Volume II

1. Hydraulic Generation Refurbishment and Modernization (2020–2021)

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2020 Capital Budget Application
Hydraulic Generation Refurbishment and Modernization (2020–2021)

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A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") aims to replace or refurbish failing or failed hydraulic generation assets to ensure the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

Starting in 2017 and continuing in 2019 with the 2020 Capital Budget Application ("CBA"), Hydro has consolidated much of its hydraulic generation capital work into one 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 ("Asset Management Overview") included with the2020 CBA at Volume II, Tab 1). In the 2020 CBA, Hydro proposes the following program-based activities under the Hydraulic Generation Refurbishment and Modernization Project:

Hydraulic Generating Units Program

1) Turbine and Generator Six-Year Overhauls;
2) Refurbish Generator Rotor and Stator; and
3) Replace/Improve Unit Metering, Monitoring, Protection, and Control Assets Including:
    - Install Partial Discharge Continuous Monitors;
    - Replace Control Cables; and
    - Replace Turbine-Generator Control and Vibration Monitoring Systems.

Hydraulic Structures Program

1) Control Structure Refurbishments; and
2) Penstock Level II Condition Assessment.

Reservoirs Program

1) Upgrade Public Safety Around Dams; and
2) Install Emergency Detection Response System.

Site Buildings and Services Program

1) Refurbish Access Road; and
2) Upgrade Bear Brook Crossing.

Common Auxiliary Equipment Program

1) Replace Sump Pump;
2) Replace Diesel Genset; and
3) Refurbish Sump Level System.

Nine activities are scheduled for a one year execution period and seven activities are scheduled for two year execution periods. The total project estimate for all activities in the Hydraulic Generation Refurbishment and Modernization Project (2020-2021) is $16,830,000.[1]

[1] $6,580,200 in 2020 and $10,249,800 in 2021.

Contents

1.0 Hydraulic Generation Refurbishment and Modernization Program

Hydro has 10 hydraulic generating stations. There are over 3,000 assets involved in the functioning of these stations. To aid asset management, the assets have been categorized based on the asset hierarchy. This grouping of the assets then makes up the individual programs within this proposal. The assets have been grouped into five programs as described in Section 2.

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.

2.0 2020-2021 Hydraulic Generation Refurbishment and Modernization Projects

Along with the 2020 CBA, Hydro's Asset management Overview outlines Hydro's asset management programs as they relate to Hydraulic Generation equipment. The assets designated for replacement, refurbishment, or modernization herein have been selected by Hydro's Asset Management staff to align with Hydro's commitment to the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner. The philosophies for assessment and selection of these projects are found in Appendix B and C of the Asset Management Overview. With this combined approach the Hydraulic Generation infrastructure has been divided into five programs. Asset management philosophies relating to each program are detailed in section 4 of the Asset Management Overview. The programs, with reference to sections within this proposal report, include:

- Hydraulic Generating Units (Section 2.1);
- Hydraulic Structures (Section 2.2);
- Reservoirs (Section 2.3);
- Site Buildings and Services (Section 2.4); and
- Common Auxiliary Equipment (Section 2.5).

2.1 Hydraulic Generating Units Program

The following equipment upgrades and/or refurbishment for hydraulic generating units are proposed for 2020/2021:

- Turbine and Generator Six-Year Overhauls;
- Refurbish Generator Stator; and
- Replace/Improve Unit Metering, Monitoring, Protection, and Control Assets including:
  - Replace Turbine-Generator Control and Vibration Monitoring Systems.
  - Replace Control Cables; and
  - Install Partial Discharge Continuous Monitors.

2.1.1 Turbine and Generator Six-Year Overhauls

Description of Equipment

The turbine and generator are the two major components that comprise a hydraulic generating unit. Water is used to rotate the turbine, which is connected to the generator to convert the mechanical energy into electricity. Further information on the equipment is contained in Appendix A to the Asset Management Overview.

Cat Arm Unit 2 is a 67 MW Pelton Hydraulic Generating Unit that was placed on-line in February 1985. The Pelton Hydraulic Generating Unit Runner ("Pelton Runner"), shown in Figure1, extracts energy from the impulse of moving water from needle valves in the distributor of the unit.

Figure 1: Pelton Runner (Spare) – Cat Arm

A preventive maintenance ("PM") 9, Six-Year Overhaul, is performed on the units with more detailed inspections than those in a PM6 Annual Inspection. The PM9 inspections incorporate the PM6 items with additional recommendations from the Original Equipment Manufacturer ("OEM") to ensure the long-term reliability of the unit. Inspection of all major components (testing and/or repairs as may be required) on a six-year frequency will help avoid forced outages, forced deratings, and unplanned maintenance outages. For further information on preventive maintenance timing, refer to Appendix C in the Asset Management Overview.

Existing State

Cat Arm Unit 2 is planned to undergo PM9 overhauls in 2020. The unit is currently in an operational condition and available for service except during maintenance or forced outages. In comparison to annual PM6 maintenance inspections, an overhaul includes activities that determine the possibility of failure between overhauls, and activities to refurbish the condition of the unit so that it will continue to operate reliably.

A list of historical major works or upgrades is listed in Table 1 for Cat Arm Unit 2.

Table 1: Major Work and Upgrades – Cat Arm Unit 2

Year	Major Work/Upgrade
2018	Upgrade to spherical valve controls on Unit 2
2009	Installed New Generator Oil Level System Unit 2
2008	Spherical Valve Duplex Strainer Replaced
2008	Spherical Valve Maintenance Seal Refurbished on Unit 2
2005	Unit 2 Governor Controls Replaced
2002	Replace Unit #1 Exciter – Unit 2
1999	Upgrades to Spherical Valve Seals
1999	Control Piping on Spherical Valve #2

Justification

This work is required to maintain reliable operation of the Cat Arm Unit 2 turbine and generator.

Project Description

The project will be executed in 2020, with estimated costs of $326,500. Table 2 contains the project estimate for the Cat Arm overhaul. This project involves the partial dismantling of Cat Arm Unit 2 turbine/generator unit to inspect, test, clean, refurbish, and replace defective components. This work includes the normal PM9 testing activities related to but not limited to:

- Mechanical:
    - generator brakes;
    - generator thrust and guide bearing;
    - surface air coolers;
    - rotor;
    - governor oil pumps;
    - distributor valve;
    - sump and accumulator;
    - turbine guide bearing;
    - spiral case door;
    - servomotors;

- bottom Ring; and
- head cover.

- Electrical:
    - exciter field breaker;
    - exciter components;
    - rotor;
    - stator;
    - slip ring and brushes;
    - generator;
    - high pressure pump;
    - permanent magnetic generator;
    - winding slot wedges;
    - hypot test;
    - air gap readings;
    - main leads;
    - neutral leads;
    - oil pump unloader;
    - air charging solenoid;
    - governor oil pump;
    - brake solenoid;
    - pressure switches;
    - oil pressure system;
    - speed signal generator;
    - neutral grounding cubical;
    - ground and surge protection cubicle;

- potential transformer cubical;
- unit isolating disconnect;
- rectifying transformer;
- shear pin circuit;
- unit breaker;
- annunciator alarms;
- temperature meters;
- relays;
- chart recorders;
- turbine and generator panels;
- shaft seal flowmeter; and
- vibration pickups.

Aside from the testing activities noted above, this overhaul/PM inspection involves cleaning and inspection of the rotor and stator assembly, electrical testing on rotor/stator assembly, calibration and testing of turbine and generator protection devices, verification of bearing and seal clearances, and a thorough inspection of turbine, draft tube, and penstock.

Budgets

Table 2 has the budget estimate for the Cat Arm Unit 2 Turbine and Generator Six-Year Overhaul.

Table 2: Cat Arm Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	23.0	0.0	0.0	**23.0**
Labour	236.0	0.0	0.0	**236.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	27.0	0.0	0.0	**27.0**
Interest and Escalation	15.0	0.0	0.0	**15.0**
Contingency	25.5	0.0	0.0	**25.5**
Total	**326.5**	**0.0**	**0.0**	**326.5**

Project Schedule

The schedule for Cat Arm Unit 2 requires a three week outage for the unit overhaul. The anticipated project schedule is shown in Table 3.

Table 3: Cat Arm Project Schedule

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules	January 2020	June 2020
Construction: Perform PM9 on Cat Arm Unit 2.	July 2020	August 2020
Commissioning: Run up the unit to confirm operation and release to operations.	August 2020	August 2020
Closeout: Close work order, complete all documentation and complete lessons learned	September 2020	September 2020

2.1.2 Refurbish Generator Stator

Description of Equipment

Unit 5 Generator Stator

Bay d'Espoir Unit 5 is a 75 MW hydraulic generating unit which consists of a generator and turbine. The generator portion of the unit is made up of two major components, the stator and rotor, which work together to generate electricity. The stator is static/stationary component of the generator while the rotor is the rotational component. The rotor's outer surface is covered with electromagnets. The stator's inner surface, or cylinder wall, is made up of copper windings. Refer to Figures 2 and 3.

Figure 2: Stator Windings - Top View

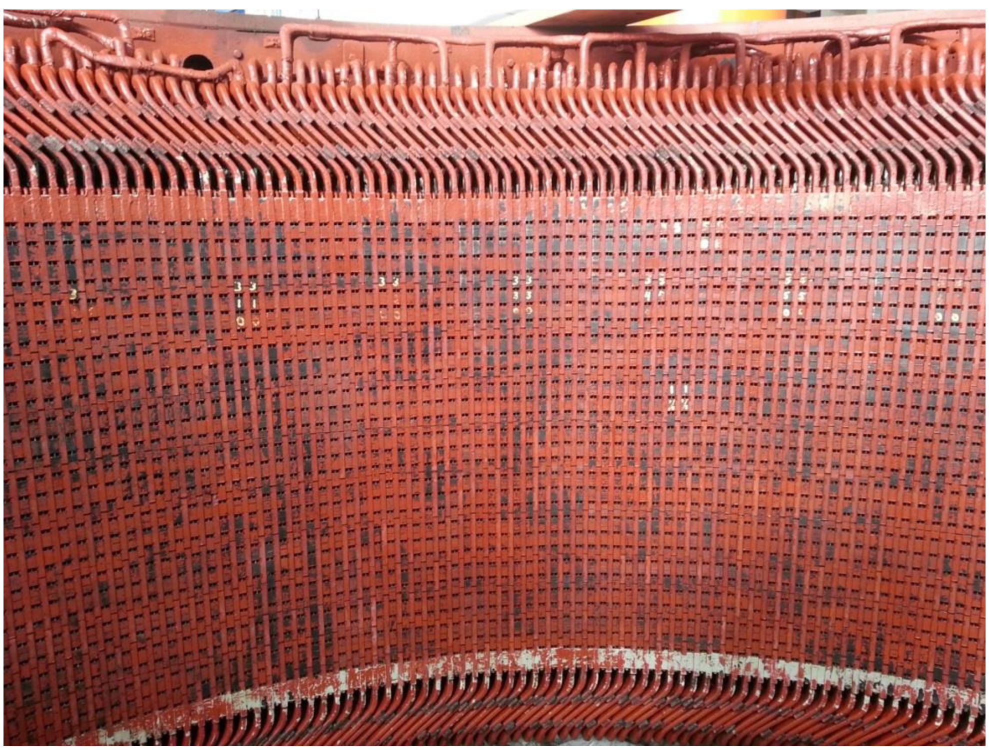

Figure 3: Stator Windings Showing Winding Strands

Air Gap Monitoring

There is no air gap monitoring system installed on Bay d'Espoir Unit 5, which, if present, would measure the air gap between the rotor and the stator. A change in the air gap can be influenced by operating conditions such as shaft oscillation, vibration, magnetic, and hydraulic forces.

Partial Discharge Analysis

The Unit 5 Stator Partial Discharge Analysis ("PDA") system is used collect partial discharge data to determine the rate and level of degradation of stator insulation.

For further information on the equipment, refer to Appendix A in the Asset Management Overview.

Existing State

Unit 5 Generator Stator

Regular maintenance is performed on the unit annually (PM6 – Minor) as well as every six years (PM9 – major). The unit PM9 consists of an overhaul to inspect, clean, and perform a more intrusive testing on the generator.

A direct current ("DC") high potential test ensures that the winding insulation has a minimum level of electrical strength to survive electrical stresses in normal service; the High Potential ("HiPot") step voltage controlled tests are in 3 kV steps for 3 minutes up to 27 kV (or 30 kVDC), and for the last step at 27 kV, the duration is 10 minutes before ending the test. The most recent HiPot test conducted in March 2018 indicated that the stator windings could not withstand a complete test. Bay d'Espoir Unit 5 stator windings to ground started to show weakness from 15 kVDC to 27 kVDC, so therefore this test was stopped.

PDA tests determine the thermal degradation of stator insulation. In March 2019, Bay d'Espoir Unit 5 stator windings have shown Qm values[2] around the 90th percentile (508 mV) of 13.8 kV air cooled generator. Qm values above the 90th percentile indicates an increased likelihood of reaching unreliable operating limits based on the Institute of Electrical and Electronics Engineers ("IEEE") objective methods to interpret Partial Discharge Data on rotating machine stator windings.

[2] Qm is the magnitude of Partial Discharge.

This testing shows Bay d'Espoir Unit 5 stator winding insulation cannot stay in service for the next six years without a rewind. If the insulation degradation continues beyond this critical condition, there is a heighted likelihood of failure, which would halt unit production. A stator failure would result in the unit being unavailable for up to at least 24 months to complete repairs.

Air Gap Monitoring

Bay d'Espoir Unit 5 is not equipped with an air gap monitoring system; rather, it is manually collected during unit annual maintenance. As such, there is no means to determine when the minimum operating air gap is reached during operation. Online monitoring of the air gap between the rotor and stator would provide significant and timely information about its physical condition as it changes over time and with different operating conditions.

Partial Discharge Analysis

An existing PDA coupler termination box installed on the generator allows Hydro maintenance staff to collect periodic PDA data from the stator; this set-up requires staff to physically set up the portable test equipment connected to a laptop computer near the generator test ports and collect PDA data through terminal box. This setup can collect one data sample at various voltage ranges at a time and does not allow continuous online trending to monitor equipment health. Use of the current equipment is also labour intensive. In addition, the equipment required to be connected to the PDA couplers is no longer functional and is expensive to replace.

Justification

This project is required to maintain the reliability of Hydro's hydraulic generating Unit 5 stator by improving data availability for air gap and PDA unit condition assessments. It can verify that the unit is operating within limits set by the manufacturers, and by trending the data Hydro can initiate proactive maintenance to deal with incipient failures. Installing the PDA and air gap equipment during the refurbishment of the stator eliminates the need for another unit outage to install that equipment.

Project Description

The project will be executed in 2020/2021, with estimated costs of $5,630,000. Table 3 contains the budget breakdown of the Refurbish Generator Stator project.

This project involves:

- Replace the stator windings, which involve the removal of the existing 360 individual braided strands that makes up the Roebel windings and supply, installation, testing, and commissioning of new stator assembly.
- Procure and install air gap monitoring system, monitored from the Bay d'Espoir control room as installed on Units 1-4.
- Procure and install continuous Partial Discharge Analysis monitoring system compatible with existing hardware. This includes:
  - Install a GuardII module;
  - Install USB and Ethernet ports, with Modbus (TCP/IP) protocol;
  - Install a 12 Partial Discharge input module for continuous on-line monitoring;
  - Re-configure the partial discharge pulse data collected through the capacitors for analysis by the GuardII software; and
  - Install a monitoring computer and PI historian for data collection.

Budgets

Table 4 has the budget estimated for the Refurbish Generator Stator project.

Table 4: Refurbish Generator Stator Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	135.0	0.0	**135.0**
Labour	130.4	746.2	0.0	**876.6**
Consultant	22.6	22.6	0.0	**45.1**
Contract Work	1025.0	2621.0	0.0	**3646.0**
Other Direct Costs	8.4	14.5	0.0	**23.0**
Interest and Escalation	71.8	409.4	0.0	**481.2**
Contingency	110.6	312.6	0.0	**423.1**
Total	**1,368.8**	**4,261.2**	**0.0**	**5,630.0**

Project Schedule

The schedule for Unit 5 requires a four month outage to be completed. The anticipated project schedule is shown in Table 5.

Table 5: Unit 5 Project Schedule

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules	January 2020	March 2020
Procurement: Develop tender for consultants and materials required.	April 2020	November 2020
Construction: Rewind unit, install air gap monitor and partial discharge system.	May 2021	August 2021
Commissioning: Run up the unit to confirm operation and release to operations.	September 2021	October 2021
Closeout: Close work order, complete all documentation and complete lessons learned	October 2021	November 2021

2.1.3 Replace/Improve Unit Metering, Monitoring, Protection and Control Assets

Replace Turbine-Generator Control and Vibration Monitoring Equipment

Description of Equipment

Turbine-Generator Control

The Paradise River Turbine-Generator Control System was purchased and commissioned in 1998. The system uses a GE Fanuc Model 90-30 programmable logic controller (“PLC”). The PLC uses various analog and discrete modules for unit control and monitoring. It is connected via Ethernet to a computer workstation running iFIX supervisory control and data acquisition (“SCADA”) software. The iFIX software is used for operator interface, control, and monitoring of the unit. This system controls the hydraulic generating unit through start-up, synchronization, motoring or generating mode, loading, normal operation, unloading and shutdown.

Vibration Monitoring System

The Paradise River Vibration Monitoring System was installed in 1989 and uses an IRD 5806 vibration monitor with reverse mounted Eddy Current probes to give an overall vibration indication of the turbine and generator. The system alarms and trip are hardwired to the Turbine-Generator Control System to provide unit protection in the event of high vibration levels.

For further information on the equipment, refer to Appendix A in the Asset Management Overview.

Existing State

Turbine Generator Control

The Paradise River GE Fanuc 90-30 Series PLC platform is over 30 years old and has been obsolete since January 1, 2018. There are some spares available but OEM parts are no longer available, therefore maintaining the system may not be possible. The SCADA computer is eight years old and is running Windows XP. Microsoft stopped support for Windows XP on April 8, 2014. There have been two forced outages of the generating unit due to control system failures. The first occurred August 7, 2017 as a result of the control system internal power supply failure. The second occurred June 20, 2018 as a result of a communication card failure.

Vibration Monitoring System

The Paradise River IRD 5806 Vibration Monitoring System is over 40 years old and has been obsolete since 1990. Although there are some spares available, maintaining the monitoring system may not be possible because the OEM has stopped supplying parts and service.

Justification

Replacements of the condition monitoring equipment listed in this project are required in order to maintain the ability to investigate issues and to identify developing problems with the generating units. Failure of the modules would result in loss of monitoring capability with resulting increase in the risk of generation equipment failure due to undetected problems.

Replace Control Cables

Description of Equipment

Control cables are used for carrying signals for protection and control purposes. Bay d'Espoir has older control cables that have insulation manufactured with an oil-based compound. For further information on the equipment, refer to Appendix A in the Asset Management Overview.

Existing State

The Bay d'Espoir control cables have been in service since 1967 and are approaching the end of their useful life. Oily residue has been found to leak from the cables into the junction boxes and onto cable connections. This is an indication of the break-down of the insulation. Also, mitigation work on leaking cables has revealed that associated junction boxes will need to be replaced.

As leaking continues, the cables will dry out and the insulation will fail. Such a failure may result in control equipment malfunction resulting in a forced outage of the generator.

Justification

Replacement of control cables listed in this project is required to maintain reliable operation of the generating units. This is the third year of a five-year program to replace all the control cables in Bay d'Espoir.

Install Partial Discharge Continuous Monitors

Description of Equipment

Partial discharges ("PD") are small electrical current sparks that occur in the high voltage stator windings insulation whenever there are small air gaps or voids in or on the surface of the insulation, which leads to deterioration of the winding over time.

The PDA systems that are presently installed at the Hinds Lake, Cat Arm, and Granite Canal Generating Plants function by manually measuring the PD data from the generator using test equipment; the data is then transferred to a computer for diagnostic analysis. This method of capturing partial discharge results is achieved by utilizing PD coupler capacitors that are permanently installed on the generators stators as well as PDA test equipment that attaches directly to the couplers. The current set-up requires operators to physically set up the portable test equipment near the generator test ports that can only capture a small sample of PDA data. PDA is used to determine the condition of stator winding insulation allowing personnel to detect early signs of degradation of stator windings. Through continual monitoring, personnel are able to detect and react to sudden changes that likely would not be detected through intermittent measurements. Continuous measurements also eliminate the introduction of errors due to different test setups, which can take place when they are performed periodically. As one aspect of PDA is analyzing trends of the data being collected, consistency is very important. For further information on the equipment, refer to Appendix A in the Asset Management Overview.

Existing State

The physical connection between the test equipment and PD coupler located on the generator has become unreliable and recently there have been instances of malfunction during PDA data collection. The connection between the test equipment and PD couplers has failed at least once in each plant in the last three years during routine maintenance. During 2017 annual maintenance, erroneous readings were collected for Cat Arm Unit 2; this was also observed in other plant locations.

The current PDA test equipment does not allow for obtaining real time data and, as the readings are taken during special requests or as part of scheduled annual maintenance, there can be years where this data is unavailable. This situation does not allow personnel to do detailed trending analysis to determine the remaining life of the stator windings.

Justification

This project is will replace failing systems and enhance the condition assessment undertaken for Hinds Lake, Cat Arm, and Granite Canal Generating Plant generator stator insulation.

Replace Turbine-Generator Control and Vibration Monitoring Equipment

Project Description

The project will be executed in 2020-2021, with estimated costs of $238,600. Refer to Table 6 for the budget breakdown of the Replace Turbine-Generator Control and Vibration Monitoring Equipment. This project includes:

Turbine-Generator Control

The project will upgrade the existing GE Fanuc 90-30 Series PLC platform to a new GE PAC Systems RX3i platform. The upgrade will include the replacement of the PLC, power supplies, racks, I/O, and communication modules. The SCADA software and communication drivers will be updated to the latest revisions and the SCADA computer will be replaced to include the most recent Windows operating system, as approved by Hydro IT Services, to run the newer versions of software and to bring the Operating System into support.

Vibration Monitoring System

The project will also include the replacement of the IRD 5806 Vibration Monitoring System and probes. The new system will include a vibration monitoring system that will monitor and display the overall vibration levels on the Turbine and Generator. The new system will be capable of monitoring unit speed and sending alarms and trip signals to the unit controller.

Replace Control Cables

Project Description

The project will be executed in 2020-2021, with estimated costs of $311,300. Refer to Table 7 for the budget breakdown of the Replace Control Cables project.

The scope of this project includes:

- Replacement of the 600V unit control cables; and

- Replacement of associated oil contaminated junction boxes and terminal blocks.

Install Partial Discharge Continuous Monitors

Project Description

The project will be executed in 2020, with estimated costs of $451,400. Refer to Table 8 for the budget breakdown of the Install Partial Discharge Continuous Monitors project.

This project will replace existing PDA attached to existing PDA couplers in Hinds Lake, Cat Arm, and Granite Canal. The scope includes:

- Install a GuardII module;
- Install USB and Ethernet ports, with Modbus (TCP/IP) protocol;
- Install a 12 Partial Discharge input module for continuous on-line monitoring;
- Re-configure the partial discharge pulse data collected through the capacitors for analysis by the GuardII software; and
- Install a monitoring computer and PI historian for data collection.

Each generator will be set up with the new equipment and a computer will be located in the plant for data collection. This data will also be sent back to a centralized computer in Bay d'Espoir so that operations personnel can monitor this data remotely in real time.

Budgets

Tables 6, 7, and 8 present the project budget estimates for Replace Turbine-Generator Control and Vibration Monitoring Equipment, Replace Control Cables, and Install Partial Discharge Continuous Monitors projects respectively.

Table 6: Replace Turbine-Generator Control and Vibration Monitoring Equipment Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	44.4	25.0	0.0	**69.4**
Labour	61.7	65.3	0.0	**127.1**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	2.3	8.1	0.0	**10.4**
Interest and Escalation	4.6	6.5	0.0	**11.1**
Contingency	10.8	9.8	0.0	**20.7**
Total	**123.9**	**114.7**	**0.0**	**238.6**

Table 7: Replace Control Cables Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	105.7	0.0	**105.7**
Labour	22.8	129.5	0.0	**152.2**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	2.3	0.0	**2.3**
Interest and Escalation	1.6	23.5	0.0	**25.0**
Contingency	2.3	23.7	0.0	**26.0**
Total	**26.6**	**284.7**	**0.0**	**311.3**

Table 8: Install Partial Discharge Continuous Monitors Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	131.5	0.0	0.0	**131.5**
Labour	113.2	0.0	0.0	**113.2**
Consultant	38.3	0.0	0.0	**38.3**
Contract Work	59.9	0.0	0.0	**59.9**
Other Direct Costs	27.4	0.0	0.0	**27.4**
Interest and Escalation	25.6	0.0	0.0	**25.6**
Contingency	55.5	0.0	0.0	**55.5**
Total	**451.4**	**0.0**	**0.0**	**451.4**

Project Schedules

Replacement of the condition monitoring, control cables, and the partial discharge equipment will be done during the annual maintenance of the hydro units. The anticipated project schedule is shown in Tables 9, 10, and 11 for all activities.

Table 9: Replace Condition Monitoring Equipment Project Schedule

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules	April 2020	May 2020
Pre-Engineering: Site visit, review CBP, develop BOM	April 2020	June 2020
Engineering: Design system, order materials, contract for diving services, migrate PLC & HMI files.	May 2020	February 2021
Construction: Install PLC and vibration monitoring modules. Install HMI server.	April 2021	April 2021
Commissioning: Confirm operation of system.	April 2021	April 2021
Closeout: Complete all documentation and complete PIR, drafting of as-built drawings, close work orders.	May 2021	May 2021

Table 10: Replace Control Cables Project Schedule

Activity	Start Date	End Date
Planning: Detail plan for the cable replacement	February 2020	August 2020
Procurement: Special material requirements	October 2020	April 2021
Construction: Perform the replacement	May 2021	August 2021
Commissioning: Confirm new equipment	August 2021	August 2021
Closeout: Closeout the project	October 2021	October 2021

Table 11: Install Partial Discharge Continuous Monitors

Activity	Start Date	End Date
Planning: Open project, review schedule	January 2020	March 2020
Design: Conduct site visits, complete detailed electrical design, internal review of consultant drawings and design	March 2020	May 2020
Procurement: Tender and award supply and installation contract	April 2020	May 2020
Construction: Install new fixtures and cabling	June 2020	August 2020
Commissioning of new equipment, final tie-ins	June 2020	August 2020
Closeout: Project close-out	October 2020	November 2020

2.2 Hydraulic Structures Program

The following equipment upgrades and/or refurbishment for Hydraulic Structures are proposed for 2020/2021:

- Control Structure Refurbishments:
  - Refurbish Hydraulic Structures; and
  - Install Frazil Ice Forecasting System.
- Penstock Condition Assessment

2.2.1 Control Structure Refurbishments

Background

This work is a continuation of a program to refurbish hydraulic structures within Hydro’s generating system. The program began in 2010 with refurbishment work in Burnt Dam. The last submission to the Board of Commissioners of Public Utilities for this program was in the 2019 CBA Hydraulic Generation Refurbishment and Modernization (2019-2020) proposal in section 2.2 Hydraulic Structures.

The structures identified for the Hydraulic Generation Refurbishment and Modernization (2020-2021) proposal are Bay d’Espoir Intake 3, Burnt Dam Spillway, and Upper Salmon Intake (Frazil Ice System).

Description of Equipment

Refurbish Hydraulic Structures

Bay d'Espoir Intake 3

The Bay d'Espoir Intake 3, which was constructed in 1969, supplies water to Bay d'Espoir Penstock 3, which in turn supplies water to Generating Units 5 and 6. The intake gate is made of a welded steel frame with a downstream steel skin plate and concrete ballast. Each gate has four preloaded side rollers and twelve main rollers. The gate is operated with a cable hoist attached to a single central lifting point. Figure 4 is a picture of Intake 1 in Bay d'Espoir, which is the same as Intake 3.

Burnt Dam Spillway

The Burnt Dam Spillway Structure, located 133 km from Millertown, was placed into service in 1967. The spillway is a concrete structure equipped with two 7 meter wide fixed wheel gates that operate under a maximum head of 8 meters and are equipped with screw-stem hoists (as seen in Figure 5).

Further information on the equipment is contained in Appendix A to the Asset Management Overview.

Figure 4: BDE Intake Gate 1

Figure 5: Burnt Dam Spillway Structure

Existing State

Bay d'Espoir Intake 3

A detailed assessment of Bay d'Espoir Intake 1 was completed in 2016 when it was determined that there were varying levels of deterioration, particularly in the submerged/embedded components. Deterioration consists of concrete erosion and corrosion on embedded parts and other gate components. Critical components that have shown deterioration include: main rollers, roll paths, side-rollers, and seals. The report also noted that the deterioration of these components is creating extra stress on the hoist system. As Bay d'Espoir Intakes 2 and Intake 3 are the same vintage as Intake 1, with similar operating conditions and in the same environment, the state of Intakes 2 and 3 were similar to the state of Intake 1. Hydro has undertaken a phased approach to refurbish these structures over the last several years, with Bay d'Espoir Intake 1 and 2 completed first, and Bay d'Espoir Intake 3 in the 2020 CBA. Figures 6 and 7 are pictures of the side and main rollers on Intakes 2 and 1, which is typical for all three structures.

Burnt Dam Spillway

In October 2017, a condition assessment was completed of the gates/embedded parts at the Burnt Dam Spillway. This inspection revealed deterioration with the gate hardware such as rollers, seals, screw stems, and transfer cases. The inspection also revealed deterioration in the embedded parts such as concrete and roll paths. Figures 8, 9, and 10 are examples of the deterioration in Burnt Dam.

Figure 6: BDE Intake 2 Side Rollers – 2013

Figure 7: Pitting Corrosion on Main Rollers – Intake 1 2016

Figure 8: Deformed Gate Knife - Burnt Dam

Figure 9: Rubbing Marks on Embedded Parts - Burnt Dam

Figure 10: Transfer Case Corrosion - Burnt Dam

Justification

This project is required to maintain the reliable operation of Bay d'Espoir Intake 3 and Burnt Dam Spillway Structure.

Deterioration of critical components such as the gate main rollers, roll paths, side-rollers, and seals directly affect the gate capacity for proper operation and can be a threat to the reliability of the powerhouse and penstock if not addressed. The impact of gate jams/failures will likely lead to a loss of production and in the event of failure, damage to the penstock and other downstream components is likely to occur.

Install Frazil Ice Forecasting System

Background

Frazil ice is a mass of super cooled ice crystals formed in a turbulent water flow. These are tiny ice particles that form at or near the water/air interface. As they have low buoyancy characteristics these particles migrate towards the bottom of the water passage and continuously build up at various elevations on the trash racks.

The intake structure is comprised of a trash rack as a primary means of defense to limit debris from entering the intake and ultimately flowing into the hydraulic generating units downstream. The trash rack is susceptible to frazil ice buildup more than other components since it is the first component the frazil ice will pass by.

Figure 11 is a picture illustrating buildup of frazil ice on an intake trash rack.

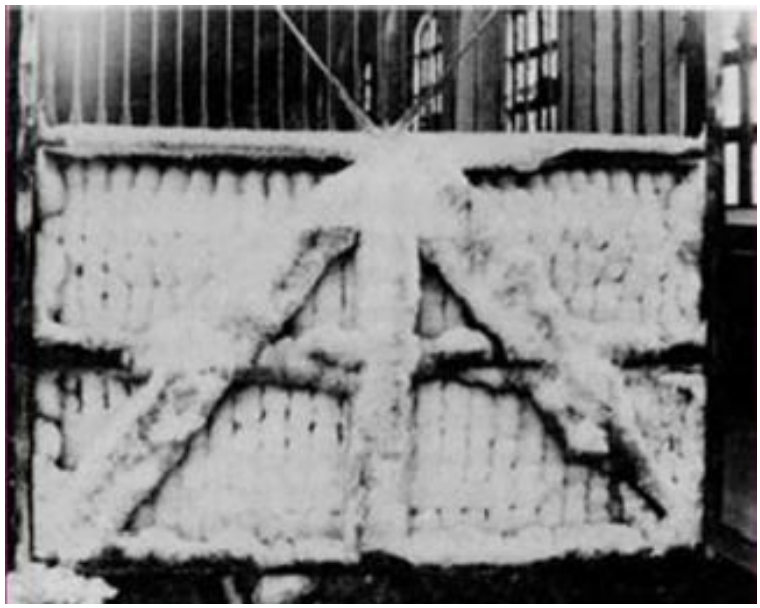

Figure 11: Frazil Ice Formation on Intake Trash Racks (US Army Corps of Engineers, 1991)

Build-up of frazil ice on intake trash racks will continue to grow until the opening between trash rack bars is effectively blocked, which could result in a catastrophic events leading to forced outages. Buildup of frazil ice is exponential in time; the longer Operations wait to clear the intake of frazil ice, the blockage to the intake worsens. Figure 12 is an illustration that demonstrates that as frazil ice forms the effect of the accumulation is exponential over time.

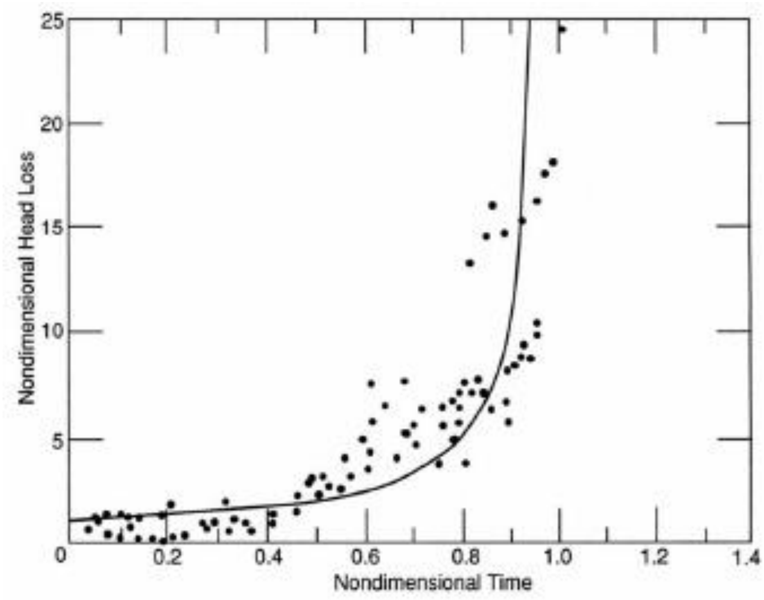

Figure 12: Head Loss through a Trach Rack during Frazil Ice Accumulation (US Army Corps of Engineers, 1991)

Description of Equipment

There are two trash-racks at Upper Salmon measuring 13.8m X 5.17m, and 0.82m thick. The frazil ice detection system consists of a temperature probe, which measures the rate of change of the water temperature around the freezing point. The temperature probe sends an alarm signal to the Energy Control Center ("ECC") when temperature conditions exist for the formation of frazil ice. There is also an upstream water level transducer that detects a rise in water level at the intake; this is used to determine the trash-rack differential, which can be an indication there is frazil ice development on the gate. This differential information is also sent to the ECC for monitoring purposes and if an alarm is present then operators can be called out to site to activate agitation systems at the intake to inhibit the formation of frazil ice. For further information on the equipment, refer to Appendix A in the Asset Management Overview, under the Hydraulic Structure section.

Existing State

The detection system is unreliable and does not allow for sufficient time to take preventive actions to avoid a quick buildup of frazil ice on the trash racks. The current equipment is obsolete. As well the temperature transmitter is designed to feed back the temperatures to a programmable logic controller. This transfer of information has certain levels of uncertainty that is significant enough to make the signal unreliable for the detection of frazil ice. This situation arose on January 23, 2006 when a rapid buildup of frazil ice on the trash-racks in association with a failed water level detection system resulted in circumstances that caused the ECC to take the unit offline to avoid damage to the intake building, trash-rack, and the penstock.

Justification

This project is justified to reduce the possibility of frazil ice damaging the intake structures, which may also cause extended outages for Upper Salmon hydro generating plant

Refurbish Hydraulic Structures

Project Description

The project will be executed in 2020/2021, with estimated costs of $5,368,500. Refer to Table 12 and 13 for the budget breakdown for each location. The project includes:

Bay d'Espoir Intake 3

The scope of the intake refurbishment project is as follows:

- Replace main and side rollers and J-seals;
- Recoat the intake gate and exposed steel surfaces;
- Replace intake hardware;
- Replace gate lifting motor; and
- Refurbish second stage concrete.

Burnt Dam Spillway

The scope of the spillway refurbishment project is as follows:

- Refurbish the right side gate heater (gate 1)
- Complete a structural analysis of the structure bracing/connections
- Refurbish gate steel frame, gate sealing and rollers
- Refurbish embedded parts and concrete.

Install Frazil Ice Forecasting System

The project will be executed in 2020, with estimated costs of $174,000. Refer to Table 14 for the budget breakdown.

This project will remove the existing frazil ice detection system and will install an anemometer (RM Young Model 86004) for wind speed/direction and an RTD based sensor for measuring ambient temp (RM Young Model 41342L), similar to the system installed in the Granite Canal intake. Both instruments will be interfaced to a field recorder and then wired to a D20 communication module in the intake structure. Data collected will be incorporated on the administration network for processing and alarm management. This new proposed system is designed to accurately detect small changes in temperature, wind speed, and wind direction. This, along with the differential readings at the intake will allow the system to more accurately predict the conditions for frazil ice and alert the ECC.

Budget

Table 12, 13, and 14 present the project budget estimates for the Bay d'Espoir Intake 3, Burnt Dam Spillway, and the Frazil Ice Forecasting System in Upper Salmon respectively.

Table 12: Bay d'Espoir Intake 3 Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	60.0	0.0	**60.0**
Labour	80.6	387.3	0.0	**467.8**
Consultant	80.5	44.5	0.0	**125.0**
Contract Work	138.5	1,171.1	0.0	**1,309.6**
Other Direct Costs	8.1	22.5	0.0	**30.6**
Interest and Escalation	18.0	184.0	0.0	**202.0**
Contingency	31.0	251.2	0.0	**282.2**
Total	**356.7**	**2,120.6**	**0.0**	**2,477.3**

Table 13: Burnt Dam Spillway Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	60.0	0.0	**60.0**
Labour	83.5	393.2	0.0	**476.7**
Consultant	138.9	61.2	0.0	**200.0**
Contract Work	165.4	1,395.0	0.0	**1,560.4**
Other Direct Costs	8.1	22.5	0.0	**30.6**
Interest and Escalation	25.3	210.7	0.0	**236.0**
Contingency	40.7	286.7	0.0	**327.4**
Total	**461.9**	**2,429.3**	**0.0**	**2,891.2**

Table 14: Frazil Ice Forecasting System Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	15.1	0.0	0.0	**15.1**
Labour	111.5	0.0	0.0	**111.5**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	15.0	0.0	0.0	**15.0**
Other Direct Costs	8.4	0.0	0.0	**8.4**
Interest and Escalation	9.0	0.0	0.0	**9.0**
Contingency	15.0	0.0	0.0	**15.0**
Total	**174.0**	**0.0**	**0.0**	**174.0**

Project Schedule

The anticipated project schedule is shown in Tables 15, 16, and 17 for the Bay d'Espoir Intake 3, Burnt Dam Spillway, and the Frazil Ice Forecasting System in Upper Salmon respectively.

Table 15: Bay d'Espoir Intake 3 Project Schedule

Activity	Start Date	End Date
Planning: Detail plan for the refurbishment	February 2020	May 2020
Procurement: Special material requirements	March 2020	June 2020
Construction: Perform the refurbishment	June 2020	August 2020
Construction: Perform the refurbishment	June 2021	September 2021
Commissioning: Commission the new equipment	September 2021	September 2021
Closeout: Closeout the project	October 2021	November 2021

Table 16: Burnt Dam Spillway Refurbishment Project Schedule

Activity	Start Date	End Date
Planning: Detail plan for the refurbishment	February 2020	May 2020
Procurement: Special material requirements	March 2020	June 2020
Construction: Perform the refurbishment	June 2020	August 2020
Construction: Perform the refurbishment	July 2021	October 2021
Commissioning: Commission the new equipment	October 2021	October 2021
Closeout: Closeout the project	October 2021	November 2021

Table 17: Frazil Ice Forecasting System Project Schedule

Activity	Start Date	End Date
Planning: Open work orders, plan and develop detailed schedules.	February 2020	March 2020
Pre-Engineering: Site visit; review CBP; develop BOM.	February 2020	March 2020
Engineering: Design system; order materials; contract for diving services; modify PLC logic.	March 2020	June 2020
Construction Install junction boxes; run cables; install devices and PLC modules.	July 2020	July 2020
Commissioning: Confirm operation of system and all values appearing on EMS web page.	August 2020	August 2020
Closeout: Closeout the project	October 2020	November 2020

2.2.2 Penstock Condition Assessment

Background

Due to its experience with Bay d'Espoir Penstocks 1 to 3 in 2016 and 2017, Hydro reviewed its penstock inspection practises. Referencing the ASCE Steel Penstocks, 2012 manual and CEATI Penstock Inspection 2017 report, Hydro has an inspection interval of 6 years, including enhanced internal inspection activities and reviews. For further information on the equipment, refer to Appendix A in the Asset Management Overview, under the Hydraulic Structure section.

Description of Equipment

The Cat Arm Generating Station was commissioned in 1985 with two 63.5 MW Pelton turbines. Water at a head of 380.5 m is supplied to the plant through a 3 km long penstock. The water passage way includes:

- A 3 km long penstock (rock cut tunnel);
- 426 m long steel liner bifurcation to direct water to each unit downstream of the penstock; and
- A 47 m long rock trap located 50 m upstream of the steel liner.

Existing State

The Cat Arm penstock has been in operation since 1985. The last internal assessment of the rock tunnel portion of the Cat Arm penstock was completed in 2006. Prior to this assessment there were four other assessments completed in 1985, 1990, 1996, and 1999. Major findings can be summarized as follows:

- 1996 – A recommendation was made to increase the time it takes to dewater the tunnel, due to concern that more damage was being done to the tunnel during the dewatering process than during operation.
- 1999 – This inspection followed a 1997 design review and included only significant rehabilitation that was undertaken in the tunnel. Rehabilitation took place on the lower portion of the tunnel.

In 2006 a recommendation was made to limit dewatering solely for the purposes of inspections; the penstock should only be dewatered for operational reasons. Some minor rock falls were present in the tunnel and there was concern that dewatering increased the likelihood of these rock falls due to pressure fluctuations in the rock structure during dewatering and watering up cycles.

Justification

To ensure the long term reliability of the Cat Arm penstock, a Level II Condition Assessment is required. Due to safety concerns with having personnel enter the penstock tunnel to complete this inspection, along with studies which note that dewatering increases the likelihood of rock falls due to pressure fluctuations in the rock structure, the assessment will be completed via an underwater ROV. This work will result in 3D mapping of the tunnel, with an accompanying report that documents any identified rock falls, significant cracks/fissures, rock trap build up, steel liner interfacing issues with the rock tunnel, etc. Hydro will use the results of the inspection to confirm the long term reliability of the asset and plan for any required maintenance or upgrades.

Project Description

This project will complete a Level II Assessment of the Cat Arm penstock, which will include an inspection of the penstock. Due to safety risk from rock falls, the assessment will be completed via an underwater ROV equipped with a specialized long range underwater camera. This camera will provide 3D mapping of rock falls, significant cracks/fissures, rock trap build up, steel liner interfacing with the rock tunnel, etc. The equipment will be operated by a specialized consultant experienced in the operation of remote underwater imaging equipment in tunnel environments. The consultant shall identify anomalies during the inspection and produce a report, which is suitable for Hydro to use in planning for tunnel maintenance.

Budget

The budget estimate for the Cat Arm Penstock Condition Assessment project in 2020 is presented Table 18.

Table 18: Condition Assessment Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.5	0.0	0.0	**0.5**
Labour	81.0	0.0	0.0	**81.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	130.0	0.0	0.0	**130.0**
Other Direct Costs	10.9	0.0	0.0	**10.9**
Interest and Escalation	14.6	0.0	0.0	**14.6**
Contingency	24.2	0.0	0.0	**24.2**
Total	**261.2**	**0.0**	**0.0**	**261.2**

Project Schedule

The anticipated project schedule for the Cat Arm Penstock Condition Assessment project in 2020 is presented Table 19.

Table 19: Condition Assessment Project Schedule

Activity	Start Date	End Date
Planning: Prepare, Award Scope, Plan Work	February 2020	July 2020
Construction: Execution of Underwater Inspection	July 2020	July 2020
Closeout: Report (Results) Review	October 2020	October 2020

2.3 Reservoirs

The following equipment upgrades and/or refurbishment for Reservoirs are proposed for 2020/2021:

- Upgrade Public Safety around Dams; and
- Install Emergency Detection Response System.

2.3.1 Upgrade Public Safety around Dams

Description of Equipment

Dams and waterways are critical assets for the hydraulic generation of electricity. A dam is a barrier that stops or restricts the flow of water, and waterways are structures that direct the flow of water. These assets require control measures to keep the public safe and informed of the impact these assets have on the surrounding area. Hydro undertakes the implementation of control and notification measures through its Public Safety Around Dams Program. For further information on the dams and waterways refer to Appendix A in the Asset Management Overview; and Section 4.6.1 of the Asset Management Overview for information about the Public Safety Around Dams ("PSAD") Program.

In the past decade, an increase in noted public interactions with hydraulic generating structures, including access by recreational vehicles and boating near spilling gates, has prompted the development of this program in accordance with Canadian Dam Association PSAD Guidelines issued in 2011. Canadian Dam Association PSAD Guidelines are considered industry practice in Canada to increase public safety around dams and associated waterways.

Public safety risks are determined by completing risk assessments in accordance with the Canadian Dam Association's Dam Safety Guidelines. Appropriate control measures are then installed to reduce the safety risk to the public. These measures include such items as signage, fencing, audible or visual alarms, booms and buoys, operational changes, and public education.
The dams and waterways included in this proposal are:

- Hinds Lake – reservoir consists of dams, control structure, and an intake structure.
- Upper Salmon – reservoir consists of dams, spillway structures, a power canal, and an intake structure.

Existing State

The Hinds Lake reservoir had a PSAD Program risk assessment completed in 2018 that outlines areas that need to be addressed.

The Upper Salmon reservoir had a PSAD Program risk assessment completed in 2017 that outlined areas that needed to be addressed. Year 1 recommendations (signage, fencing, boom design) will be completed in 2019.

Justification

This project is needed to increase public safety for Hinds Lake and Upper Salmon dams and associated waterways.

Project Description

The project will be executed in 2020, with estimated costs of $728,500. Refer to Table 20 for the budget breakdown.

The scope of this project includes completion of:

- Hinds Lake Year 1 Implementation include fencing, boom anchor design, and the installation of signage; and
- Upper Salmon Year 2 Implementation includes fencing, anchor boom installation, and completing remaining signage.

Budget

The budget estimate for the Upgrade Public Safety around Dams project in 2020 is presented Table 20.

Table 20: Upgrade Public Safety around Dams Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	147.8	0.0	0.0	**147.8**
Labour	179.0	0.0	0.0	**179.0**
Consultant	24.8	0.0	0.0	**24.8**
Contract Work	224.2	0.0	0.0	**224.2**
Other Direct Costs	49.5	0.0	0.0	**49.5**
Interest and Escalation	40.5	0.0	0.0	**40.5**
Contingency	62.8	0.0	0.0	**62.8**
Total	**728.5**	**0.0**	**0.0**	**728.5**

Project Schedule

The anticipated project schedule for the Upgrade Public Safety around Dams project in 2020 is presented Table 21.

Table 21: Upgrade Public Safety around Dams Project Schedule

Activity	Start Date	End Date
Planning: Detail plan for each location; open projects in JDE; review schedule.	February 2020	May 2020
Procurement: Special material requirements	March 2020	June 2020
Construction: Installation of public safety devices and assessment of Paradise River.	May 2020	September 2020
Closeout: Closeout the project	October 2020	November 2020

2.3.2 Install Emergency Detection Response System

Description of Equipment

Power Canal Embankment (LD-1)

LD-1 is a power canal embankment located on the Long Pond Reservoir that was constructed in 1967. The canal has a maximum height of 23m, a crest length of 1,250m and a crest elevation of 185.2m. The power canal channels water to the penstocks for Bay d'Espoir generating units 1 to 7. The embankment is highlighted in yellow in Figure 13. The canal contains seepage monitoring devices, which include six flow pipes, three weirs, and 32 piezometers.

Figure 13: LD-1 (Power Canal Embankment)

North Cut-Off Dam (LD-2)

LD-2 is a dam structure located on the Long Pond Reservoir that was constructed in 1966. The dam has a maximum height of 43m, a crest length of 650m and a crest elevation of 184.7m. The dam contains seepage monitoring devices, which include two flow pipes and one weir (See Figure 14). A weir is located downstream of the dam and is a collection point for all seepage through the dam. Workers manually check this weir and take a measurement of water level as well as flow rate.

