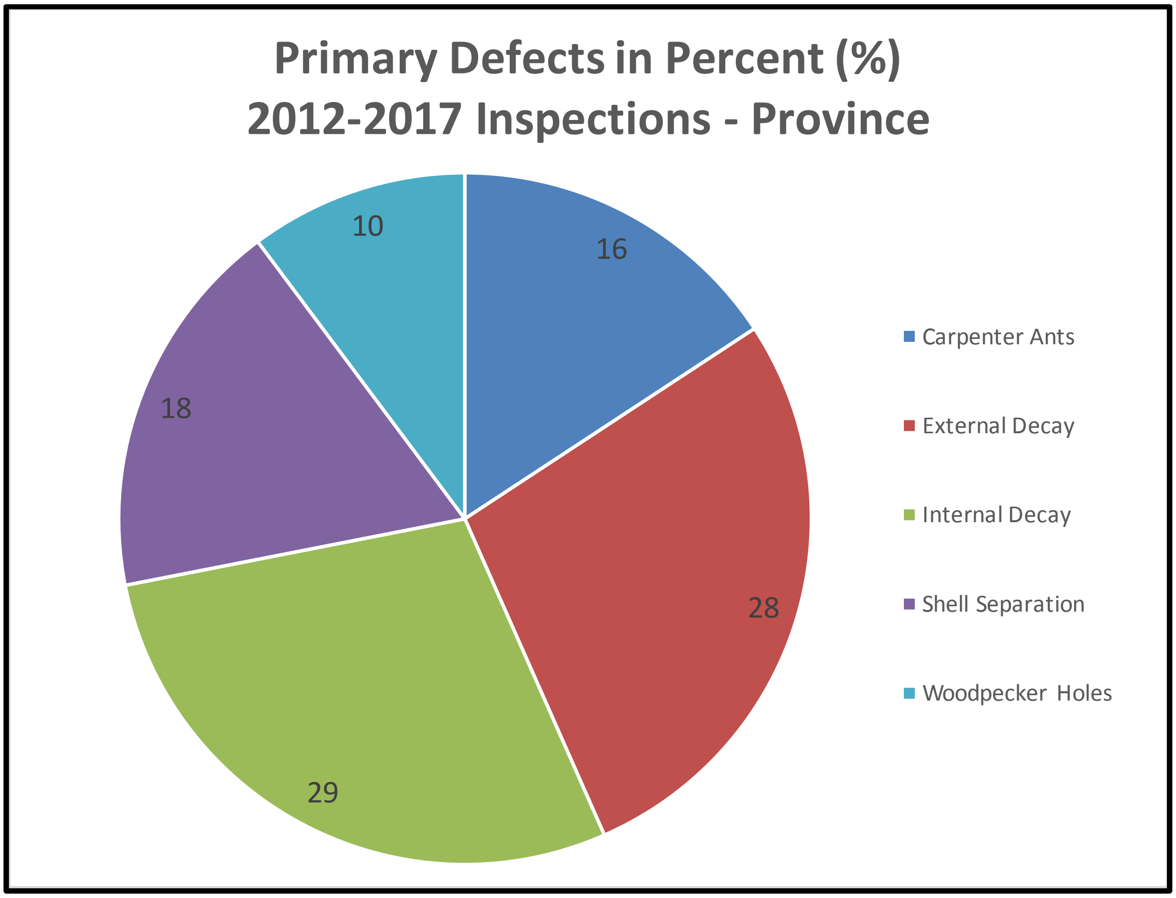

Figure 10: Primary Defects found during the Inspection of Avalon Pole System (2012-2017)

Major findings from the field tests are:

- pole strength and capacity declines with age; and
- danger poles (not climbable) or the poles that do not meet the design strength must be replaced to maintain safety and avoid forced outages.

8 Summary

In summary, Hydro's WPLM program is achieving the goals of increasing reliability, extending asset life, and reducing total cost of ownership. This WPLM Program is well aligned with best practices used in the industry.

The assessment demonstrates that the cost of the WPLM Program and the inspection interval of 10 years is well justified by cost avoidance savings through reduced in-service failures and reduced unplanned repair costs, as well as life extension of existing pole plant assets by between 10 to 20 years. The overall pole replacement rate per year is well below the published industry data. The development of a rigorous methodology to assess and analyze the pole inspection data allows Hydro to continue to proactively identify the right level of expenditure on the right poles at the right time.

9 References

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Appendix D

Gas Turbine Planning Report

Gas Turbine Planning Report

July 2018

Summary

Asset Condition and Useful Life Summary

The Hardwoods (HWD) and Stephenville (SVL) gas turbine facilities were placed in service in 1976 and 1975 respectfully. Both facilities were designed and supplied by Curtis Wright to supply 50 MW of electrical power by utilizing two 25 MW Rolls Royce Olympus C gas generators to drive a single Brush alternator. Since being placed in service, both facilities have played several key functions in maintaining the reliability of Hydro's Island Interconnected System (IIS), including peaking, emergency and continuous power supply and synchronous condense support.

Until 2014, both Hardwoods and Stephenville gas turbines saw minimal operating hours in either synchronous condense or generate modes. As such, the maintenance of the facilities was tailored to ensure the reliability of these plants based on their historical operating regime. In 2014, system requirements and operational issues on the Island Interconnected System (IIS) necessitated a significant increase in the operation of these facilities. Hydro reassessed the maintenance philosophy of its gas turbines to ensure the facilities can meet the new operational requirements of the IIS. The changes to the maintenance philosophy have resulted in an improvement of the Utilization Forced Outage Probability (UFOP) metrics for both plants. A newly adopted metric, Derated Adjusted Utilization Forced Outage Probability (DAUFOP), for both facilities have remained consistent since 2014. Therefore, while the availability (UFOP) of the facilities improved, both plants experienced deratings (DAUFOP) that were primarily a result of operational issues associated with the gas generators. Since 2014, Hydro has experienced six gas generator failures resulting in the engines being removed from service and shipped to an overhaul facility for repair/overhaul. The nature and frequency of these failures has caused Hydro to reassess the long term plans for the Hardwoods and Stephenville gas turbine facilities.

Hydro conducted an asset management review of the Hardwoods and Stephenville Gas Turbine Plants, which included a review of the plant failure history, the ability to maintain key components, and the availability and cost of replacement parts. From this review, Hydro concluded that several key components of the plants are obsolete, or are becoming increasingly more difficult and costly to procure. These components include:

- Rolls Royce Olympus C Gas Generator;
- Curtis Wright Power Turbine, including bellows and deflector rings;
- Automatic Voltage Regulator, and;
- Human Machine Interface.

Hydro has investigated options to address these obsolescence issues to allow the continued operation of the facilities to their originally planned end of service dates (HWD 2025 and SVL 2028). These options included status quo operation, repowering[1] the facilities, conversion to synchronous condenser facilities as well as early retirement. Continued status quo operation will require approximately $25.7 million in capital expenditures to ensure the continued reliable operation of Hardwoods and Stephenville gas turbines until 2025 and 2028. The majority of this investment would be overhauls of engines based on time and condition based overhaul. However, this does not address any of the known and pending obsolescence issues impacting these facilities, thus status quo operation is not a viable alternative. Repowering of these facilities was reviewed with various gas turbine manufacturers. It was determined that repowering, while possible, and is not a viable alternative as the majority of the existing facility will have to be replaced for the installation of new gas generators. The scope of replacements include but are not limited to; the gas generators; power turbines; fuel oil systems; lube oil systems; air inlet systems; exhaust systems; cooling systems; and control systems. This would be cost prohibitive and not a least cost solution.

Short and Long Term Plan Summary

As ordered by the Board in P.U. 43(2017), Hydro shall file *"a report setting out near-term and long-term plans for the Hardwoods and Stephenville gas turbines."*

[1] Repowering in this instance refers to replacing the prime movers for the plant and the associated auxiliaries as needed.

An initial review of the near term requirements for the facilities have indicated that both Hardwoods and Stephenville are required until Muskrat Falls is placed in service in 2021. The long term requirement for the Hardwoods and Stephenville gas turbines is currently under review as part of Hydro's supply adequacy study, to be filed at the Board in November 2018. As a result, Hydro has reprioritized its near term planned capital expenditures for 2019 to ensure that only those projects required to address immediate safety or reliability concerns are addressed. Regardless of the requirement for the Hardwoods and Stephenville gas turbines post 2021, a capital expenditure of $3.2 million is proposed in the 2019 Capital Budget Application.

As part of the supply adequacy study, Hydro is reviewing its existing system reliability criteria, comparing that criteria to that used in other jurisdictions, with the goal of proposing appropriate planning criteria for the system post-interconnection for the consideration of the Board and intervenors. If the study finds a requirement for generation or reactive power support, an analysis will be completed to determine the least-cost option to achieve the proposed level of reliability. As part of the options being considered in that larger study, it has been determined that Hardwoods could be converted to a synchronous condense facility, if required. Also, a transmission review of the requirement for the Stephenville gas turbine has determined that with the addition of a transformer to the Bottom Brook Terminal Station, the Stephenville facility would no longer be required from a transmission planning perspective post 2021. Therefore, Hydro has concluded the following options are possible dependent on the outcome of the Supply Adequacy Review:

1. Retire both facilities in 2021 if there is no requirement for them to support the IIS.
2. Convert Hardwoods to synchronous condense, if required, to support the Avalon Peninsula and retire Stephenville in 2021. The requirement to do so is being considered in Hydro's November 2018 Supply Adequacy Study.
3. If additional investment is determined to be required in the form of generation or synchronous condense capability and Hardwoods is not the required solution, Stephenville could be retired and spare components from Stephenville could be used to

increase the useful life of Hardwoods by 1-2 years, until a suitable replacement can be constructed if required.

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Appendicies

1 Introduction

Newfoundland and Labrador Hydro (Hydro) owns and operates three gas turbine plants as part of the Island Interconnected System (IIS). The Stephenville (SVL) gas turbine was commissioned in 1975 and is located in the town of Stephenville. The Hardwoods (HWD) gas turbine was commissioned in 1976 and is located in the west end of St. John's. Holyrood Gas Turbine Plant (Holyrood) is located at the Holyrood Thermal Generating Station and was commissioned in 2015.

The Hardwoods and Stephenville plants operate in either generation mode to meet peak and emergency power requirements or synchronous condense mode to provide voltage support to the IIS. The IIS experiences voltage fluctuations that result from changes in the supply and demand of electricity, requiring voltage correction to maintain proper voltage levels. System voltage is managed, in part, by using synchronous condensing equipment. It stabilizes voltage by acting as a shock absorber in the event that voltage drops due to system events. During synchronous condensing operation, the voltage drop is limited to no more than five percent below nominal operating levels of 230, 138, or 66 kV. Synchronous condensing is an important function of the Hardwoods and Stephenville gas turbine plants. Holyrood gas turbine plant does not have that capability. It was not a requirement of the plant when it was designed because IIS voltage support was being provided by other means. All three plants have seen increased operation from 2014 to present to support reliable customer service.

A condition assessment of the Hardwoods and Stephenville plants was completed in 2007 with the objective of increasing the useful service life of the plants to 2025 and 2028 respectively. The assessment was conducted assuming the limited operating regime of these plants would continue until the end of the plants useful life. These condition assessments determine the scope of the Gas Turbine Life Extension projects that were completed from 2010 to 2017.

In 2014, the operating regime of both Hardwoods and Stephenville materially increased. As part of Hydro's ongoing long term asset planning process, the increased operating regime necessitated that Hydro increase the operating and capital expenditures at both of these facilities.

Since 2014, Hydro has experienced several in service gas generator failures that required unforeseen additional capital and operating expenditures to ensure and improve the reliability of the Hardwoods and Stephenville plants. Due to the increasing capital expenditures, in service failures and the impacts on availability and reliability of the Hardwoods and Stephenville facilities, Hydro conducted a long term asset planning review to determine the remaining useful service life and the near and long term plans for both facilities. The asset management review has identified that obsolescence issues relating to the prime movers of these facilities impact the reliability of the facilities. The potential solutions to address the obsolescence issues will have an impact on the long term reliability of the IIS and the best solution can only be determined once the long term requirement for the plants have been determined. Thus, the long term requirements for these facilities are being reviewed as part of Hydro's on going supply adequacy study, which will set Hydro's system reliability criteria and will identify any long term requirement for additional generation or synchronous condense sources. The result of the supply adequacy study will be finalized and submitted to the Board in November 2018.

2 Description of Equipment and Operation

The Stephenville and Hardwoods gas turbines are both 50 MW modular plants designed and supplied by Curtis Wright (CW), known as the MOD POD 50. These plants consist of two 25 MW Rolls Royce Olympus C gas generators, two CW power turbines, powering a single 60 MVA electrical generator (alternator) through two SSS clutches. The plants can operate in generation mode to support the Island Interconnected System during times of peak demand.

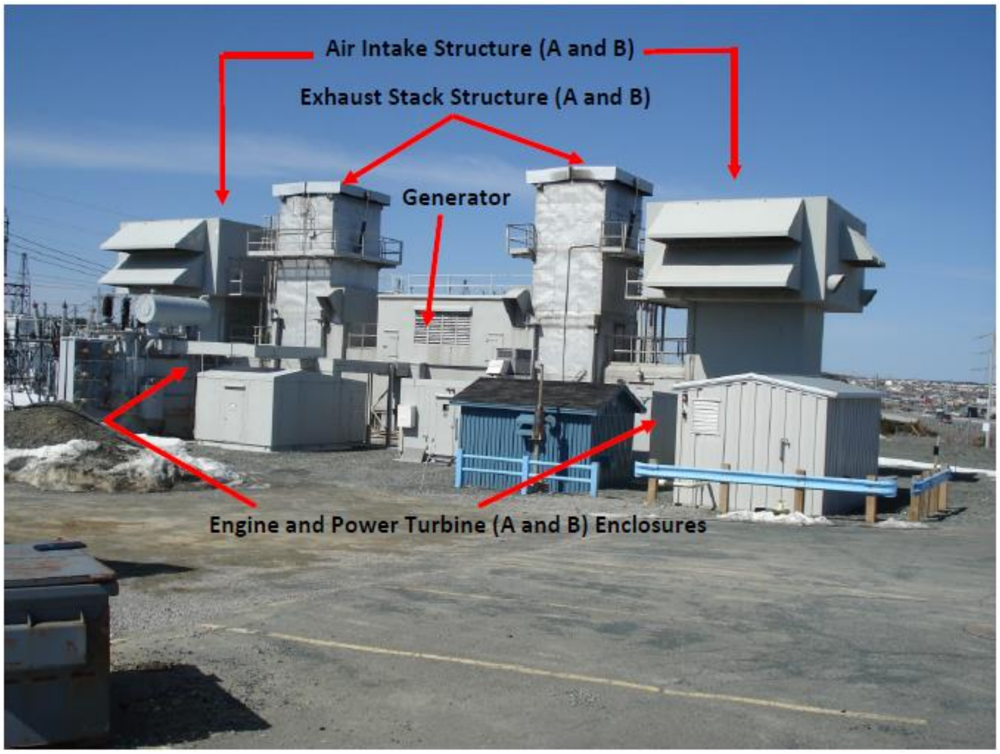

Figure 1: Hardwoods Gas Turbine

Figure 2: Stephenville Gas Turbine

When operating in generate mode, the gas generator pulls the working fluid (air) through the air intakes where it is filtered prior to entering the gas generator. The gas generator then compresses the air, mixes it with fuel and combusts the mixture to add energy to the fluid by increasing its temperature and pressure. The hot gases are blown on the gas generator's turbine section to remove the majority of energy from the exhaust gases to drive the gas generator's compressor. The hot gases then hit the power turbine, where the remaining energy is removed to drive the alternator. When generating with both gas generators in operation, the plants can produce up to 50 MW of electrical power. The plants can produce up to 25 MW with just one gas generator in operation. The plants are capable of providing synchronous condense support to the IIS by operating the alternator decoupled from the power turbines.

3 Operational Regime

Since their original installation these plants have provided the following support functions to the IIS:

- They are part of the island system reserve capacity and thus provide power under system peaking and emergency/contingency conditions;
- In synchronous condenser mode, the units provide reactive voltage support for the major load centers on the Avalon and Port aux Port peninsulas;
- The gas turbines are a part of the contingency plan for the reliable supply of power to the St. John's and Stephenville areas; and
- The units are used to facilitate planned generation outages and planned Avalon Peninsula transmission outages.

The Hardwoods and Stephenville gas turbines operated a minimal amount from 1993 to 2013, as shown in Table 1.

Table 1: Gas Turbine Average Operating Hours 1993 to 2013

Plant	Annual Average Generating Hours	Annual Average Synchronous Condense Hours	Total Average Operating Hours
HWD	69	3055	3126
SVL	28	2460	2489

In 2014, the criteria for dispatching the units materially changed and they have since been operated much more frequently and for longer periods with a good deal of operation at low loads. The load demand on the IIS has continued to increase, and coupled with new dispatching criteria, has resulted in dramatically increased operating hours for both plants as shown in the Table 2.

Table 2: Gas Turbine Operating Hours

Year	Hardwoods			Stephenville		
	Generate Hours	Synchronous Condense Hours	Total Hours	Generate Hours	Synchronous Condense Hours	Total Hours
2014	354	5,766	6,121	380	6,403	6,784
2015	410	5,626	6,036	236	4,749	4,985
2016	750	5,618	6,369	311	3,898	4,210
2017	323	7,126	7,449	140	7,666	7,807

To account for this change in operating regime, it was necessary for Hydro to reassess the previous maintenance philosophy. It was determined that an increase in maintenance and capital expenditures was required to ensure the level of reliability required to support the IIS until the in service of Muskrat Falls.

4 Maintenance Philosophy

The maintenance philosophy prior to 2014 was developed based on the operational requirements of the Hardwoods and Stephenville gas turbines at the time. Hydro carried out an extensive asset maintenance strategy (AMS) review in 2009, which reviewed the operation and maintenance practices for all of its assets, and compared Hydro's strategy to manufacturer's recommendations and to industry maintenance practices. This review determined the appropriate level of maintenance to ensure the supply of least cost, reliable power. Some of the key items of note from the AMS review for the Hardwoods and Stephenville gas turbines where:

- bi-annual borescope of the gas generator;
- annual lube oil sampling and analysis;
- five-year filter replacement interval; and
- six-year instrumentation inspection.

Though these maintenance intervals were deemed suitable for the level of operation of Hardwoods and Stephenville prior to 2014, it was not sufficient once the operating regime changed in 2014. Starting in 2014, the Gas Turbine and Diesel team began continually reassessing the AMS and modified it based on the new operational requirements. This resulted in the following changes:

- semi-annual borescope of the gas generators;
- monthly lube oil sampling during the winter operating season;
- annual filter replacements;
- annual instrumentation inspection/calibration; and
- annual generator inspections with Original Equipment Manufacturer (OEM) support.

With these changes Hydro personnel can identify potential reliability issues before they occur.

5 Gas Turbine Reliability

The reliability of the Hardwoods and Stephenville gas turbines are measured utilizing the Utilization Forced Outage Probability (UFOP) and Derated Adjusted Utilization Forced Outage Probability (DAUFOP). UFOP 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 metric that also measures the percentage of time that a unit or group of units will encounter a forced outage and not be available when required, but includes impact of unit deratings.

The UFOP for Hardwoods and Stephenville from 2005 to 2017 are presented in Figure 3. Hydro's base planning assumption is UFOP 10.62% while the near term planning assumption for UFOP is 20%. The average UFOP metrics for HWD and SVL since 2005 are 10.96% and 19.74%, respectively, if the failure of the Stephenville alternator in 2012 is included. Since the change in operating regime in 2014, the UFOP of both facilities have improved from 33.03% (HWD) and 15.55% (SVL) in 2014 to 2.91% (HWD) and 5.59% (SVL) in 2017. Since 2015 both facilities have exceeded the CEA average UFOP for 2013 to 2017, which is 18.54%. The improvement in UFOP can be attributed to modifications of Hydro's gas turbine maintenance program to match the new operational requirements, the lease of spare gas generators for installation in the event of an in-service failure, as well as increasing the size of the gas turbine and diesel team to ensure is it better resourced to respond reliability issues.

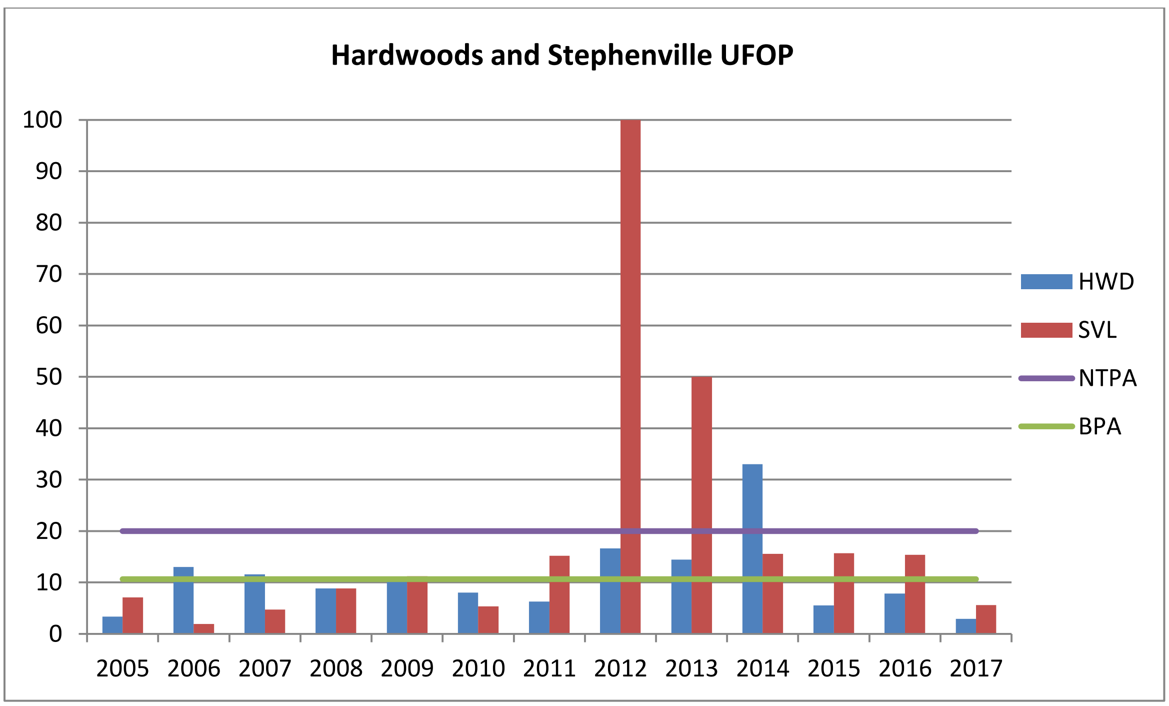

Figure 3: Gas Turbines UFOP 2005 to 2017

The DAUFOP for Hardwoods and Stephenville from 2006 to 2017 is presented in Figure 4. Hydro began reporting DAUFOP in 2018, thus the base planning assumption has not yet been set. The near-term planning assumption is 30%. The average DAUFOP since 2005 for Hardwoods and

Stephenville are 25.33% and 47.02%, respectively. The DAUFOP for Stephenville includes the failure of the SVL alternator in 2012. Since the operating regime changed in 2014, Hardwoods has improved to be consistently under the new 30% near-term planning criteria. Hardwoods DAUFOP is consistent with the 2013-2017 CEA average DAUFOP of 25.56%. Stephenville has been consistently higher than the CEA average since 2008. This was accomplished by minimizing the impact of gas generator failures by installing leased spare engines to reduce the total plant derating while Hydro's gas generators were being repaired. The failure of gas generators, and vibration issues with the End A berth in Stephenville, also negatively impacted the reliability of Stephenville such that the DAUFOP has been over 30% since 2008. Stephenville's DAUFOP has historically been higher than Hardwoods due to the criticality of the Hardwoods to the IIS. If a reliability issue occurred in Hardwoods, the impact of these issues has historically been mitigated by removing the required component from Stephenville. This improved the performance of Hardwoods while impacting Stephenville and as shown in Figure 4.

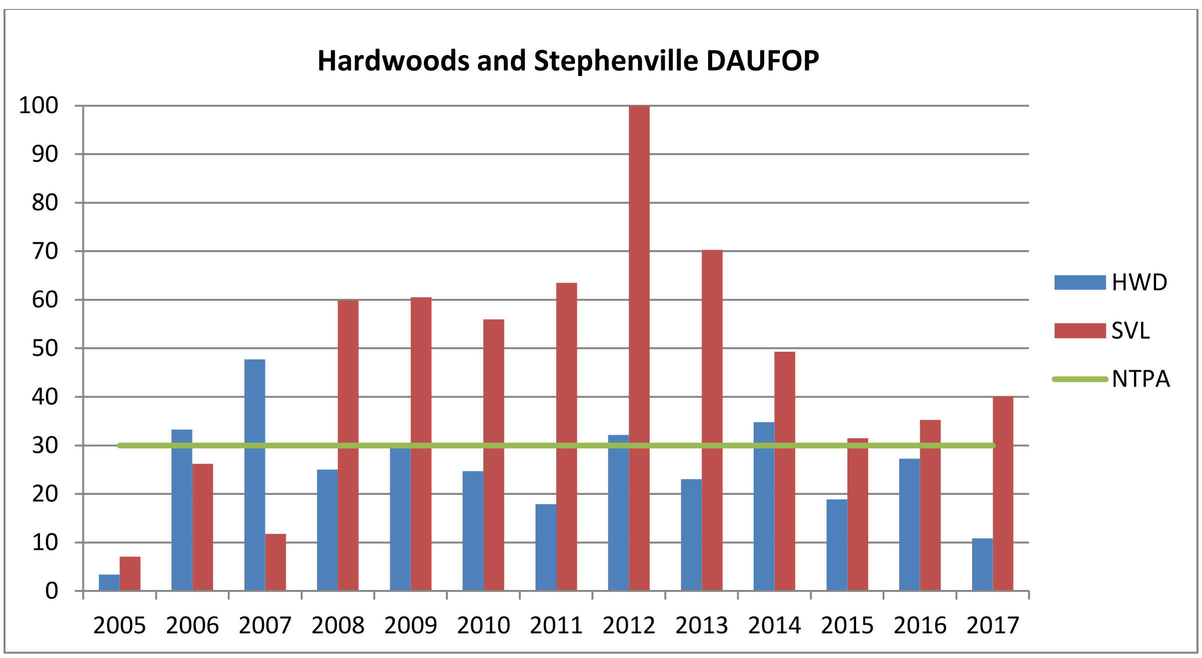

Figure 4: Gas Turbines DAUFOP 2005 to 2017

6 Operational Issues

The Hardwoods and Stephenville gas turbines have experienced several operational issues in recent years. The reliability issues that have had the greatest impact on the reliability of the plants have been related to the failure of the internal components of the gas generators. Since 2014, there have been six gas generator failures involving internal components of the gas generators. Primarily, the combustion cans have deteriorated to the point of failure resulting in additional damage to the High Pressure (HP) and Low Pressure (LP) turbine sections of the gas generator. All of these operational issues have resulted in the removal and shipping of the gas generator to an offsite facility for repair and/or overhaul.

7 Major Asset Status

As a result of the recent operational issues experienced at Hardwoods and Stephenville, in 2015 Hydro began an asset management review to determine the long-term ability to maintain the major components of each plant. This analysis included reviews of recent inspections, maintenance and failure history, and consultation with the OEM and OEM authorized representatives to determine the long-term viability of the major components. The assets included in the review are the gas generator (Rolls Royce Olympus C), power turbines, alternator, step-up transformer, automatic voltage regulator (AVR), control systems, and the unit auxiliaries. The key findings of these discussions are outlined below.

7.1 Gas Generator

In November 2004, Rolls Royce organized an Olympus operator’s forum to discuss with operators their plans for their equipment’s future so that a support strategy could be developed to manage the equipment to retirement. The information from the forum showed that the majority of the fleet would be retired from service in the 2010 to 2015 time frame.

In May 2006, Rolls Royce issued a service bulletin related to future support for Olympus gas generators to advise operators of the future support of these components. The service bulletin stated that these gas generators were introduced into service in the early 1960s and have been out of production since 1985. As a result, it was then becoming increasingly difficult and expensive to support these units. The volume of parts used in overhaul is very small and the Olympus parts use old materials and technology, accordingly suppliers were very difficult to find and would charge a premium to manufacture small quantities of parts. At that time, Rolls Royce decided to continue to supply parts until 2010. They also advised that Rolls Wood Group (RWG) would continue to maintain an overhaul facility for as long as there was sufficient demand.

Rolls Royce further advised operators of Olympus installations to develop either a retirement plan or a plan for continued operation of their equipment. Operators planning to operate past 2010 were advised to ensure they discussed their overhaul plans with RWG in advance so that parts could be provisioned to support the demand. Operators planning for continued operation past 2015 were advised to either plan to migrate to new products or build up a sufficient stock of spare parts, gas generators, etc. to provide support for the equipment's planned operational lifetime. They also committed to work with those operators who expected to operate past this date to put in place plans for continued support through to the equipment's retirement.

The OEM authorized overhaul facility for the Rolls Royce Olympus C gas turbine is RWG. In 2015 and 2016, Hydro consulted RWG to discuss the long term ability to service the Olympus C engines. RWG indicated that due to the age of the Olympus engines new replacement parts are no longer manufactured. Likewise, while some cold end (inlet and compressor sections) parts are available, there are very few new hot end (combustor and turbine sections) parts available, and as such a full overhaul to OEM specifications is not possible. The alternative is to complete repairs using rehabilitated components; however, some components such as life cycle limited spacers no longer exist. Additionally, any repairs cannot be completed to OEM specifications, which can result in increased vibration and limited service life, which Hydro is experiencing with recently repaired gas generators.

Hydro also contacted Alba Power, the third party overhaul shop that completed the most recent overhauls of Hydro's Olympus gas generators. They have utilized rehabilitated components to complete repairs for the most recent overhaul as outlined above. They have indicated that given our current operating regime, they would estimate our engines will last five to seven years or 1500 to 2000 operating hours. This is far less than previously anticipated following the completion of an overhaul. Hydro has therefore decreased the planned time between overhauls to 4 years, meaning that at least one gas generator overhaul will be required annually until 2025 assuming the plants continue to operate as they are currently operated. Hydro currently plans to overhaul one of its gas generators in 2019, which was last overhauled in 2013. Recent borescope inspections of this gas generator have indicated problems with the high pressure turbine section, which will be repaired in a planned manner in 2019.

Due to this information, it is the Hydro's position that the Rolls Royce Olympus C gas turbines are obsolete and are now the end of their service life.

7.2 Power Turbines

Hydro consulted the OEM for the Curtis Wright power turbines to discuss the long term ability to service the power turbines. FERN Engineering (the current OEM) has indicated that due to the age of the power turbines that the number of new components available is very limited. Also, the ability to have new components manufactured is becoming difficult and limited. This has resulted in increased costs and lead times to have new components fabricated as they are required. Some of the components of concern are:

- Power turbine blades: There are a limited number of new turbine blades available; there are not enough to completely rebuild a power turbine in the event of a catastrophic failure. There are a limited number of used power turbines available that might be available for purchase. The cost and lead times are currently unknown.

- Power turbine casings: There are no new casings available. There are a limited number of used power turbines that might be available for purchase. The cost and lead times are currently unknown.
- Bellows: The bellows (expansion joint between engine and power turbine) are of a design that is prone to failure due to fuel being trapped between the internal components of the bellows. This design was modified by FERN Engineering to reduce the risk of this type of failure; however, Hydro's bellows were not upgraded at the time. Two such failures were experienced in Hardwoods in 2017, one due to the apparent failure of an oil pipe within the engine resulting in accumulation of oil in the bellows and a second due to issues with a fuel control valve. Due to the age of the bellows, the tooling to fabricate/repair the bellows has to be custom made; resulting in increased fabrication costs (~$200,000 US per bellows) and long lead times (approximately 42 weeks). Hydro is currently refurbishing two bellows to incorporate the FERN Engineering's proposed modifications. These refurbished bellows will be installed prior to winter 2018.
- Deflector Ring: The deflector rings are a mechanical seal, which deflect exhaust gases away from the power turbine journal bearings to ensure the bearings do not overheat and fail while in service. The deflector rings have a limited service life (approximately 18 to 24 months) due to the thermal cycling they experience. FERN Engineering has indicated that the deflector rings, while still available, are becoming more difficult have manufactured.

Due to the limited availability and increasing cost of new components of the power turbines, the power turbines are considered to be at the end of their service life.

7.3 Alternator

Hydro consulted the OEM for the alternators, Brush GMS, related to the long term viability of the alternators. Brush has indicated that there are no obsolescence concerns with the alternators in Hardwoods and Stephenville as they have been replaced (Hardwoods) and rewound (Stephenville) recently. As these generators operate most often as synchronous condensers, there is an option to convert the alternators to synchronous condense service only. The alternators at both plants are therefore suitable for service for the foreseeable future.

7.4 Step Up Transformer

Hydro reviewed the latest inspection and test results for the step up transformers for the Hardwoods and Stephenville plants. The transformers at both facilities do not show any serious signs of deterioration despite their age. Hydro typically retires transformer assets based on test and inspection results and not on age. The transformers at both plants are therefore suitable for service for the foreseeable future.

7.5 Automatic Voltage Regulator

Hydro consulted the OEM, ABB Canada, for the Automatic Voltage Regulator (AVR) in Hardwoods and Stephenville. The AVR in Stephenville was replaced in 2009 and is still supported by ABB. ABB has advised that the AVR in Hardwoods has entered the limited phase and is approaching the obsolete phase of its life cycle. As such it will be increasingly difficult to support the AVR should operational issues occur. As such, Hydro has submitted a 2019 Capital Budget Application proposal to replace the AVR in Hardwoods in 2019-2020.

7.6 Control System

Hydro consulted the control system OEM, ABB Canada, to confirm the long-term ability to service these components. ABB did not identify any obsolescence issues with the distributed control system; however, ABB did identify that the human machine interfaces (HMI) in Hardwoods and Stephenville are obsolete. As such, Hydro has submitted a 2019 Capital Budget Application proposal to replace the HMI in Hardwoods in 2019-2020. Replacement of the HMI in Stephenville is currently under review.

7.7 Balance of Plant

The scope of the life extension projects to date has been focused on the balance of plant auxiliary equipment. As a result, many of the balance of plant components are suitable for an additional 15 to 20 years of service. In addition, replacement systems and components are readily available in the event of obsolescence or end of life issues. Therefore the balance of plant equipment is considered to be suitable for service with appropriate component replacement for the foreseeable future.

8 Plant Requirements

As part of the Hydro asset maintenance review completed for Hardwoods and Stephenville, the above noted obsolescence issues were identified. To properly determine the necessity of addressing the obsolescence issues at these facilities, Hydro is determining the near-term and long-term requirement for both Hardwoods and Stephenville facilities. The near-term life of the Hardwoods and Stephenville gas turbines is considered to be prior to the Muskrat Falls being released for service plus a full winter's operation which is estimated to be 2021. Whereas the long-term life is considered to be post Muskrat Falls in 2021 and are currently under review as part of Hydro's on going supply adequacy study, the results of which will be known in November 2018. The preliminary findings for both facilities are presented below.

8.1 Stephenville

Hydro is currently completing a resource planning and transmission planning review for the Stephenville Gas Turbine. The planning review consists of a review of the near-term and long-term generation requirements for the facility. The initial conclusion from the review has determined that the Stephenville Gas Turbine will be required for the near-term future until approximately 2021. The long-term requirement from a generating planning perspective, additional local or total system generation, is currently under review as part of the supply adequacy study, which will be finalized for November 2018.

From a transmission planning perspective, the replacement of existing gas turbine generating capacity is not required at the Stephenville site to meet transmission system planning requirements at this time provided that a 230/66 kV, 40/53.3/66.7 MVA power transformer with on load tap changer (and associated 230 kV and 66 kV circuit breakers and disconnect switches) are added at Bottom Brook Terminal Station. The addition of the 230/66 kV transformer at Bottom Brook Terminal Station will provide back up or spare transformer capacity for the loss of existing 230/66 kV transformer T1 at Stephenville Terminal Station or loss of 230 kV transmission line TL209.

8.2 Hardwoods

Hydro is currently completing a resource planning and transmission planning review for the Hardwoods Gas Turbine. The planning review consists of a review of the near-term and long-term generation requirements for this facility. The initial conclusion from the supply adequacy review has determined that the Hardwoods Gas Turbine will be required for the near-term future, until approximately 2021. The long-term requirement from a generating planning perspective, additional local or total system generation, is currently under review as part of the supply adequacy study, which will be finalized for November 2018.

From a transmission planning perspective, if the Hardwoods Gas Turbine is retired and not replaced in kind, it will be necessary to:

- advance the addition of 230/66 kV transformer capacity in the Hardwoods – Oxen Pond Loop in 2026;
- advance the rebuild of TL242 to avoid thermal overload for loss of TL266 over peak in 2031; and
- add an additional source of station service to Hardwoods 66 kV bus B8 in 2021.

9 Potential Solutions

As part of its on-going long-term asset planning process, Hydro has reviewed several options to address the obsolescence issues currently being experienced at Hardwoods and Stephenville, if the units are required post 2021. The options Hydro has considered are status quo operations, repower, the conversion of both facilities to synchronous condense operation only, and the early retirement of both facilities.

9.1 Status Quo

This option includes the continued operation of the gas turbine facilities until their end of service life as determined in 2007 as part of the "*Condition Assessment and Life Cycle Cost Analysis – Hardwoods and Stephenville Gas Turbine Facilities*", (HWD- 2025 and SVL- 2028). To ensure the reliable operation of these facilities given their current operating regime, Hydro will have to continue to invest significant capital, approximately $25.7 million, into these assets as outlined below in the capital plan review. The majority of this investment would be overhauls of engines based on time and condition based overhaul. Status quo is not considered a viable alternative as the prime movers at each plant are obsolete and despite the suggested capital investment of $25.6 million, the units would continue to experience operational issues and in-service failures resulting in plant and system reliability impacts.

9.2 Repower

Since the main components impacted by obsolescence are the prime movers (gas generators and power turbines) Hydro consulted the current suppliers of gas turbines to determine if repowering of these facilities is feasible. Repowering consists of replacing the prime movers for the plant and the associated auxiliaries as needed. In the case of Hardwoods and Stephenville, the gas generators, power turbines, air intakes, exhaust stacks, lube oil systems, fuel oil systems, and control system would have to be completely replaced or extensively modified to successfully repower these units. This results in a capital investment comparable to the construction of a new facility. Also, any of the repowering options would be a one-off design and as such OEM support and troubleshooting would prove difficult. Thus repowering is not considered a viable alternative should the facilities be required post 2021.

9.3 Conversion to Synchronous Condenser Only

The prime movers for each facility are suffering from obsolescence issues, which results in operational issues and increased Operating and Maintenance (O&M) costs to maintain an acceptable level of reliability. If it is determined that both facilities are not required to provide generation support, but voltage support is required for the long-term reliability of the IIS, both facilities can be converted to a synchronous condenser facility. Starting of the alternator for synchronous condense operation can be accomplished using the existing gas turbines or with the installation of a pony motor fitted with a variable frequency drive (VFD). Conversion of either of these facilities to a synchronous condense facility in either the near or long-term timeframe will required the transmission system modifications outlined in the plant requirements of this report. This is a viable alternative for the long-term future for these plants, in particular Hardwoods, should the need for synchronous condense be identified as result of the supply adequacy study. The cost of this option will be analyzed in the supply adequacy report if additional synchronous condensing is required in the future system.

9.4 Retirement of Stephenville

The prime movers for each facility are suffering from obsolescence issues, which results in reliability issues and increased O&M costs to maintain an acceptable level of reliability. The current status quo operation into 2025 and 2028 is no longer a viable alternative, also it has been identified that Stephenville will not be required to meet the transmission system planning requirement if the required upgrades to the Bottom Brooke Terminal Station are completed. Thus, the retirement of the Stephenville facility in 2021 can delay the retirement of the Hardwoods facility for 1-2 years. The retirement of Stephenville will provide spares of the obsolete prime mover components to minimize the impact of operational issues that may occur at Hardwoods. Thus the Hardwoods facility can continue to operate until Hydro has exhausted the spare components produced by retiring Stephenville. This option will require the proposed modification to the Bottom Brook Terminal Station (230/66 kV, 40/53.3/66.7 MVA power transformer, and associated 230 kV and 66 kV circuit breakers and disconnect switches) to ensure reliability from a transmission planning perspective for the Stephenville area.

9.5 Retirement

The prime movers for each facility are suffering from obsolescence issues, which result in reliability issues and increased O&M costs to maintain an acceptable level of reliability. If it is determined that these facilities are not required in any configuration for the long-term reliability of the IIS, both facilities can be retired and decommissioned. Retirement of either of these facilities in either the near or long-term timeframe will require the transmission system modifications outlined in the plant requirements of this report.

10 Capital Plan

As shown in the attached tables, Hydro has prioritized the capital expenditures for the Hardwoods and Stephenville gas turbines for 2019. The planned capital expenditures for Hardwoods and Stephenville in 2019 include only the projects that will be required to ensure reliable service until approximately 2021, when the Muskrat Falls is expected to be released for service.

10.1 Original Planned Retirement

To ensure the reliable operation of the Hardwoods and Stephenville gas turbines until their original retirement dates of 2025 and 2028 capital expenditures of $25.7 million will be required. The capital expenditure planned for 2019 is approximately $3.2 million, which is required regardless of the retirement date of the facilities. The detailed capital plan is outlined in Appendix A.

10.2 Early Retirement 2021

To ensure the reliable operation of the Hardwoods and Stephenville gas turbines until the first units in Muskrat Falls are placed in service a capital expenditures of $3.2 million will be required in 2019. Subsequent capital projects are subject to change depending on the results of the supply adequacy study. The detailed capital plan is outlined in Appendix A.

11 Supply Adequacy Review Update

Hydro is currently in the process of reviewing its reliability criteria and assumptions as a part of the Supply Adequacy Report (the Report), to be submitted to the board on November 15, 2018. The result of this review will allow Hydro to, among other objectives, assess the impact of the retirement of the Hardwoods and Stephenville Gas Turbines prior to the original retirement dates of 2025 and 2028. This section provides an update on the process and the current state of the Report.

Hydro currently reports to the Board two times per year on generation adequacy through the Near-Term Generation Adequacy (NTGA) Report. This report is submitted in May and November annually. The current report focuses on the ability of Hydro to reliably supply the Island Interconnected System (IIS) until the winter of 2021-2022 under a number of scenarios. The NTGA examines asset reliability, energy in storage, and forecast load, with appropriate sensitivities modeled as required. To support this analysis, Hydro conducts a thorough assessment of its assets and the potential risks to the reliable operation of key generation assets, reflected in the projections of availability metrics based on historical data and the anticipated impact of planned improvements. The NTGA also provides a probabilistic assessment of generation in the form of Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE).

Previously, Hydro had prepared an annual Generation Planning Issues Report. This report contained a discussion of load forecast and growth, sanctioned additions and retirements, suite of alternative supply options, and culminated in an expansion plan to meet provincial requirements. A separate report was produced addressing transmission issues. The last Generation Planning Issues Report was published in 2012.

11.1 Future Supply Adequacy Reporting

In August 2017, Hydro committed to provide a Report to the Board on November 15, 2018 containing:

- Demand and energy projections in the operational (<3 years) and planning (3-10 year) horizons;
- Asset integrity, in-service and retirement plans;
- System adequacy analysis including the identification of potential capacity or energy surplus/deficit;
- Discussion of near-term resource options;
- Generation expansion analysis;
- Sensitivity analysis; and
- Other issues as required.

In order to achieve this, Hydro intends to submit a report containing two volumes:

Volume I: (filed in November 2018 only)

- Review of historical and industry practices
- Recommended criteria and assumptions
- Setting of reserve margin target
- Alternate reserve margin targets for sensitivities

Volume II: (updated and filed annually)

- Assessment of 10-year supply adequacy
- Includes generation and transmission
- Identification of sources of supply
- Expansion required to meet planning criteria

After 2018, Hydro intends to request a modification to the Supply Adequacy Report submission schedule to report on an annual basis. Volume II of the report will be updated and filed annually while Volume I will be a reference document for future assessment of supply adequacy. It is Hydro's intent that the annually filed Supply Adequacy Report will incorporate aspects of the NTGA report and the Generation Issues Report, serving to apprise the Board of Hydro's ability to provide reliable service for customers in both the near and long term.

As a part of this report, the reliability criteria and assumptions that Hydro currently uses will be reviewed. Hydro has engaged a consultant, Daymark Energy Solutions (Daymark), to assist in this review. Hydro, with the assistance of Daymark, will review the best practices of other similar utilities, the NERC planning standards, and Hydro's historical practices to develop a new set of assumptions and criteria that will be appropriate for the system after interconnection.

11.2 Modelling

11.2.1 Historic Modelling

Historically Hydro has used Strategist, a software package developed by Ventyx, to calculate LOLH and to develop expansion plans. Strategist has a number of limitations that make it unsuitable after interconnection, including:

- Strategist does not support dynamic modelling of transmission lines. Accurate modelling of the Labrador Island Link is key to an accurate model of the provincial system;
- Hydraulic generation is not well supported and models become less accurate as the penetration of hydraulic generation increases; and
- The software will soon no longer be supported by manufacturer for new expansion planning activities and support is becoming more difficult to find.

11.2.2 Transition to Plexos

In 2017, Hydro started looking for a replacement for Strategist, with Plexos being identified as the preferred option. In August 2017 Hydro entered into a lease agreement with Plexos and is currently in the process of migrating its models from Strategist to Plexos. It addition to analyzing generation adequacy, Plexos is capable of embedding consideration of the hydrology, transmission and external markets when evaluating system adequacy. Plexos is used heavily in the utility industry, and is used by other Atlantic Canadian utilities.

The development of the expansion plan will be done in two phases, the setting of the reserve margin target and the development of the least cost expansion plan. Both will be done in Plexos. The specific details of the modelling approach will be described in detail in the November report. Hydro has engaged W H Energy Solutions, a Plexos modelling expert consultant, to assist in the development and verification of the model.

11.3 Generation Options

As a part of the expansion plan a number of sources of additional generation are considered as expansion candidates, should system conditions require generation expansion. Through its Plexos model, Hydro will evaluate all of the potential options and choose the lowest cost expansion plan that meets the reliability criteria. The following expansion options will be considered:

- Fast start gas turbines (60 MW and 120 MW);
- Combined cycle combustion turbine (170 MW);
- New hydro (Island Pond, Round Pond, Portland Creek, Exploits);
- Hydro units (Bay D’Espoir 8, Cat Arm 3);
- Wind (9 MW and 100 MW);
- Solar;
- Battery storage;
- Customer Demand Management (CDM) including rate-based approaches;
- Curtailable load; and
- Market purchases.

Several thermal options will be considered, 60 MW and 120 MW Simple Cycle Gas Turbines and 170 MW Combined Cycle Gas Turbines. Both options will use diesel fuel and will have fast start and synchronous capabilities. Several locations will be investigated for each thermal option.
There are three new hydro plants that will be considered, Round Pond, Island Pond and Portland Creek. Round Pond and Island Pond are 18 MW and 36 MW units respectively, on the Bay d’Espoir system. Portland Creek is a 23 MW isolated hydro plant on the Northern Peninsula.

There are also two expansions to existing plants that are being considered as a part of this analysis Bay d'Espoir Unit 8 and Cat Arm Unit 3. Bay d'Espoir Unit 8 is a 154 MW unit, identical to Unit 7. Cat Arm Unit 3 is a 68 MW Unit, identical to the other two units at Cat Arm. Both units would not provide any additional energy to the system, only capacity.

As an alternative to increasing new generation it may be more cost effective to offer incentives to reduce customer demand. The two methods of reducing customer demand that will be considered are curtailable contracts and customer demand management (CDM). Curtailable contracts include the continuation of the large industrial curtailable load contracts that are currently in place. CDM is providing incentives for smaller customers to reduce loads at peak. There are several approaches to achieving this, which will be discussed in the final report.

12 Conclusions

The Hardwoods and Stephenville gas turbines serve several important functions to the IIS and their local area. Several in-service failures have occurred in recent years that resulted in Hydro completing an asset management review of both facilities. Asset review has identified that many of the major components of at these facilities (gas generators, power turbines, HMIs and Hardwoods AVR) are obsolete. Continued status quo operation beyond 2021 of these facilities would require extensive capital expenditures to ensure the plants remain reliable until their original retirement dates (HWD- 2025 and SVL- 2028). Given the age of the gas generator and power turbines, the availability and condition of replacement components, and recent operational issues, the risk of continued in-service failures is high even with the original capital plan to reach the plants' end of service lives.

It is Hydro's opinion that these plants are not suitable for long term reliable operation as they are currently dispatched.