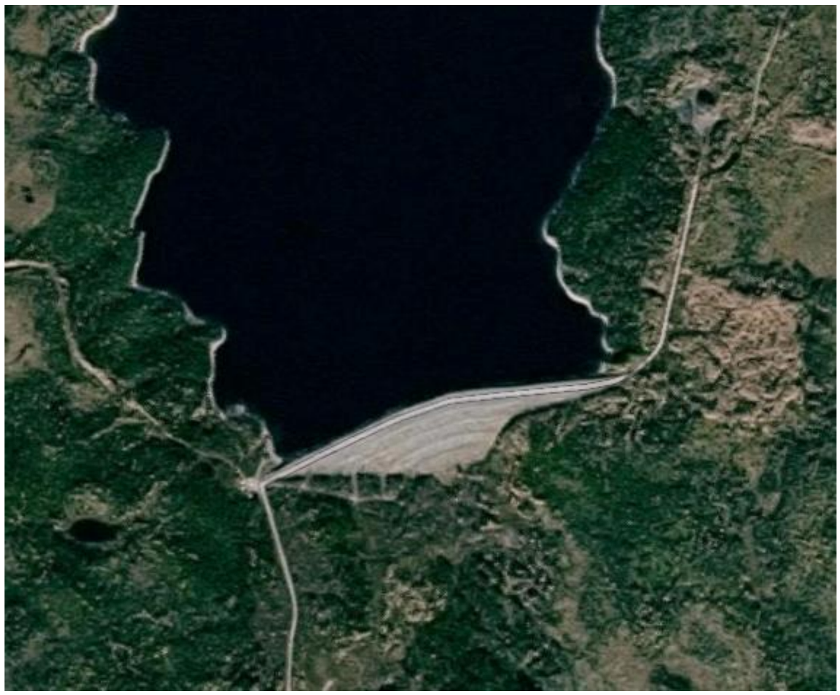

Figure 14: LD-2 (North Cut off Dam)

For LD1 and LD2 sites, seepage monitoring devices provide information used to assess the overall condition of the dam and the potential for a dam breach.[3] Increased seepage is an indication of internal issues with the dam, which if left unmitigated could cause a dam failure resulting in an uncontrolled release of water from the reservoir.

Information from the seepage monitoring devices at these structures is manually gathered bi-weekly for review by engineering personnel and, if required, future actions are initiated.

Further information on the equipment is contained in Appendix A to the Asset Management Overview.

[3] Dam Breach: An opening or a breakthrough of a dam sometimes caused by rapid erosion of a section of earth embankment by water.

Existing State

The current monitoring equipment is in good condition; however, it is not tied into any monitoring system so lacks the real time monitoring that is required to quickly identify dam issues.

Justification

This project is justified as real time monitoring will provide faster identification of dam stability issues that could result in a dam breach.

A dam breach could inundate the Bay d'Espoir site as well as the nearby town of St. Veronicas, as seen in Figures 15 and 16.

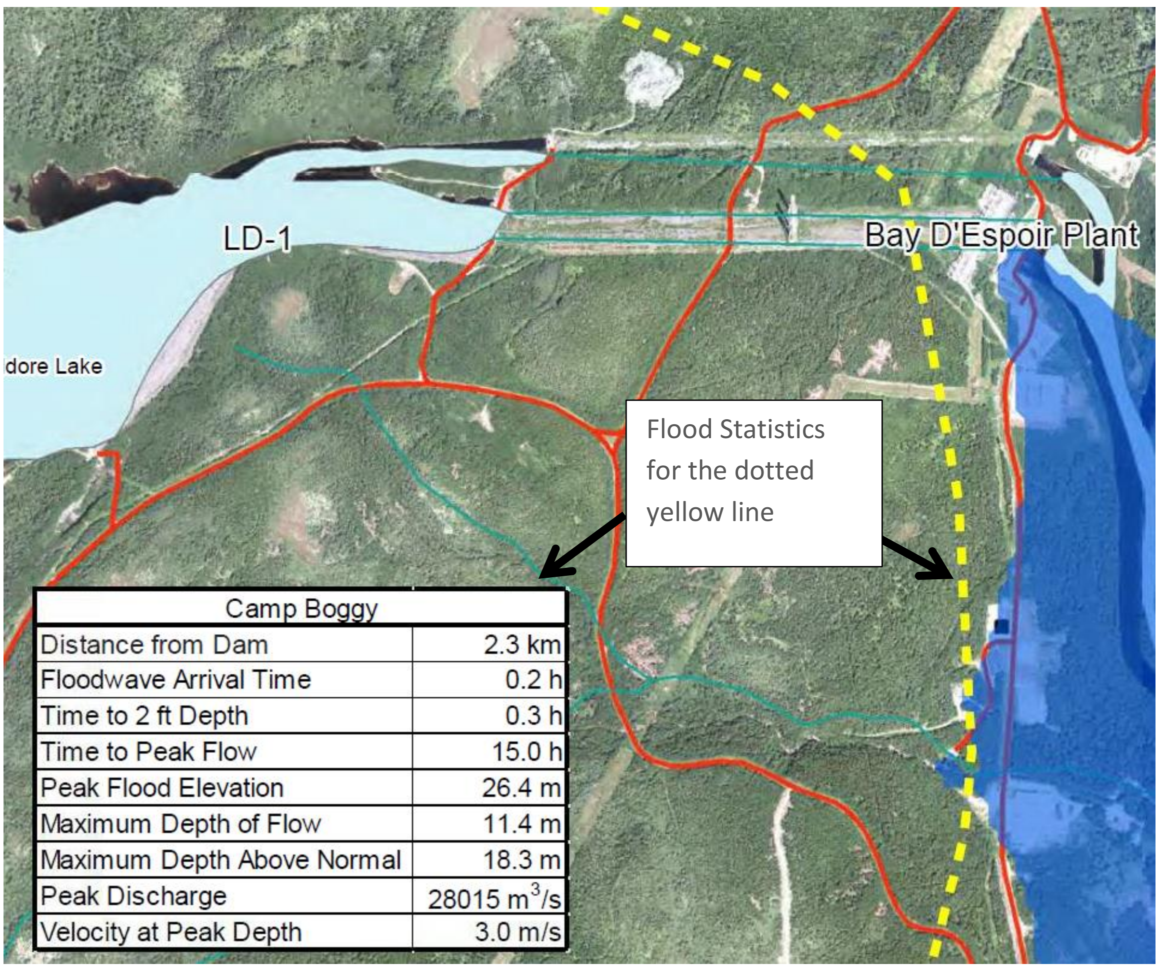

Figure 15: Flood Inundation Map (DRAFT) for LD-1

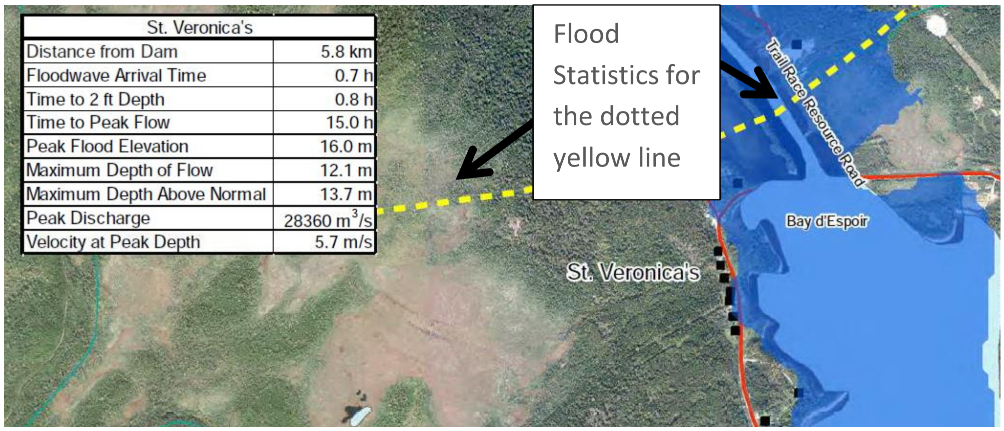

Figure 16: Flood Inundation Map (DRAFT) for LD-1

Project Description

This is a one year project to install equipment and software to provide real time monitoring of dam conditions with a budget estimate of $394,700. Table 22 has the complete budget breakdown.

The scope includes:

- Engineering for remote real time monitoring of seepage devices with integration into PI data storage and monitoring system at the Energy Control Centre; and
- Installation of real time monitoring equipment at LD-1 and LD2 and integration of the equipment data into PI.

Budget

The budget estimate for the Install Emergency Detection Response System project is presented Table 22.

Table 22: Install Emergency Detection Response System Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	188.7	0.0	0.0	**188.7**
Labour	89.0	0.0	0.0	**89.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	44.3	0.0	0.0	**44.3**
Other Direct Costs	17.8	0.0	0.0	**17.8**
Interest and Escalation	20.9	0.0	0.0	**20.9**
Contingency	34.0	0.0	0.0	**34.0**
Total	**394.7**	**0.0**	**0.0**	**394.7**

Project Schedule

The anticipated project schedule for the Install Emergency Detection Response System project in 2020 is presented Table 23.

Table 23: Install Emergency Detection Response System Project Schedule

Activity	Start Date	End Date
Planning: Detail plan for each location; open projects in JDE; review schedule.	February 2020	May 2020
Procurement: Special material requirements	March 2020	May 2020
Construction: Installation of LD-1 and LD-2 systems.	July 2020	September 2020
Closeout: Closeout the project	October 2020	November 2020

2.4 Site Buildings and Services

The following equipment upgrades and/or refurbishment for Site Buildings and Services are proposed for 2020-2021:

- Refurbish Access Road; and
- Upgrade Bear Brook Crossing.

2.4.1 Refurbish Access Road

Description of Equipment

The access road to the Ebbegunbaeg control structure, as shown in Figure 17, was constructed in 1965 and consists of an unpaved, single lane, gravel road that is approximately 65 km long, 4 m wide and is accessed from the town of Millertown. Sections of the road have no topping and consist of exposed bedrock and several culverts have collapsed and are exposed. It is the only road access to the Ebbegunbaeg water control structure. For further information on the equipment, refer to Appendix A in the Asset Management Overview.

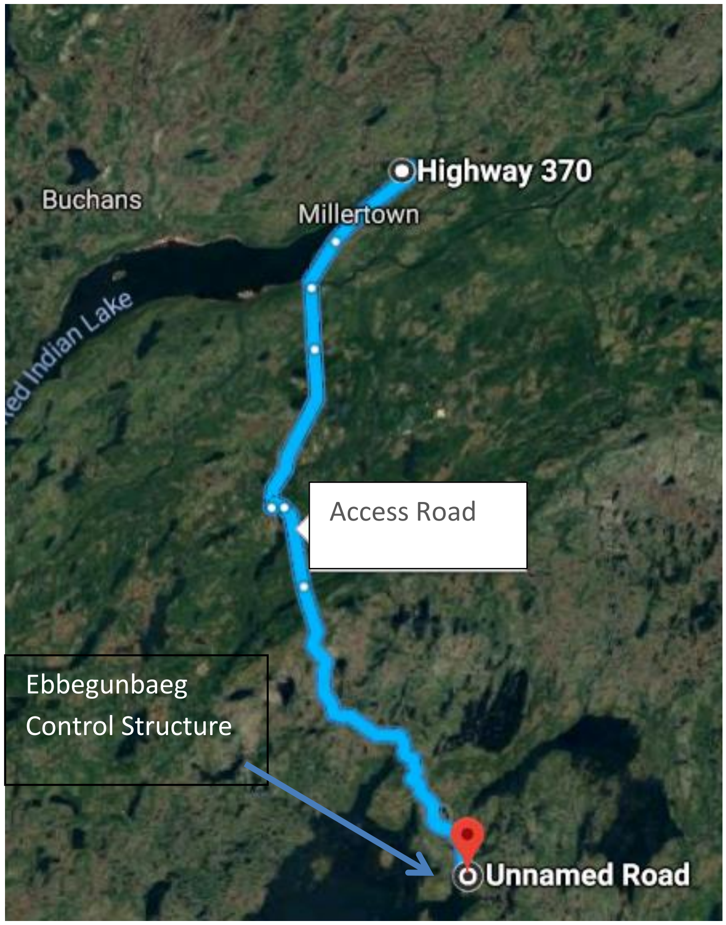

Figure 17: Ebbegunbaeg Access Road

Existing State

The condition of the road is poor with some road sections severely degraded due to weather events, erosion, age, and culvert degradation as shown in Figures 18 to 21. Ditching, an activity that involves clearing accumulated vegetation and sediment from roadside ditches to allow proper water drainage, is required in several areas and there is a lack of suitable road topping.

Figure 18: Ebbegunbaeg Access Road Condition

Figure 19: Ebbegunbaeg Access Road Condition

Figure 20: Ebbegunbaeg Access Road Condition

Figure 21: Ebbegunbaeg Access Road Condition

Justification

This project is required to ensure reliable access to the Ebbegunbaeg control structure. If the deteriorated road sections are not addressed, the road will become impassable and travel to the Ebbegunbaeg control structure will not be possible by vehicle.

Project Description

The project will be executed in 2020, with estimated costs of $803,100. Refer to Table 24 for the budget breakdown.

The scope of this project consists of:

- Ditching is required on approximately 50% of the road (18 km);
- Culvert Replacement at 8 locations;
- Manufacture (blasting/crushing) and placement of road topping material on approximately 50% of the road (18 km); and
- Grading of approximately 60% of the road (22 km).

Budget

The budget estimate for the Refurbish Access Road project in 2020 is presented Table 24.

Table 24: Refurbish Access Road Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	62.2	0.0	0.0	**62.2**
Consultant	38.6	0.0	0.0	**38.6**
Contract Work	592.8	0.0	0.0	**592.8**
Other Direct Costs	3.7	0.0	0.0	**3.7**
Interest and Escalation	37.6	0.0	0.0	**37.6**
Contingency	68.2	0.0	0.0	**68.2**
Total	**803.1**	**0.0**	**0.0**	**803.1**

Project Schedule

The anticipated project schedule for the Refurbish Access Road project in 2020 is presented Table 25.

Table 25: Refurbish Access Road Project Schedule

Activity	Start Date	End Date
Planning Open project in JDE; review schedule. Prepare tender documents for contract work.	February 2020	June 2020
Procurement Tender for contractor.	April 2020	June 2020
Construction Refurbish road as per scope.	July 2020	August 2020
Closeout Closeout the project	October 2020	November 2020

2.4.2 Upgrade Bear Brook Crossing

Description of Equipment

Bear Brook is a natural waterway that passes through the main access road between the site facilities building and Powerhouse 1 and 2 at Camp Boggy in Bay d'Espoir, as shown in Figure 22 and 23. To facilitate water flow there are four 60-inch and one 48-inch diameter corrugated galvanized steel culverts embedded in the road that were installed in 2017 after Hurricane Matthew in 2016. For further information on the equipment, refer to Appendix A in the Asset Management Overview.

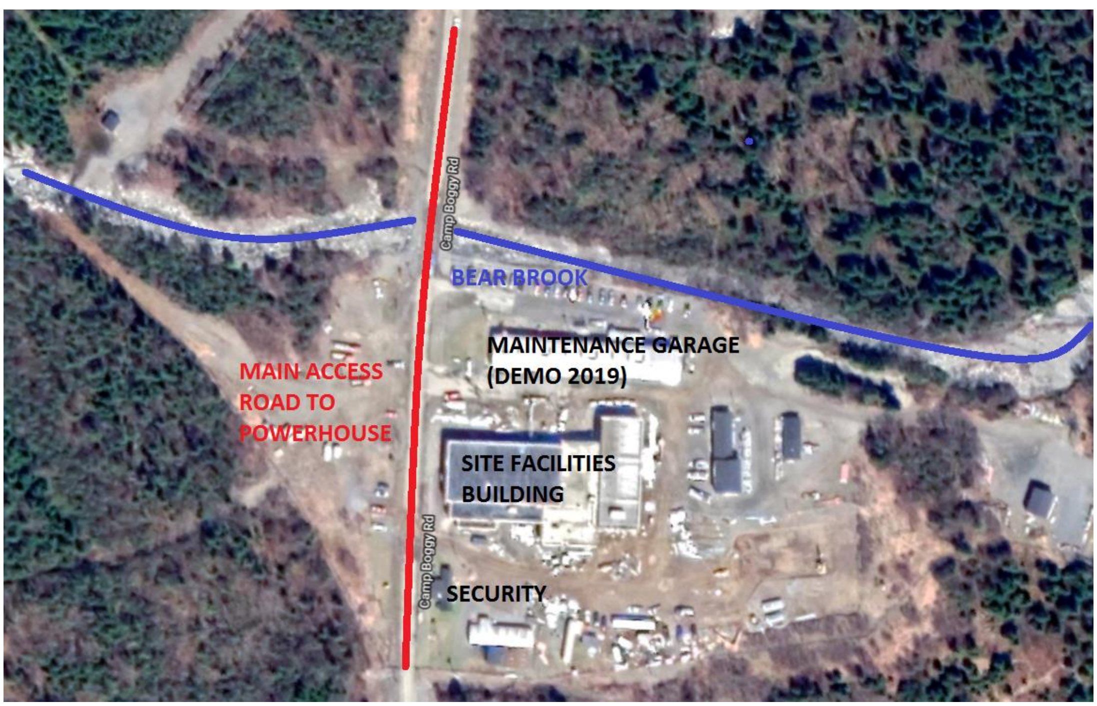

Figure 22: Aerial View of Bear Brook Crossing - Entrance to Camp Boggy

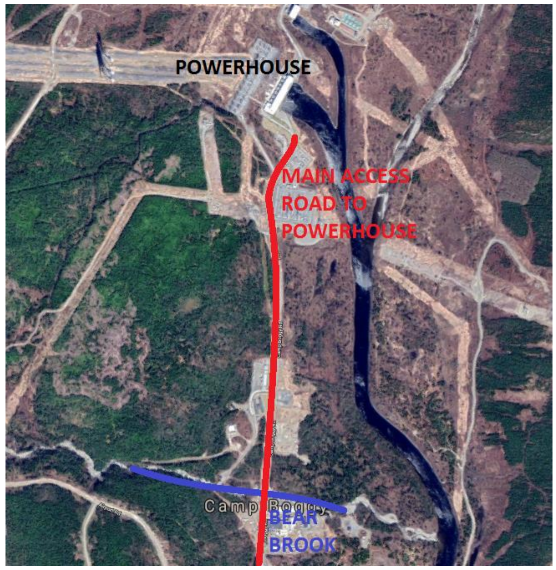

Figure 23: Aerial View of Bear Brook Crossing – Camp Boggy

Existing State

Since Hurricane Matthew, there has been several occasions when flooding occurred that damaged the crossing and impeded flow of traffic to and from Powerhouse 1 and 2. Figures 24 to 29 illustrate damage after Hurricane Matthew as well as damage incurred during weather events since.

Figure 24: Post Hurricane Matthew Bear Brook Crossing Impassable

Figure 25: Post Hurricane Matthew Damage to Surrounding Infrastructure after Bear Brook Crossing Failure

Figure 26: April 2017 - Post Weather Event - Sink Hole

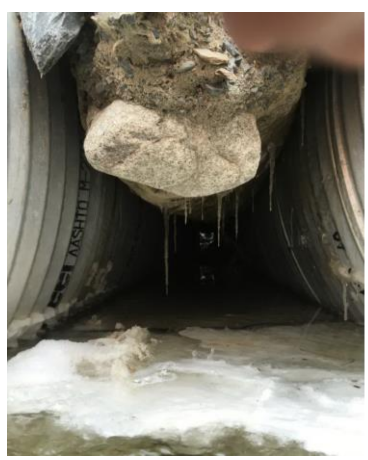

Figure 27: April 2017 - Post Weather Event - Culvert Backfill Washed Away

Figure 28: January 2019 - Rain Event - Culverts Fully Submersed

Figure 29: January 2019 Rain Event - Sinkhole

Figures 30 through 32 illustrate that debris is still building up by the culverts. While the culverts are designed to pass water freely, Bear Brook runs through a densely populated forested area and the waterway consists of loose rocks and debris such as trees, branches, sediment, rocks, etc. which can become dislodged when water flow increases. This debris then travels downstream creating blockages in and around the culverts.

Figure 30: Bear Brook Crossing (August 2017)

Figure 31: Bear Brook Crossing During Rain Storm (February 2018)

Figure 32: Bear Brook Crossing Culvert Blockage (February 2018)

Justification

This project is required to maintain adequate access to Bay d'Espoir Powerhouse 1 and Powerhouse 2 during times when Bear Brook is in a flood situation.

Without refurbishment to Bear Brook Crossing there is a heightened risk of the crossing washing out and the road being impassable, resulting in loss of main road access to Powerhouse 1 and Powerhouse 2. There is a secondary access road that will permit access to both powerhouses in the event the main access is washed away; however, this access road also passes over Bear Brook further upstream and has been susceptible to damage from weather events in the past. As well the secondary access road is unpaved and not open for traffic to the plant during the winter season and is generally snow covered and only passable by snowmobile. A large majority of the damage incurred to Bear Brook crossing has happened during the winter months or during spring run off when the secondary means of access is not available. In the event both access routes are unavailable, travel to and from the plant would have to be in the form of helicopter, all-terrain vehicle, or foot. This will increase equipment issue response times as well as limiting the amount of tools that can be transported from the site facilities building to the powerhouses such as compressors, industrial tooling, etc.

Project Description

The project will be executed in 2020, with estimated costs of $435,300. Table 26 contains the budget breakdown.

This project will include replacement of the existing culverts with a bridge reused from the construction of TL 267, as shown in Figures 33 and 34.

Figure 33: TL 267 Bridge to be Used for Bear Brook Crossing

Figure 34: TL 267 Bridge to be Used for Bear Brook Crossing

The bridge in Figures 33 and 34 was procured and installed during the construction of TL 267 and is now surplus to the transmission line operation.

Budget

The budget estimate for the Upgrade Bear Brook Crossing project in 2020 is presented Table 26.

Table 26: Upgrade Bear Brook Crossing Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	81.3	0.0	0.0	**81.3**
Consultant	26.2	0.0	0.0	**26.2**
Contract Work	261.9	0.0	0.0	**261.9**
Other Direct Costs	6.5	0.0	0.0	**6.5**
Interest and Escalation	21.9	0.0	0.0	**21.9**
Contingency	37.4	0.0	0.0	**37.4**
Total	**435.3**	**0.0**	**0.0**	**435.3**

Project Schedule

The anticipated project schedule for the Upgrade Bear Brook Crossing project in 2020 is presented in Table 27.

Table 27: Upgrade Bear Brook Crossing Project Schedule

Activity	Start Date	End Date
Planning: Open project in JDE; review schedule. Prepare tender documents for contract work.	February 2020	June 2020
Construction: Install TL 267 Bridge in Bay d'Espoir.	July 2020	August 2020
Closeout: Closeout the project	October 2020	November 2020

2.5 Common Auxiliary Equipment

The following equipment upgrades and/or refurbishment for Common Auxiliary Equipment are proposed for 2020/2021:

- Replace Sump Pump;
- Replace Diesel Genset; and
- Refurbish Sump Level System.

2.5.1 Replace Sump Pump

Description of Equipment

There are three vertical turbine sump pumps at the Upper Salmon Generating Station. Two pumps are rated at 25 HP and one at 10 HP. The 10 HP pump is used to remove waste water created by the turbine shaft seal lubrication, strainer backwash systems, floor drains, and any leakage from the generating unit.

The 25 HP pumps are used for dewatering the generating unit during the isolation of the unit. They can also be used to remove waste water in the event of a failure of the 10 HP pump. Further information on the equipment is contained in Appendix A to the Asset Management Overview.

Existing State

The 10 HP has been in near continuous operation since the commissioning of the plant in 1983. The bearings are worn and there is a leakage at the pump head resulting in reduced capacity of the pump resulting in longer run times, increased vibrations, and reduced efficiency. These conditions indicate worn internal components.

One of the 25 HP pumps has failed because bushings and bearings have corroded and seized. The other 25 HP pump is operating at higher than normal amperage level indicating that its internal components are also corroded and binding. The bearings are water lubricated and if the pumps are not used for extended periods, they dry out and seize.
All three pumps are over 35 years old and are past their life expectancy. Refurbishment is not recommended because, with components exhibiting signs of internal wear, the full scope of a refurbishment would not be known until the pump is dismantled and there would be no guarantee that the pump would be able to perform reliability once fixed.

Justification

This project is required to restore reliable operation of the sump pumps at Upper Salmon. The failure of the sump pumping system could cause flooding at the plant, and inadequate pumping can cause delays during shutdowns if the unit cannot be de-watered.

Project Description

The project will be executed in 2020-2021, with estimated costs of $407,200. Refer to Table 28 for the budget breakdown.

This project involves:

- Procurement and replacement of the 10 HP pump;
- Procurement and replacement of the two 25 HP pumps; and
- Installation of water lubricating lines on the 25 HP pumps to prevent column bearings and pump seizures.

Budget

The budget estimate for the Replace Sump Pump project in 2020-2021 is presented Table 28.

Table 28: Replace Sump Pump Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	171.0	0.0	**171.0**
Labour	55.5	106.2	0.0	**161.7**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	2.2	3.5	0.0	**5.7**
Interest and Escalation	4.1	30.8	0.0	**34.9**
Contingency	5.8	28.1	0.0	**33.9**
Total	**67.6**	**339.6**	**0.0**	**407.2**

Project Schedule

The anticipated project schedule for the Replace Sump Pump project in 2020/2021 is presented Table 29.

Table 29: Replace Sump Pump Project Schedule at Hinds Lake Generating Station

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules	January 2020	June 2020
Engineering: Site Visit, design for lubrication system and Specification development for Pump Tender/Procurement.	March 2020	July 2020
Procurement: All the required Pumps, Material's for Lubrication System	August 2020	December 2020
Construction: Remove Old Pumps and install new pumps	July 2021	August 2021
Commissioning: Run up the new pumps and lubrication system to confirm operation and release to operations.	August 2021	August 2021
Closeout: Close work order, complete all documentation and complete lessons learned	September 2021	October 2021

2.5.2 Replace Diesel Genset

Description of Equipment

The Victoria Control Structure consists of four gates that release water from the Victoria Lake reservoir into the Burnt Pond reservoir feeding the Granite Canal, Upper Salmon, and Bay d'Espoir generating stations. The gates and all auxiliary equipment at the Victoria Control Structure are powered by two 50 kW diesel generators. One diesel generator is designed to handle the full load required at Victoria and the other diesel generator is used as backup in case of failure or maintenance on the primary diesel generator. The primary diesel generator was replaced 10 years ago and the backup generator was installed in 1970. For further information on the equipment, refer to Appendix A in the Asset Management Overview.

Existing State

The backup diesel generator at the Victoria Control Structure was installed in 1970 and is over 49 years old. The OEM was a company called Dorman Inc., who is no longer in operation. With the company no longer producing spare parts it is difficult to source suitable parts to maintain this unit. With the replacement of the primary Dorman diesel generator 10 years ago the backup unit did have the old generator available for spare parts but that resource has now been exhausted and spare parts can take over a year to source or remanufacturer.

Justification

This project is required to provide reliable backup generation at the Victoria Control Structure.
If this generator is not replaced, there is no backup power supply for the Victoria Control Structure. The minimum time required to source or re-engineer a faulty part has been approximately 20 months.

Project Description

The project will be executed in 2020-2021, with estimated costs of $944,000. The budget breakdown is provided in Table 30.

This project involves the purchase and installation of a 50 kW diesel.

Budget

The budget estimate for the Replace Diesel Genset project in 2020-2021 is presented in Table 30.

Table 30: Replace Diesel Genset Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	140.4	0.0	**140.4**
Labour	147.7	228.8	0.0	**376.5**
Consultant	56.0	56.0	0.0	**112.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	4.9	148.3	0.0	**153.2**
Interest and Escalation	14.7	69.0	0.0	**83.7**
Contingency	20.9	57.4	0.0	**78.2**
Total	**244.1**	**699.9**	**0.0**	**944.0**

Project Schedule

The anticipated project schedule for the Replace Diesel Genset project in 2020-2021 is presented Table 31.

Table 31: Replace Diesel Genset Project Schedule

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules	January 2020	June 2020
Engineering: Site Visit, design/Specification development for Tender/Procurement.	March 2020	July 2020
Procurement: All the required Material's for Genset & Protection & Control Upgrade	September 2020	March 2021
Construction: Remove Old Genset & Protection & Control Equipment	July 2021	July 2021
Commissioning: Run up the new Genset & Protection & Control Equipment to confirm operation and release to operations.	August 2021	August 2021
Closeout: Close work order, complete all documentation and complete lessons learned	September 2021	October 2021

2.5.3 Refurbish Sump Level System

Description of Equipment

The fresh water storage sump at Cat Arm Generating Station is used to supply cooling water to the bearings in the two 64 MW generating units, domestic water for the entire facility, and also supply firefighting water when required. When the units are in synchronous condense mode, or of there is sump pump failure, the sump water level controller activates solenoid valves to allow water to flow from the penstocks into the sump to ensure that an adequate water level is maintained. For further information on the equipment, refer to Appendix A in the Asset Management Overview.

Existing State

The current system has been in service since the commissioning of the plant in 1985. Inadequate water levels are being experienced in the sump due to the malfunctioning of its control system and the sump fill line is too small. The solenoid globe valve for topping up the sump is open constantly and does not adequately maintain the sump level. Increasing the line size to the sump can permit more water to the sump.

Justification

Refurbishment of the Sump Level System is necessary to maintain reliable operation of the sump.

Project Description

The project will be executed in 2020, with estimated costs of $355,900. Refer to Table 32 for the budget breakdown

This project involves:

- Replacement of the sump level control system.
- Increase the size of the sump auto fill system complete with piping controls and valve, to access water supplied from the penstock. A globe valve will be installed in this line to control the pressure of the water being admitted in the sump.

Budget

The budget estimate for the Refurbish Sump Level System project in 2020 is presented Table 32.

Table 32: Refurbish Sump Level System Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	33.7	0.0	0.0	**33.7**
Labour	247.9	0.0	0.0	**247.9**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	26.3	0.0	0.0	**26.3**
Interest and Escalation	16.9	0.0	0.0	**16.9**
Contingency	31.0	0.0	0.0	**31.0**
Total	**355.9**	**0.0**	**0.0**	**355.9**

Project Schedule

The anticipated project schedule for the Refurbish Sump Level System project in 2020 is presented Table 33.

Table 33: Refurbish Sump Level System Project Schedule

Activity	Start Date	End Date
Planning: Open project in JDE, site visit, schedule review	February 2020	May 2020
Procurement: Purchase project components	March 2020	August 2020
Construction: Replace identified components	September 2020	September 2020
Commissioning: Testing of new level system and valve operation.	September 2020	September 2020
Closeout: Release For service and Asset Assignment	November 2020	November 2020

3.0 Closing Summary

This report, in conjunction with the Asset Management Overview, defines the 2020-2021 capital budget submission for all Hydraulic Generation assets.

3.1 Budget Estimate

Individual budget estimates for each activity are provided in Section 2 of this report. The budget estimate total for all activities described in the Hydraulic Generation Refurbishment and Modernization (2020-2021) project is shown in Table 34.

Table 34: Hydraulic Generation Refurbishment and Modernization Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	584.7	697.1	0.0	**1,281.8**
Labour	1,783.3	2,056.4	0.0	**3,839.7**
Consultant	425.8	184.2	0.0	**610.0**
Contract Work	2,657.1	5,187.1	0.0	**7,844.2**
Other Direct Costs	211.6	221.7	0.0	**433.3**
Interest and Escalation	342.1	933.9	0.0	**1,276.0**
Contingency	575.6	969.4	0.0	**1,545.0**
Total	**6,580.2**	**10,249.8**	**0.0**	**16,830.0**

3.2 Project Schedule

The individual schedules for each activity are in Section 2 of this report. Typically a high-level schedule for a multi-year project is as follows:

- **Year 1:** Planning, Design, and Procurement; and
- **Year 2:** Construction, Commissioning, and Closeout.

For one-year projects all activities will be completed in one year, typically one-year projects have short material lead times and shorter construction requirements.

Hydro anticipates all activities in this proposal to be completed before December 2021.

REGISTERED PROFESSIONAL ENGINEER
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7-23-19
DATE
NEWFOUNDLAND & LABRADOR

2020 Capital Budget Application
Hydraulic Generation Asset Management Overview

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has developed an ongoing capital program to replace or refurbish assets as they reach the end of their design life, or require attention due to obsolescence or anticipated failure.

Historically, Hydro's Hydraulic Generation projects could be divided into two categories; stand-alone, and programs. Programs include projects that are proposed year after year to address the need to upgrade or replace deteriorated equipment, such as control cables, and have similar justification each year. Stand-alone would include projects that do not meet the definition of a program. Hydro has had as many as 80 separate program-type projects in its capital budget applications over the past 5 years, with each stand-alone project tailored to a specific asset.

Starting with the 2018 Capital Budget Application ("CBA"), Hydro implemented a change to how the hydraulic generation programs are submitted for consideration by the Board of Commissioners of Public Utilities ("Board"). Hydro has consolidated the programs into the Hydraulic Generation Refurbishment and Modernization Project, thereby improving regulatory efficiency and easing the administrative effort for both the Board and Hydro. This change will also allow Hydro opportunities to realize efficiencies by improving the coordination of capital and maintenance work on the Hydraulic Generation assets.

With the 2020 CBA, Hydro submits this updated version of the Hydraulic Generation Asset Management Overview ("Asset Management Overview") to provide an updated overview of Hydro's hydraulic generation asset maintenance philosophies into one document. Annually, beginning with the 2018 CBA, Hydro will propose the required projects specific to each year, referencing the Asset Management Overview document.

Contents

List of Appendices

1.0 Introduction

Hydro has 10 hydraulic electric generating stations. There are over 3000 assets involved in the operation of these stations.

Hydro has an Asset Management Program which governs the life cycle of its hydraulic generation assets. This program monitors, maintains, refurbishes, replaces and disposes of assets with the objective of providing safe, reliable electrical power in an environmentally responsible manner at least cost. Within this program, assets are grouped at each location by five asset classifications, including hydraulic generating units, hydraulic structures, reservoirs, site buildings and services, and auxiliary equipment. This allows asset management personnel to establish, where possible, consistent practices as it applies to equipment specification, placement, maintenance, refurbishment, replacement and disposal. These practices ensure that monitoring, assessing, justifying for capital refurbishment, and replacing for asset sustaining purposes are consistently executed. Hydro has established programs which enact these practices for assets or sub-grouping of assets, for example, turbine overhauls are performed on each hydraulic generating unit.

Part of Hydro’s Annual Capital Program is a sustained effort to ensure the safety and reliability of generation assets. Historically, the Board’s approval for this effort has been requested by Hydro submitting either individual projects for particular assets, or programs for hydraulic generation sustaining work in its CBA. This approach has resulted in a segmented view of the expenditures to sustain generation assets. For example, in the 2017 CBA, there were 14 projects submitted. The expenditures detailed in the projects according to the Board’s classifications are normal capital expenditures. Combining these projects into a Hydraulic Generation Asset Management Program provides an opportunity to increase regulatory efficiency and provide a more focused presentation of Hydro’s sustaining efforts for hydraulic generation.

With the 2018 CBA, Hydro consolidated planned Hydraulic Generation sustaining work into a project called Hydraulic Generation Refurbishment and Modernization Project (“Project”). Additionally, in the 2018 CBA, Hydro submitted a project titled “Hydraulic Generation In-Service Failures”, to cover the replacement or refurbishment of failed equipment, or incipient failures. Hydro is utilizing the Asset Management Overview as a reference for these projects to streamline and focus information submitted.

The Asset Management Overview provides supporting information which was, historically, presented annually for projects in a CBA. The remainder of this document provides information on the assets involved, a description of each asset, and how this document will be updated in the event of changes to Hydro's asset management philosophies.

Hydro will update the Asset Management Overview each year as it implements changes to its asset management practices appropriate for inclusion in the Asset Management Overview.

1.1 Changes in Version 3

This report is Version 3 of the Asset Management Overview, submitted with the 2020 CBA. All material changes in this version are shaded in grey, and are summarized below:

- Section 4.4.9: Replace Unit Metering, Monitoring, Protection, SCADA and Control Assets Program
- This section has been updated to include the Air Gap Monitoring Program and Partial Discharge Monitoring Replacement Program.
- Section 4.5.3: Penstock Inspection Program
- This section has been added to highlight the Penstock Inspection Program that began in Bay d'Espoir and is continuing at other locations.

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

2.0 Hydraulic Generation Background

2.1 Hydraulic Generating Stations

The location, number of generators at each location, and the total rated generating capacity of Hydro's ten generating stations is as follows:

1) Bay d'Espoir ("BDE"), seven units in two powerhouses outputting 613.4 MW;
2) Cat Arm ("CAT"), two units outputting 134 MW;
3) Upper Salmon ("USL"), one unit outputting 84 MW;
4) Hinds Lake ("HLK"), one unit outputting 75 MW;

5) Granite Canal ("GCL"), one unit outputting 40 MW;

6) Paradise River ("PRV"), one unit outputting 8 MW;

7) Snook's Arm ("SAM"), one unit outputting 560 kW

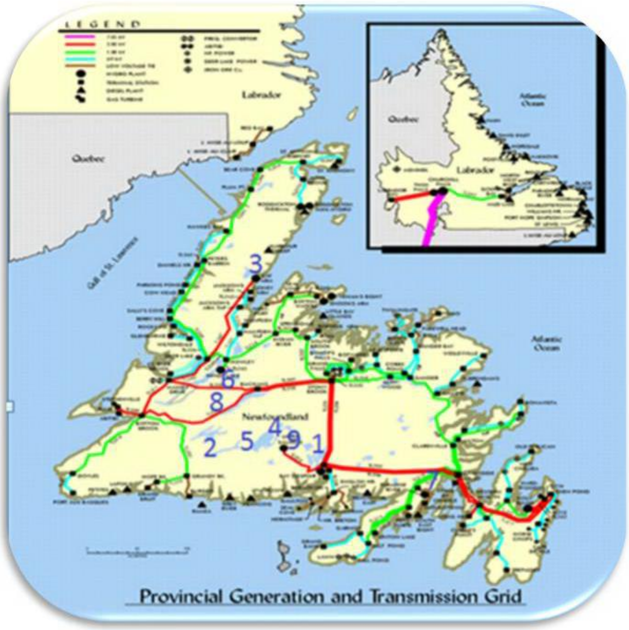
8) Venams Bight ("VBT"), one unit outputting 340 kW; and

9) Roddickton ("RMH"), one unit outputting 440 kW.

Table 1 provides the in-service dates for each turbine generating unit.

Table 1: Turbine Generating Unit In-Service Dates

#	Location	In-Service Date
1	Paradise River	February 26, 1989
2	Bay d'Espoir Powerhouse 1	Unit 1: March 1967 Unit 2: June 1967 Unit 3: October 1967 Unit 4: September 1968 Unit 5: February 1970 Unit 6: March 1970
3	Bay d'Espoir Powerhouse 2	Unit 7: December 1977
4	Upper Salmon	January 1983
5	Granite Canal	August 2003
6	Snook's Arm	September 1957 (Acquired in 1968)
7	Venams Bight	April 1957 (Acquired in 1968)
8	Hinds Lake	December 1980
9	Cat Arm	Unit 1: February 1985 Unit 2: February 1985
10	Roddickton	December 1980



1. Bay d'Espoir – Powerhouses #1 & #2
2. Burnt Dam – Spillway Structure
3. Cat Arm - Powerhouse
4. Ebbegunbaeg – Control Structure
5. Granite Canal – Powerhouse
6. Hinds Lake - Powerhouse
7. Paradise River - Powerhouse
8. Star Lake - Powerhouse
9. Upper Salmon - Powerhouse

Figure 1: Hydraulic Generation and Structures Locations

2.2 Infrastructure Classifications

The approximately 3000 hydraulic generating assets are functionally grouped into hydraulic generating units (Section 4.4), hydraulic structures (Section 4.5), reservoirs (Section 4.6), site buildings and services (Section 4.7), and auxiliary equipment classifications (Section 4.8). A functional description and further sub-classification of the infrastructure, equipment and systems within these five asset classifications is provided in Appendix A: Full Asset Description.

3.0 Hydraulic Generation Capital Projects

3.1 Historical Hydraulic Generation Capital Projects

In the 2017 CBA, there were 14 individual Hydraulic Generation projects, which accounted for $13.1 Million, or 5 percent of the Capital Budget. Historically, Hydro's generating station projects were divided into two categories; stand-alone, and programs. Programs include projects that are proposed year after year to address the required refurbishment or replacement of assets, such as control cables, and have similar justification presented each year. Of the 14 individual Hydraulic Generation projects proposed in 2017, two were program- related and the 12 stand-alone projects were similar to projects submitted in previous CBAs and as such were continuing efforts to sustain hydraulic generating assets.

3.2 Hydro's Approach to Hydraulic Generation Capital Projects

The programs now included in the Project are:

- Hydraulic Generating Units Program;
- Hydraulic Structures Program;
- Reservoirs Program;
- Site Buildings and Services Program; and
- Common Auxiliary Equipment Program.

Items which will be excluded from the Hydraulic Generation Refurbishment and Modernization Project and be proposed separately include:

- Activities which cannot be scheduled for inclusion in the annual CBA. As these projects will be submitted as either a supplementary application or executed in the Hydraulic Generating Stations In-Service Failures Project.
- Activities in response to additional load or reliability requirements. As these projects generally have unique justifications, the projects will be proposed separately.
- Activities in response to significant isolated issues in a particular station, such as a replacement of a damaged turbine. As these projects generally have unique justification, the projects will be proposed separately.

Hydro will continue to maintain individual records with regards to asset capital, maintenance and retirement expenditures and performance, to support the development of the annual capital plan.

3.3 Benefits of the New Approach

Supporting information such as asset descriptions change infrequently. Referencing the Asset Management Overview in the Project documentation will eliminate the preparation and review of repetitious information. Hydro estimates that this approach could save up to $130,000[1] annually, not including time and costs for review by the Board and Intervenors.

[1] If the work to be undertaken in the 2018 Hydraulic Generation Refurbishment and Modernization Project had been submitted as 13 individual projects, its estimated preparation cost would be approximately $10,000 per project.

Hydro has a proactive Asset Management Program to anticipate future failures so that refurbishment or replacement can be incorporated into a CBA. However, there are situations were immediate refurbishment or replacement, which has not been included in a CBA, has to be undertaken due to the occurrence of an unanticipated failure or the recognition of an incipient failure. This is necessary to maintain the delivery of safe, reliable electricity at least cost. These situations seldom include extenuating or abnormal circumstances and costs. With aging assets, unanticipated failures are expected to increase. This increase will require additional future efforts to provide and review regulatory documentation. By introducing a Hydraulic Generation In-Service Failures project, there will be a reduced need for that documentation and change management processes. Each year, Hydro will provide a concise summary of the previous year's work.

Hydro expects the Hydraulic Generation Refurbishment and Modernization Project will provide opportunities whereby Hydro can further optimize the coordination of opportunities to optimize capital and maintenance work to minimize outages on equipment as personnel look to further coordinate work by location.

4.0 Asset Management Programs

4.1 Condition Assessment Practices

Hydraulic generation asset management personnel primarily obtain information to assess the condition of hydraulic generation assets through calendar-based or equipment operating time-based activities. Calendar-based activities include, but are not limited to, daily, weekly, monthly, quarterly, annual and three-year preventive maintenance procedures. Operating time-based activities include 500, 1000 or 2000-hour preventive maintenance procedures. More information on calendar based or equipment operating time based activities is presented in Appendix B: Operational Hour and Time Based Activity Background.

Capital overhauls and refurbishments are conducted on differing timeframes depending upon the asset, but range from approximately 6 to 25-year time frames. The actual timing of this work is determined by asset management personnel after considering various factors such as reliability, safety, frequency of operation, asset criticality, condition, operating constraints and geographic location. More information on how timing is determined is presented in Appendix C: Overhaul Timing Background.

The more frequent calendar-based and equipment operating time-based maintenance procedures consist of visual inspection of the equipment to look for abnormalities, such as noticeable cracks, rust, corrosion, electrical tracking, and component malfunction, as well as minor maintenance such as oil and filter changes, as required. The remaining preventive maintenance procedures and capital program activities require outages to the equipment and entail progressive levels of disassembly, checking, testing and adjustments of systems and components allowing for the identification of abnormalities which cannot otherwise be identified. These activities require greater or complete disassembly, specialized inspections and testing of equipment and, if required based upon condition assessment, unforeseen refurbishment or replacement activities completed within the approved budget for the program.

The condition assessment information, documented by the personnel executing these activities, is reviewed by Long Term Asset Planning personnel who determine if corrective action, either expensed as operating or included as capital, is required.

Additionally, Long Term Asset Planning personnel may initiate condition assessments of existing equipment and determine whether corrective action is required when information is obtained through different sources than those outlined above. These sources may include operating personnel, vendors, industry related groups and literature. This information may relate to such situations as changes to safety practices, reports of performance indicating that an asset is approaching end of service life, industry experience identifying new equipment issues, and manufacturers withdrawing product support (obsolete equipment) resulting in Hydro being unable to obtain spare parts and obtain technical expertise to maintain the equipment . Corrective actions may be required immediately, or may be executed at a future time. Condition assessment and practices specific to an asset classification are outlined in the corresponding program described later in the Asset Management Overview.

4.2 Program Types and Timing

The programs in the Asset Management Overview are primarily focused on the capital overhauls and the execution of corrective actions required by each asset classification. As the implementation of corrective action increases or is projected to increase, a program will be added to the Asset Management Overview. Due to the volume and complexity of hydraulic generation assets, capital corrective actions are required that do not warrant the establishment of a long-term capital program.

For each asset classification, these activities are captured under the section titled "Other Sustaining Activities". Capital corrective actions that are aligned with the Asset Management Overview philosophies and practises as well as capital work which will result in economic savings, but do not reside within an established capital program, will be included in this program. Examples of capital work that could be included under Other Sustaining Activities are:

1) Deteriorated systems, equipment, components or material approaching the end of their service life;
2) Systems, equipment, and components for which manufacturers have withdrawn product support or industry experience has identified new performance issues;
3) Changes to safety practices on existing infrastructure; and
4) Replacement of existing assets with economically justified replacements.

In the Hydraulic Generation Refurbishment and Modernization Project submitted with each CBA, the "Other Sustaining Activities" items, with associated costs and a brief explanation of the work, will be provided for the Board's review.

The timing of capital overhauls is determined by Long Term Asset Planning personnel after considering various factors including asset performance, safety concerns, frequency of operation, criticality, condition, corrective actions required, operating constraints and geographic location. More information on how timing is determined is presented in Appendix C. Execution of capital corrective actions which align with philosophies and practises outlined in the Asset Management Overview will be included in the "Hydraulic Generation Refurbishment and Modernization Project" or in the "Hydraulic Generation In-service Failures Project". Immediate corrective actions stemming from an approved Hydraulic Generation Refurbishment and Modernization Project which can be accomplished within the project scope and budget may proceed within that project.[2] Future corrective actions would be included in the "Hydraulic Generation Refurbishment and Modernization Project" submitted in a future Capital Budget Application.

[2] Immediate action which cannot be accomplished within the scope and approved budget of an approved Hydraulic Generation Refurbishment and Modernization Project would be addressed either through the Hydraulic Generation In-Service Failures Project or through a Supplementary Capital Budget Application.

4.3 Asset Classification Description

Each asset classification section includes a high level functional description of the group's assets. More information about the infrastructure, systems, equipment, and components in an asset classification is provided in Appendix A: Full Asset Description.

4.4 Hydraulic Generating Units Asset Classification

Hydro's Hydraulic Generating Units Asset Classification consists of:

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

Figure 2 is a cross-section of a Hydraulic Generating Unit.

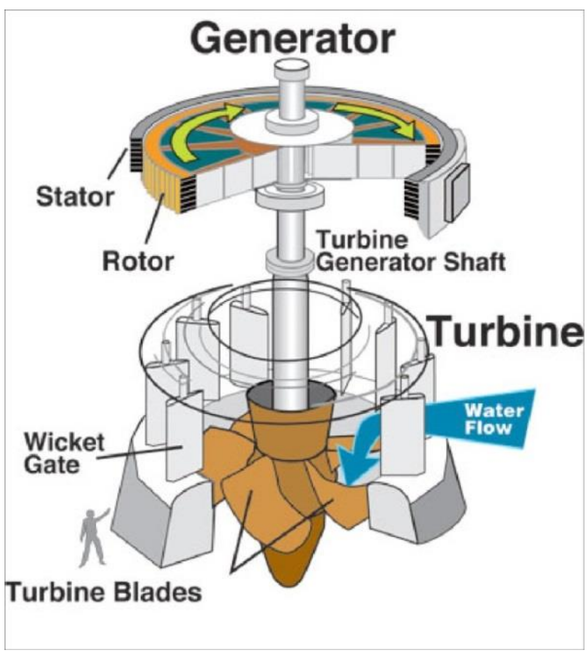


Figure 2: Hydraulic Generating Unit

Flowing water is directed from a penstock through a main inlet valve (where equipped) and into a spiral case, which encircles the turbine runner. The wicket gates direct water from the spiral case into the turbine runner (noted as turbine blades in Figure 2). The water turns the turbine runner and then flows into the draft tube attached to the turbine. The water passes through the draft tube and on to the tailrace to exit the generating station. A shaft connects the turbine runner and the generator rotor. Turning the runner causes the rotor to turn. Electrical interaction, created by the unit exciter system, between the stator and the moving rotor produces electricity for transmission to customers. A unit governor system controls the flow of water, by way of the wicket gates, to ensure an appropriate amount of water is passing through the turbine so as to supply the electrical power required from the generator. The electricity is passed from the generator to the electrical transmission system outside the hydraulic generation station through an electrical isolated phase bus system. Rotating equipment requires lubrication, so the unit has an automatic greasing system. Hydraulic generating units have protection, control, instrumentation, condition monitoring, SCADA[3] and metering equipment to ensure safe, reliable operation and asset management data for the unit.

Figure 3: Dismantled Generator

[3] Supervisory Control and Data Acquisition ("SCADA") systems gather information from the field, transfer the information back to a central site, alert the central site of abnormal system conditions, perform necessary analysis and control, and display information to operators. Operators interface with the SCADA which connects to equipment in the field.

4.4.1 Turbine and Generator Six Year Overhauls Program

The Six-Year Overhaul involves a partial dismantling of the turbine and generator to inspect, test, clean, refurbish the units. This may entail replacing defective components and, as required, undertaking corrective refurbishment or replacement action. The generator activities involve activities such as cleaning and inspection of rotor and stator assembly, electrical testing on rotor/stator assembly and calibration and testing of turbine and generator protection devices. The turbine activities involve such activities as verification of bearing and seal clearances and testing and calibration of turbine protection, control and monitoring devices. During these overhauls, due to the dewatering of the unit, the draft tube and penstock are also inspected.

4.4.2 Turbine Major Refurbishment Program

The Turbine Major Refurbishment occurs on approximately a 15 to 25-year cycle and involves completely disassembling, inspecting, testing, assessing the turbine mechanical components and, as required, carrying out corrective work to refurbish or replace components to maintain the turbine performance until the next major refurbishment. As the unit is dismantled for the turbine major refurbishment, this offers an opportunity to carry out, if required, other sustaining work on the unit, including:

- Inspection and replacement, as required, of the head cover and bottom ring bushings;
- Inspection and, as required, replacement of the operating ring bearing;
- Replacement of wicket gate V packing;
- Replacement of various gaskets and seals;
- Refurbishment of runner due to cavitation damage;
- Machining of other unit surfaces as required based on condition assessments; and
- Testing and calibration of turbine protection, control and monitoring devices.

In the past, concrete growth in the turbine foundation and the resulting erosion caused movement of the turbine lower primary stationary seal. This could cause contact between the stationary and rotating seals and require a full dismantling of the unit to correct. Therefore, as required, grouting and machining of the upper and lower primary seals is also included in the Major Turbine Refurbishment.

4.4.3 Generator Refurbishment Program

Hydro's generator stator windings have an anticipated service life of 40 years. As a unit approaches the end of its expected service life, a condition assessment is carried out. These assessments reveal signs of electrical deterioration such as seeping asphalt or cracked insulation, or mechanical deterioration such as shifting windings as a unit approaches the end of its useful life. At this point, Hydro takes action to replace the windings. Hydro undertook work to replace generator stator windings due to stator mechanical and electrical deterioration from 2009 to 2014. Future work of a similar nature will be completed within this program.

4.4.4 Spherical Valve By-Pass Refurbishment Program

Since 2013, Hydro has completed five spherical valve by-pass refurbishment projects due to deterioration and poor operating performance of the by-pass valve and control system. As the spherical valve by-pass reach the end of their service life, the valves begin to malfunction and become prone to failures due to seized internal components. Future work of this nature will be undertaken within this Program.

4.4.5 Exciter Replacement and Refurbishment Program

Hydro has undertaken ten exciter replacements due to a withdrawal of manufacturer product support. Future work to replace or refurbish existing exciters will be completed within this program.

4.4.6 Automate Generator Deluge Systems Program

Since 2013, Hydro has been automating the deluge systems at Bay d'Espoir. Future work to automate the remaining systems will be completed under this program.

4.4.7 Refurbish Generator Bearings Program

Since 2013, Hydro has been refurbishing the generator bearings and housings to eliminate oil loss from the bearing housing. Future work of this nature will occur under this program.

4.4.8 Replace Auto Greasing Systems Program

As the auto-greasing system on a generating unit ages, it becomes prone to issues such as solenoid failures, damaged timers and switches, and leaking tubing. On older units, the unavailability of replacement components makes maintenance of the systems difficult. Since 2013, Hydro has replaced six automatic greasing systems due to deterioration, incompatibility with new controllers, and on-going maintenance issues. This program will be used to undertake future work of this nature.

4.4.9 Replace Unit Metering, Monitoring, Protection, SCADA and Control Assets Program

In 2016, the Bay d'Espoir Unit 7 vibration monitoring system was replaced to improve condition monitoring of Unit 7. The previously installed vibration monitoring system was unreliable. The new monitor has increased the diagnostic information available to asset management and maintenance personnel. Hydro plans additional work starting in 2018 to replace the other monitors on Bay d'Espoir Units 1 to 5 because the monitors are obsolete. The new monitors will allow long-term trending of data. Hydro will replace protective relays, annunciators, human-machine interfaces, other metering, monitoring, protection, and control equipment as it becomes obsolete, fails or operate unreliably, to ensure reliable operation of protective devices.

In 2017, a multi-year project to install a new Asset Health Monitor system, for Upper Salmon, started. The new Asset Health Monitor system will gather diagnostic data from the generating unit and provide trending analysis for asset management and maintenance personnel. Hydro plans additional work starting in 2018 to replace obsolete monitoring devices on Bay d'Espoir Units 1 to 5.
In 2017, Hydro identified control cables in its Hydraulic Generating Station are leaking oil, which is contaminated with PCB's. In 2018, Hydro will start a five year effort to replace the cables and, if required, associated infrastructure.

Air Gap Monitoring measures the gap between the rotor and the stator on a Hydroelectric Generating Unit. Changes in air gap can be influenced by operating conditions such as shaft oscillation, vibration, magnetic and hydraulic forces. Starting in 2009 and continuing to 2014 units 1-4 in Bay d'Espoir have had the stators rewound, see section 4.4.3 of this report. During this work air gap monitors were added to the units for online real time monitoring of the air gaps. Online monitoring of the air gap between the rotor and stator can provide significant and timely information about its physical condition as it changes over time and with different operating conditions.

In 2020, Hydro has proposed to rewind Unit 5 in Bay d'Espoir and add air gap monitoring to this unit. This monitoring device requires a partial dismantle of Unit 5 and is done during the rewind for labour efficiencies associated with unit dismantling. This program will be used to undertake future work of this nature.

In 2020, also combined with the Unit 5 Stator Rewind Project, Partial Discharge ("PD") Monitoring will be upgraded on Unit 5. PD analysis is used to determine the rate and level of degradation of stator insulation. PD Monitoring along with Air Gap Monitoring upgrades are done with this rewind project for labour efficiencies associated with unit dismantling. This program will be used to undertake future work of this nature.

Hydro expects additional replacement of metering, monitoring, protection, and control equipment assets, including wiring, panels and other supporting materials and devices, due to deterioration and obsolescence; and to provide more functional equipment. Work of this nature will be covered by this program.

4.4.10 Other Sustaining Activities

As described in Section 4.2 Program Types and Timing.

4.5 Hydraulic Structures Asset Classification

Hydro's Hydraulic Structures Asset Classification consists of:

- Control Gates;
- Penstocks;
- Surge tanks; and
- Remote Water Level Systems.

Figure 4 is a cross-section of a hydroelectric installation showing the intake gate.

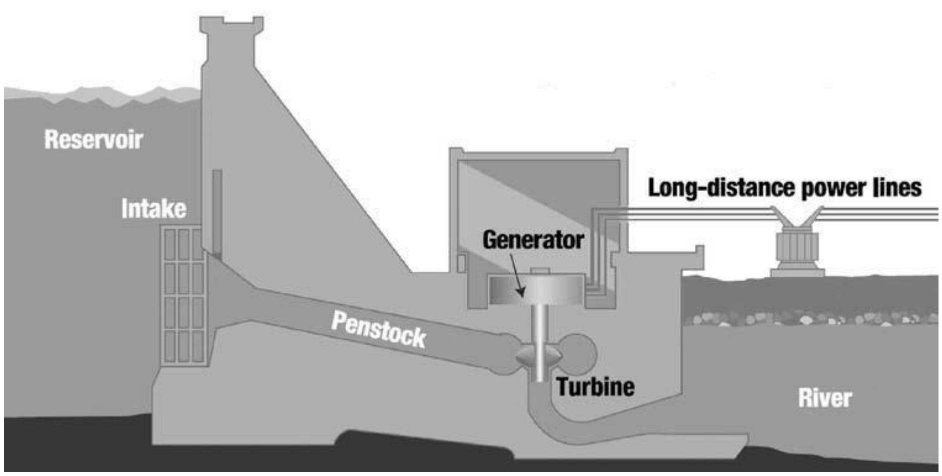


Figure 4: Cross-Section of Intake

Hydro uses hydraulic control structures to control the flow of water from reservoirs. Structures associated with a powerhouse intake control the flow of water from the reservoir into penstocks which transport water to a hydraulic generating unit (shown as a turbine and a generator in Figure 4) to produce electricity. Structures associated with a spillway control the flow of water from the reservoir into a spillway ("Spilling"). Spilling, when required, is done to avoid damage to the reservoir dams or dykes caused by excessive water in the reservoir. Hydro's control structures consist of structural, mechanical, and electrical systems. The water flows through the concrete structures and the mechanical systems incorporated into the concrete structure. The mechanical systems controlling the flow of water include vertical sliding gate, a gate hoist, gate rollers, seals, and embedded steel parts in the concrete to allow movement of the gate by the hoist. Electrical systems include heaters to prevent icing of the mechanical systems in the concrete structure, power supply systems and control systems for the gate equipment. The stoplogs are mechanical systems of wood or steel members placed by lifting devices between control structures and the reservoirs so as to stop water from flowing through the concrete structures when the mechanical gate systems are being worked upon. Hydro has 21 hydraulic control structures, which incorporate 40 gates.

Figure 5: West Salmon Spillway Control Structure

A penstock is a large pipe, most commonly constructed of welded steel, which conveys water from a reservoir to turbine. Serving the hydraulic units Hydro has eight steel and one wood stave penstock and three arrangements with penstock/power tunnel combinations.

Some hydraulic generating stations, with high head designs, have surge tanks are connected to penstocks to neutralize the impact of sudden changes in pressure on the penstock caused by operation of the station. Water flows into the tank when the penstock water pressure increases and out of the tank when penstock pressure decreases, thus mitigating the effects of water hammer on a penstock. Hydro has four surge tanks in two hydraulic generating stations.

Figure 6: Surge Tanks at the Bay d'Espoir Hydraulic Generation Station

The primary preventive maintenance procedure for Hydraulic Structures is a yearly inspection. Based upon condition, overhauls are performed on a 10-15 year frequency.

4.5.1 Refurbishment and Replacement of Control Gates Infrastructure Program

Failure of subcomponents of control structures can result in safety hazards, equipment damage, or the inability to operate gates as required. The failure of the gate control system has resulted in the filling of the penstock too quickly, creating hazardous conditions; the failure of gate heaters can result in mechanical components freezing, resulting in their failure to operate. Since 2009, Hydro has undertaken control gate refurbishments in Hinds Lake, Upper Salmon, and Bay d'Espoir for intake structures and at Salmon River, Victoria and Burnt Dam for spillway structures. This work has included structural, mechanical, electrical and control system work. Future refurbishment work will be executed through this program.

4.5.2 Refurbish Surge Tanks Program

Hydro carries out progressive inspections monthly and annually on surge tanks, and a major inspection every six years. Based on these inspections, Hydro determines whether corrective action is required. Over time, protective coatings degrade, resulting in increased corrosion which, if left unmitigated, may result in leaks or structural failure of the tanks. Failure of the cathodic protection and protective coating of the surge tanks resulted in corrosion on the Bay d'Espoir assets. In 2014, 2015, and 2016, Hydro completed projects to refurbish the surge tanks. Future refurbishment work on any surge tanks will be covered by this program.

4.5.3 Penstock Inspection Program

Issues experienced with Bay d'Espoir Penstocks 1-3 in 2016 and 2017 have compelled Hydro to make significant changes to its inspection frequency and scope for all hydraulic unit penstocks. Gaps were found in penstock inspection frequency for all Hydro's penstocks. Penstock inspection frequency was determined with assistance from ASCE Steel Penstocks, 2012 manual as well as CEATI Penstock Inspection 2017 report. Using criteria set out by both of these organizations for comprehensive internal inspections, Hydro has set up a framework to carry out internal inspections for all penstocks.

4.5.4 Other Sustaining Activities

As described in Section 4.2 Program Types and Timing.

4.6 Reservoirs Asset Classification

Hydro's Hydraulic Reservoirs Asset Classification consists of:

- Dams;

- Dykes;
- Power canals;
- Spillways;
- Control weirs;
- Fuse plugs;
- Tunnels;
- Instrumentation; and
- Public safety control measures.

Figure 7 is a general cross-section of an embankment type dam.

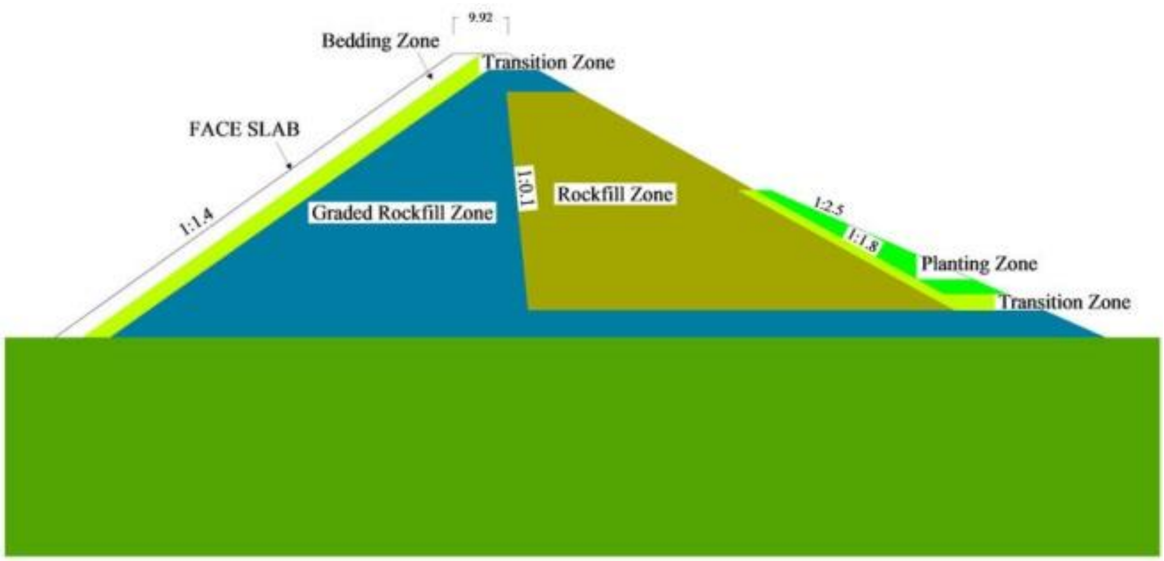


Figure 7: Dam Cross-Section

Dams and dykes are constructed to increase the storage capacity of the reservoir. The majority of Hydro’s dams are embankment type structures. The largest structure is 63m high. Power canals are typically a dyke lined canal developed to convey water between reservoirs, or from a reservoir to an intake structure. Passive overflow spillways are dams that are built to spill water from a reservoir at a specific elevation. Overflow spillways in Hydro’s system are constructed of rock fill with steel sheet pile cores, concrete or timber crib. Control Weirs are low head concrete overflow spillways that maintain the water elevation upstream of the weir to within a specified range. Fuse plugs are sections of dams that are constructed of earth materials and designed to fail in a controlled manner without damaging adjacent larger, more critical dams. Power tunnels convey water, through rock, from a reservoir to an intake structure. Diversion tunnels divert water around the work site. Dam instrumentation provides measurements for comparison to the dams design criteria.

Figure 8: Hinds Lake Power Canal

Hydro has approximately 80 dykes and major structures in this classification. Hydro carries out preventive maintenance activities at various frequencies for different asset types. For instance, dam-type assets are visually inspected biweekly and undergo semi-annual engineering inspections.

Figure 9: Safety Boom and Signage

4.6.1 Upgrade Public Safety around Dams and Waterways Program

Public safety risks are determined by completing risk assessments in accordance with the Canadian Dam Association's Dam Safety Guidelines, 2007 that includes guidelines for public safety and security around dams. Appropriate control measures are then installed to reduce the safety risk to the public. These measures include such items as signage, fencing, audible or visual alarms, booms and buoys (as shown in Figure 9), operational changes and public education. Hydro has conducted seven public safety projects since 2011. Future work to further enhance public safety around Hydro dams and waterways will be undertaken through this program.

4.6.2 Other Sustaining Activities

As described in Section 4.2 Program Types and Timing

4.7 Site Buildings and Services Asset Classification

Hydro's Site Buildings and Services Asset Classification consists of:

- Water distribution systems;
- Fuel storage and distribution systems;
- Powerhouse buildings;
- Service buildings;
- Helicopter Pads;
- Site fencing and gate controls;
- Parking lots;
- Stairways; and
- Site access roads.

Figure 10: Paradise River Generating Station

Water distribution systems collect, transmit, treat, store, and distribute domestic water. Fuel storage and distribution systems handle diesel, helicopter, and gasoline fuels. Powerhouse buildings contain the hydraulic generating unit and the unit auxiliary mechanical and electrical equipment. Service buildings are other building required for a hydraulic generating station, which includes warehouses, maintenance buildings, training facilities, site accommodations, and security offices. Helicopter pads allow helicopters to use relatively flat, clearly marked hard surfaces away from obstacles to land and take off safely. All sites have fencing and/or gates with controls to maintain site security and public safety. The parking lots and stairways provide vehicle parking and safe access to facilities. Site and access roads allow access to hydraulic generation locations, such as generating stations and dams.

Site Buildings and Services assets are inspected and, where applicable, tested annually.

4.7.1 Access Road Refurbishment Program

Since 2010, Hydro has undertaken four projects to refurbish access roads to its hydraulic generating stations to maintain safe access to Hydro sites. Refurbishment was necessary due to deterioration caused by insufficient drainage, washouts, or the need for additional road topping material. Hydro expects to undertake similar work in the future and will execute it within this program.

4.7.2 Diesel Fuel Storage Refurbishment and Replacement Program

Hydro has 19 diesel fuel storage tanks at its hydroelectric generating stations. These are subject to deterioration, such as reduced wall thickness and corrosion discovered during routine tank inspections. Tanks are also subject changing government regulations. Hydro will use this program to refurbish or replace tanks when deteriorated and to comply with Government regulations. Hydro has tanks in remote locations and since 2007 has installed remote monitoring on some of those tanks. If required to add remote monitoring to other tanks, Hydro will undertake this work within this program.

4.7.3 Draft Tube Deck Refurbishment Program

A draft tube deck is a common feature in a hydroelectric plant. The draft tube is where the exhausted water from the hydro unit exits and is directed to the tailrace. The draft tube deck is a reference to the full structure including the substructure, exit water channels, and the deck above that can be driven over or has walk access to install draft tube gates. Draft tube gates are used to isolate the hydro unit by preventing tailrace water from coming back up through the unit. For Example: The draft tube deck in Bay d'Espoir is 97 meters long, and is made up of reinforced concrete columns, pre-cast deck beams and pre-cast deck slabs, topped with a six inch concrete distribution slab and finished with 50 mm of asphalt. The structure allows for vehicles to access Powerhouse 2 on site and the substructure of the deck channels water from the draft tube of the hydro unit to the tailrace.

Over time concrete degrades and the structure experiences wear due to weather and water erosion. Once this damage occurs, refurbishment of the structures is required to ensure the reliable operation of the hydro units. Future refurbishment work on any Draft Tube Deck will be covered by this program.

4.7.4 Other Sustaining Activities

As described in Section 4.2 Program Types and Timing

4.8 Common Auxiliary Equipment Asset Classification

Hydro's Common Auxiliary Equipment Asset Classification consists of:

- Station service;
- Ancillary AC/DC electrical system;
- Standby diesel generators;
- Cranes;
- Fire protection and detection systems;
- Powerhouse public address systems;
- Compressed air systems;
- Service/cooling water systems;
- Domestic water systems;
- Drainage/unwatering systems;
- Water level systems;
- Heating, ventilation, and air conditioning systems;
- Waste oil storage tanks; and
- Lube oil storage.

Figure 11 is a picture of the Bay d'Espoir Station Service Transformers. This is one of many examples of auxiliary equipment required for Hydro's daily operations.

Figure 11: Bay D'Espoir– Station Service Transformers

Station service system uses transformers and other equipment to convert AC electricity to a voltage acceptable for use in the ancillary AC/DC electrical system which distributes electricity to ancillary equipment needed in the operation of the hydraulic generating station. Standby diesel generators are installed at locations that require electricity for operations, for use if the primary power supply is interrupted. Cranes are used during maintenance and capital work. Fire protection and detection systems are installed to protect people, buildings, power transformers, generators, and other equipment. Powerhouse public address systems allow communication within a noise working environment. Compressed air systems provide pressurized air to equipment that requires pressurized air to operate, such as governors, and spherical valves. Service/cooling water systems are used to remove heat from turbines and generators, particularly bearings and generator stators. Domestic water systems supply water where water is needed. Drainage/Unwatering Systems remove water from the hydraulic generating unit to allow access to the turbine. Water level systems provide water level monitoring in streams, lakes or reservoirs. Air conditioners control the temperature for personnel and equipment.

Heating, ventilation and air conditioning ("HVAC") systems also provide humidity control for humidity-sensitive electrical equipment. Ventilation systems remove waste heat generated by generating units, and circulate fresh air using ducts and fans. Waste oil storage tanks hold used oil for disposal. Lube oil storage are laydown areas for the 200 litre drums of lube oil that are located at most generating stations.

There is a mixture of time based preventive maintenance procedures ranging from weekly to yearly, and a mixture of operational hour preventive maintenance procedures ranging from 500 to 2000 hour checks used to assess and maintain these assets.

4.8.1 Station Service Refurbishment and Replacement Program

Station service systems in Hydraulic Generating Stations are complex systems comprised of a number of subsystems. Devices such as reclosers and circuit breakers require replacement as they become obsolete, resulting in the unavailability of replacement parts required to maintain equipment or operate unreliably. Equipment may require replacement to reduce fault levels, and arc-flash levels, or improve protection coordination, either of which may result in safety hazards or equipment damage if left unmitigated. Electrical equipment, such as transformers, is prone to insulation breakdown and other deterioration as it reaches the end of useful service life and require refurbishment or replacement. In 2015, 2016 and 2017, station service electrical equipment was replaced at Cat Arm and Bay d'Espoir due to operational failures, deterioration, and weak protective coordination between devices. Hydro expects work like this will occur in the future and will undertake that work under this program.

4.8.2 Service/Cooling Water Refurbishment and Replacement Program

Over time, cooling water pipes can become clogged with organic slime and hardened organics that attach themselves to the pipe walls causing the cooling water flows to decrease significantly. Additionally, older cooling water pipes are constructed of mild steel, which is prone to corrosion over time. Since 2009, Hydro has undertaken 11 projects to replace cooling systems and piping, pump, and instrumentation components due to pipe fouling from material build up and corrosion. Future capital work on service/cooling water systems will be undertaken within this program.

4.8.3 Air Conditioning Refurbishment and Replacement Program

Hydro has refurbished or replaced air conditioning systems and improved ventilation in four projects due to obsolescence, resulting in the unavailability of replacement components require to maintain units. Air conditioning systems are also replaced or upgraded due to increased cooling requirements. Future capital work for this will be executed through this program.

4.8.4 Standby Generator Refurbishment and Replacement Program

Since 2009, Hydro has replaced three standby generators at Bay d'Espoir due to poor performance and the inability to reliably supply station service power in an emergency. Primary power diesel generators have been replaced at the Burnt Dam and Victoria Control Structure locations. Diesel generators require an engine overhaul based on operating hours and operating performance. Typically, standby diesels rarely require this refurbishment and primary power diesel generators require this refurbishment about every five years. Future replacement and refurbishments of diesel generators will be completed under this program.

4.8.5 Ancillary AC/DC Electrical System Refurbishment and Replacement Program

In 2011 and 2013, Automatic Transfer Switches were replaced at Bay d'Espoir and Hinds Lake due to operational failures. In 2015, Hydro started the installation of Infrared Inspection Viewports in electrical equipment at various hydraulic generating stations to allow safe inspection of the equipment while energized. Installations of the viewports will occur under this Program. In addition, Hydro expects that the replacement and refurbishment of ancillary AC/DC electrical assets will continue to maintain a reliable supply of electricity. In the future, this work will occur under this program.

4.8.6 Other Sustaining Activities - Common Auxiliary Equipment Program

As described in Section 4.2 Program Types and Timing

Appendix A

Full Asset Description

Hydraulic Generating Units

Generator

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

Stator Assembly

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

Rotor Assembly

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

Thrust and Guide Bearing

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

Cooling Water System

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

Governor

The governor serves to keep the speed of the hydro unit constant in order to maintain the systems frequency of 60 hertz. Any change in load or other operational disturbances will cause the governor to open or close the wicket gates to allow more or less water to maintain the constant speed of the Hydro Unit.

Governor Speed Generators

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

Governor Pump

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

Governor Piping System

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

Accumulator Tank

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

Servomotor Assembly

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

Isolated Phase Bus

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

Disconnect Switch

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

Grounding Switch

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

Buswork

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

Main Inlet Valve

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

Turbine

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

Runner

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

Draft Tube

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

Guide Bearing

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

Auto-greasing System

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

Turbine Shaft and Coupling

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

Scroll Case

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

Headcover Assembly

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

Wicket Gates and Linkages

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

Excitation

Excitation Transformer

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

Field Breaker

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

Metering, Monitoring, Protection, SCADA and Control

Ground Cubicle

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

Auto Control Panel

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

Synchronizing Panel

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

Temperature and Frequency Control Panel

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

Time and Frequency Clock

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

Oscillogragh

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

Voltage and Megawatt Panel

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

Recorder

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

Control Cables and Junction Boxes

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

Vibration Monitoring System

Hydro Unit systems

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

Handheld Units

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

Data Acquisition System

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

Hydraulic Structure

Substructure

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

Superstructure

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

Gates

The structure gates are designed to hold back water. In a spillway the water is on one side and the other side is typically dry when the gates are closed. Depending on the function of the particular structure, the gates are opened to move water from one reservoir to another, or to spill water from the reservoir when the water level exceeds the maximum safe level.

Stoplogs/Master logs

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

Gate Hoist

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

Gate Rollers, seals, and embedded parts

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

Heating Systems

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

Control Systems

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

De-icing Systems

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

Penstock

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

Surge Tank

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

Heating Systems

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

Relief Valves

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

Coating Systems

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

Drainage Systems

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

Water Level Systems

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

Reservoirs

Dams and Dykes

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

Power canals

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

Passive Overflow Spillways

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

Control Weirs

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

Fuse Plugs

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

Power Tunnels

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

Diversion Tunnels

Diversion tunnels divert water around the work site.

Dam Instrumentation

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

Public Safety Around Dams Control Measures

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

Site Buildings and Services

Water Distribution System

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

Piping

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

Pumps

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

Storage Tanks

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

Filters

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

Fuel Storage and Distribution System

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

Diesel Fuel Tank

Tanks that house diesel fuel only.

Gasoline Fuel Tank

Tanks that house gasoline fuel only.

Jet Fuel Tank

Tanks that house jet fuel only.

Fuel Dispenser and Pumps

Apparatus used to dispense and meter the fuel.

Powerhouse Building

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

Vertical Lift Equipment Doors

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

Roof

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

Substructure

The substructure is the underlying concrete support of the powerhouse.

Superstructure

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

Service Buildings

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

Substructure

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

Superstructure

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

Septic System

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

Garage Doors

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

Exhaust Systems (Welding)

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

Ventilation Systems

Ventilation systems circulate fresh air using ducts and fans.

Security Systems

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

Helicopter Pad ("Helipad")

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

Site Fencing and Gate Controls

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

Parking Lots and Stairways

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

Site and Access Roads

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

Drainage

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

Culverts

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

Bridge

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

Common Auxiliary Equipment

Station Service

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

Station Service Transformers

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

Circuit Breakers

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

Disconnects and Switches

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

Grounding Transformers

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

Instrumentation Transformers

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

Surge Arrestors

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

Power Cables and Junction Boxes

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

Ancillary AC/DC electrical system

Switchgear and Panels

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

Power Cables and Junction Boxes

Distributes electricity to equipment

Battery Banks and Chargers

Provides DC electricity for DC powered equipment.

Diesel Standby Generator

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

Engine

This is the diesel engine used to drive the genset.

Generator

The generator converts mechanical energy from the engine to electricity.

Enclosure

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

Cranes

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

Overhead

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

Monorail

A traveling crane suspended from a single rail.

Gantry

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

Wire Rope

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

Fire Protection and Detection System

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

Transformer Deluge System

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

Fire Panels

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

Generator Deluge System

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

Inergen System

Inergen agent is a mixture of three naturally occurring gases: nitrogen, argon, and carbon dioxide. This system releases the Inergen agent when the system is activated and floods the contained room with the agent to extinguish the fire by decreasing the oxygen concentration below levels required to sustain combustion.

Office Sprinkler System

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

Passive Fire Protection

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

Powerhouse Public Address System

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

Compressed Air System

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

Air Receiver Tank

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

Air Dryer

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

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

Compressors

A machine used to supply air at increased pressure.

Service/Cooling Water System

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

Pumps

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

Basket Strainers

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

Piping, valves, and controls

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

Domestic Water System

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

Drainage/Unwatering System

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

Sump Pumps

The pumping system required to remove the water.

Water Level System

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

Air Conditioners

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

Ventilation System

Ventilation systems circulate fresh air using ducts and fans.

PCB Waste Oil and Waste Oil Tanks

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

Lube Oil Storage

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

Appendix B

Operational Hour and Time Based Activity Background

Time Based Activities

Time based maintenance is maintenance performed on equipment based on a calendar schedule that is planned in advance. Hydro's Time Based PM includes:

- Daily operational checks – running maintenance
- PM 1: Weekly Checks
- PM 2: Bi-Weekly Checks
- PM 3: Monthly Checks
- PM 4: Quarterly Checks
- 120 Day Transformer Inspection
- PM 5: Semi-Annual Checks
- PM 6: Yearly Checks
- PM 8: 3 Year Checks
- PM 9: 6 Year Checks

Note: All the PM checks except for the PM 9 are operating expenditures.

Operational Hour Activities

Operational Hour Preventative Maintenance is performed based on the actual usage time of the piece of equipment. This applies to auxiliary equipment such as compressors that have operational time checks at:

- 500 Hour PM
- 1000 Hour PM
- 2000 Hour PM

Note: All the time based PMs are operating expenditures.

For each Time Based and Operational Hour activity listed specific check sheets has been developed for each asset classification, such as mechanical, electrical, and P&C. On each check sheet, there are specific checks and duties that have to be completed. If abnormalities, such as unexpected wear on a runner, are found, then they are reported to the Long Term Asset Planning group who assessed the condition and, if required, determine the corrective action and timing. This work may or may not require capital expenditures.

Appendix C

Overhaul Timing Background

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Major Equipment and Structural Overhauls

Major Equipment and Structural Overhauls are required on assets to ensure safe reliable operation. For Major Equipment and Structural Overhauls the timing is nominally between 6 and 25 year frequency. Some examples are:

- Generating Unit Major Overhauls, approximately every 6 years
- Generating Unit Turbine Refurbishments, approximately every 15 - 25 years
- Control Structure Major Overhauls, approximately every 10 years
- Intakes, Spillways, and Bypasses Major Overhauls, approximately every 15 years

To determine the timing and the tasks in each overhaul, information such as the following is reviewed:

1) Timing
    - Is the unit overhaul required at this time (based on equipment condition)?;
    - Is there sufficient generation is available on the electrical system to allow the outage?; and
    - Will any spilling of reservoir water occur during the time the outage is required?
2) Condition

    There are two types of assessments that LTAP use to determine the condition of an asset, Class 1 or Class 2 assessments:

    - Class 1 Assessments

        These assessments are completed using information from condition monitoring or during maintenance procedures.

    - Class 2 Assessments

        These assessments are completed using information from detailed, extensive asset inspection or testing. The information is obtained through overhauls conducted and investigations completed by people with specialized expertise. The activities required can involve advanced testing and or disassembly of equipment to perform a inspections and testing.

3) Asset Criticality

Asset management personnel have ranked hydraulic generation assets criticality. This ranking is used in determining the priority of work in a given year.

4) Frequency of Operation

An asset that is used more frequently will require more maintenance, both preventative and corrective, therefore a unit that is used more will have overhauls scheduled more frequently.

5) Safety

Projects that have safety justifications are given high priority.

6) Reliability

Overhauls can be performed earlier for the units that exhibit poor reliability.

7) Geographical Location

The maintenance center for Hydro Generation is located in Bay d'Espoir. When work is required at stations or structures outside the Bay d'Espoir area plans are developed to pool many activities together to increase efficiency.

2. Rewind Unit 3 Stator - Holyrood

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2020 Capital Budget Application
Rewind Unit 3 Stator
Holyrood

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

The Holyrood Thermal Generating Station ("Holyrood TGS") Unit 3 generator is anticipated to continue generating electricity and operating as a synchronous condenser, as required, until April 2021, after which time the Holyrood TGS will transition to post-steam operation and Unit 3 will only operate as a synchronous condenser. Rewinding the Unit 3 stator will complete its useful-life extension which began in 2016 with the rewinding of the rotor. This project will enable the continued reliable operation of the Unit 3 generator.

The project will take two years to complete, with engineering and procurement in the first year, and execution in the second. The project estimate is $6,945,600.

Contents

1.0 Introduction

The Holyrood TGS Unit 3 Generator (see Figure 1) is used to generate electricity or to function as a synchronous condenser. Most modern, larger generators have a stationary armature (stator) with a rotating current-carrying conductor (rotor or revolving field) which are used to produce electricity. The stator contains armature windings through which the electricity flows.

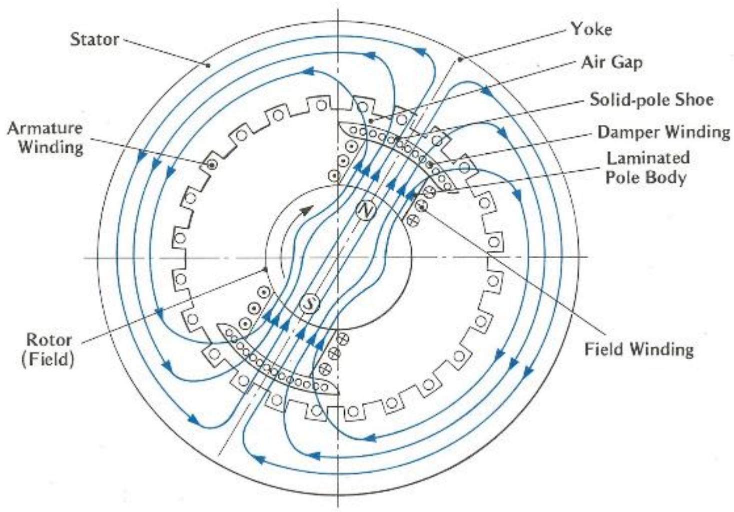

Figure 1: Typical Generator Schematic

The generator stator armature windings have reached the end of their design life but the useful life of the generator could be extended by rewinding the stator. This extension would allow the use of the generator to supply part of Hydro's reactive power requirements beyond April 2021. The generator will continue to operate as a synchronous condenser.

2.0 Background

2.1 Existing System

The Unit 3 generator was manufactured by Hitachi[1] and put in service in 1979. It is rated at 185 MVA with 0.85 power factor. As a synchronous condenser the unit can produce approximately 70 MVAR. The stator windings operate at 16 kV and are indirectly cooled by hydrogen gas. The rotor consists of two

[1] The Original Equipment Manufacturer ("OEM").

poles and operates at 3600 rpm. The generator is directly coupled to the Unit 3 steam turbine, which provides the rotational energy for electric power generation.

In 1986, the generator was modified to allow it to be optionally operated as a synchronous condenser, thereby providing voltage support to the Island Interconnected System. Modifications included the addition of a pony motor to spin the rotor up to synchronous speed, a synchro-self-shifting (“SSS”) clutch between the pony motor and the generator rotor, a control system, and required auxiliaries. Before running in synchronous condenser mode, the generator rotor is decoupled from the turbine.

2.2 Operating Experience

The generator was put in service in 1979 and has accumulated approximately 159,968 hours in generating mode and 47,603 hours in synchronous condenser mode (a total of 207,571 hours). In 2016, a major overhaul was performed on the Unit 3 generator and, to extend the life of the Unit 3 generator, the rotor was rewound. During the outage, extensive electrical testing was completed to assess the condition of the stator. No problems were identified at that time but the OEM and Iris Power, an independent third-party, recommended a rewind of the stator in the near-future due to the overall age of the unit. The Unit 3 generator has received regular maintenance through scheduled annual preventive maintenance and six-year overhauls.

The Unit 3 generator has provided acceptable performance for its operational life.

3.0 Analysis

3.1 Identification of Alternatives

There are no viable alternatives to the plan to maintain the existing Unit 3 generator for synchronous condenser operation into the future.

4.0 Project Justification

This project will enable the continued reliable operation of the Unit 3 generator as a synchronous condenser.

5.0 Project Description

This project will execute the rewind, which will involve the supply of materials and the execution of the on-site rewind activities.

Materials to be procured will include:

- Stator coils including: dimensions, transposition, effective losses, etc.;
- Insulation and insulation system materials with NEMA[2] designation;
- Other consumables and components for rewind (i.e., “rewind kit”);
- Required instrumentation (e.g., temperature monitoring);
- Factory testing, where applicable; and
- Packaging requirements for storage prior to installation.

The on-site rewind activities will include:

- Disassembly of excitation assembly housing;
- Removal of end shield and hydrogen shields;
- Disassembly of generator bearings;
- Removal and storage of generator rotor;
- Removal of end winding support system;
- Removal of stator coils and insulation system and conduct core loop tests;
- Refurbishment work, as required;
- Asbestos abatement work, as required;
- Installation of new stator coils and insulation system;
- Reassembly of components; and
- Commissioning activities and electrical testing.

[2] National Electrical Manufacturers Association (“NEMA”).

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	60.0	0.0	**60.0**
Labour	111.5	720.0	0.0	**831.5**
Consultant	22.6	22.6	0.0	**45.2**
Contract Work	970.0	3,880.0	0.0	**4,850.0**
Other Direct Costs	0.0	3.9	0.0	**3.9**
Interest and Escalation	73.6	544.7	0.0	**618.3**
Contingency	103.7	433.0	0.0	**536.7**
Total	**1,281.4**	**5,664.2**	**0.0**	**6,945.6**

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning: Outage request and project planning.	January 2020	March 2020
Procurement: Write specification, tendering, and equipment procurement.	April 2020	November 2020
Construction: Disassemble unit, remove and store rotor, install stator winding, electrical testing, and reassemble unit.	May 2021	August 2021
Commissioning: Commissioning and balancing.	September 2021	November 2021
Closeout: Close out project.	October 2021	December 2021

6.0 Conclusion

The Holyrood TGS Unit 3 generator stator windings have reached the end of their design life. The useful life of the generator could be extended by rewinding its stator.

Hydro is proposing this project to enable the continued reliable operation of Unit 3 generator for continued use as a synchronous condenser.

3. Perform Combustor Inspection – Holyrood Gas Turbine

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2020 Capital Budget Application
Perform Combustor Inspection
Holyrood Gas Turbine

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

The Holyrood Gas Turbine was placed in service in 2015 and can produce electricity to a peak of 123.5 MW. On-going combustor inspections and overhauls are required to maintain reliable operations of the gas turbine. In 2021, Newfoundland and Labrador Hydro ("Hydro") anticipates that the Holyrood Gas Turbine will reach a total equivalent starts of 1200. At that time Siemens, the gas turbine manufacturer, recommends the third combustor inspection and overhaul should be completed.

In addition, Siemens recommends completing a generator medium inspection after 53,000 operating hours, or six calendar years, whichever occurs first. The generator at the Holyrood Thermal Generating Station ("Holyrood TGS") will be in operation for six years in 2021.

Hydro is proposing to undertake planning and procurement for this project in 2020, and to complete the inspection and overhaul work in 2021. The budget estimate for this project is $5,473,500.

Contents

List of Appendices

1.0 Introduction

Hydro owns and operates a 123.5 MW gas turbine plant that is located at the Holyrood TGS, approximately 43 kilometres South West of St. John's. The major components of the plant are subjected to high temperature and internal forces that can degrade the condition of the generator over time.

2.0 Background

The Holyrood Gas Turbine plant fulfills several key functions in supplying reliable power to meet customer demand as follows:

- The plant is operated to support spinning reserves on the Island Interconnected System. It provides critical backup in the event of the loss of a major generating unit; and
- The plant provides power to the Avalon Peninsula, which is heavily reliant on the transfer of power over transmission lines from outside of the Avalon Peninsula. It provides critical backup in the event of the unexpected loss of a major transmission line into the area. The plant is also used to facilitate planned generation and transmission outages.

2.1 Existing System

The Holyrood Gas Turbine was constructed in 2014 and commissioned early in 2015. The Holyrood Gas Turbine, which was manufactured by Siemens, has two major components: a heavy frame gas turbine and a generator. The heavy frame gas turbine consists of four sections: a compressor, combustor, turbine, and exhaust (refer to Figure 1), which are directly coupled to the generator. Hot gases produced as a result of the fuel combustion in the combustor are fed into the turbine section of the gas turbine. The gases cause the turbine and generator to rotate to produce electricity.

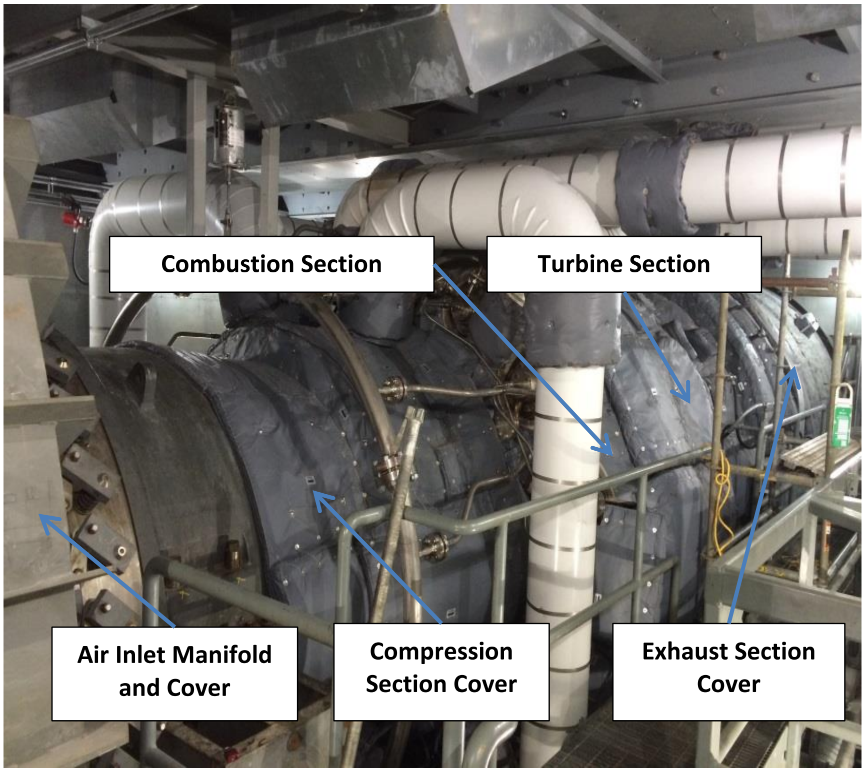

Figure 1: Holyrood Gas Turbine

Components of the heavy frame gas turbine are subjected to high temperature and pressure that causes deterioration such as thermal fatigue, cracking, wear, and corrosion of the combustor components. For this reason, the manufacturer has developed an inspection and overhaul schedule based on the number of total equivalent starts or total equivalent base hours of operation. The total equivalent starts and total equivalent base hours monitor the thermal fatigue effect based on fuel type, operating hours, starts, trips, and load changes.

A combustor inspection and overhaul involves removal of combustor components that are accessible through a manhole on the combustion section cover. Components that are not removable without lifting the combustion section cover are inspected in place. These components are re-inspected when removing the combustion section cover during hot gas path and major inspections.

2.2 Operating Experience

The Holyrood Gas Turbine plant has been in service since March 2015. As recommended by Siemens, the first combustor inspection and overhaul was completed in 2016 when the total equivalent starts on the gas turbine reached 400 (details on the calculation of total equivalent starts are included in

Appendix A). The second combustor inspection and overhaul was completed as a part of the hot gas path inspection and overhaul project in 2018 when the total equivalent starts on the gas turbine reached 800. Siemens recommends that the third combustor inspection and overhaul be completed when either of the following criteria is met:

- Total equivalent starts = 1,200; or
- Total equivalent base hours = 36,000.

Hydro anticipates that the Holyrood Gas Turbine will reach the total equivalent starts of 1,200 in 2021. However, depending upon operational requirements up to the planned overhaul, Hydro will defer the combustor inspection and overhaul if the 1200 equivalent starts threshold is not met in 2021 as anticipated, provided the overhaul can be safely deferred beyond the end of the 2021-2022 winter operating season. It should be noted that total equivalent start criteria will be achieved prior to the equivalent base hour criteria.

In addition to the combustor inspection and overhaul scope, the generator at the Holyrood TGS will be in operation for six years in 2021. The generator is subjected to high temperature and internal forces that can degrade the condition of the generator over time. To ensure reliable operation of the generator, Siemens recommends completion of a generator medium inspection every 53,000 operating hours or six calendar years, whichever occurs first. If, however, the combustor inspection and overhaul is deferred to 2021, the generator medium inspection would also be deferred as these projects will be executed at the same time.

3.0 Project Description

Hydro proposes to complete the following scope of work on the Holyrood Gas Turbine:

- Completion of combustor inspection and overhaul; and
- Completion of generator medium inspection.

The project budget estimate is provided in Table 1.

Table 1: Project Budget Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	30.0	0.0	30.0
Labour	26.7	473.1	0.0	499.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	440.0	3,550.0	0.0	3,990.0
Other Direct Costs	0.0	29.1	0.0	29.1
Interest and Escalation	32.7	437.0	0.0	469.7
Contingency	46.7	408.2	0.0	454.9
Total	**546.1**	**4,927.4**	**0.0**	**5,473.5**

The anticipated project schedule is provided in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Prepare work breakdown structure (WBS) and scope statement.	January 2020	February 2020
Procurement:		
Order and receive materials required for combustor inspection and overhaul.	March 2020	April 2021
Construction:		
Perform combustor inspection and overhaul; and Perform medium generator inspection.	August 2021	September 2021
Commissioning:		
Commission gas turbine.	September 2021	September 2021
Closeout:		
Prepare project close out documents.	October 2021	December 2021

4.0 Conclusion

Hydro has incorporated regular combustor inspections and overhauls, as well as generator medium inspections, into its long term plan to maintain reliable operations of the Holyrood Gas Turbine. According to Hydro's operational forecast, to avoid exceeding the total equivalent starts criteria to initiate a combustor inspection and overhaul, Hydro will complete a combustor inspection and overhaul in 2021. A generator medium inspection will also be completed in 2021 to avoid exceeding the equivalent operating time criteria for generator inspection.

Appendix A

Calculation of Equivalent Starts

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Calculation of Equivalent Starts

The effects of thermal stress caused by starts, trips, and load changes are cumulative and are monitored using equivalent starts.

The equivalent starts calculation includes:

$$ES = \Sigma(S * Sf*Ff) + \Sigma(A*Ff) + \Sigma(T*Tf*Ff) + \Sigma(I * Lf*Ff)$$

Where:

ES = Equivalent Start

S = Successful Start

A = Fired Abort

T = Trip from load

I = Instantaneous Load Change

Sf = Start Factor – normal start = 1; Fast start = 10

Tf = Trip Factor – based on load change % of base load

Lf = Load Change Factor – based on load change % of base load

Ff = Fuel Factor = 1.3 for distillate fuel

Definitions

- Fired Abort : A fired abort is a start attempt that aborts or is aborted after combustion ignition has occurred, but shuts down before reaching breaker closure.
- Trip From Load: A trip from load occurs if the unit is shutdown after breaker closure AND the normal shutdown full speed no load (FSNL) cool down sequence is not performed. This is a shutdown that does not follow the normal shut down sequence including but not limited to the specified FSNL cool down sequence.
- Instantaneous Load Change: Instantaneous load change occurs when a unit abruptly increases or decreases load at a rate greater than the specified ramp rate.

Sample Calculation

The following is a sample equivalent starts calculation for a period of operation in which the listed events occurred:

- 10 successful starts – normal start;
- 2 fired aborts;
- 1 trip from load at 40MW; and
- 1 instantaneous load change from 80MW to full speed no load (FSNL).

ES = Σ(S * Sf*Ff) + Σ(A*Ff) + Σ(T*Tf*Ff) + Σ(I * Lf*Ff)

ES = (10*1.0*1.3) + (2*1.3) + (1*7.0*1.3) + (1*4.0*1.3)

= 13 + 2.6 + 9.1 + 5.2

= 29.9 ES

In a month where there were 10 actual starts, the unit accumulated 29.9 equivalent starts due to fired aborts, trips, and instantaneous load changes. A fuel factor of 1.3 is applied based on the use of diesel fuel.

4. Replace Fire Suppression System – Happy Valley Gas Turbine

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2020 Capital Budget Application
Replace Fire Suppression System
Happy Valley Gas Turbine

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

The Happy Valley Gas Turbine provides backup generation and voltage support to the eastern region of Newfoundland and Labrador Hydro's ("Hydro") Labrador Interconnected System.