Hydro has concluded the following options are possible dependent on the outcome of the Supply Adequacy Review:

1. Retire both facilities in 2021 if there is no requirement for them to support the IIS.

2. Convert Hardwoods to synchronous condense, if required, to support the Avalon Peninsula and retire Stephenville in 2021. The requirement to do so is being considered in Hydro's November 2018 Supply Adequacy study.
3. If additional investment is determined to be required in the form of generation or synchronous condense capability and Hardwoods is not the required solution, Stephenville could be retired and spare components from Stephenville could be used to increase the useful life of Hardwoods by 1-2 years, until a suitable replacement can be constructed if required.

Hydro will maintain the Hardwoods and Stephenville facilities until Muskrat Falls is released for service. Hydro has determined several viable options Hardwoods and Stephenville post 2021. The exact plan for the units beyond 2021 will be confirmed in the supply adequacy report to be filed in November 2018.

Appendix A

Hardwoods and Stephenville Capital Plan

Project Description	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Hardwoods											
Overhaul Olympus Gas Generator		$1,600.00		$1,600.00		$1,950.00					
Replace Main Fuel Valves	$404.20										
Gas Turbine Equipment and Refurbishment	$214.65										
Purchase Spare Parts & Heated Lube Oil Storage	$49.80										
Upgrade HMI/replace AVR	$685.90										
Alternator Rotor out inspection					$500.00	$1,500.00					
Purchase Capital Spares - Gas Turbines (2023)					$300.00						
Stephenville											
Overhaul Olympus Gas Turbine	$1,666.80		$1,600.00		$1,600.00			$2,000.00	$2,100.00		
Gas Turbine Equipment and Refurbishment	$214.65										
Upgrade Control System		$100.00	$1,531.00								
Stack Replacements		$500.00	$1,000.00								
Purchase Capital Spares - Gas Turbines (2020)		$300.00									
Install Infrared Scanning Ports - Stephenville		$250.00									
Purchase Capital Spares - Gas Turbines (2021)			$300.00			$300.00					
Alternator Rotor out inspection				$500.00	$1,500.00						
Fuel Tank Inspection								$1,500.00			
Annual Total	**$3,236.00**	**$2,750.00**	**$4,431.00**	**$2,100.00**	**$3,900.00**	**$3,750.00**	**$0.00**	**$3,500.00**	**$2,100.00**	**$0.00**	**$25,767.00**

Holyrood Overview

Future Operation and Capital Expenditure Requirements

July 2018

newfoundland labrador hydro
a nalcor energy company

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1.0 Background

In Orders No. P.U. 5(2012) and No. P.U. 4(2013), the Board of Commissioners of Public Utilities (the Board) directed Newfoundland and Labrador Hydro (Hydro) to file, in conjunction with its 2014 Capital Budget Application, an overview in relation to the proposed capital expenditures for the Holyrood Thermal Generating Station (Holyrood). The Board required that the overview include the following: [1]

- An updated outlook regarding anticipated changes in the role of Holyrood on the system;
- an updated schedule of anticipated changes in Holyrood operations that may reasonably be expected to have an impact on capital expenditure requirements;
- a summary description of all proposed Holyrood 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 Holyrood'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 Holyrood operations.

In Order No. P.U. 42(2013), the Board further required Hydro to update and file the Holyrood Overview report with future capital budgets. This report contains the update to the future operation and capital expenditure requirements for the Holyrood Thermal Generating Station.

[1] *Order No. P.U. 5(2012)*

2.0 Introduction

Hydro's Holyrood Thermal Generating Station (Holyrood) is a critical part of the Island Interconnected System (IIS). With three oil-fired generating units providing an installed capacity of 490 MW, the plant represents approximately one third of Hydro's total IIS generating capacity and approximately one quarter of the total IIS capacity, when included with all other customer-owned generation. Units 1 and 2 were commissioned in 1970 and 1971, respectively, and Unit 3 in 1979. Units 1 and 2 were originally designed to produce 150 MW 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 IIS during periods when power generation from this unit is not required.

The three major components of the thermal generating process are the boiler, the turbine, and the generator, with supporting systems such as fuel storage and delivery, controls, and cooling and feed water 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 to the IIS. The generator itself is pressurized and cooled by hydrogen gas to provide maximum efficiency both in heat transfer and reduced windage losses.[2]

Holyrood is essential for meeting both winter peak demand and annual energy requirements. Holyrood supplies the balance of customer load that cannot be met by Hydro's hydroelectric generating facilities and purchases from non-utility generators. Annual production at Holyrood will vary depending on hydroelectric reservoir storage and inflows. In the existing system configuration, Holyrood units are also critical for securing the transmission and providing voltage support for the major load centre on the Avalon Peninsula.

[2] 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 occurs in electric rotating machines such as motors and generators.

Figure 1: Holyrood Thermal Generating Station

3.0 Current Operational Outlook and Schedule

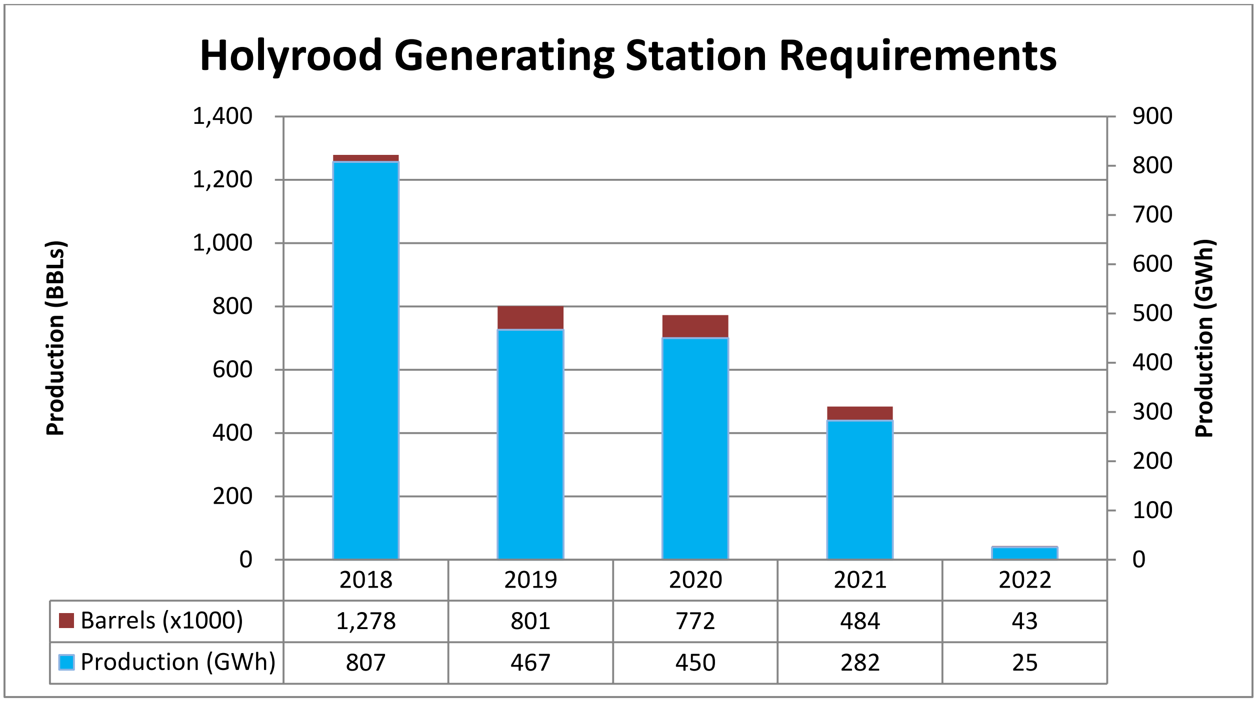
There have been two important changes to the IIS. The first is the in-service of a third 230 kV transmission line, TL 267, between the Bay d'Espoir and Western Avalon Terminal Stations. The second is the interconnection to the North American grid, achieved via the successful integration of the Maritime Link (ML) and ongoing integration of the Labrador-Island Link (LIL). TL 267 has increased Hydro's capability to deliver power to the major load centre on the Avalon Peninsula, eliminating the major transmission constraints on the IIS. The second is the completion of the ML. The ML is a high voltage Direct Current (DC) line connecting the island of Newfoundland to Nova Scotia, providing the first interconnection of the IIS to the North American Grid. To date, Hydro has made market purchases over the ML to both offset thermal generation at Holyrood and gas turbine production.

Work is currently underway on the construction and integration of the Muskrat Falls Project Assets. The Muskrat Falls Project includes an 824 megawatt hydroelectric generating facility at Muskrat Falls and the Labrador-Island Link (LIL) that will transmit power from Muskrat Falls to

Soldiers Pond on the Avalon Peninsula. The LIL will provide the IIS with a second interconnection to the North American Grid and provide the IIS with access to recapture energy in excess of the Labrador Interconnected System requirements. The LIL is expected to be in-service in the third quarter of 2018 and will be available for the 2018-2019 winter peak.

Once the LIL and the ML are in-service, Hydro expects to reduce Holyrood production by importing energy from off-island supply. Hydro will continue to use Holyrood to provide reliable service to customers, and as satisfactory operating experience is obtained over the LIL and the ML, the Holyrood units will be placed in standby mode. The number of units placed in standby mode will depend on the availability of reliable capacity and energy from off-island supply and sustained reliable operation of the interconnections.

While in standby mode, the plant will remain fully available for generation and will be periodically operated to ensure availability until Hydro is satisfied with the reliability of the Lower Churchill Project assets. At that time, it is projected that the remaining fuel in the tanks will be consumed, Units 1 and 2 and the steam components of Unit 3 will be decommissioned, and Unit 3 will continue to operate in synchronous condenser mode only, with no generation capability.



	2018	2019	2020	2021	2022
Barrels (x1000)	1,278	801	772	484	43
Production (GWh)	807	467	450	282	25

Figure 2: Holyrood Annual Production Requirements 2018 to 2022

Figure 2 indicates Holyrood's forecasted annual production requirements for the five-year period from 2018 to 2022. Forecasts are based on average hydrologic inflow conditions. The LIL is expected to supplement the supply to the IIS by delivering recall power[3] in excess of Labrador Interconnected System (LIS) requirements from Churchill Falls. The Holyrood production shown for 2018 and 2019 assumes that both recall energy and contracted off-island supply are available to reduce Holyrood production.

In 2020, the construction activities and final commissioning of the Muskrat Falls Project are expected to be completed. Holyrood units will be operated as required to support successful integration and commissioning of these assets. Once the assets have been successfully

[3] On May 12, 1969, Hydro-Quebec (HQ) and the Churchill Falls (Labrador) Corporation (CF(L)Co) entered into a power contract for the purchase of power from the CF(L)Co plant by HQ (the 1969 Power Contract). Pursuant to section 6.6 of the 1969 Power Contract, CF(L)Co has exercised its right to recapture 300 MW of power (Recapture Energy) generated at the CF power plant. Under the terms of a Power Purchase Agreement (PPA) between Hydro and CF(L)Co (the NLH-CF(L)Co PPA) dated March 9, 1998, and amended on April 1, 1999, Hydro is able to, and does, purchase up to 300 MW of Recapture Energy from CF(L)Co for use outside of the Province of Quebec.

commissioned, placed in service, and proven reliable, the Holyrood generating units will be placed in standby mode until their subsequent decommissioning.

The production at Holyrood may vary from the forecast depending on customer requirements, the timing of in-service of the Lower Churchill assets, the availability of off-Island supply, and hydrologic conditions impacting Hydro's hydraulic supply capabilities.

In summary, the specific phases of operation and the timeframes for each phase are anticipated to be as follows:

- **Phase 1** – Normal Production Phase (Completed - 2016 through to the second quarter 2018): All three units are available for prime power generation with Unit 3 also available for synchronous condenser operation, as required;
- **Phase 2** – Standby Production Phase (Second quarter 2018 through to the end of the winter 2021): Units will be placed in Standby Mode as reliable off-Island supply is secured, Unit 3 will be operated in synchronous condenser mode, as required; and
- **Phase 3** – Post Interconnection Phase (Post-winter 2021): All Muskrat Falls Units have been placed in-service and both the plant and the LIL have operating experience. Holyrood Units 1 and 2 have been placed in Standby Mode, until decommissioning is appropriate. Holyrood Unit 3 continues to operate as a synchronous condenser. There will be no power production from Holyrood after remaining excess fuel has been consumed.

3.1 Phase 1 – Normal Production Phase

In the existing system configuration, Holyrood was required to meet customer requirements. This phase concluded as of the second quarter of 2018.

3.2 Phase 2 – Standby Production Phase

Following the in-service of the LIL and the ML, and prior to full availability of MF generation, the Holyrood plant will continue to be an essential component of the provincial electrical grid. Until the end of the winter 2021, the plant will function as a standby facility and depending on the availability of off-island supply, will operate at some level of base loading. While in standby mode, Holyrood can be called upon to provide energy and capacity to the Island Interconnected System as required.

During the period of standby operation, Unit 3 is expected to operate primarily in synchronous condenser mode as required for system security, with the option to return to full generating mode if required.

3.3 Phase 3 – Synchronous Condenser Operation Phase

Following the Standby Production Phase, remaining fuel inventory will be consumed and Hydro will commence decommissioning of the thermal components of the station required for power production. All Lower Churchill Project assets will be in service and sufficient operational experience has occurred. Unit 3 will continue to operate as a synchronous condenser; however there will be no power generation at Holyrood to meet system requirements. The conclusion of power production is currently projected to be at the end of the winter operating season 2020-2021 (March 31, 2021).

The systems to be decommissioned at this stage include:

- The fuel storage and delivery system, including the tank farm and day tank;
- the boilers, including air systems and emission monitoring systems;
- the feedwater and condensate systems, including the deaerator systems; and
- the marine terminal.

The systems required for synchronous condenser operation following the standby phase include:

- Unit 3 synchronous condenser specific equipment including the unit generator and exciter; and
- auxiliary systems including electrical, controls, cooling water, fire protection, etc.

Table 1: Holyrood Operating Requirements 2018-2022

Year	Holyrood Production (GWh)	Total Unit Operating Hours	Annual Required Hydro Generation	Holyrood Production as Percentage of Total Load
2018	807	10,272	7,072	11%
2019	467	6,696	7,139	7%
2020	450	6,446	7,111	6%
2021	282	4,032	6,995	4%
2022	25	371	6,872	0%

4.0 Maintenance Strategy through the Operational Phases

Phase 1 is complete. Scheduled overhauls of plant equipment, such as auxiliary system pumps, were continued during this phase to ensure plant reliability. The upgrade of equipment at or near the end of its useful service life and replacement of obsolete equipment that could no longer be maintained was also continued with serious consideration given to the short service life.

Phase 2 starts the evolution of the plant maintenance strategy. While significant changes will not be made at this point, as unit reliability will continue to be important during the standby period, equipment maintenance intervals may change. As some intervals are based on annual operating hours, extension beyond more typical timeframes during the standby period may be achieved in some instances, allowing Hydro to reduce cost while maintaining reliability.

In Phase 3, assets with operational requirements beyond the post-winter 2021 timeframe will continue to be optimally maintained with investment reflecting that continued requirement.

5.0 Holyrood 2019 Capital Plan Summary

The complexity of the thermal generating units, along with the age of the Holyrood plant and changing requirements for Holyrood, necessitates a review of the assets to ensure future generating requirements can be met. Condition assessments and inspections ensure that critical systems receive the appropriate level of refurbishment. Additionally, preparation has begun to operate in synchronous condenser mode as part of the Phase 3 operational requirements.

The 2019 capital project proposals (Tables 2, 3 and 4) were prepared considering asset condition, equipment obsolescence (both end-of-life and availability of support), and forecast production requirements to identify the necessary rehabilitation and replacement projects to ensure customer needs can be met. In the event of unforeseen failure or unexpected as-found condition, adjustments or additions may be required beyond the current plan.

Table 2 provides a summary description of all proposed 2019 Holyrood capital projects. All of the proposed projects are required to ensure that the Holyrood facility is available and ready to ensure reliable service for Hydro's customers in advance of the full in-service of the Lower Churchill Project assets.

Hydro is managing several deteriorating pieces of infrastructure, notably the waste water basins building, concrete exhaust stacks, and fuel oil storage tanks, with the intention of reaching end-of-generation life with minimal refurbishment costs. Condition assessments are completed annually and minor interventions are addressed as a means to mitigate safety and asset integrity risk. Should additional measures be required, Hydro will seek capital refurbishment at that time.

The Condition Assessment and Miscellaneous Upgrades project relates to plant common support systems and infrastructure, which are required to ensure the plant continues to operate safely, reliably, and with regulatory compliance through the normal operation and standby production phases to post-winter 2021.

The Replace 258 VDC Battery Chargers and Batteries project, Overhaul Unit 3 Turbine Valves project, and the majority of the scope of the Condition Assessment and Miscellaneous

Upgrades project relate directly to the major components (i.e. boiler, turbine, generator, and associated supporting systems) of the power generation process. These projects relate to the steam turbines, generators, boilers, and associated systems required for safe and reliable operation.

Table 3 provides a summary guide to all internal and external reports filed in support of the capital expenditure proposals summarizing the alternatives considered and recommendations made.

Table 4 provides an explanation of the necessity of all proposed capital expenditures in the context of the changes in operations at Holyrood.

Table 2: Holyrood Projects Included in the 2019 Capital Plan

Project	Scope Summary	Proposal Location
Overhaul Unit 3 Turbine Valves	This project proposes the completion of a scheduled overhaul of Unit 3 turbine valves. This overhaul consists of total dismantling of all turbine valves, inspection of the valves, lapping of the valve seats, and adjustment of valve clearances.	>$500k Projects Tab 2
Replace 258 VDC Battery Chargers and Batteries	This project proposes the replacement of two banks of 258 VDC batteries and associated chargers that are beyond the expected life cycle for these products. The battery banks provide power to the emergency lube oil pumps of Unit 1 and Unit 2. It is critical for safe operation that these batteries function properly during a loss of power to the electric turbine and generator bearing oil pumps.	>$200k and <$500k
Condition Assessment and Miscellaneous Upgrades	The scope of the proposed project consists of three separate pieces of work. The primary piece of work is to perform a condition assessment related to internal components of the main steam	>$500k Projects Tab 3

Project	Scope Summary	Proposal Location
	generators (boilers) and also associated external high energy piping. This work is part of a three-year program that will be completed in 2019. Additional Level 2 condition assessment work will be completed on other critical systems in the plant. Finally, miscellaneous upgrades will take place. These upgrades will include an upgrade to the site security camera system, and boiler component replacements, such as the replacement of expansion joints.	
Thermal In-Service Failures	The purpose of this program is to allow completion of capital work due to failure of equipment, or the recognition of an incipient failure that cannot wait for the next capital submission cycle. Previously, capital work of this nature required a supplemental submission for approval. This project also includes the purchase of critical capital spares to reduce downtime and increase availability should a failure of a key component occur.	>$500k Projects

Table 3: Reports Filed in Support of the 2019 Project Proposals

Project	Reports filed	Alternatives Considered	Recommendation
Overhaul Unit 3 Turbine Valves	-	There are no alternatives	Overhaul turbine valves
Replace 258 VDC Battery Banks	-	There are no alternatives	Replace the battery banks and chargers
Condition Assessment and Miscellaneous Upgrades	Holyrood Thermal Generating Station Level II Condition Assessment 2017 NDE Inspections	There are no alternatives	Perform condition assessment and upgrades.

Thermal In-Service Failures	-	There are no alternatives	Complete refurbishments/ replacements as required

Table 4: 2019 Project Necessity in the Context of Changing Role of Holyrood

Major System or Subsystem	Project	Necessity by Operational Phase		
		Phase 1[4]	Phase 2[5]	Phase 3[6]
Fuel Storage & Delivery	No projects included	-	-	-
Feedwater & Condensate	No projects included	-	-	-
Boiler	Condition Assessment and Miscellaneous Upgrades	-	Required	Not required
Turbine Generator	Overhaul Unit 3 Turbine Valves	-	Required	Not required
	Replace 258 VDC Battery Charger and Batteries	-	Required	Not Required
Cooling Water Systems	No Projects Included	-	-	-
Buildings & Grounds	Condition Assessment and Miscellaneous Upgrades	-	Required	Required
Common Systems	No projects included	-	-	-

6.0 Holyrood 2019-2023 Capital Expenditures Outlook

Capital investment will be necessary throughout the period of 2019 to 2023 to ensure continued security 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 facility are anticipated, including refurbishment, upgrade or replacement of failed or obsolete equipment, and general plant infrastructure work. In reviewing future capital projects for Holyrood, Hydro has considered the three phases of operations and will submit for approval

[4] Phase 1, 2016 to Q2 2018, is complete – normal production.
[5] Phase 2 – Q2 2018 to end of Winter 2021 – stand-by production.
[6] Phase 3 – Post-Winter 2021 – synchronous condenser operation.

only those projects it deems necessary for the safe and reliable operation of the plant as a generator up to the time of decommissioning.

Capital projects proposed are reviewed in light of the future plant requirements and considered essential to fulfill Hydro's mandate to serve its customers and meet safety and environmental requirements.

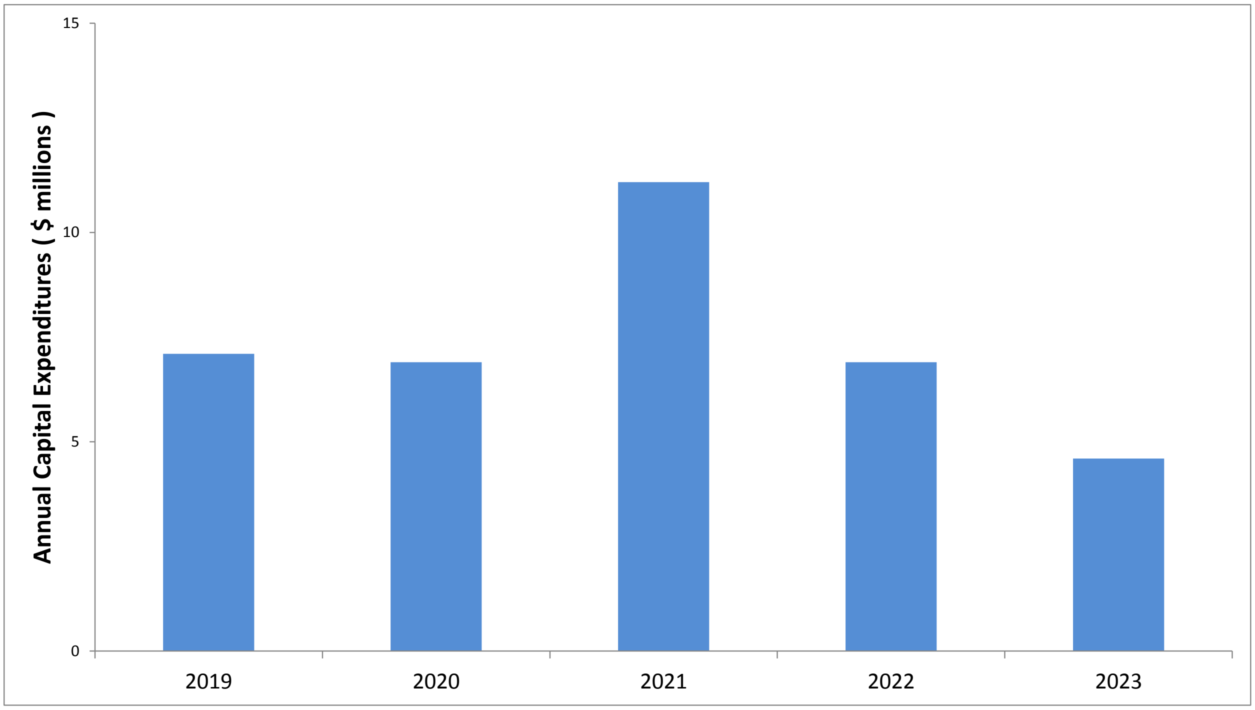
The maintenance strategy for Holyrood to its end-of-life as a generating station is to extend the life of the existing assets at minimum cost through continued preventive maintenance, repair, and rehabilitation, where critical, to provide safe and reliable energy at the forecast levels. In cases where repair and rehabilitation are not viable alternatives, and where the associated assets remain critical to operation, assets will be renewed in the least-cost manner. Phase 1 is complete. Phase 2 entails minimal changes in the maintenance strategy since the plant is generally expected to produce with a high level of reliability through to commissioning of the Muskrat Falls Project and must be fully available until winter 2021. Non-critical assets will receive minimal attention and may be allowed to deteriorate where such action does not significantly increase risk to safe and reliable production. Assets with operational requirements beyond 2021 will continue to be optimally maintained with investment reflecting that continued operation requirement. Data will be collected from inspections, on-line monitoring, and formal condition assessments and used to determine the optimal work plan for the assets in light of the changing role of Holyrood.

Figure 3 provides the planned level of expenditure for Holyrood over the 2019 to 2023 period. The annual average expenditure is $7.3 million, ranging from a high of $11.2 million in 2021 to a low of $4.6 million in 2023. Projects planned for the pending five years include:

- $3.1 million for the overhaul of the Unit 3 Generator;
- $4.8 million to replace Stage II Electrical Distribution Equipment; and
- $7.1 million for the rewind of Unit 3 generator stator.

All of these projects are required for the Phase 3 operation. Planned expenditures for the five year period total $36.8 million.

Figure 3: Holyrood Capital Expenditures 2019 to 2023



Holyrood Project Operating and Maintenance Expenditures

Plan of Projected Operating Maintenance Expenditures

2019 – 2028

For Holyrood Generating Station

July 2018

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1.0 Introduction

In Order No. P. U. 14(2004), the Board of Commissioners of Public Utilities (the Board), directed Newfoundland and Labrador Hydro (Hydro) to **"**file a ten year plan of maintenance expenditures for the Holyrood Generating Station (Holyrood) with its annual capital budget application, until otherwise directed by the Board."[1] As this requirement is specifically related to system equipment maintenance (SEM) costs, non-maintenance SEM costs and capital expenditures have not been included in the following report. Capital expenditures for the Holyrood plant are submitted annually to the Board with other Hydro capital proposals as part of the annual capital budget application, as well as in the Holyrood Overview.

This report addresses the identified and expected maintenance expenditures for the years 2019 to 2028 inclusive. With respect to these expenditures, it should be noted that Units 1 and 2, as well as two of the main fuel storage tanks and other associated ancillary equipment, have been in service for 48 years and that Unit 3 and its associated equipment have been in service for 38 years. While many components of this equipment have been replaced and additional items added through the maintenance and capital program over the years, numerous pieces of equipment and components are original.

An accurate, uniform ten-year plan of SEM is difficult to complete. The harsh operating environment, evolving production requirements, and the age of units may trigger revision of the maintenance plan to address unforeseen events. Even though expenses for major overhauls are included in capital, some variability in the annual 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. This report will endeavor to identify the regular variations in the annual operating costs for Holyrood.

[1] Board Order No. P.U. 14(2004), at page 166.

2.0 Maintenance Philosophy

In Order No. P. U. 14(2004), the Board stated that "The Board will require NLH's ten-year plan of maintenance expenditures for the Holyrood Generating Station to be updated annually to reflect changing operating circumstances."[2]

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 the impact on safe, reliable service when applying maintenance strategies and tactics. There are four main types or categories of maintenance undertaken at Holyrood, including: preventive maintenance; corrective maintenance; boiler overhauls; and operating projects.

2.1 Preventive Maintenance

Holyrood 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 rather than repairing them when it is less costly to do so.

[2] Board Order No. P.U. 14(2004), at page 64.

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.

2.2 Corrective Maintenance

In addition to the preventive maintenance techniques outlined above, there are also corrective maintenance requirements. This includes 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.

2.3 Boiler Overhauls

Boiler overhauls consist of the maintenance and refurbishment work required to ensure reliable boiler operation for the upcoming season. 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, 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 overhaul. In some cases the nature of defined work meets criteria for capitalization, and in such cases is not included in SEM.

2.4 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 Waste Water Treatment Plant.

3.0 Cost Variability

Preventive maintenance costs are generally incurred annually at a constant level and do not fluctuate significantly. This principle does not apply to corrective maintenance costs, which are unavoidable and unpredictable due to the changing energy production demands on the units from year to year. Due to accounting methodology changes approved in Order P.U. 13(2012), major overhauls and inspections with a frequency of greater than one year are capitalized, reducing the fluctuation in maintenance expenditures that were experienced in prior periods. Projects for Holyrood are planned on a five-year basis, but as with any plan, it is not fixed or definitive, as other events can cause a shift in the prioritization of such projects. The five-year maintenance plan is updated on a regular basis to reflect any shifts in priority.

4.0 Detailed Analysis

Appendices A through D set out the ten-year maintenance plan for Holyrood. Appendix A is a summary that outlines the expected expenditures in each of the major equipment groupings containing SEM costs for the years 2019 to 2028. Appendices B through D, inclusive, show the expected SEM costs categorized according to Preventive, Corrective, Annual Overhauls, and Operating Projects for each of the major equipment groupings containing SEM costs.

Appendix B lists the categories of SEM costs for generating units for the years 2019 to 2028 in each of the major equipment groupings. The categories listed are:

- **Preventive**: Routine preventive maintenance activities carried out every year.
- **Corrective**: Typical but unknown breakdown/emergency repairs carried out during the year.
- **Boiler**: Boiler overhauls carried out annually with one unit per year overhauled on a reduced scope as a result of better fuel quality. For 2020 and 2021, all boiler overhauls are expected to be on a reduced scope. No boiler overhauls are expected beyond 2021.
- **Operating Projects**: Non-capitalized projects justified on the basis of safety, environment, reliability, or cost benefit analysis.

Appendices C and D provide a listing of the remaining equipment groupings, including Common Equipment, Building and Grounds, Water Treatment Plant, Waste Water Treatment Plant and Environmental Monitoring and use only Preventive, Corrective, and Operating Projects.

It should be noted that this ten-year plan spans the period during which the role of Holyrood will change as a result of the interconnection between Labrador and the Island. These events significantly impact cost and activity levels for Holyrood for the standby period and for the synchronous condenser period, as reflected in this plan. Generation from the Holyrood Thermal Generation Plant has already started to reduce as a result of the availability of the Labrador Island Transmission Link and the Maritime Link. The units at Holyrood will start to be placed in standby mode as these systems are fully proven to be ready for reliable service, and units at

Muskrat Falls are brought on-line. The timing of the final shut down and repurposing of the Holyrood plant will be made once commissioning of the infrastructure related to the Muskrat Falls Project is complete in 2020 and reliable service has been demonstrated over the following winter period. This is anticipated to occur in the 2020/2021 timeframe. For the purposes of projecting operating costs in this report, a placeholder assumption has been made that the standby phase begins in 2018 and continues into 2021. Delivery of power and energy via the Labrador Island Transmission Link started in 2018, but remains limited to available recall power from Churchill Falls as the Muskrat Falls powerhouse is not yet in service.

Hydro does not normally use any escalation in its five-year operating plan at the Plant or regional level as the five-year plan is primarily used for internal purposes and generation of work plans rather than detailed financial planning. However, in the attached ten-year plan, a single escalation factor of 2.5% per year has been used for 2019 to 2028 based on an average rate from Hydro's current corporate assumptions.

It should be noted that the appendices do not itemize preventive and corrective items. The preventive maintenance program consists of approximately 1,500 preventive maintenance work orders performed on plant equipment annually. Corrective items include a large number of low cost projects, the majority of which are largely unknown until they happen; thus, it is not practical to provide a breakout of the costs.

5.0 Summary

This Plan is based on the 2019 budget for system equipment and adjusted for future years 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 Plant. As with any forecast, it is subject to change depending on the operating demands of the plant, the results of inspections and assessments of changing equipment conditions.

Appendix A

Total Holyrood 10 Year SEM Expenditures ($000s)

	Base Year 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Unit 1 Total SEM	$1,871	$996	$258	$0	$0	$0	$0	$0	$0	$0
Unit 2 Total SEM	$1,420	$1,092	$258	$0	$0	$0	$0	$0	$0	$0
Unit 3 Total SEM	$1,880	$1,003	$262	$268	$275	$282	$289	$296	$303	$311
Common Equipment Total SEM	$1,820	$1,399	$673	$690	$707	$725	$743	$762	$781	$800
Buildings & Grounds Total SEM	$282	$289	$297	$304	$312	$319	$327	$336	$344	$353
WT Plant Total SEM	$57	$58	$20	$21	$21	$22	$22	$23	$23	$24
WWT Plant Total SEM	$10	$8	$8	$8	$8	$8	$9	$9	$9	$9
Environmental Monitoring Total SEM	$112	$115	$115	$118	$121	$124	$127	$130	$133	$137
Total Operating Projects	$241	$118	$61	$0	$33	$150	$35	$0	$37	$0
Total Holyrood SEM	**$7,694**	**$5,079**	**$1,952**	**$1,408**	**$1,477**	**$1,630**	**$1,551**	**$1,555**	**$1,630**	**$1,633**

Appendix B

10 Year SEM Expenditures for Generating Units ($000s)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Unit No. 1										
Preventive	385	296	138	0	0	0	0	0	0	0
Corrective	335	258	120	0	0	0	0	0	0	0
Boiler O/H	1,151	442	0	0	0	0	0	0	0	0
Subtotal	1,871	996	258	0	0	0	0	0	0	0
Operating Projects										
Boiler Chemical Clean										
Total Op Projects - Unit 1	0	0	0	0	0	0	0	0	0	0
Total - Unit No. 1	**1,871**	**996**	**258**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Unit No. 2										
Preventive	385	296	138	0	0	0	0	0	0	0
Corrective	335	258	120	0	0	0	0	0	0	0
Boiler O/H	700	538	0	0	0	0	0	0	0	0
Subtotal	**1,420**	**1,092**	**258**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Operating Projects										
Boiler Chemical Clean										
Total Op Projects - Unit 2	0	0	0	0	0	0	0	0	0	0
Total - Unit No. 2	**1,420**	**1,092**	**258**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Unit No. 3										
Preventive	390	300	140	143	147	150	154	158	162	166
Corrective	339	261	122	125	128	131	135	138	141	145
Boiler O/H	1,151	442	0	0	0	0	0	0	0	0
Subtotal	**1,880**	**1,003**	**262**	**268**	**275**	**282**	**289**	**296**	**303**	**311**
Operating Projects										
Boiler Chemical Clean										
Total Op Projects - Unit 3	0	0	0	0	0	0	0	0	0	0
Total - Unit No. 3	**1,880**	**1,003**	**262**	**268**	**275**	**282**	**289**	**296**	**303**	**311**

Appendix C

10 Year SEM Expenditures for Ancillary Units ($000s)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Common Equipment										
Preventive	1,635	1,257	597	608	623	639	655	671	688	705
Corrective	185	142	76	82	84	86	88	91	93	95
Subtotal	**1,820**	**1,399**	**673**	**690**	**707**	**725**	**743**	**762**	**781**	**800**
Operating Projects										
Total Op Projects - Common	0	0	0	0	0	0	0	0	0	0
Total - Common Equipment	**1,820**	**1,399**	**673**	**690**	**707**	**725**	**743**	**762**	**781**	**800**
Buildings & Grounds										
Preventive	260	267	273	280	287	294	302	309	317	325
Corrective	22	23	23	24	24	25	26	26	27	28
Subtotal	**282**	**289**	**297**	**304**	**312**	**319**	**327**	**336**	**344**	**353**
Operating Projects										
Total Op Projects - Bldgs & Grounds	0	0	0	0	0	0	0	0	0	0
Total - Bldgs & Grounds	**282**	**289**	**297**	**304**	**312**	**319**	**327**	**336**	**344**	**353**
Water Treatment Plant										
Preventive	32	33	11	11	12	12	12	12	13	13
Corrective	25	26	9	9	9	10	10	10	10	11
Subtotal	**57**	**58**	**20**	**21**	**21**	**22**	**22**	**23**	**23**	**24**
Operating Projects										
Resin Replacement	82	63	29	0	0	0	0	0	0	0
Total Op Projects - WTP	82	63	29	0	0	0	0	0	0	0
Total - Water Treatment Plant	**139**	**121**	**49**	**21**	**21**	**22**	**22**	**23**	**23**	**24**

Appendix D

10 Year SEM Expenditures for Ancillary Units ($000s)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Environmental Monitoring										
Preventive	16.00	16.40	16.40	16.81	17.23	17.66	18.10	18.56	19.02	19.49
Corrective	96.26	98.66	98.66	101.13	103.66	106.25	108.90	111.63	114.42	117.28
Subtotal	**112.26**	**115.06**	**115.06**	**117.94**	**120.89**	**123.91**	**127.01**	**130.18**	**133.44**	**136.77**
Operating Projects										
Thermal Plant	54.00	55.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GT and Diesel Plant	30.00		31.52		33.11		34.79		36.55	
Total Op Projects - Environment	84.00	55.35	31.52	0.00	33.11	0.00	34.79	0.00	36.55	0.00
Total - Environmental Monitoring	**196.26**	**170.41**	**146.58**	**117.94**	**154.00**	**123.91**	**161.80**	**130.18**	**169.99**	**136.77**
Waste Water Treatment Plant										
Preventive	5.04	3.88	4.00	4.00	4.10	4.20	4.31	4.42	4.53	4.64
Corrective	5.04	3.88	4.00	4.00	4.10	4.20	4.31	4.42	4.53	4.64
Subtotal	**10.09**	**7.75**	**8.00**	**8.00**	**8.20**	**8.41**	**8.62**	**8.83**	**9.05**	**9.28**
Operating Projects										
WWTP Periodic Basin Cleaning						150.00				
WWTP Continuous Basin Clean-Out	75.00									
Total Op Projects - WWTP	75.00	0.00	0.00	0.00	0.00	150.00	0.00	0.00	0.00	0.00
Total - Waste Water Treatment	**85.09**	**7.75**	**8.00**	**8.00**	**8.20**	**158.41**	**8.62**	**8.83**	**9.05**	**9.28**

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	Expended to 2018	2019	Future Years	Total
		($000)		
Generation	25,082.5	32,603.7	8,492.5	66,178.7
Transmission and Rural Operations	64,329.7	75,965.9	45,727.2	186,022.8
General Properties	2,522.8	8,599.2	1,172.5	12,294.5
Allowance for Unforeseen Items	0.0	1,000.0	0.0	1,000.0
Total Capital Budget	**91,935.0**	**118,168.8**	**55,392.2**	**265,496.0**

	Expended to 2018	2019	Future Years	Total
		($000)		
Generation				
Hydraulic Plant	15,174.4	18,995.8	8,174.8	42,345.0
Thermal Plant	80.3	7,139.6	0.0	7,219.9
Gas Turbines	9,827.8	6,319.4	317.7	16,464.9
Tools and Equipment	0.0	148.9	0.0	148.9
Total Generation	**25,082.5**	**32,603.7**	**8,492.5**	**66,178.7**
Transmission and Rural Operations				
Terminal Stations	42,063.1	40,772.3	30,581.3	113,416.7
Transmission	17,731.5	4,714.0	0.0	22,445.5
Distribution	447.5	12,159.9	5,810.0	18,417.4
Generation	3,694.7	14,527.8	9,213.7	27,436.2
Properties	104.0	765.4	122.2	991.6
Metering	75.2	1,197.4	0.0	1,272.6
Tools and Equipment	213.7	1,829.1	0.0	2,042.8
Total Transmission and Rural Operations	**64,329.7**	**75,965.9**	**45,727.2**	**186,022.8**
General Properties				
Information Systems	0.0	1,597.1	0.0	1,597.1
Telecontrol	595.4	4,312.0	577.6	5,485.0
Transportation	1,667.2	2,001.8	594.9	4,263.9
Administrative	260.2	688.3	0.0	948.5
Total General Properties	**2,522.8**	**8,599.2**	**1,172.5**	**12,294.5**
Allowance for Unforeseen Items	0.0	1,000.0	0.0	1,000.0
Total Capital Budget	**91,935.0**	**118,168.8**	**55,392.2**	**265,496.0**

Project Description	Expended to 2018	2019	Future Years	Total	Page Ref
		($000)			
Hydraulic Plant					
Hydraulic Generation Refurbishment and Modernization (2018-2019)	10,325.4	4,283.1	0.0	14,608.5	
Refurbish Powerhouse Station Services - Bay d'Espoir	2,886.5	1,460.6	0.0	4,347.1	
Replace Exciter Controls Units 1 to 6 - Bay d'Espoir	1,040.4	877.0	1,429.6	3,347.0	
Install Remote Operation of Salmon River Spillway - Bay d'Espoir	645.9	1,862.5	0.0	2,508.4	
Energy Efficiency Improvements - Various	276.2	168.9	0.0	445.1	
Hydraulic Generation Refurbishment and Modernization (2019-2020)	0.0	9,093.7	6,745.2	15,838.9	C4
Hydraulic In-Service Failures	0.0	1,250.0	0.0	1,250.0	C14
Total Hydraulic Plant	**15,174.4**	**18,995.8**	**8,174.8**	**42,345.0**	
Thermal Plant					
Upgrade Cranes and Hoists - Holyrood	80.3	300.3	0.0	380.6	
Overhaul Unit 3 Turbine Valve - Holyrood	0.0	3,290.5	0.0	3,290.5	C7
Condition Assessment and Miscellaneous Upgrades - Holyrood	0.0	1,968.8	0.0	1,968.8	C9
Thermal In-Service Failures	0.0	1,250.0	0.0	1,250.0	C17
Replace 258VDC Battery Banks - Holyrood	0.0	330.0	0.0	330.0	D10
Total Thermal Plant	**80.3**	**7,139.6**	**0.0**	**7,219.9**	

Project Description	Expended to 2018	2019	Future Years	Total	Page Ref
		($000)			
Gas Turbines					
Increase Fuel and Water Treatment System Capacity - Holyrood Gas Turbine	8,829.9	3,012.7	0.0	11,842.6	
Gas Turbine Equipment and Refurbishment - Hardwoods and Stephenville	997.9	429.3	0.0	1,427.2	
Overhaul Olympus Gas Generator - Stephenville	0.0	1,666.8	0.0	1,666.8	C12
Upgrade HMI and AVR - Hardwoods	0.0	685.9	0.0	685.9	C20
Replace Main Fuel Valves - Hardwoods	0.0	404.2	0.0	404.2	D2
Upgrade Compressed Air System - Holyrood Gas Turbine	0.0	70.7	317.7	388.4	D7
Construct Heated Storage for Spare Parts and Lube Oil - Hardwoods and Happy Valley	0.0	49.8	0.0	49.8	
Total Gas Turbines	**9,827.8**	**6,319.4**	**317.7**	**16,464.9**	
Tools and Equipment					
Purchase Tools & Equipment Less than $50,000 - Bay d'Espoir & Holyrood	0.0	148.9	0.0	148.9	
Total Tools and Equipment	**0.0**	**148.9**	**0.0**	**148.9**	
Total Generation	**25,082.5**	**32,603.7**	**8,492.5**	**66,178.7**	
Terminal Stations					
Upgrade Circuit Breakers - Various (2016-2020)	33,186.4	6,597.3	11,116.8	50,900.5	
Terminal Station Refurbishment and Modernization (2018-2019)	8,170.6	18,625.1	0.0	26,795.7	
Replace Transformer T1 - Buchans	249.0	2,086.1	0.0	2,335.1	
Implement Terminal Station Flood Mitigation - Springdale	186.2	787.8	0.0	974.0	
Purchase Mobile DC Power Systems	270.9	695.6	0.0	966.5	
Terminal Station Refurbishment and Modernization (2019-2020)	0.0	10,891.1	19,061.8	29,952.9	C22
Terminal Station In-Service Failures	0.0	1,000.0	0.0	1,000.0	C42
Upgrade Terminal Station for Mobile Substation - St. Anthony	0.0	89.3	402.7	492.0	D13
Total Terminal Stations	**42,063.1**	**40,772.3**	**30,581.3**	**113,416.7**	
Tranmission					
Muskrat Falls to Happy Valley Interconnection	17,731.5	2,247.0	0.0	19,978.5	
Wood Pole Line Management Program - Various	0.0	2,467.0	0.0	2,467.0	C35
Total Transmission	**17,731.5**	**4,714.0**	**0.0**	**22,445.5**	

Project Description	Expended to 2018	2019	Future Years	Total	Page Ref
		($000)			
Distribution					
Distribution System Upgrades (2018-2019) - Various	383.8	2,771.2	0.0	3,155.0	
Install Recloser Remote Control (2018-2019) - English Harbour West and Barachoix	63.7	275.0	0.0	338.7	
Distribution System Upgrades (2019-2020)	0.0	390.8	5,490.1	5,880.9	C25
Provide Service Extensions - All Regions	0.0	4,700.0	0.0	4,700.0	C29
Upgrade Distribution Systems - All Regions	0.0	3,470.0	0.0	3,470.0	C31
Install Recloser Remote Control (2019-2020) - Rocky Harbour	0.0	66.1	319.9	386.0	D22
Condition Assessment for Submarine Cable - Farewell Head to Change Islands	0.0	300.1	0.0	300.1	D51
Additions for Load - Distribution System	0.0	186.7	0.0	186.7	E4
Total Distribution	**447.5**	**12,159.9**	**5,810.0**	**18,417.4**	
Generation					
Diesel Genset Replacements - Makkovik	604.1	4,703.3	3,592.8	8,900.2	
Replace Secondary Containment System Liner - Nain	1,639.2	1,450.4	0.0	3,089.6	
Replace Automation Equipment - St. Anthony Diesel Plant	307.4	1,565.9	0.0	1,873.3	
Diesel Plant Engine Cooling System Upgrades - Various	638.4	671.6	0.0	1,310.0	
Diesel Plant Fire Protection - Postville	505.6	336.4	0.0	842.0	
Diesel Genset Replacements (2019-2020)	0.0	525.6	3,421.8	3,947.4	C27
Overhaul Diesel Units - Various	0.0	2,511.3	0.0	2,511.3	C33
Additions for Load - Isolated Generation Systems	0.0	1,523.6	658.9	2,182.5	C38
Diesel Plant Fire Protection (2019-2020)	0.0	377.2	1,540.2	1,917.4	C40
Upgrade Diesel Plant Building - Ramea	0.0	352.5	0.0	352.5	D33
Replace Human Machine Interface - Cartwright	0.0	306.9	0.0	306.9	D43
Inspect Fuel Storage Tanks - Gray River	0.0	203.1	0.0	203.1	D54
Total Generation	**3,694.7**	**14,527.8**	**9,213.7**	**27,436.2**	

Project Description	Expended to 2018	2019	Future Years	Total	Page Ref
		($000)			
Properties					
Install Energy Efficiency Lighting in Diesel Plants - Various	104.0	119.0	122.2	345.2	
Upgrade Line Depots - Roddickton	0.0	344.7	0.0	344.7	D38
Install Pole Storage Ramps - Wabush	0.0	301.7	0.0	301.7	D48
Total Properties	**104.0**	**765.4**	**122.2**	**991.6**	
Metering					
Install Automated Meter Reading (2018-2019) - Bottom Waters	75.2	1,001.0	0.0	1,076.2	
Purchase Meters and Metering Equipment - Various	0.0	196.4	0.0	196.4	E2
Total Metering	**75.2**	**1,197.4**	**0.0**	**1,272.6**	
Tools and Equipment					
Replace Off Road Track Vehicle Unit No. 7239 & 7954 - Bishop's Falls & Bay d'Espoir	213.7	986.3	0.0	1,200.0	
Replace Light Duty Mobile Equipment - Various	0.0	469.6	0.0	469.6	D17
Purchase Tools & Equipment Less than $50,000 - Central	0.0	171.2	0.0	171.2	
Purchase Tools & Equipment Less than $50,000 - Labrador	0.0	109.2	0.0	109.2	
Purchase Tools & Equipment Less than $50,000 - Northern	0.0	92.8	0.0	92.8	
Total Tools and Equipment	**213.7**	**1,829.1**	**0.0**	**2,042.8**	
Total Transmission and Rural Operations	**64,329.7**	**75,965.9**	**45,727.2**	**186,022.8**	

Project Description	Expended to 2018	2019	Future Years	Total	Page Ref
		($000)			
General Properties					
Information Systems					
Software Applications					
Upgrade Energy Management System - Hydro Place	0.0	271.7	0.0	271.7	D78
Upgrade Software Applications - Hydro Place	0.0	110.4	0.0	110.4	E23
Refresh Security Software - Hydro Place	0.0	90.7	0.0	90.7	E25
Perform Minor Enhancements - Hydro Place	0.0	47.1	0.0	47.1	
Total Software Applications	**0.0**	**519.9**	**0.0**	**519.9**	
Computer Operations					
Replace Personal Computers - Hydro Place	0.0	496.0	0.0	496.0	D69
Upgrade Core IT Infrastructure - Hydro Place	0.0	359.4	0.0	359.4	D73
Replace Peripheral Infrastructure - Hydro Place	0.0	221.8	0.0	221.8	D95
Total Computer Operations	**0.0**	**1,077.2**	**0.0**	**1,077.2**	
Total Information Systems	**0.0**	**1,597.1**	**0.0**	**1,597.1**	