The existing carbon dioxide ("CO2") fire suppression system was installed when the plant was constructed in 1992. It consists of four zones (Turbine Hall, Turbine Enclosure, Generator Enclosure, and Battery Room). Due to its age and service life this system now requires recertification for continued use. Due to safety concerns total-flooding CO2 systems are no longer accepted by Hydro when other systems exist. Therefore, replacement of the CO2 system with an alternative fire suppression system is proposed for the Happy Valley Gas Turbine plant to ensure a reliable automatic fire suppression system is in service.

The project estimate is $2,642,500 and scheduled to be complete in 2021.

Contents

1.0 Introduction

Hydro's Gas Turbine in Happy Valley Goose Bay, Labrador was commissioned in 1992 and has a capacity of 25 MW.

The gas turbine is a critical asset in the provision of electricity to the eastern region of the Labrador Interconnected System.

Gas turbines are combustion based equipment using flammable fuel and as such, if a fire occurred, the equipment and building could be damaged or destroyed. Such damage could have an extended impact on the provision of reliable electricity to Hydro's customers. To mitigate this risk, Hydro installs automatic fire suppression systems in its gas turbine buildings.

Figure 1: Happy Valley Gas Turbine Building.

2.0 Background

In the event of a fire an automatic fire suppression system needs to be in service to ensure operation of the gas turbines by minimizing fire damage and the subsequent duration of an unplanned outage. When the Happy Valley Gas Turbine was constructed, it was fitted with a CO_2 fire suppression system. At that time the designers determined it to be the best alternative available for the application. However, in recent years there has been more focus on CO_2 systems from a safety perspective. In other organizations there have been instances where fatalities have occurred due to asphyxiation when CO_2 systems have been discharged. Other fire suppression systems have since been developed that eliminate these safety concerns.

2.1 Existing System

The Happy Valley Gas Turbine has two fire suppression systems installed. The largest is a CO_2 gas system that extends throughout the plant with the exception of the control room, which is protected by an INERGEN®[1] system. The following spaces are protected by the CO_2 suppression system, with the turbine and generator enclosures shown in Figure 2:

- Turbine Enclosure
- Generator Enclosure
- Battery Room
- Turbine Hall

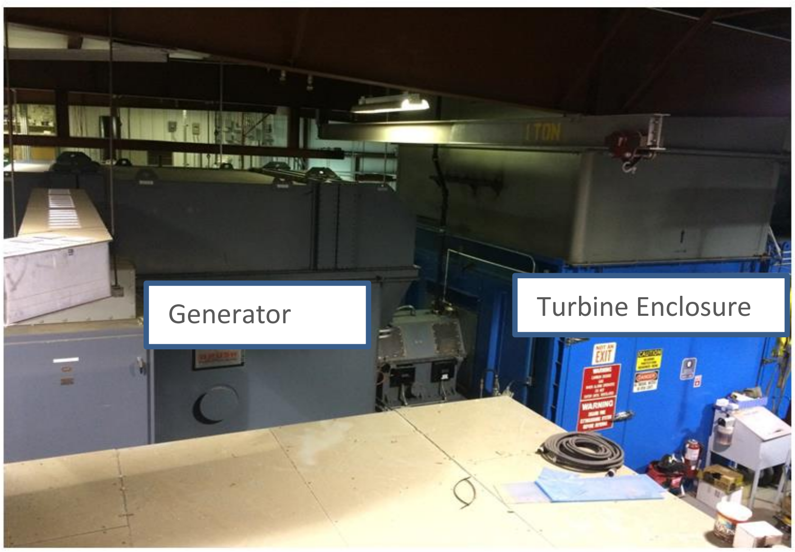

Figure 2: Happy Valley Turbine and Generator Enclosures

[1] INERGEN® is a mixture of 52% Nitrogen, 40% Argon, and 8% CO_2. However, in the event of a fire, when INERGEN® is discharged, it mixes with the air present in the room to create a mixture that comprises of 67.3% Nitrogen, 12.5% Oxygen, 17% Argon, and 3.2% CO_2.

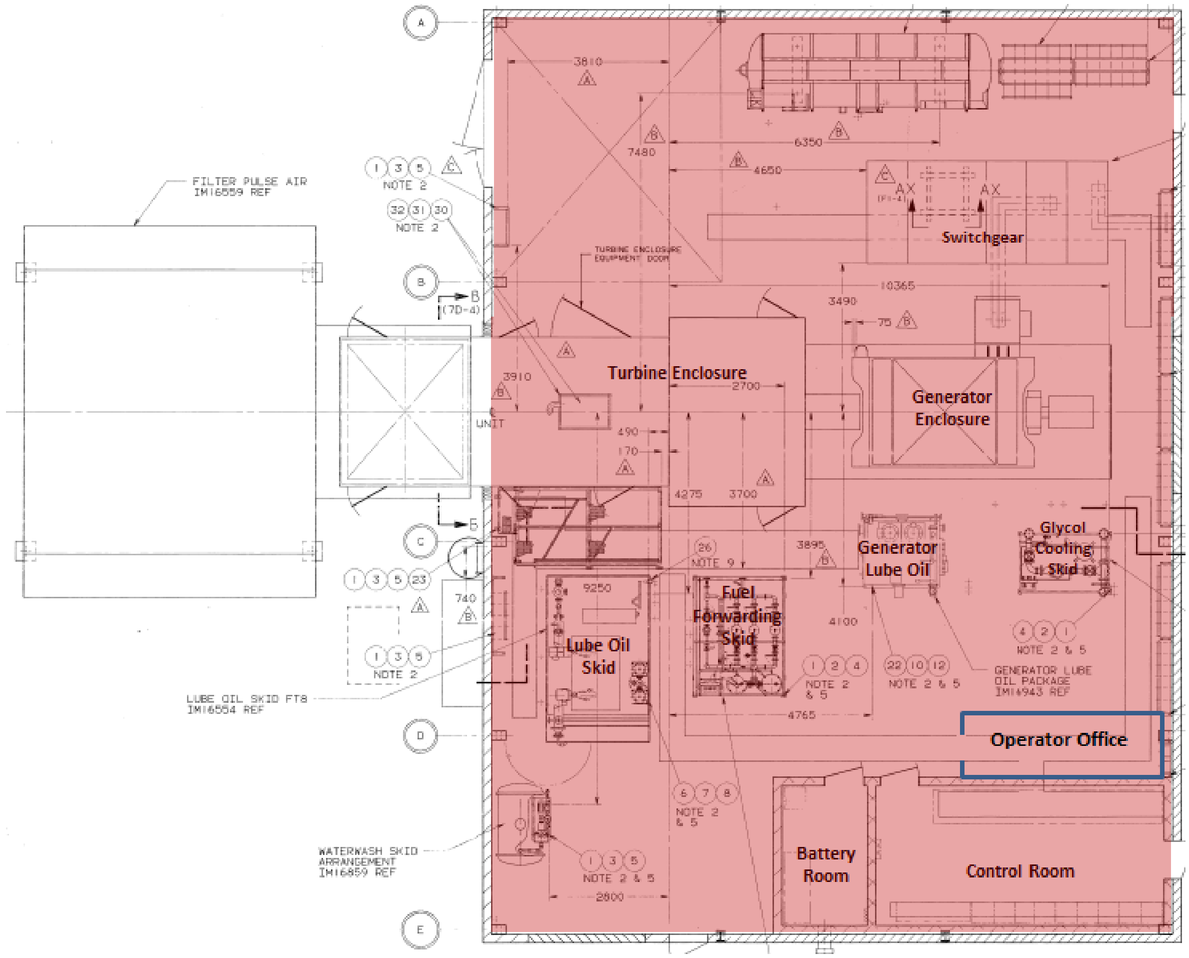

Figure 3: Happy Valley Gas Turbine Building Layout

2.2 Operating Experience

The existing CO_2 system was installed when the plant was constructed in 1992. The system consists of four zones (Turbine Hall, Turbine Enclosure, Generator Enclosure, and Battery Room).[2] A floor plan of the Happy Valley Gas Turbine building layout is shown in Figure 3. The shading in Figure 3 shows the Turbine Hall. The Turbine Hall space extends over the battery room, control room, operator office, turbine enclosure, and generator enclosure, as shown in Figure 2. When carbon dioxide is released into a space it displaces oxygen and could potentially result in asphyxiation if employees are unable to evacuate the building prior to system discharge. For this reason, Hydro disabled the CO_2 zone in the Turbine Hall in 2018. The other CO_2 zones within the Turbine Hall (Turbine Enclosure, Generator

[2] The Turbine Enclosure, Generator Enclosure, and Battery Room are separate areas within the Turbine Hall, and can be addressed separately from the remainder of the Turbine Hall.

Enclosure, and Battery Room) are taken out of service when performing maintenance in these areas. To date, the CO_2 system has never been activated to suppress a fire.

Due to its age and service life, recertification of this system is now required.

3.0 Analysis

3.1 Discussion of Fire Suppression Systems

The existing CO_2 system was installed when the plant was constructed in 1992. At that time it was considered to be suitable for the application. Since that time there has been increased focus on these systems by the National Fire Protection Association ("NFPA") from a safety perspective. There have been a number of fatalities in other organizations due to asphyxiation when CO_2 has been discharged; therefore, CO_2 systems are no longer permitted as new installations under NFPA Standards when an alternative system is available. In the event of a CO_2 gas release at the Happy Valley Gas Turbine there is concern that occupants may not be able to evacuate the building before being asphyxiated by the gas. This is of particular concern when the building has only one occupant, which is often the case at the Happy Valley Gas Turbine, and when people are working outside regular working hours.

The existing CO_2 fire suppression system in the Happy Valley Gas Turbine hall is no longer considered to be safe for this application by Hydro. Four fire suppression systems were considered to replace the existing CO_2 system at the Happy Valley Gas Turbine and are described as follows:

Wet Sprinkler

A Wet Sprinkler system suppress fire by discharging water through a grid of sprinkler heads installed over the full area of the protected space. Such systems require a larger water supply than other water based systems. The water supply to the gas turbine plant is not adequate to provide the volume of water required by this system. An adequate water supply can be obtained from the municipal water system if 800 meters of underground piping was installed to a new connection point in the municipal water system. The capital cost for this alternative has been estimated to be much higher than any of the other alternatives. Also, as this system uses large volumes of water for fire suppression, the equipment in the Turbine Enclosure, Generator Enclosure, and Battery Room would be damaged by the water. Therefore, the use of this system in these areas was rejected.

Water Mist

A Water Mist system suppresses fire by discharging a fine water spray through a grid of spray nozzles installed over the full area of the protected space. Such systems require a large water supply, but much less than that of a Wet Sprinkler system. An adequate water supply can be obtained from the municipal water system by either installing 800 meters of underground piping to a new connection point in the municipal water system, or by installing a water storage tank adjacent to the Gas Turbine building. Installing a water storage tank is the least capital cost of these two options.

As this system uses a significant volume of water to suppress fire there is concern the equipment in the Turbine Enclosure, Generator Enclosure, and Battery Room would be damaged by the water. Therefore the use of this system was also rejected for these areas.

Hybrid Nitrogen-Water

A Hybrid Nitrogen-Water system suppresses fire by discharging a spray mixture of fine water mist and nitrogen gas through a grid of spray nozzles installed over the full area of the protected space. These systems require an even smaller water supply compared to water mist and sprinkler systems.

The cost of a hybrid nitrogen-water system is estimated to be the same as a water mist only system for the Turbine Hall. However, as this system does use water, there is a concern that equipment in the Turbine Enclosure, Generator Enclosure, and Battery Room could be damaged by moisture contamination or rapid cooling of the engine/turbine casing. It is expected that a relatively low amount of damage would be caused as the volume of water is small; however, due to the role of the gas turbine for the Labrador Electrical System, a water based system is not acceptable for these areas given an alternative system is available.

INERGEN Gas

An INERGEN system suppresses fire by discharging INERGEN gas through a grid of spray nozzles installed over the full area of the protected space. INERGEN is a mixture of three gases and is non-toxic. It reduces the oxygen content of the space sufficiently to supress the fire, but not to a level that would be harmful to occupants. It is generally used in areas where there is risk of harm to people or equipment. It is non-conductive and will not harm electrical equipment.

For an INERGEN system to be effective, the protected space has to be tightly enclosed. The Turbine Hall is a large space and difficult to enclose tightly; therefore, INERGEN may not be suitable for the Turbine Hall. As INERGEN systems do not use water to suppress fire, the equipment in the Turbine Enclosure, Generator Enclosure, and Battery Room would not be damaged by the suppression medium. Therefore, INERGEN would be suitable for those areas.

3.2 Identification of Alternatives

The risk of damage to the equipment in the Turbine Enclosure, Generator Enclosure, and Battery Room by a water based suppression system is not acceptable. INERGEN is the only alternative for these areas within the Turbine Hall. As three of the systems outlined in Section 3.1 were an acceptable means of fire suppression for the remainder of the Turbine Hall, the cost of these alternatives were established for analysis. The alternatives for the Turbine Hall are as follows:

- Alternative 1: Install a Wet Sprinkler System;
- Alternative 2: Install a Water Mist System; and
- Alternative 3: Install a Hybrid Nitrogen-Water System.

3.3 Evaluation of Alternatives

The project capital cost estimates for different alternatives are provided in Table 1.

Table 1: Project Cost Estimate – Alternatives Comparison ($000)

Protected Zone		
Turbine Enclosure, Generator Enclosure, and Battery Room	**Remainder of Turbine Hall**	**Project Cost Estimate[3]**
INERGEN System	Wet Sprinkler System	$4,031
	Water Mist System	$2,642
	Hybrid Nitrogen-Water System	$2,647

The capital cost estimate for the wet sprinkler system alternative is high compared to the other alternatives as it includes new water supply piping from the municipal water system. In addition, sprinkler systems discharge a large amount of water, which could damage equipment in the Turbine Hall, particularly electrical and controls equipment. Therefore, the sprinkler system alternative was deemed to be not viable.

[3] Cost of INERGEN is included in all three scenarios.

The capital cost estimates for the water mist and hybrid nitrogen-water system alternatives are comparable. The expected life span and maintenance costs for each alternative are also comparable. Therefore, a Net Present Value analysis is not required to compare the alternatives.

3.4 Recommended Fire Suppression System for Installation

From Table 1, the recommended fire suppression system for the Happy Valley Gas Turbine plant is a combination of the following:

- An INEREGEN system for the Turbine Enclosure, Generator Enclosure, and Battery Room. The control room already has an INERGEN system; and
- Either a water mist or hybrid nitrogen-water system for the Turbine Hall. The final selection will be determined after more detailed investigation during the design phase of project execution.

4.0 Project Justification

This project is required to replace the existing CO_2 fire suppression system at the Happy Valley Gas Turbine plant to ensure a reliable automatic fire suppression system is in service.

5.0 Project Description

The project scope of work will include the following:

- Removal and disposal of the existing CO_2 fire suppression system.
- Installation of an INERGEN fire suppression system for the turbine enclosure, generator enclosure, and battery room.
- Installation of either a water mist or hybrid nitrogen-water fire suppression system in the remainder of the Turbine Hall after more detailed investigation during the project execution stage to determine the best suited system.

The project estimate is provided in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	10.0	0.0	**10.0**
Labour	71.8	225.7	0.0	**297.5**
Consultant	140.0	60.0	0.0	**200.0**
Contract Work	0.0	1,611.0	0.0	**1,611.0**
Other Direct Costs	6.3	16.8	0.0	**23.1**
Interest and Escalation	13.7	165.9	0.0	**179.6**
Contingency	32.8	288.5	0.0	**321.3**
Total	**264.6**	**2,377.9**	**0.0**	**2,642.5**

The project schedule is provided in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Prepare scope statement and work breakdown structure.	January 2020	March 2020
Design:		
Prepare technical conditions.	June 2020	August 2020
Procurement:		
Prepare Request for Proposals (RFP) for technical conditions.	April 2020	May 2020
Prepare tender documents for supply and installation work.	September 2020	December 2020
Award contracts.	January 2021	January 2021
Procure materials	January 2021	July 2021
Construction:		
Install fire suppression systems.	July 2021	August 2021
Commissioning:		
Commission fire suppression systems.	September 2021	September 2021
Closeout:		
Prepare closeout documents.	October 2021	December 2021

6.0 Conclusion

The Happy Valley Gas Turbine is a critical asset in the provision of electricity to the eastern region of the Labrador Interconnected System.

The Happy Valley Gas Turbine plant was constructed with a CO_2 fire suppression system to ensure minimal damage would be incurred in the event of a fire. This system requires recertification. The CO_2 fire suppression system was disabled in 2018 in the Turbine Hall zone due to safety concerns. The system is still active in the Turbine Enclosure, Generator Enclosure, and Battery Room zones, as these spaces are not normally occupied.

Hydro is proposing this project to restore fire suppression capability to minimize damage to the Happy Valley Gas Turbine equipment and building in the event of a fire.

5. Generator Assessment – Happy Valley Gas Turbine

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2020 Capital Budget Application
Generator Assessment
Happy Valley Gas Turbine

July 2019

newfoundland labrador hydro
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A report to the Board of Commissioners of Public Utilities

Executive Summary

The Happy Valley Gas Turbine provides back up electrical generation and synchronous condense support to the Labrador Interconnected System ("LIS"). The generator has over 120,000 hours of operation and as a result, the Original Equipment Manufacturer ("OEM")[1] recommends a Level II Assessment be conducted. The Level II assessment requires the gas turbine generator to be disassembled and the rotor removed. The Happy Valley Gas Turbine was placed in service in 1992 and provides 25 MW of back up electrical generation and reactive power ranging from -10 to +23.8 MVAR as a synchronous condenser for the LIS. The Happy Valley Gas Turbine generator OEM recommends a Level II Assessment be conducted after the unit has 100,000 operating hours or after the unit has been in service for 10 to 12 years. Hydro will use the assessment to determine if corrective action is required to facilitate the continuation of the reliable operation of the Happy Valley Gas Turbine.

This proposed project will be completed during the planned unit outage in 2020 at an estimated cost of $1,097,600.

[1] The Happy Valley Gas Turbine generator OEM is Brush.

Contents

1.0 Introduction

The Happy Valley Gas Turbine was placed in service in 1992 and provides 25 MW of back up electrical generation and reactive power ranging from -10 to +23.8 MVAR as a synchronous condenser to the LIS. The Happy Valley Gas Turbine OEM, which also specializes in generator inspection and maintenance, recommends a Level II Assessment be conducted after the unit has 100,000 operating hours or after the unit has been in service for 10 to 12 years. A Level II Assessment requires partial disassembly of the generator to allow for testing and inspection of the rotor, and assessment by personnel who specialize in generator design, inspection and maintenance. Hydro will use the assessment to determine if corrective action is required to facilitate the continuation of the reliable operation of the Happy Valley Gas Turbine.

2.0 Background

2.1 Existing System

The generator rotor is the rotating component of the generator. The Happy Valley Gas Turbine is a two-pole rotor that rotates at 3600 rpm. The rotor is connected to the unit's power turbine, which rotates by extracting energy from the gas generator exhaust gases when it is operated. A concept drawing of a gas turbine generator is provided in Figure 1.

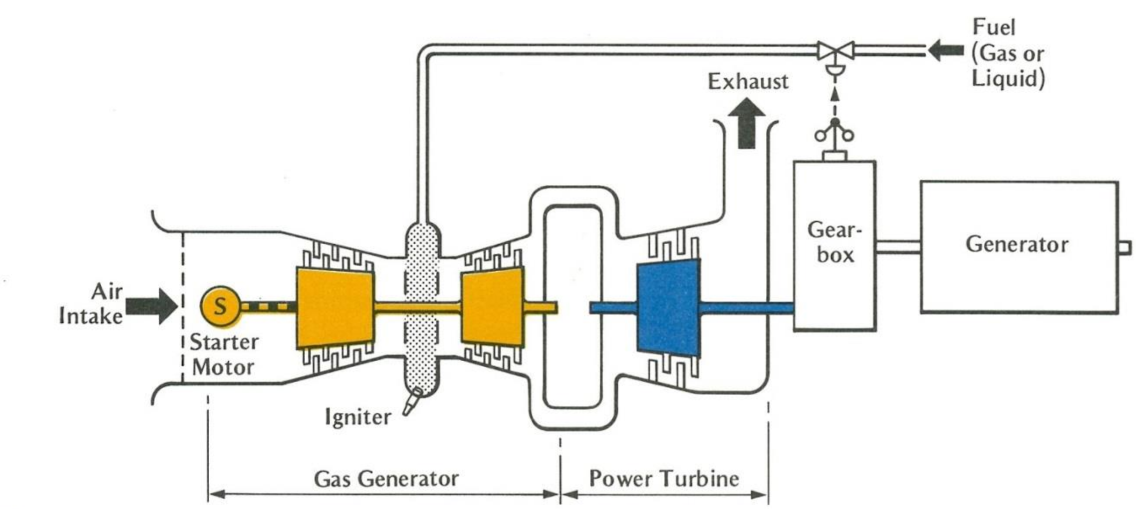

Figure 1: Gas Turbine Generator

A generator major components diagram is provided in Figure 2.

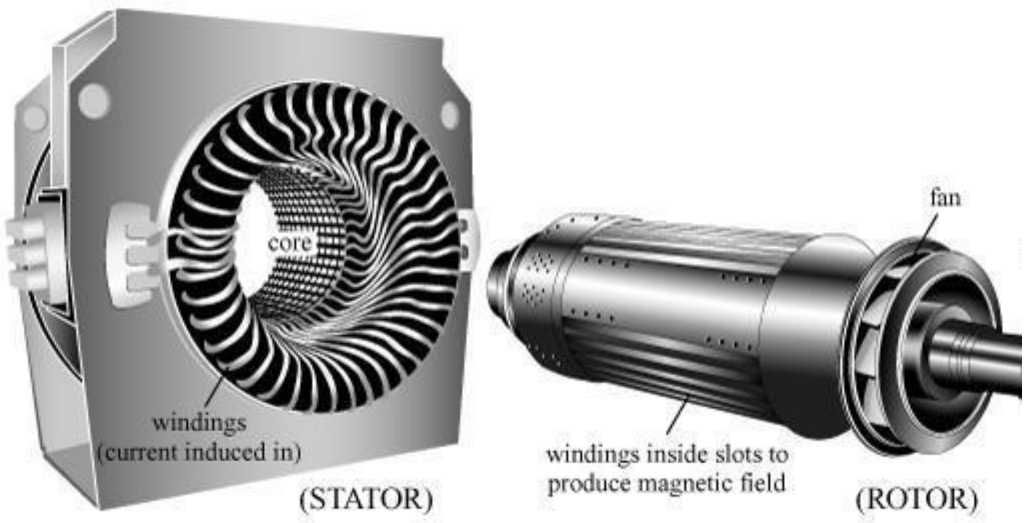

Figure 2: Typical Generator Components

2.2 Operating Experience

Since its installation, the Happy Valley Gas Turbine generator has accumulated 120,496 operating hours (2,576 hours in generation mode; 117,920 hours in synchronous condense mode) and is forecast to operate approximately 4,000 hours in synchronous condense mode in 2019.

A Level II Assessment has not been completed for the Happy Valley Gas Turbine generator. Other inspections have not indicated any major operational issues with the generator rotor.

3.0 Project Justification

The project is required to assess the generator to determine if corrective actions are required to facilitate the continuation of reliable operation of the Happy Valley Gas Turbine. The Happy Valley Gas Turbine generator exceeds the manufacturer recommended criteria for a Level II Assessment.

4.0 Project Description

The Happy Valley Gas Turbine Generator Assessment project includes the dismantling of the generator to inspect, test, and clean the generator rotor and the generator stator. The work includes such activities as:

- Removal of wall panels to allow access to the generator;
- Disassembly of generator;

- Removal of the rotor to complete the following:
    - Visual inspection of generator (general condition of generator enclosure, shaft earthing brush, oil pipe flanges, fans, rectifier assembly, cooler, stator end windings and blocking, bushings, bearings, bearing seal air pipe work, and rotor);
    - Mechanical checks (bearing shaft seals, cooler leak detectors, heaters, air differential pressure transmitter, filters);
    - Stator electrical testing;
    - Rotor electrical testing;
    - Exciter electrical testing;
    - Mechanical scope (record clearances of bearing shaft seals, check operation of the stator space heaters, check internal condition of air duct, check jacking oil lift, record bearing alignment clearances, remove and check generator bearing condition, check and clean the stator-end windings, carry out boroscope inspection of the rotor under cap windings and carryout a stator wedge inspection);
    - Minor refurbishments or repairs; and
- Reassembly of generator.

From the information obtained through the associated field work, personnel specialized in generator design, inspection, maintenance, and assessment will provide a Level II Assessment report.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	62.9	0	0	**62.9**
Labour	328.1	0	0	**328.1**
Consultant	0.0	0	0	**0.0**
Contract Work	536.7	0	0	**536.7**
Other Direct Costs	27.2	0	0	**27.2**
Interest and Escalation	9.2	0	0	**9.2**
Contingency	133.5	0	0	**133.5**
Total	**1097.6**	**0**	**0**	**1097.6**

The project schedule is provided in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning Scope:		
Schedule, cost, risk, quality and communication planning.	February 2020	June 2020
Design:		
Site visit and develop contract.	March 2020	May 2020
Procurement:		
Negotiate contract.	March 2020	April 2020
Construction:		
Inspection.	August 2020	August 2020
Commissioning:		
Commissioning.	August 2020	August 2020
Closeout:		
Financial closeout and post implementation review.	November 2020	November 2020

5.0 Conclusion

The Happy Valley Gas Turbine provides back up electrical generation and synchronous condense support to the LIS.

A Level II Assessment of the generator is required as it has exceeded the recommended operating hours and in-service operation time.

This project is being proposed to assess the generator rotor to determine if corrective action is required to facilitate the continuation of the reliable operation of the Happy Valley Gas Turbine.

6. Install Partial Discharge Monitoring – Holyrood Gas Turbine

2020 Capital Budget Application
Install Partial Discharge Monitoring
Holyrood Gas Turbine

July 2019

A report to the Board of Commissioners of Public Utilities

Executive Summary

The Holyrood Gas Turbine Generator, which was installed in 2015, has a peaking capacity of 123.5 MW and is not equipped with a generator insulation partial discharge monitoring system.

On-line partial discharge monitoring provides information required for condition assessment of the Holyrood Gas Turbine Generator winding insulation. Such assessment allows Newfoundland and Labrador Hydro ("Hydro") to implement, if necessary, corrective action to avoid an internal generator electrical fault due to winding insulation failure.

The lack of a partial discharge monitoring system for the Holyrood Gas Turbine Generator increases the risk of undetected insulation deterioration and the possible development of a generator internal electrical fault, that could take six months or more to repair.

Hydro is proposing this project to facilitate the continued reliable operation of the Holyrood Gas Turbine.

This project estimate is approximately $612,800 with scheduled completion in 2021.

Contents

1.0 Introduction

The Holyrood Gas Turbine Generator, which was installed in 2015, has a peaking capacity of 123.5 MW. It is not equipped with a partial discharge monitoring system as is installed on many of Hydro's other larger generators to allow on-going assessment of a generator's insulation.

2.0 Background

Partial discharges are small electrical sparks or pulses that occur when voids exist within or on the surface of the high voltage insulation of generator or motor windings. Partial discharge occurs due to the manufacturing / installation process, thermal deterioration, aging, winding contamination, or stator bar movement during operation. These stresses can lead to insulation degradation and, ultimately, an electrical fault. As the insulation degrades the number and magnitude of the partial discharge pulses increases. Partial discharge measurements and the analysis of this data is a well-established method of assessing the condition of electrical insulation in generators and motors. On-Line partial discharge monitoring provides information required for condition assessment of the Holyrood Gas Turbine Generator winding insulation. Such assessment allows Hydro to detect potential issues and implement, if necessary, corrective action to avoid an internal generator electrical fault due to winding insulation failure.

2.1 Existing System

The Holyrood Gas Turbine Generator is not equipped with a Partial Discharge Monitoring System. Hydro has partial discharge monitoring on the other high speed gas turbine generators, as well as other generating units such as the units in Bay d'Espoir. The 2020 Capital Budget Application ("CBA") also includes continuous partial discharge monitoring upgrades for other units such as Hinds Lake and Granite Canal. While the Holyrood Gas Turbine did not have partial discharge monitoring when purchased, this equipment is necessary for assessing the condition of the generator and for making decisions regarding any necessary corrective action in the event of the identification of issues prior to failure.

2.2 Operating Experience

There have been no indications of issues with the high voltage insulation systems of the Holyrood Gas Turbine.

3.0 Justification

The lack of a partial discharge monitoring system, for the Holyrood Gas Turbine Generator, increases the risk of undetected insulation deterioration and the possible development of a generator internal electrical fault, that could take 6 months or more to repair. This project will facilitate the continued reliable operation of the Holyrood Gas Turbine.

4.0 Project Description

This project will:

- Procure and install a generator partial discharge monitoring system at the Holyrood Gas Turbine; and
- Integrate the generator insulation condition monitoring system with an existing remote monitoring system.

The project estimate is included in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	15.0	0.0	**15.0**
Labour	30.9	122.8	0.0	**153.7**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	321.0	0.0	**321.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	2.3	47.2	0.0	**49.5**
Contingency	4.6	69.0	0.0	**73.6**
Total	**37.8**	**575.0**	**0.0**	**612.8**

The project schedule is included in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning: Open project, planning and scheduling	March 2020	April 2020
Design: Conduct site visits, complete detailed design	May 2020	July 2020
Procurement: Ordering and delivery of equipment, internal review of consultant drawings and design	August 2020	March 2021
Construction: Install new equipment	May 2021	June 2021
Commissioning: Commissioning of new equipment, final tie-ins	July 2021	August 2021
Closeout: Project close-out	September 2021	October 2021

5.0 Conclusion

On-Line partial discharge monitoring provides information required for condition assessment of the Holyrood Gas Turbine Generator winding insulation. Such assessment would allow Hydro to detect potential issues and implement, if necessary, corrective action to avoid an internal generator electrical fault due to winding insulation failure. The Holyrood Gas Turbine Generator is not equipped with a Partial Discharge monitoring system; however, this equipment is necessary for assessing the condition of the generator and for making decisions regarding any necessary corrective action in the event of the identification of issues prior to failure.

The project which Hydro is proposing will install on-line partial discharge monitoring and thereby facilitate the continued reliable operation of the Holyrood Gas Turbine.

7. Terminal Station Refurbishment and Modernization (2020–2021)

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2020 Capital Budget Application
Terminal Station Refurbishment and Modernization (2020–2021)

July 2019

newfoundland labrador
hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro (“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.

Hydro’s philosophy for the assessment of equipment and the selection and justification of projects is outlined in the “Terminal Station Asset Management Overview” (“Asset Management Overview”). Version 4 of the Asset Management Overview is included in the 2020 Capital Budget Application (“CBA”) (Volume II, Tab 7). Changes in this revision are outlined in a section 1.1 of the Asset Management Overview, entitled “Changes in Version 4.”

In the 2020 CBA, Hydro proposes the following activities under the Terminal Station Refurbishment and Modernization project:

- Replacement of Instrument Transformers;
- Replacement of Disconnect Switches;
- Replacement of Surge Arrestors;
- Refurbishment and Modernization of Power Transformers;
- Replacement of Insulators;
- Replacement of Terminal Station Lighting;
- Replace Battery Banks and Chargers;
- 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.

Hydro will execute the majority of these activities in a multi-year (two-year) approach, with all activities scheduled for completion before the end of 2021.

The total project estimate is $9,779,800

Contents

1.0 Terminal Station Refurbishment and Modernization Project

Terminal stations perform a critical role in the transmission and distribution of power across the Province. Terminal stations contain electrical equipment, including transformers, circuit breakers, instrument transformers, 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 has 70 terminal stations across the Island and Labrador Interconnected Systems.

Hydro executes a robust capital program to ensure the delivery 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.

Historically, the replacement of terminal station lighting was completed on a stand-alone basis, as required. Beginning with the 2020 CBA, Hydro intends to carry out the replacement of terminal station lighting as a component of the Terminal Station Refurbishment and Modernization project, as detailed in Version 4 of the "Terminal Station Asset Management Overview," included with the 2020 CBA.

2.0 Terminal Station Refurbishment and Modernization 2020 Projects

In the 2020 CBA, Hydro has submitted Version 4 of the Asset Management Overview, which outlines Hydro's asset management programs as they relate to terminal station equipment. The assets designated for replacement, refurbishment, or modernization herein have been selected by Hydro's Asset Management staff to align with Hydro's commitment to the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner. The philosophy for assessment, selection, and justification of these projects are found in the Asset Management Overview.

2.1 Electrical Equipment

The following electrical equipment upgrades and/or refurbishments are planned for 2020:

- Replace Instrument Transformers;

- Replace Disconnect Switches;
- Replace Surge Arrestors;
- Refurbish and Upgrade Power Transformers;
- Replace Insulators;
- Replace Station Lighting; and
- Replace Battery Banks and Chargers.

2.1.1 Replace Instrument Transformers

The estimate of direct costs for this project is shown in Table 1.

Table 1: Direct Costs Estimate for the Replace Instrument Transformers Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	161.6	0.0	161.6
Labour	28.0	85.4	0.0	113.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	10.4	0.0	10.4
Total Direct Costs	**28.0**	**257.4**	**0.0**	**285.4**

Project Scope

Hydro replaces instrument transformers due to physical or electrical deterioration, or to comply with federal regulations regarding the use of polychlorinated biphenyls (“PCB”), as detailed in section 4.1.1 of the Asset Management Overview. Hydro plans to replace the instrument transformers in Table 2.

Table 2: Instrument Transformer Replacements

Station	Equipment ID	Replacement Criteria
Deer Lake	B1 BØ, PT	Age (39)
Happy Valley	L1302 AØ, PT	Corrosion and/or Leaking
Happy Valley	L1302 BØ, PT	Corrosion and/or Leaking
Hardwoods	TL242 AØ, PT	Corrosion and/or Leaking
Hardwoods	TL242 BØ, PT	Corrosion and/or Leaking
Hardwoods	TL242 CØ, PT	Corrosion and/or Leaking
Massey Drive	B4 AØ, CT	Failed Electrical Testing
Massey Drive	B4 BØ, CT	Failed Electrical Testing
Massey Drive	B4 CØ, CT	Failed Electrical Testing
Springdale	T1 AØ, metering CT	Age (51)
Springdale	T1 BØ, metering CT	Age (51)
Springdale	T1 CØ, metering CT	Age (51)

2.1.2 Replace Disconnect Switches

The estimate of direct costs for this project is shown in Table 3.

Table 3: Direct Costs Estimate for the Replace Disconnect Switches Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	345.0	0.0	345.0
Labour	51.3	325.0	0.0	376.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	110.0	0.0	110.0
Other Direct Costs	0.0	66.7	0.0	66.7
Total Direct Costs	**51.3**	**846.7**	**0.0**	**898.0**

Project Scope

Hydro replaces disconnect switches when damaged beyond repair, when parts required for repair are unavailable due to obsolescence, or when it is not economical to repair, as detailed in section 4.1.2 of the Asset Management Overview. Hydro plans the replacement of the disconnect switches in Table 4.

Table 4: Disconnect Switches Replacements

Station	Equipment ID	Replacement Criteria
Bay d'Espoir	B1T1-1	Age (53)
Bay d'Espoir	B2T3-1	Age (53) Deficiencies in recent years
Bay d'Espoir	B2T4-1	Age (53) Deficiencies in recent years
Bay d'Espoir	B3T5-1	Age (53) Deficiencies in recent years
Churchill Falls	22B25	Obsolescence of parts Deficiencies in recent years
Churchill Falls	21B26	Obsolescence of parts Deficiencies in recent years
Oxen Pond	B1L36-1	Age (50) Obsolescence of parts Deficiencies in recent years
Oxen Pond	B1L36-2/L36G	Age (52) Obsolescence of parts
Deer Lake	B1T1	Deficiencies in recent years Linkage and alignment Issues

2.1.3 Replace Surge Arresters

The estimate of direct costs for this project is shown in Table 5.

Table 5: Direct Costs Estimate for the Replace Surge Arresters Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	29.4	0.0	0.0	29.4
Labour	84.1	0.0	0.0	84.1
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
Total Direct Costs	**113.5**	**0.0**	**0.0**	**113.5**

Project Scope

Hydro replaces surge arrestors based on physical and electrical deterioration, as detailed in section 4.1.3 of the Asset Management Overview. The surge arresters in Table 6 have exceeded their expected service life of 40 years, and will be replaced to avoid in-service failure and subsequent service interruption.

Table 6: Surge Arresters Replacement Plan

Station	Equipment ID	Replacement Criteria
Holyrood	T1 H1	Age (40)
Holyrood	T1 H2	Age (40)
Holyrood	T1 H3	Age (40)
Holyrood	SST-34 H1	Age (40)
Holyrood	SST-34 H2	Age (40)
Holyrood	SST-34 H3	Age (40)
Grandy Brook	T1 H1	Change with T1 H2 during outage Age nearing end of life
Grandy Brook	T1 H2	Condition (Poor doble results)
Grandy Brook	T1 H3	Change with T1 H2 during outage Age nearing end of life
Oxen Pond	T2 H1	Condition (Poor doble results)
Oxen Pond	T2 H2	Condition (Poor doble results)
Oxen Pond	T2 H3	Condition (Poor doble results)

2.1.4 Refurbish and Upgrade Power Transformers

The estimate of direct costs for this project is shown in Table 7.

Table 7: Direct Costs Estimate for the Refurbish and Upgrade Power Transformers Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	235.5	30.0	0.0	265.5
Labour	119.5	204.6	0.0	324.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	359.0	0.0	359.0
Other Direct Costs	5.1	90.8	0.0	95.9
Total Direct Costs	**360.1**	**684.4**	**0.0**	**1044.5**

Project Scope

Hydro carries out a number of refurbishment and upgrade activities on power transformers, including:

- Oil reclamation or replacement;
- Oil dehydration;
- Corrosion remediation;
- Refurbishment to address leaks;
- Tap changer overhauls;

- Bushing replacements;
- Protective device replacements;
- Cooling fan/radiator replacement; and
- Major refurbishment, which may include combinations of the above.

Hydro also installs online dissolved-gas analysis devices on critical power transformers. Hydro's power transformer refurbishment and modernization philosophies can be found in section 4.1.6 of the Asset Management Overview. Hydro plans to complete refurbishments and upgrades on the power transformers in Table 8.

Table 8: Power Transformer Upgrades and Refurbishment

Refurbishment Activity	Station	Equipment ID
Bushing Replacement	Hampden	T1 HV, LV, N
	Jackson's Arm	T1 HV, LV, N
	Hawke's Bay	T1 HV
	Stephenville	GT1 H1, H2, N
	Muskrat Falls	T1 HV, LV, N
Internal Inspection	Jackson's Arm	T1
Application of Protective Coating	Hampden	T1
	Jackson's Arm	T1

2.1.5 Replace Insulators

The estimate of direct costs for this project is shown in Table 9.

Table 9: Direct Costs Estimate for the Replace Insulators Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	15.8	32.8	0.0	48.6
Labour	27.7	64.8	0.0	92.5
Consultant	25.0	23.0	0.0	48.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	13.7	0.0	13.7
Total Direct Costs	**68.5**	**134.2**	**0.0**	**202.7**

Project Scope

Hydro replaces insulators that are at risk of failure due to cement growth, as detailed in section 4.1.4 of the Asset Management Overview. In 2015, Hydro carried out a condition assessment of insulators in

TRO Northern and TRO Labrador. Insulators with known cement growth issues were identified for replacement. In 2020, Hydro is targeting such insulators in the following stations:

- Peter's Barren;
- Roddickton;
- Happy Valley; and
- Churchill Falls.

2.1.6 Replace Station Lighting

The estimate of direct costs for this project is shown in Table 10.

Table 10: Direct Costs Estimate for the Replace Station Lighting Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	31.5	21.8	0.0	53.3
Consultant	7.5	7.5	0.0	15.0
Contract Work	0.0	282.9	0.0	282.9
Other Direct Costs	0.0	0.2	0.0	0.2
Total Direct Costs	**39.0**	**312.4**	**0.0**	**351.4**

Project Scope

Hydro replaces or adds station lighting due to deteriorated physical condition or inadequacy of existing lighting in order to ensure adequate station lighting during the night for the safety of operations personnel, as detailed in section 4.1.11 of the Asset Management Overview. Hydro assessed the terminal station lighting in the Holyrood Terminal Station and identified significant corrosion and moisture ingress issues impacting the function of the lighting system. Hydro plans to replace the Holyrood Terminal Station lighting in 2020.

2.1.7 Replace Battery Banks and Chargers

The estimate of direct costs for this project is shown in Table 11.

Table 11: Direct Costs Estimate for the Replace Battery Banks and Chargers Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	62.3	0.0	0.0	62.3
Labour	66.0	0.0	0.0	66.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	30.0	0.0	0.0	30.0
Other Direct Costs	11.8	0.0	0.0	11.8
Total Direct Costs	**170.1**	**0.0**	**0.0**	**170.1**

Project Scope

The service life of flooded cell batteries is 18-20 years and valve regulated lead acid ("VRLA") batteries is 7-10 years. Battery chargers have a service life of 20 years. Hydro replaces battery banks and chargers that meet this age criteria. Hydro also replaces battery banks and chargers if testing shows that they are deteriorating or are approaching insufficient capacity, as detailed in section 4.1.9 of the Asset Management Overview. Hydro plans to replace battery banks in the following locations:

- Cow Head (VRLA batteries – 10 years old at replacement); and
- Daniel's Harbour (VRLA batteries – 11 years old at replacement).

2.2 Civil Works and Buildings

The following Civil Works and Buildings activities are proposed for 2020:

- Repair Equipment Foundations;
- Install Fire Suppression; and
- Refurbish Control Buildings.

2.2.1 Repair Equipment Foundations

The estimate of direct costs for this project is shown in Table 12.

Table 12: Direct Costs Estimate for the Repair Equipment Foundations Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	63.6	0.0	0.0	63.6
Consultant	51.3	0.0	0.0	51.3
Contract Work	187.5	0.0	0.0	187.5
Other Direct Costs	5.1	0.0	0.0	5.1
Total Direct Costs	**307.5**	**0.0**	**0.0**	**307.5**

Project Scope

Hydro repairs concrete foundations in terminal stations when the foundations have deteriorated severely, compromising structural integrity if not addressed, as detailed in section 4.2.1 of the Asset Management Strategy. Based on a condition assessment Hydro plans to repair equipment foundations in Bottom Brook Terminal Station.

2.2.2 Install Fire Suppression

The estimate of direct costs for this project is shown in Table 13.

Table 13: Direct Costs Estimate for the Install Fire Suppression Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	4.0	0.0	4.0
Labour	23.9	35.8	0.0	59.7
Consultant	74.0	106.0	0.0	180
Contract Work	0.0	332.0	0.0	332.0
Other Direct Costs	0.5	1.4	0.0	1.9
Total Direct Costs	**98.3**	**479.2**	**0.0**	**577.5**

Project Scope

Hydro is installing fire suppression systems in all 230 kV terminal station control buildings due to the station criticality, as detailed in section 4.2.2 of the Asset Management Strategy. Hydro plans to install a fire suppression system in the following terminal station control building:

- Stony Brook was selected as the next control building upgrade.

2.2.3 Refurbish Control Buildings

The estimate of direct costs for this project is shown in Table 14.

Table 14: Direct Costs Estimate for the Refurbish Control Buildings Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	60.3	0.0	0.0	60.3
Consultant	76.6	0.0	0.0	76.6
Contract Work	147.0	0.0	0.0	147.0
Other Direct Costs	0.7	0.0	0.0	0.7
Total Direct Costs	**284.7**	**0.0**	**0.0**	**284.7**

Project Scope

Hydro will refurbish control buildings with an emphasis on structural, building envelope, and roofing refurbishment, to ensure the structural integrity and security of the buildings and to prevent leaks, as detailed in section 4.2.3 of the Asset Management Overview. Hydro will refurbish the following control buildings in 2020:

- Western Avalon (Roof Replacement): This roof is original to the building, built in 1966, and has developed leaks. Based on the condition it is in need of replacement.

2.3 Protection, Control, and Monitoring Refurbishment and Upgrades

The estimate of direct costs for this project is shown in Table 15.

Table 15: Direct Costs Estimate for the Protection, Control, and Monitoring Refurbishment Upgrades Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	645.2	30.6	0.0	675.8
Labour	317.0	486.0	0.0	803.0
Consultant	5.6	126.0	0.0	131.6
Contract Work	10.0	0.0	0.0	10.0
Other Direct Costs	10.7	102.8	0.0	113.5
Total Direct Costs	**988.5**	**745.4**	**0.0**	**1,733.9**

2.3.1 Project Scope

Hydro has an ongoing program to replace electromechanical and obsolete solid-state relays with modern digital relays, improving reliability and functionality. Hydro's approach to protection, control, and modernization asset management is detailed in section 4.3 of the Asset Management Overview. Hydro does not plan to replace any Protection and Control relays in the 2020 Capital Budget.

Following a 2014 review of Hydro's breaker failure protection, Hydro began implementing a program to expand breaker failure protection beyond its 230 kV stations, including terminal stations rated 66 kV and above. Under this program, Hydro plans to install breaker failure protection in the Hawkes Bay Terminal Station in 2020.

Additionally, Hydro assesses the condition of legacy Breaker Failure protection systems in 230 kV stations during regular maintenance procedures. Through these assessments, Hydro has identified the requirement to replace the breaker failure protection in the Buchans Terminal Station in 2020-2021.

Hydro will also upgrade Data Alarm Management in the following stations, to provide higher data resolution for the prompt and accurate identification and troubleshooting of system issues:

- Massey Drive.

Hydro will also install Digital Fault Recorders in the following locations to improve the analysis of system events in the area served by the station:

- Happy Valley.

2.4 Wabush Terminal Station Refurbishment

The estimate of direct costs for this project is shown in Table 16.

Table 16: Direct Costs Estimate for the Wabush Terminal Station Refurbishment Project ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	110.1	177.5	0.0	287.6
Labour	291.9	453.6	0.0	745.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	351.1	515.9	0.0	867.0
Other Direct Costs	34.2	78.2	0.0	112.4
Total Direct Costs	**787.3**	**1,225.2**	**0.0**	**2,012.5**

Project Scope

On August 5, 2016, Hydro applied to the Board for approval to acquire the Wabush Terminal Station. This application was approved in Order No. P.U. 37(2016). Within the application Hydro identified that many of the assets in the Wabush Terminal Station are nearing the end of their useful lives and will require refurbishment or replacement in coming years.

In a supplemental capital budget application titled "Assessment and Refurbishment – Wabush Terminal Station," submitted on March 17, 2017, Hydro proposed to address immediate concerns to ensure reliability of the Wabush Terminal Station. Additional refurbishment activities consistent with Hydro's asset management principles outlined in the Asset Management Overview were proposed and approved in Hydro's 2018 and 2019 CBAs. Hydro plans to continue the refurbishment of the Wabush Terminal Station, proposing the following work for the 2020 Capital Budget Application:

- Replacement of 46 kV circuit breaker 46-3 (PCB contamination, legislated for removal by 2025);
- Replacement of 230 kV disconnect switches T4B1/T4G (obsolete, no parts available);
- Replacement of 46 kV disconnect switch 13B15 (obsolete, no parts available);

- Installation and commissioning of transformer T3 protection upgrades (obsolete electromechanical protection); and
- Level 2 Condition Assessment of Synchronous Condenser 2 (Level 2 condition assessment required every 3 years).

3.0 Project Cost

3.1 Project Estimate

The estimate for this project is shown in Table 17.

Table 17: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	1,098.3	781.4	0.0	1,879.7
Labour	1,164.8	1,677.0	0.0	2,841.8
Consultant	240.0	262.5	0.0	502.5
Contract Work	725.6	1,599.8	0.0	2,325.4
Other Direct Costs	68.2	364.1	0.0	432.3
Total Direct Costs	**3,296.9**	**4,684.8**	**0.0**	**7,981.7**
Interest and Escalation	186.1	499.0	0.0	685.1
Contingency	229.0	884.0	0.0	1,113.1
Total	**3,712.0**	**6,067.8**	**0.0**	**9,779.8**

3.2 Project Schedules

Due to the large number of activities enveloped in this project, it is not practical to provide individual project schedules. Detailed project schedules will be developed at project initiation. A typical high-level schedule for a multi-year project is as follows:

- Year 1: Planning, Design, and Procurement; and
- Year 2: Construction, Commissioning, and Closeout.

All activities will be completed before the end of 2021.

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2019/07/22
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NEWFOUNDLAND & LABRADOR

2020 Capital Budget Application
Terminal Station Asset Management Overview

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") has developed an ongoing capital program to replace or refurbish assets as they reach the end of their design life or require attention due to obsolescence or anticipated failure.

Before 2017, Hydro's terminal station projects could be divided into two categories: (1) stand-alone and (2) programs. Programs included projects that are proposed year after year to address the upgrade or replacements of deteriorated equipment, such as disconnects or instrument transformers, and have similar justification each year. Stand-alone would include projects that do not meet the definition of a program. Hydro has typically had as many as 15 separate program-type terminal station projects in its capital budget applications, with each program based upon a particular type of asset.

Starting with the "2017 Capital Budget Application" ("CBA"), Hydro implemented a change to how the terminal station projects are submitted for consideration by the Board of Commissioners of Public Utilities ("Board"). Hydro has consolidated the programs into the Terminal Station Refurbishment and Modernization project ("Project"), thereby improving regulatory efficiency and easing the administrative effort for both the Board and Hydro and allowing Hydro to look for opportunities to realize efficiencies by improving coordination of capital and maintenance work in terminal stations.

In 2019, Hydro submitted a revised Terminal Station Asset Management Overview ("Asset Management Overview") to provide an updated overview of Hydro's asset maintenance philosophies in one document. Hydro will submit the Project within annual CBAs going forward, proposing required terminal station work and referencing this Asset Management Overview document.