Project Description	Expended to 2018	2019	Future Years	Total	Page Ref
		($000)			
Telecontrol					
Network Services					
Replace PBX Phone Systems - Various	91.7	1,150.6	0.0	1,242.3	
Replace MDR 6000 Microwave Radio - Various	64.0	1,137.0	0.0	1,201.0	
Replace Battery Banks and Chargers (2018- 2019) - Various	382.1	555.8	0.0	937.9	
Replace Teleprotection - TL261	57.6	459.8	0.0	517.4	
Upgrade Telecontrol Facilities - Gull Pond Hill and Bay d'Espoir Hill	0.0	96.3	577.6	673.9	C55
Replace Radomes - Various	0.0	263.5	0.0	263.5	D81
Replace Teleprotection - TL202 & TL206	0.0	196.8	0.0	196.8	E13
Replace Network Communications Equipment - Various	0.0	189.5	0.0	189.5	E16
Upgrade Remote Terminal Units - Various	0.0	167.7	0.0	167.7	E18
Upgrade Site Facilities - Various	0.0	49.4	0.0	49.4	
Purchase Tools & Equipment Less than $50,000	0.0	45.6	0.0	45.6	
Total Telecontrol	**595.4**	**4,312.0**	**577.6**	**5,485.0**	
Transportation					
Replace Vehicles and Aerial Devices - Hydro System (2018-2019) - Various	1,667.2	753.7	0.0	2,420.9	
Replace Vehicles and Aerial Devices - Hydro System (2019-2020) - Various	0.0	1,248.1	594.9	1,843.0	C53
Total Transportation	**1,667.2**	**2,001.8**	**594.9**	**4,263.9**	
Administration					
Upgrade Exterior of Building - Hydro Place	260.2	405.7	0.0	665.9	
Remove Safety Hazards - Various	0.0	197.5	0.0	197.5	E10
Security Improvements - Hydro Place	0.0	47.1	0.0	47.1	
Purchase Office Equipment	0.0	38.0	0.0	38.0	
Total Administration	**260.2**	**688.3**	**0.0**	**948.5**	
Total General Properties	**2,522.8**	**8,599.2**	**1,172.5**	**12,294.5**	

B. Capital Budget Summary with Multi-Year Projects Separated

Newfoundland and Labrador Hydro 2019 Capital Budget ($000)	
	2019
Generation	10,995.1
Transmission and Rural Operations	17,183.2
General Properties	2,565.0
Allowance for Unforeseen Items	1,000.0
Total Projects Under $50,000	277.0
Multi-Year (2019 Expenditures)	
Multi-year Projects Commencing in 2019	24,372.5
Multi-year Projects Commencing in 2018	52,841.1
Multi-year Projects Commencing prior to 2018	
Upgrade Circuit Breakers - Various (2016-2020)	6,597.3
Refurbish Powerhouse Station Service - Bay d'Espoir	1,460.6
Replace Exciter Controls Units 1 to 6 - Bay d'Espoir	877.0
Total Capital Budget	**118,168.8**

Newfoundland and Labrador Hydro 2019 Capital Budget Single Year Projects over $50,000 ($000)	
Project Description	
Generation	
Hydraulic Plant	
Hydraulic In-Service Failures	1,250.0
Thermal Plant	
Overhaul Unit 3 Turbine Valve - Holyrood	3,290.5
Condition Assessment and Miscellaneous Upgrades - Holyrood	1,968.8
Thermal In-Service Failures	1,250.0
Replace 258VDC Battery Banks - Holyrood	330.0
Gas Turbine	
Overhaul Olympus Gas Generator - Stephenville	1,666.8
Upgrade HMI and AVR - Hardwoods	685.9
Replace Main Fuel Valves - Hardwoods	404.2
Tools and Equipment	
Purchase Tools & Equipment Less than $50,000 - Bay d'Espoir & Holyrood	148.9
Total Generation	**10,995.1**

Newfoundland and Labrador Hydro
2019 Capital Budget
Single Year Projects over $50,000
($000)

Project Description	
Transmission & Rural Operations	
Terminal Stations	
Terminal Station In-Service Failures	1,000.0
Transmission	
Wood Pole Line Management Program - Various	2,467.0
Distribution	
Provide Service Extensions - All Regions	4,700.0
Upgrade Distribution Systems - All Regions	3,470.0
Condition Assessment for Submarine Cable - Farewell Head to Change Islands	300.1
Additions for Load - Distribution System	186.7
Generation	
Overhaul Diesel Units - Various	2,511.3
Upgrade Diesel Plant Building - Ramea	352.5
Replace Human Machine Interface - Cartwright	306.9
Inspect Fuel Storage Tanks - Gray River	203.1
Properties	
Upgrade Line Depots - Roddickton	344.7
Install Pole Storage Ramps - Wabush	301.7
Metering	
Purchase Meters and Metering Equipment - Various	196.4
Tools and Equipment	
Replace Light Duty Mobile Equipment - Various	469.6
Purchase Tools & Equipment Less than $50,000 - Central	171.2
Purchase Tools & Equipment Less than $50,000 - Labrador	109.2
Purchase Tools & Equipment Less than $50,000 - Northern	92.8
Total Transmission and Rural Operations	**17,183.2**

Newfoundland and Labrador Hydro 2019 Capital Budget Single Year Projects over $50,000 ($000)	
Project Description	
General Properties	
Information Systems	
Software Applications	
Upgrade Energy Management System - Hydro Place	271.7
Upgrade Software Applications - Hydro Place	110.4
Refresh Security Software - Hydro Place	90.7
Computer Operations	
Replace Personal Computers - Hydro Place	496.0
Upgrade Core IT Infrastructure - Hydro Place	359.4
Replace Peripheral Infrastructure - Hydro Place	221.8
Telecontrol	
Network Services	
Replace Radomes - Various	263.5
Replace Teleprotection - TL202 & TL206	196.8
Replace Network Communications Equipment - Various	189.5
Upgrade Remote Terminal Units - Various	167.7
Administration	
Remove Safety Hazards - Various	197.5
Total General Properties	**2,565.0**
Total Single Year Properties over $50,000	**30,743.3**

Newfoundland and Labrador Hydro
2019 Capital Projects
Projects over $50,000
Multi-Year Projects
($000)

Multi-Year Projects Commencing in 2019

Project Description	2019	2020	2021	2022	2022	Total
Terminal Station Refurbishment and Modernization (2019-2020)	10,891.1	19,061.8				29,952.9
Hydraulic Generation Refurbishment and Modernization (2019-2020)	9,093.7	6,745.2				15,838.9
Distribution System Upgrades (2019-2020)	390.8	5,490.1				5,880.9
Diesel Genset Replacements (2019-2020)	525.6	3,421.8				3,947.4
Replace Vehicles and Aerial Devices - Hydro System (2019-2020) - Various	1,248.1	1,248.1				2,496.2
Additions for Load - Isolated Generation Systems	1,523.6	658.9				2,182.5
Diesel Plant Fire Protection (2019-2020)	377.2	1,540.2				1,917.4
Upgrade Telecontrol Facilities - Gull Pond Hill and Bay d'Espoir Hill	96.3	577.6				673.9
Upgrade Terminal Station for Mobile Substation - St. Anthony	89.3	402.7				492.0
Upgrade Compressed Air System - Holyrood Gas Turbine	70.7	317.7				388.4
Install Recloser Remote Control (2019-2020) - Rocky Harbour	66.1	319.9				386.0
Total Multi-Year Projects over $50,000 commencing in 2019	**24,372.5**	**39,784.0**	**0.0**	**0.0**	**0.0**	**64,156.5**

Newfoundland and Labrador Hydro
2019 Capital Projects
Projects over $50,000
Multi-Year Projects
($000)

Multi-Year Projects Commencing in 2018

Project Description	Expended to 2018	2019	2020	2021	2022	2022	Total
Terminal Station Refurbishment and Modernization (2018-2019)	8,170.6	18,625.1					26,795.7
Muskrat Falls to Happy Valley Interconnection	17,731.5	2,247.0					19,978.5
Hydraulic Generation Refurbishment and Modernization (2018-2019)	10,325.4	4,283.1					14,608.5
Increase Fuel and Water Treatment System Capacity - Holyrood Gas Turbine	8,829.9	3,012.7					11,842.6
Diesel Genset Replacements - Makkovik	604.1	4,703.3	3,592.8				8,900.2
Distribution System Upgrades (2018-2019) - Various	383.8	2,771.2					3,155.0
Replace Secondary Containment System Liner - Nain	1,639.2	1,450.4					3,089.6
Install Remote Operation of Salmon River Spillway - Bay d'Espoir	645.9	1,862.5					2,508.4
Replace Vehicles and Aerial Devices - Hydro System (2018-2019) - Various	1,667.2	753.7					2,420.9
Replace Transformer T1 - Buchans	249.0	2,086.1					2,335.1
Replace Automation Equipment - St. Anthony Diesel Plant	307.4	1,565.9					1,873.3
Gas Turbine Equipment and Refurbishment - Hardwoods and Stephenville	997.9	429.3					1,427.2
Diesel Plant Engine Cooling System Upgrades - Various	638.4	671.6					1,310.0
Replace PBX Phone Systems - Various	91.7	1,150.6					1,242.3
Replace MDR 6000 Microwave Radio - Various	64.0	1,137.0					1,201.0
Replace Off Road Track Vehicle Unit No. 7239 & 7954 - Bishop's Falls & Bay d'Espoir	213.7	986.3					1,200.0
Install Automated Meter Reading (2018-2019) - Bottom Waters	75.2	1,001.0					1,076.2
Implement Terminal Station Flood Mitigation - Springdale	186.2	787.8					974.0
Purchase Mobile DC Power Systems	270.9	695.6					966.5
Replace Battery Banks and Chargers (2018- 2019) - Various	382.1	555.8					937.9
Diesel Plant Fire Protection - Postville	505.6	336.4					842.0
Upgrade Exterior of Building - Hydro Place	260.2	405.7					665.9
Replace Teleprotection - TL261	57.6	459.8					517.4
Energy Efficiency Improvements - Various	276.2	168.9					445.1
Upgrade Cranes and Hoists - Holyrood	80.3	300.3					380.6
Install Energy Efficiency Lighting in Diesel Plants - Various	104.0	119.0	122.2				345.2
Install Recloser Remote Control (2018-2019) - English Harbour West and Barachoix	63.7	275.0					338.7
Install Breaker ByPass Switches - Howley	0.0	0.0					0.0
Total Multi-Year Projects over $50,000 commencing in 2018	**54,821.7**	**52,841.1**	**3,715.0**	**0.0**	**0.0**	**0.0**	**111,377.8**

Newfoundland and Labrador Hydro
2019 Capital Projects
Projects over $50,000
Multi-Year Projects
($000)

Multi-Year Projects Commencing before 2018

Project Description	Expended to 2018	2019	2020	2021	2022	2022	Total
Upgrade Circuit Breakers - Various (2016-2020)	33,186.4	6,597.3	11,116.8				50,900.5
Refurbish Powerhouse Station Services - Bay d'Espoir	2,886.5	1,460.6					4,347.1
Replace Exciter Controls Units 1 to 6 - Bay d'Espoir	1,040.4	877.0	1,429.6				3,347.0
Total Multi-Year Projects over $50,000 commencing before 2018	**37,113.3**	**8,934.9**	**12,546.4**	**0.0**	**0.0**	**0.0**	**58,594.6**

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Newfoundland and Labrador Hydro
2019 Capital Budget
Projects over $500,000
($000)

Project Description Generation	Expended to 2018	2019	Future Years	Total	Definition	Classification	Page Ref
Hydraulic Generation Refurbishment and Modernization (2018-2019)	10,325.4	4,283.1	0.0	14,608.5	Pooled	Normal	
Increase Fuel and Water Treatment System Capacity - Holyrood Gas Turbine	8,829.9	3,012.7	0.0	11,842.6	Pooled	Justifiable	
Refurbish Powerhouse Station Services - Bay d'Espoir	2,886.5	1,460.6	0.0	4,347.1	Pooled	Normal	
Replace Exciter Controls Units 1 to 6 - Bay d'Espoir	1,040.4	877.0	1,429.6	3,347.0	Pooled	Normal	
Install Remote Operation of Salmon River Spillway - Bay d'Espoir	645.9	1,862.5	0.0	2,508.4	Other	Normal	
Gas Turbine Equipment and Refurbishment - Hardwoods and Stephenville	997.9	429.3	0.0	1,427.2	Pooled	Normal	
Hydraulic Generation Refurbishment and Modernization (2019-2020)	0.0	9,093.7	6,745.2	15,838.9	Pooled	Normal	C4
Overhaul Unit 3 Turbine Valve - Holyrood	0.0	3,290.5	0.0	3,290.5	Other	Normal	C7
Condition Assessment and Miscellaneous Upgrades - Holyrood	0.0	1,968.8	0.0	1,968.8	Other	Normal	C9
Overhaul Olympus Gas Generator - Stephenville	0.0	1,666.8	0.0	1,666.8	Other	Normal	C12
Hydraulic In-Service Failures	0.0	1,250.0	0.0	1,250.0	Other	Normal	C14
Thermal In-Service Failures	0.0	1,250.0	0.0	1,250.0	Other	Normal	C17
Upgrade Human Machine Interface & Automatic Voltage Regulator - Hardwoods	0.0	685.9	0.0	685.9	Pooled	Normal	C20
Total Generation	**24,726.0**	**31,130.9**	**8,174.8**	**64,031.7**			

Newfoundland and Labrador Hydro
2019 Capital Budget
Projects over $500,000
($000)

Project Description							
Transmission and Rural Operations	**Expended to 2018**	**2019**	**Future Years**	**Total**	**Definition**	**Classification**	**Page Ref**
Terminal Station Refurbishment and Modernization (2018-2019)	8,170.6	18,625.1	0.0	26,795.7	Pooled	Normal	
Upgrade Circuit Breakers - Various (2016-2020)	2,369.2	6,597.3	11,116.8	20,083.3	Pooled	Normal	
Muskrat Falls to Happy Valley Interconnection	17,731.5	2,247.0	0.0	19,978.5	Other	Normal	
Diesel Genset Replacements - Makkovik	604.1	4,703.3	3,592.8	8,900.2	Other	Normal	
Distribution System Upgrades (2018-2019) - Various	383.8	2,771.2	0.0	3,155.0	Pooled	Normal	
Replace Secondary Containment System Liner - Nain	1,639.2	1,450.4	0.0	3,089.6	Other	Mandatory	
Replace Transformer T1 - Buchans	249.0	2,086.1	0.0	2,335.1	Other	Normal	
Replace Automation Equipment - St. Anthony Diesel Plant	307.4	1,565.9	0.0	1,873.3	Other	Normal	
Diesel Plant Engine Cooling System Upgrades - Various	638.4	671.6	0.0	1,310.0	Pooled	Normal	
Replace Off Road Track Vehicle Unit No. 7239 & 7954 - BIF & BDE	213.7	986.3	0.0	1,200.0	Pooled	Normal	
Install Automated Meter Reading (2018-2019) - Bottom Waters	75.2	1,001.0	0.0	1,076.2	Other	Justifiable	
Implement Terminal Station Flood Mitigation - Springdale	186.2	787.8	0.0	974.0	Other	Normal	
Purchase Mobile DC Power Systems	270.9	695.6	0.0	966.5	Other	Justifiable	
Diesel Plant Fire Protection - Postville	505.6	336.4	0.0	842.0	Other	Normal	
Terminal Station Refurbishment and Modernization (2019-2020)	0.0	10,891.1	19,061.8	29,952.9	Other	Normal	C22
Distribution System Upgrades (2019-2020)	0.0	390.8	5,490.1	5,880.9	Pooled	Normal	C25
Diesel Genset Replacements (2019-2020)	0.0	525.6	3,421.8	3,947.4	Pooled	Normal	C27
Provide Service Extensions - All Regions	0.0	4,700.0	0.0	4,700.0	Pooled	Normal	C29
Upgrade Distribution Systems - All Regions	0.0	3,470.0	0.0	3,470.0	Pooled	Normal	C31
Overhaul Diesel Units - Various	0.0	2,511.3	0.0	2,511.3	Pooled	Normal	C33
Wood Pole Line Management Program - Various	0.0	2,467.0	0.0	2,467.0	Other	Normal	C35
Additions for Load - Isolated Generation Systems	0.0	1,523.6	658.9	2,182.5	Pooled	Normal	C38
Diesel Plant Fire Protection (2019-2020)	0.0	377.2	1,540.2	1,917.4	Other	Normal	C40
Terminal Station In-Service Failures	0.0	1,000.0	0.0	1,000.0	Other	Normal	C42
Total Transmission and Rural Operations	**33,344.8**	**72,381.6**	**44,882.4**	**150,608.8**			

Newfoundland and Labrador Hydro
2019 Capital Budget
Projects over $500,000
($000)

Project Description	Expended to 2018	2019	Future Years	Total	Definition	Classification	Page Ref
General Properties							
Replace Vehicles and Aerial Devices - Hydro System (2018-2019) - Various	1,667.2	753.7	0.0	2,420.9	Pooled	Normal	
Replace PBX Phone Systems - Various	91.7	1,150.6	0.0	1,242.3	Pooled	Normal	
Replace MDR 6000 Microwave Radio - Various	64.0	1,137.0	0.0	1,201.0	Other	Normal	
Replace Battery Banks and Chargers (2018- 2019) - Various	382.1	555.8	0.0	937.9	Pooled	Normal	
Upgrade Exterior of Building - Hydro Place	260.2	405.7	0.0	665.9	Other	Normal	
Replace Teleprotection - TL261	57.6	459.8	0.0	517.4	Other	Normal	
Replace Vehicles and Aerial Devices - Hydro System (2019-2020) - Various	0.0	1,248.1	594.9	1,843.0	Pooled	Normal	C53
Upgrade Telecontrol Facilities - Gull Pond Hill and Bay d'Espoir Hill	0.0	96.3	577.6	673.9	Pooled	Normal	C55
Total General Properties	**2,522.8**	**5,807.0**	**1,172.5**	**9,502.3**			
Total Projects $500,000 and Over	**60,593.6**	**109,319.5**	**54,229.7**	**224,142.8**			

Project Title: Hydraulic Generation Refurbishment and Modernization
Location: Various
Category: Generation - Hydraulic
Definition: Pooled
Classification: Normal

Project Description

Hydro has consolidated much of its hydraulic generation capital work into the Hydraulic Generation Refurbishment and Modernization Project. Hydro's philosophies for the assessment of equipment and the selection of capital work for the Hydraulic Generation Refurbishment and Modernization Project are outlined in the "*Hydraulic Generation Asset Management Overview*," which has been submitted with this proposal in the 2019 Capital Budget Application (Volume II, Tab 1). Hydro proposes the following program-based activities under the Hydraulic Generation Refurbishment and Modernization Project:

Hydraulic Generating Units Program

- Turbine and Generator Six-Year Overhauls;
- Turbine Major Refurbishment;
- Upgrade Units 1-6 Generator Bearing Cover Seals;
- Refurbish Generator Rotor; and
- Replace/Improve Unit Metering, Monitoring, Protection, and Control Assets.

Hydraulic Structures Program

- Refurbish Hydraulic Structures

Reservoirs Program

- Upgrade Public Safety Around Dams

Site Buildings and Services Program

- Refurbish Draft Tube Deck (Phase 1)

Common Auxiliary Equipment Program

- Replace Cooling Water Pump and Strainer
- Replace Drainage Pump
- Refurbish Sump Level System

The estimate for all the activities included in the 2019 Hydraulic Generation Refurbishment and Modernization Project are in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	1,014.7	428.5	0.0	1,443.2
Labour	2,729.3	836.0	0.0	3,565.3
Consultant	892.4	131.4	0.0	1,023.8
Contract Work	2,562.2	3,247.5	0.0	5,809.7
Other Direct Costs	223.6	222.9	0.0	446.5
Interest and Escalation	529.5	621.2	0.0	1,150.7
Contingency	1,142.0	1,257.7	0.0	2,399.7
Total	**9,093.7**	**6,745.2**	**0.0**	**15,838.9**

Project Justification

Hydro executes a robust capital program to ensure the generation of safe, reliable, least-cost electricity in an environmentally responsible manner. Hydro's capital program sees the replacement and refurbishment of equipment based on Hydro's long-term asset management strategy.

Future Plans

Hydro will submit a proposal for the Hydraulic Generation Refurbishment and Modernization Project on an annual basis.

Attachments

Refer to the report entitled "*Hydraulic Generation Refurbishment and Modernization*" (Volume II, Tab 1) for further project details.

Project Title: Overhaul of Unit 3 Turbine Valves
Location: Holyrood
Category: Generation - Thermal
Definition: Other
Classification: Normal

Project Description

This project is required to complete scheduled turbine valve overhauls for Generating Unit 3 at the Holyrood Thermal Generating Station.

This major overhaul consists of a total dismantling, disassembly, inspection and reassembly of the following:

- Two main stop valves;
- two combined reheat stop/intercept valves;
- four control valves; and
- auxiliary valves (blow down valve and non-return valves).

The valves will be refurbished as required through replacement of damaged parts.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	30.0	0.0	0.0	30.0
Labour	386.3	0.0	0.0	386.3
Consultant	24.0	0.0	0.0	24.0
Contract Work	2,156.3	0.0	0.0	2,156.3
Other Direct Costs	0.4	0.0	0.0	0.4
Interest and Escalation	174.2	0.0	0.0	174.2
Contingency	519.3	0.0	0.0	519.3
Total	**3,290.5**	**0.0**	**0.0**	**3,290.5**

Operating Experience

In line with Original Equipment Manufacturer recommendation and industry standard practice, turbine valves are overhauled in three year cycles. The Unit 3 turbine valves were last overhauled in 2016 and are due for their next overhaul in 2019.

Project Justification

This project is justified on the requirement to maintain the generating equipment in its optimal operating condition. It will also identify any unusual findings (internally or externally) that, if not corrected or controlled, could lead to premature failure of the equipment.

To ensure that Unit 3 operates reliably and at peak performance, providing maximum energy on demand, it is necessary that the turbine valves undergo overhauls on a scheduled basis.

Future Plans

None.

Attachments

Refer to the report entitled *"Overhaul Unit 3 Turbine Valves – Holyrood"* (Volume II, Tab 2) for further project details.

Project Title: Condition Assessment and Miscellaneous Upgrades
Location: Holyrood
Category: Generation - Thermal
Definition: Other
Classification: Normal

Project Description

The proposed project will include a Level 2 condition assessment on internal components of the main steam generators (boilers) and associated external high energy piping to detail refurbishment or replacement work to be completed in succeeding years at Holyrood.

Additionally, the following miscellaneous upgrades will be completed:

- Replacement of boiler expansion joints and boiler refractory;
- upgrade of site security; and
- replacement of back-up control center building air conditioning system.

Other miscellaneous upgrades or replacements identified in the 2017 to 2019 condition assessments or recommended by the boiler contractor during unit overhauls that are confirmed as capital and are required to ensure reliable operation of Holyrood will be completed within the approved budget for this project and reported in the Hydro's "*2019 Capital Expenditures and Carryover Report*".

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	150.2	0.0	0.0	150.2
Labour	127.9	0.0	0.0	127.9
Consultant	384.0	0.0	0.0	384.0
Contract Work	883.0	0.0	0.0	883.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	114.7	0.0	0.0	114.7
Contingency	309.0	0.0	0.0	309.0
Total	**1,968.8**	**0.0**	**0.0**	**1,968.8**

Operating Experience

The activities listed in the project description are required as a result of deteriorated infrastructure and equipment, and require refurbishment to ensure reliable operation of Holyrood.

These activities can be classified into the following:

- Level 2 inspections and condition assessments are required to determine an appropriate course of action;
- work resulting from deterioration that was previously identified during operation of the plant. In addition, recommended interventions based on the previous year condition assessment project would also be included; and
- work resulting from asset management practices for infrastructure and equipment that have to be refurbished on a regular basis.

Project Justification

Holyrood has exceeded the normal life expectancy for thermal generating stations. Units 1 and 2 at Holyrood are 48 years old. Unit 3 is 38 years old. Considering the age, there are infrastructures and equipment that need to undergo Level 2 condition assessment and upgrades, or replacements, to maintain reliable operation of Holyrood.

Future Plans

None.

Attachments

Refer to the report entitled *"Condition Assessment and Miscellaneous Upgrades"* (Volume II, Tab 3) for further project details.

Project Title: Overhaul Gas Turbine
Location: Stephenville
Category: Generation - Gas Turbines
Definition: Other
Classification: Normal

Project Description

This project will overhaul the 50 MW gas turbine End B engine, serial number 202223, at Stephenville.

The scope of work for the project includes the following:

- Removal and transportation of the engine to a service facility for disassembly, inspection and overhaul. The service facility will be determined by public tender;
- post-overhaul performance testing of the refurbished engine at the service facility; and
- return transportation, installation and commissioning of the overhauled engine.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	1.0	0.0	0.0	1.0
Labour	121.2	0.0	0.0	121.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	1,151.0	0.0	0.0	1,151.0
Other Direct Costs	45.7	0.0	0.0	45.7
Interest and Escalation	84.0	0.0	0.0	84.0
Contingency	263.9	0.0	0.0	263.9
Total	**1,666.8**	**0.0**	**0.0**	**1,666.8**

Operating Experience

The Stephenville gas turbine has been in service for approximately 43 years. The Rolls Royce Olympus C engines are no longer supported by the original manufacturer. As such, new internal components are not being manufactured and only refurbished parts are available. The service life of the engine overhauls, which utilize refurbished parts, is five years. The End B engine has been in service since the time of its last overhaul in 2014. Thus, this engine is nearing the end of its useful overhaul life.

Project Justification

To maintain operational reliability of the gas turbine plant, the gas generator engine needs to be sent to a gas turbine service facility for a scheduled overhaul.

Future Plans

None

Attachments

Refer to the report entitled *"Overhaul Olympus Gas Generator – Stephenville"* (Volume II, Tab 4) for further project details.

Project Title: Hydraulic Generation In-Service Failures

Location: Hydro Generation

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description

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 Board approval for inclusion in its annual Capital Budget Application. The identification is done through the Hydraulic Generation 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 capital budget applications. There are situations, however, where immediate refurbishment or replacement must be completed due to actual failures, the identification of an incipient failure, or faster than anticipated equipment deterioration. These situations can be caused by events such as vandalism, storm damage, lightning, accidental damage, abnormal electrical system operations, cavitation, etc.

Similar to Hydro's "*Terminal Station In-Service Failures Project,"* Hydro will use a stand-by pool of equipment (formerly referred to as Capital Spares) and undertake the timely refurbishment and replacement work required to maintain the integrity and reliability of the electrical system. These activities will be undertaken in accordance with the philosophies outlined throughout the "*Hydraulic Generation Asset Management Overview"* (Volume ll, Tab 1) document.

Annual purchases for the standby pool will be undertaken to allow responsive action to failures. It is expected that over time many of these purchases will be usable in various Hydro plants, but Hydro anticipates purchasing the following in 2019:

- Hinds Lake station service breaker;
- Hinds Lake surface air stator cooler; and
- Hinds Lake upper guide bearing cooler.

The Hydraulic Generation In-Service Failures Project will support hydraulic generation operations in case of an unforeseen event. Once identified, materials will be procured, or obtained from Hydro's stocked inventory, and the refurbishment and/or replacement work required to maintain the integrity and reliability of the Hydraulic Generation asset will be completed.

Examples of possible in-service failure work that could be completed under this project include:

- Generating unit bearing cooler failure;
- hydraulic structure jammed gates;
- replacement of rollers;
- erosion of dam reservoir;
- building damage from weather; and
- replacement of pumps or compressors due to accelerated wear or premature failure.

Hydro uses historical data and engineering judgement to predict the magnitude of in-service failures.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	681.3	0.0	0.0	681.3
Labour	347.5	0.0	0.0	347.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	65.2	0.0	0.0	65.2
Interest and Escalation	73.7	0.0	0.0	73.7
Contingency	82.3	0.0	0.0	82.3
Total	**1,250.0**	**0.0**	**0.0**	**1,250.0**

Operating Experience

On an electrical system, unexpected in-service failures occur. This program will allow Hydro to address such failures without impacting planned sustaining projects on hydraulic generation assets.

Project Justification

The failure of hydraulic generation equipment, if not addressed in a timely manner, can impact the robustness of the electrical system. This project provides the resources to address such failures promptly and minimize impacts to Hydro's electrical system.

Future Plans

This project will be proposed annually. Work executed under this project in 2019 will be reported in 2020 as part of the 2021 Capital Budget Application.

Project Title: Thermal Generation In-Service Failures
Location: Holyrood
Category: Generation - Thermal
Definition: Other
Classification: Normal

Project Description

Hydro conducts its 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 Board approval for inclusion in its annual Capital Budget Application. The identification is done through the Thermal Generation Preventive Maintenance Program using various condition based assessments and testing procedures. Hydro has had success in projecting the deterioration rate of equipment so as to submit refurbishment or replacement work in capital budget applications. There are situations, however, were immediate refurbishment or replacement has to be undertaken due to actual failures or the recognition of an incipient failure, as well as faster than anticipated equipment deterioration.

Some examples of this work are:

- Replacement or refurbishment of auxiliary equipment (such as pumps, compressors, motors) due to accelerated deterioration or premature failure;
- replacement or refurbishment of boiler or steam system components due to accelerated deterioration or premature failure;
- level 2 assessment of aging equipment suspect of failure;
- damages caused by abnormal weather events, vandalism, etc.

The probability of in-service failures at the Holyrood Thermal Generating Station has increased, given the age of the facility and its operating life stage. This project will allow Hydro to promptly address failures of a similar nature to those listed in Table 2.

Currently, Hydro has no plans to make purchases in 2019 under this project for the stand-by pool; however, should a purchase be required, it will be reported to the Board along with any projects executed under this project.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	548.3	0.0	0.0	548.3
Labour	314.3	0.0	0.0	314.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	120.0	0.0	0.0	120.0
Other Direct Costs	3.9	0.0	0.0	3.9
Interest and Escalation	66.2	0.0	0.0	66.2
Contingency	197.3	0.0	0.0	197.3
Total	**1,250.0**	**0.0**	**0.0**	**1,250.0**

Operating Experience

Table 2 shows a list of supplemental capital budget applications for the previous 10 years where portions or the entire project could have been executed within the Thermal In-Service Failures Project budget.

Table 2: Historical Supplemental Projects ($000s)

Year	Description	Cost
2016	Tank 1 Inspection and Condition Assessment	39
2015	Inspect and Repair Transformer UST-3	82
2015	Replace Unit 1 and 2 Rectifying Transformers	756
2014	Replace Air Compressor	308

Some common high temperature and pressure components that are prone to failure include expansion joints, seals, piping, fittings, and valves. Replacement of these components were undertaken in the 2017 Reliability Improvements supplemental project, which also included inspection and testing to predict the potential source of failures as accurately as possible. The Thermal In-Service Failures Project can be utilized to inspect, test, evaluate weak points, and perform smaller replacements thereby eliminating the need file for a supplemental project.

Future Plans

This project will be proposed annually. Work executed under this project in 2019 will be reported in 2020 as part of the 2021 Capital Budget Application.

Project Title: Upgrade Human Machine Interface and Automatic Voltage Regulator

Location: Hardwoods Gas Turbine

Category: Generation - Gas Turbines

Definition: Pooled

Classification: Normal

Project Description

The scope of this project includes:

- Removal and disposal of the existing obsolete Human Machine Interface (HMI) software and computer;
- procurement and installation of new HMI which includes:
    - provision of new HMI software and computer;
    - provision of communications modules in control system to facilitate new HMI interaction with control system;
    - conversion and integration of existing HMI graphics into new software; and
    - testing of HMI interaction with control system.
- removal and disposal of existing obsolete Automatic Voltage Regulator (AVR); and
- procurement, installation, and testing of new AVR.

The project estimate is shown in Table 1. The HMI project is $368,500 and the AVR project is $317,400.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	9.0	0.0	0.0	9.0
Labour	234.0	0.0	0.0	234.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	291.0	0.0	0.0	291.0
Other Direct Costs	7.0	0.0	0.0	7.0
Interest and Escalation	36.7	0.0	0.0	36.7
Contingency	108.2	0.0	0.0	108.2
Total	**685.9**	**0.0**	**0.0**	**685.9**

Operating Experience

The HMI is used for local control and data collection for the Hardwoods Gas Turbine. It provides detailed alarms for troubleshooting and collects trend data for historical analysis. The HMI consists of specialized software called PCView and an operating system called QNX (not a Windows® compatible product) running on an obsolete computer that is connected to the gas turbine control system. The HMI software cannot be transferred to a Windows®-based computer if the HMI computer fails. In this situation, the gas turbine cannot be locally controlled or monitored and, in the event of failure, the gas turbine operation would be using the only available obsolete spare HMI and it would take approximately three months to have a new HMI prepared, installed, and tested, during which time Hydro would be exposed to a subsequent failure of the spare HMI.

The AVR maintains acceptable generator voltage. The AVR was installed in 2006 and has moved into the 'Limited' phase of its life cycle, which means that the manufacturer cannot guarantee life cycle services and support. Therefore, a component failure may result in unavailability of the gas turbine until a new AVR is purchased, installed, and tested. It is anticipated that the development and installation of a new AVR would require 5 months.

Project Justification

This project is justified on the reliable operation of the Hardwoods Gas Turbine.

Attachments

Refer to the report entitled "*Upgrade HMI and AVR – Hardwoods Gas Turbine*" (Volume II, Tab 5) for further project details.

Project Title: Terminal Station Refurbishment and Modernization
Location: Various
Category: Transmission and Rural Operations - Terminal Stations
Definition: Other
Classification: Normal

Project Description

Terminal stations play a critical role in the transmission and distribution of power across the province. Terminal stations contain electrical equipment (e.g. transformers, circuit breakers, instrument transformers, and disconnect switches) and all associated protection and control relays and equipment required to protect, control, and operate the province's electrical grid. Terminal stations act as transition points in the transmission system and interface points with the lower voltage distribution and generation systems. Hydro owns and operates 69 terminal stations across the Island and Labrador Interconnected Systems.

Hydro aims to replace or refurbish failing or failed terminal station assets to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

In the 2019 Capital Budget Application, Hydro proposes the following activities under the Terminal Station Refurbishment and Modernization Program:

- Replacement of instrument transformers;
- replacement of disconnect switches;
- replacement of surge arrestors;
- refurbishment and modernization of power transformers;
- replacement of insulators;
- refurbishment and upgrade of station grounding;
- refurbishment of equipment foundations;
- installation of fire suppression systems in control buildings;
- refurbishment of control buildings;

- protection, control, and monitoring replacements and modernization; and
- refurbishment of the Wabush terminal station.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	2,973.1	2,025.6	0.0	4,998.7
Labour	2,202.8	3,354.8	0.0	5,557.6
Consultant	1,870.3	1,383.2	0.0	3,253.5
Contract Work	2,087.0	6,477.5	0.0	8,564.5
Other Direct Costs	347.9	815.5	0.0	1,163.4
Interest and Escalation	421.6	1,382.9	0.0	1,804.5
Contingency	988.4	3,622.3	0.0	4,610.7
Total	**10,891.1**	**19,061.8**	**0.0**	**29,952.8**

The Terminal Station Refurbishment and Modernization Project is a consolidation of various asset management programs for the refurbishment or replacement of terminal station assets. Descriptions of these assets and Hydro's asset management strategies are found in the "*Terminal Station Asset Management Overview, Version 3"* submitted with this 2019 Capital Budget Application (Volume II, Tab 6).

The Terminal Station Refurbishment and Modernization Project does not include projects related to growth or isolated issues for a particular terminal station. These projects are proposed separately.

Hydro will continue to maintain individual records on asset capital, maintenance and retirement expenditures, assessments and performance.

Project Justification

Hydro replaces or refurbishes assets that have deteriorated or pose a safety or environmental risk (e.g. assets containing polychlorinated biphenyls - PCBs). The replacement of such assets is required to ensure Hydro continues to deliver safe, reliable, least-cost electricity in an environmentally responsible manner. Further details on Hydro's philosophies for the assessment of equipment condition and selection and justification of projects can be found in the "*Terminal Station Asset Management Overview, Version 3"* submitted with this 2019 Capital Budget Application (Volume II, Tab 6).

Future Plans

Hydro will submit a proposal for the Terminal Station Refurbishment and Modernization Project on an annual basis.

Attachments

Refer to the report entitled "*Terminal Station Refurbishment and Modernization*" (Volume II, Tab 6) for further project details.

Project Title: Distribution System Upgrades
Location: Various Sites
Category: Transmission and Rural Operations - Distribution Central
Definition: Pooled
Classification: Normal

Project Description

Hydro provides service to residents in select rural communities within the province through the use of distribution systems. Historically, Hydro has used a condition assessment inspection based approach to identify parts of its distribution system that need to be replaced to ensure reliable operation. With this approach Hydro uses its inspection and condition grading procedures to identify distribution system components that are deteriorated and have remaining life spans of only one to five years before failure occurs, which would result in unplanned power outages to customers. In the 2019 Capital Budget Application, Hydro has enhanced its distribution reliability improvement effort by also including distribution feeders which have poor Customer Hours of Interruption (CHI), System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI) performance. This project proposal includes distribution lines located in the distribution systems of Bottom Waters, Barachoix and Hawke’s Bay that have been identified through the examination of the worst performing feeders.

This proposal also includes the installation of LED lighting fixtures on distribution feeders in Hopedale, Postville, Makkovik, Rigolet, Black Tickle, Charlottetown, Port Hope Simpson, St. Lewis, Mary’s Harbour, L’Anse au Loup, Grey River, Francois, McCallum, St. Brendan’s, and Little Bay Islands

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	70.0	1,510.0	0.0	1,580.0
Labour	220.0	525.0	0.0	745.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	80.0	2,130.0	0.0	2,210.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	20.8	418.1	0.0	438.9
Contingency	0.0	907.0	0.0	907.0
Total	**390.8**	**5,490.1**	**0.0**	**5,880.9**

Operating Experience

Hydro continues to focus on rebuilding poor performing distribution feeders in an effort to enhance reliable operation. The lines being refurbished in Bottom Waters, Barachoix and Hawke's Bay are have been identified through the examination of Hydro's worst performing feeders.

The street lights being replaced are inefficient fixtures. Replacing them with LED fixtures require less energy consumption, which will mean cost savings when installed in communities serviced by a diesel plant.

Project Justification

This project is justified so as to maintain or improve the reliable operation of Hydro's distribution system and to obtain energy efficiency gains in communities supplied electricity by diesel generators.

Future Plans

Future distribution line upgrades will be proposed in future capital budget applications

Attachments

Refer to the report entitled "*Distribution System Upgrades 2019*" (Volume II, Tab 8) for further project details.

Project Title: Diesel Genset Replacement

Location: Cartwright Diesel Plant

Category: Transmission and Rural Operations - Distribution Labrador

Definition: Pooled

Classification: Normal

Project Description

This project proposes the replacement of genset Unit 2052 at the Cartwright diesel generating plant. The proposal includes all costs associated with the procurement and installation of a new 925 kW diesel generator set and piping modifications to the existing cooling system to accommodate the new unit. The existing exhaust system will be reused with minor modifications.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	10.0	1,059.3	0.0	1,069.3
Labour	221.6	662.5	0.0	884.1
Consultant	243.3	549.6	0.0	792.9
Contract Work	0.0	50.0	0.0	50.0
Other Direct Costs	20.0	187.6	0.0	207.6
Interest and Escalation	30.7	312.0	0.0	342.7
Contingency	0.0	600.8	0.0	600.8
Total	**525.6**	**3,421.8**	**0.0**	**3,947.4**

Operating Experience

Unit 2052 in Cartwright was installed in 1998 and has been in service for 20 years. The unit has been overhauled four times while in service and has 107,909 hours of operation as of March 31, 2018.

Project Justification

This project is justified under Hydro's asset management strategy to replace gensets after 100,000 hours of operation to ensure reliability.

Attachments

Refer to the report entitled "*Diesel Genset Replacement*" (Volume II, Tab 7) for further project details.

Project Title: Provide Service Extensions

Location: All Service Areas

Category: Transmission and Rural Operations – Distribution

Definition: Pooled

Classification: Normal

Project Description

This project is an annual allotment based on past expenditures to provide for service connections, including street lights to new customers.

Table 1 identifies the total estimate for the Central, Northern, and Labrador operating regions.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	2,168.1	0.0	0.0	2,168.1
Labour	1,832.1	0.0	0.0	1,832.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	157.2	0.0	0.0	157.2
Other Direct Costs	124.7	0.0	0.0	124.7
Interest and Escalation	206.0	0.0	0.0	206.0
Contingency	411.9	0.0	0.0	411.9
Sub-Total	4,900.0	0.0	0.0	4,900.0
Cost Recoveries	(200.0)	0.0	0.0	(200.0)
Total	**4,700.0**	**0.0**	**0.0**	**4,700.0**

Operating Experience

In recent years, rural areas of the Island have generally experienced increased expenditures for service extensions due to customer growth and economic activity.

The five year actual expenditures for service extensions by region are shown in Table 2.

Table 2: Five Year Expenditures ($000s)

Region	**2013**		**2014**		**2015**		**2016**		**2017**	
	Budget	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**
Central	1,437	1,751	1,490	1,660	1,600	1,842	1,750	1,531	1,660	1,794
Northern	1,371	1,218	1,460	1,366	1,460	1,498	1,470	1,623	1,270	1,154
Labrador	2,198	2,720	3,220	1,848	3,020	1,242	1,930	1,522	1,590	1,275
Total	**5,006**	**5,689**	**6,170**	**4,814**	**6,080**	**4,582**	**5,150**	**4,675**	**4,520**	**4,223**

Project Justification

The forecast budget estimate for 2019 is based on an analysis of the historical expenditures within the past five years on new customer connections by region, supplemented with regional planning input with respect to future activity expenditure levels.

The service extension budget for Labrador is forecast for 2019 on the basis of the two-year historical average expenditures from 2016 and 2017 to reflect the expected decline in activity from the historically high levels experienced in 2012 and 2013. A five-year historical average was used for the Central Region and a five year historical average was used for the Northern Region respectively. The 2019 budget was developed assuming distribution line cost escalation of 2.1% over 2018. The budget by region is shown in Table 3.

Table 3: Estimate for 2019 Service Extensions ($000s)

Region	**Budget**
Central	1,810
Northern	1,460
Labrador	1,430
Total	**4,700**

Future Plans

This is an annual allotment that is adjusted from year to year depending on historical expenditures. For a detailed budget breakdown, refer to Appendix A of the *"2019-2023 Capital Plan"* (Volume I).

Project Title: Upgrade Distribution Systems
Location: All Service Areas
Category: Transmission and Rural Operations - Distribution
Definition: Pooled
Classification: Normal

Project Description

This project is an annual allotment based on historical expenditures, which provide for the replacement of deteriorated poles, substandard structures, corroded and damaged conductors, transformers/street lights/reclosers, and other associated equipment. Upgrading requirements for distribution systems are identified through preventive maintenance inspections, or when there is damage caused to equipment by adverse weather conditions, such as storms, or salt contaminations.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	1,882.9	0.0	0.0	1,882.9
Labour	1,090.0	0.0	0.0	1,090.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	137.1	0.0	0.0	137.1
Other Direct Costs	2.9	0.0	0.0	2.9
Interest and Escalation	150.4	0.0	0.0	150.4
Contingency	301.8	0.0	0.0	301.8
Subtotal	3,564.0	0.0	0.0	3,564.0
Cost Recoveries	(94.0)	0.0	0.0	(94.0)
Total	**3,470.0**	**0.0**	**0.0**	**3,470.0**

Operating Experience

The five-year expenditures for distribution upgrades by region are shown in Table 2.

Table 2: Five Year Expenditures ($000s)

Region	2013		2014		2015		2016		2017	
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual
Central	1,095	1,692	1,700	1,861	1,720	1,887	1,870	1,671	1,870	1,877
Northern	1,237	678	1,270	854	1,210	730	1,120	924	880	993
Labrador	458	604	400	859	410	370	900	610	900	709
Total	**2,790**	**2,974**	**3,370**	**3,574**	**3,340**	**2,987**	**3,890**	**3,204**	**3,650**	**3,579**

Project Justification

The forecast budget estimate for 2019 is based on an analysis of the historical expenditures for distribution upgrading by region supplemented with regional planning input with respect to future activity expenditure levels. The 2019 budgets for the Central, Northern, and Labrador regions are based on the five-year average for distribution system upgrades for the period 2013-2017. Inflation adjusted budgets for 2019 were developed assuming distribution upgrading cost escalation of approximately 2.1% over 2018.

Table 3: Budget for 2019 Distribution System ($000s)

Region	Budget
Central	1,910
Northern	890
Labrador	670
Total	**3,470**

Future Plans

This is an annual allotment, which is adjusted from year to year depending on historical expenditures. For the five-year capital plan, refer to Appendix A of the "*2019-2023 Capital Plan"* (Volume I).

For a history of other specific distribution system upgrades that have been completed over the past five years, refer to the "*Distribution System Upgrades 2019"* Project (Volume II, Tab 8).

Project Title: Overhaul Diesel Engines

Location: Various

Category: Transmission and Rural Operations - Generation Northern

Definition: Pooled

Classification: Normal

Project Description

This proposed project is required to overhaul the diesel engines at various diesel generating plants. The project consists of 10 overhauls of diesel engine that are projected to reach the required overhaul criteria in 2019, and four alternator overhauls. This projection is based on the engines being overhauled every 20,000 hours of operation (with the exception of the 100,000 hours milestone, at which point the engine is replaced instead of being overhauled), and alternators being overhauled every 40,000 hours of operation.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	1,223.0	0.0	0.0	1,223.0
Labour	477.5	0.0	0.0	477.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	179.0	0.0	0.0	179.0
Other Direct Costs	109.0	0.0	0.0	109.0
Interest and Escalation	125.1	0.0	0.0	125.1
Contingency	397.7	0.0	0.0	397.7
Total	**2,511.3**	**0.0**	**0.0**	**2,511.3**

Operating Experience

Hydro's existing system of diesel generating stations consists of 24 diesel generating stations, 20 of which are prime power generating stations and four of which are emergency backup generating stations. Isolated diesel generation plants operate continuously since they provide the primary source of electricity to communities isolated from the Province's electrical grids.

A given unit is not in service continually since the number of units in service varies based on the demand. Emergency backup diesel generation plants operate only in emergency situations, which are rare but critical. In automated plants the engine mix is automatically controlled by a control system to maximize fuel efficiency, while in manual plants this control is completed by the operator. In all of the plants, the operator has the flexibility to shut down engines for maintenance provided there is another engine available to take the load for that time. As a result, outages to engines can occur without outages to customers.

Project Justification

Hydro's current maintenance philosophy is to complete an engine overhaul on all diesel engines every 20,000 hours. This philosophy was established as a result of a 2003 review of the maintenance tactics and failure history. Performing overhauls too frequently results in additional expenditure for negligible improvement in reliability. An overhaul interval of 20,000 hours is considered to be the optimum interval for providing least-cost, reliable electrical service.

Future Plans

The overhaul of diesel engines is a continuous program that will need to continue as long as there are prime power diesel generating plants. The long term plan for diesel engine overhauls forecasts 45 overhauls over the next five years (i.e. 2019-2023), which is an average of approximately nine overhauls annually and is based on an overhaul interval of 20,000 operating hours. The long term plan is based on the present-day operating conditions, which are subject to change as the loading on a plant, or other factors, change with time. Changes to the operating conditions can change the average number of annual overhauls.

Attachments

Refer to the report entitled *"Overhaul Diesel Engines"* (Volume II, Tab 9) for further project details.

Project Title: Wood Pole Line Management Program (2019)
Location: Various
Category: Transmission and Rural Operations - Transmission
Definition: Other
Classification: Normal

Project Description

The objective of the Wood Pole Line Management (WPLM) program is to maintain a comprehensive pole inspection and testing program using the conventional sound and bore methods supplemented by Non Destructive Evaluation (NDE), periodic full scale tests of poles removed from service, and remedial treatment application. Structural analysis to assess the line reliability is applied against all inspection information. Any replacement and/or refurbishment will be based on the assessment of quantitative risk with respect to in-service pole strength.

Under the program, transmission line inspection data in each year is analyzed and appropriate recommendations made for necessary refurbishment and/or replacement of line components such as poles/structures, hardware, and conductors in the subsequent year. The inspection data and any refurbishment and/or replacement of assets are recorded in a centralized database for future access and tracking.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	295.2	0.0	0.0	295.2
Labour	1,471.0	0.0	0.0	1,471.0
Consultant	99.6	0.0	0.0	99.6
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	73.8	0.0	0.0	73.8
Interest and Escalation	139.5	0.0	0.0	139.5
Contingency	387.9	0.0	0.0	387.9
Total	**2,467.0**	**0.0**	**0.0**	**2,467.0**

Operating Experience

Hydro operates approximately 2,500 kilometers of wood pole transmission lines, including approximately 26,000 poles. Hydro inspects and treats approximately 10 percent of these poles each year, and these inspections indicate decreasing preservative levels and increasing decay in aging poles.

Project Justification

As wood poles age, their preservative retention levels decrease and the poles become increasingly subjected to deterioration by different agents including fungi and insects. Wood poles must be regularly inspected and treated in-situ to proactively identify and assess any deterioration. The WPLM program detects deteriorated poles and other line components early to avoid safety hazards and to identify poles that are at early stages of decay to ensure that corrective measures can be taken to extend the average life of these poles. Money is saved through the deferring of rebuilding lines and avoiding forced outages.

In addition to proactively managing wood poles, the project detects deteriorated line components before the integrity of a structure is jeopardized. If the deterioration of the components is not detected early enough then the reduced integrity of the structure will result in component failures. This would cause a customer outage, thus affecting the reliability of the line and the system as a whole and could lead to increased failure costs.

Future Plans

The program is based on two 10-year inspection cycles that began in 2003. It provides annual data to identify problem areas for the regional asset managers and develop recommendations for appropriate pole replacements, as well as other components in the following years. Hydro has provided a *"Wood Pole Line Management 2018 Update"* in Appendix C of the *"2019-2023 Capital Plan"* report (Volume I)

Attachments

Refer to the report entitled *"Wood Pole Line Management Program"* (Volume II, Tab 10), for further project details.

Project Title: Additions for Load – Isolated Systems

Location: Makkovik

Category: Transmission and Rural Operations - Generation Labrador

Definition: Pooled

Classification: Normal

Project Description

This is a two year project that includes removal of the two existing 68,190 L horizontal fuel tanks that are approaching the end of their useful life and the procurement and installation of one new 400,000 L vertical fuel storage tank at the Makkovik Diesel Generating Station. In addition, the scope of this project includes modifications to existing secondary containment systems, piping, and any other work required to facilitate the installation of the new tank.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	45.0	0.0	0.0	45.0
Labour	139.0	54.3	0.0	193.3
Consultant	177.5	37.5	0.0	215.0
Contract Work	1,047.9	110.1	0.0	1,158.0
Other Direct Costs	25.4	9.3	0.0	34.7
Interest and Escalation	88.8	118.5	0.0	207.3
Contingency	0.0	329.2	0.0	329.2
Total	**1,523.6**	**658.9**	**0.0**	**2,182.5**

Operating Experience

The bulk fuel storage in Makkovik is 1,078,380 liters, comprised of two 68,190 litre horizontal tanks and three 314,000 litre vertical tanks.

The 2017 Makkovik fuel forecast has indicated that there will be a net deficit in available winter fuel storage for the winter of 2020-2021.

Project Justification

The available bulk fuel storage in Makkovik is not adequate to maintain the required nine month winter fuel requirement beyond 2020.

Attachments

Refer to the report entitled *"Additions for Load – Isolated Systems - Makkovik"* (Volume II, Tab 11) for further project details.

Project Title: Diesel Plant Fire Protection
Location: Black Tickle
Category: Transmission and Rural Operations - Distribution Labrador
Definition: Other
Classification: Normal

Project Description

This project proposes the installation of an automated fire protection system at the Black Tickle diesel plant. The work includes:

- Design, procurement, installation, and commissioning of the new fire protection equipment; and
- installation of a new storage shelter for nitrogen cylinders, water cylinders and associated equipment outside the powerhouse, which includes foundations, electrical work and ventilation.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	20.0	0.0	20.0
Labour	87.8	75.0	0.0	162.8
Consultant	56.0	64.0	0.0	120.0
Contract Work	168.9	923.0	0.0	1091.9
Other Direct Costs	42.4	25.0	0.0	67.4
Interest and Escalation	22.1	140.8	0.0	162.9
Contingency	0.0	292.4	0.0	292.4
Total	**377.2**	**1,540.2**	**0.0**	**1,917.4**

Operating Experience

Hydro has experienced six fires at its diesel plants that have resulted in extensive damage or total loss of plant. Black Tickle is not equipped with automated fire protection system.

Project Justification

This project is justified by the requirement to minimize the damage that could result if a fire were to occur in the Black Tickle diesel plant. It has been Hydro's experience that fire related damage may be extensive without an automated fire protection system. This damage could result in the community being left without power for an extended period of time.

Future Plans

At present 17 of Hydro's 21 diesel plants do not have fire suppression system. It is anticipated that Hydro will submit proposals in subsequent years to have automated fire protection systems installed at additional remote diesel plants.

Attachments

Refer to the report entitled *"Install Diesel Plant Fire Protection"* (Volume II, Tab 12) for further project details.

Project Title: Terminal Station In-Service Failures
Location: Various
Category: Transmission and Rural Operations - Terminal Stations
Definition: Other
Classification: Normal

Project Description

Hydro conducts its asset management activities to proactively identify, replace, repair, or refurbish equipment to minimize the disruption of service and to avoid unsafe working conditions that result from equipment failure. An objective of Hydro's Asset Management Program is to identify refurbishment and replacement activities that require the Board's approval for inclusion in its annual Capital Budget Application. The identification is done through the *Terminals Station Preventive Maintenance Program* using various condition based assessments and testing procedures. Hydro has had success in projecting the deterioration rate of equipment so as to submit refurbishment or replacement work in capital budget applications. There are situations, however, where immediate refurbishment or replacement has to be undertaken due to actual failures or the recognition of an incipient failure, as well as faster than anticipated equipment deterioration. These situations can be caused by events such as vandalism, storm damage, lightning, accidental damage, abnormal electrical system operations, corrosion, etc.

In this project, Hydro will continue to develop its equipment stand-by pool and undertake the timely refurbishment and replacement work required to maintain the integrity and reliability of the electrical system. These activities will be undertaken in accordance with the philosophies outlined throughout the *"Terminal Station Asset Management Overview"* document (Volume II, Tab 6).

Hydro reviews its standby pool requirements annually for a number of asset types, including:

- On-Load Tap Changers;

- synchronous Condensers; and
- protection and Control Equipment

Currently, Hydro has no plans to make purchases in 2019 under this project for the stand-by pool; however, should a purchase be required, it will be reported to the Board along with any projects executed under this project.

Hydro uses historical data and engineering judgement to predict the magnitude of in-service failures expenditures.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	634.8	0.0	0.0	634.8
Labour	258.9	0.0	0.0	258.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	46.9	0.0	0.0	46.9
Interest and Escalation	59.4	0.0	0.0	59.4
Contingency	0.0	0.0	0.0	0.0
Total	**1,000.0**	**0.0**	**0.0**	**1,000.0**

Operating Experience

On an electrical system, unexpected in-service failures occur. This program will allow Hydro to address failures without impacting planned sustaining projects in terminal stations.

In 2017, the total expenditure on terminal station in-service failures was $1,440,945. The activities carried out under the 2017 Terminal Station In-Service Failures project are outlined in Appendix A.

Project Justification

The failure of terminal station equipment, if not addressed in a timely manner, affects the robustness of the electrical system. This project provides the resources to address such failures promptly, to minimize impacts to Hydro's electrical system.

Future Plans

Hydro will continue to propose the *Terminal Station In-Service Failures* project annually. Work executed under this project in 2019 will be reported in 2020 as part of the 2021 Capital Budget Application.

Appendix A

2017 In-Service Failures Activities

Project Title and Location	Expenditure ($000s)	Failure Identified	Project Scope
Replace Breaker B3L19 Sunnyside Terminal Station	$852.5	Breaker B3L19 (138 kV-SF6) at the Sunnyside Terminal Station failed when it flashed over internally on A and C phases due to lightning on November 21, 2016. An original equipment manufacturer representative (ABB) visited the site to carry out a non-intrusive inspection of the breaker. While the contact resistance on A and C phases and the gas purity on A phase were not ideal, ABB recommended that the breaker could be put back in service, and should be overhauled in the spring/summer of 2017. The overhaul was scheduled and commenced during the week of July 31, 2017. Teardown of the breaker revealed that both A and C phase interrupters suffered significant damage during the November 21, 2016 event and that extensive component replacement would be required in order to put the breaker back in	The failed breaker B3L19 was replaced with an available spare breaker.

Project Title and Location	Expenditure ($000s)	Failure Identified	Project Scope
		service. Considering the age (27 years) and condition of the breaker, the long lead time for parts to repair the breaker, and the need to restore the breaker for system reliability, it was necessary to immediately replace the breaker.	
Transformer Protective Devices Various Terminal Stations	$232.2	A number of transformer protective devices failed due to moisture ingress into the relays. These devices protect power transformers that are critical to the Island Interconnected System. The protection devices include winding temperature, oil temperature and gas relays. These failures were investigated after an outage on Holyrood T3 when the transformer tripped due to ingress of moisture in the oil temp relay. From a broader review of the others that have been changed out in recent years, it was discovered that recently purchased and installed winding/oil temperature relays were seeing	Failed transformer protective devices were replaced with a newer, more robust design for the following transformers: • Sunnyside Terminal Station Transformer T4 • Voisey's Bay Nickel Terminal Station Transformer T2 • Western Avalon Terminal Station Transformer T2 Hardwoods Terminal Station Transformers T2, T4, T5 and GT1 • Holyrood Terminal Station Transformers UST-1, UST-3, T1, T2, T3, T5, T7, SST-12 and SST-34 • Bottom Brook Terminal Station Transformers T1

Project Title and Location	Expenditure ($000s)	Failure Identified	Project Scope
		significant moisture build up inside the relay, resulting in the possibility that the relay may cause an inadvertent outage. It was also determined from the review that the manufacturer had made a design change in the later part of 2016 to improve their design in order to minimize moisture ingress and condensation and any relays purchased after that will receive an updated improved design.	and T3 • Massey Drive Terminal Station Transformer T2 Stephenville Terminal Station Transformer T3
Mobile Transformer Refurbishment Bishops Falls	$151.0	Upon discovery of a leak from one of the oil pumps in the mobile transformer in October 2017, the pump was dismantled for inspection. The inspection revealed that the pump impellor was damaged from internal impact by an object. This was likely caused by a pump seal and part of the seal being sucked into the pump. This work required removal, processing, and reinstallation of the transformer oil.	The mobile transformer was refurbished. Refurbishment included the replacement of gaskets and seals and the processing of the oil.
Replace Station Service	$116.8	A station service transformer failure occurred in Sally's Cove. As	A replacement station service transformer was procured and installed at the St. Anthony

Project Title and Location	Expenditure ($000s)	Failure Identified	Project Scope
Transformer St. Anthony Airport Terminal Station		there was no redundant station feed in Sally's Cove, immediate replacement was required. The station service transformer at St. Anthony Airport Terminal Station was identical to the failed unit at Sally's Cove and St. Anthony Airport Terminal Station has a backup station service supply from the distribution system. To ensure continued reliable service to customers, the station service transformer was removed from St. Anthony and installed in Sally's Cove. As this meant St. Anthony Airport Terminal Station was operating on a backup feed from the diesel generators, St. Anthony was vulnerable without immediate replacement.	Airport Terminal Station.
Interrupter Replacement Western Avalon Terminal Station	$45.8	Interrupter B1T1 failed in February, 2017. The interrupter switch isolates equipment in the event of overload conditions and, in case of faults, interrupts the fault current to avoid damage to protected equipment. A failed interrupter leaves	The failed interrupter B1T1 was replaced with an available spare.

Project Title and Location	Expenditure ($000s)	Failure Identified	Project Scope
		protected equipment vulnerable to overload conditions and can result in equipment failure and extended unplanned customer outages. Immediate replacement of Western Avalon B1T1 interrupter was required to maintain system reliability.	
Upgrade Breaker Failure Protection Hardwoods Terminal Station	$24.4	On March 11, 2017, the breaker failure circuit associated with breaker B1L01 at the Hardwoods Terminal Station failed following a trip due to high winds on 230 kV transmission line TL 201 (Western Avalon to Hardwoods). As a result, 230 kV bus B1 locked out, isolating critical equipment from the bus. This failure contributed to a widespread outage later in the day when 230 kV transmission line TL 218 (Holyrood to Oxen Pond) tripped as well due to high winds. Subsequently, Breaker Failure Protection associated with bus B1 at Hardwoods needed to be upgraded in 2017. Upgrading the Breaker	An upgrade of the breaker failure protection associated with bus B1 was completed.

Project Title and Location	Expenditure ($000s)	Failure Identified	Project Scope
		Failure Protection associated with bus B1 was executed without delay in 2017, in order to ensure safe, reliable, and secure operation of bus B1 and associated equipment.	
Replace Surge Arrestors Holyrood Terminal Station	$15.1	Three 69 kV surge arrestors failed in Holyrood Terminal Station due to a weather event in March 2017. Surge arresters are used on critical terminal station equipment to protect that equipment from overvoltage due to lightning, extreme system operating voltages and switching transients. In these situations, voltage at the equipment can rise to levels which could damage the equipment's insulation. The surge arrestors act to maintain the voltages within acceptable levels. Without surge arrestors, equipment insulation could be damaged and faults could result during overvoltage events. When a surge arrester fails, it is not repairable and must be replaced immediately;	Three failed 69 kV surge arrestors were replaced with available spares.

Project Title and Location	Expenditure ($000s)	Failure Identified	Project Scope
		otherwise the major equipment may be exposed to damaging overvoltage events.	
Replace Surge Arrester Stony Brook Terminal Station	$3.3	The low voltage surge arrester replacement at Stony Brook Terminal Station was based on October 2017 test results (obtained via Stony Brook T2 Doble Preventive Maintenance check). Doble test results indicated that the surge arrester condition was deteriorated and hence at increased risk of failure. Failure of the surge arrester would result in a loss of surge protection of the B phase winding from the 138 kV transmission network and also a forced transformer outage if the failure mode resulted in a fault.	Surge Arrestor was replaced with an available spare.

Project Title: Replace Vehicles and Aerial Devices

Location: Various Sites

Category: General Properties - Transportation

Definition: Pooled

Classification: Normal

Project Description:

This project proposes the replacement of 27 light-duty vehicles and five heavy-duty vehicles in accordance with the established replacement criteria for vehicle age and kilometers (km) as follows in Table 1. Table 2 shows the replacement criteria of three other electric utilities Hydro surveyed in 2014.

Table 1: Replacement Criteria - Hydro

Hydro	
Light-duty vehicles	5-7 years or > 150,000 km and Condition/Maintenance Cost
Heavy-duty vehicles:	
Class 4, 5, and 6	6-8 years or > 200,000 km and Condition/Maintenance Cost
Class 7 and 8	7-9 years or > 200,000 km and Condition/Maintenance Cost

Table 2: Replacement Criteria - Other Utilities

Utility #1	
Light-duty vehicles	5 years or 200,000 km
Heavy-duty vehicles	8 years or 300,000 km
Utility #2	
Light-duty vehicles	5-6 years or 200,000 km
Heavy-duty vehicles:	
Class 3, 4, 5, and 6	8 years or 300,000 km
Class 7 and 8	10 years or 300,000 km
Utility #3	
Light-duty vehicles	5 years or 150,000 km
Heavy-duty vehicles	10 years or 250,000 km

The project estimate is shown in Table 3.

Table 3: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	1,194.5	479.9	0.0	1,674.4
Labour	7.0	0.5	0.0	7.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	1.0	0.0	3.0
Interest and Escalation	44.6	29.3	0.0	73.9
Contingency	0.0	84.2	0.0	84.2
Total	**1,248.1**	**594.9**	**0.0**	**1,843.0**

Operating Experience

Hydro’s transportation section maintains a close liaison with other utilities across Canada and has established the replacement criteria based on industry standards and Hydro's operating experience. Extension of the service life of a vehicle beyond the replacement criteria result in increased operating and maintenance costs.

Project Justification

Hydro operates in many diverse locations across the Province and it is critical that employees are provided with safe and reliable vehicles for the provision of economical and reliable electricity.

Future Plans

Future replacement of vehicles and aerial devices will be proposed in future Capital Budget Applications.

Attachments

Refer to the report entitled “*Replace Vehicles and Aerial Devices*” (Volume II, Tab 13) for further project details.

Project Title: Upgrade Telecontrol Facilities
Location: Gull Pond Hill and Bay d'Espoir Hill
Category: General Properties - Telecontrol
Definition: Pooled
Classification: Normal

Project Description

This two year project proposes to refurbish the shelters at Gull Pond Hill and Bay d'Espoir Hill.

The scope of the work includes:

- Replace the siding, wall sheathing and insulation, roof ice guard, and door;
- replace the deteriorated concrete foundations with new concrete;
- install new porch and entrance steps and platform;
- bury the ground rods and ground grid; and
- sand blast and treat the building metal floor frame to prevent further deterioration.

The project estimate is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	43.0	78.1	0.0	121.1
Consultant	45.0	99.0	0.0	144.0
Contract Work	0.0	240.0	0.0	240.0
Other Direct Costs	2.4	7.0	0.0	9.4
Interest and Escalation	5.9	50.6	0.0	56.5
Contingency	0.0	102.9	0.0	102.9
Total	**96.3**	**577.6**	**0.0**	**673.9**

Operating Experience

The Bay d'Espoir Hill and Gull Pond Hill telecommunications sites are located near Bay d'Espoir. These sites are microwave hubs in Hydro's communications system and are links between Hydro's Energy Control Centre and the generating facilities at Bay d'Espoir, Upper Salmon and Granite Canal. They provide System Control and Data Acquisition control of the Hydro generating facilities and teleprotection of the 230kV transmission lines.

These shelters protect critical equipment from water, ice and wind damage, which ensures uninterrupted communications and control of system operations.

The telecommunications shelters at Bay d'Espoir Hill and Gull Pond Hill were constructed in the late 1970's. A condition assessment was completed in 2014 and a follow-up site visit completed in May 2018 found the buildings were deteriorated, and if not arrested, the equipment inside the buildings were at risk of being damaged from water, ice and wind.

Project Justification

The project is justified on the requirement to refurbish deteriorated infrastructure in order to ensure reliable operation of Hydro's microwave system which is used to control and protect Hydro's electrical system.

Attachments

Refer to the report entitled *"Upgrade Telecontrol Facilities - Gull Pond Hill and Bay d'Espoir Hill"* (Volume II, Tab 14) for further information.

D. Projects over $200,000 and less than $500,000

Newfoundland and Labrador Hydro
2018 Capital Budget Application
Projects over $200,000 but less Than $500,000
($000)

Project Description	Expended to 2018	2019	Future Years	Total	Definition	Classification	Page Ref
Generation							
Upgrade Cranes and Hoists - Holyrood	80.3	300.3	0.0	380.6	Other	Normal	
Replace Main Fuel Valves - Hardwoods	0.0	404.2	0.0	404.2	Other	Normal	D2
Upgrade Compressed Air System - Holyrood Gas Turbine	0.0	70.7	317.7	388.4	Other	Normal	D7
Replace 258VDC Battery Banks - Holyrood	0.0	330.0	0.0	330.0	Other	Normal	D10
Total Generation	**80.3**	**1,105.2**	**317.7**	**1,503.2**			
Transmission and Rural Operations							
Install Energy Efficiency Lighting in Diesel Plants - Various	104.0	119.0	122.2	345.2	Pooled	Justifiable	
Install Recloser Remote Control (2018-2019) - English Harbour West and Barachoix	63.7	275.0	0.0	338.7	Pooled	Normal	
Upgrade Terminal Station for Mobile Substation - St. Anthony	0.0	89.3	402.7	492.0	Other	Normal	D13
Replace Light Duty Mobile Equipment - Various	0.0	469.6	0.0	469.6	Pooled	Normal	D17
Install Recloser Remote Control (2019-2020) - Rocky Harbour	0.0	66.1	319.9	386.0	Other	Normal	D22
Upgrade Diesel Plant Building - Ramea	0.0	352.5	0.0	352.5	Other	Normal	D33
Upgrade Line Depots - Roddickton	0.0	344.7	0.0	344.7	Other	Normal	D38
Replace Human Machine Interface - Cartwright	0.0	306.9	0.0	306.9	Other	Normal	D43
Install Pole Storage Ramps - Wabush	0.0	301.7	0.0	301.7	Other	Normal	D48
Condition Assessment for Submarine Cable - Farewell Head to Change Islands	0.0	300.1	0.0	300.1	Other	Normal	D51
Inspect Fuel Storage Tanks - Gray River	0.0	203.1	0.0	203.1	Other	Normal	D54
Total Transmission and Rural Operations	**167.7**	**2,828.0**	**844.8**	**3,840.5**			
General Properties							
Replace Personal Computers - Hydro Place	0.0	496.0	0.0	496.0	Pooled	Normal	D69
Upgrade Core IT Infrastructure - Hydro Place	0.0	359.4	0.0	359.4	Pooled	Normal	D73
Upgrade Energy Management System - Hydro Place	0.0	271.7	0.0	271.7	Other	Normal	D78
Replace Radomes - Various	0.0	263.5	0.0	263.5	Pooled	Normal	D81
Replace Peripheral Infrastructure - Hydro Place	0.0	221.8	0.0	221.8	Pooled	Normal	D95
Total General Properties	**0.0**	**1,612.4**	**0.0**	**1,612.4**			
Total Projects Over $200,000 but less than $500,000	**248.0**	**5,545.6**	**1,162.5**	**6,956.1**			

Project Title: Replace Fuel Control Valves
Location: Hardwoods
Category: Generation - Gas Turbines
Type: Other
Classification: Normal

Project Description

This project is for the replacement of the fuel control valves at the Hardwoods Gas Turbine. The scope of work for this project includes:

- removal of main fuel valves;
- installation of the spare Woodward LQ25 fuel control valves and an external Digital Valve Positioner (DVP) specific for this valve; and
- commissioning and tuning of new main fuel valves.

This work will be undertaken in 2019.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	150.0	0.0	0.0	150.0
Labour	142.6	0.0	0.0	142.6
Consultant	20.0	0.0	0.0	20.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.1	0.0	0.0	4.1
Interest and Escalation	24.2	0.0	0.0	24.2
Contingency	63.3	0.0	0.0	63.3
Total	**404.2**	**0.0**	**0.0**	**404.2**

Justification

This project is justified on the requirement to replace failing or deteriorated equipment in order for Hydro to provide safe, least-cost, reliable electrical service.

Due to its poor reliability, Hydro is proposing to replace the current Continental Control Corporation ALV10 fuel control valve with the Woodward LQ25 fuel control valve and an external digital valve positioner specific for this valve. This type of valve and digital valve positioner arrangement is used in the Stephenville plant without any operational issues.

Existing System

The Hardwoods gas turbine provides 50 MW of backup generation and synchronous condenser support to the Island Interconnected System. The plant consists of two Rolls Royce Olympus C gas engines. Each gas engine is fitted with a Continental Control Corporation (CCC) ALV10 control valve, which controls the fuel flow to each gas engine. To operate the control valve an external Digital Valve Positioner is required for each valve.

Hardwoods has been in service since 1977 and will remain in service after the Muskrat Falls development is brought into service.

The major mechanical components of Hardwoods includes two gas generator engines, two power turbines, and an alternator (also called power generator), refer to Figure 1 and Figure 2.

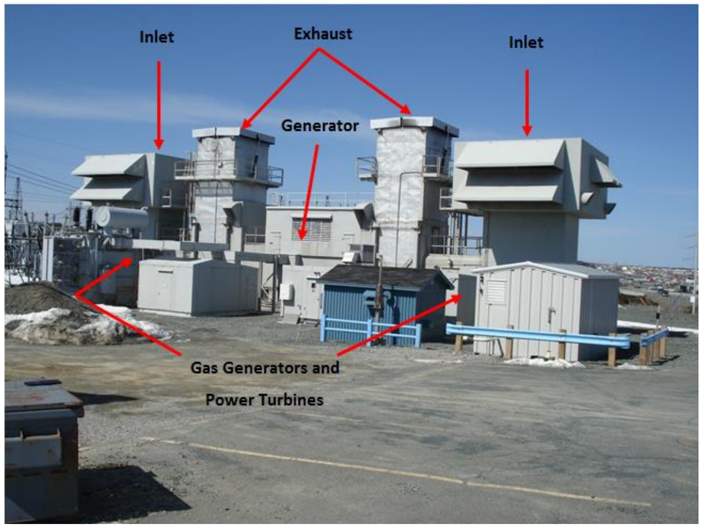

Figure 1: Hardwoods Gas Turbine Plant

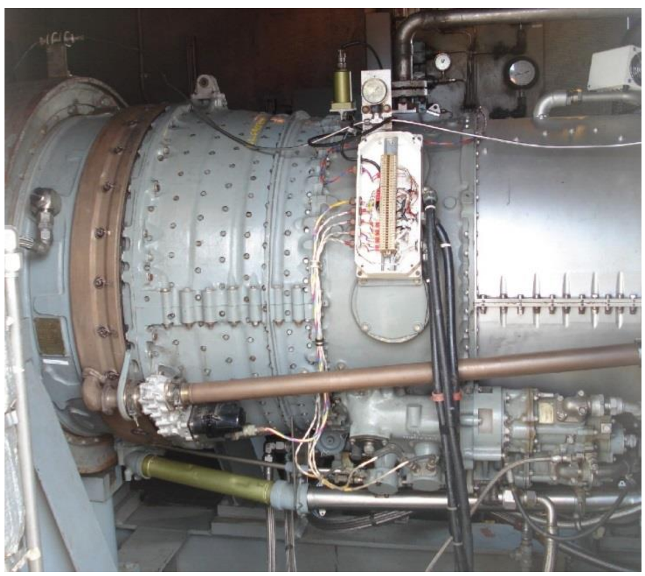

Figure 2: Gas Turbine Engine

Operating Experience

Reliability Performance

The Continental Control Corporation ALV10 fuel control valves have performed poorly since their installation in 2013. Since their installation there have been seven failures of these valves, which have affected the reliability of Hardwoods. Specifically, valve failures have caused failed starts of the unit and repeated unplanned outages to replace valves with spares. In one case where both spares had been used, a third failure occurred, which resulted in a unit not being available for two weeks until one of the failed valves was repaired. Table 2 summarizes the valve failures annually since their initial installation.

Table 2: Valve Failures

Year	Number of Valve Failures	Impact
2014	3	Outages of varying duration. With spare valves on hand, little impact until 3rd valve failed. Third spare valve was purchased as a result.
2015	0	No impact.
2016	2	One failure resulted in multiple failed starts as a result of erratic valve operation.
2017	2	One failure resulted in multiple failed starts as a result of erratic valve operation. One failed full open and resulted in the unit going into over speed requiring Operator to shut down. The cost of repair of the failed units amounted to half the cost of a new valve, plus shipping costs.

Valve failures create the potential for the gas turbine to operate outside its normal operating parameters (exhaust temperature, turbine speed, etc.) and to cause the premature failure of major components of the gas turbine plant such as combustion and power turbine components for which new replacement components are no longer available.

Maintenance History

The five-year maintenance history for the entire fuel system is provided in Table 3.

Table 3: Five-Year Fuel System Maintenance History ($000s)

Year	Preventive Maintenance	Corrective Maintenance	Total Maintenance
2017	3.0	3.0	6.0
2016	0.0	50.1	50.1
2015	0.0	4.2	4.2
2014	0.0	98.4	98.4
2013	0.0	0.3	0.3

Anticipated Useful Life

The anticipated useful life of the fuel valves and DPV is 25 years.

Conclusion

Hardwoods has experienced repeated fuel valve failures since the Continental Control Corporation ALV10 valves were installed in 2013. To ensure reliable operation of the unit for the foreseeable future the Continental Control Corporation ALV10 valves need to be replaced with the more reliable Woodward LQ25 valves and DVP specific for this control valve.

Project Schedule

The anticipated project schedule is provided in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Open project, Prepare scope statement; and Review work breakdown structure.	Feb 2019	Mar 2019
Design	Review installation procedure and materials.	Apr 2019	Jun 2019
Construction	Installation of valves and instrumentation.	Jul 2019	Jul 2019
Commissioning	Commission valves and instrumentation.	Jul 2019	Jul 2019
Closeout	As built drawings, closeout documents.	Aug 2019	Sep 2019

Project Title: Upgrade Compressed Air System
Location: Holyrood Gas Turbine Plant
Category: Generation - Gas Turbines
Type: Other
Classification: Normal

Project Description

This proposed project is required to upgrade the compressed air system at the Holyrood Gas Turbine plant. The project scope includes:

- procurement and installation of variable speed rotary screw compressor (125 PSIG[1] capacity and a flow rate of 100 standard cubic feet per minute);
- installation of concrete support pad for new compressor;
- installation of new piping system to tie in to the existing compressed air distribution system; and
- upgrade of compressed air system in turbine enclosure and turbine starting package (including piping system from new compressed air system to the turbine enclosure and turbine starting package).

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	77.0	0.0	77.0
Labour	34.0	81.1	0.0	115.1
Consultant	32.0	0.0	0.0	32.0
Contract Work	0.0	70.0	0.0	70.0
Other Direct Costs	0.0	1.0	0.0	1.0
Interest and Escalation	4.7	29.6	0.0	34.3
Contingency	0.0	59.0	0.0	59.0
Total	**70.7**	**317.7**	**0.0**	**388.4**

[1] Pounds per square inch gauge

Justification

This project is justified on the need to replace unreliable compressor equipment to ensure reliable operation of the Holyrood Gas Turbine.

Existing System

The Holyrood Gas Turbine is a 123.5 MW rated generating unit that was installed in 2015 as a standby unit for the Island Interconnected System (IIS). During operation, the gas turbine produces high pressure air to atomize the liquid fuel to ensure efficient combustion as well as to cool sections of the gas turbine. When the gas turbine is in standby mode or during startup, atomizing air is provided to the gas turbine by the plant compressed air system.

The plant's compressed air system is comprised of three reciprocating compressors that produce compressed air at 115 PSIG and a flow rate of 30 standard cubic feet per minute each. The air flows from the compressors to either an instrument air tank, or an atomizing air tank. On turbine startup, air flows from the atomizing air tank to the fuel nozzles for combustion. When the gas turbine is not generating, it remains in standby mode except for planned or forced outages. During standby mode, air is continuously consumed in various parts of the gas turbine (bleed valves, instrumentation, etc.) to maintain a state of operational readiness. The requirements to be in standby mode results in the plant air compressors operating continuously.

Operating Experience

The continuous operation of the reciprocating compressors results in frequent failures as they are not designed for continuous operation. Reciprocating compressors typically have an allowable duty cycle of 60 to 70 percent. The proposed addition of a rotary screw compressor, which is designed to operate continuously with a duty cycle of 100 percent, will allow the reciprocating compressors to operate on a more suitable duty cycle and increase the time between failures, resulting in cost savings as well as improved reliability of the compressed air system.

Table 2 provides information related to work performed on the compressors over the last three years.

Table 2: Three Year Corrective Maintenance History

Work Order No.	Completion Date	Description	Cost
1301393	February 5, 2018	PM work order	$1,067
1287616	October 17, 2017	Purchase parts kits (3)	$3,384
1268250	September 21, 2017	PM work order	$4,020
1211891	November 12, 2016	Replace Compressor #1	$10,489

Conclusion

The air compressor system is a critical auxiliary system for power generation at Holyrood Gas Turbine Generation Station. Without sufficient compressed air supply, the unit will be unable to operate or remain in standby mode. The existing reciprocating compressors are not designed for continuous operation. The continuous operation of these compressors in standby mode results in frequent failures of the compressors. The addition of a screw compressor will reduce the risk and on-going costs of compressor failures as well as reduce the risk of a lack of compressed air affecting the reliable operation of the gas turbine.

Project Schedule

The anticipated project schedule is provided in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Open Project, and Prepare Scope Statement	Jan 2019	Jan 2019
Design	Site Visit, Detailed Design, and Contract Preparation	Feb 2019	Jun 2019
Procurement	Equipment Tender	Jul 2019	Sep 2019
	Installation Tender	Sep 2019	Oct 2019
Construction	Install Concrete Pad	Apr 2020	May 2020
	Replace Compressor	Jul 2020	Aug 2020
Commissioning	Start-up and Commissioning	Aug 2020	Aug 2020
Closeout	Project Closeout	Oct 2020	Oct 2020

Project Title: Replace 258 VDC Battery Banks

Location: Holyrood Thermal Generating Station

Category: Generation - Thermal

Type: Other

Classification: Normal

Project Description

This project consists of replacing the two 258 VDC Battery Banks, #1 and #2, for servicing Holyrood Unit 1 and Unit 2, respectively.

Battery banks and chargers are required to provide 258 VDC power to emergency equipment upon the loss of the main AC power supply to the AC lube oil pumps that supply lube oil to the turbine and generator bearings at the Holyrood Thermal Generating Station.

The banks consist of flooded-cell batteries with an associated charger with a series of individual cells connected together to supply the required voltage and amperage.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2019	2020	Beyond	Total
Material Supply	172.0	0.0	0.0	172.0
Labour	77.3	0.0	0.0	77.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	31.0	0.0	0.0	31.0
Other Direct Costs	1.1	0.0	0.0	1.1
Interest and Escalation	20.5	0.0	0.0	20.5
Contingency	28.1	0.0	0.0	28.1
Total	**330.0**	0.0	**0.0**	**330.0**

Justification

Hydro replaces flooded-cell batteries based upon a normal service life of 18-20 years as indicated by battery manufacturers. Replacement is based on End-of-Life and not running to failure. As batteries age, they rapidly deteriorate, no longer providing sufficient power in the event of an outage and are more likely to fail.

The battery banks for Units 1 and 2 are approaching the end of their useful lives and require replacement to ensure reliable service. If the 258 V batteries fail to provide required power to the DC pumps, the turbine and generator shaft bearings would lose lubrication and the bearings would likely fail while operating. The result would be similar to the result of the January 11, 2013 failure of Unit 1 DC lube oil pump, which resulted in multimillion dollar repairs to Unit 1 turbine and generator and downtime of approximately ten months.

Existing System

Holyrood has three 258 V flooded-cell type battery banks, one servicing each of the three generating units. Bank #1 and #2 were installed in 1998.

The primary purpose of the banks is to provide power to the emergency DC lube oil pumps that supply lube oil to the turbine and generator bearings should there be a failure of the alternating current (AC) power supply to the AC driven pumps.

Operating Experience

Bank #1 and Bank #2 at Holyrood are beyond their rated service life. Annual inspection and maintenance are performed on these batteries.

Reliability Performance

The batteries have performed acceptably since their installation date. The batteries degrade naturally with time and are expected to deteriorate below the accepted limit of operation when used past the service life, resulting in an increased risk of failure. The batteries are being replaced due to their age so they do not degrade below an acceptable level of performance before replacement. These batteries have reached or exceeded their industry and manufacturer-rated service life and may not operate reliably.

Alternatives

Status quo is not an alternative to replacing the equipment that it is at or past the End-of-Life criteria. Also a run-to-failure operation of the bank is not an unacceptable alternative.

Conclusion

Flooded-cell batteries have a normal service life of 18-20 years. Bank #1 and #2 have been in service for 20 years and are at the end of their normal service life. As batteries age, unreliable operation of this equipment may occur. Therefore due to the criticality of the lube oil pumps, to which these banks supply direct current (DC) power, the batteries should be replaced.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open Project Complete Design Transmittal	Jan 2019	Jan 2019
Design	Engineering Design	Feb 2019	Mar 2019
Procurement	Purchase Battery	Apr 2019	May 2019
Construction	Install and Commission Battery Bank	Aug 2019	Sep 2019
Commissioning	Commission the new systems	Sep 2019	Sep 2019
Closeout	As-Builts, Project Closeout	Oct 2018	Nov 2019

Project Title: Upgrade Terminal Station for Mobile Substation
Location: St. Anthony Airport Terminal Station
Category: Transmission and Rural Operations - Terminal Stations
Type: Other
Classification: Normal

Project Description

This project involves construction of an extension to the St. Anthony Airport Terminal Station to facilitate the use of a mobile substation for maintenance, repair and capital work. The project involves a 26m x 26m extension on the southern side of the existing yard, as shown in Figure 1, that includes the installation of fencing (including double gates and station and fence grounding) and site work (i.e. yard grading and gravel). Sections of the existing fencing that do not meet Hydro's current height standard for public safety will be upgraded as part of this project.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	76.1	84.5	0.0	160.6
Consultant	0.0	40.0	0.0	40.0
Contract Work	0.0	156.0	0.0	156.0
Other Direct Costs	7.5	12.0	0.0	19.5
Interest and Escalation	5.7	35.0	0.0	40.7
Contingency	0.0	75.2	0.0	75.2
Total	**89.3**	**402.7**	**0.0**	**492.0**

Justification

The project provides a permanent site set-up for the use of a mobile substation, which is required for emergency response and to complete preventive maintenance and capital work. Installation of a permanent mobile laydown area reduces response time during emergency situation, which translates into reduced customer outage duration, offers greater public safety (i.e. proper fencing and grounding set-up) and enhances operational efficiency (i.e. less time required per job which translates into cost savings) for maintenance and capital work.

Existing System

The St. Anthony Airport Terminal Station contains a 25 MVA, 138/69 kV transformer and three capacitor banks and supplies approximately 3,500 customer in the communities of St. Anthony, Roddickton, and Main Brook.

The existing St. Anthony Terminal Station is not large enough to allow for the installation of a mobile substation inside the Terminal Station fenced area. In addition, sections of the existing station fence do not meet Hydro's current height standard of 3.05 meters. Figure 1 shows the existing station with proposed mobile laydown area.

Figure 1: St. Anthony Airport Terminal Station

In 2011, Hydro created a mobile generator and transformer laydown area at the St. Anthony Terminal Station in this area. This area will be incorporated into the new yard extension and can be seen in Figure 1.

Typically, a mobile substation is mounted on a tractor trailer and consists of a power transformer, high voltage breaker and a disconnect switch with associated protection and control equipment. A mobile substation is installed at a terminal station for the purposes of bypass to complete maintenance or capital work or to circumvent failed equipment to restore electrical supply to customers. Hydro and Newfoundland Power share mobile substations, which differ in size and weight, thereby requiring a laydown area which accommodates the larger size unit.[1] Installation of a mobile substation requires adequate level space to maneuver and an appropriately secured, safe space (i.e. chain link fencing to protect the general public and a ground grid).

Operating Experience

Without a permanent mobile laydown area, a temporary site must be established each time work is to be completed. Establishing a temporary installation site for a mobile substation at St. Anthony Airport takes approximately 3 to 5 working days to complete. The installation time on a prepared site, such as that proposed, takes 1 to 2 days. In emergency situations temporary fencing or barriers may not be as secure as the normal fence around the station until corrected later.

Historical Information

Hydro has completed similar projects to extend terminal stations for inclusion of a mobile substation at Cow Head and Barachoix Terminal Stations. Table 3 provides the historical information.

Table 3: Historical Information ($000s)

Year	Capital Budget	Actual Expenditures	Comments
2017	484.7	387.3	Cow Head TS for Mobile Station
2015	489.3	516.5	Barachoix TS – 2015 Construction

[1] Hydro's mobile substation is 16.0 metres long by 5.2 metres wide and weighs approximately 39,000 kilograms. Newfoundland Power's units are larger in size and weight.

Conclusion

Extension of the St. Anthony Terminal Station to accommodate a permanent mobile laydown area provides greater reliability for the service area through reduced outage time, while enhancing public and workplace safety. Similar projects have been completed by Hydro in other operational areas and proved to be beneficial in providing safe, reliable, least-cost energy.

Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Review Project Scope/Design Transmittal	Jan 2019	Apr 2019
Design	Site Visit/Design/Specification Development	May 2019	Oct 2019
Design	Complete Tender Documentation	Oct 2019	Dec 2019
Procurement	Tender/Award Contract	Jan 2020	Apr 2020
Construction	Upgrade to Terminal station and Extension to Chain link fence	Jun 2020	Jul 2020
Commissioning	Final Inspection	Jul 2020	Jul 2020
Closeout	Closeout project	Aug 2020	Oct 2020

Project Title: Replace Light Duty Mobile Equipment

Location: Various

Category: General Properties - Transportation

Type: Pooled

Classification: Normal

Project Description

This project proposes the replacement of 13 all-terrain vehicles, 14 snowmobiles, and 8 trailers in accordance with the established replacement criteria as follows:

- Snowmobiles/All-Terrain Vehicles (Transmission Line crews): 3-5 years
- Snowmobiles/All-Terrain Vehicles (Other): 5-7 years
- Light-Duty Trailers: 6-8 years
- Heavy-Duty Trailers: 12-15 years

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	430.0	0.0	0.0	430.0
Labour	2.4	0.0	0.0	2.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	15.6	0.0	0.0	15.6
Contingency	21.6	0.0	0.0	21.6
Total	**469.6**	**0.0**	**0.0**	**469.6**

Justification

Hydro operates in many diverse locations across the province and it is critical that employees are provided with safe and reliable equipment in order to provide economical and reliable electricity.

Existing System

Newfoundland and Labrador Hydro (Hydro) operates a fleet of light-duty mobile equipment comprised of approximately 120 snowmobiles, 70 all-terrain vehicles, 120 trailers, ten forklifts and ten miscellaneous attachments (for example, lawn mowers, backhoes, salt spreaders, snow plows, etc.).

The mobile equipment fleet is strategically distributed across Hydro's operating areas throughout the Province and is utilized on a daily basis to support staff engaged in the maintenance and repair of the electrical system.

The Transportation Department of Hydro maintains a close liaison with other Canadian Utilities through participation on the Canadian Utility Fleet Council and has established mobile equipment replacement guidelines, which consider the age and operating conditions for the equipment.

Age of Equipment

Refer to Appendix A for a detailed listing of the age of the assets being replaced under this project.

Operating Experience

Failure to replace units in accordance with the replacement policy will lead to increasing maintenance costs and less reliable vehicles. Employees maintain the electrical system 24 hours a day, seven days a week, and require dependable and safe vehicles for their work. As equipment ages, it experiences increasing downtime, which could negatively impact response times for emergency outages or planned maintenance.

Historical Information

Table 2 provides a history of light-duty mobile equipment purchases.

Table 2: Mobile Equipment less than $50,000 ($000s)

Year	Units Purchased					Budget	Actual
	All-Terrain Vehicles	Snowmobiles	Trailers	Forklifts	Attachments		
2018B	13	6	9	0	1	429.0	-
2017	10	10	3	1	1	270.9	179.8
2016	13	8	6	0	0	348.0	351.3
2015	7	33	4	0	0	494.4	505.9
2014	11	18	9	0	0	579.1	465.3
2013	14	21	3	1	0	476.5	448.2

Evaluation of Alternatives

Purchase of this equipment is the only viable option to support the maintenance of Hydro assets.

Conclusion

This project provides for the normal replacement of light-duty mobile equipment that is approaching the end of its useful life and is no longer dependable. Purchase of this equipment is the only viable option to support the maintenance of Hydro's assets.

Project Schedule

This project is to be completed by December 31, 2019.

Appendix A

Light Duty Mobile Equipment Replacements

Type	Unit	Age at Retirement	Age	Condition	LTD[1] Maintenance Cost
ATV	V7278	7.2	X		$21,015
ATV	V7299	6.0	X		$18,318
ATV	V7200	10.1	X		$1,555
ATV	V7228	9.2	X		$680
ATV	V7229	9.2	X		$1,547
ATV	V7274	7.2	X		$4,008
ATV	V7276	7.2	X		$3,412
ATV	V7291	6.1	X		$2,598
ATV	V7292	6.1	X		$4,244
ATV	V7330	5.2	X		$1,423
ATV	V7331	5.2	X		$1,775
ATV	V7337	5.1	X		$866
ATV	V7338	5.0	X		$9,190
LD Trailer	V8889	10.6	X		$11,000
LD Trailer	V8905	9.1	X		$12,010
LD Trailer	V8906	9.1	X		$14,010
LD Trailer	V8931	7.8	X	High Use	$2,139
LD Trailer	V8937	7.7	X		$1,599
LD Trailer	V8966	6.0	X	High Use	$3,600
LD Trailer	V8832	20.6	X		$1,292
HD Trailer	V8878	13.0	X		$27,870
Snowmobile	V7153	10.7	X		$1,490
Snowmobile	V7181	10.3	X		$2,814
Snowmobile	V7187	10.3	X		$2,432
Snowmobile	V7190	10.3	X		$2,816
Snowmobile	V7208	9.6	X		$1,359
Snowmobile	V7209	9.6	X		$130
Snowmobile	V7211	9.2	X		$1,214
Snowmobile	V7212	9.2	X		$3,547
Snowmobile	V7216	9.2	X		$1,453
Snowmobile	V7255	7.7	X		$1,507
Snowmobile	V7314	5.8	X		$4,633
Snowmobile	V7315	5.8	X		$1,098
Snowmobile	V7356	4.7	X		$593
Snowmobile	V7357	4.7	X		$3,631

[1] Life to Date.

Project Title: Recloser Remote Control Installation Program
Location: Rocky Harbour
Category: Transmission and Rural Operations - Distribution Northern
Type: Other
Classification: Normal

Program Description

Reclosers are installed on distribution lines to interrupt fault current caused by either temporary or permanent electrical faults to the distribution systems. Reclosers are also used as a means to disconnect power to a distribution line for the purpose of maintenance and troubleshooting activities. This switching can be conducted manually by personnel at the recloser or remotely by Energy Control Centre (ECC) personnel in St. John's if the recloser is connected to Hydro's Supervisory Control and Data Acquisition (SCADA) system.

For reclosers not connected to SCADA, once personnel have located the distribution line failure, personnel have to travel to the nearest recloser in order to operate the appropriate recloser to enact safe working procedures and return to the failure location to perform repairs. The travel and time consumed by personnel to operate reclosers increases the customer power outage duration and therefore impacts System Average Interruption Duration Index (SAIDI) and Customer Hours of Interruption (CHI). Automation of reclosers in terminal stations will eliminate the need for the line crew to travel back to the terminal station to re-energize the line since this will be done remotely by the ECC through the SCADA system.

As part of Hydro's 2015 Integrated Action Plan for Customer Service Reliability Improvements, IAP 22, in response to recommendation 4.6 from the Liberty Consulting Group report dated December 17, 2014, a structured analysis of expanding the remote control of Hydro's reclosers through SCADA was conducted throughout the Hydro distribution on the Island Interconnected System. In response to that analysis, Hydro has added remote control to six reclosers.

Hydro has 49 reclosers on the Island Interconnected System which are not yet automated. With the 2019 Capital Budget Application, Hydro is proposing to establish a recloser automation program. The automation of the 49 reclosers has been prioritized based on the individual recloser accumulated scores for six factors which are;

- Number of customers serviced;
- Site accessibility;
- Site location;
- Major customer serviced (ex, mine, hospital, etc.);
- Energy Control Center rotation list for load shedding; and
- Reliability performance measure, SAIDI[1].

Refer to Appendix A for a description of the factors and the methodology on how the reclosers were prioritized.

The ranking scores for reclosers ranked 11 to 49 diminish significantly compared to the scores for the top ten reclosers. Hydro will re-assess the need to automate those remaining reclosers. From 2019 to 2024, the top ten reclosers from the 2018 analysis, as shown in Appendix A, are proposed to be automated. Hydro will submit annual Capital Budget Application proposals to automate reclosers.

Table 1 shows the projected program costs to automate the ten highest prioritized reclosers.

[1] System Average Interruption Duration Index

Table 1: Program Cost ($000s)

Location	2019	2020	2021	2022	2023	2024	Total
Rocky Hr.	66.1	319.9					386.0
Hampden		25.0	250.0				275.0
Upper Salmon		25.0	250.0				275.0
Coney Arm			25.0	256.6			281.6
Jackson’s Arm			25.0	256.6			281.6
Bottom Waters				25.0	263.0		288.0
Farewell Head				25.0	263.0		288.0
Main Brook					25.0	270.0	295.0
Total	**66.1**	**369.9**	**550.0**	**563.2**	**551.0**	**270.0**	**2,370.2**

2019 Project Description:

The 2019 project proposes the installation of recloser remote control at the Rocky Harbour Terminal Station for RH1-R1 and RH2-R1 reclosers for use by the Energy Control Center in St. John’s.

Including remote control for RH1-R1 recloser in this project resulted in a small increase in the project estimate, but avoided having to execute a more expensive stand-alone project for the recloser in 2022/2023.

The project estimate is provided in Table 2.

Table 2: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	40.0	0.0	40.0
Labour	58.0	132.0	0.0	190.0
Consultant	0.0	8.7	0.0	8.7
Contract Work	0.0	25.0	0.0	25.0
Other Direct Costs	4.5	28.2	0.0	32.7
Interest and Escalation	3.6	26.7	0.0	30.3
Contingency	0.0	59.3	0.0	59.3
Total	**66.1**	**319.9**	**0.0**	**386.0**

Justification

This program is justified on the requirement to provide reliable service.

Existing System

The existing Rocky Harbor reclosers are not remotely controlled from the Energy Control Center. Presently, these reclosers can only be operated locally by personnel at the terminal station.