Contents

1.0 Introduction

Hydro has 70 terminal stations that contain electrical equipment such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment required to protect, control, and operate Hydro's electrical grid.

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

Part of Hydro's annual capital program is a sustained effort to ensure the safety and reliability of terminal station assets. Historically, the Board's approval for this effort has been requested by Hydro submitting either individual projects for particular assets, or programs for Station sustaining work in its CBA. This approach can result in a segmented view of the expenditures to sustain Station assets. For example in the 2016 CBA, there were 15 separate program-type projects submitted. The expenditures detailed in these projects according to the Board's classifications are normal capital expenditures. This situation provides an opportunity to increase regulatory efficiency.

With the 2017 CBA, Hydro consolidated planned terminal station sustaining work into the Project. Additionally, Hydro submitted a project titled "Terminal Station In-Service Failures" to cover the replacement or refurbishment of failed equipment, or incipient failures. Hydro is utilizing the Asset Management Overview as a reference for both projects to streamline and focus information submitted. The Asset Management Overview provides supporting information which was, historically, annually presented for similar classification projects in the CBA. The remainder of this document provides information as to the assets involved, an overview of each asset program, and how this document will be updated in the event of changes to Hydro's asset management philosophies.

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

1.1 Changes in Version 4

Hydro submits Version 4 of this document with the 2020 CBA. All material updates in this version are shaded in grey, and are summarized below:

- Addition of section 4.1.11: Replace Station Lighting;
- Addition of age-based replacement criteria for instrument transformers;
- Addition of hot oil dry-out as a means of addressing high moisture content for power transformers;
- Extension of the 2016–2020 Circuit Breaker Replacement Program to 2022;
- Addition of 66 kV breakers to 20-year refurbishment requirement for SF_6 circuit breakers
- Place a hold on plans for breaker bypass switches; and
- Addition of replacement of breaker failure protection upgrades in 230 kV stations for breaker failure protection.

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

2.0 Background

2.1 Newfoundland and Labrador Hydro's Terminal Stations

Terminal stations play a critical role in the transmission and distribution of electricity. Terminal stations contain electrical equipment, such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment required to protect, control, and operate the Hydro's electrical grid. Stations act as transition points within the transmission system, and interface points with the lower voltage distribution and generation systems. Hydro has 70 terminal stations throughout Newfoundland and Labrador.

2.2 Terminal Station Infrastructure

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

- Transformers;
- Circuit breakers;
- Instrument transformers;
- Disconnect, bypass, and ground switches;
- Surge arresters;
- Grounding;
- Buswork;
- Steel structures and foundations;
- Insulators
- Control buildings;
- Protection and control relays;
- Yards, fences, and access roads;
- Battery banks; and
- Terminal station lighting

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

3.0 Terminal Station Capital Projects

3.1 Historical Terminal Station Capital Projects

In the 2016 CBA there were 22 individual terminal station projects which accounted for $30 million, or 16% of the capital budget. Historically, Hydro's terminal station projects were divided into two categories: (1) stand-alone and (2) programs. Programs include projects that are proposed year after year to address the required refurbishment or replacement of assets such as disconnects or instrument transformers, and have similar justification and other information presented each year. Of the 22 individual terminal station projects proposed in 2016, 15 were program-type projects. In the 2017 CBA, Hydro consolidated the historical station projects into the Project.

3.2 Hydro's Approach to Terminal Station Capital Project Proposals

The programs now included in the Project are:

- Upgrade Circuit Breakers (Beyond 2020);
- Replace Disconnect Switches;
- Install Fire Protection ;
- Replace Surge Arresters;
- Upgrade Terminal Station Foundations;
- Refurbish Control Buildings;
- Replace Station Lighting;
- Replace Battery Banks and Chargers;
- Upgrade Terminal Station for Mobile Substation;
- Install Breaker Bypass Switches;
- Protection and Control Refurbishment and Upgrades;[1]

The Project excludes:

- Transformer replacement and spares: although transformer replacement fits within the description of a terminal station program, these projects often have unique justification and a high project cost and, therefore, are proposed separately.
- Accelerated circuit breaker replacement: Hydro proposed the accelerated replacement of 230 kV circuit breakers as part of the 2016 CBA "Upgrade Circuit Breakers" project. This project involves the replacement of high-voltage circuit breakers through the year 2020 and is now moved to 2022. As this project has already been approved, it is not included in the Project.

[1] As noted in the 2017 version of the Asset Management Overview, the 2016 Upgrade Terminal Station Protection and Control Upgrade, Upgrade Protective Relays, Upgrade Fault Recorders, Upgrade Data Alarm Systems and Install Breaker Failure Protection projects were combined in the Asset Management Overview and the Project as the Protection and Control Refurbishment and Upgrades Program.

However, future breaker replacements not captured in the 2016–2020 “Upgrade Circuit Breakers” project will be included in future CBAs, and, therefore, the justification for such programs is included in this report.

- Activities which cannot be scheduled for inclusion in a CBA as these will be submitted as either supplemental to the CBA or executed in the Terminal Stations In-Service Failures project.
- Activities in response to additional load or reliability requirements. As these projects generally have unique justification, and will be proposed separately.
- Activities in response to significant isolated issues in a particular station, such as replacement of a failed power transformer. As these projects generally have unique justification, the projects will be proposed separately.

Hydro continues to maintain individual records with regards to asset capital, maintenance, and retirement expenditures and performance, which will be queried to support the development of the annual capital plan.

This document is submitted to the Board as part of the 2020 CBA. Hydro will annually submit proposals for the Terminal Station Refurbishment and Modernization project and Terminal Station In-Service Failures project referencing the most recent Asset Management Overviews. Future CBAs will not include a copy of the Asset Management Overview unless Hydro revises its contents. When the Asset Management Overview is revised, Hydro will clearly denote such changes, highlighted in gray, for review and approval by the Board.

3.3 Benefits of This Approach

As supporting information for programs changes infrequently, referencing the Asset Management Overview in the Project documentation will eliminate the preparation and review of repetitious information. Hydro estimates that this approach could save up to $120,000[2] annually, not including time and costs for review by the Board and Intervenors.

[2] If the work undertaken in the 2017 Terminal Station Refurbishment and Modernization project had been submitted as 12 individual projects, it is estimated preparation would be approximately $10,000 per project.

Hydro has a proactive Asset Management System which strives to anticipate future failures so that refurbishment or replacement can be incorporated into a CBA. However, there are situations were immediate refurbishment or replacement, which has not be included in an CBA, has to be undertaken due to the occurrence of an unanticipated failure or the recognition of an incipient failure so as to maintain the delivery of safe, reliable electricity at least cost. These situations seldom include extenuating or abnormal circumstances and costs. With aging terminal station assets unanticipated failures may increase. This increase will require additional future efforts to provide and review regulatory documentation. By introducing a Terminal Station In-Service Failures project, there will be a reduced need for that documentation and change management processes. Each year, Hydro will provide a concise summary of the previous year's work.

Hydro expects the Project will provide opportunities whereby Hydro can further optimize capital and maintenance work so as to minimize outages to customers and equipment as personnel look to further coordinate work by location.

4.0 Asset Management Programs

4.1 Electrical Equipment

4.1.1 High-Voltage Instrumentation Transformer Replacements

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

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

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

Hydro manages planned budgeted Instrument Transformer replacements in four categories:

1) Condition
2) PCB Compliance Replacements
3) Manufacturer and model (not required after 2019)
4) Age

Condition

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

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

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

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

Figure 2: Rusting PT

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

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

PCB Compliance Replacements

Environment Canada's polychlorinated biphenyl ("PCB") Regulations requires that by 2025 all instrument transformers will not have a PCB concentration greater that 50 mg/kg. Instrument transformers are sealed oil filled units, where the oil, which acts as an electrical insulator, has been known to contain PCBs for equipment prior to 1985. Due to the age of the units and the risk of introducing contamination such as air into the unit, which could impact the electrical integrity of instrument transformers, Hydro does not sample instrument transformers. Therefore, establishing the actual PCB concentration in an Instrument Transformer is not possible. Hydro, in consultation with manufacturers, has established that units manufactured before 1985 are suspected to contain PCBs in concentration levels greater than or equal to 50 mg/kg. Thus Hydro has a program to replace all suspect oil-filled instrument transformers before 2025.

Manufacturer and Model

In 2010 Hydro experienced a failure of a 230 kV ASEA IMBA Current Transformer. The failure analysis recommended this manufacturer and model be replaced over time. These replacements are included in this program. The last of these replacements was completed in 2019 and hence this criterion will be removed from this program.

Age

Hydro targets replacement at 40 years of age to reduce the risk of in-service failures and minimize service interruptions. Original Equipment Manufacturers ("OEM") recommend that the life of an instrument transformer is approximately 30 to 40 years. Recent in-service failures occurred between 20–39 years of life (three of which occurred between 29–39 years of life).

Exclusions from Instrument Transformer replacement program

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

4.1.2 High-Voltage Switch Replacements

High-voltage switches are used to isolate equipment either for maintenance activities or for system operation and control (disconnect switches). Switches are also used to bypass equipment to prevent customer outages while work is being performed on the equipment. Disconnect switches are an important part of the Work Protection Code as they provide a visible air gap (i.e., visible isolation) for utility workers. Work protection is defined as "a guarantee that an ISOLATED, or ISOLATED and DE-ENERGIZED, condition has been established for worker protection and will continue to exist, except for authorized tests." Proper operation of disconnect switches is essential for a safe work environment and for reliable operation.

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

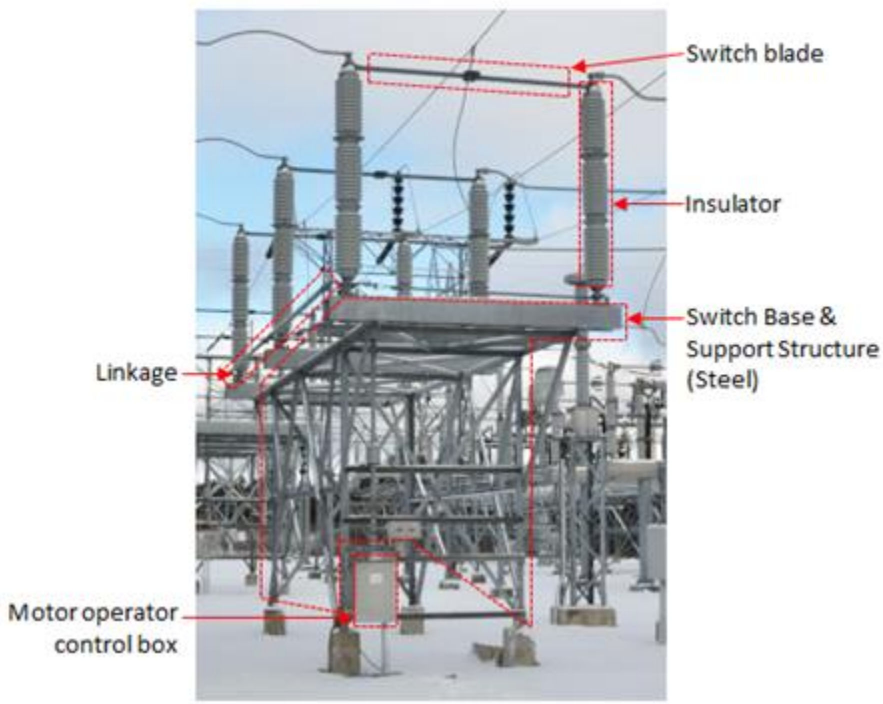

Figure 3: Various Components of a High-Voltage Disconnect Switch

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

JDE E1 work order system or staff who operate the switch, outlining problems such as inoperable mechanical linkages, misalignment of switch blades, broken insulators, and seizing of moving parts. Asset management personnel determine the timing of corrective maintenance or switch replacement. If the required parts are available then repairs are undertaken as part of on-going maintenance. Switches that have operating deficiencies and have reached a service life of 50 years or greater are designated for replacement. Switches that have no replacement parts available due to obsolescence, damaged beyond repair, or cannot be economically repaired and do not require immediate replacement are designated for replacement under this program.

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

Figure 4: Broken Insulator on 69 kV Disconnect Switch

4.1.3 Surge Arrester Replacement

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

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

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

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

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

- Removal of gapped type arresters with zinc oxide design due to enhanced performance;
- Replacement of units due to a condition identified through visual inspections for chips or cracks or electrical testing such as power factor testing;

- If failures occur on a given transformer, all arresters on both the high and low side are considered for replacement either immediately or in a planned fashion; and
- If transformers are being planned for maintenance or other capital work, consideration is given to changing aged arresters on a common outage. Hydro targets replacement at 40 years of age, to reduce the risk of in-service failures and minimize service interruptions.

4.1.4 Insulator Replacement

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

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

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

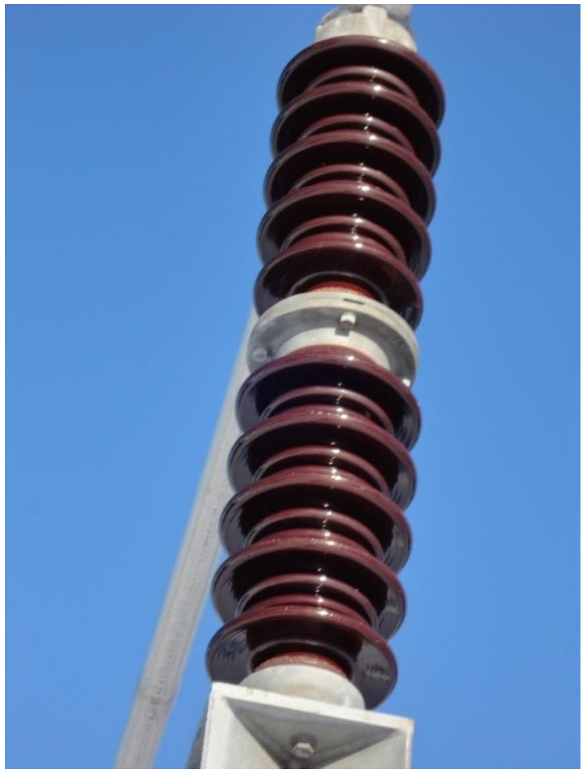

Figure 6: Multi-Cone Type Insulator Prone to Failure due to Cement Growth

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

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

4.1.5 Grounding Refurbishment and Upgrades

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

Figure 7: Typical Grounding Connection on Terminal Station Fence

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

4.1.6 Power Transformer Upgrades and Refurbishment

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

Hydro has over 130 power transformers 46 kV and above, as well as several station service transformers at voltages lower than 46 kV.

The basic components of a power transformer are:

- Transformer steel tank containing the metal core and paper insulated windings; oil which is part of the insulating system, and a gasket system which keeps the oil from getting into the environment;
- Bushings mounted to the top of the transformer tank, which connects the windings to the external electrical conductors;
- Radiators and cooling fans, which remove heat for the transformer's internal components;
- On-Load tap changer, which is a device attached internally or externally through which transformer voltages are maintained at acceptable levels; and
- Protective devices to ensure the safe operation of the transformer, such as gas detector relays, oil level and temperature relays, and gauges.

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

Figure 8: Power Transformer

Transformers are expensive components of the electrical system. Hydro, like many North American utilities, is working to maximize and extend the life of its transformer by regularly assessing their condition; executing regularly schedule maintenance and testing and undertaking refurbishment or corrective actions as required. Transformers regularly undergo visual inspection as part of Hydro's terminal station inspection and scheduled preventive maintenance and testing, to identify concerns regarding a the following transformer conditions:

- Insulating oil and paper deterioration;
- Oil moisture content;
- Oil leaks;
- Tank, radiators, and other component rusting/corrosion;

- Tap changer component wear or damage;
- Damaged/Deteriorated and PCB contaminated bushings;
- Failure of the protective devices; and
- Cooling fan failures.

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

Transformer Oil Deterioration

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

Moisture Content

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

Oil Leaks and Corrosion

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

On-Load Tap Changer

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

Bushings

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

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

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

Protective Devices and Fans

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

Online Oil Analysis

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

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

[3] Newfoundland and Labrador Hydro "Report to the Board of Commissioners of Public Utilities Regarding Work to be Performed on Transformers," July 2, 2014.

4.1.7 Circuit Breaker Refurbishment and Replacements

The circuit breaker is a critical component of the power system. Located in a terminal station, each circuit breaker performs switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of circuit breakers through its fast response and complete interruption of current flow is essential for the protection and stability of the power system. The failure of a breaker to operate as designed may affect reliability and safety of the electrical system resulting in failure of other equipment and the occurrence of an outage affecting more end users. Hydro has over 200 terminal station circuit breakers in service with a voltage rating of 46 kV or greater.

Currently, Hydro maintains three different types of high-voltage circuit breakers:

1) Air blast circuit breakers ("ABCB"): use high-pressure air to interrupt currents and will be at least 38 years old at replacement. In the 2016 CBA Upgrade Circuit Breakers – Various Sites project, approval was obtained to replace ABCBs on an accelerated schedule by the end of 2020. This work is covered under a separate project and is not part of the work outlined in the Asset Management Overview. Hydro has since modified this program and is targeting completion in 2022.

2) Oil circuit breakers ("OCB"): use oil to interrupt currents and will be at least 36 years old at replacement. In the 2016 CBA Upgrade Circuit Breakers – Various Sites project, approval was obtained for the replacement of 10 OCBs up to 2020 which were not compliant with Environment Canada's PCB regulations. Hydro has since modified this program and is targeting completion of that scope in 2022. The remaining non-compliant breakers will be replaced before 2025. From 2017, any replacements not previously approved in the 2016 CBA will be included in the work conducted under this section of the Asset Management Overview.

3) Sulphur hexafluoride ("SF_6") circuit breakers: use SF_6 gas to interrupt current and installation of these breakers started in 1979 and continue for all new installations. In the 2016 CBA Upgrade Circuit Breakers – Various Sites project, approval was obtained, until the end of 2020, for the mid-life refurbishment and replacement of SF_6 circuit breakers with voltage rates 66 kV and above. From 2017, any SF_6 replacements and refurbishments not previously approved in the 2016 CBA will be included in the work conducted under this section of the Asset Management Overview.

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

As presented in the 2016 CBA, Upgrade Circuit Breakers – Various Sites project, SF_6 circuit breakers rated at 138 kV and above are required to be refurbished after 20 years of service. In 2018 Hydro added 66 kV-rated breakers to also be refurbished after 20 years. Replacement of SF_6 circuit breakers rated at 66 kV and above will be after 40 years of service, as is consistent with Hydro’s philosophy, most recently presented to the Board in the 2016 CBA Upgrade Circuit Breakers – Various Sites project. Some SF_6 circuit breakers may require replacement before the 40-year service life period based upon their condition and operational history. Hydro expects to replace up to six breakers per year beyond 2020 and an average of five breakers and overhaul one breaker per year for 2022 and 2023 and not require overhauls again until beginning 2030. As per the 2016 CBA, “Upgrade Circuit Breakers – Various Sites” project, Hydro does not currently overhaul breakers rated below 138 kV.

Figure 10 shows the age distribution of circuit breakers not approved for replacement prior to 2017.

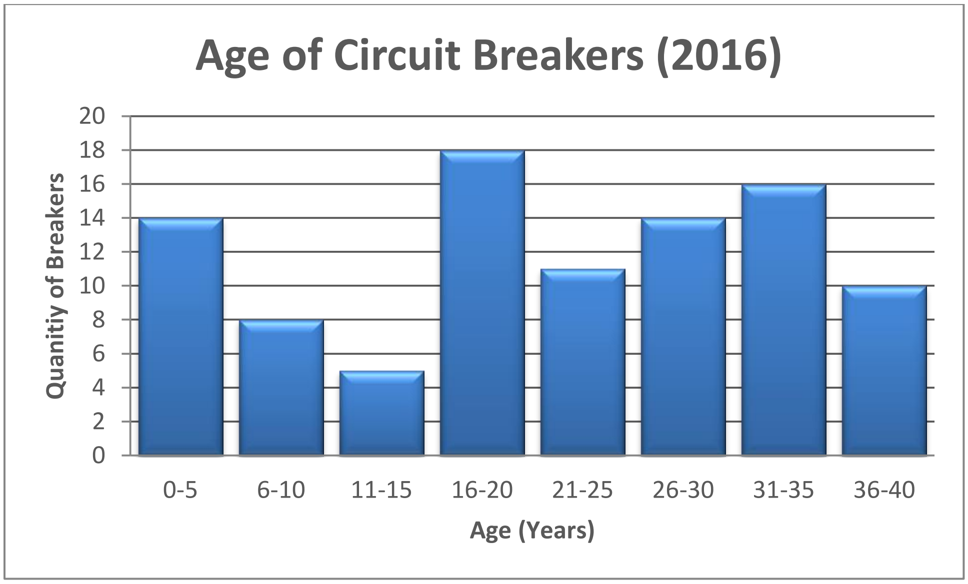

Figure 10: Age of Circuit Breakers not Included in Ongoing Replacement Program

4.1.8 Station Service Refurbishment and Upgrades

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

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

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

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

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

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

4.1.9 Battery Banks and Chargers

Battery banks and their chargers supply dc power to critical station infrastructure such as circuit breakers, protection and control relays, disconnect switch motor operators, and telecontrol equipment. Battery banks are designed to provide a minimum of eight hours of auxiliary power to critical infrastructure in the event of a loss of ac station service supply. The majority of Hydro's battery banks consist of lead-acid flooded-cell type batteries, whose capacity deteriorates over time. Hydro currently completes discharge testing on criticality A and B battery banks and will plan replacements if the battery bank's capacity has fallen to 80% or less of its rated capacity. Also, due to the critical nature of battery banks, flooded cell batteries are replaced after 20 years while valve-regulated lead-acid batteries are replaced after 10 years.

Figure 11: 125 Vdc Terminal Station Battery Bank

4.1.10 Install Breaker Bypass Switches

High-voltage circuit breakers, with their associated protection and control equipment, are used to control the flow of electrical current to ensure safe and reliable operation of the electrical system. When a breaker is removed from service for maintenance, troubleshooting, refurbishment, or replacement, an alternate electrical path must be implemented to avoid customer outages. On radial systems,[4] this alternate path is accomplished using a bypass switch. When closed, the bypass switch allows electricity to flow around the breaker allowing the breaker to be safely de-energized, while maintaining service continuity.

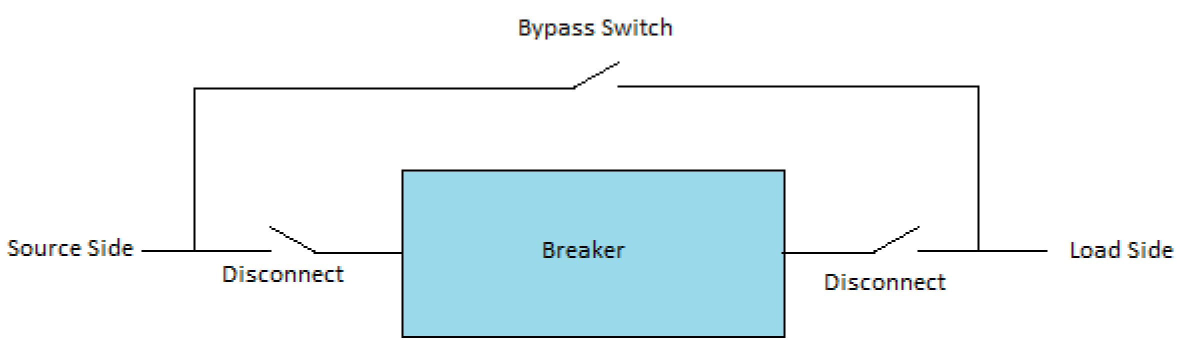

Figure 12: Example of Bypass Switch Installation

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

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

Table 1: Circuit Breakers Without Bypass Switches

Breaker Location	Customers Affected
Bottom Waters L60T1	2253 Bottom Waters area customers
Buchans B2T1	665 Buchans area Newfoundland Power customers and Duck Pond Mine
Doyles B1L15	3563 Grand Bay, Port aux Basques, and Long Lake area Newfoundland Power customers.
Howley B1T2	773 Hampden and Jackson's Arm area customers and 665 Newfoundland Power Howley area customers
Peter's Barren B1L41	1900 Great Northern Peninsula customers north of Daniel's Harbor
South Brook L22T1	2340 South Brook area customers.

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

4.1.11 Replace Station Lighting

Terminal station lighting is essential to provide adequate illumination for a safe working environment, as well as for deterring theft and vandalism in terminal stations. Hydro utilizes a variety of lighting technologies and configurations, depending on the application and vintage of the lighting system. Over time, exposure to the elements can cause physical deterioration, such as corrosion, leading to moisture ingress which impacts the function of the lighting system. Also some legacy lighting technologies have become obsolete.

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

Figure 13: Corroded Ballast Requiring Replacement

Figure 14: Light Fixture Showing Perforations due to Corrosion, Enabling Moisture Ingress

4.2 Civil Works and Buildings

4.2.1 Equipment Foundations

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

The service life of galvanized steel structures varies depending on the operating environment, but can exceed 100 years, outliving the foundations on which they are built. A number of the foundations in Hydro terminal stations have deteriorated significantly due to repeated exposure to damaging freeze/thaw cycles, weathering, and age, leading to concerns over their integrity. Examples of degraded structure foundations are shown in Figure 15 and Figure 16.

Figure 15: Structure B1T1 Bottom Brook Terminal Station

Figure 16: Structure L01L37-1 Western Avalon Terminal Station

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

4.2.2 Fire Protection

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

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

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

4.2.3 Control Buildings

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

Typical refurbishment activities for control building involve replacement of the roof membrane (Figure 17), siding, and doors (Figure 18), and may also include replacement of electrical equipment (such as distribution panels, transfer switches, or low-voltage disconnects), plumbing (such as water service entries and internal plumbing), and HVAC (such as intake and exhaust fans, louvers, heaters, and air conditioning equipment).

In 2016, Hydro submitted its "Upgrade Office Facilities and Control Buildings Condition Assessment and Refurbishment Program Asset Management Strategy Plan" in its 2017 CBA, which outlined Hydro's approach to address aging and failing building infrastructure. Beginning with the 2019 CBA, Hydro will undertake the refurbishment of control buildings under the Project.

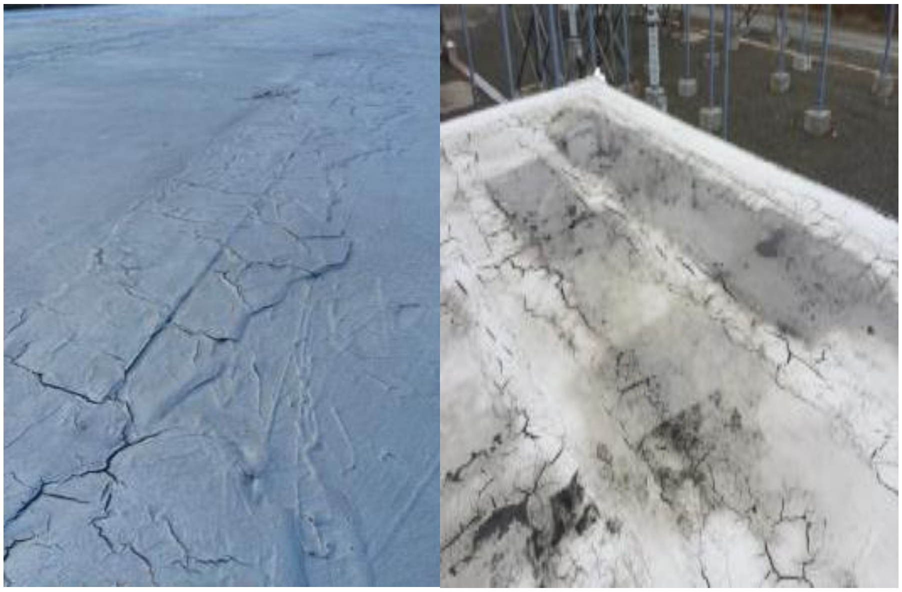

Figure 17: Terminal Station Control Buildings (Come by Chance and Sunnyside) Showing Cracking and Deterioration of the Roof Membrane System

Figure 18: Building Exterior Cladding and Exterior Doorways Displaying Severe Rusting and Deterioration

4.3 Protection, Control, and Monitoring

4.3.1 Protection and Control Upgrades and Refurbishment

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

- Protective relays;
- Breaker failure protection;
- Tap changer controls;
- Data alarm systems;
- Frequency monitors;
- Digital fault recorders; and
- Cables and panels.

Electromechanical and Solid State Protective Relay Replacement

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

Older relays existing on Hydro's system are the electromechanical and older solid state types, and lack features such as data storage and event recording capability. Modern digital multifunction relays are used to replace these older style relays, as they have increased setting flexibility, fault disturbance monitoring, communications capability and metering functionality, and offer greater dependability and security, enhancing system reliability. Digital and electromechanical relays are showing in Figure 19.

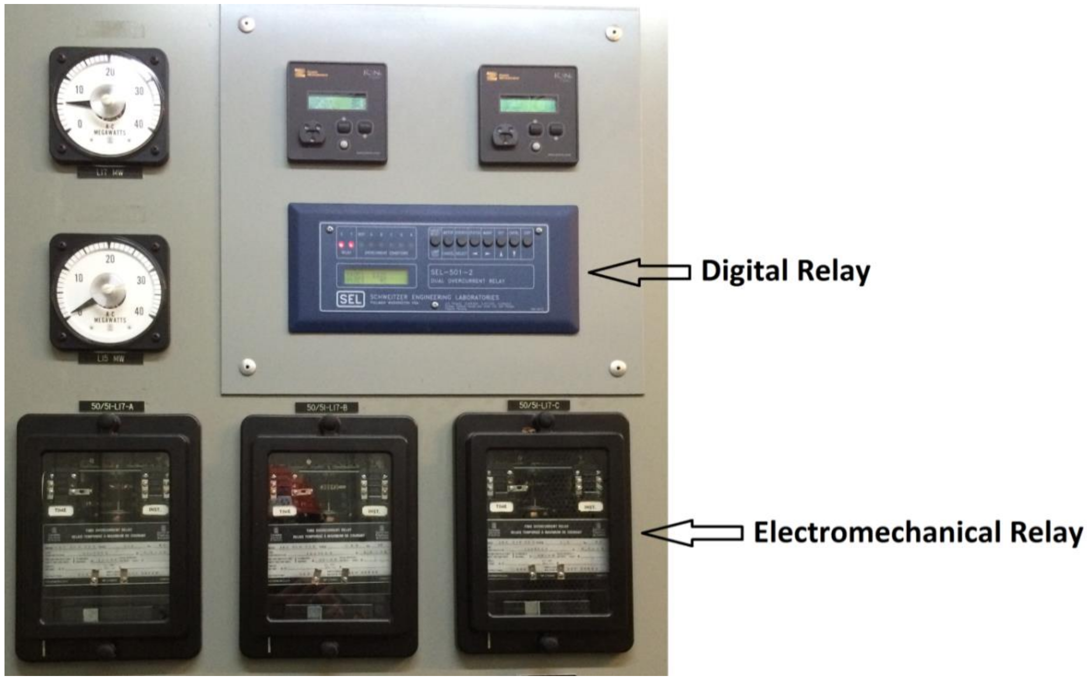

Figure 19: Digital and Electromechanical Relays

In the "Report to the Board of Commissioners of Public Utilities Related to Alarms, Event Recording Devices, and Digital Relays" dated August 1, 2014, Section 3.1 stated that "*Hydro plans to review its existing transformer, bus, and line protections in an effort to develop plans for future implementation of modern digital relays with data storage and fault recording capabilities.*" To fulfill this commitment, Hydro completed the following:

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

As part of the annual Terminal Station Refurbishment and Modernization project, Hydro will continue to execute the replacement of 230 kV electromechanical and obsolete solid-state transformer, line, and bus relays with modern digital multifunction relays, which began in 2016 under the Replace Protective Relays Program. Additionally, in line with Hydro's response to CA-NLH-037 as part of the 2016 CBA, Hydro installed redundant multifunction transformer protection relays in 2016 for transformers rated above 10 MVA. Under this program Hydro will continue to install these upgrades.

Breaker Failure Protection

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

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

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

Tap Changer Paralleling Control Replacement

Tap changer paralleling controls are designed to:

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

Current tap changer controls are of similar vintage as the power transformers dating back to the late 1960's, and require replacement. Recent feedback from the tap changer paralleling control supplier indicated older equipment has capacitors that will dry out over time resulting in control issues.

Additionally, it was recommended the same controller model be applied to all transformers to optimize tap changing control. The control issues as described by the supplier have been seen by Hydro staff at numerous sites.

Hydro plans to start replacing tap changer paralleling controls in 2018 beginning at Western Avalon Terminal Station.

Equipment Alarm Upgrades

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

Figure 20: Annunciator Commonly Found in Hydro Terminal Stations

Hydro's review of Alarms, Event Recording Devices, and Digital Relays found that by providing more detailed alarm schemes, the ECC and local operators are able to troubleshoot system events more accurately and quickly.

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

Frequency Monitoring Additions

As a result of investigations into the outage of January 2013, a recommendation was made to install frequency monitoring devices on the Island Interconnected System to allow better analysis of system events, such as pre and post-fault scenarios. It was recommended that one such device be installed in an Eastern, Western, and Central location on the Island Interconnected System. Hydro Place (East), Massey Drive Terminal Station (West), and Bay d'Espoir Terminal Station #2 (Central) have been chosen for the installation of frequency monitoring devices. This work was completed in 2018 and will be removed from this program.

Digital Fault Recorders

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

Protection and Control Cable and Panel Modifications

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

8. Diesel Genset Replacements – Mary's Harbour

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2020 Capital Budget Application
Diesel Genset Replacements
Mary's Harbour

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Mary's Harbour is an isolated community located on the southeast coast of Labrador. Newfoundland and Labrador Hydro ("Hydro") provides electrical service from Mary's Harbour Diesel Generating Plant ("Diesel Plant") to approximately 260 customers in the community.

In the Diesel Plant, Unit 2083 has had a long standing vibration problem which has proven to be difficult to solve. After numerous consultations with the manufacturer, and after incurring repeated high maintenance costs and extended unit outages, Hydro has decided it is not feasible to continue operating this unit and is therefore proposing replacement. In addition, diesel generator Unit 2037 has exceeded its expected service life.

Hydro is proposing this project for the replacement of Unit 2037 and Unit 2083 diesel generator sets ("gensets") to maintain reliable operation of the Mary's Harbour Diesel Generating Plant.

This project estimate is approximately $3,900,700 and is scheduled for completion in 2020.

Contents

1.0 Introduction

Many communities in Labrador are not connected to the Labrador Interconnected System for power supply. Isolated communities along the coast of Labrador are provided with electricity from diesel generating plants owned and operated by Hydro.

Mary's Harbour is located on the southeast coast of Labrador. Figure 1 is a map of Labrador showing the location of Mary's Harbour. Hydro provides electrical service to approximately 260 customers in the community from its diesel generating plant, which consists of four gensets; two rated at 545 kW, one at 800 kW and one mobile unit at 725 kW. In addition to serving domestic customers, Hydro also serves the local fish plant, which results in the Mary's Harbour system being a summer peaking system.

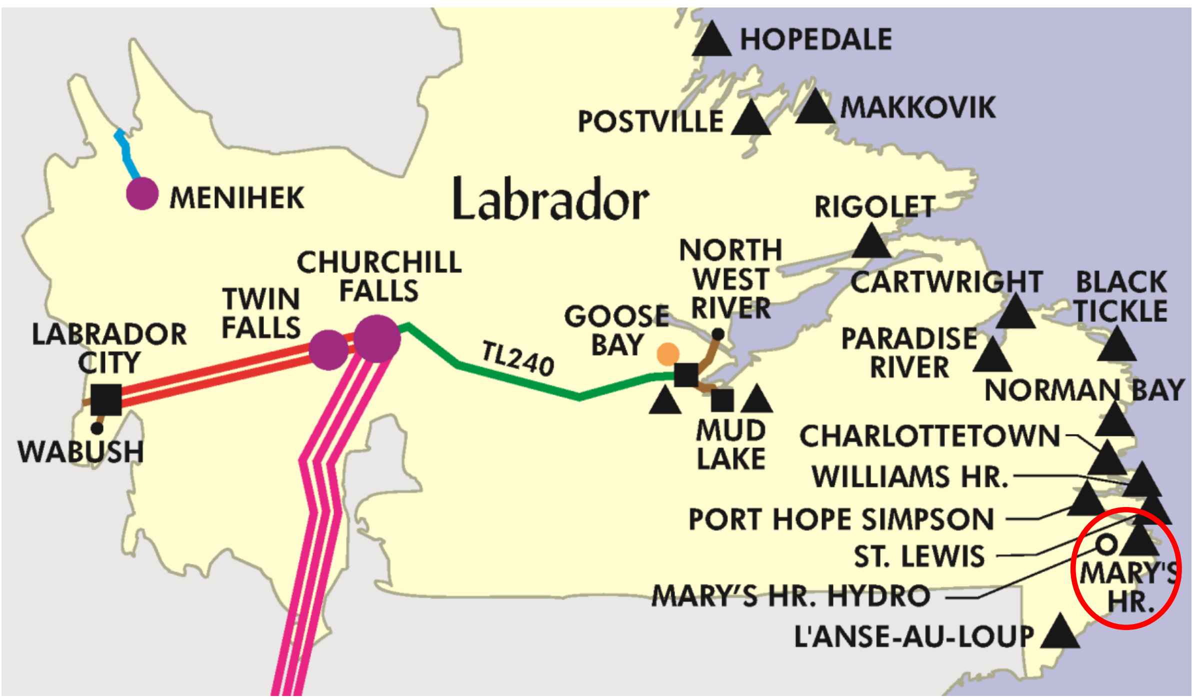

Figure 1: Map of Southern Labrador – Mary's Harbour

2.0 Background

2.1 Existing System

There are four gensets installed at Mary's Harbour. Three units (Unit 2037, Unit 2083, and Unit 2093) are housed inside the power plant building (see Figure 2) and an additional mobile unit (Figure 3) is installed outside. The size and installation date of each unit are listed in Table 1.

Table 1: Size and Installation of Units

Unit	Size	Installed
Unit 2037	545 kW	1993
Unit 2093	545 kW	2016
Unit 2083	800 kW	2009
Mobile	725 kW	2013

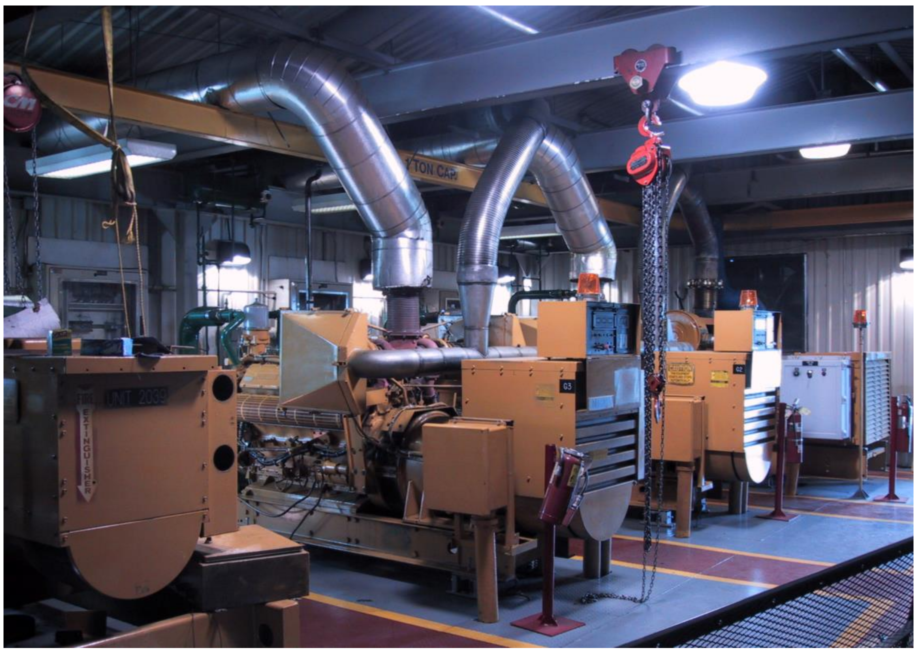

Figure 2: Mary's Harbour – Diesel Generators in Power House

Figure 3: Mary's Harbour Diesel Generating Plant With Mobile Unit on Left

2.2 Operating Experience

The gensets at Mary's Harbour have an expected service life of 100,000 operating hours, and are normally replaced when they have accumulated that much operating time. On occasion, a unit may develop a problem that cannot be resolved and requires it to be replaced before the expected service life is achieved.

2.2.1 Unit 2037

Mary's Harbour Unit 2037 was overhauled in 2016 to extend its usable life to 132,000 hours.[1] At the end of 2018 Unit 2037 had accumulated approximately 125,000 operating hours. Unit 2037 is due for replacement when it accumulates 132,000 hours, forecast to occur in 2020. Hydro filed a letter with the Board on July 31, 2019 regarding the continuation of the analysis of the Southern Labrador Interconnection. The replacement unit is of a typical size common in Hydro's diesel generation facilities, and could be repurposed, along with the other units in the plant, should there be some outcome that renders the plant redundant in the future.

2.2.2 Unit 2083

Unit 2083 was installed in 2009 and has been in service for 10 years. It has had one engine overhaul, completed in November 2016, after 23,756 hours of operating time and has incurred a total of approximately 26,923 hours of operation as of December 31, 2018. The unit has experienced eight generator failures since commissioned. Table 2 details the history of these generator failures. Hydro believes these failures are related to engine vibration, which it has not been able to eliminate. The vibrations are transmitted to the generator resulting in the eight events and causing damage to the generator requiring a rewind. After numerous consultations with the manufacturer, and after incurring high maintenance costs with extended unit outages, Hydro has decided it is not feasible to continue operating this unit and proposed its replacement.

[1] Unit 2037 was submitted for replacement in the 2014 Capital Budget Application; however, replacement was deferred to allow for the completion of the Southern Labrador Interconnection Report. Instead, this unit was overhauled at that time.

Table 2: Generator Failure History Unit 2083

Date of Occurrence	Work Scope	Repair Cost
February 2019	Repair Generator	$10,147
June 2018	Repair Generator	$2,360
February 2017	Repair Generator	$27,372
January 2016	Repair Generator	$12,522
July 2015	Repair Generator	$13,268
September 2012	Replace Generator	$46,687
October 2009	Repair Generator	$19,019
May 2009	Repair Generator	$11,198

2.3 Maintenance History

2.3.1 Unit 2037

Unit 2037 has been overhauled eight times (twice due to premature failures of components in early life), with the most recent overhaul completed in 2016. At that time it had accumulated approximately 112,000 operating hours, but was considered to be in a suitable operating condition to extend its service life by completing an additional overhaul.

2.3.2 Unit 2083

Unit 2083 has been in service for 10 years. This unit has had one engine overhaul, completed in November 2016 after 23,756 hours of operation, and has incurred approximately 26,923 hours of operation as of December 31, 2018. The unit has experienced eight generator failures since being placed in service in 2009. In each case engine vibration transmitted to the generator resulted in severe damage that required a generator rewind and a unit outage. The two most recent generator failures have occurred less than 1,000 operating hours after rebuild.

3.0 Analysis

To determine the most cost effective size for unit 2083, Hydro completed a cost-benefit analysis of four alternative units with capacities ranging from 725 kW to 1500 kW. This analysis indicated that the least cost alternative is to replace unit 2083 with a unit having a capacity of approximately 725 kW. The results of the analysis are summarized below in Table 3.

Table 3: Cost Benefit Analysis ($)

Mary's Harbour Unit 2083 Replacement
Alternative Comparison
Cumulative Net Present Value To the Year 2019

Alternatives	Cumulative Net Present Value (CPW)[2]	CPW Difference between Alternative and the Least Cost Alternative
725 kW	1,518,987	0
1500 kW	2,740,579	>1,221,592[3]
1067 kW	2,790,307	>1,271,321
910 kW	2,823,472	>1,304,485

The 2018 Operating Load forecast indicates that the summer peak load is expected to be 1090 kW in 2019 and grow to 1106 kW by the year 2039. The forecasted summer peak load of 1106 kW in the year 2039 is only 61% of 1810 kW, the summer firm capacity in Mary's Harbour, which satisfies Hydro's Diesel planning criteria.

During the winter the peak load is expected to be 950 kW in 2019 and grow to 966 kW by 2039. The mobile diesel unit is not reliable for winter operation, and therefore firm plant capacity in winter is 1090 kW. The forecasted winter peak load of 966 kW in the year 2039 is 89% of 1090 kW, the winter firm capacity in Mary's Harbour, which satisfies Hydro's Diesel planning criteria.

Hydro proposes to replace Unit 2037 with a similar size unit as this will satisfy Hydro's diesel planning criteria.

4.0 Project Description

This project will replace each of Units 2037 and Unit 2083 with new 545 kW and 725 kW diesel gensets, respectively.

[2] Cumulative net present value includes overhaul costs, replacement costs, and capital cost related to plant extensions. The capital cost for the supply and installation of gensets are not included as they would only increase the CPW between the least cost alternative and others.
[3] Building modifications costing over $1.5M are required to install units with capacity equal to or greater than 910 kW. The $1.5 M book-end estimates are included in the cost benefit analysis to demonstrate that these alternatives are not the least cost.

Each genset will require a new radiator, fuel cooler, aftercooler, switchgear with breaker, Motor Control Centre ("MCC"), and all other equipment necessary to ensure smooth operation. The 725 kW genset will also require a new exhaust stack and associated equipment. Upgrades to some existing protection and control equipment will be required including additions to the MCC programmable logic controller ("PLC") Cabinet, modifications to the main PLC, human machine interface configuration, and modification and testing of PLC logic. Modifications to the existing cooling system will also be necessary to accommodate the new diesel gensets. The project estimate is provided in Table 4.

Table 4: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	1361.6	0.0	0.0	**1361.6**
Labour	1197.6	0.0	0.0	**1197.6**
Consultant	334.0	0.0	0.0	**334.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	480.2	0.0	0.0	**480.2**
Interest and Escalation	189.9	0.0	0.0	**189.9**
Contingency	337.4	0.0	0.0	**337.4**
Total	**3,900.7**	**0.0**	**0.0**	**3,900.7**

The project schedule is shown in Table 5.

Table 5: Project Schedule

Activity	Start Date	End Date
Planning	January 2020	January 2020
Engineering	February 2020	February 2020
Procurement	February 2020	March 2020
Construction	July 2020	August 2020
Commissioning	September 2020	September 2020
Closeout	November 2020	November 2020

5.0 Conclusion

The operating hours for Mary's Harbour Unit 2037 will exceed its life expectancy in 2020 and Mary's Harbour Unit 2083 has a long standing vibration problem that has caused repeated generator failures and required major repairs. Hydro is proposing this project to replace these two gensets to maintain reliable operation of the Diesel Plant.

9. Purchase New Mobile Substation – Bishop's Falls

2020 Capital Budget Application
Purchase New Mobile Substation
Bishop's Falls

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") uses mobile substations to facilitate planned capital and maintenance work and as an emergency spare.

A review of the availability of the five mobile substations, owned by Hydro or Newfoundland Power, has identified a risk of extended outages to Hydro customers during situations where an emergency spare transformer is required.

The procurement of a mobile substation, designed to accommodate numerous terminal stations and transformers located throughout Hydro's interconnected system, will mitigate this risk.

This project has an estimated cost of $3,436,500. Due to the required extended delivery time for this type of equipment, the project has an estimated schedule of 18 months.

Contents

1.0 Introduction

Hydro owns one mobile substation and Newfoundland Power owns four mobile substations. The two companies cooperate in optimizing use of the five units to facilitate capital and maintenance work and in providing prompt response as emergency spares for both companies. Hydro has experienced instances in which the five mobile substations have been in service and were not available to be installed as an emergency spare transformer.

2.0 Background

Hydro owns one mobile substation ("P235") which is an emergency spare for 21 terminal stations located throughout the Hydro interconnected system. These terminal stations are as follows:

- Barachoix ("BCX");
- Bear Cove ("BCV");
- Bottom Waters ("BWT");
- Cow Head ("CHD");
- Conne River ("CRV");
- Doyles ("DLS");
- English Harbour West ("EHW");
- Farewell Head ("FHD");
- Grandy Brook ("GBK");
- Glenburnie ("GLB");
- Hampden ("HDN");
- Howley ("HLY");
- Jackson's Arm ("JAM");
- Parson's Pond ("PPD");
- Plum Point ("PPT");
- Rocky Harbour ("RHR");

- Roddickton Woodchip ("RWC");
- South Brook ("SOK");
- St. Anthony Airport ("STA");
- St. Anthony Diesel Plant ("SDP"); and
- Wiltondale ("WDL");

P235 also serves as an emergency spare for three power transformers:

- Bottom Brook Transformer T2 ("BBK T2");
- Bay d'Espoir Transformer T11 ("BDE T11"); and
- and Buchans T2 ("BUC T2").

Four of Newfoundland Power-owned mobile substations ("P1", "P3", "P4", and "P5") are suitable emergency spares available to Hydro via a sharing agreement. With the exception of P1, four of the five mobile substations (P235, P3, P4 and P5) are suitable as emergency spares for all 21 terminal stations and the three power transformers. Table 1 separates the sites into two groups. For the sites categorized as Group 1, P1 is not suitable for use as an emergency spare. For the sites categorized as Group 2, all 5 mobile substations can be used as an emergency spare.