Operating Experience

Using the priority ranking method included in Appendix A, the Rocky Harbour recloser, RH2-R1 obtained a score of 405, ranking it as the first recloser that should be automated under this program. The following is a description of how this score was determined:

- Factor 1: (Number of Customers Serviced) yields a score of **3** since Rocky Harbour Line 2 services less than 500 customers (480).
- Factor 2: (Site Accessibility) yields a score of **1** since there is road access to the site with no difficulty.
- Factor 3: (Site Location) yields a score of **5** since the recloser is located in the Rocky Harbour Terminal Station.
- Factor 4: (Major Customer Serviced) yields a score of **3** since there is a hospital being supplied by Line 2.
- Factor 5: (Energy Control Rotation List for Load Shedding) yields a score of **3** since it is on the ECC rotation list for under frequency trips.
- Factor 6: (Reliability Performance Measure, SAIDI) yields a score of **3** since the SAIDI value for Line 2 is less than 15 (11.9).

The product of the individual scores yields an overall score of 405.

Similarly, for RH1-R1 the following is a description of how its score was determined:

- Factor 1: (Number of Customers Serviced) yields a score of **5** since Rocky Harbour Line 1 services less than 1000 customers (670).
- Factor 2: (Site Accessibility) yields a score of **1** since there is road access to the site with no difficulty.
- Factor 3: (Site Location) yields a score of **5** since the recloser is located in the Rocky Harbour terminal station.
- Factor 4: (Major Customer Serviced) yields a score of **1** since there are no major customers supplied by Line 1.
- Factor 5: (Energy Control Rotation List for Load Shedding) yields a score of **3** since it is on the ECC rotation list for under frequency trips and
- Factor 6: (Reliability Performance Measure, SAIDI) yields a score of **2** since the SAIDI value for Line 1 is less than 10 (5.96).

The product of the individual scores yields an overall score of 150.

Reliability Performance

SAIDI is one of the six factors used in the ranking of the reclosures under the program. Table 3 lists the five year average (2013 to 2017) for SAIDI data for Rocky Harbour and the Hydro system. The table shows that SAIDI for RH2-R1, Line 2 is above Hydro Corporate average.

Table 3: Five Year Average SAIDI

System	SAIDI All Causes	SAIDI All Causes excluding planned outages, loss of supply and customer requests
Rocky Harbour, Line 1	17.839	2.175
Rocky Harbour, Line 2	26.787	9.841
Hydro Corporate	17.796	4.463

1 **Project Schedule**

2 The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Complete Work Breakdown Schedules	Jan 2019	Mar 2019
Design	Complete site visits and detailed designs with drawings	Apr 2019	Dec 2019
Procurement	Order and receive all equipment	Jan 2020	Apr 2020
Construction	Install, configure and test equipment at the terminal stations	Apr 2020	Aug 2020
Commissioning	Commission each site to ECC	Aug 2020	Sep 2020
Closeout	Complete all drawings and project closeout accounting and reporting	Sep 2020	Dec 2020

Appendix A

Recloser Automation Priority List and Methodology

Methodology to Determine Priority for Recloser Automation

There are six factors considered in the prioritization of recloser automation as shown in Table A1. Each of the six factors has a number of levels to indicate the impact of that factor on the Distribution System. To evaluate a recloser for automation, Hydro determined a score for each of the six factors. The total overall score assigned for the recloser is the product of each of the factor's individual scores.

Table A1: Factors Considered in Prioritizing Recloser Automation

Factor 1 - Number of Customers Serviced

Level	Definition	Score
1	< 100	1
2	< 500 Customers	3
3	< 1000 Customers	5
4	> 1000 Customers	7

Factor 2 - Site Accessibility

Level	Definition	Score
1	Road access with no difficulty	1
2	Road access with minor difficulty	3
3	Road access with moderate difficulty	5
4	Road access with major difficulty	7
5	Access by Ferry	9
6	Access by Airplane	11

Factor 3 - Site Location of Recloser

Level	Definition	Score
1	Line	1
2	Substation	3
3	Terminal Station	5

Factor 4 - Major Customer Serviced		
Level	**Definition**	**Score**
1	No	1
2	Mine, Hospital, Large Sawmill, Small Generation Plant	3
3	Large Generation Plant	5

Factor 5 – Feeder Included in Energy Control Center Rotation List for Under Frequency Trips[2]		
Level	**Definition**	**Score**
1	No	1
2	Yes	3

Factor 6 – Reliability Performance Measure, SAIDI value excluding loss of supply, schedule power outage and Customer Request[3]		
Level	**Definition**	**Score**
1	< 5	1
2	< 10	2
3	< 15	3
4	< 20	4
5	< 25	5
6	< 30	6
7	< 35	7
8	< 40	8
9	< 45	9
10	< 50	10
11	> 50	11

The following example shows how the priority score was determined for Rocky Harbor Recloser, RH2-R1:

- Number of Customers Serviced: Level 2 which gives a Score of 3
- Site Accessibility: Level 1 which gives a Score of 1

[2] Hydro has a set of feeders that may be shed for under frequency trips so as to maintain electrical system stability.
[3] This is the SAIDI value before recloser automation.

- Site Location: Level 3 which gives a Score of 5
- Any Major Customer Serviced: Level 2 which gives a Score of 3
- Energy Control Center Rotation List for Load Shedding: Level 2 which gives a Score of 3
- SAIDI: Level 3 which gives a Score of 3

The total overall score for recloser RH2-R1 is the product of 3, 1, 5, 3, 3, and 3, which equals 405.

Table A2 provides a list of Hydro's reclosers ranked from highest to lowest priority for automation.

Table A2: Recloser Priority List

Rank	Distribution System	Location	Recloser	Total Score	Program Year
1	Rocky Harbour	Terminal Station	RH2-R1	405	2019/20
2	Hampden	Terminal Station	HA1-R1	405	2020/21
3	Upper Salmon	Recloser Station	B1L1	275	2020/21
4	Coney Arm	Terminal Station	CA1-R1	275	2021/22
5	Jackson's Arm	Terminal Station	JA2-R1	270	2021/22
6	Jackson's Arm	Terminal Station	JA1-R1	270	2021/22
7	Bottom waters	Burlington Substation	BU4-R1	225	2022/23
8	Farewell Head	Fogo Island Substation	FH1-R3	189	2022/23
9	Rocky Harbour	Terminal Station	RH1-R1	150	2019/20
10	Main Brook	Terminal Station	MB1-R2	150	2023/24
11	Conne River	Terminal Station	CR1-R1	135	
12	Parson's Pond	Terminal Station	PP1-R1	135	
13	South Brook	Robert Arm Substation	SB7-R2	126	
14	Monkstown	Paradise River TS	L58T1	125	
15	Farewell Head	Fogo Island Substation	F06-R1	108	
16	Bay d'Espoir	Terminal Station	BD1-R1	105	
17	South Brook	Trition Substation	TR5-R1	90	
18	Bottom waters	Feeder L3	BW3-R2	90	
19	English Harbour West	Feeder L1	EH1-R2	90	

Rank	Distribution System	Location	Recloser	Total Score	Program Year
20	Glenburnie	Terminal Station	GL1-R1	90	
21	Glenburnie	Terminal Station	GL2-R1	90	
22	Bottom waters	Feeder L1	BW1-R4	81	
23	Bottom waters	LA Scie Substation	LS7-R1	81	
24	Farewell Head	Change Island Substation	CH3-R1	81	
25	Holyrood	Terminal Station	HR1-R1	75	
26	Roddickton	Feeder L1	R01-R3	60	
27	Farewell Head	Fogo Island Substation	F05-R1	60	
28	Upper Salmon	Feeder L1	US1-R2	55	
29	Bottom waters	Brent's Cove Substation	BW3-R3	54	
30	Fleur-de-Lys	Recloser Sub	FL1-R2	54	
31	St. Anthony	Cook's Hr. Substation	CH7-R1	54	
32	Bottom waters	Feeder L2	BW2-R3	45	
33	Wiltondale	Terminal Station	WD1-R1	45	
34	South Brook	Feeder L4	SB1-R4	30	
35	Barachoix	Feeder L4	BA4-R2	30	
36	St. Anthony	Feeder L1	SA1-R3	30	
37	Farewell Head	Fogo Island Substation	F04-R1	27	
38	Bay d'Espoir	Terminal Station	BD2-R1	25	
39	Bay d'Espoir	Terminal Station	BD3-R1	25	
40	Bottom Waters	Feeder L2	BW2-R2	18	
41	Fleur-de-Lys	Feeder L1	FL1-R1	18	
42	Barachoix	Feeder L1	BA1-R2	18	
43	King's Point	Feeder L1	KP1-R2	18	
44	Bay d'Espoir	Feeder L1	BD1-R2	15	
45	Grandy Brook	Burgeo Substation	BU3-R1	9	
46	Grandy Brook	Burgeo Substation	BU2-R1	9	
47	Hawke's Bay	Feeder L3	HB3-R2	5	
48	Bay d'Espoir	Feeder L1	BD1-R3	3	
49	Grandy Brook	Burgeo Substation	BU4-R1	3	

Project Title: Upgrade Diesel Plant Building

Location: Ramea

Category: Transmission and Rural Operations – Generation Central

Type: Other

Classification: Normal

Project Description

The proposed project scope includes:

- replacement of steel girts on the southwest corner and north side of the plant;
- replacement of rusted exterior siding fasteners where the girts are being replaced; and
- modification of stairs and stair enclosure to meet current building standards.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	80.7	0.0	0.0	80.7
Consultant	80.0	0.0	0.0	80.0
Contract Work	108.9	0.0	0.0	108.9
Other Direct Costs	7.2	0.0	0.0	7.2
Interest and Escalation	20.5	0.0	0.0	20.5
Contingency	55.2	0.0	0.0	55.2
Total	**352.5**	**0.0**	**0.0**	**352.5**

Justification

This project is required to maintain the building's structural reliability. While the contractor is on site addressing the girt deterioration, Hydro will take the opportunity to implement changes to the stairs, which will enhance employee safety.

Existing System

The Ramea Diesel Plant building was built in 1998 and is a pre-engineered steel building. The exterior walls are steel frame with pre-painted vertical metal siding, vinyl faced glass fiber insulation and pre-painted vertical steel liner panels. The vertical steel panels are secured to steel girts. These girts are horizontal members that provide lateral support to the building structure. The siding was replaced in 2005. The building contains a control room, workshop, lunch room, utility room, switchgear room, washroom, and engine hall.

Operating Experience

Due to the close proximity of the ocean, the Ramea Diesel Plant building is susceptible to high levels of corrosion.

The wall girts on the southwest corner and on the north side of the plant are corroded and significant cross-sectional area loss of girts has been identified (see Figure 1 to Figure 3). Inspections by Hydro personnel have found that extensive corrosion has occurred due to the infiltration of water behind the siding because of improper flashing around windows and the improper attachment of a roof access ladder on the side of the building. In areas where girts are corroded, the siding fasteners attaching the sliding to the girts are corroded.

Figure 1: South Wall Corrosion of Horizontal Girt

Figure 2: South Wall Corrosion of Intake Louver Framing

Figure 3: East Wall Corrosion of Lower Girt

The amount of corrosion that was observed was significantly higher than would normally be expected based on the age of the building. As a result of the continued corrosion of the wall girts the building integrity is compromised.

The stairs to the second level of the plant do not contain a fire separation wall that extends to the exterior of the building. In the event of a fire at the Ramea Diesel plant, the fire separation wall will allow time for employees on the second level to vacate the building. The bottom of the existing wooden stairs extends towards the center of the building. The orientation of the wooden stairs needs to extend towards the exterior of the building for safe exit. These existing wooden stairs also do not meet building standards pertaining to rise/run on the steps and inclusion of non-skid treads on the steps.

Conclusion

The Ramea Diesel Plant building was built in 1998. Due to the close proximity of the ocean, the pre-engineered steel structure is susceptible to high levels of corrosion. Building girts are corroded and related sliding fasteners are corroded. The building integrity is compromised due to the girt corrosion.

In addition, Hydro will implement changes to the stairs to enhance employee safety.

This project will address the risk of structural unreliability due to girt corrosion and enhance employee safety.

Project Schedule

The project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Design transmittal, Project schedule, etc.	Jan 2019	Feb 2019
Design	Site Visit and Engineering for Engineering consultant for Structural/Architectural	Mar 2019	Apr 2019
Procurement	Tender construction of the replacement of the corroded wall girts and construction of the second level stairs.	May 2019	Jun 2019
Construction	Replacement of the corroded wall girts and construction of the new stairs.	Aug 2019	Oct 2019
Commissioning	Final acceptance of the construction work completed	Oct 2019	Oct 2019
Closeout	Project Closeout	Nov 2019	Dec 2019

Project Title: Upgrade Line Depot

Location: Roddickton

Category: General Properties - Administrative

Type: Other

Classification: Normal

Project Description

This proposed project is for the refurbishment of the Roddickton Line Depot. The scope of the work includes:

- replacement of shingled roof on the main line depot building;
- replacement of front entrance concrete pad, enclosure and door;
- installation of a Heat Recovery Ventilator Unit(HRV) unit;
- replacement of workshop heaters; and
- replacement of storage shed structure and concrete slab.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	66.3	0.0	0.0	66.3
Consultant	68.0	0.0	0.0	68.0
Contract Work	130.0	0.0	0.0	130.0
Other Direct Costs	6.3	0.0	0.0	6.3
Interest and Escalation	20.0	0.0	0.0	20.0
Contingency	54.1	0.0	0.0	54.1
Total	**344.7**	**0.0**	**0.0**	**344.7**

Justification

This project is justified on the requirement to refurbish deteriorated infrastructure.

Existing System

Roddickton is located on the Great Northern Peninsula (Figure 1).

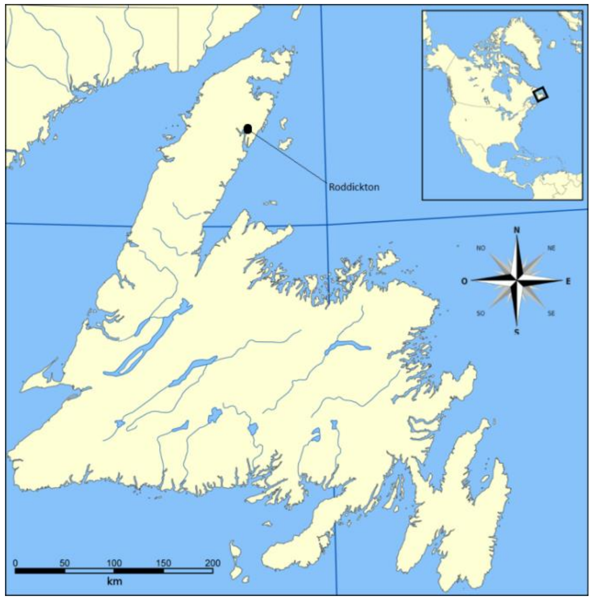

Figure 1: Roddickton Line Depot location

The line depot at Roddickton is a single level wood frame building that was constructed in 1995. The building area is approximately 155 square meters. The floors and foundations are poured in place concrete. The building consists of three offices, a kitchen/lunch room, a washroom and warehouse/workshop. The building is clad with commercial vertical metal siding and the sloped roof is finished with asphalt shingles (Figure 2).

Figure 2: Roddickton Line Depot building

The storage shed is a single room structure constructed in 1992 of wood frame with vinyl siding, a sloped asphalt shingle roof, and concrete slab on grade floor. The storage shed is approximately 18 square meters.

Operating Experience

Roddickton Line Depot Building

The Roddickton Line Depot roof system is in serviceable condition but the asphalt shingles are at the end of life and the roof has had leaks in recent years (Figure 3).

Figure 3: Roof – Shingles lifting and deformed

The front entrance enclosure is on a concrete pad and the material below this concrete pad has eroded away. In order to replace the concrete pad, the front entrance enclosure must be replaced.

The main building does not have a Heat Recovery Ventilator Unit (HRV) and does not have another means to ventilate stale air within the building. This results in excess moisture within the building that can be harmful to the buildings structure and excess pollutants in the air. Heaters in the workshop are non-operational resulting in no heating in this area which causes the area to be damp and cold. This damp and cold areas increase the amount of moisture within the building that can be harmful to the buildings structure.

Roddickton Storage Shed

The Roddickton storage shed has a concrete slab that is part of the storage shed structural integrity. This slab has deteriorated (Figure 4), which could be due to weathering of the concrete slab.

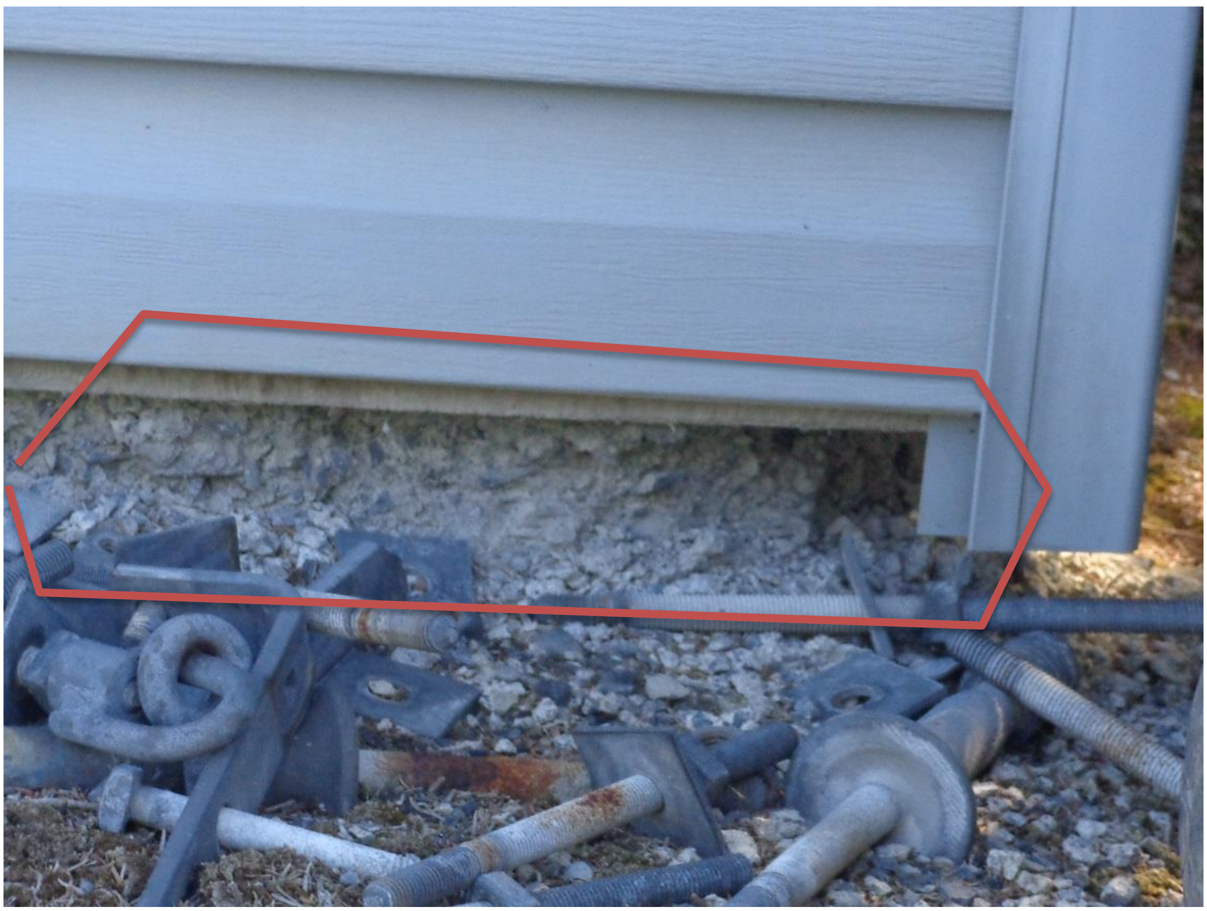

Figure 4: Deteriorated Concrete Slab under the Storage Shed walls

The walls are being undermined by this deteriorating concrete. As well, the roof trusses are sagging. These two situations results in a storage shed that has diminishing structural integrity.

Conclusion

The line depot at Roddickton requires refurbishment due to its leaking roof, eroded front entrance and inadequate heating and ventilation. The storage shed requires replacement due to its deteriorated roof and foundation.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Planning – Design Transmittal, Project schedule, etc.	Jan 2019	Mar 2019
Tender/Award	Tender/Award Construction contract for Roddickton Line Depot	Apr 2019	May 2019
Construction	Construction – Roddickton Line Depot	Jul 2019	Sep 2019
Commissioning	Final Inspection of Roddickton Line Depot	Sep 2019	Oct 2019
Closeout	Closeout Project	Oct 2019	Dec 2019

Project Title: Replace Human Machine Interface

Location: Cartwright

Category: Transmission and Rural Operations - Generation Labrador

Type: Other

Classification: Normal

Project Description

This project will replace the existing Human-Machine-Interface (HMI) at the Cartwright diesel plant with a system that is similar to that installed in other rural automated diesel plants in recent years. Additional infrastructure modifications are required to facilitate the new HMI as indicated below.

The scope of work includes the:

- replacement of the HMI computer and addition of network switches;
- design and installation of HMI software;
- addition of communications adapters for distributed controls; and
- replacement of the existing centralized Programmable Logic Controller (PLC) and programming to support the HMI.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	51.0	0.0	0.0	51.0
Labour	165.0	0.0	0.0	165.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	26.0	0.0	0.0	26.0
Interest and Escalation	16.5	0.0	0.0	16.5
Contingency	48.4	0.0	0.0	48.4
Total	**306.9**	**0.0**	**0.0**	**306.9**

Justification

The project is required to replace obsolete equipment in order to continue providing reliable operation.

Existing System

The Human-Machine-Interface (HMI) in Cartwright Diesel Plant was installed in 2006 when the plant switchgear was replaced and later upgraded to the last available version in 2010. The software provides automated, centralized monitoring and control of the plant's generators, electronic recording and display of engine parameters, metering, and alarms. The operator needs the HMI for interaction with the equipment (i.e. to start and stop units, to respond to unit alarms) and for scheduling generator operation cycles.

The existing HMI system uses Schneider Electric Monitor Pro 7.2 SCADA software, which is no longer available and support for the software ceased on December 31, 2017. The HMI computer server has a Windows 2003 Operating System, which is no longer supported by Microsoft and replacing the existing server with a newer server is not possible as the installed Monitor Pro software is not compatible with newer operating system software.

The HMI computer is connected to a central PLC over a proprietary communications network. This type of network is no longer used in Hydro diesel plant applications and has been replaced by an Ethernet version. As Schneider Electric no longer manufactures the computer accessory for the existing communications, the HMI will not operate in the event of its failure. In order to evolve the system architecture to one of Ethernet communications, the PLC processor and local modules also need to be upgraded. Distributed modules across the four diesel generator sets require Ethernet attachments to enable connectivity to the central PLC.

If the HMI system is not replaced and a failure of the existing HMI occurs full automation of the plant and the centralized control of the plant by the operators will be lost until a replacement is installed. The local operator would no longer be able to schedule unit operations in Priority Mode, which is the sequential scheduling of unloading and offloading of diesel units. The replacement would take up to 12 weeks. The failure of the HMI or the Server would result in the immediate need to execute the replacement of the failed component as well as the remaining components (PLC, HMI, server, etc.) as a result of incompatibility of these components with new technology. The plant could run during this time; however, it would be running without centralized monitoring and control by the operator.

The Cartwright HMI is shown Figure 1.

Figure 1: Cartwright HMI

Operating Experience

The HMI software has performed satisfactorily since installation. There has been no requirement for major work or upgrades to the HMI until now.

Cartwright is the last automated plant that requires the replacement of an obsolete HMI system. All other systems have either been replaced or have planned replacements in approved scopes.

Historical Information

Hydro started a program in 2014 to replace the HMIs at diesel plants due to the systems approaching the end of their life cycles and modifications to their configurations cannot be made. L'Anse au Loup, Nain, and Hopedale HMIs have been upgraded. The HMIs at St. Lewis and Mary's Harbor plants are to be upgraded in 2018.

Anticipated Useful Life

The anticipated useful life of an HMI is 18 years although lifecycle announcements issued by the manufacture influence scheduling of upgrades.

Development of Alternatives

An assessment of HMI alternatives in 2013 resulted in the selection of the HMI software product VTScada, by Trihedral, which has been established as the standard application for Hydro Diesel Plants.

Conclusion

The HMI system at the Cartwright Diesel Plant is in need of being replaced with the standard Hydro application on the basis of obsolescence and termination of support from the manufacturer. The PLC processor, some associated controls modules, and communications components are not compatible with the HMI replacement hardware and software and will also be replaced.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Prepare scope statement	Feb 2019	Feb 2019
Design	Prepare engineering drawings	Mar 2019	May 2019
	Develop programming (VTScada HMI, M340 PLC) in office	Apr 2019	Jun 2019
Procurement	Order materials	Apr 2019	Apr 2019
	Receive materials	Jun 2019	Jun 2019
Construction	Installation	Jul 2019	Aug 2019
	Complete programming (HMI, PLC) at site	Aug 2019	Aug 2019
Commissioning	Commissioning	Aug 2019	Aug 2019
Closeout	Project closeout information	Sep 2019	Sep 2019
	As built drawings and documentation	Sep 2019	Sep 2019

Project Title: Install Pole Storage Ramps

Location: Wabush

Category: Transmission and Rural Operations - Properties Labrador

Type: Other

Classification: Normal

Project Description

This project proposal is to construct five Pole Storage Ramps at Wabush in 2019. The pole storage ramps will be constructed, in accordance with Government of Canada "*Industrial Treated Wood Users Guidance"* document, so as to store wood poles off the ground on galvanized steel beams supported on reinforced concrete pedestals. Underneath the footprint of each ramp will be a 150 mm impervious soil layer covered by geotextile fabric, and 150 mm layer of granular fill.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	67.9	0.0	0.0	67.9
Consultant	24.0	0.0	0.0	24.0
Contract Work	140.0	0.0	0.0	140.0
Other Direct Costs	4.8	0.0	0.0	4.8
Interest and Escalation	17.7	0.0	0.0	17.7
Contingency	47.3	0.0	0.0	47.3
Total	**301.7**	**0.0**	**0.0**	**301.7**

Justification

This project is justified to mitigate the environmental risk of wood pole preservative toxins leaching into the ground.

Existing System

Hydro stores treated poles on the ground. The existing pole storage area in Wabush is currently located on leased land and is not up to the standards of the Government of Canada's guidelines. Figure 1 is a representative picture of a newly constructed storage ramp at Nain.

Figure 1: Example of New Pole Storage Ramp in Nain

Operating Experience

Most of the wooden poles are treated with either chromate copper arsenate (CCA) or pentachlorophenol preservatives (PCP), which are toxins and are stored outside. The storage of treated poles can result in an environmental impact as there is no infrastructure to prevent the preservatives from leaching into the ground.

Environmental Performance

At the Wabush pole storage sites, poles are stored in direct contact with the native soil resulting in preservatives leaching into the ground.

Anticipated Useful Life

The anticipated useful life of a storage ramp is 20 years.

Conclusion

Most of the wood poles at Hydro's storage sites listed above are treated with either chromate copper arsenate (CCA) or pentachlorophenol (PCP) preservatives, which are toxins. These sites do not have any infrastructure to prevent the preservatives from leaching into the ground.

Constructing pole storage ramps at these sites in accordance with Government of Canada *"Industrial Treated Wood Users Guidance"* will mitigate the environmental risk of wood poles preservatives leaching into the ground.

Project Schedule

Table 2 shows the anticipated project schedule for the new pole storage ramps to be constructed.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Planning Activity – Design transmittal, Project schedule, etc. for Wabush	Jan 2019	May 2019
Tender/Award	Tender/Award Construction Contract for Wabush	Mar 2019	May 2019
Construction	Construction of Pole Storage Ramps: Wabush	Jul 2019	Aug 2019
Commissioning	Final Inspection of Pole Storage ramps – Wabush	Aug 2019	Sep 2019
Closeout	Closeout Project	Sep 2019	Nov 2019

Project Title: Level 2 Condition Assessment of Submarine Cables Farewell Head to Fogo Island

Location: Farewell Head Distribution System

Category: Distribution

Type: Other

Classification: Normal

Project Description

This project involves engaging a company that specializes in assessment of submarine cables to perform a Level 2 condition assessment of Hydro's submarine cables servicing Fogo Island and Change Islands. The condition assessment will include appropriate non-destructive testing for this type of equipment and the interpretation of the resulting data to establish the suitability of the cables for continued operation.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	10.0	0.0	0.0	10.0
Labour	67.8	0.0	0.0	67.8
Consultant	160.0	0.0	0.0	160.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	14.7	0.0	0.0	14.7
Contingency	47.6	0.0	0.0	47.6
Total	**300.1**	**0.0**	**0.0**	**300.1**

Justification

This proposed project is required to establish the suitability of these cables for continued operation.

Existing System

Hydro supplies electricity to customers on Change Islands and Fogo Island by means of a 10.4 kilometer, three-phase submarine cable system consisting of two segments. Segment I is 5.1 kilometers in length and consists of four single 25 kV conductor cables from Farewell Head to Change Islands, supplying electricity to approximately 240 customers. Segment II is 5.3 kilometers in length and consists of four single 25 kV conductor cables from Change Islands to Fogo Island, supplying electricity to approximately 1,600 customers. In 2014, Newfoundland Power replaced similar cables to Bell Island with a budget of $14,520,000. Should the replacement of the cables be required after completion of this condition assessment and based upon the $2,800,000 per kilometer cost of replacing those cables, Hydro’s preliminary estimate of replacing the cables servicing Fogo Island and Change Island is approximately $30,000,000. If replacement is required, a proposal will be included in a future capital budget application.

Operating Experience

The existing submarine cable system interconnecting Change Islands and Fogo Island to the Island Interconnected grid was installed in 1988 and is now 30 years old. Nexans Canada Inc., a worldwide leader of electrical cables, estimates that the average life expectancy of submarine cables of this type is between 30 to 40 years. Hydro’s current assessment routine for this equipment includes infrared imaging of the cable termination points and visual inspection of the exterior of the cables by underwater divers. The last infrared imaging was completed in 2013 and showed three locations with temperature differential deficiencies that have since been corrected. The last inspection by divers was completed in 2016 and showed no external damage to the cable casing.

Reliability Performance

To date, several failures have occurred at the cable termination points. The underwater cable spans have not experienced any failures.

In 2014, Newfoundland Power replaced the Bell Island submarine cable system, which was identical to and of the same vintage as the Change Islands to Fogo Island submarine cable system, after experiencing three failures from 2008 to 2012.

Conclusion

The existing submarine cable system interconnecting Change Islands and Fogo Island to the Island Interconnected grid was installed in 1988 and is now 30 years old. The average life expectancy of submarine cables of this type is between 30 to 40 years. A Level 2 condition assessment is required to establish the suitability of these cables for continued operation to supply Fogo Island and Change Islands.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Procurement	Procure Professional Services	March 2019	May 2019
Execution	Preform Onsite Testing	Dependent on availability of professional services and equipment outages	Dependent on availability of professional services and equipment outages pendent
Closeout	Obtain Report	Nov 2019	Dec 2019

Project Title: Inspect Fuel Storage Tanks
Location: Grey River
Category: Transmission and Rural Operations - Generation Central
Type: Other
Classification: Normal

Project Description

The scope of work for this project involves the completion of internal tank inspections for two 22,730 litre, above ground, single-wall, horizontal fuel storage tanks at the Grey River diesel plant; however, Hydro may inspect a higher priority tank should conditions change and defer the inspection of a lower priority tank.

The project scope includes:

- draining and cleaning of the tank in preparation for the inspection;
- comprehensive inspection of all accessible tank components; and
- ultrasonic thickness surveys of the floor, shell, roof, and nozzles.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	66.6	0.0	0.0	66.6
Consultant	15.0	0.0	0.0	15.0
Contract Work	77.2	0.0	0.0	77.2
Other Direct Costs	1.2	0.0	0.0	1.2
Interest and Escalation	11.1	0.0	0.0	11.1
Contingency	32.0	0.0	0.0	32.0
Total	**203.1**	**0.0**	**0.0**	**203.1**

Justification

To maximize the service life of its assets and adhering to its Environmental Policy and Guiding Principles, Hydro has formalized its tank inspections into a coordinated program.

The inspection plan consists of a listing of the diesel fuel storage tanks, along with the corresponding dates of the proposed inspections. Please refer to Appendix B for Hydro's Fuel Storage Tank Inspection Plan. The plan places priority on the completion of inspections on those tanks that have exceeded the required inspection interval. Fuel volume, availability of temporary storage, existing work plans, and equipment outages have also been considered. As data is made available on tank corrosion rates, through the completion of these inspections, the frequency and timing of future inspections may change.

Hydro must ensure that its fuel storage tanks are maintained in a reliable operating condition. Tank inspections determine the required work to be completed to ensure the tank compiles with operational standards, as well as plan for the replacement of those assets that are nearing the end of service life. This proactive approach will enable the tanks to continue to perform as designed, ensuring that they are structurally sound, suitable for operation, and not at risk of releasing fuel into the environment.

Existing System

Hydro has two 22,730 litre, above ground, single-walled, horizontal fuel storage tanks at its Grey River diesel plant. The tanks were installed in 1990.

Operating Experience

The fuel storage tanks in Grey River last underwent an internal inspection in 2009 and are due for inspection under Hydro's tank inspection program. The fuel storage tanks have performed well throughout their service life with no environmental incidents to date.

Industry Experience

Industry experience with above ground fuel oil storage tanks indicates the floors and ceilings of the tanks are affected the most by oxidation. Trapped water at the bottom of tank and air voids above the fuel oil result in corrosion of the tank floor and the tank ceiling. Generally, the walls of the steel storage tanks do not experience corrosion from the inside because they are continuously coated with fuel oil through refilling. The main protection against oxidation for the exterior surfaces has been epoxy coating systems.

Inspections

API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction, Section 6 (Appendix A) is widely accepted as the benchmark for the implementation of tank inspection programs for the early detection of tank deterioration. Though written for vertical storage tanks, the inspection procedures employed in the standard are adaptable to all types of tanks.

Hydro performs routine daily tank inspections at its Grey River diesel plant to help identify any equipment deficiency or leaks into the environment. These routine inspections are completed on a daily basis by operations personnel and are limited to visual checks of the tanks and associated fuel supply system.

Standardized internal tank inspections for single-walled, horizontal tanks are typically completed on a ten-year cycle. Table 2 details the costs associated with tank cleaning and inspection projects within the past five years.

Table 2: Historical Information[1] ($000s)

Year	Capital Budget	Actual Expenditures	Units	Cost per unit	Comments
2018B	818.7	-	Two 257,000 L, vertical tanks	409.4	Clean and Inspect Tanks (Black Tickle)
2017	1,058.8	717.3	Three 314,000 L, vertical tanks; and Two 68,190 L, horizontal tanks	211.8	Clean and Inspect Tanks (Makkovik)
2016*	1,326.9	1,024.5	One 600,000 L, vertical tank; Three 144,140 L, vertical tanks; and One 45,000 L, horizontal tanks	265.4	Clean and Inspect Tanks (Nain and Hawke's Bay)
2015	1,761.1	769.3	One 2,273,000 L, vertical tank, One 90,800 L, vertical tank, and Four 22,730 L, horizontal tanks	128.2	Clean and Inspect Tanks (Hardwoods, McCallum, Port Hope Simpson and L'Anse Au Loup)
2014	495.0	271.6	Three 501,000 L, vertical tanks and Three 22,700 L, horizontal tanks	45.3	Clean and Inspect Tanks (Stephenville and St. Anthony)

As can be seen in Table 2, the costs associated with tank cleaning and inspections vary significantly on a per unit basis. This fluctuation is primarily affected by the size of the tanks, the geographic location of the work area, and the number of tanks located at the site. The cleaning and inspection effort associated with the larger vertical tanks is greater than that of the smaller horizontal tanks and consequently more costly. Remote sites containing a single tank, such as Little Bay Islands, are subject to an increase in cost, resulting from the requirement to arrange for temporary site fuel storage to facilitate the draining of the existing tank for cleaning and inspection purposes.

[1] After a detailed review and prioritization of the sites to be inspected, the 2016 scope of work was modified as detailed in the *"Capital Expenditures and Carryover Report for the Year Ended December 31, 2016."*

Conclusion

Hydro has a systematic approach for its fuel storage system inspections using the API 653 standard as the basis for this standardized approach. Inspection of the fuel tanks is imperative as they serve to identify necessary maintenance and repair items, as well as forecast their remaining service life.

The completion of the proposed inspections is necessary to ensure that the tanks are structurally sound, suitable for operation, and not at risk of releasing fuel into the environment.

Project Schedule

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Scope Statement, Schedule, Work Breakdown Structure	Jan 2019	Feb 2019
Design	Prepare Tender Package	Mar 2019	Mar 2019
Procurement	Tender and Award Contract	Apr 2019	May 2019
Construction	Clean and Inspect Fuel Storage Tanks	Jul 2019	Sep 2019
Commissioning	Fuel Tank Recertification	Aug 2019	Sep 2019
Closeout	Project Completion	-	Oct 2019

Appendix A

API Standard 653 – Section 6 Inspection

Section 6—Inspection

6.1 General
Periodic in-service inspection of tanks shall be performed as defined herein. The purpose of this inspection is to assure continued tank integrity. Inspections, other than those defined in 6.3 shall be directed by an authorized inspector.

6.2 Inspection Frequency Considerations

6.2.1 Several factors must be considered to determine inspection intervals for storage tanks. These include, but are not limited to, the following:

a) the nature of the product stored;
b) the results of visual maintenance checks;
c) corrosion allowances and corrosion rates;
d) corrosion prevention systems;
e) conditions at previous inspections;
f) the methods and materials of construction and repair;
g) the location of tanks, such as those in isolated or high risk areas;
h) the potential risk of air or water pollution;
i) leak detection systems;
j) change in operating mode (e.g. frequency of fill cycling, frequent grounding of floating roof support legs);
k) jurisdictional requirements;
l) changes in service (including changes in water bottoms);
m)the existence of a double bottom or a release prevention barrier.

6.2.2 The interval between inspections of a tank (both internal and external) should be determined by its service history unless special reasons indicate that an earlier inspection must be made. A history of the service of a given tank or a tank in similar service (preferably at the same site) should be available so that complete inspections can be scheduled with a frequency commensurate with the corrosion rate of the tank. On-stream, non-destructive methods of inspection shall be considered when establishing inspection frequencies.

6.2.3 Jurisdictional regulations, in some cases, control the frequency and interval of the inspections. These regulations may include vapor loss requirements, seal condition, leakage, proper diking, and repair procedures. Knowledge of such regulations is necessary to ensure compliance with scheduling and inspection requirements.

6.3 Inspections from the Outside of the Tank

6.3.1 Routine In-service Inspections

6.3.1.1 The external condition of the tank shall be monitored by close visual inspection from the ground on a routine basis. This inspection may be done by owner/operator personnel, and can be done by other than authorized inspectors as defined in 3.4. Personnel performing this inspection should be knowledgeable of the storage facility operations, the tank, and the characteristics of the product stored.

6.3.1.2 The interval of such inspections shall be consistent with conditions at the particular site, but shall not exceed one month.

6.3.1.3 This routine in-service inspection shall include a visual inspection of the tank's exterior surfaces. Evidence of leaks; shell distortions; signs of settlement; corrosion; and condition of the foundation, paint coatings, insulation systems, and appurtenances should be documented for follow-up action by an authorized inspector.

6.3.2 External Inspection

6.3.2.1 All tanks shall be given a visual external inspection by an authorized inspector. This inspection shall be called the external inspection and must be conducted at least every five years or *RCA*/4*N* years (where *RCA* is the difference between the measured shell thickness and the minimum required thickness in mils, and *N* is the shell corrosion rate in mils per year) whichever is less. Tanks may be in operation during this inspection.

6.3.2.2 Insulated tanks need to have insulation removed only to the extent necessary to determine the condition of the exterior wall of the tank or the roof.

6.3.2.3 Tank grounding system components such as shunts or mechanical connections of cables shall be visually checked. Recommended practices dealing with the prevention of hydrocarbon ignition are covered by API 2003.

6.3.3 Ultrasonic Thickness Inspection

6.3.3.1 External, ultrasonic thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell. The extent of such measurements shall be determined by the owner/operator.

6.3.3.2 When used, the ultrasonic thickness measurements shall be made at intervals not to exceed the following.

a) When the corrosion rate is not known, the maximum interval shall be five years. Corrosion rates may be estimated from tanks in similar service based on thickness measurements taken at an interval not exceeding five years.
b) When the corrosion rate is known, the maximum interval shall be the smaller of *RCA*/2*N* years (where *RCA* is the difference between the measured shell thickness and the minimum required thickness in mils, and *N* is the shell corrosion rate in mils per year) or 15 years.

6.3.3.3 Internal inspection of the tank shell, when the tank is out of service, can be substituted for a program of external ultrasonic thickness measurement if the internal inspection interval is equal to or less than the interval required in 6.3.3.2 b).

6.3.4 Cathodic Protection Surveys

6.3.4.1 Where exterior tank bottom corrosion is controlled by a cathodic protection system, periodic surveys of the system shall be conducted in accordance with API 651. The owner/operator shall review the survey results.

6.3.4.2 The owner/operator shall assure competency of personnel performing surveys.

6.4 Internal Inspection

6.4.1 General

6.4.1.1 Internal inspection is primarily required to do as follows.

a) Ensure that the bottom is not severely corroded and leaking.
b) Gather the data necessary for the minimum bottom and shell thickness assessments detailed in Section 6. As applicable, these data shall also take into account external ultrasonic thickness measurements made during in-service inspections (see 6.3.3).

c) Identify and evaluate any tank bottom settlement.

6.4.1.2 All tanks shall have a formal internal inspection conducted at the intervals defined by 6.4.2. The authorized inspector who is responsible for evaluation of a tank must conduct a visual inspection and assure the quality and completeness of the non-destructive examination (NDE) results. If the internal inspection is required solely for the purpose of determining the condition and integrity of the tank bottom, the internal inspection may be accomplished with the tank in-service utilizing various ultrasonic robotic thickness measurement and other on-stream inspection methods capable of assessing the thickness of the tank bottom, in combination with methods capable of assessing tank bottom integrity as described in 4.4.1. Electromagnetic methods may be used to supplement the on-stream ultrasonic inspection. If an in-service inspection is selected, the data and information collected shall be sufficient to evaluate the thickness, corrosion rate, and integrity of the tank bottom and establish the internal inspection interval, based on tank bottom thickness, corrosion rate, and integrity, utilizing the methods included in this standard. An individual, knowledgeable and experienced in relevant inspection methodologies, and the authorized inspector who is responsible for evaluation of a tank must assure the quality and completeness of the in-service NDE results.

6.4.2 Inspection Intervals

6.4.2.1 The interval from initial service until the initial internal inspection shall not exceed 10 years. Alternatively, when either a risk-based inspection (RBI) assessment per 6.4.2.4, or a similar service assessment per Annex H is performed, and the tank has one of the following leak prevention, detection, or containment safeguards, the initial internal inspection interval shall not exceed the applicable maximum interval as shown below.

Tank Safeguard	**Max. Initial Interval**
i) Original nominal bottom thickness 5/16 in. or greater	12 Years
ii) Cathodic protection of the soil-side of the primary tank bottom per Note 1	12 Years
iii) Thin-film lining of the product-side of the tank bottom per Note 2	12 Years
iv) Fiberglass-reinforced lining of the product-side of the tank bottom per Note 2	13 Years
v) Cathodic protection plus thin-film lining	14 Years
vi) Cathodic protection plus fiberglass-reinforced lining	15 Years
vii) Release prevention barrier per Note 3 (when similar service assessment performed)	20 Years
viii) Release prevention barrier per Note 3 (when RBI assessment performed)	25 Years
NOTE 1 For purposes of 6.4.2.1, effective cathodic protection of the soil-side of the primary tank bottom means a system installed and maintained in accordance with API 651. NOTE 2 For purposes of 6.4.2.1, lining of the product-side of the tank bottom means a lining installed, maintained and inspected in accordance with API 652. NOTE 3 For purposes of 6.4.2.1, a release prevention barrier means an under-bottom leak detection and containment system designed in accordance with API 650, Appendix I.	

6.4.2.2 The interval between subsequent internal inspections shall be determined in accordance with either the corrosion rate procedures of 6.4.2.3 or the RBI procedures as outlined in 6.4.2.4. and shall not exceed the applicable maximum intervals as shown below.

Procedure Used	Max. Interval
i) Corrosion rate procedures in 6.4.2.3	20 Years
ii) RBI assessment per 6.4.2.4	25 Years
iii) RBI assessment per 6.4.2.4 and a release prevention barrier per Note	30 Years
NOTE: For purposes of 6.4.2.2, a release prevention barrier means an under-bottom leak detection and containment system designed in accordance with API 650, Appendix I.	

6.4.2.3 An owner/operator who has obtained data on the thickness and condition of the tank bottom during an internal inspection may calculate the interval until the subsequent internal inspection using the measured tank bottom corrosion rate and the minimum remaining thickness in accordance with 4.4.7.

6.4.2.4 As an alternative to the procedures in 6.4.2.3, an owner/operator may establish the internal inspection interval using RBI procedures in accordance with this section.

RBI assessment shall be performed by an individual or team of individuals knowledgeable in the proper application of API 580 principles to aboveground storage tanks, and experienced in tank design, construction details, and reasons for tank deterioration, and shall be reviewed and approved by an authorized inspector and a storage tank engineer. The initial RBI assessment shall be re-assessed at intervals not to exceed 10 years, at the time of a premature failure, and at the time of proposed changes in service or other significant changes in conditions.

RBI assessment shall consist of a systematic evaluation of both the likelihood of failure and the associated consequence of failure, utilizing the principles of API 580. RBI assessment shall be thoroughly documented, clearly defining all factors contributing to both likelihood and consequence of tank leakage or failure.

6.4.2.4.1 Likelihood Factors

Likelihood factors that should be considered in tank RBI assessments include, but are not limited to, the following:
a) original thickness, weld type, and age of bottom plates;
b) analysis methods used to determine the product-side, soil-side and external corrosion rates for both shell and bottom and the accuracy of the methods used;
c) inspection history, including tank failure data;
d) soil resistivity;
e) type and quality of tank pad/cushion;
f) water drainage from berm area;
g) type/effectiveness of cathodic protection system and maintenance history;
h) operating temperatures;
i) effects on internal corrosion rates due to product service;
j) internal coating/lining/liner type, age and condition;
k) use of steam coils and water draw-off details;
l) quality of tank maintenance, including previous repairs and alterations;
m) design codes and standards and the details utilized in the tank construction, repair and alteration (including tank bottoms);
n) materials of construction;
o) effectiveness of inspection methods and quality of data;
p) functional failures, i.e. floating roof seals, roof drain systems, etc.;
q) settlement data.

6.4.2.4.2 Consequence Factors
Consequence factors that should be considered in tank RBI assessments include, but are not limited to, the following:
a) tank bottom with a release prevention barrier (RPB);
b) product type and volume;

c) mode of failure (i.e. slow leak to the environment, tank bottom rupture or tank shell brittle fracture);
d) identification of environmental receptors such as wetlands, surface waters, ground waters, drinking water aquifers, and bedrock;
e) distance to environmental receptors;
f) effectiveness of leak detection systems and time to detection;
g) mobility of the product in the environment, including, releases to soil, product viscosity and soil permeability;
h) sensitivity characteristics of the environmental receptors to the product;
i) cost to remediate potential contamination;
j) cost to clean tank and repair;
k) cost associated with loss of use;
l) impact on public safety and health;
m) dike containment capabilities (volume and leak tightness).

More qualitative approaches may be applicable that do not involve all of the factors listed above. In these cases, conservative assumptions must be used and conservative results should be expected. A case study may be necessary to validate the approach.

The results of the RBI assessment are to be used to establish a tank inspection strategy that defines the most appropriate inspection methods, appropriate frequency for internal, external and on-stream inspections, and prevention and mitigation steps to reduce the likelihood and consequence of tank leakage or failure.

6.4.2.5 Tank owners/operators should review the internal inspection intervals of existing tanks, as they could be modified by the requirements of this section. The following outlines the applicability of the intervals determined in

a) Tanks that have been internally inspected and whose internal inspection intervals were determined solely by corrosion-rate data per 6.4.2.3 need not be included in this review, as their internal inspection intervals remain unaffected.
b) Tanks that have never been internally inspected should be reviewed for compliance with 6.4.2.1.
c) Tanks that have been internally inspected and whose internal schedules were determined by RBI assessment should be reviewed for compliance with 6.4.2.2. If RB assessment that complies with 6.4.2.4 determined an interval that has already exceeded the applicable maximum interval under 6.4.2.2, or will exceed it within a period of five years from the publication date of this edition of API 653, then the owner/operator may use the RBI assessment to schedule and complete the inspection, independent of the applicable maximum interval, so long as the inspection is completed within the five-year period. After the five-year period, the interval shall not exceed the applicable maximum interval under 6.4.2.2.

6.4.2.6 If RBI assessment or similar service assessment has been performed, the applicable maximum interval under 6.4.2.1 or 6.4.2.2 does not apply to a tank storing highly viscous substances which solidify at temperatures below 110 °F. Some examples of these substances are: asphalt, roofing flux, resid, vacuum bottoms and reduced crude.

6.5 Alternative to Internal Inspection to Determine Bottom Thickness

In cases where construction, size, or other aspects allow external access to the tank bottom to determine bottom thickness, an external inspection in lieu of an internal inspection is allowed to meet the data requirements of Table 4.4. However, in these cases, consideration of other maintenance items may dictate internal inspection intervals. This alternative approach shall be documented and made part of the permanent record of the tank.

6.6 Preparatory Work for Internal Inspection

Specific work procedures shall be prepared and followed when conducting inspections that will assure personnel safety and health and prevent property damage in the workplace (see 1.4).

6.7 Inspection Checklists

Annex C provides sample checklists of items for consideration when conducting in-service and out-of-service inspections.

6.8 Records

6.8.1 General

Inspection records form the basis of a scheduled inspection/maintenance program. (It is recognized that records may not exist for older tanks, and judgments must be based on experience with tanks in similar services.) The owner/operator shall maintain a complete record file consisting of three types of records, namely: construction records, inspection history, and repair/alteration history.

6.8.2 Construction Records

Construction records may include nameplate information, drawings, specifications, construction completion report, and any results of material tests and analyses.

6.8.3 Inspection History

The inspection history includes all measurements taken, the condition of all parts inspected, and a record of all examinations and tests. A complete description of any unusual conditions with recommendations for correction of details which caused the conditions shall also be included. This file will also contain corrosion rate and inspection interval calculations.

6.8.4 Repair/Alteration History

The repair/alteration history includes all data accumulated on a tank from the time of its construction with regard to repairs, alterations, replacements, and service changes (recorded with service conditions such as stored product temperature and pressure). These records should include the results of any experiences with coatings and linings.

6.9 Reports

6.9.1 General

For each external inspection performed per 6.3.2 and each internal inspection performed per 6.4, the authorized inspector shall prepare a written report. These inspection reports along with inspector recommendations and documentation of disposition shall be maintained by the owner/operator for the life of the tank. Local jurisdictions may have additional reporting and record keeping requirements for tank inspections.

6.9.2 Report Contents

Reports shall include at a minimum the following information:
a) date(s) of inspection;
b) type of inspection (external or internal);
c) scope of inspection, including any areas that were not inspected, with reasons given (e.g. limited scope of inspection, limited physical access;

d) description of the tank (number, size, capacity, year constructed, materials of construction, service history, roof and bottom design, etc.), if available;
e) list of components inspected and conditions found (a general checklist such as found in Annex C may be used to identify the scope of the inspection) and deficiencies found;
f) inspection methods and tests used (visual, MFL, UT, etc.) and results of each inspection method or test;
g) corrosion rates of the bottom and shell;
h) settlement survey measurements and analysis (if performed);
i) recommendations per 6.9.3.1;
j) name, company, API 653 certification number and signature of the authorized inspector responsible for the inspection;
k) drawings, photographs, NDE reports and other pertinent information shall be appended to the report.

6.9.3 Recommendations

6.9.3.1 Reports shall include recommendations for repairs and monitoring necessary to restore the integrity of the tank per this standard and/or maintain integrity until the next inspection, together with reasons for the recommendations. The recommended maximum inspection interval and basis for calculation that interval shall also be stated. Additionally, reports may include other less critical observations, suggestions and recommendations.

6.9.3.2 It is the responsibility of the owner/operator to review the inspection findings and recommendations, establish a repair scope, if needed, and determine the appropriate timing for repairs, monitoring, and/or maintenance activities. Typical timing considerations and examples of repairs are:
a) *prior to returning the tank to service*—repairs critical to the integrity of the tank (e.g. bottom or shell repairs);
b) *after the tank is returned to service*—minor repairs and maintenance activity (e.g. drainage improvement, painting, gauge repairs, grouting, etc.);
c) *at the next scheduled internal inspection*—predicted or anticipated repairs and maintenance (e.g. coating renewal, planned bottom repairs, etc.);
d) *monitor condition for continued deterioration*—(e.g. roof and/or shell plate corrosion, settlement, etc.). The owner/operator shall ensure that the disposition of all recommended repairs and monitoring is documented in writing and that reasons are given if recommended actions are delayed or deemed unnecessary.

6.10 Nondestructive Examinations (NDEs)

Personnel performing NDEs shall meet the qualifications identified in 12.1.1.2, but need not be certified in accordance with Annex D. The results of any NDE work, however, must be considered in the evaluation of the tank by an authorized inspector.

Appendix B

Fuel Storage Tank Inspection Plan

LOCATION	Area	YEAR FABRICATED /INSTALLED	CAP (Litres)*	API 653 (Last 10 yr Initial Internal Inspection Year)	Planned API 653 Internal Inspections (Year)		
MAKKOVIK	TROL	1982/90	68,190	2006	2017	2028	2038
MAKKOVIK	TROL	1982/90	68,190	2006	2017	2028	2038
MAKKOVIK	TROL	1990/90	314,000	2006	2017	2028	2038
MAKKOVIK	TROL	1990/90	314,000	2006	2017	2028	2038
MAKKOVIK	TROL	1990/90	314,000	2006	2017	2028	2038
BLACK TICKLE	TROL	1992/92	257,000	2007	2018	2029	2039
BLACK TICKLE	TROL	1992/92	257,000	2007	2018	2029	2039
GREY RIVER	TROC	1990/90	22,730	2009	2019	2029	2039
GREY RIVER	TROC	1990/90	22,730	2009	2019	2029	2039
GOOSE BAY, NORTH PLANT	TROL	1996	45,400	2010	2020	2030	2040
GOOSE BAY, NORTH PLANT	TROL	1996	45,400	2010	2020	2030	2040
LITTLE BAY ISLANDS	TROC	1990/90	22,730	2010	2020	2030	2040
CHARLOTTETOWN	TRON	1984/84	300,000	2008	2020	2030	2040
CHARLOTTETOWN	TRON	2001	10,000	-	2020	2030	2040
POSTVILLE	TROL	2011	319,000	-	2021	2031	2041
POSTVILLE	TROL	2011	319,000	-	2021	2031	2041
MARY'S HARBOUR	TRON	1990/90	314,000	2012	2022	2032	2042
MARY'S HARBOUR	TRON	1990/90	314,000	2012	2022	2032	2042
STEPHENVILLE GT	TROC	1975/2000	501,000	2014	2024	2033	2043
STEPHENVILLE GT	TROC	1975/2000	501,000	2014	2024	2033	2043
STEPHENVILLE GT	TROC	1975/2000	501,000	2014	2024	2033	2043
McCALLUM	TROC	1998/98	90,800	2015	2025	2034	2044
HARDWOODS GT	TROC	1976/97	2,273,000	2015	2025	2034	2044
PARADISE RIVER	TROL	2005/05	45,400	-	2025	2035	2045
HOPEDALE	TROL	2005/05	22,700	-	2025	2035	2045
PORT HOPE SIMPSON	TRON	1975/75	22,730	2015	2025	2035	2045
PORT HOPE SIMPSON	TRON	1995/95	22,730	2015	2025	2035	2045
RIGOLET	TROL	1997/97	45,400	2007	2026	2036	2046
RIGOLET	TROL	1997/97	45,400	2007	2026	2036	2046
RIGOLET	TROL	1998/2000	22,730	2007	2026	2036	2046
RIGOLET	TROL	1995/95	90,920	2008	2026	2036	2046
RIGOLET	TROL	1983/95	90,900	2008	2026	2036	2046
RIGOLET	TROL	1985/85	300,000	2007	2026	2036	2046
RIGOLET	TROL	2015/15	400,000	-	2026	2036	2046
HAWKES BAY	TRON	1974/96	23,730	2016	2026	2036	2046
HAWKES BAY	TRON	1996/96	23,730	2016	2026	2036	2046
GOOSE BAY, G T	TROL	1990/1991	54,552	2016	2026	2036	2046
GOOSE BAY, G T	TROL	1990/1991	54,552	2016	2026	2036	2046
GOOSE BAY, G T	TROL	1990/1991	54,552	2016	2026	2036	2046
NORMAN BAY	TRON	2007	32,400	-	2027	2037	2047
NORMAN BAY	TRON	2007	32,400	-	2027	2037	2047
NORMAN BAY	TRON	2011	20,000	-	2027	2037	2047
NAIN	TROL	2001/01	45,400	-	2028	2038	2048
NAIN	TROL	1974/74	144,140	2002	2028	2038	2048
NAIN	TROL	1974/74	144,140	2002	2028	2038	2048
NAIN	TROL	1974/74	144,140	2002	2028	2038	2048
NAIN	TROL	1987/87	600,000	2006	2028	2038	2048
CARTWRIGHT	TROL	2009	46,202	-	2029	2039	2049
ST. LEWIS	TRON	2012	45,000	-	2032	2042	2052
ST. LEWIS	TRON	2012	45,000	-	2032	2042	2052
RAMEA	TROC	2014/14	30,000		2034	2044	2054
RAMEA	TROC	2014/14	30,000		2034	2044	2054
ST. ANTHONY	TRON	2015	22,730	-	2035	2045	2055
ST. ANTHONY	TRON	2015	22,730	-	2035	2045	2055
ST. ANTHONY	TRON	2016	22,730	-	2035	2045	2055
L'ANSE au LOUP	TRON	2015	22,730	-	2035	2045	2055
L'ANSE au LOUP	TRON	2015	22,730	-	2035	2045	2055
ST. BRENDANS	TROC	2016	22,730	-	2035	2045	2055

Project Title: Replace Personal Computers
Location: Hydro Place
Category: General Properties - Information Systems
Type: Pooled
Classification: Normal

Project Description

The Personal Computer (PC) Replacement project will replace 151 computers (consisting of 44 laptops, 104 Desktops and three Workstations) along with 186 thin-client PCs and 61 monitors which were deployed up to, and including 2014.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	322.2	0.0	0.0	322.2
Labour	14.4	0.0	0.0	14.4
Consultant	4.8	0.0	0.0	4.8
Contract Work	50.4	0.0	0.0	50.4
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	25.8	0.0	0.0	25.8
Contingency	78.4	0.0	0.0	78.4
Total	**496.0**	**0.0**	**0.0**	**496.0**

Justification

Hydro must keep computers current to adequately support and protect the software applications and information on the computers required to operate its business.

The assignment of a particular device is determined by the employee's manager or supervisor. Generally, if an employee is expected to use their computer while away from the office, a laptop is assigned. In addition, the computers to be replaced under this project are approaching the end of the lifecycle and failures can be expected, which would result in loss of productivity due to the computers not being available for the user to do their day-to-day work. The maintenance agreements for these computers will have expired and replacement parts can no longer be guaranteed.

Existing System

Hydro has approximately 1,150 end-user personal computers in service. Minimum specifications for replacement of personal computers are reviewed on an annual basis to ensure that the PCs in service continue to remain effective. Industry best practices, technology and application trends are taken into consideration when specifications for computer devices are decided for the current year. The replacement life cycle is currently to replace laptops at every five years in-service, desktops and workstations at every six years, and thin-clients at every seven years. The previous in-service computer product lifecycle was extended by 12 months in 2018, as previously laptops were deployed for four years, desktops and workstations for five years and thin-clients for six years. The replacement of computer monitors and other required hardware upgrades are assessed based on failure, compatibility with newer hardware, and user application requirements.

Operating Experience

The projected costs of the units are as follows:

- Laptop: $2,100
- Desktop: $1,125
- Workstation: $1,900
- Thin Client: $491
- Monitor: $257

Age of Equipment or System

The existing PCs that are to be replaced under this project will have been in service between five and eight years depending on the hardware platform used.

Availability of Replacement Parts

Replacement parts are readily available for the duration of the maintenance agreements. Once the maintenance agreement has expired there is no guarantee that replacement parts can be obtained.

Status Quo

If the end user infrastructure is not kept current the following scenarios could potentially occur:

- New applications may not run on the old hardware platform.
- Decreased speed and lost data may result in lost production.
- Failure rates will exceed 50 percent.
- Maintenance agreements will not be offered by vendor.
- Operating systems may be unsupported.
- Loss of productivity and employee downtime during the repair or re-imaging process.

Industry Experience

Hydro has a similar life cycle plan for computer equipment as other companies in the utility industry, including Newfoundland Power.

Maintenance or Support Arrangements

Hydro has purchased maintenance agreements with Lenovo Corporation, the manufacturer, which provides warranty coverage for laptops for a period of four years and desktops/workstations for five years. This agreement was established through public tendering.

Historical Information

Historical information on computer replacement over the last five years as well as those budgeted for 2018 is presented in Table 2.

Table 2: Historical Information ($000s)

Year	Capital Budget	Actual Expenditures	Units	Cost per unit
2018	493.0			
2017	401.0	394.4	240	1.64
2016	861.7	849.9	211	4.03[1]
2015	573.3	571.8	358	1.60
2014	463.9	529.1	271	1.95
2013	463.9	518.2	237	2.18

Anticipated Useful Life

As of 2018, an update to the PC replacement program was made to extend in-service life and Hydro has adopted a five to seven year computer life cycle and utilizes extended warranties and run-to-failure modes to ensure reliable operation.

Conclusion

Hydro has 151 computers (consisting of 44 laptops, 104 Desktops and three Workstations) along with 186 thin-client PCs and 61 monitors which were deployed up to, and including 2014. The maintenance agreements for these computers and other devices will have expired and replacement parts can no longer be guaranteed. Hydro must keep computers maintained and current to adequately support and protect the software applications and information on the computers required to operate its business.

Project Schedule

The project is scheduled to start in January 2019 and be completed before December 2019.

[1] 2016 included the replacement of 39 rugged field laptops that had higher unit costs.

Project Title: Upgrade Hydro Core IT Infrastructure
Location: Hydro Place
Category: General Properties - Information Systems
Type: Pooled
Classification: Normal

Project Description

This project involves the replacement, addition and upgrade of hardware components and software related to Hydro Energy Management System (EMS) server and storage infrastructure.

Based on the age of existing systems, each year an appropriate number of units will be refreshed. This ensures that Hydro has a reliable, secure infrastructure environment to support operations.

The scope of this project includes:

- the replacement of two server hosts and two enterprise data backup units;
- one virtual server host at Hydro Place is at end of the lifecycle and will be replaced with a similar unit;
- one virtual server host in the Backup Control Center environment is at end of useful life and will be replaced with a similar unit;
- one enterprise tape-based data backup unit in the Hydro Place environment has been in service for six years and will be replaced by a new unit with performance and capacity to support current and future workloads; and
- one enterprise tape-based data backup unit in the Backup Control Center environment has been in service for six years and will be replaced by a new unit with performance and capacity to support current and future workloads.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	208.1	0.0	0.0	208.1
Labour	22.4	0.0	0.0	22.4
Consultant	51.4	0.0	0.0	51.4
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	21.2	0.0	0.0	21.2
Contingency	56.3	0.0	0.0	56.3
Total	**359.4**	**0.0**	**0.0**	**359.4**

Justification

Servers

The factors that are driving Hydro's proposal to upgrade servers in its environment include:

- addressing obsolescence/maintaining vendor support;
- providing security/managing the infrastructure; and
- supporting current versions of applications.

<u>Maintaining Vendor Support</u>

At this time, the vendor support and inventory of spare parts for the servers are discontinued. Without vendor support, the functions and services reliant on this core Information Technology (IT) infrastructure are at risk as security and support patches for the operating systems and hardware, as well as hardware spare parts, will no longer be available. As a result, Hydro's ability to support and ensure continuation of these functions and services is impeded. These servers run software used by Hydro employees on a daily basis to run the business.

<u>Providing Security/Managing the Infrastructure</u>

Improved system management technologies improve the security of the servers and simplify management including hardware remote access, system diagnostics and automated alerting. Hardware and software, however, must be maintained at manufacturer supported levels to take advantage of improved system management technologies to improve the security of the servers and simplify management including hardware remote access, system diagnostics and automated alerting.

Supporting Current Versions of Applications

As applications are upgraded and new applications implemented, the underlying infrastructure must provide the required performance and capacity to run these systems and provide reliable operations to the business.

Enterprise Tape-Based Data Backup Units

The storage systems provide critical functionality to the server systems used by Hydro employees to provide support in running the business on a daily basis. Loss of availability of these systems would have a negative effect on employee productivity by not allowing access to software applications and the data housed within the storage system.

Existing System

Hydro has an ongoing refresh program to maintain hardware performance. The current server and storage hardware replacement life cycle is to replace devices after five years or more in-service.

There are both physical and virtual servers that support and run various applications for the organization. The applications that run on these servers include the Energy Management System and numerous other applications that comprise the Hydro operating environment. These applications are used by staff in running the business on a day-to-day basis and fall into one of four classification levels (0 to III) for the purpose of assigning an age at which hardware is replaced (Table 2).

Table 2: Hardware Replacement Age Criteria

Classification	Criteria	Age
Level 0	Critically important to business operations; hardware is known to have a longer general life expectancy; This classification requires additional measures for redundant components, application fault tolerance architectures, and signoff by system owners to extend the standard lifecycle timeframes accepting all associated risks in doing so.	8+ years
Level I	Critically important to business operations; access required on daily basis; outage/failure will have immediate negative impact on business and requires expedited problem resolution within 1 day or less.	5 years
Level II	Standard operating importance; used/accessed daily to weekly; outage would have less impact to business and requires immediate attention/resolution within 1 – 3 days.	6 years
Level III	Non-critical to business operations; accessed occasionally or performs automated procedures on a scheduled basis; outage would not impact business significantly unless not recovered after 3 days or more.	7 years

Operating Experience

This budget proposal is for lifecycle replacement of hardware and software related to Hydro's existing core IT infrastructure.

Reliability Performance

Hydro's servers and storage are used on a continuous basis. The systems are active for the life of the unit once placed in service. Hydro standard is to use enterprise grade hardware for energy-management systems and applications. Hydro has had reliable performance from this hardware as a result.

Industry Experience

General industry practice is to replace servers and storage devices on a five year lifecycle. Parts may not be available after five years for the servers and storage devices depending on the component that fails.

Maintenance or Support Arrangements

Hydro has determined that the standard three year manufacturer warranty is not sufficient for its server and storage infrastructure and increases this warranty to five years at time of purchase. After the initial five year warranty, the storage and server components are placed on a maintenance program with IBM and Lenovo, which are proactively reviewed and renewed quarterly until the devices are replaced.

Conclusion

Hydro has an ongoing refresh program for servers, storage units and applications to maintain system reliability and performance. Hydro must keep its servers current in order to adequately support and protect the Operational Technology infrastructure required to operate its business. Failure to keep this infrastructure current will put Hydro at risk of unplanned outages, possible data loss, and data corruption. The replacement, addition, and upgrading of hardware components to achieve this goal requires investment over the lifecycle of the infrastructure.

Project Schedule

The project is scheduled to start in March 2019 and be completed by the end of July 2019 as set out in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Create/review work plan and schedules	Mar 2019	Mar 2019
Design	Generate detailed design and specification	Mar 2019	Apr 2019
Procurement	Tender for hardware; 20 day delivery time (average)	Apr 2019	May 2019
Construction	Assembly, software installation, testing	May 2019	Jun 2019
Commissioning	Install assets, migrations, and documentation	Jun 2019	Jun 2019
Closeout	Decommissioning and project closeout	Jul 2019	Jul 2019

Project Title: Update Energy Management System Software
Location: Hydro Place
Category: General Properties - Information Systems
Type: Other
Classification: Normal

Project Description

This project will upgrade the Energy Control Centre (ECC) OSI Monarch Energy Management System (EMS) used by the Energy Control Centre (ECC) to control and monitor the provincial transmission grid and generation facilities operated by Hydro. The system software is upgraded on a biannual basis for update fixes and functionality changes to the software.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	34.2	0.0	0.0	34.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	177.2	0.0	0.0	177.2
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	18.0	0.0	0.0	18.0
Contingency	42.3	0.0	0.0	42.3
Total	**271.7**	**0.0**	**0.0**	**271.7**

Justification

This project is a normal continuation of updates to ensure proper functionality. The EMS is essential to the continued reliable operation of the provincial transmission grid and generation facilities operated by Hydro. The EMS provides a critical function for Hydro and the operation of the Island Interconnected System. Without a properly functioning EMS, remote control of any system would be impossible.

Existing System

The Energy Control Centre in St John's uses OSI Monarch Energy Management System on a 24 hour basis to control and monitor the provincial transmission grid and generation facilities operated by Hydro.

The existing system was installed in 2006 and the software has been upgraded on an annual basis until 2017. In 2018, Hydro changed the upgrade schedule to a biannual schedule.

Table 2 contains upgrades that have occurred over the past five years:

Table 2: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2017	Software Upgrade	Elimination of software bugs and increased functionality of software
2016	Software Upgrade	Elimination of software bugs and increased functionality of software
2015	Software Upgrade	Elimination of software bugs and increased functionality of software
2014	Software upgrade and Server Upgrade	Replaced servers and upgraded software for elimination of software Bugs fix and increased functionality of software
2013	Software Upgrade	Elimination of software bugs and increased functionality of software

Operating Experience

The EMS has been in continuous operation since 2006 and has performed in an acceptable manner.

Maintenance or Support Arrangements

The software is on maintenance support, which allows for the following from Open Systems International:

- Dedicated support staff for handling incoming support calls;
- After hours on-call support service
- 24/7 support coverage;
- Web-based Customer Support portal;
- Fast response for critical support requests; and
- Comprehensive database tracking and reporting on support requests.

Historical Information

Table 3 provides information from previous capital budget applications.

Table 3: Historical Information ($000s)

Year	Capital Budget	Actual Expenditures
2018	0.0	0.0
2017	427.0	433.1
2016	246.2	256.5
2015	194.4	185.1
2014	187.9	184.3

Conclusion

This project is necessary as to allow Hydro to control and monitor the provincial transmission grid and generation facilities operated by Hydro. This project is performed on a bi-annual basis to eliminate software bugs and increase the functionality of the software.

Project Schedule

The project will be started in January 2019 and completed by the end of September 2019.

Project Title: Replace Radomes
Location: Various Sites
Category: General Properties - Telecontrol
Type: Pooled
Classification: Normal

Project Description

This project is an ongoing program to replace microwave antenna radomes.[1] Hydro has initiated a radome replacement program for the microwave antennas of the corporate network to reduce the probability of system outages resulting from radome failure. The radome replacement program proposed by Hydro is based on operational experience and the manufacturers' recommendations. Due to operational risks associated with the failure of corporate microwave equipment, this project is a proactive approach to minimize the likelihood of failure of microwave antenna radomes. The white cover illustrated in Figure 1 is an example of a radome on an uninstalled antenna.

Figure 1: Microwave Antenna with Radome

[1] Radomes are the protective covers that enclose the delicate components of the microwave antennas in Hydro's microwave radio system.

Radomes are replaced at different sites throughout the network each year, depending on age and condition. The radome replacement schedule for 2019-2023 is provided in Appendix A. Ten radomes are scheduled to be replaced in 2019. This project will be completed as a joint effort with an external contractor who will perform the field work, and internal personnel who will provide project management and technical support.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	63.6	0.0	0.0	63.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	135.9	0.0	0.0	135.9
Other Direct Costs	8.9	0.0	0.0	8.9
Interest and Escalation	13.4	0.0	0.0	13.4
Contingency	41.7	0.0	0.0	41.7
Total	**263.5**	**0.0**	**0.0**	**263.5**

Justification

Manufacturers suggested schedule for replacement of CableWave (made of Hypalon material) and Andrew Solutions (made of Teglar material) radomes should be after seven year and eight years, respectively. Also, Hydro has developed an inspection program to identify radomes that are torn or otherwise damaged, as illustrated in Figure 2. These radomes must be replaced as soon as the damage is identified to ensure the integrity of the microwave system. A radome failure could result in the microwave system failing.

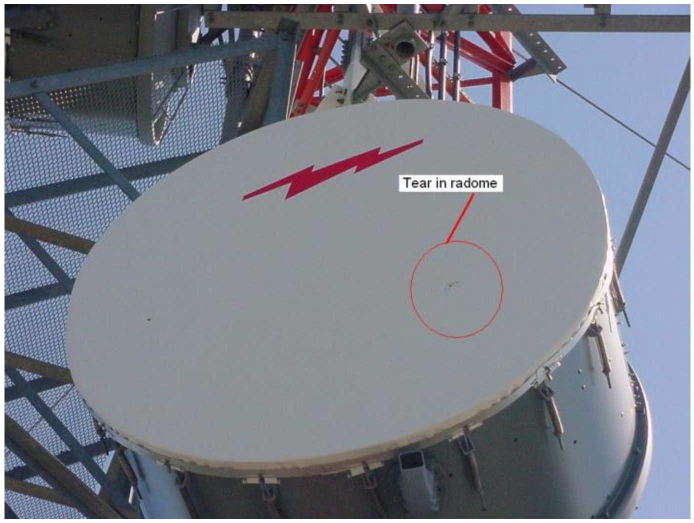

Figure 2: Tear in Radome

The impact of a microwave failure today could have a greater effect than the incident of 1996[2] due to the fact that teleprotection signals, which protect transmission lines in the event of a system disturbance, are now transmitted using the microwave network. Teleprotection signals[3] for the majority of the 230kV transmission lines are carried on the microwave network. In addition, a microwave failure could cause the Energy Control Centre to lose control of the system stations and likely cause and/or extend customer outages. The current schedule for the next five years is included in Appendix A.

Existing System

Hydro has a network of microwave radios, by which corporate communications and system data are transmitted. The microwave radio system provides the backbone for all corporate voice and data communications. Traffic carried over the microwave system includes:

- teleprotection signals for the provincial transmission system;
- data pertaining to the provincial Supervisory Control and Data Acquisition (SCADA) system;
- data pertaining to the corporate administrative system; and

[2] Refer to the Operating Experience section of this document for further details.
[3] Teleprotection is used to transfer secure and reliable information between protective relays at the terminal station ends of a transmission line. This information is used to coordinate the protective relays for faster and secure tripping for faults on the transmission line.

- operational and administrative voice systems.

Microwave radio signals are transmitted from one location to the next using parabolic antennas attached to towers. These antennas are mounted up to heights of 120 meters and range in diameter from two meters to five meters. At such extreme heights, the antennas are subjected to high wind and ice loading when storms occur and must be protected. To provide this protection, the feed horn of the antennas (responsible for sending and receiving microwave radio signals) are covered with a flexible covering, stretched over the antenna shroud, known as a radome. These covers are made of advanced plastics known as Hypalon and Teglar that prevent the accumulation of ice and snow which could bend or break the feed horn, and do not interfere with the microwave radio signals.

Damage to radomes can occur in several ways. Exposure to wind, sun, rain, and ice causes the radomes to deteriorate over time. When the radome weakens, tears form in the fabric (Figure 2). Left unchecked, the tears quickly grow in size (Figure 3) and the material can be torn free by wind. Such tears may result in severe damage to the delicate antenna components.

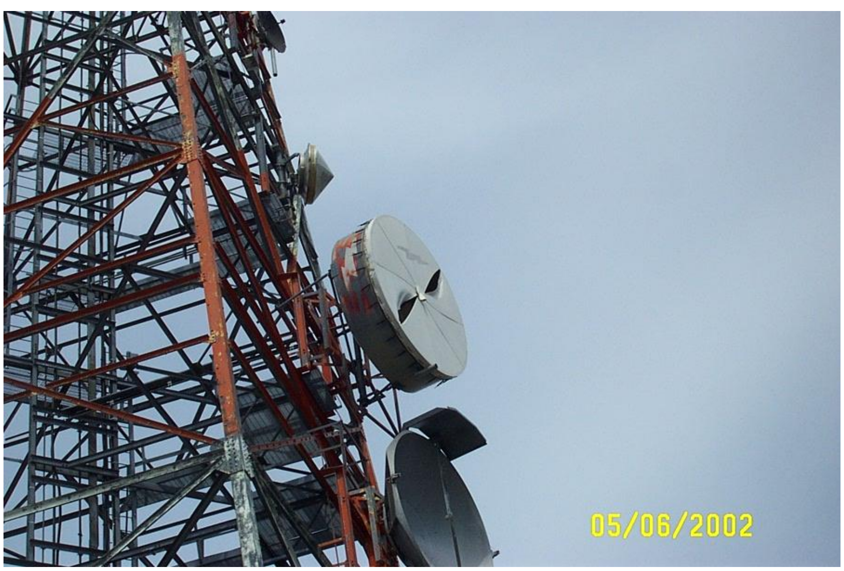

Figure 3: Heavily Damaged Radome

Other modes of failure are less common. Ice falling from the tower can damage radome components, such as the hardware that hold the radome in place, as shown in Figure 4. Vandalism by the use of shotguns, rocks, or other projectiles has also occurred at sites that are accessible by road. Each of these occurrences has the potential to damage the radome and make it prone to complete failure.

Figure 4: Missing Radome Mounts

There are 77 radomes throughout Hydro's system. They are installed on towers from St. John's west to Deer Lake, and south to Bay d'Espoir. Figure 5 shows Hydro's Telecommunication Network.

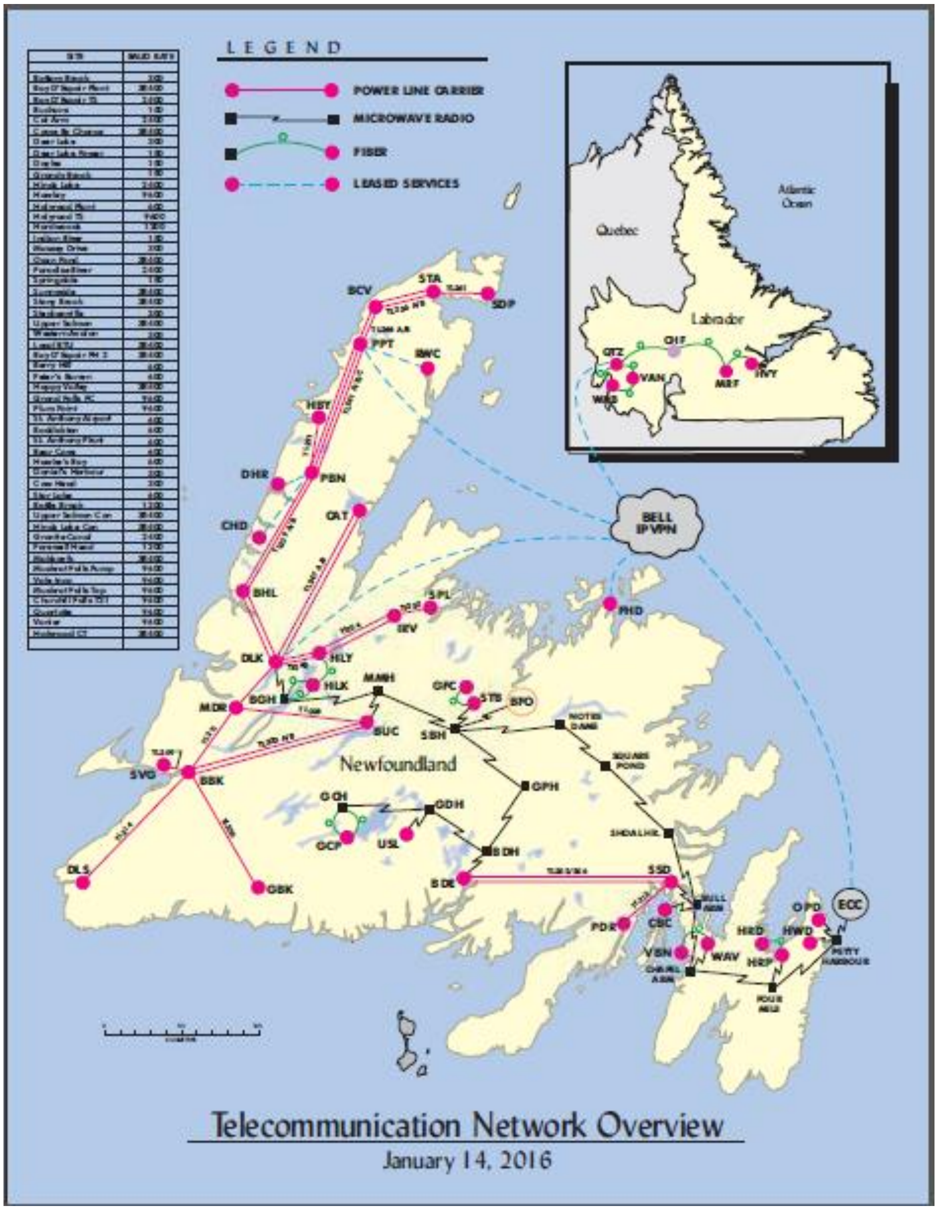

Figure 5: Location of Towers

Major Work and/or Upgrades

There are no upgrades available for a radome. It must be replaced based upon the estimated useful life or upon observed damage during inspection.

Operating Experience

Outage Statistics

In the winter of 1996, a wind storm resulted in the failure of two separate radomes at the

Sandy Brook Hill and Mary March Hill Microwave Sites, which caused a significant and sustained outage to a part of Hydro's communications network. Despite routine inspections, the radomes were torn and the material of the shells became entangled in the antenna feed horns. As a result, critical components at both sites were irreparably damaged and the antennas required replacement. Once the storm cleared and the cause of the outage was identified it took three weeks for replacement of the antennas due to lead times associated with material procurement and weather related delays.

In total, the microwave radio system was out of service for approximately six weeks. During that time, temporary leased services were procured and installed, resulting in unanticipated labour and materials costs.

There have been no other communication outages caused by radome failures since the 1996 wind storm.

Vendor Recommendations

As a result of the costs and outage time associated with the 1996 storm, personnel from Hydro consulted with manufacturers to develop a proactive radome replacement plan. Based on discussions with representatives from radome manufacturers Andrew Solutions and CableWave, the following replacement frequency was developed:

- CableWave radomes (made of Hypalon material) should be replaced on a seven-year cycle; and
- Andrew Solutions radomes (made of Teglar material) should be replaced on an eight-year cycle.

Andrew Solutions radomes, with a slightly longer life, cannot be substituted for CableWave radomes on CableWave antennas due to the structural differences associated with each type of antenna.

Maintenance or Support Arrangements

There are no maintenance or support arrangements associated specifically with radomes. Radome inspection is included as part of an overall tower inspection which occurs annually.

Maintenance History

Radomes are visually inspected each year when the tower is inspected, or as soon as practical after any extremely severe storm that might have affected a particular site. A visual inspection may also be required as part of any corrective maintenance investigation into any loss or degradation of signal that may have been caused by a radome tear damaging the feed horn assembly. The radomes are inspected for any tears and any failure of the mounting hardware. Radomes cannot be repaired and must be replaced when a tear of any size is visually detected. Even a small tear is unacceptable as it will become much larger due to the high stresses caused by wind and other environmental factors, including icing.

Historical Information

Table 2 shows the historical information for the Radome Replacement Program since 2014.

Table 2: Capital Budget and Expenditures since 2014 ($000s)

Year	Capital Budget	Actual Expenditures	Units	Cost per unit	Comments
2018	360.3		16		Project underway.
2017	0.0	0.0	0.0	0.0	No replacements required
2016	235.2	230.0	11	20.9	
2015	0.0	0.0	0.0	0.0	No replacements required
2014	324.9	217.8	14	15.6	

Anticipated Useful Life

Hydro's microwave antennas are supplied primarily by two manufacturers, Andrew Solutions and CableWave. Each manufacturer uses a different radome. Radomes used on antennas manufactured by CableWave have a useful life of seven years, and the radomes used on Andrew antennas have a useful life of eight years.

Alternatives

No viable alternatives exist to radome replacement.

Conclusion

Hydro's Radome Replacement Program is necessary in order to prevent outages caused by radome damage.

The radome replacement program is based on operational experience and manufacturers' recommendations. Historically, this project has been executed by external contractors and supported by internal resources and this joint effort will continue in 2019.

Due to operational risks associated with the failure of corporate microwave equipment, this project is a proactive approach to minimizing failures of microwave antenna radomes, and subsequent damage to the antenna feed horns.

Future Plans

Future plans will be proposed in future capital budget applications. Radome replacements are planned for each of the next five years as listed in Appendix A.

Project Schedule

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Prepare Project Plan and site visits	Jan 2019	Feb 2019
Design	Complete Tender Package	Feb 2019	Mar 2019
Procurement	Purchase Radomes	Apr 2019	Apr 2019
Installation	Install Radomes	May 2019	Sep 2019
Commissioning	Site Inspections	Oct 2019	Oct 2019
Closeout	Project Closeout	Nov 2019	Dec 2019

Appendix A

Radome Replacement Schedule

2019 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BAH	SHH (main)	2.4m (8')	Andrew	HP8-71GE	2011
BAH	SHH (div)	2.4m (8')	Andrew	HP8-71GE	2011
CBC	BAH	1.8m (6')	Andrew	HP6-71E	2011
DLP	DLK	3m x 4.9m	Microflect	90392	2011
ECC	PHH	1.8m (6')	Andrew	HP6-71E	2011
HWD	PHH	2.4m (8')	Andrew	HP8-71D	2011
MMH	SBH	3.0m (10')	Andrew	HP10-71D	2011
PHH	OPD	1.8m (6')	Andrew	HP6-71E	2011
PHH	HWD	1.8m (6')	Andrew	HP6-71E	2011
SSD	BAH	1.8m (6')	Andrew	HP6-71E	2011

2020 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BAH	CAH	3.0m(10')	Andrew	HP10-71D	2012
BGH	MMH	2.4m(8')	CW	DA8-71hp	2013
BGH	DLP	3.6m(12')	CW	DA12-71hp	2013
GCH	GDH	3.0m(10')	Andrew	HP10-71D	2012
GCH	GDH	2.4m(8')	Andrew	HP8-71D	2012
GDH	GCH (main)	3.0m(10')	Andrew	HP10-71D	2012
GDH	GCH (div)	2.4m(8')	Andrew	HP8-71D	2012
GDH	BDH	3.0m(10')	CW	DA10-71hp	2013
GDH	USL	3.0m(10')	CW	DA10-71hp	2013
HRP	FMH	2.4m(8')	Andrew	HP8-71D	2012
MMH	SBH	3.6m(12')	CW	DA12-71hp	2013
MMH	BGH	2.4m(8')	CW	DA8-71hp	2013
PHH	ECC	2.4m(8')	Andrew	HP8-71D	2012
SBH	MMH	3.6m(12')	CW	DA12-71hp	2013
USL	GDH	3.0m(10')	CW	DA10-71hp	2013

2021 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BDE	BDH	1.8m(6')	CW	DA6-71hp	2014
BDH	GPH	1.8m(6')	CW	DA6-71hp	2014
BDH	BDE	1.8m(6')	CW	DA6-71hp	2014
BFI	SBH	2.4m(8')	Andrew	HP8-71GE	2013
BUC	MMH	1.8m(6')	CW	DA6-71hp	2014
DLK	DLP	4.5m(15')	Gabriel	SR15-71B	2013
FMH	PHH (div)	1.8m(6')	Andrew	HP6-71E	2013
NDH	SPH (main)	3.6m(12')	Andrew	HP12-71E	2013
NDH	SPH (div)	3.6m(12')	Andrew	HP12-71E	2013
NDH	SBH (main)	3.6m(12')	Andrew	HP12-71E	2013
NDH	SBH (div)	3.6m(12')	Andrew	HP12-71E	2013
SBH	NDH (main)	3.6m(12')	Andrew	HP12-71E	2013
SBH	NDH (div)	3.0m(10')	Andrew	HP10-71D	2013
SBH	BFI	2.4m(8')	Andrew	HP8-71GE	2013

2022 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BDH	GPH	2.4m(8')	Andrew	HP8-71D	2014
BDH	GDH	3.0m(10')	Andrew	HP10-71D	2014
SHH	BAH (main)	2.4m(8')	Andrew	HP8-71GE	2014
SHH	BAH (div)	2.4m(8')	Andrew	HP8-71GE	2014
SHH	SPH (main)	3.6m(12')	Andrew	HP12-71E	2014
SHH	SPH (div)	3.6m(12')	Andrew	HP12-71E	2014
SPH	SHH (main)	3.6m(12')	Andrew	HP12-71E	2014
SPH	SHH (div)	3.6m(12')	Andrew	HP12-71E	2014
SPH	NDH (main)	3.6m(12')	Andrew	HP12-71E	2014
SPH	NDH (div)	3.6m(12')	Andrew	HP12-71E	2014

2023 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
GPH	SBH (div)	3.6m(12')	CW	DA12-71hp	2016
GPH	BDH	1.8m(6')	CW	DA6-71hp	2016
SBH	GPH	3.6m(12')	CW	DA12-71hp	2016
SBH	STB	1.8m(6')	CW	DA6-71hp	2016

Abbreviations for Site Names

Abbreviation	Site Name
BAH	Bull Arm Hill Microwave/Repeater
BDE	Bay D'Espoir Terminal Station
BDH	Bay D'Espoir Hill Microwave/Repeater
BFI	Bishop Falls Office
BGH	Blue Grass Hill Microwave/Repeater
BUC	Buchans Terminal Station
CAH	Chapel Arm Hill Microwave/Repeater
CBC	Come By Chance Terminal Station
DLK	Deer Lake Terminal Station
DLP	Deer Lake Passive Repeater
ECC	Energy Control Center
FMH	Four Mile Hill Microwave/Repeater
GCH	Granite Canal Hill Microwave
GDH	Godaleich Hill Microwave/Repeater
GPH	Gull Pond Hill Microwave
GDH	Godaleich Hill Microwave/Repeater
GPH	Gull Pond Hill Microwave
HRP	Holyrood Plant
HWD	Hardwoods Terminal Station

Abbreviation	Site Name
MMH	Mary March Hill Microwave
NDH	Notre Dame Hill
OPD	Oxen Pond Terminal Station
PHH	Petty Harbour Hill Microwave/Repeater
SBH	Sandy Brook Hill Microwave
SHH	Shoal Harbour Hill
SPH	Square Pond Hill
SSD	Sunnyside Terminal Station
STB	Stony Brook Terminal Station
USL	Upper Salmon Plant
WAP	Western Avalon Passive Repeater
WAV	Western Avalon Terminal Station

Project Title: Replace Peripheral Infrastructure
Location: Hydro Place
Category: General Properties - Information Systems
Type: Pooled
Classification: Normal

Project Description

The Replace Peripheral Infrastructure Project replaces 26 Multi-Function Devices (MFDs) used for printing, copying, faxing and scanning, including nine devices with support for large format printing. Two units will be replaced at Holyrood, four at Bishops Falls, one at Deer Lake, three at Bay d'Espoir, two at Happy Valley Goose Bay, one at Port Saunders, two at Stephenville, one at Whitbourne, and one at Wabush, as well as nine printing devices in terminal stations, diesel plants, warehouses and ancillary offices.

In addition, this project includes replacement of 16 video projectors and two video-conference units in Hydro office locations where existing display equipment has exceeded product lifecycle and service-affecting issues require hardware replacement.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	139.6	0.0	0.0	139.6
Labour	35.6	0.0	0.0	35.6
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	11.6	0.0	0.0	11.6
Contingency	35.0	0.0	0.0	35.0
Total	**221.8**	**0.0**	**0.0**	**221.8**

Justification

This is the continuation of the *"Replace Peripheral Infrastructure Project"* to replace peripheral devices as they reach the end of their useful lives. The units scheduled for replacement in 2019 have all been in service for five years or more and maintenance contracts and warranties have expired. While the manufacturer will provide extended maintenance (at an increased cost) they will not guarantee the performance of these devices after five years.

Hydro must keep its peripheral infrastructure current in order to adequately support the needs of its business. This project makes it possible for such equipment to be replaced in a planned and consistent manner and ensures that these peripherals are available and reliable to support the user's needs. Continued review of the products' lifecycle allows Hydro to adjust plans based on performance, technology changes, and new business requirements.

Existing System

Age of Equipment or System

The units scheduled for replacement have been in service for over five years. The decision to replace a printer or MFD is based on many criteria, including:

- vendor's product roadmap (new features like secure print and scanning will not be supported on older equipment);
- users' printing requirements (color need, print volumes and speed);
- number of users supported by the equipment;
- availability of alternate printing;
- available support for the equipment; and
- age and failure-status of equipment.

Availability of Replacement Parts

Replacement parts are readily available for the duration of the maintenance agreements and warranties. Once these agreements and warranties have expired replacement parts may or may not be available.

Table 2 presents a list of peripheral devices in service at different Hydro sites.

Table 2: Peripheral Devices in Service

Office Location	Number of Printers	Number of Employees	Buildings Per Location
Bay d'Espoir	19	93	4
Happy Valley/Goose Bay	5	50	2
St. Anthony	6	22	2
Stephenville	3	20	2
Deer Lake	3	6	1
Wabush	2	10	2
Whitbourne	3	26	2
Bishop's Falls	21	89	4
Holyrood	18	111	5
Port Saunders	3	20	1
Springdale	1	08	1

Operating Experience

Industry Experience

The average age of Hydro's printers is five to seven years. According to Gartner,[1] the useful life for a color printer is three years while a black and white printer is between three and five years. These Industry best practices indicate that the typical service life for a peripheral device is four to five years. Hydro has a life cycle plan for peripheral devices similar to that of other companies in the utility industry.

[1] Gartner Inc. provides research and analysis on the global Information Technology industry. They assist companies in making informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology.

Maintenance or Support Arrangements

Hydro has purchased a maintenance agreement with a supplier (Xerox) that covers the larger multi-function devices for five years. This agreement was established through public tendering. Smaller laser printers have a manufacturer's warranty of one to three years duration.

Vendor Recommendations

The vendor (Xerox) recommends a maximum lifespan of five years for these devices. Other major vendors have not stated their recommended lifespan.

Historical Information

Table 3 contains a five-year history as well as the 2018 budget for the Peripheral Infrastructure Replacement Project.

Table 3: Historical Information ($000s)

Year	Capital Budget	Actual Expenditures	Units	Cost per Unit[2]
2018	258.3	-	-	-
2017	0 (cancelled)	n/a	n/a	n/a
2016	611.1	569.4	65	8.7
2015	200.5	201.7	43	4.6
2014	200.7	220.4	54	4.1
2013	309.9	298.6	41	7.3

Anticipated Useful Life

According to Gartner, the useful life for a color printer is three years while a black and white printer is between three and five years. The average age of Hydro's printers is five to seven years.

Evaluation of Alternatives

There is no viable alternative to the planned replacement of peripheral infrastructure.

[2] The variability in unit costs are due to specifications of the printers being replaced such as pages per minute, memory, fax and scanning capability.

Conclusion

The ongoing program involves a coordinated effort to keep Hydro's peripheral infrastructure in good working order and use current technologies while delivering a cost effective solution to the end-user. If the peripheral infrastructure is not kept current, there is an increased risk of failure rates and lack of maintenance offered by vendor

Project Schedule

The project is scheduled to start in January 2019 and be completed in December 2019.

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Newfoundland and Labrador Hydro
2019 Capital Budget Application
Projects over $50,000 but less than $200,000

Project Description	Expended to 2018	2019	Future Years	Total	Definition	Classification	Page Ref
Generation							
Energy Efficiency Improvements - Various	276.2	168.9	0.0	445.1	Pooled	Justifiable	
Purchase Tools & Equipment Less than $50,000 - Bay d'Espoir & Holyrood	0.0	148.9	0.0	148.9	Pooled	Normal	
Total Generation	**276.2**	**317.8**	**0.0**	**594.0**			
Transmission and Rural Operations							
Purchase Meters and Metering Equipment - Various	0.0	196.4	0.0	196.4	Pooled	Mandatory	E2
Additions for Load - Distribution System	0.0	186.7	0.0	186.7	Pooled	Normal	E4
Purchase Tools & Equipment Less than $50,000 - Central	0.0	171.2	0.0	171.2	Pooled	Normal	
Purchase Tools & Equipment Less than $50,000 - Labrador	0.0	109.2	0.0	109.2	Pooled	Normal	
Purchase Tools & Equipment Less than $50,000 - Northern	0.0	92.8	0.0	92.8	Pooled	Normal	
Total Transmission and Rural Operations	**0.0**	**756.3**	**0.0**	**756.3**			
General Properties							
Remove Safety Hazards - Various	0.0	197.5	0.0	197.5	Other	Normal	E10
Replace Teleprotection - TL202 & TL206	0.0	196.8	0.0	196.8	Other	Normal	E13
Replace Network Communications Equipment - Various	0.0	189.5	0.0	189.5	Pooled	Normal	E16
Upgrade Remote Terminal Units - Various	0.0	167.7	0.0	167.7	Pooled	Normal	E18
Upgrade Software Applications - Hydro Place	0.0	110.4	0.0	110.4	Pooled	Normal	E23
Refresh Security Software - Hydro Place	0.0	90.7	0.0	90.7	Pooled	Normal	E25
Total General Properties	**0.0**	**952.6**	**0.0**	**952.6**			
Total Projects over $50,000 but less than $200,000	**276.2**	**2,026.7**	**0.0**	**2,302.9**			

Project Title: Purchase Meters and Metering Equipment

Location: Various

Category: Transmission and Rural Operations - Metering

Definition: Pooled

Classification: Mandatory

Project Description

This project consists of purchasing 178 demand meters, 250 residential meters and other associated equipment for use in revenue metering, which require replacement each year due to government retest, technology changes, or obsolescence.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	137.0	0.0	0.0	137.0
Labour	32.0	0.0	0.0	32.0
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	10.5	0.0	0.0	10.5
Contingency	16.9	0.0	0.0	16.9
Total	**196.4**	**0.0**	**0.0**	**196.4**

Operating Experience

Revenue meters enable Hydro to accurately record energy and power consumption by its customers. Meters and associated equipment are required to satisfy new service requests as well as to replace expired or damaged metering equipment. Hydro maintains an inventory of all types of metering and associated equipment required to minimize outage durations and satisfy customer billing. Annually, Hydro completes required Government Retest Orders that involve sample testing of specific meter types for which replacements are required to be kept on hand in case of retest failure.