Table 1: Suitable Mobile Substation Groups

Group	Stations/Transformers	Suitable Mobile Substations
Group 1	BBK T2, BWT, DLS, GBK, HLY, SOK, BCV, PPT, STA	P235, P3, P4, P5
Group 2	BCX, BDE T11, BUC T2, CRV, EHW, FHD, HDN, JAM, CHD, GLB, PPD, RHR, RWC, SDP, WDL	P235, P1,P3, P4, P5

3.0 Justification

Hydro has experienced instances when all mobile substations have been in service and are unavailable for immediate use as an emergency spare. If a mobile substation is needed for emergency use during times of unavailability, an extended customer outage would occur and would last until a mobile substation could be freed and moved to the site of the emergency.

Tables 2 through 4 quantify mobile substation unavailability over the past five years (2014–2018). Table 2 identifies the date range of each unavailability occurrence. Table 3 summarizes the number of days during each year when no suitable mobile substation was available. Table 4 summarizes the number of station-days[1] during each year when no suitable mobile substation was available. The station-day metric is presented to quantify both the frequency and the duration of the unavailability. Table 5 summarizes the duration of the periods during which no suitable mobile substation was available and shows that the longest period of unavailability was 24 days.

Table 2: Mobile Substation Unavailability Dates

Group	Year	Date Ranges
Group 1	2014	May 22-June 14
		October 12-October 17
		November 3-November 22
	2015	May 28-June 13
	2018	July 19-August 10
		November 27-November 30
Group 2	2014	May 22-June 14
		October 12-October 17
		November 3-November 7
	2018	July 19-August 10
		November 27-November 30

Table 3: Mobile Substation Unavailability in Days

	Number of Days of Unavailability						
Group	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**	**Average**
Group 1	50	17	0	0	27	**94**	**19**
Group 2	35	0	0	0	27	**62**	**12**

Table 4: Mobile Substation Unavailability in Station-Days

	Number of Station-Days of Unavailability						
Group	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**	**Average**
Group 1	450	153	0	0	243	**846**	**169**
Group 2	525	0	0	0	405	**930**	**186**
All Groups	**975**	**153**	**0**	**0**	**648**	**1,776**	**355**

[1] A station-day is one station/transformer for one day. For example, if no mobile substations were available to 15, Group 2 stations/transformers, for 27 days (as was the case in 2018) then this represents 405 station-days (15 stations/transformers multiplied by 27 days).

Table 5: Mobile Substation Unavailability Periods

		Unavailability Periods				
Group		**2014**	**2015**	**2016**	**2017**	**2018**
Group 1	No. of Occurrences	3	1	0	0	2
	Average Duration (days)	17	17	0	0	14
	Longest Duration (days)	24	17	0	0	23
Group 2	No. of Occurrences	3	0	0	0	2
	Average Duration (days)	12	0	0	0	14
	Longest Duration (days)	24	0	0	0	23

If a new mobile substation is not purchased, Hydro believes there is an unacceptable risk of an extended customer outage due to the unavailability of a mobile substation. As shown in Table 3, there were 1,776 station-days of mobile substation unavailability during the period of 2014-2018. This is equivalent to a 4.1%[2] average probability that a mobile substation was unavailable. Broken down by group, this is equivalent to an average probability that a mobile substation was unavailable if it was needed of 5.2%[3] and 3.4%[4] for Group 1 and 2, respectively.

This project is required to reduce the risk of extended customer outages due to the unavailability of a mobile substation for use as an emergency spare.

4.0 Project Description

This project consists of the procurement of a new 30 MVA, 138-69/25-12.5 kV mobile substation complete with a disconnect switch and on-load tap changer suitable for all of Hydro's 21 terminal stations to add to the current island pool of five units.

The project estimate is included in Table 6.

[2] 1,776 station-days of unavailability/(24 stations/transformers * 365 days/year * 5 years) = 0.041
[3] 846 station-days of unavailability/(9 stations/transformers * 365 days/year * 5 years) = 0.052
[4] 930 station-days of unavailability/(15 stations/transformers * 365 days/year * 5 years) = 0.034

Table 6: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	591.0	2,364.0	0.0	**2,955.0**
Labour	60.3	59.8	0.0	**120.1**
Consultant	23.7	9.9	0.0	**33.6**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	0.0	12.3	0.0	**12.3**
Interest and Escalation	26.0	133.5	0.0	**159.5**
Contingency	33.7	122.3	0.0	**156.0**
Total	**734.7**	**2,701.8**	**0.0**	**3,436.5**

The project schedule is included in Table 7.

Table 7: Project Schedule

Activity	Start Date	End Date
Planning: Open project, planning and scheduling	January 2020	February 2020
Design / Procurement: Specification and tendering	March 2020	April 2020
Construction / Commissioning: Design review / drawing review / factory acceptance testing	November 2020	April 2021
Delivery: Transportation of mobile to Bishop Falls	May 2021	May 2021
Closeout: Project close-out	June 2021	June 2021

5.0 Conclusion

A review of mobile substation availability has identified a risk of extended outages to customers located in various locations during emergency outages. Hydro is proposing to purchase a mobile substation to join the existing units currently available to mitigate this risk.

10. Distribution System Upgrades (2020–2021) - Various

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2020 Capital Budget Application
Distribution System Upgrades (2020–2021)
Various

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") uses two approaches to maintain or improve distribution system reliability performance. One approach is detailed in the Upgrade Distribution Project (refer to Volume I, Section C), which Hydro uses to address smaller distribution replacements. The other approach is outlined in this document and addresses larger refurbishment requirements. These larger efforts to maintain or improve reliable distribution operation are determined either by condition assessments or by identification of distribution feeders that have poor reliability performance.

Through reliability performance analysis, feeders in the Bear Cove, St Anthony, and Fleur-de-Lys areas have been identified as requiring refurbishment and upgrading.

Hydro proposes to undertake the following work:

- Bear Cove L6: replace poles, insulators, cribs, crossarms, anchors, downguys, and hot line clamps, and install fault circuit indicators;
- St Anthony L3: replace poles, insulators, conductor, cribs, crossarms, anchors, downguys, and transformers, reroute feeder, and install animal guards;
- Fleur-de-Lys L1: replace poles, insulators, conductor, cribs, crossarms, anchors, downguys, and transformers, reroute feeder, and install fault circuit indicators; and
- Fleur-de-Lys L2: replace poles, insulators, cribs, crossarms, anchors, downguys, and transformers, and reroute feeder.

The estimated cost of the project is $3,257,100. The project will commence in 2020 and be completed in 2021.

Contents

List of Appendices

1.0 Introduction

Hydro uses two approaches to maintain or improve distribution system reliability performance. One approach is detailed in the Upgrade Distribution Project (Volume I, Section C), which Hydro uses to address smaller distribution replacements. The other approach is outlined in this document and addresses larger refurbishment requirements. These larger efforts to maintain or improve reliable distribution operation are determined either by condition assessments or by identification of distribution feeders that have poor reliability performance. Hydro uses Customer Hours of Interruption ("CHI")[1], System Average Interruption Frequency Index ("SAIFI")[2], and System Average Interruption Duration Index ("SAIDI")[3] to identify poor reliability performing feeders, known as "Worst Performing Feeders". Worst Performing Feeders are identified by a process that includes:

- Calculating reliability indices for all distribution feeders based on data for 2014-2018. All these reliability indices are calculated excluding loss of supply outages, planned outages, customer requests and major events. The five year average value is considered for ranking the feeders.
- Ranking the feeders based on CHI, and SAIFI/SAIDI;[4]
- Analysing the reliability data for the top twenty five worst performing feeders to identify the root cause of the poor performance; and
- Where necessary, performing a feeder assessment includes such activities as inspection data review, system design review, site visit, and recommendations for corrective actions.

Distribution lines located in Bear Cove, St Anthony, and Fleur-de-Lys areas have been identified as requiring refurbishment or replacement.

[1] CHI is the sum of the products of the outage duration multiplied by the number of customers affected during the outage for each event within a one year period.
[2] SAIFI is the System Average Interruption Frequency Index per year, which indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.
[3] SAIDI indicates the System Average Interruption Duration Index for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.
[4] CHI ranks the feeder based on the impact the feeder has on overall reliability indices; directing resources on these feeders will improve the corporate level statistics; however, this might lead to ignoring the smaller problematic feeders. To overcome this problem, the top twenty worst performing feeders based on SAIFI/SAIDI are also examined.

2.0 Background

2.1 Existing System

2.1.1 Bear Cove L6

Bear Cove L6 is a three-phase, 35 km feeder that supplies 693 customers in the Flower's Cove, Nameless Cove, Savage Cove, Sandy Cove, Shoal Cove East, Pine's Cove, Green Island Cove, and Eddie's Cove East areas.

2.1.2 St. Anthony L3

St. Anthony L3 is a three-phase, 8.2 km feeder plus a single-phase, 6.2 km tap, that supplies 791 customers in the St Anthony and Goose Cove areas.

2.1.3 Fleur-de-Lys L1

Fleur-de-Lys L1 is a three-phase, 33 km feeder that supplies 182 customers in the Fleur-de-Lys community. This feeder also supplies power to Fleur-de-Lys L2.

2.1.4 Fleur-de-Lys L2

Fleur-de-Lys L2 is a single-phase, 6.5 km feeder that supplies 70 customers in the Coachman's Cove community.

2.2 Operating Experience

A list of Hydro's worst-performing feeders and summary of data analysis for these feeders are included in Appendix A.

Feeder Assessment Reports for Bear Cove L6, St Anthony L3, Fleur-de-Lys L1, and Fleur-de-Lys L2 are included in Appendix B. These reports include a description of the feeder and the communities serviced, analysis of factors that contributed to the reliability performance, and corrective actions recommended.

2.3 Outage Statistics

Table 1 lists five-year average distribution reliability data excluding loss of supply outages, planned outages, customer request, and major events for Bear Cove L6, St Anthony L3, Fleur-de-Lys L1, and Fleur-de-Lys L2, and compares those data to corporate values.

Table 1: Outage Statistics

Feeder	CHI	SAIFI	SAIDI
Bear Cove L6	4643	2.93	6.66
St Anthony L3	2177	1.38	2.69
Fleur-de-Lys L1	1397	1.93	7.65
Fleur-de-Lys L2	639	1.96	9.02
Hydro Corporate	1041	1.79	3.96

2.4 Maintenance History

The five-year maintenance histories for the distribution lines in this report are shown in Table 2 through Table 5.

Table 2: Bear Cove L6 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2018	5.6	58.2	**63.8**
2017	4.0	44.2	**48.2**
2016	7.6	76.8	**84.4**
2015	1.0	73.4	**74.4**
2014	1.4	53.5	**54.9**

Table 3: St Anthony L3 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2018	0.8	32.6	**33.4**
2017	2.2	33.8	**36.0**
2016	2.7	38.3	**41.0**
2015	0.5	19.5	**20.0**
2014	0.4	18.6	**19.0**

Table 4: Fleur-de-Lys L1 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2018	19.0	4.2	**23.2**
2017	0.0	4.9	**4.9**
2016	0.0	3.3	**3.3**
2015	4.2	13.6	**17.8**
2014	0.0	3.4	**3.4**

Table 5: Fleur-de-Lys L2 Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2018	5.8	1.3	**7.1**
2017	1.0	6.1	**7.1**
2016	0.0	1.9	**1.9**
2015	0.0	1.8	**1.8**
2014	2.3	1.7	**3.9**

3.0 Analysis

3.1 Identification of Alternatives

The alternatives considered for each feeder to improve reliability were:

- Constructing an entirely new distribution line and retiring the existing line (Alternative 1); and
- Replacing deteriorated line components and retaining existing non-deteriorated line components (Alternative 2).

3.2 Evaluation of Alternatives

3.2.1 Alternative 1: New Distribution Line

There are existing line components that are still operable such as poles, conductor, insulators, and cross arms; the construction of an entirely new line would lose the benefit of this existing and functional equipment. This alternative requires capital spending that is unnecessary for the achievement of reliable provision of electricity.

3.2.2 Alternative 2: Replace Deteriorated Line Components and Retain Non-Deteriorated Components

Replacing deteriorated line components reduces the chance of outages due to deteriorated line components, while retaining existing non-deteriorated line components means Hydro can defer the cost of replacing the retained line components to their end of life.

3.3 Recommended Alternatives

Alternative 2 is the most acceptable of these alternatives.

4.0 Project Justification

This project will improve the reliability of Bear Cove L6, St. Anthony L3, Fleur-de-Lys L1, and Fleur-de-Lys L2 feeders. Additional details are included in Appendix B.

5.0 Project Description

This project will complete the following activates:

- Bear Cove L6:
  - Replace poles, insulators, cribs, crossarms, anchors, and downguys;
  - Install fault circuit indicators; and
  - Replace hot line clamps.
- St Anthony L3:
  - Replace poles, insulators, transformers, cribs, crossarms, anchors, and downguys;
  - Replace sections of deteriorated conductor;
  - Reroute a 300 m section of the single-phase tap travelling to the Goose Cove-West Side; and
  - Install animal guard for transformer bushings.
- Fleur-de-Lys L1:
  - Replace poles, insulators, transformers, cribs, crossarms, anchors, and downguys;
  - Replace sections of poor conductor;
  - Reroute a 3.2 km section of the three-phase, main trunk section travelling to the community of Fleur-de-Lys and a 250 m single-phase section in the Fleur-de-Lys community; and
  - Install fault circuit indicators.
- Fleur-de-Lys L2:
  - Replace poles, insulators, transformers, cribs, crossarms, anchors, and downguys; and
  - Reroute a 2.2 km section of the single phase tap travelling to the community of Coachman's Cove.

The projects estimated cost is provided in Table 6.

Table 6: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	931.2	0.0	**931.2**
Labour	62.2	262.2	0.0	**324.4**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	1380.0	0.0	**1,380.0**
Other Direct Costs	26.0	79.5	0.0	**105.5**
Interest and Escalation	5.7	236.2	0.0	**241.9**
Contingency	8.8	265.3	0.0	**274.1**
Total	**102.7**	**3,154.4**	**0.0**	**3,257.1**

The projects schedule is provided in Table 7.

Table 7: Project Schedule

Activity	Start Date	End Date
Planning:		
Engineering and Planning	January 2020	January 2021
Design:		
Assessment Completed	September 2018	February 2019
Procurement:		
Materials Ordered	January 2021	March 2021
Construction:		
Construction	May 2021	September 2021
Closeout:		
Project Closeout	September 2021	November 2021

6.0 Conclusion

Hydro executes larger feeder refurbishment and replacement requirements to maintain or improve distribution system reliable performance. These larger efforts are determined either by condition assessments or reliability performance analysis.

This project is proposed to improve the reliability of Bear Cove L6, St Anthony L3, Fleur-de-Lys L1, and Fleur-de-Lys L2 feeders.

Appendix A

Worst Performing Feeder List and Summary of Data Analysis

Table A-1: Worst Performing Feeders Sorted by CHI

Rank	Feeder	CHI	Comments
1	Barachoix, Line 4	9504	Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents, and other defective line hardware incidents during the 2014–2018 period. Work is being carried out on this feeder under the 2019–2020 Distribution System Upgrades project.
2	English Harbour, Line 1	8550	In 2014, poor reliability statistics were driven by several line hardware failure incidents. In 2016, reliability statistics of this feeder have been impacted by conductor galloping events. In 2018, a broken pole incident during adverse weather contributed to poor reliability statistics. Work is being carried out on this feeder under the 2018–2019 Distribution System Upgrades project.
3	Hawke's Bay, Line 3	5801	In 2018, a broken pole incident during adverse weather contributed to poor reliability statistics. There was a significant broken conductor incident in 2017 due to galloping; that power outage impacted the overall reliability of this feeder. In 2016 reliability was impacted by three broken insulator incidents. In 2015 Poor reliability statistics were due to line hardware failures. Work is being carried out on this feeder under the 2019–2020 Distribution System Upgrades project.
4	Barachoix, Line 1	5461	Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents during the 2014–2018 period. Work is being carried out on this feeder under the 2019–2020 Distribution System Upgrades project.
5	Bottom Waters, Line 1	5369	In 2015 and 2016, poor reliability statistics were driven by broken insulators. As a result of the poor performance, this feeder had a significant upgrading during the 2016–2017 Period. In 2017, a new distribution feeder (line 9) was constructed to offload a portion of the existing feeder L1. In 2017–2018, poor reliability statistics were driven by tree related events. Tree trimming is being carried out on this feeder; and no additional work is required at this time.
6	Bottom Waters, Line 7	4911	Poor reliability statistics were driven by several insulator failures in 2016–2018. Overall reliability was impacted due to broken line hardware (i.e., crossarm, primary conductor, overhead transformer). All these issues will be addressed through the 2019-2020 distribution upgrade capital project.

Rank	Feeder	CHI	Comments
7	Bear Cove, Line 6	4643	Broken conductor and protective equipment issues contributed to poor reliability statistics in 2014. In 2018, a significant outage was caused by broken primary conductor. Conductor failure and equipment failures are dominating outage causes in recent years. A Feeder Assessment has been carried out and it is recommended to include this feeder in the 2020 Distribution System Upgrades project.
8	Roddickton, Line 1	4606	Poor reliability statistics were driven by several incidents of line hardware failures in 2014. This feeder was upgraded as part of the 2013–2014 Distribution System Upgrades project. Since then reliability has generally been good. No additional work is required at this time.
9	Farewell Head, Line 4	4110	In 2014–2018, multiple incidents of broken primary conductor contributed to poor reliability statistics. This will be addressed through 2018–2019 Distribution System Upgrades project (Replace primary conductor for FHD, L4).
10	Happy Valley, Line 7	4081	Overall reliability statistics on this feeder have been impacted by several equipment issues and vegetation related events. Vegetation issues were addressed in 2017. No work is proposed at this time but the feeder will continue to be monitored.
11	Kings Point, Line 1	3875	Poor reliability statistics were driven by mainly tree-related events in 2015, 2017, and 2018. Vegetation issues will be addressed and no additional work is required at this time.
12	Bottom Waters, Line 4	3851	Poor reliability statistics in 2014 were caused by a power transformer failure; one of the three 833 KVA transformers in Burlington substation failed and the line was down for 19.25 hours. In addition this feeder had several outages due to broken conductor failures in 2016. This feeder will continue to be monitored to determine if it should be considered for upgrading in a future capital budget.
13	Glenbernie, Line 1	3738	The poor reliability statistics are driven by tree contacts in 2015, 2017, and 2018. Tree trimming has been planned for 2019 and 2020. No additional work is required at this time.
14	South Brook, Line 5	3614	In 2014, reliability was impacted by a broken pole caused by third party. Poor reliability statistics in 2017 were driven by a prolong power outage due to a leaning pole incident. No work is required at this time.

Rank	Feeder	CHI	Comments
15	L'Anse Au Loup, Line 2	3416	Poor reliability statistics in 2018 were due to two broken insulator incidents. Overall reliability statistics on this feeder have been impacted by numerous recloser operations due to unknown reason. Work has been planned to investigate the recloser operations. No additional further work is required at this time.
16	Happy Valley, Line 16	3167	In 2014 equipment overload on this line caused problem. After that, some load from this line was transferred and the problem was mitigated. This feeder was upgraded as a part of the 2016-2017 Distribution System Upgrades project. No additional work is required at this time.
17	Rocky Harbour, Line 2	3071	In 2017 a prolonged power outage due to a tree contacts impacted the reliability. In 2018 reliability was poor sue to broken hardware incidents. Work is being carried out on this feeder under the 2018–2019 Distribution System Upgrades project.
18	Rocky Harbour, Line 1	2619	Overall reliability of this feeder was impacted by broken line hardware incidents during 2014–2018. Work is being carried out on this feeder under the 2018–2019 Distribution System Upgrades project.
19	Farewell Head, Line 5	2605	In 2016 and 2018, broken line hardware incidents during adverse weather contributed to poor reliability statistics. This feeder has been upgraded in 2017–2018 as a part of Distribution System Upgrades project. No additional work is required at this time.
20	South Brook, Line 1	2605	Overall reliability statistics on this feeder have been impacted by trees falling across the line during wind storms. Work is being carried out to address the vegetation issues and no additional work is required at this time.
21	St. Anthony, Line 6	2407	Reliability has generally been good. Conductor issues in 2014 contributed to reduced reliability in that year. No work is required at this time.
22	Burgeo, Line 3	2221	Overall reliability of this feeder was impacted by broken line hardware incidents during 2014–2018. This feeder has been upgraded during 2017–2018 distribution capital project. No additional work is required at this time.
23	Burgeo, Line 2	2216	Overall reliability of this feeder was impacted by broken line hardware incidents during 2014–2018. This feeder has been upgraded during 2017–2018 distribution capital project. No additional work is required at this time.

Rank	Feeder	CHI	Comments
24	St. Anthony, Line 3	2117	In 2018, this feeder reliability was poor due to high wind and a broken overhead-Jumper. Overall reliability statistics on this feeder have been impacted by numerous issues. A Feeder Assessment has been carried out and it is recommended to include this feeder in the 2020 Distribution System Upgrades project.
25	Plum Point, Line 1	2098	Poor reliability statistics were driven by broken line hardware incidents in 2014, 2017, and 2018. No work is proposed at this time but the feeder will continue to be monitored.

Table A-2: Worst Performing Feeders Sorted by SAIFI and SAIDI based Feeder Score[5]

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI Based-List	Comments
1	Burgeo, Line 5	2.578	18.133	10.355	No	In 2015–2018, poor reliability statistics were driven by primary conductor failures and other line hardware failures. This feeder is located in extremely remote area. Power restoration is often delayed significantly due to limited access during adverse weather. This feeder will continue to be monitored to determine if it should be considered for upgrading in a future capital budget.
2	Bottom Waters, Line 1	4.198	16.412	10.305	Yes	See comments in Table A-1.
3	Farewell Head, Line 1	2.258	13.889	8.073	No	In 2016, all the customers of this feeder experienced a 16 hour power outage caused by an overhead guy failure during adverse weather. Power outage was extended due to remote access. In 2018, two protective equipment issues (a faulty sectionalizer and a faulty circuit breaker) contributed to poor reliability statistics. No work is required at this time.
4	Bottom Waters, Line 7	4.143	11.170	7.656	Yes	See comments in Table A-1.
5	Barachoix, Line 4	3.360	11.735	7.547	Yes	See comments in Table A-1.

[5] Feeder Score= (.5 × SAIFI) + (.5 × SAIDI).

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI Based-List	Comments
6	English Harbour, Line 1	4.277	10.553	7.415	Yes	See comments in Table A-1.
7	Barachoix, Line 5	1.400	12.350	6.875	No	This feeder is a 2.4KV tap to Pass Island. This area is extremely remote and it has only two customers. In 2015, poor reliability statistics were driven by a defective transformer. No additional work is required at this time.
8	Barachoix, Line 1	2.714	10.951	6.833	Yes	See comments in Table A-1.
9	Kings Point, Line 2	3.222	10.140	6.681	No	Poor reliability statistics were principally driven by multiple tree-related incidents in 2017-2018. Tree trimming work has been planned in 2019. No Additional work is required at this time.
10	Farewell Head, Line 4	3.016	10.073	6.545	Yes	See comments in Table A-1.
11	Burgeo, Line 1	1.695	11.282	6.488	No	This feeder was upgraded as part of the 2017-2018 Distribution System Upgrades project. Prior to the capital project, this line performed poor due to broken line hardware incidents. No additional work is required at this time.
12	Bottom Waters, Line 3	3.125	9.815	6.470	No	Overall reliability statistics on this feeder have been impacted by several weather events, tree related incidents and broken line component issues during the 2014-2018 period. Work is being carried out on this feeder under the 2019-2020 Distribution System Upgrades project.

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI Based-List	Comments
13	Burgeo, Line 4	2.093	10.126	6.110	No	This feeder was upgraded as part of the 2017-2018 Distribution System Upgrades project. Prior to the capital project, this line performed poor due to broken line hardware incidents. No additional work is required at this time.
14	Roddickton, Line 4	2.496	9.067	5.781	No	In 2010-2011, a project was carried out to replace wood poles, insulators, and cutouts on this feeder. In 2015-2018, this distribution line has experienced several forced outages related to the failure of vertical type line post insulators which were installed under the 2010-2011 project. The failures have been attributed to manufacturing defects in the insulators. The broken insulators have been sent to the manufacture for investigation. A project will be carried out on this feeder based on the investigation report.
15	Bottom Waters, Line 6	3.088	8.130	5.609	No	In 2014-2018, poor reliability statistics were driven by several weather events, tree related incidents and line hardware failures. Work is being carried out on this feeder under the 2019-2020 Distribution System Upgrades project.

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI Based-List	Comments
16	Fleur-de-Lys, Line 2	1.959	9.018	5.488	No	Poor reliability statistics in 2017 were driven by several broken primary conductor incidents. The feeder performed poorly in 2018 due to broken line hardwires incidents and a tree related event. Overall reliability statistics on this feeder have been impacted by broken primary conductor and other defective line hardware incidents during the 2014-2018 period. A Feeder Assessment has been carried out and it is recommended to include this feeder in the 2020 Distribution System Upgrades project.
17	Main Brook, Line 2	2.729	8.169	5.449	No	This feeder was upgraded as part of the 2014-2015 distribution system upgrades project. Prior to the capital project, this line had a high number of deteriorated poles, and transformers that were installed when the original line was constructed. During the upgrade project, most of the aged transformers were replaced and major part of the line was rebuilt with new poles and conductors. As a result, this feeder has performed well in 2016-2017. However; in 2018, poor reliability statistics were driven by numerous equipment and line component issues. No work is proposed at this time but the feeder will continue to be monitored.

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI Based-List	Comments
18	Roddickton, Line 1	2.369	8.321	5.345	Yes	See comments in Table A-1.
19	Bottom Waters, Line 4	2.025	8.553	5.289	Yes	See comments in Table A-1.
20	L'Anse-Au-Loup, Line 2	4.461	5.638	5.049	Yes	See comments in Table A-1.
21	Black Tickle, Line 1	1.961	7.967	4.964	No	Black Tickle is a remote isolated community in Labrador. Line crews have to fly to the community to repair any damage on distribution line. Power restoration is often delayed significantly due to flight restriction during adverse weather. In 2014-2018, poor reliability statistics were mainly driven by weather-related events. This feeder will continue to be monitored to determine if it should be considered for upgrading in a future capital budget.
22	Glenbernie, Line 1	2.171	7.513	4.842	Yes	See comments in Table A-1.
23	Bear Cove, Line 6	2.929	6.657	4.793	Yes	See comments in Table A-1.
24	Fleur-de-Lys, Line 1	1.928	7.649	4.789	No	Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents, and other defective line hardware incidents during the 2014-2018 period. A Feeder Assessment has been carried out and it is recommended to include

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI Based-List	Comments
						this feeder in the 2020 Distribution System Upgrades project.
25	Hawke's Bay, Line 3	3.514	5.952	4.733	Yes	See comments in Table A-1.

Appendix B

Feeder Assessment Reports

Bear Cove L6

Bear Cove L6 is a three phase distribution feeder approximately 35 km in length. Communities serviced include Flower's Cove, Nameless Cove, Savage Cove, Sandy Cove, Shoal Cove East, Pine's Cove, Green Island Cove, and Eddie's Cove East. The total number of customers in the community serviced is 693.

Table B-1 summarizes the reliability data and Table B-1 shows the reliability trends for Bear Cove L6 from 2014 to 2018. All reliability indices are calculated excluding loss of supply outages, planned outages, customer requests, and major events.

Table B-1: Five-Year Average (2014–2018) Reliability Data for Bear Cove L6

Location	CHI	SAIFI	SAIDI
Bear Cove L6	4,643	2.93	6.66
Hydro Corporate	1041	1.79	3.96

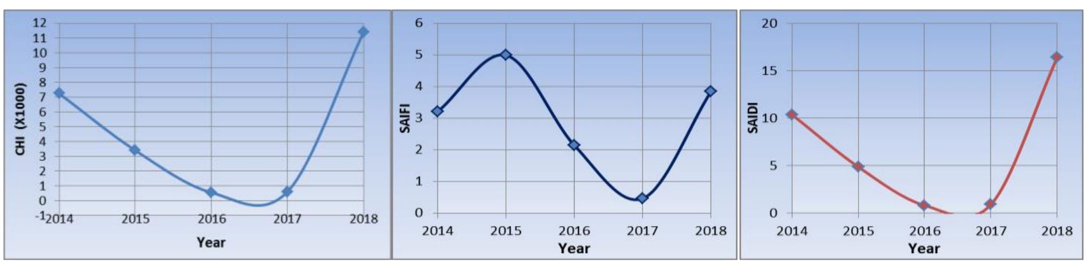

Figure B-1: KPI Trends for Bear Cove L6

Feeder Analysis

Broken conductor and protective equipment issues contributed to poor reliability statistics in 2014. In 2018, a significant outage was caused by broken primary conductor. Conductor failure and equipment failures are dominating outage causes in recent years.

The main trunk has several single phase and three phase taps that are connected to the primary conductor through hot line clamps. The high salt concentration and high winds in the area have resulted in hot line clamps corroding and deteriorating. Failure of the primary conductor due to corroded hot line clamps has been an issue over the past number of years.

An 8.5 km section of the main trunk is located off road, which greatly increases response times and therefore outage duration. However, the poles and other line component on this section are in good condition. To minimize the power outage, Fault Circuit Indicators should be installed in this long radial circuit (see Figure B-2). This will improve the power restoration by allowing crews to locate faults and isolate faulted sections faster.

Inspections have identified that this line has 111 deteriorated poles and several damaged line components, which require replacement soon.

Recommendations

The following work is required to improve the reliability of Bear Cove L6:

- Replace deteriorated poles, insulators, transformers, cribs, crossarms, anchors, and downguys
- Install Fault Circuit Indicators on the off road section.
- Install stirrups for all tapped connections on the main trunk section.

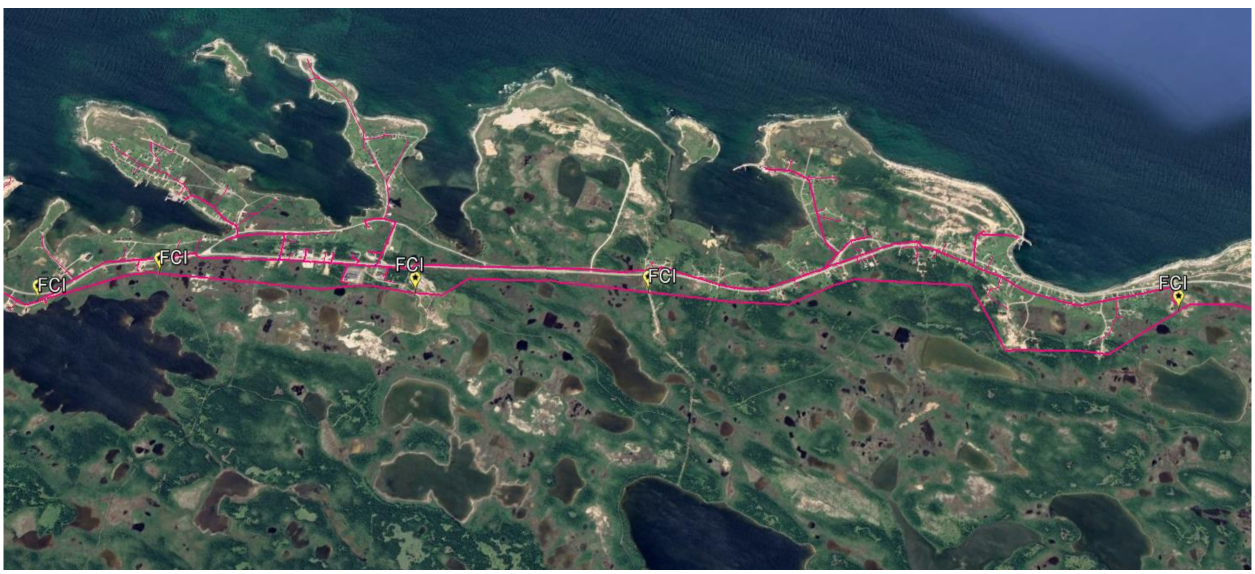

Figure B-2: Fault Circuit Indicator ("FCI") approximate locations for Bear Cove L6

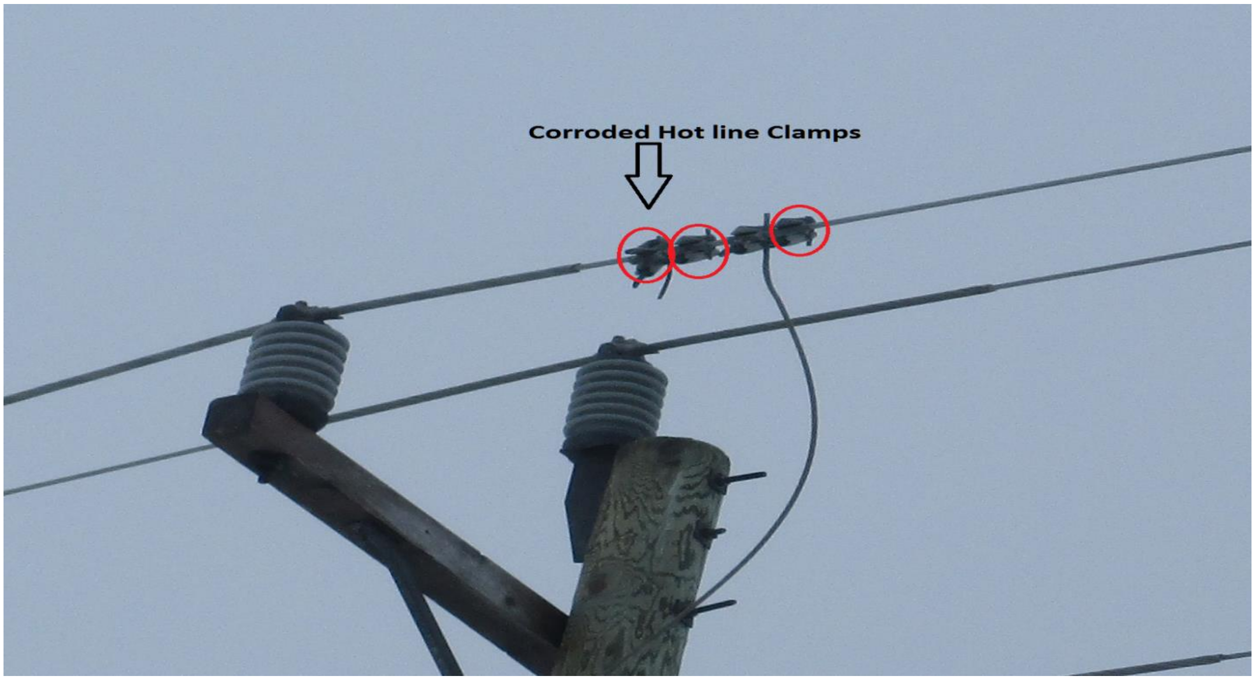

Figure B-3: Corroded Hot Line Clamps – Bear Cove L6

St. Anthony L3

St. Anthony L3 is a three phase distribution feeder approximately 8.2 km in length. It has 6.2 km single phase tap that supplies power to Goose Cove. Communities serviced include St. Anthony and Goose Cove. The total number of customers in the communities serviced is 791.

Table B-2 summarizes the reliability data and Figure B-4 shows the reliability trends for St Anthony L3 for 2014 to 2018 period. All the reliability indices are calculated excluding loss of supply outages, planned outages, customer requests and major events.

Table B-2: Five-Year Average (2014–2018) Reliability Data for St. Anthony L3

Location	CHI	SAIFI	SAIDI
St. Anthony L3	2177	1.38	2.66
Hydro Corporate	1041	1.79	3.96

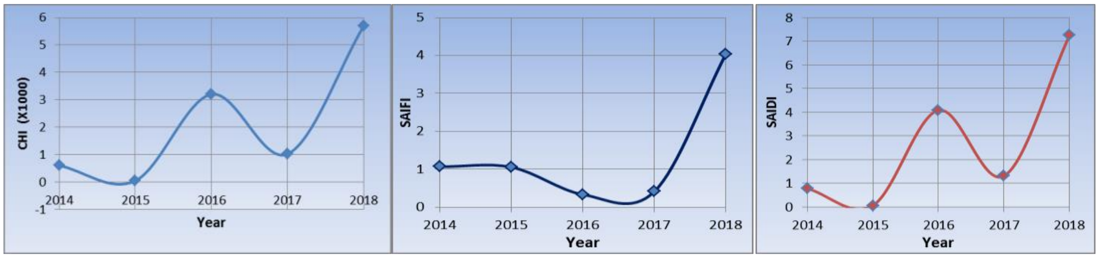

Figure B-4: KPI Trends for St. Anthony L3

Feeder Analysis

In 2018, reliability for this feeder was poor due to high wind and a broken overhead jumper. Overall reliability statistics on this feeder have been impacted by numerous issues. From the pole line inspection record, this line has several deteriorated line components, including 51 poles and 4 transformers.

A 1.2 Km of this line has deteriorated conductor and it needs to be replaced. This section has many inline splices, which are evidence of repairs made after the conductor failed.

It has also been identified that the single phase tap to Goose Cove has a problematic long span section that crosses a pond. It is required to be rerouted.

Analysis of the outage data also reveals that this feeder has experienced many power outages due to damage caused by animals to transformer fuses in some areas in the town of St. Anthony. The use of animal guards for transformer bushings with lead covers or insulated leads is recommended to prevent animal-caused damage and outages.

Recommendations

The following work is required to improve the reliability of St. Anthony L3:

- Replace deteriorated poles, insulators, transformers, anchors and downguys;
- Replace sections of deteriorated conductor;
- Reroute long span section; and
- Install animal guards for transformer bushings with lead covers or insulated leads for problematic areas.

Fleur-de-Lys L1

Fleur-de-Lys L1 is a three phase distribution line approximately 33 km in length. This feeder provides power to the Fleur-de-Lys community. The total number of customers in the community serviced is 182. This feeder also supplies power to Fleur-de-Lys L2.

Table B-3 summarizes the reliability data and Figure B-5 shows the reliability trends for Fleur-de-Lys L1 for 2014 to 2018 period. All the reliability indices are calculated excluding loss of supply outages, planned outages, customer requests, and major events.

Table B-3: Five-Year Average (2014–2018) Reliability Data for Fleur-de-Lys L1

Location	CHI	SAIFI	SAIDI
Fleur-de-Lys L1	1397	1.93	7.65
Hydro Corporate	1041	1.79	3.96

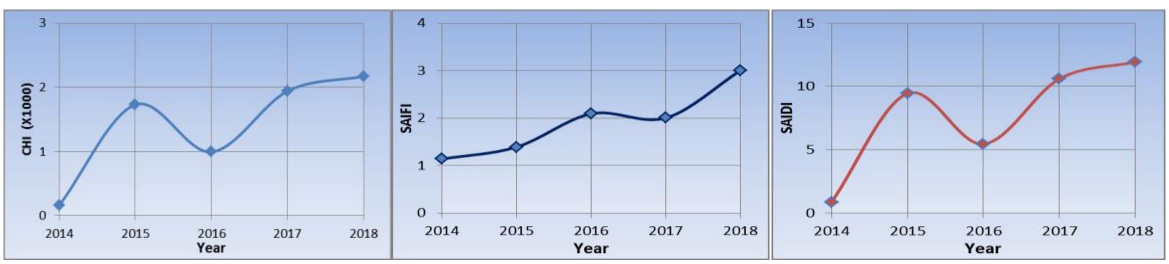

Figure B-5: Reliability Trends for Fleur-de-Lys L1

Feeder Analysis

Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents, and other defective line hardware incidents during the 2014 to 2018 period.

From the pole line inspection record, this line has several deteriorated line components, including 79 poles, 34 cross arms, and 22 transformers. It has also been identified that the existing primary conductor on many sections of this feeder is in poor condition with multiple sleeves.

Fleur-de-Lys is a severe ice and wind loading area and due to the age and condition of the poles, crossarms, and conductor the feeder is becoming more prone to damage when exposed to heavy wind, ice and snow loading.

A 3.2 km section of the main trunk has many long span structures that are susceptible to conductor galloping and failure. This section is located off road and required to be rerouted to roadside for better access (see Figure 6). This reroute will improve the structure visibility from the roadside during outage line patrol and will minimize power restoration time for any repair work on this section.

Recommendations

The following work is required to improve the reliability of Fleur-de-Lys, L1:

- Replace deteriorated poles, insulators, transformers, cribs, crossarms, anchors and downguys
- Replace sections of deteriorated conductor.
- Reroute off road section.

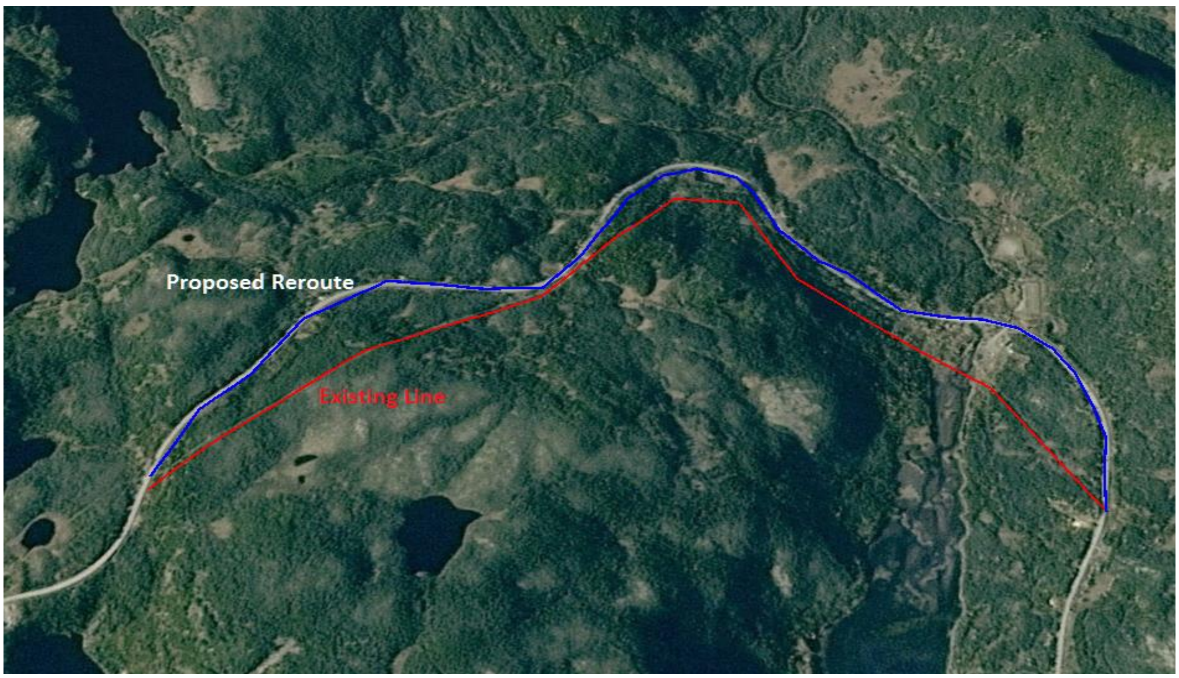

Figure B-6: Fleur-de-Lys L1 Reroute

Fleur-de-Lys L2

Fleur-de-Lys L2 is a single-phase distribution line approximately 6.5 km in length. This feeder provides power to Coachman's Cove community. The total number of customers in the community serviced is 70.

Table B-4 summarizes the reliability data and Figure B-7 shows the reliability trends for Fleur-de-Lys L2 for 2014 to 2018 period. All the reliability indices are calculated excluding loss of supply outages, planned outages, customer requests and major events.

Table B-4: Five-Year Average (2014–2018) Reliability Data for Fleur-de-Lys L2

Location	CHI	SAIFI	SAIDI
Fleur-de-Lys L2	639	1.96	9.02
Hydro Corporate	1041	1.79	3.96

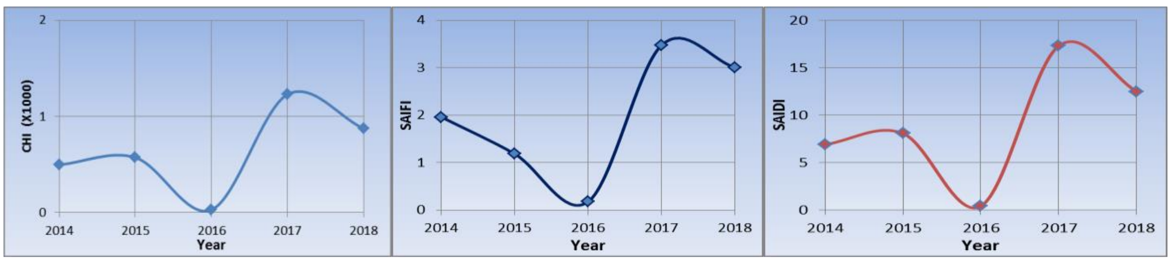

Figure B-7: Reliability Trends for Fleur-de-Lys L2

Feeder Analysis

Poor reliability statistics in 2017 were driven by several broken primary conductor incidents. The feeder performed poorly in 2018 due to broken line hardwires incidents and a tree related event. Overall reliability statistics on this feeder have been impacted by primary conductor and other defective line hardware incidents during the 2014 to 2018 period. Work is required to mitigate the above issues.

The first 2.3 km section of this feeder has substandard #2 Aluminum conductor. This section has many long span structures that are susceptible to conductor galloping and failure. Most of the structures of this section are located off road and required to be rerouted to roadside for better access (see Figure B-8). Recent inspections have identified 11 deteriorated poles and two decayed or damaged cribs on this section.

Inspection has also identified 12 deteriorated poles and 3 transformers in the Coachman's Cove community, which are required to be replaced.

Recommendations

The following work is required to improve the reliability of Fleur-de-Lys, L2:

- Replace deteriorated poles, insulators, transformers, cribs, crossarms, anchors, and downguys; and
- Reroute off-road section.

Figure B-8: Proposed Reroute for Fleur-de-Lys, L2

11. Wood Pole Line Management Program - Various

REGISTERED PROFESSIONAL ENGINEER
PEG
Newfoundland and Labrador
ANDRE C. MARSHALL
SIGNATURE
JULY 22, '19
DATE
NEWFOUNDLAND & LABRADOR

2020 Capital Budget Application
Wood Pole Line Management Program
Various

July 2019

newfoundland labrador
hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

The Wood Pole Line Management ("WPLM") Program is a condition-based program that uses reliability-centered maintenance ("RCM") principles and strategies.[1] Under the program, transmission line inspection data of each year is analyzed and appropriate recommendations made for necessary refurbishment and/or replacement of line components including 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 analysis and tracking.

The program is aimed at early detection and treatment of deteriorating wood poles and line components before the integrity of a structure is jeopardized. If the deterioration of the structure or components is not detected early enough then the reduced integrity of the structure can affect the reliability of the line and the system as a whole. It could also lead to increased failure costs and, potentially, customer interruptions. Safety issues and hazards for Newfoundland and Labrador Hydro ("Hydro") personnel and for the general public could also result from issues with weakened structural integrity.

[1] RCM is a corporate level maintenance strategy that is implemented to optimize the maintenance program of a company or facility.

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1.0 Introduction

As wood poles age, their preservative retention levels decrease and the poles become increasingly subject to deterioration by different agents including fungi and insects. Wood poles must be regularly inspected and treated to proactively identify and assess any deterioration. The WPLM Program is an annual program that 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. This is a least-cost strategy in the long-term through the deferring of rebuilding lines and avoiding forced outages.

2.0 Background

Hydro first initiated the WPLM Program as a pilot study in 2003. Hydro determined that the program should continue as a long-term asset management and life extension program. The WPLM Program was presented to the Board of Commissioners of Public Utilities ("Board") as part of Hydro's "2005 Capital Budget" Application and was entitled "Replace Wood Poles – Transmission." The proposal was supported in the application by Hydro's report entitled "Wood Pole Line Management Using RCM Principles."[2]

2.1 Existing System

Hydro maintains approximately 2,500 km of wood pole transmission lines operating at voltages of 69 kV, 138 kV, and 230 kV. These lines consist of approximately 26,000 poles of varying ages, with the maximum age being 54 years. As of 2019, approximately 95% of the transmission pole assets are more than 20 years old, about 55% of these poles are at least 40 years old, and the remaining pole assets less than 20 years old.

2.2 Operating Experience

Prior to 2003, Hydro's pole inspection and maintenance practices followed the traditional utility approach of sounding inspections only. In 1998, Hydro began to collect core samples on selected poles to test for preservative retention levels and pole decay. The results of early tests raised concerns regarding the general preservative retention levels in the poles. This testing confirmed that there were poles in Hydro's system that had a preservative level below that required to maintain the required

[2] Asim Halder, "Wood Pole Line Management Using RCM Principles," Newfoundland and Labrador Hydro, January 9, 2004.

design criteria. During this period, certain poles were replaced because the preservative level had lowered to the point that decay had advanced and the pole was no longer structurally sound. These inspections and the analysis of the data confirmed that a more rigorous wood pole line management program was required.

Figure 1 illustrates typical wood pole inspection techniques. Figure 2 shows typical wood pole inspection results.

Figure 1: WPLM Inspection Techniques. Clockwise from Bottom Left: (1) Typical Field Data Collector, (2) Installing Boron Treatment, (3) Climbing Inspection, (4) Destructive Testing at MUN.

Figure 2: Typical Wood Pole Inspection Results

The anticipated useful life of a wood pole transmission line not subject to inspection or maintenance is approximately 40 years. Hydro has implemented a WPLM Program with the mandate to thoroughly inspect, treat, and refurbish the transmission structures prior to any serious failure on the line. Through this type of proper inspection and maintenance the life of a transmission line could be extended by 10 years or more.