Project Justification

Revenue meters and associated equipment are required to be purchased each year so that meters are available for new service applications and for replacements due to government retest, damaged meters, technology changes, and obsolescence. Under the *Electricity & Gas Inspection Act and Regulations*, Hydro is mandated by Measurement Canada to ensure that in-service meters are accurate and in good working condition. Furthermore, revenue meters must be certified and sealed, and the requirement states that these meters are to be removed from service before the expiry date. Failure to replace meters that are due to be replaced may result in monetary penalties as per the new requirements under the *Electricity & Gas Inspection Act and Regulations*.

It is more economical to purchase new electronic meters then it is to certify and seal electromechanical meters because the capital and operating costs of the new electronic meters is less than the cost of re-sealing electromechanical meters. As well, it is more efficient, accurate, and cost effective to certify and seal electronic meters.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Prepare Orders	Jan 2019	Jan 2019
Design	Prepare Drawings	Jan 2019	Feb 2019
Procurement	Order Meters and Equipment	Jan 2019	Apr 2019
Construction	Install Meters and Equipment	May 2019	Oct 2019
Commissioning	Verify Installations	May 2019	Oct 2019
Closeout	Closeout Projects	Nov 2019	Dec 2019

Project Title: Additions for Load Growth – Distribution

Location: Wabush Substation

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Normal

Project Description

This proposed project involves the design, procurement, and installation of a 46 kV box structure[1] modification to allow Wabush Terminal Station (WAB) Transformer T4 to be permanently connected and paralleled[2] with WAB Transformer T6.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	4.7	0.0	0.0	4.7
Labour	56.3	0.0	0.0	56.3
Consultant	24.0	0.0	0.0	24.0
Contract Work	55.5	0.0	0.0	55.5
Other Direct Costs	6.8	0.0	0.0	6.8
Interest and Escalation	10.1	0.0	0.0	10.1
Contingency	29.3	0.0	0.0	29.3
Total	**186.7**	**0.0**	**0.0**	**186.7**

Operating Experience

The Wabush Distribution System supplies power to Hydro customers in the Town of Wabush. The Wabush Substation (Appendix A) has six 12.5 kV distribution feeders L3, L7, L9, L11, L12, and L13 that supply power to the customers.

The substation has four power transformers that reduce the voltage from 46 kV to 12.5 kV, so that electricity can be distributed to Wabush customers. Transformers T3 and T4 are rated at

[1] A box structure is a metal lattice support for electrical infrastructure.
[2] Paralleling of transformers allow the transformers to share the load and reduce the voltage drop across them.

8.3 MVA, T5 is rated at 4 MVA, and T6 is rated at 16.7 MVA. Transformers T4[3] and T5 are spares and can be brought in service within a few hours in the event of a failure of other transformers. T3 provides power to bus B5 and feeders L7, L11, L3 and L12 while T6 provides power to bus B3 and feeders L9 and L13.

Project Justification

Hydro's Rural Planning annual system review has shown that the voltage level at the end of feeder L11, which services the Wabush industrial park, is below Hydro's distribution planning normal voltage criteria of 116 V during peak load, and transformer T3 is currently loaded beyond its planning rating[4] by 7 percent.

By upgrading the system, customers on the feeder L11 will no longer continue to experience voltage conditions under peak load, which could result in damage to customer owned equipment. Also, T3 will no longer be loaded beyond the Newfoundland and Labrador System Operator (NLSO) rating during peak load, which could lead to increased aging, premature equipment failure, and customer outages.

To address the low voltage conditions and the transformer overload, two alternatives were considered.[5]

[3] In 2014, this transformer was relocated from Quartzite substation to Wabush substation to increase the firm transformer capacity of the substation. This transformer was not permanently connected because the transformer's primary phase sequence was reversed from the other transformers in the station.

[4] The planning rating of the transformers in Wabush substation is the 25 or 30 degree ambient temperature nameplate rating provided by the manufacturer. This transformer rating allows an operational margin to account for cold load pickup or other emergency situations. Upon the creation of the Newfoundland and Labrador System Operation (NLSO) the Wabush substation was re-assigned from a distribution substation to part of the NL transmission system and is now governed by Transmission Facilities Rating Guide available on the NLSO OASIS website. These ratings are lower than those used in previous studies and board submissions.

[5] Conservation and Demand Management was not considered a valid alternative because Hydro has no proven alternatives that can be depended on to decrease the peak demand. Work is ongoing on developing new programs and technology that may allow this option in the future. Voltage reduction was not considered as a valid alternative because the system is already experiencing low voltage conditions during peak load.

Alternative 1 – Reconfigure WAB Substation and Connect Transformer T4

This alternative allows Transformer T4 to be paralleled with Transformer T6 so that enough load can be transferred from feeder L11 to L13 to eliminate low voltages on feeder L11 and to ensure Transformer T3 is not loaded beyond the NLSO ratings. This alternative is estimated to cost $186,700.

Alternative 2 - Voltage Regulator

This alternative considers installing a set of three 400 A voltage regulators on feeder L13 so that enough load can be transferred from feeders L11 to L12 to eliminate low voltages on feeder L11 and to ensure Transformer T3 is not loaded beyond the NLSO ratings. This alternative is estimated to cost between $450,000 and $550,000[6].

Evaluation of Alternatives

The least cost and preferred alternative is Alternative 1, which consists of the reconfiguration of the WAB substation to allow Transformer T4 to be paralleled with Transformer T6.

A detailed Net Present Value analysis was not required to evaluate these two alternatives because Alternative 2 has a materially higher capital cost, and introduces additional losses and maintenance costs on the system.

Project Schedule

The anticipated project schedule is shown in Table 3.

[6] Price is based historical project information.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Open Job, Develop Project Scope Statement and Baseline Schedule	Jan 2019	Feb 2019
Design	Detailed Electrical and Structural Design	Jan 2019	Mar 2019
Procurement	Tender Steel Supply, Procure Materials	Mar 2019	Jun 2019
Construction	Install Transposition Structural Modification	Jul 2019	Jul 2019
Commissioning	Commission T4 for Return to Service	Jul 2019	Jul 2019
Closeout	Project Closeout	Aug 2019	Oct 2019

Appendix A

System Operating Diagram - Wabush Substation

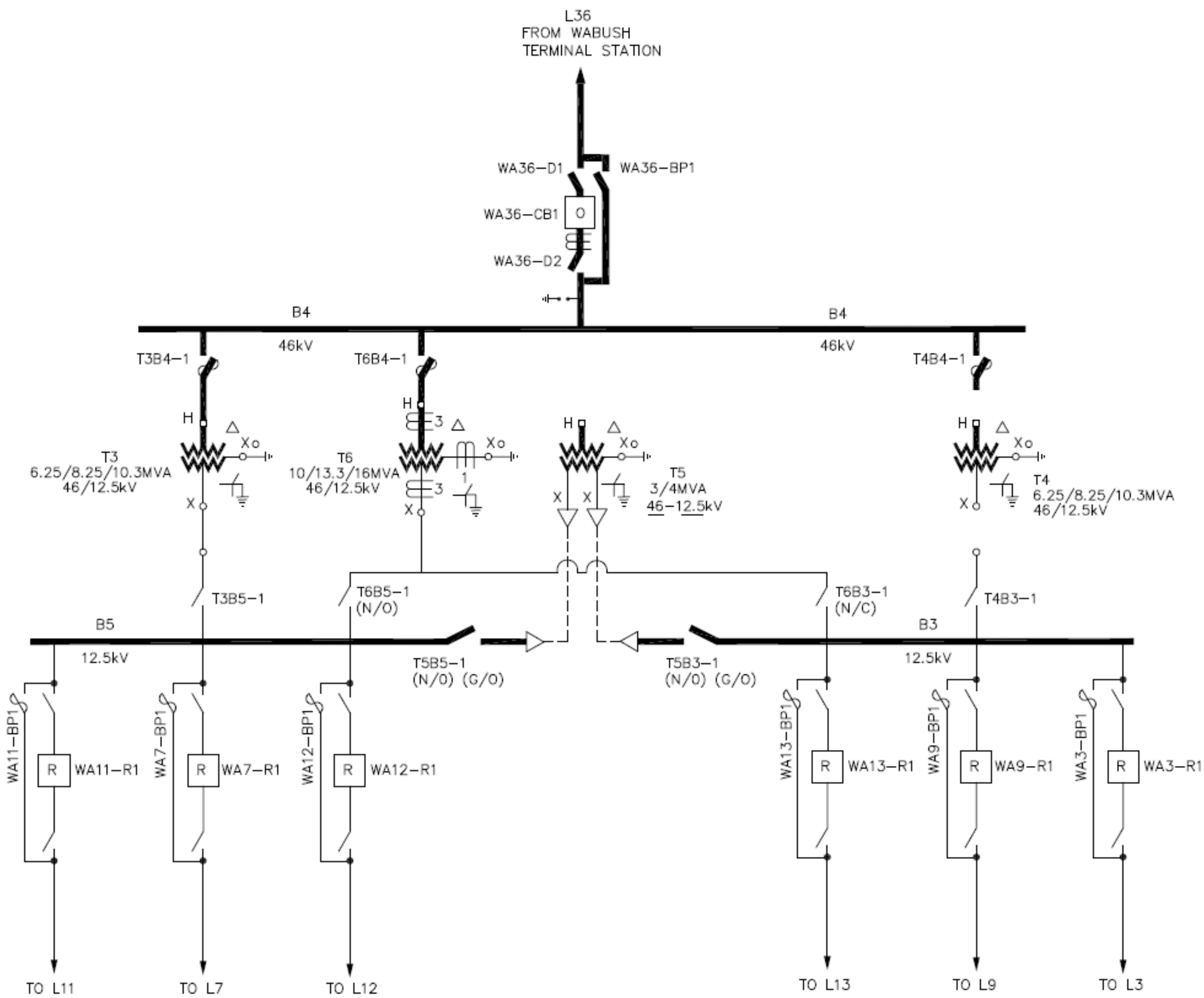

Figure 1: System Operating Diagram - Wabush Substation (Temporary Connection for T6)

Project Title: Remove Safety Hazards
Location: Various
Category: General Properties - Administrative
Definition: Other
Classification: Normal

Project Description

This proposed project is required to ensure adequate capital funding is available to quickly address safety hazards that require capital expenditure. These hazards are identified through Newfoundland and Labrador Hydro's (Hydro) Safe Work Observation Program (SWOP)[1] and have to be addressed before submission of the next Capital Budget Application.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	45.0	0.0	0.0	45.0
Labour	88.9	0.0	0.0	88.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	45.0	0.0	0.0	45.0
Other Direct Costs	6.7	0.0	0.0	6.7
Interest and Escalation	11.9	0.0	0.0	11.9
Contingency	0.0	0.0	0.0	0.0
Total	**197.5**	**0.0**	**0.0**	**197.5**

Existing Systems

In Hydro's 2017 Capital Budget Application, the Board approved a budget of $198,600 to remove safety hazards in the workplace. Table 2 lists the projects completed in 2017, which total $182,300.

[1] SWOP involves identifying, reporting, and addressing hazardous conditions that can potentially lead to an incident.

Table 2: Work Completed in 2017 ($000)

Location	Work Description	Cost
Bay d'Espoir	Purchase Hydraulic Pole Key Removal Tool	46.0
Bay d'Espoir	Install Roadway Guard Rails	16.7
Holyrood	Construct Vestibule and Stairwell Approach Walkways	119.6
Total		**182.3**

Process for Selecting Eligible Projects

Safety hazards are identified through Hydro's SWOP by employees, contractors, and others who access Hydro facilities. Often, mitigation of the safety concern can be accomplished through an operating or procedural change (e.g., a communication or corrective work), which is an operating expense. When it is determined that the appropriate mitigation measure requires a capital expenditure and has to be executed before the next Capital Budget Application, a cost estimate is prepared and submitted to the Project Execution Department of Hydro's Engineering Services Division for consideration under the "*Remove Safety Hazards Project*". These requests are reviewed and, if warranted, approved to proceed by the Manager of Project Execution.

Historical Information

Table 3 shows the budget and actual expenditures for years 2014-2017 for the "*Remove Safety Hazards Project*".

Table 3: Capital Expenditure History ($000)

Year	Capital Budget	Actual Expenditures
2018	199.4	-
2017	198.6	185.9
2016	199.3	175.4
2015	194.9	176.9
2014	257.8	207.6

Some variability in actual expenditures is expected from year-to-year since the number of hazards identified and nature of the required mitigation work is unknown.

Project Justification

This project is justified based on Hydro's requirement to provide a safe work environment for its employees in compliance with the *Occupational Health and Safety Regulations*, Section 14 which states:

> *14. (1) An employer shall ensure, so far as is reasonably practicable, that all buildings, structures, whether permanent or temporary, excavation, machinery, workstations, places of employment and equipment are capable of withstanding the stresses likely to be imposed upon them and of safely performing the functions for which they are used or intended.*
>
> *(2) An employer shall ensure that necessary protective clothing and devices are used for the health and safety of his or her workers.*

Future Plans

Hydro plans to propose a "*Remove Safety Hazards Project"* in future annual Capital Budget Applications. Expenditures will be reported in the annual "*Capital Expenditures and Carryover Report"*, submitted on March 1, which covers the previous year.

Project Schedule

As the project estimate relates to unanticipated safety hazards and mitigation, no schedule is currently available.

Project Title: Replace Teleprotection
Location: Bay d'Espoir to Sunnyside (TL 202 and TL 206)
Category: General Properties – Telecontrol
Definition: Other
Classification: Normal

Project Description

Hydro proposes the installation of required communications equipment to replace the existing Powerline Carrier (PLC) equipment on TL 202 and TL 206 between the Bay d'Espoir (BDE) and Sunnyside (SSD) Terminal Stations. With the completion of TL 267, Hydro now has an optical fiber link direct from BDE to SSD. This fiber link can now be used to provide tele-protection for TL 202 and TL 206 utilizing much less expensive Telecommunications Multiplexers called IMUX instead of replacing the older PLC with newer PLC equipment. This IMUX equipment is currently being used by Hydro in numerous sites and has been proven to be very reliable equipment.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	63.3	0.0	0.0	63.3
Labour	86.6	0.0	0.0	86.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	17.6	0.0	0.0	17.6
Interest and Escalation	12.7	0.0	0.0	12.7
Contingency	16.6	0.0	0.0	16.6
Total	**196.8**	**0.0**	**0.0**	**196.8**

Operating Experience

The PLC equipment on transmission lines TL 202 and TL 206 was installed in 1998 and has exceeded its design service life. In 2008, ABB informed customers that the repair of faulty

Power Line modules would cease, primarily due to the unavailability of electronic components and that they would no longer support this model. This equipment has a depreciable asset life of 15 years and will have been in service for 22 years before it is replaced. There have been no recorded failures of the TL 202 and TL 206 PLC equipment; however, due to high reliability requirements for teleprotection and SCADA communication, replacement of this equipment is required before failures occur. TL 202 and TL 206 are critical for power delivery and require a high availability protection scheme or major damage could occur to the transmission lines, transformers, and breakers resulting in a sustained power outage.

Currently, the PLC equipment provides primary communications, with utilization of a microwave communication system as backup. The microwave system will continue to be the backup system in the event of issues on the optical fibre link.

Project Justification

TL 202 and TL 206 PLC equipment model ETL40 PLC is obsolete. TL 202 and TL 206 are critical for power delivery and require a high availability protection scheme or major damage could occur to the transmission lines, transformers, and breakers resulting in a sustained power outage. Thus, continued utilization of this equipment poses the risk of failure and loss of communications required for the protection and control of the power system. Replacement ensures reliable communications to monitor and control power devices.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning	Jan 2019	Mar 2019
Design	Mar 2019	May 2019
Procurement	Mar 2019	Apr 2019
Construction	May 2019	Aug 2019
Commissioning	Aug 2019	Sep 2019
Closeout	Sep 2019	Nov 2019

Project Title: Replace Network Communications Equipment
Location: Various
Category: General Properties - Telecontrol
Definition: Pooled
Classification: Normal

Project Description

Hydro currently has 36 Cisco 2800 and 1800 series routers in its communications network that have been deemed End-of-Life since 2016. In 2019, Hydro proposes the replacement of 11 of these routers with updated technology equivalents from the same vendor (Cisco Systems).

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	66.0	0.0	0.0	66.0
Labour	80.9	0.0	0.0	80.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.2	0.0	0.0	1.2
Interest and Escalation	11.8	0.0	0.0	11.8
Contingency	29.6	0.0	0.0	29.6
Total	**189.5**	**0.0**	**0.0**	**189.5**

Operating Experience

Cisco Systems networking devices have been proven to be reliable and secure when properly maintained and kept up-to-date. Cisco regularly releases software updates to address any identified deficiencies as well as security updates. These updates only continue until Cisco deems the devices End-of-Life as per its product life cycle management.

Project Justification

The networking devices are critical to daily operations for hundreds of users in the Hydro system that require corporate network access to e-mail, file server access, and basic internet connection. The Cisco 2800 and 1800 series routers are at End-of-Life and are no longer covered by Cisco's maintenance and support packages. Cisco also no longer releases software updates to address software deficiencies or security updates for these devices. Hydro has adopted a staged, multi-year approach to replacement of the Cisco 2800 and 1800 series routers as, while the fleet is performing reliably, the longer the replacement is deferred the greater the risk to reliable and secure operation of Hydro's communications network.

Future Plans

Hydro plans to continue replacement of the remaining 25 of the 2800 and 1800 series routers on a priority basis.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Scope Statement, Resource and network outage schedule	Jan 2019	Feb 2019
Design	Network drawings and design packages, Refine Bill of Materials	Feb 2019	Mar 2019
Procurement	Submit requisition for Cisco Equipment (Standing Offer)	Mar 2019	Apr 2019
Construction	Configure and install new equipment	Apr 2019	Nov 2019
Commissioning	Test network connectivity	May 2019	Nov 2019
Closeout	Update As-Built drawing and close-out project	Nov 2019	Dec 2019

Project Title: Upgrade Remote Terminal Units
Location: Various Sites
Category: General Properties - Telecontrol
Definition: Pooled
Classification: Normal

Project Description

A critical component of Hydro's Supervisory Control and Data Acquisition (SCADA) network is the GE Multilin D20-based Remote Terminating Unit (RTU). This equipment is used in substations, generating stations, or any part of the network from which data must be collected and sent back to the Energy Control Center (ECC) for monitoring of the Hydro system, and to allow the ECC to send signals to stations to control electrical equipment. Hydro has used the D20 RTU since the early 1990s and has an installed base of 78 units throughout the province.

In order to minimize the probability of an outage attributable to an RTU, Hydro proposes the replacement of the processor modules in five (5) older RTUs with the latest model of the D20 processor (please refer to Appendix A). The original D20 RTU processor card, the D20M++, has been discontinued by the manufacturer and cannot be repaired. Replacement with new D20MX processors will maintain reliability and provide increased functionality with the advanced communications features, such as Ethernet, built into the newer processors. Due to operational risks associated with the failure of any portion of the SCADA network, this project is a proactive approach to ensuring that the likelihood of in-service failure of the oldest D20 modules is minimized.

The proposed project will be completed using Hydro personnel. All changes will be fully tested in a lab environment before deployment to the field due to the critical role that the RTU plays in the monitoring and control of the network.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	54.2	0.0	0.0	54.2
Labour	71.7	0.0	0.0	71.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	5.2	0.0	0.0	5.2
Interest and Escalation	10.4	0.0	0.0	10.4
Contingency	26.2	0.0	0.0	26.2
Total	**167.7**	**0.0**	**0.0**	**167.7**

Operating Experience

The GE D20 RTU processors have proven to be very reliable for Hydro. This, combined with regular attention to maintenance, has helped to minimize complete site SCADA outages attributable to the D20M++ processor. The last failure, in July of 2014, required that a spare RTU be used to complete repairs as GE indicated that they can no longer repair defective modules.

Table 2 shows the inventory of existing D20 processor unit in service.

Table 2: D20 Installed Base

GE Multilin D20 Processor Model	Installed Base
D20M++ (1990s)	14
D20ME (2000s)	43
D20MX (2013+)	11
Total	**78**

Project Justification

The D20 RTU processor card, the D20M++, has been discontinued by the manufacturer since the late 1990s. Due to the unavailability of electronics components for the D20M++, the manufacturer will no longer accept defective modules for repair. As a result, the Hydro spares inventory has been depleted. A failure of the D20M++ processor will lead to a forced and unscheduled upgrade of the D20 RTU, which would result in a two-to-four-day outage during which the ECC has no monitoring or control ability of the affected station(s). An isolated station may need to be continually staffed in order to prevent extended customer outages.

Future Plans

Upgrades continue to be proposed in future capital budget applications. It is anticipated that D20M++ replacements will be completed by 2021.

Project Schedule

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Prepare Project Plan and site visits	Jan 2019	Feb 2019
Design	Complete Tender Package	Feb 2019	Mar 2019
Procurement	Purchase Upgrade Kits	Apr 2019	Apr 2019
Construction	Install Upgrade Kits	May 2019	Sep 2019
Commissioning	Site Inspections	Oct 2019	Oct 2019
Closeout	Project Closeout	Nov 2019	Dec 2019

Appendix A

D20M++ Locations

Site	Location	Site Type	Replacement Date
HLC	Hinds Lake	Control Structure	**2019**
HLI	Hinds Lake	Intake	**2019**
HLS	Hinds Lake	Spillway	**2019**
HLX	Hinds Lake	Concentrator	**2019**
HMC	Hinds Lake	Control Structure	**2019**
CAS	Cat Arm Sync Remote	Remote	2020
CMS	Cat Arm Sync Sub	Sync	2020
HMI	Hinds Lake	Intake Sub	2020
HMS	Hinds Lake	Spillway Sub	2020
RBK	Rattle Brook	Plant	2021
HBY	Hawkes Bay	Terminal Station	2021
PBN	Peter’s Barren	Terminal Station	2021
SDP	St. Anthony Diesel	Plant	2021
STA	St. Anthony Airport	Terminal Station	2021

Project Title: Upgrade Software Applications

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Pooled

Classification: Normal

Project Description

Hydro proposes upgrades for the following software applications:

- PI database software used by the Energy Management System for reporting and historic operating data information;
- lightning tracking software used by System Operations to track lightning storms for system reliability; and
- Work Protection software across Hydro for isolation of equipment for work permits.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	30.0	0.0	0.0	30.0
Labour	18.0	0.0	0.0	18.0
Consultant	40.0	0.0	0.0	40.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	4.8	0.0	0.0	4.8
Contingency	17.6	0.0	0.0	17.6
Total	**110.4**	**0.0**	**0.0**	**110.4**

Project Justification

Hydro reviews its software application portfolio on an annual basis. The status of vendor support for the applications is reviewed and, if unsupported, the software version is upgraded to a vendor supported level.

The upgrades are made to continue reliable operations of the software used in the running of the electrical system and to maintain customer service systems. By keeping software in a supported state, vendor notification is received for any software bugs and associated available fixes. In addition, newer releases can increase functionality of the software and can increase efficiency.

Project Schedule

This project is scheduled to begin in January 2019 with planned completion by December 2019.

Future Plans

Software reviews occur on an annual basis and upgrades to the software put forward in future capital budget applications.

Project Title: Refresh Security Software
Location: Hydro Place
Category: General Properties - Information Systems
Definition: Pooled
Classification: Normal

Project Description

This project is proposed to refresh Hydro's Information Security and Cyber Safety tools and improve Hydro's cyber threat detection and mitigation capabilities.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	51.0	0.0	0.0	51.0
Labour	3.9	0.0	0.0	3.9
Consultant	16.5	0.0	0.0	16.5
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	5.0	0.0	0.0	5.0
Contingency	14.3	0.0	0.0	14.3
Total	**90.7**	**0.0**	**0.0**	**90.7**

Operating Experience

Hydro uses and maintains security software tools and hardware to mitigate threats to computers systems and networks. The security software tools are used by Information System Security staff and Information System Support staff on a daily basis. While Hydro has been successful in protecting its Information Technology assets from malicious threats, continual updates and improvements are necessary to protect against the global growth and increasing sophistication of cyber threats and the cybercriminal industry.

Project Justification

Hydro's increasing reliance on information systems and expanding data networks increases exposure to information security threats to its critical infrastructure. Major risk exposures in this environment relate to information security (e.g., loss of critical infrastructure stability and processing capability due to hardware/software failure or threat of virus attacks), availability of information (e.g., loss of communication across the wide area network), and risk of corporate data loss (e.g., loss of data through cybercriminal malware and attacks).

External threats to Hydro's computer systems are mitigated through the use of firewalls, anti-virus tools and detection/intrusion prevention appliances. Internet access is tightly controlled and managed by security appliances and software that help reduce the risk of potential computer viruses. A serious incident involving access to critical business, plant or energy control systems, or the loss of corporate data, could negatively affect the power grid and would result in unplanned costs to contain, investigate, and remediate the incident. Additional investments to change systems and/or processes after such an incident might also be required.

Future Plans

Hydro's computer systems and network infrastructure require constant protection from cyber threats. This is accomplished through continuous evaluation and maintenance of Information System security tools and services.

Project Schedule

This project is scheduled to begin in January 2019 with planned completion by December 2019.

F. Leasing Costs

THERE ARE NO ITEMS FOR THIS SECTION

E, A_ngr_j Cvnclbgrspcq 0./2+0.01

E, A_ngr_j Cvnclbgrspcq 0./2+0.01

	Actuals				Budget					
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Generation	122,571	54,189	64,260	39,101	58,718	32,924.0	39,039.2	43,469.5	33,444.9	25,243.7
Transmission and Rural Operations	75,771	62,202	130,612	293,203	134,069	76,608.3	87,540.6	79,597.4	82,202.0	92,237.3
General Properties	6,386	8,729	9,069	8,436	7,603	8,636.5	7,041.7	9,655.9	6,049.2	6,403.7
Total Capital Expenditures	**204,728**	**125,119**	**203,941**	**340,741**	**200,390**	**118,169**	**133,622**	**132,723**	**121,696**	**123,885**

H. Status Report

Total Capital Project Variance 2018 Overview ($000)			
Asset Type	**Board Approved Budget**	**Total Project Expenditures and Forecast**	**Variance**
Hydraulic	52,680	52,880	200
Thermal	18,341	19,495	1,155
Gas Turbines	27,353	26,499	(855)
Terminal Stations	142,121	141,528	(593)
Transmission	326,860	326,860	(0)
Distribution	20,465	20,465	0
Rural Generation	31,235	31,482	247
Properties	4,262	4,262	0
Metering	4,409	4,656	247
Rural System Tools and Equipment	2,297	2,297	0
Information Systems	3,058	2,405	(653)
Telecontrol	6,449	6,283	(166)
Transportation	4,821	4,821	0
Administrative	1,465	1,465	(0)
Allowance for Unforeseen	2,000	6,220	4,220
Supplemental Projects	10,892	12,088	1,196
Projects Approved for less than $50,000	267	267	0
Total Capital Budget	**658,974**	**663,973**	**4,999**

2018 Capital Expenditures By Year
($000)

Summary	Capital Budget[1]										Actual Expenditure and Forecast										
	A					B	C	D (B+C)	E	F (A+C+E)	G					H	I	J	K (G+H+I+J)	K-F
	2013	2014	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2013	2014	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance
2018 Projects							85,565.8	85,565.8	64,508.5	150,074.3						23,004.1	66,729.1	64,508.5	154,241.8	4,167.5
2017 Projects					30,801.8	10,529.1	45,572.6	56,101.7	3,767.2	80,141.6					19,758.5	9,448.9	45,907.9	3,767.2	78,882.5	(1,259.1)
2016 Projects				22,893.1	43,682.6	12,953.9	34,899.2	47,853.1	28,274.1	129,749.0				18,714.6	36,587.8	24,723.9	23,332.1	28,274.1	131,632.6	1,883.6
2015 Projects			389.6	868.5	245.1	305.1	0.0	305.1	0.0	1,503.2			534.2	474.1	436.5	212.0	93.1	0.0	1,749.9	246.7
2014 Projects		211.5	4,431.4	76,322.7	195,454.0	1,069.8	17,418.3	18,488.1	0.0	293,837.9		211.5	2,046.4	59,337.7	213,754.2	3,094.1	15,394.0	0.0	293,837.9	(0.0)
2013 Projects	593.2	552.8	538.4	1,511.7	471.9	31.9	0.0	31.9	0.0	3,668.0	240.3	699.0	755.5	1,190.3	711.0	15.8	16.1	0.0	3,628.0	(40.0)
Grand Total	**593.2**	**764.3**	**5,359.4**	**101,596.0**	**270,655.4**	**24,889.8**	**183,455.9**	**208,345.7**	**96,549.8**	**658,974.0**	**240.3**	**910.5**	**3,336.1**	**79,716.7**	**271,248.0**	**60,498.8**	**151,472.5**	**96,549.8**	**663,972.7**	**4,998.7**

2018 Capital Budget Approved by Board Order No. P.U. 43 (2017) and P.U. 5 (2018)	181,193.7
New Project Approved by Board Order No. 11 (2017)	327.3
New Project Approved by Board Order No. 1 (2018)	748.4
New Project Approved by Board Order No. 1 (2018)	(748.4)
New Project Approved by Board Order No. 6 (2018)	719.4
New Project Approved by Board Order No. 6 (2018)	(50.4)
New Project Approved by Board Order No. 19 (2018)	1,000.0
2018 New Projects under $50,000 Approved by Hydro	265.9
Total Approved Capital Budget Before Carryovers	183,455.9
Carryover Projects 2017 to 2018	24,889.8
Total Approved Capital Budget Before Carryovers	**208,345.7**

[1] Annual budgets previous to 2018 pertain to projects that have expenditures in 2017.

2018 Capital Expenditures By Category ($000)

Hydraulic Generation Projects	Capital Budget								Actual Expenditure and Forecast								
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J	K (G+H+I)	K-F	
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Install Remote Operation of Salmon Spillway - Bay d'Espoir	-	-	-	-	645.9	645.9	1,862.5	2,508.4	-	-	-	149.0	496.9	1,862.5	2,508.4	-	
Refurbish Backfill on Penstock #1 - Bay d'Espoir	-	-	-	-	1,630.4	1,630.4	-	1,630.4	-	-	-	52.2	1,578.2	-	1,630.4	-	
Hydraulic In-Service Failures	-	-	-	-	1,251.1	1,251.1	-	1,251.1	-	-	-	137.0	1,114.1	-	1,251.1	-	
Energy Efficiency Improvements - Various Sites	-	-	-	-	276.2	276.2	168.9	445.1	-	-	-	22.8	253.4	168.9	445.1	-	
Hydraulic Generation Refurbishment and Modernization - Various Sites	-	-	-	-	10,325.4	10,325.4	4,283.1	14,608.5	-	-	-	1,027.3	9,298.1	4,283.1	14,608.5	-	
Purchase Tools and Equipment Less than $50,000	-	-	-	-	235.2	235.2	-	235.2	-	-	-	29.0	206.2	-	235.2	-	
2017 Projects																	
Install Asset Health Monitoring System - Upper Salmon	-	-	438.0	223.1	203.4	426.5	-	641.4	-	-	214.9	18.1	408.4	-	641.4	-	
Refurbish Main Generator Breaker - Upper Salmon	-	-	271.1	147.9	-	147.9	-	271.1	-	-	123.2	14.3	133.6	-	271.1	-	
Water System Replacements - Bay d'Espoir and Cat Arm	-	-	265.5	88.8	2,288.3	2,377.1	-	2,553.8	-	-	176.7	409.8	1,967.3	-	2,553.8	-	
Refurbish Powerhouse Station Services - Bay d'Espoir	-	-	413.2	370.2	2,473.3	2,843.5	1,460.6	4,347.1	-	-	43.0	279.8	2,563.7	1,460.6	4,347.1	-	
Replace Exciter Controls Units 1 to 6 - Bay d'Espoir	-	-	119.2	(63.5)	921.2	857.7	2,306.6	3,347.0	-	-	182.7	194.4	663.3	2,306.6	3,347.0	-	
Upgrade Ventilation in Powerhouse 1 and 2 - Bay d'Espoir	-	-	134.1	22.3	863.8	886.1	-	997.9	-	-	111.8	96.3	789.8	-	997.9	-	
Purchase Capital Spares - Hydraulic	-	-	487.4	362.2	-	362.2	-	487.4	-	-	325.2	297.8	64.4	-	687.4	200.0	1
Replace Slip Rings Units 1-6 - Bay d'Espoir	-	-	312.6	210.2	159.7	369.9	-	472.3	-	-	102.4	9.7	360.2	-	472.3	-	
Refurbish Sump Level System for Powerhouse 2 - Bay d'Espoir	-	-	38.7	28.1	264.5	292.6	-	303.2	-	-	10.6	96.4	196.2	-	303.2	-	
Install Wind Monitoring Station North Salmon Dam SD-2 - Bay d'Espoir	-	-	165.5	113.2	-	113.2	-	165.5	-	-	52.3	20.0	93.2	-	165.5	-	
Control Structure Refurbishments	-	-	1,735.3	743.9	452.9	1,196.8	-	2,188.2	-	-	991.4	170.3	1,026.5	-	2,188.2	-	
2016 Projects																	
Refurbish Station Water System - Upper Salmon	-	96.6	197.6	94.9	-	94.9	-	294.2	-	38.3	161.0	36.6	58.3	-	294.2	-	
Upgrade Work - Cat Arm	-	558.3	1,353.0	910.3	-	910.3	-	1,911.3	-	240.4	760.6	176.5	733.8	-	1,911.3	-	
Rehabilitate Shoreline Protection - Cat Arm	-	112.2	1,030.7	977.2	-	977.2	-	1,142.9	-	104.7	61.0	35.2	942.0	-	1,142.9	-	
Replace Site Facilities - Bay d'Espoir	-	928.3	4,736.3	3,162.6	6,316.7	9,479.3	-	11,981.3	-	270.4	2,231.6	4,358.0	5,121.3	-	11,981.3	-	
Replace Spherical By-Pass Valves Units 1 and 2 - Bay d'Espoir	-	183.6	167.9	144.9	-	144.9	-	351.5	-	154.8	51.8	49.7	95.2	-	351.5	-	
2015 Projects																	
Replace Pump House and Associated Equipment - Bay d'Espoir	22.7	522.5	0.0	253.6	-	253.6	-	545.2	137.0	128.6	26.0	39.8	213.8	-	545.2	-	
Total Hydraulic Generation Projects	**22.7**	**2,401.5**	**11,866.1**	**7,789.9**	**28,308.0**	**36,097.9**	**10,081.7**	**52,680.0**	**137.0**	**937.2**	**5,626.2**	**7,720.1**	**28,377.8**	**10,081.7**	**52,880.0**	**200.0**	

2018 Capital Expenditures By Category
($000)

Thermal Generation Projects	Capital Budget A 2015	A 2016	A 2017	B Carryover 2018	C Original 2018	D (B+C) Revised 2018	E 2019 and Beyond	F (A+C+E) Total	Actual Expenditure and Forecast G 2015	G 2016	G 2017	H YTD 2018	I Forecast Jul-Dec 2018	J 2019 and Beyond	K (G+H+I+J) Total	K-F Project Variance	Notes
2018 Projects																	
Thermal In-Service Failures	-	-	-	-	1,250.0	1,250.0	-	1,250.0	-	-	-	1,432.7	(182.7)	-	1,250.0	-	
Overhaul Pumps - Holyrood	-	-	-	-	438.3	438.3	-	438.3	-	-	-	31.4	406.9	-	438.3	-	
Condition Assessment and Miscellaneous Upgrades - Holyrood	-	-	-	-	2,749.6	2,749.6	-	2,749.6	-	-	-	1,554.1	1,195.5	-	2,749.6	-	
Overhaul Unit 1 Generator - Holyrood	-	-	-	-	1,005.0	1,005.0	-	1,005.0	-	-	-	27.3	977.7	-	1,005.0	-	
Overhaul Unit 1 Turbine Valves - Holyrood	-	-	-	-	2,485.7	2,485.7	-	2,485.7	-	-	-	135.5	2,350.2	-	2,485.7	-	
Upgrade Cranes and Hoists - Holyrood	-	-	-	-	80.3	80.3	300.3	380.6	-	-	-	29.1	51.2	300.3	380.6	-	
Install Raw Water Line - Holyrood	-	-	-	-	1,252.6	1,252.6	-	1,252.6	-	-	-	707.2	1,145.8	-	1,853.0	600.4	2
Install Fire Detection in Outbuildings - Holyrood	-	-	-	-	198.6	198.6	-	198.6	-	-	-	12.6	186.0	-	198.6	-	
Purchase Tools and Equipment Less than $50,000	-	-	-	-	16.5	16.5	-	16.5	-	-	-	-	16.5	-	16.5	-	
2017 Projects																	
Upgrade Holyrood Access Road - Holyrood	-	-	579.3	-	583.4	583.4	-	1,162.7	-	-	825.7	-	-	-	825.7	(337.0)	3
Upgrade Underground Plant Drainage System - Holyrood	-	-	923.1	(10.7)		(10.7)	-	923.1	-	-	1,825.2	0.4	(11.1)	-	1,814.5	891.4	4
2016 Projects																	
Upgrade Powerhouse Building Envelope - Holyrood	-	2,723.8	2,969.9	1,075.6	784.1	1,859.7	-	6,477.8	-	2,239.9	2,378.2	459.2	1,400.5	-	6,477.8	-	
Total Thermal Generation Projects	**0.0**	**2,723.8**	**4,472.3**	**1,064.9**	**10,844.1**	**11,909.0**	**300.3**	**18,340.5**	**-**	**2,239.9**	**5,029.1**	**4,389.6**	**7,536.4**	**300.3**	**19,495.3**	**1,154.8**	

2018 Capital Expenditures By Category
($000)

Gas Turbine Generation Projects	Capital Budget A 2015	A 2016	A 2017	B Carryover 2018	C Original 2018	D (B+C) Revised 2018	E 2019 and Beyond	F (A+C+E) Total	Actual Expenditure and Forecast G 2015	G 2016	G 2017	H YTD 2018	I Forecast Jul-Dec 2018	J 2019 and Beyond	K (G+H+I+J) Total	K-F Project Variance	Notes
2018 Projects																	
Purchase Capital Spares - Gas Turbines	-	-	-	-	626.9	626.9	-	626.9	-	-	-	280.7	346.2	-	626.9	-	
Gas Turbine Equipment Replacement and Refurbishment - Hardwoods and Stephenville	-	-	-	-	997.9	997.9	429.3	1,427.2	-	-	-	6.7	991.2	429.3	1,427.2	-	
Increase Fuel and Water Treatment System Capacity - Holyrood Gas Turbine	-	-	-	-	8,829.9	8,829.9	3,012.7	11,842.6	-	-	-	437.1	8,392.8	3,012.7	11,842.6	-	
Turbine Hot Gas Path Level 2 Inspection and Overhaul - Holyrood Gas Turbine	-	-	-	-	6,538.8	6,538.8	4,607.7	11,146.5	-	-	-	5,502.9	1,035.9	4,607.7	11,146.5	-	5
2017 Projects																	
Gas Turbine Life Extension - Stephenville	-	-	847.5	24.1	505.7	529.8	-	1,353.2	-	-	342.2	113.6	416.2	-	872.0	(481.2)	6
Gas Turbine Life Extension - Hardwoods	-	-	675.3	28.3	281.4	309.7	-	956.7	-	-	273.6	117.4	192.3	-	583.3	(373.4)	7
Total Gas Turbine Generation Projects	**-**	**-**	**1,522.8**	**52.4**	**17,780.6**	**17,833.0**	**8,049.7**	**27,353.1**	**-**	**-**	**615.8**	**6,458.5**	**11,374.5**	**8,049.7**	**26,498.5**	**(854.6)**	

2018 Capital Expenditures By Category
($000)

Terminal Stations Projects	Capital Budget										Actual Expenditure and Forecast											
	A					B	C	D (B+C)	E	F (A+C+E)	G					H	I	J	K (G+H+I+J)	K-F	
	2013	2014	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2013	2014	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																					
Terminal Station In-Service Failures	-	-	-	-	-	-	1,000.0	1,000.0	-	1,000.0	-	-	-	-	-	1,079.0	(79.0)	-	1,000.0	-	
Upgrade Aluminum Support Structures - Holyrood	-	-	-	-	-	-	287.6	287.6	-	287.6	-	-	-	-	-	44.9	242.7	-	287.6	-	
Replace Transformer T1 - Buchans	-	-	-	-	-	-	249.0	249.0	2,086.1	2,335.1	-	-	-	-	-	30.2	218.8	2,086.1	2,335.1	-	
Install Breaker Bypass Switch - Howley	-	-	-	-	-	-	83.1	83.1	1,440.9	1,524.0	-	-	-	-	-	17.9	65.2	1,440.9	1,524.0	-	8
Implement Terminal Station Flood Mitigation - Springdale	-	-	-	-	-	-	186.2	186.2	787.8	974.0	-	-	-	-	-	67.6	118.6	787.8	974.0	-	
Purchase Mobile DC Power Systems	-	-	-	-	-	-	270.9	270.9	695.6	966.5	-	-	-	-	-	8.2	262.7	695.6	966.5	-	
Terminal Station Refurbishment and Modernization - Various Sites	-	-	-	-	-		8,170.6	8,170.6	22,625.1	30,795.7	-	-	-	-	-	485.3	7,685.3	22,625.1	30,795.7	-	
2017 Projects																					
Upgrade Corner Brook Frequency Converter - Corner Brook	-	-	-	-	194.6	152.4	2,749.2	2,901.6	-	2,943.8	-	-	-	-	42.2	(2.7)	2,904.3	-	2,943.8	-	9
Replace 66 kV Station Service Feed - Holyrood	-	-	-	-	62.8	(17.9)	1,198.6	1,180.7	-	1,261.4	-	-	-	-	80.7	43.6	1,137.1	-	1,261.4	-	
Replace Substation - Holyrood	-	-	-	-	439.4	324.0	758.6	1,082.6	-	1,198.0	-	-	-	-	115.4	148.1	934.5	-	1,198.0	-	
Replace Power Transformers - Oxen Pond	-	-	-	-	297.5	188.4	850.1	1,038.5	-	1,147.6	-	-	-	-	109.1	95.1	943.4	-	1,147.6	-	
Terminal Station Refurbishment and Modernization - Various Sites	-	-	-	-	10,831.3	3,138.3	16,550.8	19,689.1		27,382.1	-	-	-	-	5,852.1	2,275.5	17,413.6		25,541.2	(1,840.9)	
2016 Projects																					
Upgrade Circuit Breakers - Various Sites	-	-	-	6,969.1	10,808.7	3,300.5	15,408.6	18,709.1	28,274.1	61,460.5	-	-	-	5,599.5	8,877.8	7,620.6	11,088.5	28,274.1	61,460.5	-	10
Replace Protective Relays - Various Sites	-	-	-	700.6	1,156.4	267.5	-	267.5	-	1,857.0	-	-	-	1,425.8	1,134.5	265.0	2.5	-	2,827.8	970.8	11
Replace Disconnect Switches - Various Sites	-	-	-	646.9	1,320.9	771.2	-	771.2	-	1,967.8	-	-	-	131.7	1,064.9	88.0	683.2	-	1,967.8	-	
Upgrade Data Alarm Systems - Various Sites	-	-	-	74.4	234.1	142.8	-	142.8	-	308.5	-	-	-	49.7	116.0	131.8	11.0	-	308.5	-	
Install Breaker Failure Protection - Various Sites	-	-	-	65.7	211.3	22.2	-	22.2	-	277.0	-	-	-	81.8	382.4	115.1	(92.9)	-	486.4	209.4	12
Install Fire Protection in 230 kV Stations - Bay d'Espoir	-	-	-	200.0	566.0	681.7	-	681.7	-	766.0	-	-	-	91.4	100.7	41.4	640.3	-	873.8	107.8	13
2013 Projects																					
Replace Instrument Transformers - Various Sites	593.2	552.8	538.4	1,511.7	471.9	31.9	-	31.9	-	3,668.0	240.3	699.0	755.5	1,190.3	711.0	15.8	16.1	-	3,628.0	(40.0)	
Total Terminal Stations Projects	**593.2**	**552.8**	**538.4**	**10,168.4**	**26,594.9**	**9,003.0**	**47,763.3**	**56,766.3**	**55,909.6**	**142,120.6**	**240.3**	**699.0**	**755.5**	**8,570.2**	**18,586.9**	**12,570.4**	**44,195.9**	**55,909.6**	**141,527.7**	**(592.9)**	

2018 Capital Expenditures by Category
($000)

Transmission Projects	Capital Budget									Actual Expenditure and Forecast									
	A				B	C	D	E	F (A+C+E)	G				H	I	J	K(G+H+I+J)	K-F	
	2014	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2014	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																			
Wood Pole Line Management Program - Various Sites	-	-	-	-	-	3,532.9	3,532.9	-	3,532.9	-	-	-	-	712.1	2,820.8	-	3,532.9	-	
2017 Projects																			
Transmission Line Upgrades - TL212 and TL218	-	-	-	1,378.2	1,091.1	1,133.3	2,224.4	-	2,511.5	-	-	-	287.1	368.7	1,855.7	-	2,511.5	-	
Replace Insulators - TL227	-	-	-	145.6	128.9	271.3	400.2	-	416.9	-	-	-	16.7	119.2	281.0	-	416.9	-	
2016 Projects																			
Construct 230 kV Transmission Line - Soldiers Pond to Hardwoods	-	-	3,699.0	10,985.4	(27.8)	11,876.5	11,848.7	-	26,560.9	-	-	3,501.6	11,210.6	10,345.9	1,502.8	-	26,560.9	-	
2014 Projects																			
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	211.5	28.4	1,038.4	901.6	1,829.8	-	1,829.8	-	2,179.9	211.5	28.2	19.9	90.5	13.1	1,816.7	-	2,179.9	-	
230 kV Transmission Line - Bay d'Espoir to Western Avalon	-	4,403.0	75,284.3	194,552.4	(760.0)	17,418.3	16,658.3	-	291,658.0	-	2,018.2	59,317.8	213,663.7	3,080.9	13,577.4	-	291,658.0	-	
Total Transmission Projects	**211.5**	**4,431.4**	**80,021.7**	**207,963.2**	**2,262.0**	**34,232.3**	**36,494.3**	**-**	**326,860.1**	**211.5**	**2,046.4**	**62,839.3**	**225,268.6**	**14,640.0**	**21,854.3**	**-**	**326,860.1**	**-**	

2018 Capital Expenditures By Category ($000)

Distribution Projects	Capital Budget								Actual Expenditure and Forecast								
	A			B	C	D (B+C)		F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F	
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Provide Service Extensions - All Service Areas	-	-	-	-	4,642.0	4,642.0	-	4,642.0	-	-	-	1,319.2	3,322.8	-	4,642.0	-	
Provide Service Extensions - All Service Areas - CIAC	-	-	-	-	(122.0)	(122.0)	-	(122.0)	-	-	-	(39.4)	(82.6)	-	(122.0)	-	
Upgrade Distribution Systems - All Service Areas	-	-	-	-	3,711.0	3,711.0	-	3,711.0	-	-	-	1,203.1	2,507.9	-	3,711.0	-	
Upgrade Distribution Systems - All Service Areas - CIAC	-	-	-	-	(61.0)	(61.0)	-	(61.0)	-	-	-	(8.7)	(52.3)	-	(61.0)	-	
Distribution System Upgrades - Various Sites	-	-	-	-	383.8	383.8	2,771.2	3,155.0	-	-	-	86.2	297.6	2,771.2	3,155.0	-	
Install Recloser Remote Control - English Harbour West and Barachoix	-	-	-	-	63.7	63.7	275.0	338.7	-	-	-	7.6	56.1	275.0	338.7	-	
Additions for Load Growth Happy Valley	-	-	-	-	505.0	505.0	-	505.0	-	-	-	35.2	469.8	-	505.0	-	
2017 Projects																	
Distribution Upgrades - Various Sites	-	-	64.2	(14.5)	1,130.9	1,116.4	-	1,195.1	-	-	78.7	221.8	894.6	-	1,195.1	-	
Install Recloser Remote Control - Bottom Waters	-	-	47.1	(16.8)	418.6	401.8	-	465.7	-	-	63.9	287.2	114.6	-	465.7	-	
2016 Projects																	
Upgrade Distribution Systems - Various Sites	-	285.6	6,350.3	911.0	-	911.0	-	6,635.9	-	361.8	5,363.1	213.0	698.0	-	6,635.9	-	
Total Distribution Projects	**-**	**285.6**	**6,461.6**	**879.7**	**10,672.0**	**11,551.7**	**3,046.2**	**20,465.4**	**-**	**361.8**	**5,505.7**	**3,325.4**	**8,226.3**	**3,046.2**	**20,465.4**	**-**	

2018 Capital Expenditures By Category
($000)

Rural Generation Projects	A			B	C	D	E	F (A+C+E)	Actual Expenditure and Forecast: G			H	I	J	K (G+H+I+J)	K-F	
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																-	
Overhaul Diesel Units - Various Sites	-	-	-	-	2,852.4	2,852.4	-	2,852.4	-	-	-	401.0	2,451.4	-	2,852.4	-	
Diesel Plant Engine Cooling System Upgrades - Various Sites	-	-	-	-	638.4	638.4	671.6	1,310.0	-	-	-	84.6	553.8	671.6	1,310.0	-	
Additions for Load Growth - Makkovik and Rigolet	-	-	-	-	730.1	730.1	-	730.1	-	-	-	40.4	689.7	-	730.1	-	
Upgrade Ventilation - Cartwright	-	-	-	-	465.7	465.7	-	465.7	-	-	-	33.0	432.7	-	465.7	-	
Diesel Plant Fire Protection - Postville	-	-	-	-	505.6	505.6	336.4	842.0	-	-	-	18.4	487.2	336.4	842.0	-	
Inspect Fuel Storage Tanks - Black Tickle	-	-	-	-	818.7	818.7	-	818.7	-	-	-	45.2	773.5	-	818.7	-	
Install Sub-Surface Drainage System - Paradise River	-	-	-	-	524.9	524.9	-	524.9	-	-	-	71.6	453.3	-	524.9	-	
Replace Secondary Containment System Liner - Nain	-	-	-	-	1,639.2	1,639.2	1,450.4	3,089.6	-	-	-	139.6	1,499.6	1,450.4	3,089.6	-	
Diesel Genset Replacements - Makkovik	-	-	-	-	604.1	604.1	8,296.1	8,900.2	-	-	-	117.7	486.4	8,296.1	8,900.2	-	
Replace Automation Equipment - St. Anthony	-	-	-	-	307.4	307.4	1,565.9	1,873.3	-	-	-	17.9	289.5	1,565.9	1,873.3	-	
Replace Human Machine Interface - St. Lewis	-	-	-	-	280.8	280.8	-	280.8	-	-	-	104.7	176.1	-	280.8	-	
2017 Projects																	
Diesel Plant Engine Auxiliary Upgrades - Various Sites	-	-	790.6	145.9	416.3	562.2	-	1,206.9	-	-	644.7	363.7	198.5	-	1,206.9	-	
Replace Automation Equipment - Mary's Harbour	-	-	120.3	32.9	1,021.7	1,054.6	-	1,142.0	-	-	87.4	98.5	956.1	-	1,142.0	-	
Diesel Genset Replacements - Port Hope Simpson and Charlottetown	-	-	658.8	445.2	5,148.0	5,593.2	-	5,806.8	-	-	213.6	1,097.3	4,495.9	-	5,806.8	-	
2016 Projects																	
Upgrade Human Machine Interface - Various Sites	-	114.0	320.0	73.0	-	73.0	-	434.0	-	125.3	235.7	87.1	(14.14)	-	434.0	-	
2015 Projects																	
Replace Programmable Logic Controllers - Various Sites	366.9	346.0	245.1	51.5	-	51.5	-	958.0	397.2	345.5	410.5	172.2	(120.7)	-	1,204.7	246.7	14
Total Rural Generation Projects	**366.9**	**460.0**	**2,134.8**	**748.5**	**15,953.3**	**16,701.8**	**12,320.4**	**31,235.4**	**397.2**	**470.8**	**1,591.9**	**2,893.0**	**13,808.8**	**12,320.4**	**31,482.1**	**246.7**	

2018 Capital Expenditures By Category
($000)

Properties Projects	Capital Budget								Actual Expenditure and Forecast								
	A			B	C	D	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F	
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Upgrade Office Facilities and Control Buildings - Various	-	-	-	-	1,180.6	1,180.6	-	1,180.6	-	-	-	194.2	986.4	-	1,180.6	-	
Line Depot Condition Assessment and Refurbishment - Various	-	-	-	-	1,233.0	1,233.0	-	1,233.0	-	-	-	248.6	984.4	-	1,233.0	-	
Install Fall Protection Equipment - Various	-	-	-	-	46.7	46.7	-	46.7	-	-	-	5.8	40.9	-	46.7	-	
Install Energy Efficiency Lighting in Diesel Plants - Various	-	-	-	-	104.0	104.0	241.2	345.2	-	-	-	40.0	64.0	241.2	345.2	-	
2017 Projects																	
Construct New Facilities - Various Sites	-	-	422.0	184.2	1,034.1	1,218.3	-	1,456.1	-	-	237.8	76.7	1,141.6	-	1,456.1	-	
Total Properties Projects	**-**	**-**	**422.0**	**184.2**	**3,598.4**	**3,782.6**	**241.2**	**4,261.6**	**-**	**-**	**237.8**	**565.4**	**3,217.2**	**241.2**	**4,261.6**	**-**	

2018 Capital Expenditures By Category
($000)

Metering Projects	Capital Budget								Actual Expenditure and Forecast								
	A			B	C	D	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F	
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Install Automated Meter Reading - Bottom Waters	-	-	-	-	75.2	75.2	1,001.0	1,076.2	-	-	-	-	75.2	1,001.0	1,076.2	-	
Purchase Metering and Metering Equipment - Various Sites	-	-	-	-	198.5	198.5	-	198.5	-	-	-	8.1	190.4	-	198.5	-	
2017 Projects																	
Install Automated Meter Reading - Happy Valley	-	-	78.6	(105.2)	1,891.6	1,786.4	-	1,970.2	-	-	183.8	248.0	1,376.9	-	1,808.7	(161.5)	
Purchase New Meter Calibration Test Console - Hydro Place	-	-	196.9	212.7	-	212.7	-	196.9	-	-	0.1	-	212.7	-	212.8	15.9	
2016 Projects																	
Install Automated Meter Reading - Labrador West	-	433.8	533.4	(3.2)	-	(3.2)	-	967.2	-	130.4	1,232.8	48.2	(51.4)	-	1,360.0	392.8	15
Total Metering Projects	**-**	**433.8**	**808.9**	**104.3**	**2,165.3**	**2,269.6**	**1,001.0**	**4,409.0**	**-**	**130.4**	**1,416.8**	**304.4**	**1,803.7**	**1,001.0**	**4,656.3**	**247.3**	

2018 Capital Expenditures By Category
($000)

Information Systems Projects	Capital Budget A 2015	A 2016	A 2017	B Carryover 2018	C Original 2018	D Revised 2018	E 2019 and Beyond	F (A+C+E) Total	Actual Expenditure and Forecast G 2015	G 2016	G 2017	H YTD 2018	I Forecast Jul-Dec 2018	J 2019 and Beyond	K (G+H+I+J) Total	K-F Project Variance	Notes
2018 Projects																	
Upgrade Software Applications - Hydro Place	-	-	-	-	114.7	114.7	-	114.7	-	-	-	50.6	64.1	-	114.7	-	
Refresh Security Software - Hydro Place	-	-	-	-	62.2	62.2	-	62.2	-	-	-	5.6	56.6	-	62.2	-	
Perform Minor Enhancements - Hydro Place	-	-	-	-	49.4	49.4	-	49.4	-	-	-	11.2	38.2	-	49.4	-	
Replace Personal Computers - Hydro Place	-	-	-	-	493.0	493.0	-	493.0	-	-	-	51.2	47.4	-	98.6	(394.4)	16
Upgrade Core IT Infrastructure - Hydro Place	-	-	-	-	352.4	352.4	-	352.4	-	-	-	25.8	405.1	-	430.9	78.5	
Replace Peripheral Infrastructure - Hydro Place	-	-	-	-	258.4	258.4	-	258.4	-	-	-	9.4	249.0	-	258.4	-	
Upgrade Energy Management System - Hydro Place	-	-	-	-	336.8	336.8	-	336.8	-	-	-	-	-	-	-	(336.8)	17
2016 Projects																	
Upgrade Microsoft Project - Hydro Place	-	683.7	953.4	20.1	957.3	977.4	-	2,594.4	-	656.9	960.0	-	977.5	-	2,594.4	-	
Cost Recoveries	-	(317.1)	(442.2)	(9.0)	(444.0)	(453.0)	-	(1,203.3)	-	(304.8)	(445.5)	-	(453.0)	-	(1,203.3)	-	
Total Information Systems Projects	**-**	**366.6**	**511.2**	**11.1**	**2,180.2**	**2,191.3**	**-**	**3,058.0**	**-**	**352.1**	**514.5**	**153.7**	**1,385.0**	**-**	**2,405.3**	**(652.7)**	

2018 Capital Expenditures By Category
($000)

Tools and Equipment	Capital Budget								Actual Expenditure and Forecast									
	A			B	C	D	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F	
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Replace Light Duty Mobile Equipment - Various Sites	-	-	-	-	429.0	429.0	-	429.0	-	-	-	104.5	324.5	-	429.0	-	
Replace Front End Loader Unit No. 9628	-	-	-	-	170.2	170.2	-	170.2	-	-	-	168.7	1.5	-	170.2	-	
Replace Off-Road Track Vehicles - Bishop's Falls and Bay d'Espoir	-	-	-	-	213.7	213.7	986.3	1,200.0	-	-	-	-	213.7	986.3	1,200.0	-	
Tools and Equipment Less than $50,000	-	-	-	-	497.7	497.7	-	497.7	-	-	-	30.4	467.3	-	497.7	-	
Total Tools and Equipment	**-**	**-**	**-**	**-**	**1,310.6**	**1,310.6**	**986.3**	**2,296.9**	**-**	**-**	**-**	**303.7**	**1,006.9**	**986.3**	**2,296.9**	**-**	

2018 Capital Expenditures By Category
($000)

Telecontrol Projects	Capital Budget								Actual Expenditure and Forecast							K-F	
	A			B	C	D	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)		
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Replace PBX Phone Systems - Various	-	-	-	-	91.7	91.7	1,150.6	1,242.3	-	-	-	49.3	42.4	1,150.6	1,242.3	-	
Replace MDR 6000 Microwave Radio - Various	-	-	-	-	64.0	64.0	1,137.0	1,201.0	-	-	-	38.8	25.2	1,137.0	1,201.0	-	
Replace Teleprotection - TL261	-	-	-	-	57.6	57.6	459.8	517.4	-	-	-	30.8	26.8	459.8	517.4	-	
Replace Network Communications Equipment - Various	-	-	-	-	199.5	199.5	-	199.5	-	-	-	76.0	123.5	-	199.5	-	
Upgrade Site Facilities - Various	-	-	-	-	49.0	49.0	-	49.0	-	-	-	1.2	47.8	-	49.0	-	
Replace Radomes - Various	-	-	-	-	360.3	360.3	-	360.3	-	-	-	7.6	352.7	-	360.3	-	
Replace RTUs - Various	-	-	-	-	118.3	118.3	-	118.3	-	-	-	47.9	70.4	-	118.3	-	
Replace Air Conditioners - Various	-	-	-	-	74.4	74.4	-	74.4	-	-	-	29.0	45.4	-	74.4	-	
Replace Battery Banks and Chargers - Various	-	-	-	-	382.1	382.1	555.8	937.9	-	-	-	81.9	300.2	555.8	937.9	-	
Purchase Tools and Equipment less than $50,000	-	-	-	-	46.0	46.0	-	46.0	-	-	-	4.1	41.9	-	46.0	-	
2017 Projects																	
Replace Battery Banks and Chargers - Various Sites (2017-2018)	-	-	379.3	(4.3)	566.2	561.9	-	945.5	-	-	217.6	247.0	314.9	-	779.5	(166.0)	18
Upgrade Telecontrol Facilities - Mary March Hill and Blue Grass Hill	-	-	91.2	(32.1)	665.9	633.8	-	757.1	-	-	123.3	72.1	561.7	-	757.1	-	
Total Telecontrol Projects	**-**	**-**	**470.5**	**(36.4)**	**2,675.0**	**2,638.6**	**3,303.2**	**6,448.7**	**-**	**-**	**340.9**	**685.7**	**1,952.9**	**3,303.2**	**6,282.7**	**(166.0)**	

2018 Capital Expenditures By Category
($000)

Transportation	Capital Budget A 2015	A 2016	A 2017	B Carryover 2018	C Original 2018	D Revised 2018	E 2019 and Beyond	F (A+C+E) Total	Actual Expenditure and Forecast G 2015	G 2016	G 2017	H YTD 2018	I Forecast Jul-Dec 2018	J 2019 and Beyond	K (G+H+I+J) Total	K-F Project Variance	Notes
2018 Projects																	
Replace Vehicles and Aerial Devices - Various Sites	-	-	-	-	1,667.2	1,667.2	753.7	2,420.9	-	-	-	166.4	1,500.8	753.7	2,420.9	-	
2017 Projects																	
Replace Vehicles and Aerial Devices - Various Sites	-	-	2,001.4	725.6	398.8	1,124.4	-	2,400.2	-	-	1,275.8	1,441.8	(317.4)	-	2,400.2	-	
Total Transportation	**-**	**-**	**2,001.4**	**725.6**	**2,066.0**	**2,791.6**	**753.7**	**4,821.1**	**-**	**-**	**1,275.8**	**1,608.2**	**1,183.4**	**753.7**	**4,821.1**	**-**	

Administrative	Capital Budget 2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	Actual Expenditure and Forecast 2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Remove Safety Hazards - Various	-	-	-	-	199.4	199.4	-	199.4	-	-	-	6.4	193.0	-	199.4	-	
Upgrade Exterior of Building - Hydro Place	-	-	-	-	260.2	260.2	405.7	665.9	-	-	-	31.0	229.2	405.7	665.9	-	
Replace Washroom Fixtures - Hydro Place	-	-	-	-	49.5	49.5	-	49.5	-	-	-	6.1	43.4	-	49.5	-	
Security Improvements - Hydro Place	-	-	-	-	45.5	45.5	-	45.5	-	-	-	2.3	43.2	-	45.5	-	
Purchase Office Equipment	-	-	-	-	90.0	90.0	150.8	240.8	-	-	-	-	90.0	150.8	240.8	-	
2016 Projects																	
Replace Air Conditioning Units 8 and 14 - Hydro Place	-	34.6	229.5	19.5	-	19.5	-	264.1	-	31.0	213.6	30.8	(11.3)	-	264.1	-	
Total Administrative	**-**	**34.6**	**229.5**	**19.5**	**644.6**	**664.1**	**556.5**	**1,465.2**	**-**	**31.0**	**213.6**	**76.5**	**587.6**	**556.5**	**1,465.2**	**-**	

2018 Capital Expenditures By Category
($000)

Allowance For Unforeseen	Capital Budget								Actual Expenditure and Forecast								
	A			B	C	D	E	F (A+C+E)	G			H	I	I	K (G+H+I+J)	K-F	
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Contingency Fund	-	-	-	-	1,000.0	1,000.0	-	1,000.0	-	-	-	-	1,000.0	-	1,000.0	-	19
Penstock 3 Refurbishment - Bay d'Espoir	-	-	-	-	-	-	-	-	-	-	-	4,219.8	-	-	4,219.8	4,219.8	20
Allowance for Unforeseen - Top Up P.U. 19 (2018)	-	-	-	-	1,000.0	1,000.0	-	1,000.0	-	-	-	-	1,000.0	-	1,000.0	-	19
Total Allowance For Unforeseen	**-**	**-**	**-**	**-**	**2,000.0**	**2,000.0**	**-**	**2,000.0**	**-**	**-**	**-**	**4,219.8**	**2,000.0**	**-**	**6,219.8**	**4,219.8**	

Supplemental Projects	Capital Budget								Actual Expenditure and Forecast								
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Provide Service to Western Reional Servce Baord's Waste Transfer Site - Hampden	-	-	-	-	748.4	748.4	-	748.4	-	-	-	208.9	539.5	-	748.4	-	
Provide Service to Western Reional Servce Baord's Waste Transfer Site - Hampden - CIAC	-	-	-	-	(748.4)	(748.4)	-	(748.4)	-	-	-	(748.4)	-	-	(748.4)	-	
Perform Voltage Conversion of the Distribution Feeder VA26 - Labrador City	-	-	-	-	719.4	719.4	-	719.4	-	-	-	60.1	659.3	-	719.4	-	
Perform Voltage Conversion of the Distribution Feeder VA26 - Labrador City - CIAC	-	-	-	-	(50.4)	(50.4)	-	(50.4)				-	(50.4)	-	(50.4)	-	
2017 Projects																	
Terminal Station Upgrades - Wabush	-	-	2,585.2	1,644.5	327.3	1,971.8	-	2,912.5	-	-	940.7	419.5	1,552.3	-	2,912.5	-	
Reliability Improvements - Holyrood	-	-	2,610.0	16.7	-	16.7	-	2,610.0	-	-	3,586.6	(36.5)	53.2	-	3,603.3	993.3	21
								-									
2016 Projects																	
Purchase of 12 MW Diesel Generation - Holyrood	-	4,700.0	-	418.9	-	418.9	-	4,700.0	-	3,784.0	497.1	621.8	-	-	4,902.9	202.9	
Total Supplemental Projects Approved by PUB	**-**	**4,700.0**	**5,195.2**	**2,080.1**	**996.3**	**3,076.4**	**-**	**10,891.5**	**-**	**3,784.0**	**5,024.4**	**525.3**	**2,754.0**	**-**	**12,087.6**	**1,196.2**	

Projects Less than $50,000	Capital Budget								Actual Expenditure and Forecast								
	2015	2016	2017	Carryover 2018	Original 2018	Revised 2018	2019 and Beyond	Total	2015	2016	2017	YTD 2018	Forecast Jul-Dec 2018	2019 and Beyond	Total	Project Variance	Notes
2018 Projects																	
Replace Alternator Bearing - Stephenville Gas Turbine	-	-	-	-	47.9	47.9	-	47.9	-	-	-	27.8	20.1	-	47.9	-	
Back-up Control Center Cooling Upgrade - Holyrood	-	-	-	-	49.0	49.0	-	49.0	-	-	-	-	49.0	-	49.0	-	
Stage 2 Emergency Diesel Generator Refurbishment - Holyrood	-	-	-	-	49.5	49.5	-	49.5	-	-	-	5.3	44.2	-	49.5	-	
Penstock 3 Laser Scanning - Bay d'Espoir	-	-	-	-	46.3	46.3	-	46.3	-	-	-	-	46.3	-	46.3	-	
Penstock 3 Press Transducer - Bay d'Espoir	-	-	-	-	29.5	29.5	-	29.5	-	-	-	-	29.5	-	29.5	-	
2017 Projects																	
Replace Tracks for V7601 Groomer - Bay d'Espoir	-	-	1.0	1.0	43.7	44.7	-	44.7	-	-	-	26.1	18.6	-	44.7	-	
Total Projects Less than $50,000	**-**	**-**	**1.0**	**1.0**	**265.9**	**266.9**	**-**	**266.9**	**-**	**-**	**-**	**59.1**	**207.8**	**-**	**266.9**	**-**	

Explanations are provided below for projects whose overall expenditures, on a total project basis, have a forecasted variance of more than $100,000 and 10% from the budgeted amount. Due to this being a mid-year report, variances are based on focused management and reforecasting efforts, and are subject to change throughout the year as the projects proceed. Actual variances at completion of each project will be discussed in the year-end Capital Expenditures Report when annual expenditures are final. All variance amounts are presented as ($000).

Hydraulic Generation Projects

1. Purchase Capital Spares – Hydraulic

Original Budget*: 487.4* ***Forecast to Completion:*** *687.4* ***Variance:*** *200.0*

This is a one-year project that commenced in 2017 and carried over to 2018 for the procurement of several capital spare components.

In 2017, Hydro experienced failures of generator bearing coolers in Hinds Lake, and determined that spare coolers were required in the event of additional failures in the 2017-2018 winter season. A spare set of coolers were ordered under this project and received in 2017. The forecasted variance in total project expenditure is attributed to the addition of the Hinds lake coolers to the project scope.

Thermal Generation Projects

2. Install Raw Water Line - Holyrood

Original Budget*: 1,252.6* ***Forecast to Completion****: 1,853.0* ***Variance****: 600.4*

The publicly tendered price for this project was higher than the estimate prepared at the budget phase. This is attributed to additional design requirements determined during detailed project planning and engineering, including: the requirement for a higher grade of piping than originally estimated; the requirement to bury the piping to a greater depth than originally estimated; the requirement to install an intake at the Quarry Brook Dam; and the requirement to incorporate a powerhouse utilidor[1] crossing into the design.

[1] The utilidor includes cables, piping, and a walkway that could not be relocated.

3. Upgrade Holyrood Access Road - Holyrood

***Original Budget**: 1,162.7* ***Forecast to Completion**: 825.7* ***Variance**: (337.0)*

This was a two-year project (2017-2018) that commenced in 2017 and was completed in 2017. Hydro tendered the construction work with optional pricing to complete all of the construction in the first year. The optional pricing was favorable and Hydro proceeded to complete the project in 2017. The variance in project expenditures is attributed to lower than estimated contract pricing as well as savings associated with completing the project in a single year.

4. Upgrade Underground Plant Drainage System - Holyrood

***Original Budget**: 923.1* ***Forecast to Completion**: 1,814.5* ***Variance:** 891.4*

This is a one-year project that commenced in 2017 and carried over to 2018. The project is substantially complete and in service. It was determined during construction that one section of piping planned to be replaced during a generating unit outage in 2017 could only be completed during a total plant outage. This portion of the project construction has been rescheduled to the next available total plant outage in 2018.

The forecasted variance in total project expenditures is attributed to the requirement to replace more piping that originally estimated (due to further deterioration of the piping from the time of the budget proposal), higher than expected contract tender prices, and the requirement for asbestos removal, which was not included in the original estimate.

Gas Turbine Generation Projects

5. Turbine Hot Gas Path Level 2 Inspection and Overhaul - Holyrood Gas Turbine

***Original Budget**: 11,146.5* ***Forecast to Completion**: 11,146.5* ***Variance**: 0*

This project was planned as a two year project (2018/2019) based on actual operating data at the time of the application and the forecast future operation of the unit. Originally anticipated with an execution date of spring 2019, use of the unit more than forecasted meant that it was necessary to advance the completion of the overhaul to September 2018. A letter notifying this was provided to the Board and the 2018 Capital Budget Application intervenors on July 26, 2018. The 2019 Capital Budget Application takes this change into account, with the removal of the 2019 forecast in the capital projects.

6. Gas Turbine Life Extension - Stephenville

***Original Budget**: 1,353.2* ***Forecast to Completion**: 872.0* ***Variance**: (481.2)*

This is a two-year project (2017-2018) that commenced in 2017. The forecast variance in total project expenditures is attributed to the removal of a portion of the project scope. As a result of the uncertainty around the longer term requirements of the Hardwoods and Stephenville gas turbines, Hydro continues to assess any proposed capital expenditures for these units. As a result of a comprehensive review of the project scope prior to project execution, Hydro removed from the scope the installation of closed circuit television cameras, and planned instrumentation upgrades were revised to include only those requiring immediate replacement, based on function testing and evaluation results. Project scope pertaining to the replacement of lube oil and fuel filters is being reviewed in 2018.

7. Gas Turbine Life Extension - Hardwoods

***Original Budget**: 956.7* ***Forecast to Completion**: 583.3* ***Variance**: (373.4)*

This is a two-year project (2017-2018) that commenced in 2017. The forecast variance in total project expenditures is attributed to the removal of a portion of the project scope. As a result of the uncertainty around the longer term requirements of the Hardwoods and Stephenville gas turbines, Hydro continues to assess any proposed capital expenditures for these units. As a result of a comprehensive review of the project scope prior to project execution, Hydro removed from the scope the installation of closed circuit television cameras, and planned instrumentation upgrades were revised to include only those requiring immediate replacement, based on function testing and evaluation results. Project scope pertaining to the replacement of lube oil and fuel filters is being reviewed in 2018.

Terminal Station Projects

8. Install Breaker Bypass Switch - Howley

Original Budget: *1,524.0* ***Forecast to Completion:*** *1,524.0* ***Variance:*** *0*

During a review to smooth the 5-year Capital Plan it was determined that an improvement in the least cost option would likely be to execute the Breaker Bypass Switch program when other terminal station work is planned for the same area. Since this option is being re-evaluated, Hydro concluded that the Howley project could be deferred to a future year at low risk, and that continued schedule optimization would better optimize the implementation timing. Hydro has therefore cancelled the Howley project and will apply for this and other individual bypass switches at a later date, as the opportunities arise. The 2019 Capital Budget Application takes this change into account, with the application including the revised forecast for 2019.

9. Upgrade Corner Brook Frequency Converter

Original Budget: *2,943.8* ***Forecast to Completion:*** *2,943.8* ***Variance:*** *0*

Although this project has not yet been re-forecasted, it is currently on hold while the Board addresses an application to sell the assets to Corner Brook Pulp and Paper. Depending on the results of the application, the project may proceed or be cancelled. A further update will be provided in the year-end Capital Expenditures and Carry-Over Report.

10. Upgrade Circuit Breakers - Various Sites

Original Budget: *61,460.5* ***Forecast to Completion:*** *61,460.5* ***Variance:*** *0*

Project change management is in progress to remove 10 Circuit Breakers from the scope of the work, and reduce the forecast from the original project estimate of approximately $61M to a new planned estimate of $51M. Asset management personnel determined that these 10 breakers can be deferred until 2021/2022. The 2019 Capital Budget Application takes this change into account, with the application including the revised forecast for 2019. The actual breakers that are being removed from the plan will be further detailed in the 2018 Capital

Expenditures and Carry-Over Report, and Hydro will apply to replace these breakers in a subsequent application to the Board in the 2021 Capital Budget Application.

11. Replace Protective Relays – Various Sites

Original Budget: *1,857.0* ***Forecast to Completion:*** *2,827.8* ***Variance:*** *970.8*

The forecast variance in total project expenditure is attributed to higher than estimated engineering, procurement and construction cost. During the design phase of the project, Hydro's design standard for protective relays was revised. The changes to the standard were made to address lessons learned from system events. The updated standard significantly impacted the overall design for these protection systems. This increased the engineering design effort on this project and resulted in increased procurement and construction costs due to the requirement for additional components to adhere to the new standard.

12. Install Breaker Failure Protection – Various Sites

Original Budget: *277.0* ***Forecast to Completion:*** *486.4* ***Variance:*** *209.4*

The forecast variance in total project expenditure is attributed to higher than estimated engineering, procurement and construction cost. During the design phase of the project, Hydro's design standard for breaker failure protection was revised. The changes to the standard were made to address lessons learned from system events. The updated standard significantly impacted the overall design for breaker failure protection. This increased the engineering design effort on this project and resulted in increased procurement and construction costs due to the requirement for additional components to adhere to the new standard.

13. Install Fire Protection in 230 kV Stations - Bay d'Espoir

Original Budget: *766.0* ***Forecast to Completion:*** *873.8* ***Variance:*** *107.8*

This project is to construct a new fire protection system to protect the Bay d'Espoir Terminal Station 2 Control Building. That building was modified in 2017 as part of the separate project to construct a transmission line from Bay d'Espoir to Western Avalon (TL 267). Modifications included a building extension and new ventilation equipment, which impacted the design of the fire protection system. The building modifications were completed in 2017 and the fire protection project is on track for construction in 2018. The forecasted variance in overall project expenditures is attributed to the fire protection system design changes to incorporate protection of the extension to the building.

Rural Generation Projects

14. Replace Programmable Logic Controllers - Various Sites

Original Budget: *958.0* ***Forecast to Completion:*** *1,204.7* ***Variance:*** *246.7*

This is a three-year project (2015-2017) that commenced in 2015 and carried over to 2018. The forecasted variance in total project expenditures is attributed to more engineering and construction effort required compared to the original estimates.

Metering Projects

15. Install Automated Meter Reading - Labrador West

Original Budget: *967.2* ***Forecast to Completion:*** *1,360.0* ***Variance:*** *392.8*

This is a two-year project (2016-2017) that commenced in 2016 and carried over into 2018. The forecast variance in total project expenditure is attributed to the requirement for additional terminal station equipment as well as higher than estimated unit pricing for the new automatic meter readers. An updated project cost estimate and updated assumptions for project benefits were used to re-evaluate the project. The updated cost-benefit analysis confirmed that the project remains the least cost alternative versus the status quo.

Information Systems Projects

16. Replace Personal Computers - Hydro Place

Original Budget: *493.0* ***Forecast to Completion:*** *98.6* ***Variance:*** *(394.4)*

In 2018, the personal computer replacement strategy was updated to extend the in-service life. Hydro has adopted a five to seven year computer life cycle and utilizes extended warranties and run-to-failure modes to ensure reliable operation. Therefore, personal computer replacements were reduced in 2018, and the forecast was made to reflect that change.

17. Upgrade Energy Management System - Hydro Place

Original Budget: *336.8* ***Forecast to Completion:*** *0.0* ***Variance:*** *(336.8)*

After discussion with the Energy Management System (EMS) product vendor, Hydro revised the frequency of software upgrades from every year to every two years. Therefore, the 2018 Upgrade Energy Management System project was cancelled. Hydro will apply to upgrade the EMS in the 2019 Capital Budget Application.

Telecontrol Projects

18. Replace Battery Banks and Chargers - Various Sites (2017-2018)

Original Budget: *945.5* ***Forecast to Completion:*** *779.5* ***Variance:*** *(166.0)*

This is a two-year project (2017-2018) that commenced in 2017. The forecasted variance in total project expenditures is attributed to lower than estimated construction and procurement costs.

Allowance for Unforeseen Items

19. Allowance for Unforeseen Items

Original Fund: *1,000.0* ***Revised Fund:*** *2,000.0*

The Allowance for Unforeseen Items budget was restored to $1,000,000 through the approval of a top-up application (P.U. 19(2018)) due to the execution of the Penstock 3 Refurbishment (see item 20).

20. Penstock 3 Refurbishment - Bay d'Espoir

Original Budget: *0.0* ***Forecast to Completion:*** *6,000.0* ***Variance:*** *6,000.0*

On May 9, 2018, an external consultant commenced a reduced scope inspection of the longitudinal weld seams on Penstock 3. This inspection identified cracks in the existing welding of the penstock. Hydro originally initiated this work under the Hydraulic In-Service Failures project; however, as the inspection continued, it was determined on May 15, 2018 that due to the significant number cracks in the welds, the scope of refurbishment required the use of the Allowance for Unforeseen Items Account. The project was completed on July 9, 2018, with the refurbishment of approximately 1,050 meters of weld.

Supplemental Projects

21. Reliability Improvements - Holyrood

Original Budget: *2,610.0* ***Forecast to Completion:*** *3,603.9* ***Variance:*** *993.3*

This is a one-year supplemental project approved in 2017 and carried over to 2018.

The variance in project expenditure is attributed to five new capital scope items identified during the discovery and execution phases of the project, as summarized in Table 1, Items 2 to 6.

Table 1: Reliability Improvements – Holyrood Thermal Generating Station

Item	Description	Cost ($000)	Scope of Work and Justification
1	Additional cost for original planned project scope items	313.6	During the discovery and execution phases of the original scope of work, additional cost were incurred as a result of the as-found condition being worse than expected for some components, with an over-run of the original scope estimate of $313,600.
2	Replacement of steam piping components	442.5	Replacement of steam piping components including large flanges with pipe spools, flange studs and bolts, and auxiliary valves was necessary to address identified steam leaks.

Item	Description	Cost ($000)	Scope of Work and Justification
3	Replacement of Unit 2 condenser cooling water outlet piping	300.0	Inspection of the Unit 2 condenser cooling water piping during the planned unit outage revealed that it was in similar deteriorated condition as Unit 1 condenser cooling water outlet piping. Replacement of Unit 1 condenser cooling water outlet piping was an approved scope item for this project. Replacement of Unit 2 condenser cooling water outlet piping was completed.
4	Replacement of flow elements	160.0	The original project scope including refurbishment of flow elements. Inspection during planned unit outages revealed that elements were at the end of useful life and required full replacement. The flow elements were replaced.
5	Replacement of safety valves for Unit 2 cold reheat, atomizing steam and low pressure / high pressure headers	146.0	The valves for Unit 2 cold reheat, atomizing steam and low pressure / high pressure headers were opening prematurely when in service. The valve service provider inspected the valves and determined that replacement was required. Safety valves for Unit 2 cold reheat, atomizing steam and low pressure / high pressure headers were replaced.
6	Replacement of Unit 1 and Unit 2 air heater water wash piping	60.0	Extensive corrosion of Unit 1 and Unit 2 air heater water wash piping was identified by boiler service provider during planned unit outages, and replacement was necessary. Unit 1 and Unit 2 air heater water wash piping was replaced.
Total		**1,422.1**	

1 **Terminal Station In-Service Failures**

2 ***Original Budget**: 1,000.0* ***Current Expenditures:** 2,027.0*

Table 2: Terminal Station In-Service Failures

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Holyrood B7L38 69kV Breaker Replacement	150.0	During a period of inclement weather breaker B7L38 was discovered to have had its line side bushings burned on all three phases due to Newfoundland Powers breaker at Seal Cove not clearing the fault due to fuses blown in the trip circuit for the breaker. The faulted breaker was replaced with the available spare from inventory.	The failed breaker B7L38 was replaced with an available spare breaker.
Cow Head B1 Potential Transformer Replacement	20.0	The existing B1 Potential Transformer was found to be in deteriorated condition and was at high risk of failure in 2018 if not replaced. An inspection completed in October 2017 identified accelerated deterioration placing the unit at a higher risk of failure.	Cow Head B1 Potential Transformer was replaced with a new unit which met current standards.
Hardwoods Transformer T4 Tap Changer Overhaul	30.0	The Hardwoods transformer T4 tap changer diverter switch was determined to be in poor condition. The Tapchanger Activity Signature Analysis Assessment value of 4 of both December 2017 samples indicates a high risk of failure and hence overhaul of this tap changer was required in 2018.	Hardwoods transformer T4 tap changer was overhauled.
Purchase Spare Disconnects for Stand-By Equipment Pool (per 2017 PUB	193.3	Spare disconnects are required for the standby equipment pool to allow quick reaction and restoration to unanticipated disconnect failure. Typical lead time for disconnects is 36 weeks.	6 spare disconnects (2 for each voltage class) were ordered for the stand-by equipment pool.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
submission)			
Bay d'Espoir B9B10-1 B-Phase Current Transformer	35.0	The 230 kV Current Transformer was found to be excessively heating at primary connection terminals due to galvanic corrosion on the copper-aluminum connection. As a result of the reliability risk to the system, immediate replacement was required.	The failed Current Transformer on B9B10-1 B-Phase was replaced.
Purchase Spare Station Service Voltage Transformer for Oxen Pond Terminal Station	22.0	Three new Station Service Voltage Transformers are being installed in Oxen Pond Terminal Station for a second station service supply and a spare Station Service Voltage Transformer is required as we do not currently have a spare available for this equipment.	A spare Station Service Voltage Transformer was ordered for the stand by equipment pool.
Purchase Spare Breakers for Stand by Equipment Pool (per 2017 PUB submission)	446.2	Spare breakers are required for the standby equipment pool to allow quick reaction and restoration to unanticipated breaker failure. Typical lead time for breakers is 20-24 weeks.	3 spare breakers (1 for each voltage class) were ordered for the stand-by equipment pool.
Stony Brook B3T2-1 Disconnect Replacement	65.0	A 138 kV disconnect at Stony Brook has damaged hinge side parts, identified as hot spots. The disconnect requires immediate replacement and replacement parts are not readily available.	Disconnect B3T2-1 is scheduled for replacement.
Wabush 46-38 B Phase Current Transformer Replacement	35.0	During an inspection, 46-38 Current Transformer was found to have an oil leak on the top head unit. The oil level is indicating low. Immediate replacement is required to avoid an in service failure, possible customer	Current Transformer 46-38 is scheduled for replacement.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
		outage and/or collateral damage to other equipment.	
Buchans TL205 B-Phase Current/Voltage Transformer	20.0	230kV Combination Current/Voltage Transformers on TL 205 B-Phase developed high and low fluctuations in secondary voltages noticed by Energy Control Center operators followed by a protection failure alarm. TL205 was removed from service and crews dispatched to site. Immediate replacement was required to restore TL205 to service.	TL205 B-Phase Current/Voltage Transformer was replaced.
St. Anthony Airport Terminal Station C2 Capacitor Bank 59 Relay-Replacement	17.0	While performing Station Protection preventive maintenance on March 28, 2018, the 59N relay was found to be inoperative. Immediate replacement of this relay was required to return Capacitor Bank 2 to service.	Relay 59N was replaced.
Bear Cove Terminal Station Battery Bank Replacement	30.0	A 125 V DC battery bank at the Bear Cove Terminal Station failed a scheduled discharge test. A temporary battery bank was installed at the Bear Cove Terminal Station until a replacement battery bank is installed.	Replace the 125VDC Battery Bank at the Bear Cove Terminal Station.
Plum Point Terminal Station Neutral Overcurrent Relay Replacement	7.0	During inclement weather, protective relaying at the Plum Point Terminal Station locked out transformer T1 in response to a fault on Line 1. Analysis of the event determined that the neutral overcurrent relay on transformer T1 had tripped for a feeder fault due to a failure of the induction disc to reset. Immediate replacement was required.	Neutral overcurrent relay at the Plum Point Terminal Station was replaced.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Churchill Falls Replacement of 2 Current Transformers and 3 Current/Potential Transformer Combination Units	650.8	The 230 kV Churchill Falls station assets associated with the 230 kV lines to Labrador West were acquired into Hydro through a lease agreement on July 1, 2017. When acquired, the assets 230-22 A-Phase Current/Potential Transformer, 230-23 A-Phase Current/Potential Transformer, 230-21 A-Phase Current/Potential Transformer, 230-21 B-Phase Current Transformer and 230-21 C-Phase Current Transformer had been identified as leaking and would require replacement. Due to the condition of the instrument transformers and the lead time on the units bringing the delivery into 2018, it was decided to complete this work under the 2018 In-Service Failure Project. All five units had oil leaks identified and the oil forms a part of the insulation system of the instrument transformers. If not replaced, the instrument transformer can fail in service resulting in possible outages to Labrador West and IOCC. Also a failure could result in other equipment damage or harm to employees due to flying debris.	Replacement of 2 Current Transformers and 3 Current/Potential Transformer Combination Units is scheduled.
Wabush Terminal Station SS2 Station Service Transformer	306.0	Station Service Transformer SS2 in Wabush Terminal Station failed due to an internal fault. The fault resulted in damage that open-circuited phases of the winding. This station Service transformer requires replacement in order to restore station service transformer redundancy and also provide a grounding source for Bus 15 and Bus 16. In Wabush Terminal Station, with one station service transformer out of service and the grounding source removed from Bus 15 and	Replacement of Wabush Terminal Station Service Transformer SS2 is scheduled.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
		Bus 16, the tie breaker must be closed resulting in only one Synchronous Condenser being operational. This in turn causes a reduction in the load that can be supplied to Labrador West and possible load restrictions to IOCC.	

Thermal Generation In-Service Failures

Original Budget: *1,250.0* ***Current Expenditures:*** *1,050.0*

Table 3: Thermal Generation In-Service Failures

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Refurbish 4160 VFD Fan and Boiler Feed Pump Motors at Holyrood Thermal Generating Station	70.0	The Unit 1 West Forced Draft (FD) Fan motor and the Unit 2 West Boiler Feed Pump (BFP) motor both failed while in service, The FD fan motor exhibited high winding temperatures that were in alarm. The unit was removed from service and replaced with the capital spare motor as this was the most cost effective and expedient approach. Unit 1 requires both fans to be in service for operation, and the unit was unavailable while the motor was being replaced. The BFP motor had to be removed from service when a motor bearing failed. The most cost effective and expedient alternative was to replace the motor with the capital spare motor, Unit 2 is only capable of approximately 50% load when one BFP is out of service. Until the two motors are refurbished, there are no capital spares available should an additional failure of one of the other motors occur. Rather than purchase additional spare motors, which would be expensive and take many months, it is proposed to refurbish the motors and return them to inventory.	Refurbish A160 V FD Fan and Boiler Feed Pump motors that were removed from service due to failure, and were replaced by capital spare motors. The refurbished motors are to be returned to inventory as capital spares to maintain critical spare inventory.
Boiler Defined Work at Holyrood Thermal	571.0	Observation ports are essentially small windows in the boiler casing that allow the operators to view the fires in the furnace. They consist of special glass, metal frames	1. Replace observation ports that have deteriorated to the point where they are at risk of

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Generating Station		and refractory seals. Pressurized air is supplied to keep them clean and cool. Over many years the refractory deteriorates to the point where the hot gas in the boiler, which is at a higher pressure than the air outside, can find a way through potentially to the outside causing a boiler gas leak and forced outage. It is necessary to proactively replace ports that are showing refractory damage and are at an elevated risk of sudden failure. There are five of these areas in the Unit 1 and Unit 2 boilers and one has been identified for refractory replacement in 2018. Each unit has steam coil air heaters to preheat the combustion air prior to the air entering the main air heaters. On Unit 3 they consist of eight loops of finned steam tubes that span across the air duct, with two problems identified on Unit 3. At least two of the four coils on the west side are leaking steam and had to be isolated in the fall of 2017. Failures of additional coils are reasonably expected. All of the coils are in poor condition with damaged and fouled fins, which affects fan performance by increasing the pressure drop across them.	failing during operation and causing a forced outage; two ports in each of Unit 1 and Unit 2 2. Replace refractory in Unit 2 header vestibule that is at risk of failure during operation 3. Replace failed steam coil air heaters
Replace Field Control Processors in Holyrood Thermal Generating Station’s Distributed	35.0	Hydro received a Schneider Electric Customer Advisory, “2018001abi” detailing a manufacturing defect in their Field Control Processors (FCPs). Although Holyrood's FCPs have, to-date, not shown symptoms of an impending failure, as outlined in the advisory there is an incipient failure that needs to be corrected before entering into the 2018-	Replace nine Schneider Electric FCP270 Field Control Processors with nine factory-updated FCPs. One stocked spare FCP will also be replaced.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Control System		2019 winter season to maintain reliability of this critical system.	
Remove and Refurbish Unit 3 East Cooling Water Pump Motor at Holyrood Generating Station	65.0	Cooling Water (CW) pump motors are large, 4160V vertical motors used in the cooling water and condenser cycle. There are two CW pumps per unit and both are required to make full load on a unit. The drive-end bearing was found to be noticeably noisy during the 2017/2018 winter operating season. In addition, the motor was running hotter than normal and hotter that the U3 CW pump West motor. These observed conditions indicated that failure was imminent and that intervention was required before returning the unit to service for the winter season.	Removal and refurbishment to be completed with a combination of Hydro plant and motor contractor personnel .
Upgrade and Reinstate 4” pump out line at Holyrood Marine Terminal	150.0	In late Fall of 2017 the 4" pump out line at the Marine Terminal was found to be damaged. Investigation revealed that several pipe supports on this line had failed, causing the damage to the pipe.	1. Upgrade failed 4" pump out line supports and piping 2. Reinstate 4" pump out line and return for service
Mark V Assessment at Holyrood Thermal Generating Station	85.0	Due to a failure of the turbine reheat valve controls, the plant was not able to perform on-line testing of the reheat valves since February 21, 2018. These valves are critical for safe shutdown and control of the turbine and the OEM recommends regular testing while on-line to verify they are working properly. A Mark V Technician from GE was brought to site and determined that two solenoids had failed on the reheat valves. Because of these failed solenoids, other components (fuses, circuit boards and ribbon cables) also failed. The failed components were replaced and the valves tested	1. GE Mark V Technician assessed condition of the Unit 1 Turbine Control System and replaced failed components to restore proper function. 2. GE Mark V Technician assessed the seized reheat valve on the Unit 2 turbine and replaced the failed components in the control system to restore proper function of the valves.

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
		successfully. The same valve tests were completed on Unit 2. During the test, one of the reheat valves failed. The servos were removed from both reheat valves and replaced. The unit was returned to service and the valves were successfully tested.	
Unit 1&2 VFD's at Holyrood Thermal Generating Station	74.0	On March 5, 2018, the Unit 2 west VFD B4 power cell was replaced by plant electricians because the cell had failed. The drive bypassed the failed cell and the unit did not trip. On March 19, 2018, the west VFD tripped on Unit 1. This caused the boiler to trip on loss of airflow and led to a unit trip and forced outage. Plant electricians investigated and determined that there was a control power fault on one of the power cells. They replaced the B2 power cell and two blown cell control fuses. Unit 2 was put back on line and tested at different loads before releasing it for service. The replacement power cells and fuses were drawn from the plant warehouse inventory. On March 26, the east VFD tripped on Unit 1. This caused the boiler to trip on loss of airflow and lead to a unit forced outage. Plant electricians worked with Siemens and determined that the failure was very similar to the failure that occurred on March 19, but on the other fan. The replacement power cell and fuse were drawn from the plant warehouse inventory.	1. Replace failed components on Unit 2 West Fan Variable Frequency Drive 2. Replace failed components on Unit 1 West Fan Variable Frequency Drive 3. Replace failed components on Unit 1 East Fan Variable Frequency Drive

1 **Hydraulic Generation In-Service Failures**

2 ***Original Budget:*** *1,250.0* ***Current Expenditures:*** *142.0*

Table 4: Hydraulic Generation In-Service Failures

Project Title and Location	Expenditure ($000)	Failure Identified	Project Scope
Bear Brook Culvert Repair	35.0	The road at the Bear Brook crossing along the Bay d'Espoir road near the Generating Station has deteriorated and is in an unacceptable condition to travel over. There are five 1200mm culverts at this road crossing. Material between these culverts has eroded away and no longer adequately supports the surface of the road.	The refurbishment of the culverts and road will including: placement of a berm to redirect flow into the 2 or 3 culverts; removal of frozen material between the top of the culverts and the road surface; placement and compaction of bedding material, minus material, road surface, large blast rock, etc. for each of the culverts.
Sump Pump for Unit #1 Bay d'Espoir Replacement	33.0	Sump Pump for Unit 1 in Bay d'Espoir is unable to meet demand of inflow into the sumps. If the inflow increases and the pump allows water to rise quickly there is a risk of flooding the powerhouse. The sump system is comprised of three pumps with Pump 1 having a longer in-service history than the others and is required to ensure the sump levels can be maintained to avoid unforeseen issues such as powerhouse flooding or excessive discharge to the tailrace	Procure and install a replacement pump for Sump 1.
Replace AC Unit in Cat Arm Control Room	74.0	The current air conditioning unit has failed due to the loss of refrigerant. R22 refrigerant is being phased out nationally due to the environmental impacts of this refrigerant. In 2020 this gas will no longer be imported or produced.	Purchase and install control room /shielded room air conditioner at Cat Arm Generating station.

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	2014	2013
Total Capital Assets	1,613,191	1,463,070
Deduct Items Excluded from Rate Base		
Work in Process	(128,002)	(13,822)
Asset Retirement Obligations (net of amortization)	(16,801)	(16,715)
Net Capital Assets	1,468,388	1,432,533
Net Capital Assets, Previous Year	1,432,533	1,387,986
Unadjusted Average Capital Assets	1,450,461	1,410,259
Deduct		
Average Net Capital Assets Excluded from Rate Base *	(9,773)	(8,544)
Average Capital Assets	1,440,688	1,401,716
Cash Working Capital Allowance - Return 8	8,331	5,875
Fuel Inventory - Return 10	60,041	48,949
Supplies Inventory - Return 10	26,424	25,763
Average Deferred Charges - Return 11*	85,498	64,627
Average Rate Base at Year-End - Return 12	**1,620,982**	**1,546,930**

* Updated to reflect the Board's approval of the Prudence Compliance Application in P.U. 49 (2016) resulting in a decrease in assets excluded from rate base from $15.2M to $9.8M and an increase of average deferred to reflect Board Order P.U. 49 (2016), inclusion in rate base of the Lab City Terminal Stations and Black Tickle Fire Restoration. The deferred charges were updated. As per Board Order P.U. 13 (2016) and P.U 49 (2016), the average assets excluded from Rate Base have been updated to reflect the charges from $64.6M to $85.5M.