Extension of the life of the transmission line is evidenced when considering Hydro's current system. As the anticipated useful life of a wood pole transmission line not subject to inspection or maintenance is approximately 40 years. Hydro currently has 22 wood pole transmission lines that have surpassed this anticipated useful life. Of these lines, 18 are over the age of 45 years with the oldest wood pole line having been installed 54 years ago in 1965. This life extension can be attributed to the inspection, treatment, and refurbishment that Hydro has been conducting on its transmission lines. For details, please refer to "Review of Current WPLM Program, Interim Report."[3]

[3] Filed as part of Hydro's "2013 Capital Budget Application," revised August 31, 2012, vol. II, tab 17, app. B (originally filed August 8, 2012).

3.0 Analysis

3.1 Identification of Alternatives

There are no alternatives for undertaking the activities outlined in this program. In 2005, the Board found that this approach was justified and prudent and approved the project and expenditures as submitted in the "2005 Capital Budget" Application in Board Order No. P.U. 53(2004).

> This approach is a more strategic method of managing wood poles and conductors and associated equipment and is persuaded that the new WPLM Program, based on RCM principles, will lead to an extension of the life of the assets, as well as a more reliable method of determining the residual life of each asset. One of the obvious benefits of RCM will be to defer the replacement of these assets thereby resulting in a direct benefit to the ratepayers.[4]

As part of its annual Capital Budget Application process, Hydro committed to provide the Board with an update of the program work that includes both a progress summary of the work completed as well as a forecast of the future program objectives. These details are included in this report.

4.0 Project Description

The WPLM Program is a condition-based program that uses the basic principles and strategies of RCM. Under the WPLM Program, line inspection data is analyzed each year and appropriate recommendations are made for necessary refurbishment or replacement of deteriorated line components (e.g., poles, structures, hardware, conductor, etc.) in the subsequent year. The inspection data and any refurbishment or replacement of assets is recorded in a centralized database for analysis and future tracking. Hydro may inspect and find an item that should be replaced in the current year, as opposed to waiting and scheduling replacement in a subsequent year. This will be managed within the existing budget and will only be implemented if the component is deemed not able to last another year.

The WPLM Program is aimed at early detection and rehabilitation or replacement of the wood poles and components before the integrity of the structures is jeopardized. If the deterioration of the structures is not detected early enough, the reliability of the structures will affect the reliability of the line and the system as a whole. It may also create safety issues and hazards for Hydro personnel and for the general public.

[4] "Order No. P.U. 53(2004) Reasons for Decision," Board of Commissioners of Public Utilities at p.23/13–18.

The WPLM inspection schedule is generally built on the strategy of focusing on older lines first and working toward newer lines. The exact lines and the number of poles to be included in the program are reviewed on an annual basis and may be modified based on the following criteria: age; priority (radial or redundant); and known problems.

The WPLM Program is based on a 10-year inspection cycle. To provide the quantitative benefits on the improvement of transmission line reliability, sufficient long-term data derived from two full inspection cycles will be required to provide adequate statistical evidence. The second WPLM inspection cycle is scheduled for completion by 2023. In the absence of this long-term data, an analysis of recent ice storms (such as the storms in March 2008 and March 2010) can provide an indication of how the transmission lines are performing.

In March 2008, there was a severe ice storm on the Avalon Peninsula. Hydro's test site at Hawke Hill recorded more than 25 mm of radial glaze ice, which exceeds the design load of the wood poles on the Avalon Peninsula. There were no reported failures because the poles that were not structurally sound had already been replaced during the first WPLM inspection cycle between 2003 and 2007. This was also the case during the ice storm of March 2010, in which there were no failures of Hydro's wood pole assets on the Avalon Peninsula. This supports Hydro's continued proactive condition-based management program.

4.1 Historical Information

4.1.1 Historical Expenditures

The five-year historical cost information for the WPLM Program, as well as the budget for 2019, is provided in Table 1. Information regarding number of units or cost per unit is not available as the work is not defined into individual units (e.g., line or structure number) as the actual work completed is variable and is dependent on the actual condition of the asset. For example, in most cases, the work completed on any one structure is not related to the work on the next structure (i.e., one structure may require a pole replacement and the next structure may need a crossarm or an insulator replacement). The same is true for a breakdown by individual transmission line, where the cost will be affected by the configuration, voltage, age, and geographical location of the line.

Table 1: Historical WPLM Program Expenditures ($000)

Year	Budget	Actuals
2019B	2,467.0	-
2018	3,532.9	3,185.6
2017	2,404.1	3,234.7
2016	2,919.0	3,180.0
2015	2,830.6	3,058.5
2014	2,564.2	2,496.8

4.1.2 Historical Replacement Information

Table 2 and Table 3 provide the statistics for pole and pole component replacement for the five years prior to implementation of the WPLM Program and for the years since implementation of the program.

Table 2: Annual Statistics of Pole and Pole Component Replacement

Year(s)	Poles	Crossarms	Knee Bracing	Cross Bracing	Comments
2018	29	19	1	9	
2017	31	32	36	76	
2016	38	39	28	23	
2015	50	14	15	5	
2014	57	11	10	6	
2013	34	8	88	8	
2012	32	14	4	4	
2011	53	19	80	22	
2010	60	20	45	58	
2009	81	12	14	25	
2008	93	27	27	25	
2007	97	31	11	19	
2006	142	30	18	21	
2005	98	47	43	58	
2004	51	13	12	22	Start of WPLM Program
2003	31	29	13	55	
2002	126	53	6	61	
2001	21	16	2	2	
2000	44	30	21	30	
1999	135	7	20	2	
Total	**1,303**	**471**	**494**	**531**	

Table 3: Statistics of Pole and Pole Component Replacement

Period	Poles	Crossarms	Knee Bracing	Cross Bracing	Comments
1999–2003	357	135	62	150	5 Years Before WPLM Program
2004–2018	946	336	432	381	15 Years Since WPLM Program

1 ## 4.2 Review of 2018 Wood Pole Line Management Program

2 The first objective of the 2018 WPLM Program was to inspect, test, and treat 2,747 poles and associated
3 line components. Table 4 summarizes the inspection accomplishments for 2018.

Table 4: 2018 Inspections Completed

Regions	Line Name	Year In Service	Voltage Level (kV)	Pole Inspections (Planned)	Pole Inspections (Actuals)	Completion (%)
Eastern	TL 219	1990	138	598	595	99
Central	TL 220	1970	69	235	235	100
	TL 223	1966	138	175	177	101
	TL 252	1981	69	202	202	100
	TL 253	1982	69	192	200	104
Western	TL 225	1970	69	46	31	67
Northern	TL 229	1976	69	0	195	-
	TL 239	1982	138	352	175	50
	TL 241	1983	138	198	189	95
	TL 256	1995	138	249	251	101
Labrador	TL 240	1976	138	500	500	100
Total				**2,747**	**2,750**	**100**

4 Another objective of the 2018 WPLM Program was the refurbishment of defective components
5 identified in inspections. A summary of the work completed in 2018 is given in Table 5.

Table 5: Summary of 2018 Refurbishment

Component	Region					Total
	Eastern	Central	Western	Northern	Labrador	
Poles	7	16	-	4	2	**29**
Crossarms	1	6	-	1	11	**19**
Cross bracing	2	7	-	-	-	**9**
Knee bracing		1	-	-	-	**1**
Foundations	8	1	-	5	-	**14**
Miscellaneous (Insulators, hardware, etc.)	31	15	20	41	8	**115**

The total expenditure of $3.2 million was approximately $347,000 or 9.8% under the budget estimate of $3.5 million. This can be partially attributed to the deferral of refurbishment work on TL 203 to 2019 due to the unavailability of outages on the line in 2018. This work included the replacement of 11 poles, 9 crossarms, 5 sets of cross bracing, 7 sets of knee bracing, 1.5 km of overhead ground wire, and other miscellaneous items. This work was completed in March 2019 under the 2019 WPLM Program.

4.3 Update of 2019 Wood Pole Line Management Program

The inspection and treatment work scheduled for 2019 is summarized in Table 6. This work began in mid-April and will run until October 2019.

Table 6: 2019 Inspection Plan

Region	Line No.	Year Built	Age of Line	Pole Inspections (Target)
Eastern	TL 219	1990	29	371
Central	TL 220	1970	49	231
	TL 223	1966	53	176
	TL 233	1973	46	240
	TL 252	1981	38	235
Western	TL 215	1969	50	150
Northern	TL 226	1970	49	200
	TL 229	1976	43	129
	TL 239	1982	37	63
	TL 241	1983	36	60
	TL 256	1996	23	53
	TL 257	1988	31	220
Labrador	TL 240[5]	1976	43	501
Totals				**2,629**

As a result of the 2018 inspection program, a refurbishment program began during the spring months of 2019 and will continue into the fall. This includes the replacement of approximately 37 poles, 45 crossarms, 10 sets of cross bracing, 7 sets of knee bracing, and other components.

A list of the refurbishment work scheduled for completion in 2019 is provided in Table 7.

[5] TL240 contains both L1301 and L1302 in Labrador. All planned work in 2019 for TL 240 occurred on the L1301 section of the line. With approval of the Muskrat Falls to Happy Valley Goose Bay Interconnection Project in Board Order No. P.U. 9(2019) on March 5, 2019, the planned inspection of L1301 under the WPLM Program has been cancelled. There is no planned work for L1302 in 2019. Hydro will review the plan and assess whether or not a different line should be incorporated in 2019 activity.

Table 7: 2019 Refurbishment Plan

Component	Region					Total
	Eastern	Central	Western	Northern	Labrador	
Poles	13	13	10	1	-	**37**
Crossarms	10	26	3	4	2	**45**
Cross bracing	9	1	-	-	-	**10**
Knee bracing	7	-	-	-	-	**7**
Foundations	1	-	-	2	-	**3**
Miscellaneous (Insulators, hardware, etc.)	69	5	21	57	4	**156**

4.4 Budget Estimate

The project estimate is provided in Table 8 includes the complete inspection of the stated lines, including the visual inspection supported by inspecting each pole using non-destructive evaluation tools and treatment of the pole as required. The budget for 2021 and beyond will be established in future Capital Budget Applications based on the annual inspection results.

To establish a projected cost of refurbishment or replacement, it is assumed that a percentage of those poles inspected will also be rejected according to the IOWA curve (shown in Appendix A, Figure A-1) depending on their age and group.[6] Poles rejected in the field will be analyzed with respect to reliability issues, and if rejected after structural analysis, a recommendation to refurbish or replace will be made.

Using the average age of the poles being inspected, along with the IOWA curve, the anticipated pole replacement rate is calculated and this is used to develop the future refurbishment program. A schedule of the pole inspections from 2019 to 2024 is provided in Appendix A, Table A-1. Table A-1 also provides the average age and anticipated pole rejection rate for each year.

[6] Iowa curves display functional failures or retirements of asset classes and were developed in a study at the University of Iowa. Each curve represents a probability distribution and has a series of attributes. The curves help make realistic forecasts of the remaining useful life of groups of assets.

Table 8: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	304.6	0.0	0.0	**304.6**
Labour	1,636.9	0.0	0.0	**1,636.9**
Consultant	100.0	0.0	0.0	**100.0**
Contract Work	406.0	0.0	0.0	**406.0**
Other Direct Costs	95.8	0.0	0.0	**95.8**
Interest and Escalation	3.1	0.0	0.0	**3.1**
Contingency	246.3	0.0	0.0	**246.3**
Total	**2,792.7**	**0.0**	**0.0**	**2,792.7**

4.5 Project Schedule

The annual project schedule involves many transmission lines and is dependent on the annual work load and availability of outages. It will be managed to commence as soon as system conditions allow. The schedule is determined during the spring of each year.

5.0 Conclusion

In conclusion, the major objectives for the 2018 WPLM Program were achieved, the plan for 2019 is ongoing, and Hydro is proposing to continue the WPLM Program in 2020.

Appendix A

Wood Pole Line Management Inspection Schedule 2019–2024
(With Average Age of Transmission Lines and Estimate Pole Rejection Rates)

Table A-1: WPLM Inspection Schedule and Expected Pole Rejection Rates (Summary)

Year	Average Age of Lines	No. of Planned Poles Inspections	Estimated Approximate Pole Rejection Rate	No. of Anticipated Poles Rejections
2019	38.7	2,629	1.6%	42
2020	41.6	2,783	2.2%	61
2021	36.1	2,402	1.6%	39
2022	41.1	2,303	1.1%	26
2023	42.6	2,357	2.3%	55
2024	49.4	2,629	2.3%	60

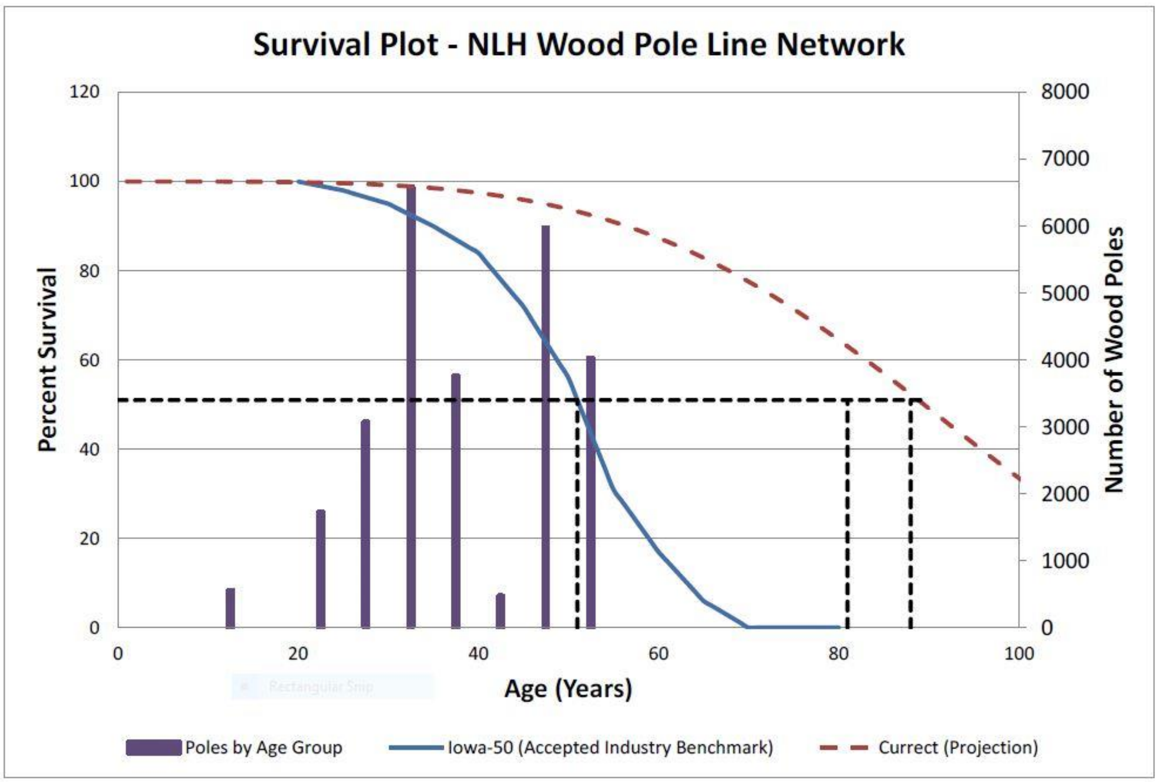

Figure A-1: IOWA Curve

12. Replace Transformer T7 - Holyrood

REGISTERED PROFESSIONAL ENGINEER

PAUL NOLAN

SIGNATURE

23 - JULY - '19

DATE

PROVINCE OF NEWFOUNDLAND

2020 Capital Budget Application
Replace Transformer T7
Holyrood Terminal Station

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

The 138 kV section of the Holyrood Terminal Generating Station (“Holyrood TGS”) has three 230 kV/138 kV transformers, T6, T7, and T8. Holyrood Transformer T7 (“Holyrood T7”) is a power transformer with a 230 kV/138 kV voltage rating and a maximum rated capacity of 41.7 MVA. Holyrood T7 was manufactured in 1969. An internal inspection of this transformer in late 2018 indicated that this unit has reached the end of it operational life and it has been removed from service.

The absence of Holyrood T7 results in an increased probability of shedding customer loads supplied via the 138 kV transmission loop between the Western Avalon Terminal Station (“Western Avalon TS”) and the Holyrood TGS. A replacement transformer must be installed to maintain the reliable operation of the Northeast Avalon 230-138 kV transmission system.

Using Churchill Falls Transformer T31 (“Churchill Falls T31”), a 75/100/125 MVA transformer, to replace the existing transformer is the least cost alternative and will expedite the replacement due to the elimination of the ordinarily extended delivery time for a new transformer.

Newfoundland and Labrador Hydro (“Hydro”) is proposing this project to replace Holyrood T7 to maintain the reliable operation of the Northeast Avalon 230-138 kV transmission system.

This project estimate is approximately $2,678,100 with scheduled completion in 2020.

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List of Appendices

1.0 Introduction

The 138 kV section of the Holyrood TGS has three 230 kV/138 kV transformers, T6, T7, and T8. Holyrood T7 is a 50 year old, 25/33.3/41.7 MVA power transformer, with a 230 kV/138 kV voltage rating that has reached the end of its service life and is currently out of service.

Background Holyrood T7 is located within the 138 kV Western Avalon TS to Holyrood TGS transmission loop (“138 kV loop”), which is shown in the simplified single line diagram in Figure 1. This 138 kV loop supplies power to the majority of the northwest Avalon Peninsula and has a firm transformer capacity of 341.8 MVA.

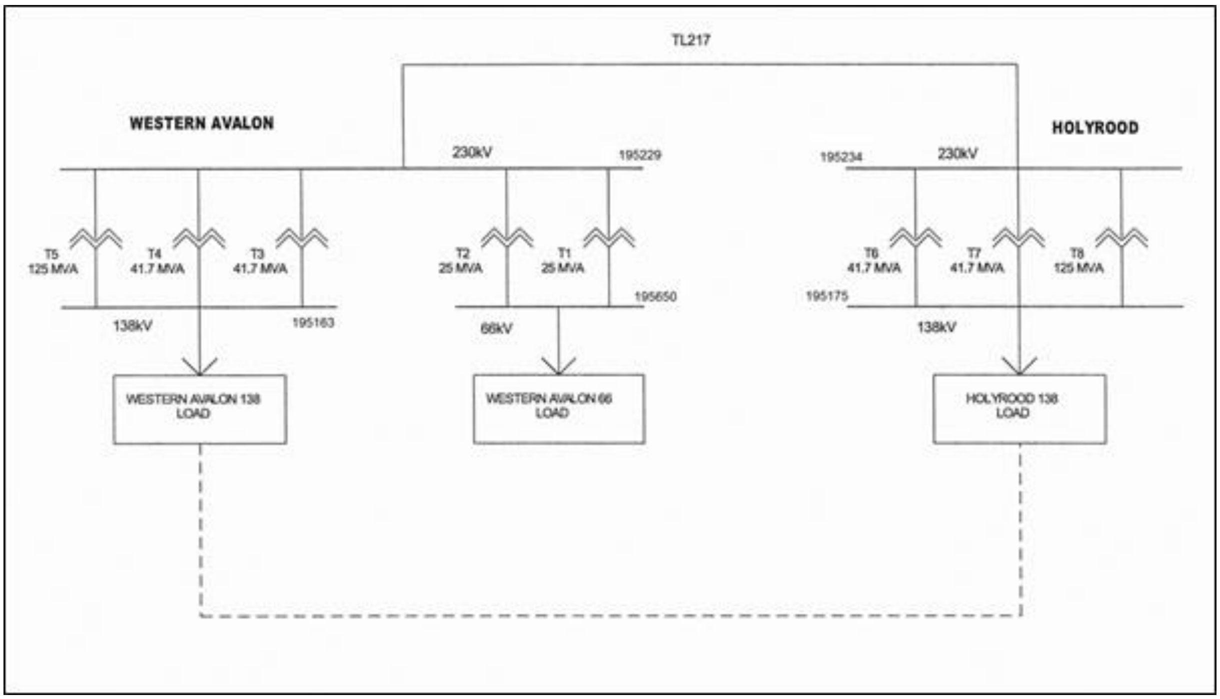


Figure 1: Western Avalon-Holyrood 138kV loop

The loss of Holyrood T7 weakens Hydro’s ability to supply the load on the 138 kV loop. While Hydro can meet peak load conditions with all remaining equipment in service, the loss of the largest transformer in the loop (Holyrood T8), with Holyrood T7 out of service, would result in the overload of transformer Holyrood T6. The loss of Newfoundland Power’s transmission line 64L, with Holyrood T7 out of service, would result in the overload of Western Avalon Transformers T1 and T2 in the Western Avalon TS. Load flow analysis indicates that load shedding would be required to eliminate these transformer overloads.

1.1 Existing System

During the capital refurbishment of Holyrood T7, an internal inspection on October 26, 2018 revealed that the transformer was rusted internally, including its core. Some of the rust was loose and had migrated around the transformer, resulting in an increased risk of dielectric failure. The transformer was removed from service due to this condition and is unsuitable for energization.

The internal inspection report completed by PTI Transformers is included in Appendix A.

1.2 Operating Experience

In 2016, a high moisture level of 15% relative saturation was measured during a routine oil sample. Hydro planned to address the high moisture through the installation of an online oil dehydrator in 2017. However, in 2017 it was decided to defer the online oil dehydrator installation to 2018 for better overall project execution during the capital refurbishment project. This deferral was deemed reasonable given that the moisture level in the 2017 routine oil sample wasn’t concerning.

With the exception of maintenance outages, Holyrood T7 has been in service on a continual basis for approximately 50 years.

2.0 Justification

Included as Appendix B is Hydro’s Technical Note regarding the Holyrood Transformer T7 replacement analysis. This note provides additional details regarding the options available for replacement.

Replacement of Holyrood T7 is required to restore the reliable operation of the Northeast Avalon 230 - 138 kV transmission system. Churchill Falls T31 was purchased and installed by the Muskrat Falls Project in 2013 to facilitate increased capacity and supply of construction power for the Muskrat Falls Project via L1301. This will be a surplus asset once the transmission line for the Muskrat Falls to Happy Valley Interconnection project is in service. Churchill Falls T31 will receive its six-year preventive maintenance and condition assessment in 2019. The purchase and utilization of Churchill Falls T31 to replace Holyrood T7 is the least cost option and will expedite the replacement due to the elimination of the extended delivery time for a new transformer.

3.0 Analysis

3.1 Identification of Alternatives

As noted in Appendix B, and after negotiation with Nalcor Energy regarding the purchase price for Churchill Falls T31, the purchase of a new transformer is more expensive than purchase of Churchill Falls T31. Therefore, the purchase of a new 42 MVA transformer was excluded as an option.

The following alternatives were analyzed:

- Replace Transformer T7 with a 75/100/125 MVA transformer (designated as Churchill Falls T31) available for purchase from Nalcor Energy;
- Repair Transformer T7 on site; assume that the transformer will be replaced in 2033 at the end of its service life of approximately 65 years; and
- Repair Transformer T7 at an offsite location; assume that the transformer will be replaced in 2033 at the end of its service life of approximately 65 years.

The use of an available transformer is the least cost option and will expedite the replacement due to the elimination of the extended delivery time (approximately 36 weeks) for a new transformer.

3.2 Evaluation of Alternatives

A cost benefit analysis of the three options was completed and is outlined in Table 1.

Table 1: Holyrood T7 Upgrades Cost Benefit Analysis

Alternative Comparison
Cumulative Net Present Value to the Year 2019

Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Replace Transformer 2020	2,092,169	0
Repair Onsite/Repl 2033	2,516,965	424,796
Repair Offsite/Repl 2033	3,207,568	1,115,399

3.3 Recommended Alternatives

The least cost alternative is the replacement of the transformer, and is the recommended alternative.

4.0 Project Description

This scope includes the following items:

- Removal and disposal of Holyrood T7;
- Removal of Churchill Falls T31 from the Churchill Falls Switchyard;
- Transportation of Churchill Falls T31 from the Churchill Falls Switchyard to the Holyrood TGS;
- Installation and commissioning of Churchill Falls T31, including refurbishment of the on-load tap changer, at the Holyrood TGS on a new pad with an oil containment system;
- The completion of protection upgrades to replace protection relays, metering equipment, wiring, and cables; and
- Commissioning shall include paralleling of the new transformer with the existing Holyrood T6 and T8 transformers.

The project estimate is provided in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	1,195.8	0.0	0.0	**1,195.8**
Labour	230.9	0.0	0.0	**230.9**
Consultant	130.0	0.0	0.0	**130.0**
Contract Work	734.2	0.0	0.0	**734.2**
Other Direct Costs	8.3	0.0	0.0	**8.3**
Interest and Escalation	149.0	0.0	0.0	**149.0**
Contingency	229.9	0.0	0.0	**229.9**
Total	**2,678.1**	**0.0**	**0.0**	**2,678.1**

The project schedule is provided in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning: Open project, review schedule	January 2020	February 2020
Design: Conduct site visits, detailed design	February 2020	March 2020
Procurement: Tender and award contracts	April 2020	May 2020
Construction/Commissioning: Remove / dispose of HRD T7 and transport / install CF T31 in the Holyrood TGS	August 2020	October 2020
Closeout: Project close-out	November 2020	December 2020

5.0 Conclusion

Holyrood T7 is a 50 year old, 25/33.3/41.7 MVA power transformer with a 230 kV/138 kV voltage that is rusted internally resulting in an increased risk of dielectric failure. The transformer was removed from service due to this condition and is unsuitable for re-energization.

Without Holyrood T7 in service there is an increased probability of shedding customer loads supplied via the Western Avalon TS – Holyrood TGS transmission loop. A replacement transformer must be installed to restore the reliable operation of the Northeast Avalon 230 - 138 kV transmission system.

Using Churchill Falls T31, a 75/100/125 MVA transformer, to replace the existing transformer is the least cost alternative and will expedite the replacement due to the elimination of the extended delivery time for a new transformer.

Appendix A

Appendix A: PTI Transformers Report Oct-31-2018

newfoundland labrador hydro
a nalcor energy company

PTI TRANSFORMERS

Daily Report

Label	Holyrood T7
	3101768 - SC18.0108
26	Wednesday, October 31st 2018, 7:15 AM (CDT -05:00)

Report

List your daily activities, being as descriptive as possible. Provide photos.

Date	*October 26, 2018*

Daily activities of:

Chris Sarrasin

Report

Internal inspection on a NALCOR transformer T7 serial number 287064 located at Holyrood substation built by Canadian General Electric in 1969.

On arrival to site the transformer had already been drain of the oil, flushing had been completed and the HV, LV and neutral bushings had been removed.

The top manhole cover between H1 and X1 was my entrance point. The first thing that I noticed prior to my entry was the large amounts of debris deposits on the tank floor. Once inside I noticed that the top yoke was covered in rust. There is so much rust formation that the individual sheets were starting to bond themselves together. As a small note, only a small amount of their top yoke was able to be inspected as the remainder has a steel sheet/barrier over top were the tap leads are secured. There was rust formation on a lot of the metal hardware found throughout the active assembly as well. Once at the bottom of the unit, I determined that the debris deposits that I initially noticed was actually deposits of rust settlement and small particles. There were these deposits throughout the tank floor.

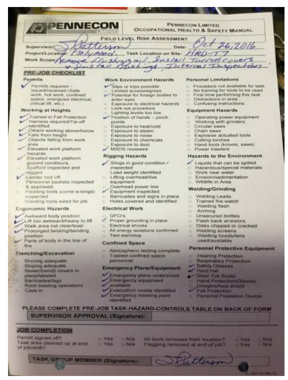
Continuing with my inspection, the winding blocks were tight throughout the unit, the leads exists on the HV side were in good condition. I did find a nylon stud on the LV side that had been displaced which I re-secured. There was also a nylon stud on the top tap lead structure that had broken. This stud I was not able to repair as this would involve removing most of the lead structure on the top of the unit. On the floor beneath the neutral bushing I found a large piece of plastic which came from one of the bush gas deflectors.

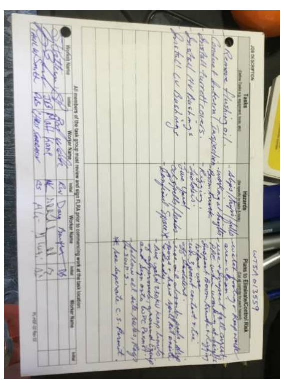
Inside the tap changer compartment, which is open at the top to the main unit, I once again found rust deposits on the floor. The leads were all tight to the gear with the required clearances. The thing that concerns me with the tap changers is the developmental rust that is starting to form on the metal components on them.

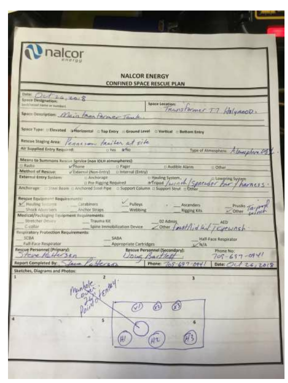
In conclusion of my inspection, structurally this unit is tight however the concern I have with this unit is the internal rusting and the extent of the rust. It is obvious that this rusting has been developing over the years. Somewhere on this unit, above the oil levels, there is an ingress of moisture. Yes the deposits on the tank floor as well as other surfaces can be cleaned up however there is no way to determine were all the sediment has gone, such as in the windings. Another thing that cannot be determined, is how much of the core is rusting and the extent. This cannot be determined inside the tank as the top yoke would need to be removed.

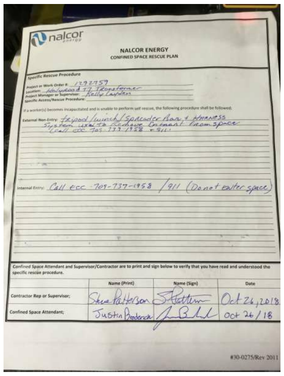
It is my recommendation that this unit not be energized for a few reasons 1) the extent of the rusting and the locations *cannot be fully determined while the unit is inside the tank. The active assembly would need to be removed from the tank and completely disassembled 2) the fusing of the sheets on the top yoke cannot be repaired but has to be replaced. 3) the draining of the unit of oil and flushing may have also spread the rust to other area within the active unit 4) leaving the rust on the core with the sheets bonded together will cause circulating currents which are producing lethal gases. Without seeing past oil samples I cannot determine whether gas increase has not already started to elevate. So again, I recommend that this unit not be placed back into service. Do not energize.*

T7 serial number 287064









NALCOR ENERGY
CONFINED SPACE RESCUE PLAN

Specific Rescue Procedure

Project or Work Order #: 1292759
Location: Holyrood T7 Transformer
Project Manager or Supervisor: Kelly Lawden
Specific Access/Rescue Procedure:

If a worker(s) becomes incapacitated and is unable to perform self rescue, the following procedure shall be followed:

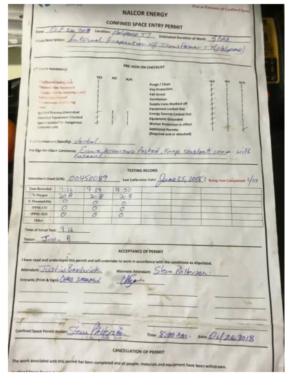
External Non-Entry: tripod/winch/spreader Bar & Harness System used to Remove Entrant from space (call ecc 709-737-1958 & 911)

Internal Entry: Call ecc 709-737-1958 / 911 (Do not enter space)

Confined Space Attendant and Supervisor/Contractor are to print and sign below to verify that you have read and understood the specific rescue procedure.

	Name (Print)	Name (Sign)	Date
Contractor Rep or Supervisor:	Steve Patterson	S Patterson	Oct 26, 2018
Confined Space Attendant:	Justin Broderick	J Broderick	Oct 26/18

#30-0275/Rev 2011



Post at Entrance of Confined Space

NALCOR ENERGY
CONFINED SPACE ENTRY PERMIT

Date: Oct 26, 2018 Location: Holyrood T7 Estimated Duration of Work: 3 hrs
Work Description: Internal Inspection of Transformer T7 (Holyrood)

PRE-SIGN ON CHECKLIST

	YES	NO	N/A		YES	NO	N/A
[illegible]				Purge / Clean			
[illegible]				Fire Protection			
[illegible]				Fall Arrest			
[illegible]				Ventilation			
[illegible]				Supply Lines Blanked off			
[illegible]				Equipment Locked Out			
Ignition Sources Eliminated				Energy Sources Locked Out			
Electrical Equipment Checked				Equipment Grounded			
Space Isolated for Dangerous Contaminants				Worker Protection in effect			
				Additional Permits (Required and or attached)			

Communications (Specify): Verbal.
Pre Sign On Check Comments: Ensure Attendant Posted. Keep constant comm. with Entrant.

TESTING RECORD

Instrument Used (S/N): 00450089 Last Calibration Date: June 25, 2018 Bump Test Completed Yes

Time Recorded	9 16	9 34	9 50				
% Oxygen	20.8	20.8	20.8				
% Flammability	0	0	0				
(PPM) CO	0	0	0				
(PPM) H2S	0	0	0				
Other							

Time of Initial Test: 9 16
Tester: Justin B

ACCEPTANCE OF PERMIT

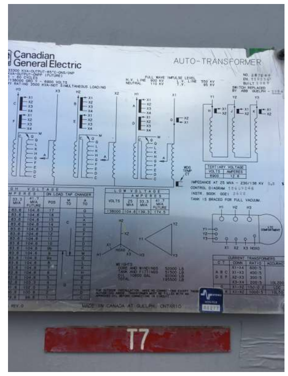
I have read and understand this permit and will undertake to work in accordance with the conditions as stipulated.

Attendant: Justin Broderick Alternate Attendant: Steve Patterson
Entrants (Print & Sign): CHRIS SADRAMJ

Confined Space Permit Holder: Steve Patterson Time: 8:00 AM Date: Oct 26, 2018

CANCELLATION OF PERMIT

The work associated with this permit has been completed and all people, materials and equipment have been withdrawn.



Rust formation on the top yoke near leg one.

Rust deposits on the tank floor on the HV side

More rust deposits on the the HV side

Rust formation on the ground bonding hardware on the top clamp.

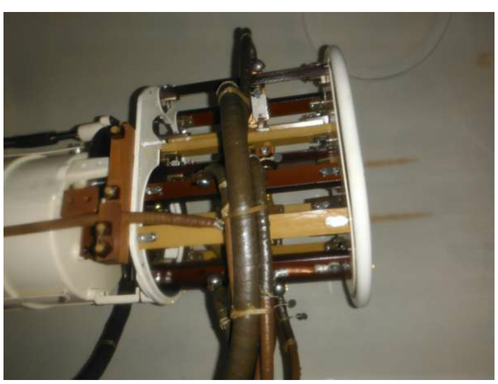
Missing bolt on the LV centre phase LV side lead structure. The bolt I found on the tank floor.

I re-secured the bolt.

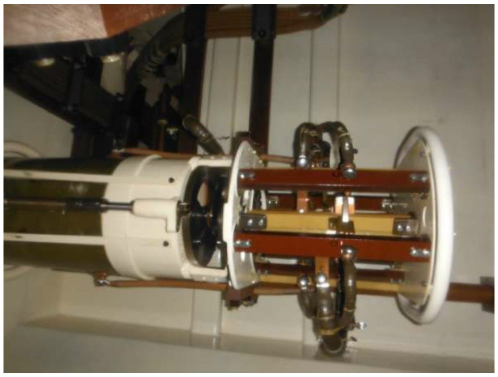
Broken stud on the top LV lead structure. The stud was not able to be repaired at the time as most of the lead work on the top of the yoke would have to be removed.

Rust deposits in the tap changer compartment.

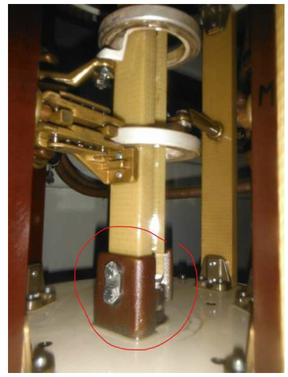
Large piece of plastic from the LV gas deflectors.



"A" phase



"B" phase



"C" phase

Chris Sarrasin,
Parts & Service Supervisor
October 31st 2018, 7:15 AM (CDT -05:00)

49.8449822, -97.1549468

Appendix B

Appendix B: TP-TN-053 – Holyrood Transformer T7 Replacement Analysis

Doc #: TP-TN-053

Document Type: Technical Note

TP-TN-053

Holyrood Transformer T7 Replacement Analysis

Purpose

The purpose of this technical note is to summarize analysis performed by Transmission Planning used to determine the least cost option for the replacement of Holyrood Transformer T7.

1 Introduction

Following the failure of Holyrood Transformer T7 (HRD-T7), it was recommended that Hydro not re-energize the transformer and that it should be refurbished or replaced. In consultation with vendors, Engineering Services determined that due the condition of HRD-T7, replacing the transformer was the best decision.

HRD-T7 is a 25/33.3/41.7 MVA power transformer located in the Western Avalon-Holyrood loop, which is shown in the simplified single line diagram in Figure 1. This 138 kV loop supplies power to the majority of the northwest Avalon Peninsula and has a firm transformer capacity of 341.8 MVA. Table 1 provides a summary of the transformer capacity on the Western Avalon – Holyrood Loop.

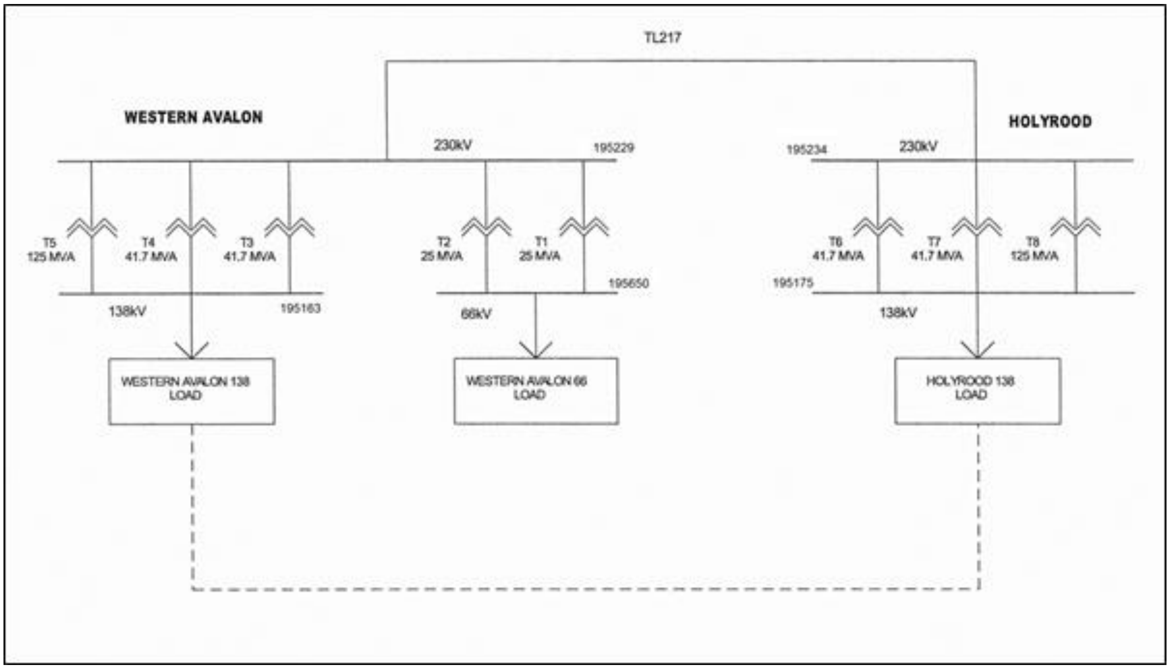


Figure 1 - Western Avalon-Holyrood 138kV loop

Table 1 - Western Avalon - Holyrood 138kV Loop - Transformation Capacity

Transformer	Transformer Rating (MVA)[1]
WAV-T1	25
WAV-T2	25
WAV-T3	41.7
WAV-T4	41.7
WAV-T5	125
HRD-T6	41.7
HRD-T7	41.7
HRD-T8	125
Transformer Capacity (N-0)	**466.8**
Transformer Capacity (N-1)	**341.8**

[1] Prior to de-rating

The loss of HRD T7 weakens Hydro's ability to supply the load on the WAV-HRD 138 kV loop. Hydro can meet peak load conditions with all remaining equipment in service. The loss of the largest transformer in the loop (HRD-T8) with HRD-T7 out of service would result in the overload of transformer HRD-T6. Following this event, the 138 kV loop would have to be broken to balance the load on the Western Avalon and Holyrood Terminal Station to offload HRD-T6. The loss of transmission line 64L with HRD-T7 out of service would result in the overload of transformers WAV-T1 and WAV-T2. Load flow analysis indicates that load shedding would be required to eliminate these transformer overloads. Therefore it can be concluded that HRD-T7 must be replaced, because without it, the loss of HRD-T8 or 64L would result in transformer overloads and therefore a violation in the Transmission Planning Criteria.

A 75/100/125 MVA transformer (CF-T31) may be available for purchase from Nalcor to replace HRD-T7. This transformer is currently used for the supply of the transmission system in eastern Labrador. As part of its 2018 Capital Budget Application, Hydro proposed that loads in this system be supplied by a new 138 kV interconnection to Muskrat Falls, Terminal Station 2. If this project is approved, the supply to Happy Valley from Churchill Falls would only serve as a backup, and it is possible that the CFT-31 transformer could be removed or replaced without an appreciable reliability impact. The reliability assessment presented in Section 4 of this technical note provides a conclusion on the impact of CF-T31 in its role as a back-up source of supply for Labrador East.

The following alternatives were originally considered for the replacement of HRD-T7:

- **Alternative 1 - Straight Replacement of HRD-T7 with a new 25/33.3/41.7 MVA Power Transformer**
- **Alternative 2 - Replace HRD-T7 with a Larger Transformer**
    - **(A) Relocation of CF-T31 to replace HRD-T7**
    - **(B) Purchase of a <u>new</u> 75/100/125MVA transformer to replace HRD-T7**

The reliability analysis outlined in Sections 3 and 4 was performed to determine the viability of Alternatives 2a and 2b in order to consider them as part of the cost benefit analysis.

2 Load Flow Analysis – WAV/HRD 138kV Loop

Based on the most recent operating load forecast and assuming the straight replacement of HRD-T7 with a new 25/33.3/41.7 MVA unit, the transformer capacity of the WAV/HRD 138kV loop can support forecasted peak demand[2] for the foreseeable future. However, there is a potential for unserved energy following the loss of HRD-T8 and transmission line 64L. From the perspective of Transmission Planning Criteria, this is an N-1-1 contingency and controlled load shedding for such an event is permitted. The replacement of HRD-T7 with a larger transformer is therefore not a requirement, and any incremental cost associated with the purchase of a larger transformer would have to be justified on the basis of a probabilistic reliability review. An analysis was therefore performed to compare the expected unserved energy (EUE) of two different scenarios (1) HRD-T7 as a 25/33.3/41.7MVA transformer and (2) HRD-T7 as a 75/100/125 MVA transformer.

With HRD-T8 and 64L out of service and HRD-T7 as a 25/33.3/41.7 MVA transformer, there would be an overload on the remaining transformers in the WAV/HRD loop. A load flow diagram of this peak load scenario is shown in Figure 3. Further load flow analysis shown in Figure 4 indicates that these overloads could be removed if 30% of the load in the WAV/HRD loop is shed. As shown in Figure 5, these overload conditions would also exist under the same scenario if HRD-T7 were to be replacement with a 75/100/125 MVA transformer. However, there would be much less of an impact since only 8% of the load would have to be shed under peak load conditions to offload the other transformers in the loop (Figure 6).

As indicated in the load duration curve (Figure 7)[3], the load on the WAV/HRD Loop is greater than 70% of peak for about 40% of the year. This translates into approximately 612 GWh per year. Figure 7 also shows that the load on the WAV/HRD Loop is greater than 92% of peak for only 4% of the year, which corresponds to approximately 2.4 GWh per year. Therefore there is a difference of 610 GWh between HRD-T7 as a 25/33.3/41.7 MVA transformer compared to if it were a larger 125 MVA transformer.

[2] 2028 peak for the WAV/HRD loop is approximately 178.5MW

[3] Based on 2028 peak forecast

The reliability assessment in the following section will summarize the EUE for both scenarios, to the customers on the WAV/HRD loop based on the projected unavailability of HRD-T8 and 64L.

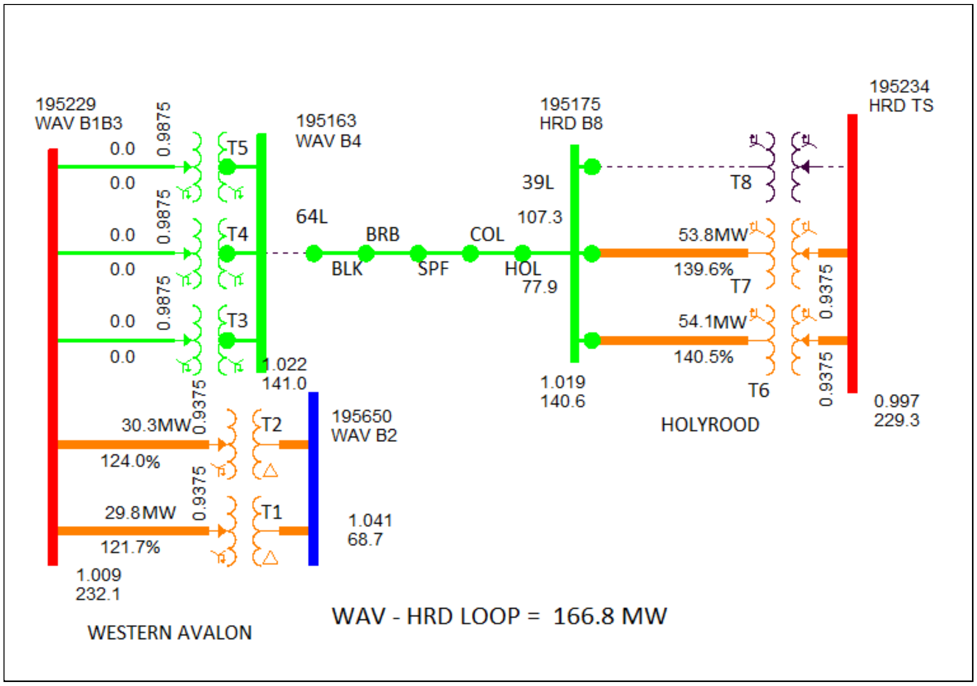


Figure 2 – Load Flow Diagram – 100% Peak load - 64L and HRD-T8 out of service – HRD-T7 (25/33.3/41.7 MVA)

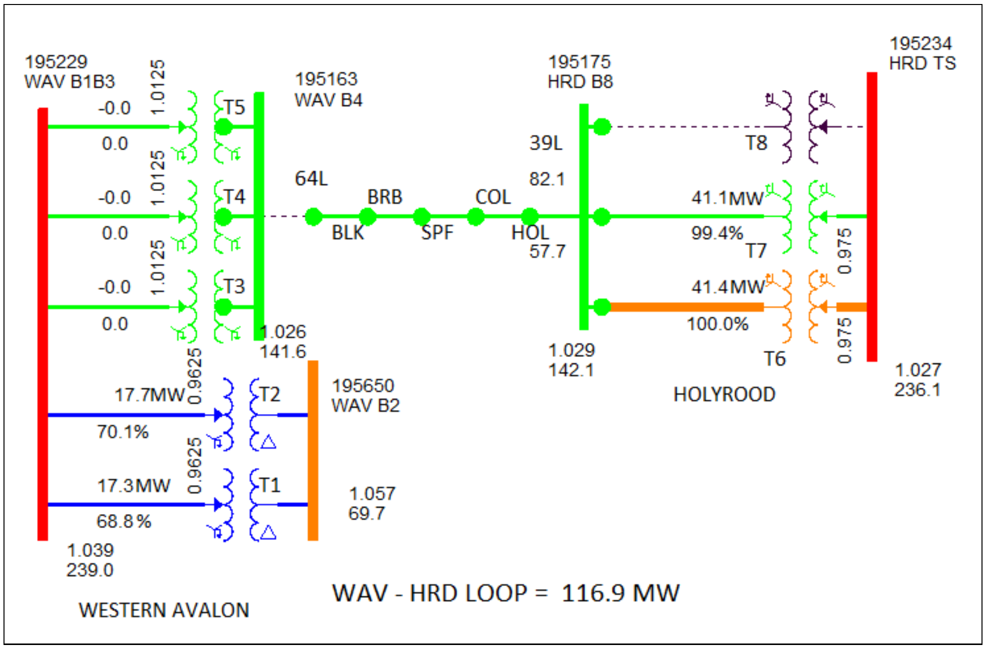


Figure 3 - Load Flow Diagram –70% Peak Load - 64L and HRD-T8 out of service – HRD-T7 (25/33.3/41.7 MVA)

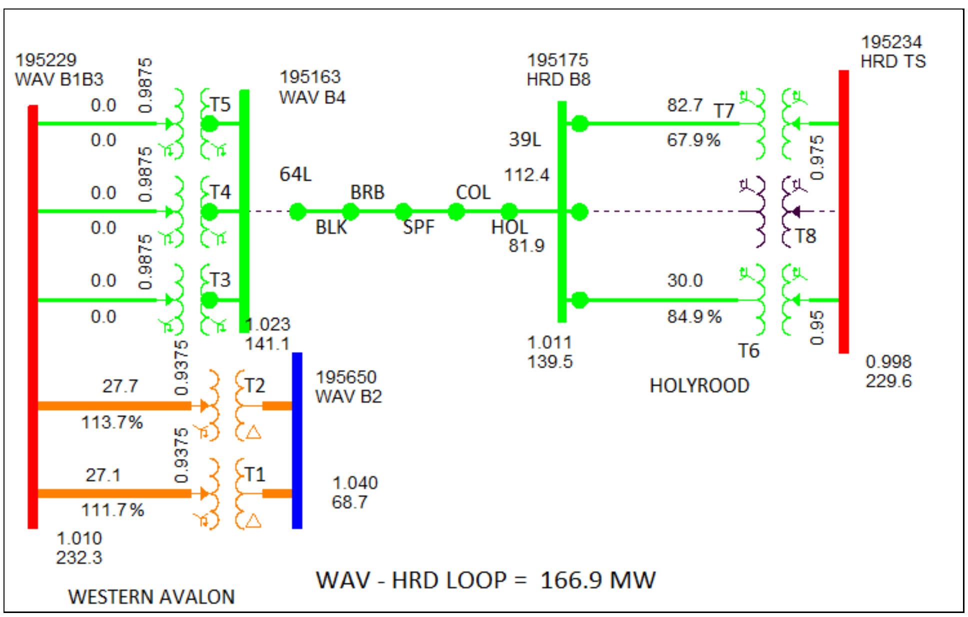


Figure 4 - Load Flow Diagram – 100% Peak load - 64L and HRD-T8 out of service – HRD-T7 (75/100/125 MVA)

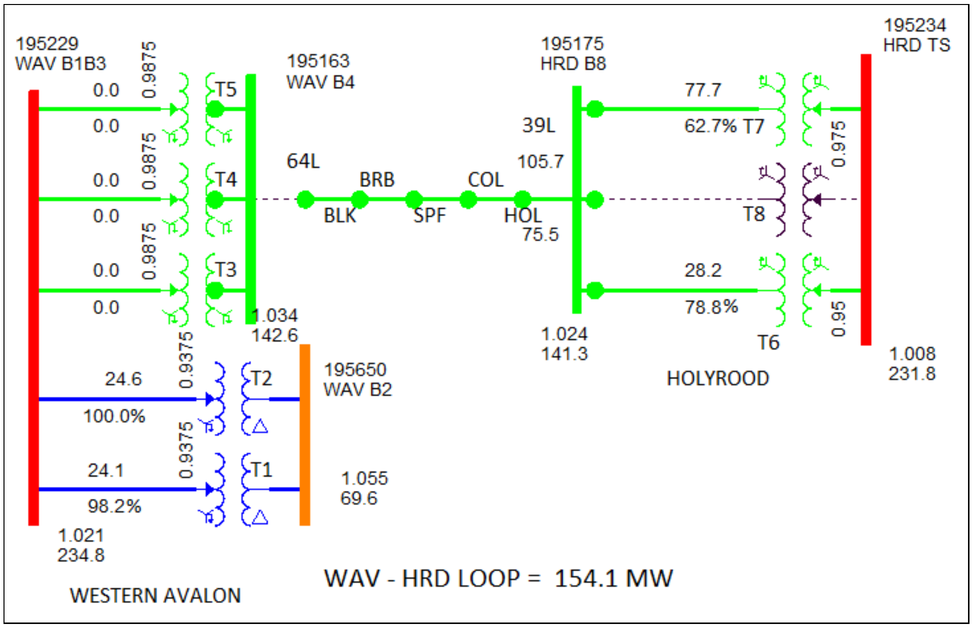


Figure 5 - Load Flow Diagram – 92% Peak load - 64L and HRD-T8 out of service – HRD-T7 (75/100/125 MVA)

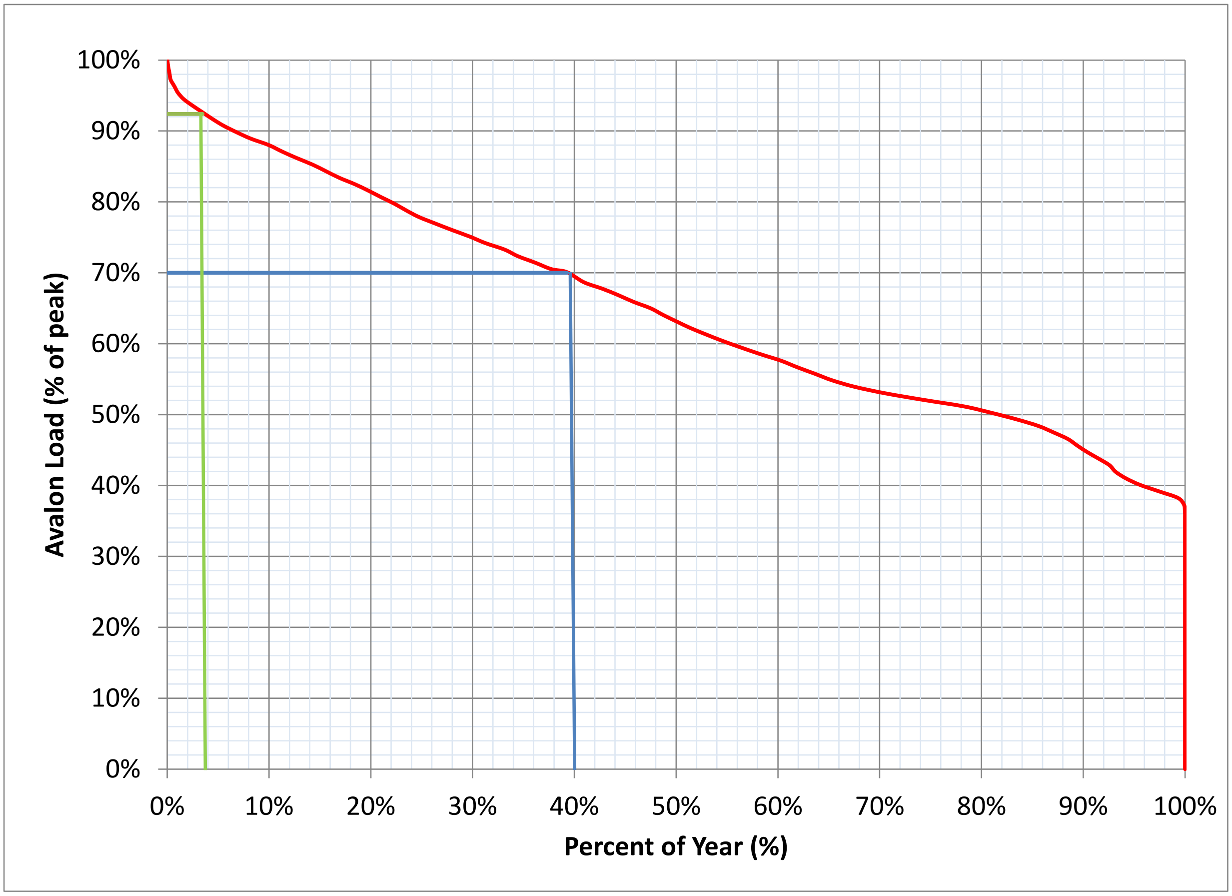


Figure 6 - Load Duration Curve - WAV/HRD Loop

3 Reliability Assessment – WAV/HRD 138kV Loop

The unavailability (%) for a transmission line and transformer with a voltage classification between 110-149kV was obtained from the "Forced Outage Performance of Transmission Equipment 5 year report (2013-2017)" prepared by CEA. The expected unavailability of a 138kV line (per 100km) is 0.107%, while a transformer for the same voltage class is 0.291%. This information was used to calculate the expected unavailability with 64L and HRD-T8 out of service at the same time. This total unavailability is used to determine the difference in annual expected unserved energy for both scenarios - (1) HRD-T7 as a 25/33.3/41.7 transformer and (2) HRD-T7 as a 75/100/125 MVA transformer.

$$U_{Line(64L)} = \frac{13.9km}{100km} * 0.00107 = 1.487 * 10^{-4}$$

$$U_{Total} = U_{Line(64L)} * U_{Xfmr\ (T8)} = (1.487 * 10^{-4}) * 0.00291 = 4.327 * 10^{-7}$$

Based on the total unavailability, the difference in expected unserved energy for both scenarios can be determined:

$$EUE = U_{Total} * (E_{Load>70\%} - E_{Load>92\%}) = 4.327 * 10^{-7} * (612\ GWh - 2.4\ GWh) = \mathbf{0.264\ MWh}$$

The incremental cost for the purchase of new larger transformer is estimated to be in the order of two to three million dollars. The cost of the reliability improvement is therefore expected to be in the range of $7.6 M to $11.4 M per MWh. As a result of this high cost, "Alternative 2b - Purchase of a 75/100/125MVA transformer to replace HRD-T7" is excluded from further consideration.

The purchase of a larger transformer is not justifiable on the basis of reliability. The option involving the purchase and relocation of the larger transformer, CF-T31, is therefore only viable from a financial perspective if the cost does not exceed that of a 25/33.3/41.7 MVA power transformer. This project is only viable from a technical standpoint if it does not result in an appreciable decrease in reliability for the transmission system in eastern Labrador. The following reliability assessment was therefore performed to assess these reliability impacts.

4 Reliability Assessment – Labrador East 138kV System

An analysis was performed to assess reliability impacts associated with the operation of CF-T31 in Churchill Falls and using L1301 as a back-up supply for the Labrador East 138kV System. This analysis only applies for the case where the Muskrat Falls-Happy Valley Interconnection is approved. The following are the two alternatives considered for this reliability assessment:

1. **Option 1: CF-T31 as a back-up supply to Labrador East**
2. **Option 2: No back-up feed to Labrador East**

These two options are the best and worst case scenarios from a system reliability perspective for Labrador East, respectively.[4]

Reliability analysis was completed on a simplified component model of the two options mentioned above. Each model only consists of transmission lines and transformers up to the 138 kV bus at Happy Valley Terminal Station. For this analysis, CEA's "Forced Outage Performance of Transmission Equipment 5 year report" data was used for transmission line and transformer components. CEA's 2017 Annual Report is based on data for the period January 1, 2013 to December 31, 2017.

Table 2 outlines the CEA summary of transmission line statistics for line-related sustained forced outages for 138 kV. Table 3 outlines the CEA summary of transformer bank statistics for forced outages involving integral subcomponents and terminal equipment.

[4] A Transmission Planning analysis will be performed to develop a long term plan for the 138 kV interconnection to Churchill Falls. This plan may involve the decommissioning of the interconnection, or maintaining the link as a backup source of supply for Happy Valley using transformers available onsite at Churchill Falls. For the purposes of this investigation, only two scenarios were considered. By assessing the best and worse case backup scenarios, the maximum benefit associated with the purchase of the power transformer from Nalcor Energy can be calculated.

Table 2 - Transmission Line Sustained Forced Outage Statistics (Per 100km)

Voltage Classification (kV)	Sustained Outage Frequency (Per 100 km.a)	Mean Duration (yrs)	Unavailability (%)
138	0.7811	0.00137	0.107

Table 3 - Transformer Forced Outage Statistics Involving Integral Subcomponents and Terminal Equipment

Voltage Classification (kV)	Sustained Outage Frequency (Per a)	Mean Duration (yrs)	Unavailability (%)
230	0.1356	0.02537	0.344
315	0.1813	0.03945	0.715

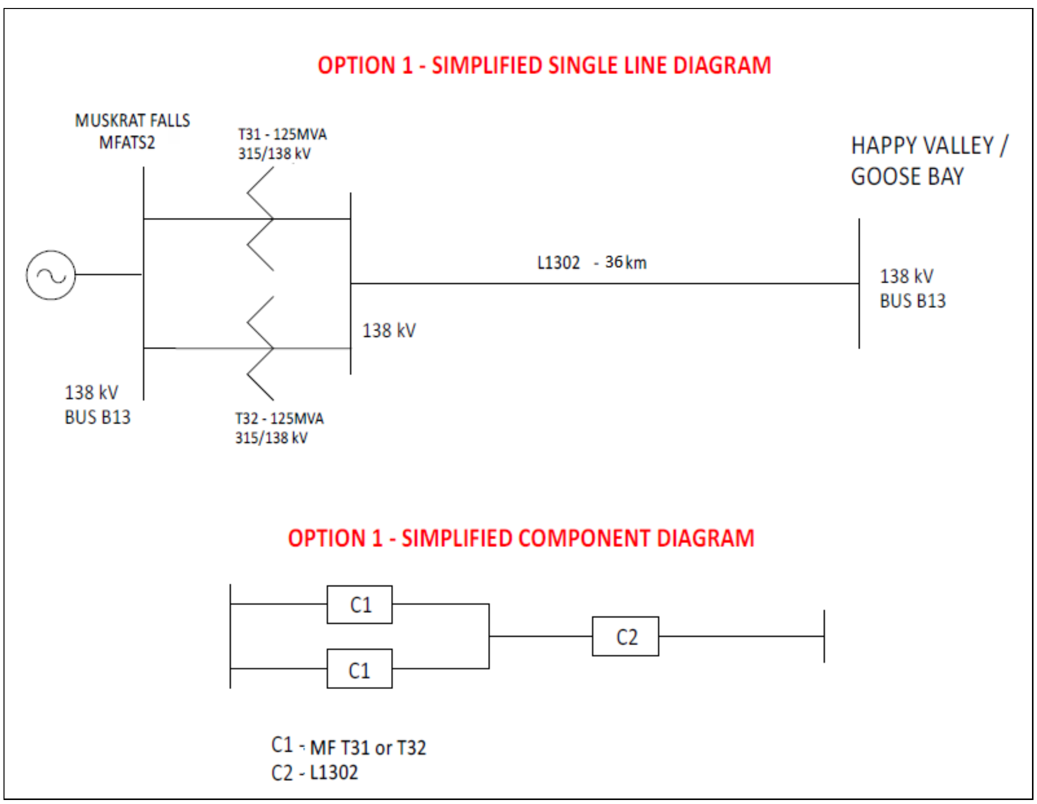


Figure 7 - Option 1: CF-T31 as a back-up supply to Labrador East

Table 4 - Sustained Outage Data

Component	Description	Freq (f)	Mean Time to Repair (r)		Unavailability
		occur/year	(hours)	(Years)	U (f × r)
C1	MF T31 or T32	0.1813	345.6	0.03945	0.00715
C2	L1302	0.2812[5]	12	0.00137	0.000385

Unavailability for Option 1 is derived by calculating the unavailability of the parallel combination of C1 and C1, in series with C2 as follows:

$U_{C1C1pa} = U_{C1} \times U_{C1} = 0.00751 \times 0.00751 = 0.0000564$

$U1 = U_{C1C1pa} + U_{C2} - (U_{C1C1pa} \times U_{C2}) = 0.0004414$

U1 = 0.0004414 or 0.04414%

[5] L1302 = (0.7811 occurrences / 100km.a) × 36 km = 0.2812.

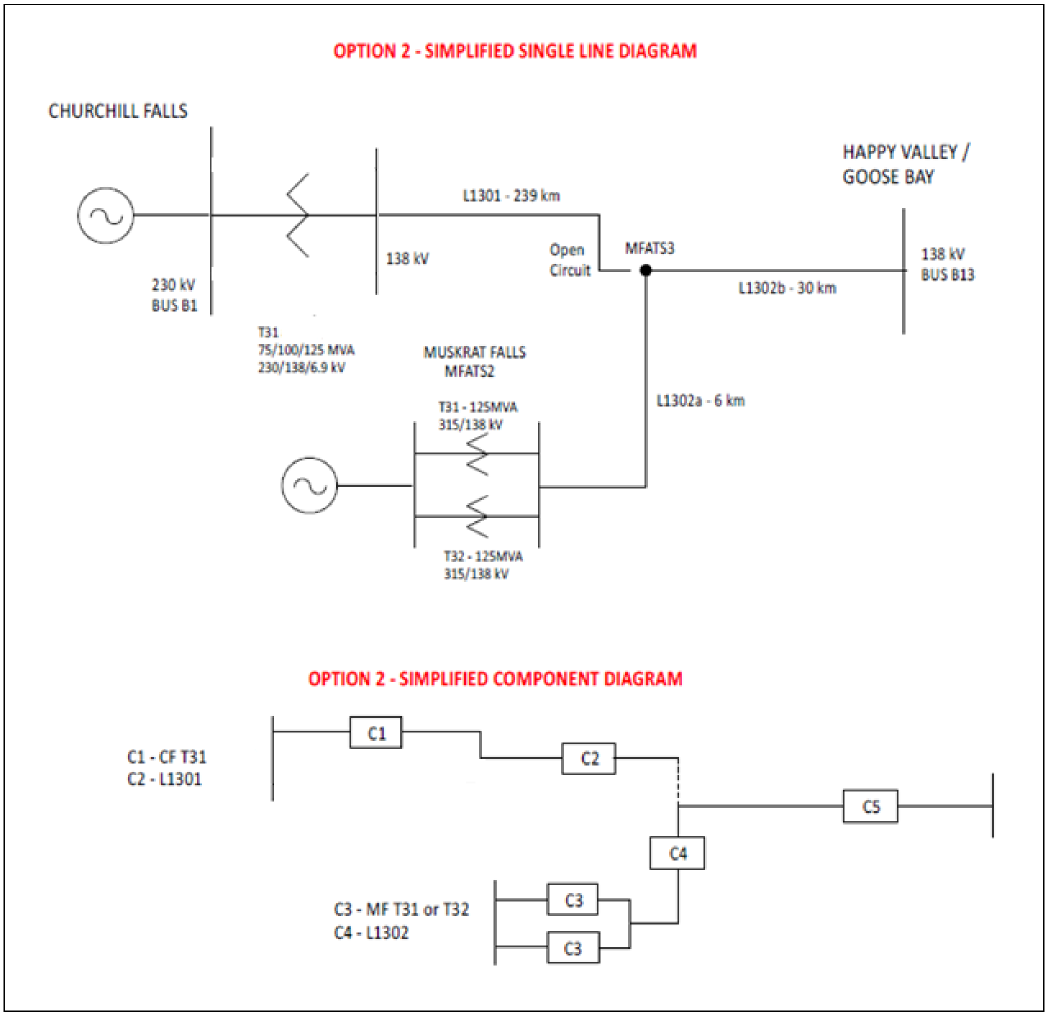


Figure 8 - Option 2: No back-up feed to Labrador East

Table 5 - Sustained Outage Data

Component	Description	Freq (f)	Mean Time to Repair (r)		Unavailability
		occur/year	(hours)	(Years)	U (f x r)
C1	CF T31	0.1356	222.2	0.02537	0.344
C2	L1301	1.8668[6]	12	0.00137	0.002558
C3	MF T31 or MF T32	0.1813	345.6	0.03945	0.00715
C4	L1302a (6km)	0.046866[7]	12	0.00137	0.0000642
C5	L1302b (30km)	0.23433[8]	12	0.00137	0.000321

Option 2 unavailability is derived by calculating the unavailability of the combination of:

i) Series combination of C1 and C2.

$U_{C1C2se} = U_{C1} + U_{C2} – (U_{C1} \times U_{C2}) = 0.344 + 0.002558 – (0.344 \times 0.002558) = 0.3457$

ii) Parallel combination of C3 and C3, in series C4.

$U_{C3C3pa} = U_{C3} \times U_{C3} = 0.00715 \times 0.00715 = 0.0000564$

$U_{C3C3paC4se} = U_{C3C3pa} + U_{C4} – U_{C3C3pa} \times U_{C4} = 0.0000564 + 0.0000642 – (0.0000564 \times 0.0000642) = 0.0001206$

iii) Parallel combination of items U_{C1C2se} (i) and $U_{C3C3paC4se}$ (ii) in series with C5.

$U_iU_{iipa} = U_i \times U_{ii} = 0.3457 \times 0.0001206 = 0.00004169$

$U_2 = U_iU_{iipa} + U_{C5} - (U_iU_{iipa} \times U_{C5}) = 0.00004169 + 0.000321-(0.00004169 \times 0.000321)$

U_2 = 0.0003627 or 0.03627%

Table 6 shows that the expected unserved energy difference between the scenarios is calculated to be in the order of 27 MWh. Both alternatives also provide an acceptable level of reliability in consideration of Hydro's business continuity criteria for an outage on the island is 300 GWh of unserved energy.[9] On this

[6] L1301 = (0.7811 occurrences / 100km.a) x 239 km = 1.8668.

[7] L1302a = (0.7811 occurrences/100km.a) x 6 km = 0.046866.

[8] L1302b = (0.7811 occurrences/100km.a) x 30 km = 0.23433.

[9] Muskrat Falls to Happy Valley Interconnection Report, revised January 25, 2018, page 41.

basis, it may be stated that the relative level of reliability of the two interconnection alternatives is approximately equal and that the there is no appreciable difference in expected unserved energy.

Table 6 - Unavailability/EUE Comparison of Options

Interconnection Option	Calculated Unavailability (U)	Calculated Expected Unserved Energy (MWh)[10]
1	0.0004414	147
2	0.0003627	120
	EUE Difference:	27

5 Cost Analysis – Purchase of Power Transformer from Nalcor Energy and Replacement of HRD-T7

On the basis of the above, there are three options with respect to the replacement of HRD-T7 and the purchase of CHF-T31 from Nalcor Energy:

1. Purchase the power transformer from Nalcor Energy for relocation to HRD
2. Purchase the power transformer from Nalcor Energy and leave it in place
3. Do not purchase the power transformer from Nalcor Energy

Engineering costs estimates were developed and the replacement of HRD-T7 with an equivalent 25/33.3/41.7 MVA unit is $2.99 million. If the CHF-T31 power transformer were to be purchased from Nalcor Energy, the estimated cost of the relocation to HRD is estimated to be $1.36 million.

On this basis, the power transformer should only be purchased from Nalcor Energy for a cost not to exceed $1.63 million. Otherwise, it would be more cost effective to purchase a new power transformer.

As stated in the previous section, there is no appreciable reliability benefit associated with the operation of L1301 as a backup for the transmission system in eastern Labrador. Any incremental costs associated with backup supply for this system are therefore not justifiable.

[10] Based upon the Happy Valley-Goose Bay 2020 annual energy requirement of 332 GWh.

6 Conclusion/Recommendations

The analysis outlined in this technical note concludes the following:

- HRD T7 must be replaced to ensure that there are violations to Transmission Planning Criteria.
- On the basis of a probabilistic reliability analysis, it is not justifiable to incur incremental costs to replace HRD T7 with a transformer with a rating that exceeds 25/33.3/41.7 MVA.
- The lowest cost options, consistent with reliable service, for the replacement of HRD-T7 are summarized as follows. Either:
  - Purchase a new 25/33.3/41.7 MVA power transformer at a cost of $2.99 million or
  - Purchase the 75/100/125 MVA power transformer that is owned by Nalcor Energy, currently being used as CHF-T31, for a cost not to exceed $1.63 million and relocate the unit to HRD at a cost of $1.36 million.
- There is no appreciable reliability benefit associated with the operation of L1301 as a backup for the transmission system in eastern Labrador. Any incremental costs associated with backup supply for this system are therefore not justifiable.

Document Summary

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Document Distribution:	H. Ireland, K. Layden, B. Eddy, R. Spurrell, D. Moore, D. Hicks, H. Richards, K. Tucker, L. Kingsley, M.Churchill, R. Champion, M. Couves, K. Hayward, G. Read, T. Gardiner, R. Leblanc, B. Butler, K.Goulding, J. Decoste, Transmission Planning

Revision History

Revision	Prepared by	Reason for change	Effective Date
1	M.Carter	Original Document	2019/02/15

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13. Overhaul Diesel Units - Various

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
DAVE ROYLE
SIGNATURE
7-23-19
DATE
NEWFOUNDLAND & LABRADOR

2020 Capital Budget Application
Overhaul Diesel Units
Various

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

This report presents the capital budget proposal for diesel unit overhauls that are performed on a usage-based schedule. Newfoundland and Labrador Hydro ("Hydro") has 24 diesel generating stations, 20 of which are the sole source of power to the community. The two main components of a diesel unit overhaul include the engine and alternator. Diesel engines are overhauled or replaced, depending on cost, approximately four times during the life of the diesel generation unit ("genset"), while the alternator is overhauled once during the life of the genset. The interval of performing overhauls has been reviewed and changed with 1200 RPM units now being overhauled at a 30,000 operating hour frequency and 1800 RPM units continuing to be overhauled at 20,000 operating hours. Overhauls are required to ensure each engine is able to meet its expected life of 120,000 hours for 1200 RPM units and 100,000 for 1800 RPM units.

This project proposal is for the overhaul of ten diesel engines and two alternators in 2020 at an estimated cost of $2,310,900. Hydro forecasts 33 overhauls over the 2020 to 2024 period.

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List of Appendices

1.0 Introduction

Hydro has 24 diesel generating stations. Twenty of these diesel generating stations are isolated and the sole source of power to the community, serving a total of approximately 4,400 customers. The number of diesel generating units at each generating station ranges from three to six generators and the rated output of the units ranges from 40 kW to 2,500 kW. The diesel engines across the system range in age from less than one year to 51 years, and currently range in operating hours from 535 to over 126,000[1]. These units operate at either 1200 or 1800 RPM.

2.0 Background

A diesel genset is the combination of a diesel engine with an electric alternator[2] used to generate electrical energy as shown in Figure 1. Gensets can be classified in one of three ways, depending on their mode of operation:

1) Continuous;
2) Prime; and
3) Standby/Emergency.

Continuous and prime gensets are very similar as they function as the main source of power and are designed to operate continuously or for extended periods of time. The major difference between the two is that continuous gensets are designed to operate continually with a consistent load while prime gensets are designed to operate for long durations at variable load. Standby/emergency gensets are to be run only when there is an outage or in a backup situation. For Hydro, prime power gensets are the class purchased based on the mode of operation for use in its isolated locations.

[1] As of March 31, 2019.
[2] An alternator is an electric generator that converts mechanical energy to electrical energy in the form of alternating current.

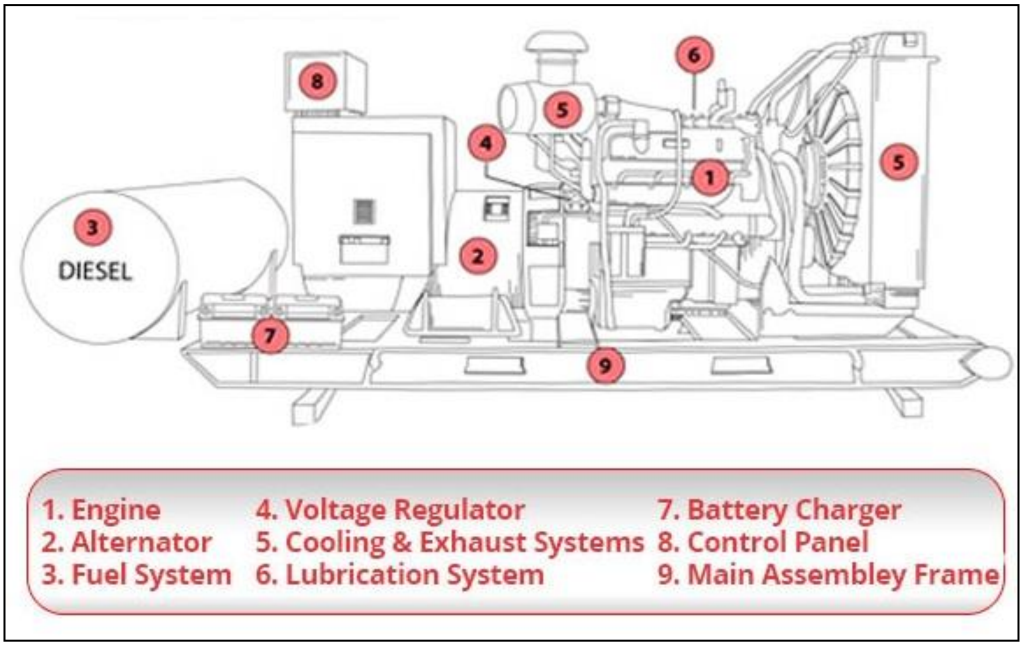

Figure 1: Diesel Genset

2.1 Existing System

Hydro historically overhauled diesel engines after 20,000 hours of operation, with complete replacement of the genset after 100,000 hours. Alternator overhauls were completed once in the lifetime of the genset. This usually takes place at 40,000-60,000 hours of operation during the second engine overhaul. Hydro has revised the overhaul and replacement timeline for 1200 rpm engines.

2.2 1200 RPM Engines Overhaul and Replacement

In recent years, Hydro has found that 1200 rpm diesel engines, and parts being replaced during unit overhauls, were in very good condition. In 2018, Hydro reviewed its overhaul and replacement timing for 1200 RPM and 1800 RPM engines, which had been every 20,000 hours of operation and replacement after 100,000 hours of service.

In 2018, at the Ramea Diesel Generation Station, the Original Equipment Manufacturer (“OEM”) Caterpillar inspected the 1200 rpm engine components as an engine was disassembled. The technician’s report indicated that the components replaced had minimal wear and the overhaul frequency could be extended based on the condition of the parts removed and the load profile of the engine.
Also in 2018, for 1200 RPM engines manufactured by MTU Onsite Energy (“MTU”), Hydro engaged the vendor, Wajax, to review load profiles for each 1200 rpm unit. Wajax determined that, based on the

load data and duty cycles of the MTU units Hydro has in service, the overhaul interval of these units could be increased to 30,000 hours.

After a review by Hydro found other utilities overhaul 1200 rpm diesel units after 40,000 hours, Hydro decided to start overhauling 1200 RPM units after 30,000 hours of operation and replacing these units after 120,000 hours of operation. If this change in overhaul frequency results in acceptable operation and maintenance results, Hydro will assess the possibility of a further extension of the overhaul frequency to 40,000 hours for its 1200 rpm engines. 1800 rpm engines will continue with an overhaul frequency of 20,000 hours of operation and replacement after 100,000 hours.

2.3 Units in Current Plan for 2020

Ten diesel engines and the two alternators for St. Lewis, unit 2080, and St. Anthony, unit 544, are projected to exceed their overhaul timing in 2020. The equipment to be overhauled is listed in Table 1.

Table 1: Overhaul List for 2020

Genset Location & Unit Number	Engine Rating (kW)	Engine Speed (RPM)	Alternator Rating[3] (kW)	Age (Years)	Year of Last Overhaul
Grey River 2062	232	1800	136	18	2015
Little Bay Islands 2058	232	1800	205	19	2016
McCallum 2063	238	1800	210	18	2011
St. Anthony 544	2000	720	2000	39	N/A
Charlottetown 2089	725	1800	725	7	2012
Postville 2096	450	1800	450	2	N/A
Cartwright 2036	450	1800	450	27	2010
Makkovik 2029	664	1800	450	29	2015
Nain 574	1007	1800	865	17	2010
Nain 591	1105	1200	750	5	N/A
St. Lewis 2080	529	1800	455	13	2017

2.4 Operating Experience

All the units identified in Table 1 are operational with most in regular daily service.

[3] The Alternator Rating is also the rating for the unit.

3.0 Analysis

3.1 Identification of Alternatives

During the 2018 overhauls it was realized that the cost of overhaul parts had significantly increased, but were subject to fluctuation. Based upon this information Hydro has determined that in some cases it may be cost comparable to replace the engine with a new engine instead of overhauling an existing engine. These new engines are also covered by a manufacturer's warranty. In these cases the engine must be available with acceptable delivery timing. While there are no alternatives to executing the project to overhaul or replace an engine that has reached the timing for intervention, when both options are possible and available, Hydro will select the least-cost option during execution of the project.

Overhauls performed on alternators by a third party, Siemens, have no alternative. The alternators are cleaned and rewound if necessary.

4.0 Project Description

Occasionally, a unit in one of the diesel plants across Hydro's operating area experiences an issue that necessitates an unplanned overhaul, or reaches the numbers of operating hours earlier than anticipated. Where appropriate, Hydro may complete such an overhaul under this project and, if possible, defer one of the units noted above that are planned for completion. In 2019 three engines previously approved for overhaul will not reach their forecasted hours and were subsequently moved to the 2020 Overhaul Diesel Units project. These units were Little Bay Islands 2058, McCallum 2063, and Charlottetown 2089. In 2019 three units (McCallum 2064, Mary's Harbour 2093, and Charlottetown 2092) will reach their overhaul timing earlier than planned and will be executed under the 2019 Overhaul Diesel Units project.

This current plan for the 2020 Overhaul Diesel Units project is to overhaul the following diesel engines:

- Grey River 2062;

- Little Bay Islands 2058;[4]
- McCallum 2063;
- Charlottetown 2089;
- Postville 2096;
- Cartwright 2036;
- Makkovik 2029;
- Nain 574;
- Nain 591; and
- St. Lewis 2080.

As the cost of parts may fluctuate, early in 2020 Hydro will determine the cost of the overhaul parts and replacement engines and select the least cost option with acceptable delivery. If an overhaul occurs it will include such items as pistons, liners, main bearings, connecting rod bearings, fuel injectors, oil cooler, turbo charger, water pump, oil pump, cylinder heads, fuel lines, fuel pumps and gaskets. In addition, the following units will have their alternators overhauled:

- St. Anthony 544; and
- St. Lewis 2080

The project estimate is shown in Table 2.

Table 2: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	1,027.0	0.0	0.0	**1,027.0**
Labour	707.9	0.0	0.0	**707.9**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	88.0	0.0	0.0	**88.0**
Other Direct Costs	205.1	0.0	0.0	**205.1**
Interest and Escalation	75.9	0.0	0.0	**75.9**
Contingency	207.0	0.0	0.0	**207.0**
Total	**2,310.9**	**0.0**	**0.0**	**2,310.9**

[4] The residents of Little Bay Islands have voted to relocate. It is likely that this will happen in 2020, and if so this overhaul will not be completed.

The project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning:		
Schedule annual overhauls.	February 2020	September 2020
Procurement:		
Purchase overhaul components.	March 2020	October 2020
Installation:		
Complete overhaul.	April 2020	November 2020
Commissioning:		
Testing after overhaul.	April 2020	November 2020
Closeout:		
Release for service and asset assignment.	December 2020	December 2020

5.0 Conclusion

Hydro overhauls 1200 rpm engines after 30,000 hours of operation with replacement after 120,000 hours and 1800 rpm engines after 20,000 hours of operation with replacement after 100,000 hours. Hydro has determined, based upon the cost of replacement parts, installation, and travel costs that it may be cost effective to replace an engine instead of overhauling it, if a replacement engine is available with acceptable delivery. As the cost of parts can fluctuate, Hydro will execute the lowest cost alternative for each of the engines overhauls.

This project is proposed to facilitate the maintenance of reliable operation of the units listed in the Project Descriptions.

Appendix A

Diesel Engine Overhaul Five-Year Plan

Table A-1: Diesel Engine Overhaul Five-Year Plan

2020	
Grey River 2062	2020
Little Bay Islands 2058	2020
McCallum 2063	2020
Charlottetown 2089	2020
Cartwright 2036	2020
Makkovik 2029	2020
Nain 574	2020
Nain 591	2020
Postville 2096	2020
St. Lewis 2080	2020
2021	
Grey River 2067	2021
Black Tickle 582	2021
Cartwright 2086	2021
Rigolet 2081	2021
Mary’s Harbour 2090	2021
2022	
Francois 587	2022
Cartwright 2045	2022
Hopedale 2074	2022
Nain 2085	2022
Paradise River 324	2022
L’Anse Au Loup 2012	2022
Norman Bay 581	2022
Port Hope Simpson 2073	2022
2023	
Francois 588	2023
St. Brendan’s 2055	2023
Postville 2084	2023
Charlottetown 2088	2023
Charlottetown 2087	2023
Mary’s Harbour 2093	2023
2024	
Ramea 2077	2024
Hopedale 590	2024
Paradise River 585	2024
St. Lewis 2080	2024

14. Diesel Plant Fire Protection (2020–2021)

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2020 Capital Budget Application
Diesel Plant Fire Protection (2020–2021)

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Without automated fire protection, Newfoundland and Labrador Hydro's ("Hydro") experience has been that fire related damage to a Diesel Generating Plant may be extensive and result in in an extended customer outage. In 2014, Hydro initiated a program to install automatic fire protection systems to mitigate the risk of fire damage to its Diesel Generating Stations.

Hydro is proposing a project to install an automated fire protection system in the Charlottetown Diesel Generating Plant to mitigate the risk of a fire destroying or damaging equipment. The project is estimated to cost approximately $1,867,900 with scheduled completion in 2021.

Contents

1.0 Introduction

Hydro currently has 16 generating plants without a fire suppression system. There have been six fires in Hydro’s diesel generating plants, resulting in the loss of equipment and facilities and causing customer outages up to 50 hours in duration. In 2014, Hydro commenced a program to install automatic fire protection systems in its diesel generating plants.

Figure 1: Charlottetown Diesel Generating Plant

2.0 Background

When Hydro’s diesel generating plants were constructed, they were not fitted with automatic fire suppression systems. After experiencing a number of fires that caused large scale station damage and unplanned power outages, Hydro started a program in 2014 to install automatic fire suppression systems. To date, four installations have been completed. The type of system installed is referred to as a hybrid nitrogen water mist suppression system. It sprays a mixture of water mist and nitrogen gas onto the fire to form a blanket that absorbs heat and displaces oxygen thereby extinguishing the fire.

Figure 2: Diesel Generators In Powerhouse

2.1 Existing System

The Charlottetown Diesel Generating Plant is equipped with a fire detection system that consists of heat detectors, manual pull stations, fire alarm annunciation control panels, audible alarms, and auto dialers. When a fire is detected, the fire alarm system will alarm and the auto dialer will attempt to contact the shift operator or Energy Control Center in St. John's. In addition, the control panel, which interfaces with the plant's operating equipment, is activated to shut down all ventilation systems and on-line generators. The plant is also equipped with a number of portable fire extinguishers. Extinguishing a fire is done by plant personnel or by the local volunteer fire department. The Diesel Generating Plant is not staffed 24 hours per day, so if a fire occurs during the time the plant is not staffed then greater damage may occur due to the response time to initiate firefighting.

3.0 Analysis

There were four alternatives considered. The selected alternative uses a mixture of a fine water mist and nitrogen gas for fire suppression. The system works in areas where an adequate supply of water limits the application of water based systems.

Consideration was given to other types of automatic fire suppression systems, but each option was rejected as follows:

- Energyn: Unacceptable due to risk of inadequate fire suppressing performance for this type of application as it was judged that the building envelope would allow the Energyn to leak out of the building before proper suppression can be established;
- Water Mist: Unacceptable due to inadequate water supply in the immediate area. Installing a suitable water supply would increase the project cost significantly; and
- Water Sprinklers: Unacceptable due to inadequate water supply in the immediate area. Installing a suitable water supply would increase the project cost significantly.

4.0 Project Justification

This project is required to minimize the damage that could result if a fire were to occur in the Charlottetown Diesel Plant. The damage could result in the community being left without power for an extended period of time.

5.0 Project Description

This proposed project will install an automated fire protection system at the Charlottetown Diesel Generating Plant. The work includes:

- Design, procurement, installation, and commissioning of a hybrid nitrogen water mist fire protection system; and
- Installation of a new storage shelter for nitrogen cylinders, water cylinders, pipe distribution system, monitoring/activation system, and associated equipment outside the powerhouse, including required foundations, electrical work, and ventilation.

The project estimate is presented in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	86.9	104.6	0.0	**191.5**
Consultant	60.0	60.0	0.0	**120.0**
Contract Work	0.0	1,258.9	0.0	**1,258.9**
Other Direct Costs	5.7	8.1	0.0	**13.8**
Interest and Escalation	8.7	116.6	0.0	**125.3**
Contingency	15.2	143.2	0.0	**158.4**
Total	**176.5**	**1,691.4**	**0.0**	**1,867.9**

The project schedule for the project is presented in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Open work order, plan and develop detailed schedules	January 2020	February 2020
Engineering:		
Site visit, design for design/specification for tender/procurement of storage shelter.	February 2020	May 2020
Site visit, design for design/spec for fire protection contract.	March 2020	September 2020
Procurement:		
All the required materials for supply and installation contract develop and publish tender.	October 2020	February 2021
Construction:		
Install new storage shelter.	May 2021	July 2021
Install new fire protection system.	July 2021	September 2021
Commissioning:		
Confirm operation and release to operations.	September 2021	October 2021
Closeout:		
Close work order, complete all documentation, and complete lessons learned	October 2021	November 2021

6.0 Conclusion

The Charlottetown Diesel Generating Plant is not equipped with a fire protection system. Hydro relies on plant personnel, or the local volunteer fire department, to extinguish a fire in the plant. Fires in diesel generating stations without automatic fire protection systems have resulted in the loss of equipment and facilities, and extended outages to customers.

Hydro is proposing a project to install an automated fire protection system to mitigate the risk of a fire destroying or damaging equipment.

15. Replace Powerhouse Roofing System – L'Anse Au Loup and St. Anthony

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2020 Capital Budget Application
Replace Powerhouse Roofing System
L'Anse Au Loup and St. Anthony

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

The powerhouse roofing systems for Newfoundland and Labrador Hydro's ("Hydro") L'Anse au Loup and St. Anthony Diesel Generating Stations have performed well since their original installations; however, at nearly 50 years of age, they are nearing the end of their anticipated service lives. Exposed seams, in conjunction with enlarged fastener penetrations, have resulted in the formation of leaks within the engine hall, office, and storage areas.

Failure to restore the integrity of the roofing system will result in continued infiltration of water. This will inevitably lead to deterioration of the powerhouse structure and poses a water damage risk to the sensitive electrical equipment and other infrastructure.

This is a two year project with detailed design completed during the first year of the project and completion of the roof replacements in 2021.

The project estimate is $1,321,100.

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1.0 Introduction

Hydro's L'Anse au Loup and St. Anthony Diesel Generating Station powerhouse roofing systems are nearly 50 years of age and in recent years they have developed leaks within the engine hall, office, and storage areas. Attempts to seal the roofing system have not been effective and leaks have continued to develop. Replacement is required to arrest the infiltration of water into the powerhouse.

2.0 Background

2.1 Existing System

Hydro's L'Anse au Loup and St. Anthony Diesel Generating Stations were constructed in 1974 and 1970, respectively. The powerhouse structures are comprised of pre-engineered, metal buildings complete with a roll formed panel roofing system. These facilities house the generation units required to satisfy electrical load requirements.

2.2 Operating Experience

The roofing systems have generally performed well since their original installation; however, with both systems at nearly 50 years of age they have developed leaks and are nearing the end of their anticipated service life. Figure 1 provides typical condition of these roof systems.

Figure 1: Typical roof panel condition

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Many of the roof panel fasteners have failed due to the effects of corrosion and movement of the panels as a result of vibration and flexure throughout the years. In many cases the fasteners have widened the holes in the panels, enabling the infiltration of water and compromising their connection to the substructure. The St. Anthony and L'Anse Au Loup Diesel Plants are located in exposed areas, frequented by high winds. Failure to replace the fasteners could inevitably result in catastrophic failure of the roof panels. The movement of the roof panels have also caused the seams to fail over time, as panels have deformed and no longer provide an adequate seal along their seam line. These failed seams have contributed the formation of leaks throughout the buildings.

Attempts to repair the leaks through the application of an elastomeric roof panel coating system, as shown in Figures 2 and 3, have only provided short-term elimination of leaks.

Figure 2: Previous attempt to repair leaks with elastomeric coating system

Figure 3: Ineffective elastomeric coating system

2.3 Maintenance History

In the past 5 years, numerous repairs have been enacted to address the leaking roofs. Since the application of an elastomeric roof coating system, frequent repairs to the roof mounted exhaust fan flashing have been completed. The repairs have provided short term relief and the leaks have reoccurred.

3.0 Analysis

3.1 Identification of Alternatives

The alternatives considered to restore the integrity of the powerhouse roofing system included:

1) The application of an elastomeric roof coating system applied to the existing roof panels;
2) Application of a new roof system over the existing metal roof panels; and
3) Replacement of the metal roof panels.

3.2 Evaluation of Alternatives

The application of elastomeric roof coatings to extend the service life of roofing systems is a common practice in today's industry. These coatings can increase energy efficiency, protect the roofing membrane from the damaging effects of the environment, and can be a cost effective alternative to increase a roof's service life. These coatings can be used directly to stop minor leaks; however, repairs to address larger penetrations, failed seams, and corroded roof fasteners would be required prior to the application of such a system. Previous attempts to repair leaks with such a system have proven to be a short-term fix. Also, this option does not expose the existing roof insulation for removal and replacement. Failure to remove and replace the insulation could result in the formation of mold, which typically develops in insulation that has been exposed to water. For these reasons, this alternative was rejected.

The application of a new roofing system, directly over the existing metal roof, has a cheaper installation cost; however, there are a number of issues associated with this option. As with the elastomeric coating system, this option does not permit the removal and replacement of the roofing insulation. Furthermore, the existing powerhouses are pre-engineered structures. These structures are manufactured following an economy based design philosophy, which minimizes the size of structural members. While cost effective, these buildings do not generally have the structural capacity required to support the addition of the dead load associated with this alternative. For these reasons, this alternative was rejected.

The recommended alternative is the replacement of the metal roofing panels, which will resolve the current issues with the powerhouse roofing and ensure that the integrity of the powerhouse roofing systems is maintained for the next 40-50 years. This alternative also allows the replacement of the existing roof insulation, which will eliminate the potential for future mold formation.

4.0 Project Description

This project will replace of the powerhouse metal panel roofs for Hydro's L'Anse au Loup and St. Anthony Diesel Generating Stations.

The scope of work includes the following:

- The completion of the designs for each location, including the preparation of architectural details for various roof, flashing, and trim components, and design of roof top fall protection system;
- Replacement of existing roof insulation, metal roofing panels, and ridge venting; and
- Supply and installation of permanent fall protection system.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	64.3	78.8	0.0	**143.1**
Consultant	42.7	108.4	0.0	**151.1**
Contract Work	0.0	792.7	0.0	**792.7**
Other Direct Costs	1.9	9.3	0.0	**11.2**
Interest and Escalation	7.6	88.8	0.0	**96.4**
Contingency	8.8	117.8	0.0	**126.6**
Total	**125.3**	**1,195.8**	**0.0**	**1,321.1**

The project schedule is provided in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning: Budget Review, Scope Statement , Risk Assessment	February 2020	February 2020
Design: Complete Design, Prepare Tender Package	March 2020	August 2020
Procurement: Tender and Award Roof Replacement Contract	February 2021	March 2021
Construction: Replace Powerhouse Roofs (STA & LAL)	June 2021	September 2021
Closeout: Project Completion, Interest Cut-Off	October 2021	November 2021

5.0 Conclusion

The L'Anse au Loup and St. Anthony Diesel Generating Station powerhouse roofing systems are nearing the end of their service lives. The infiltration of water poses a risk to the electrical equipment housed within these structures. Previous attempts to repair the roofs via the application of an elastomeric coating system have proven to be a short-term solution. Given the roofing system's age and condition, replacement is required to ensure the integrity of the building envelopes.

16. Diesel Plant Ventilation Upgrade - Nain

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2020 Capital Budget Application
Diesel Plant Ventilation Upgrade
Nain

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") owns and operates 24 diesel powered generation plants. Most are located in remote coastal areas of Newfoundland and Labrador and are not staffed 24 hours per day.

The diesel plant in Nain was built in 2002 and is a two story building that houses four diesel generators ("gensets") with a combined capacity of 3,865 kW. At the time of construction a ventilation system was installed to exchange air inside the building with outside air and to ensure a minimum number of air changes take place each hour. This was required for two reasons. One was to extract stale air containing fumes and odors from the building, and the other was to ensure the engine hall did not exceed an acceptable ambient air temperature due to heat build-up from the gensets. Since the plant was constructed additional generation has been added, increasing ventilation requirements, but the ventilation system has not been upgraded since that time.

The ventilation system has been effective in preventing the build-up of stale air and fumes inside the building but in the summer months it does not provide adequate cooling of the engine hall. During the summer the gensets have operated in ambient temperatures of 40°C and higher. These temperatures are above the equipment design specifications required to ensure reliable unit performance and to ensure that service life is not negatively impacted. The manufacturer advises that for engine hall temperatures exceeding 40°C the generators must be de-rated as per their generator de-rate schedule.

In addition to insufficient cooling capability of the ventilation system, the exhaust fans are in poor condition. They also have high maintenance costs due to their internal design and roof mounted installation.

This project is required to provide adequate diesel plant cooling and allow more efficient maintenance of the ventilation system.

The project estimate is $853,100 with scheduled completion in 2021.

Table of Contents

1.0 Introduction

The Nain Diesel Generating Plant (see Figure 1) was built in 2002 and houses four diesel generators with a combined capacity of 3,865 kW. The plant is the only source of electric power for this isolated community.

Figure 1: Nain Diesel Generating Plant

2.0 Background

The Nain Diesel Generating Plant ventilation system was designed and installed when the plant was constructed in 2002. At that time it was fitted with three 865 kW gensets (See Figure 2). In 2008 a fire damaged one genset and it was replaced with a larger 1,275 kW unit. A fourth genset with a capacity of 860 kW was added in 2014. Although these larger units were installed, there were no modifications to the original plant ventilation system.

Figure 2: Nain Diesel Generators in Powerhouse

2.1 Existing System

The ventilation system at Nain Diesel Generating Plant includes three exhaust fans and four intake fans. The intake fan and hood assemblies are located in an exterior wall and the exhaust fans are installed on the roof (see Figure 3). The fans are arranged to take in cool air from the outside, pass it across the gensets, and then discharge it to the outside. It displaces heated air created during operation and exhausts it to the outside.

Figure 3: Nain Plant Existing Ventilation Arrangement with Roof Top Exhaust Fan

2.2 Operating Experience

In the summer months the ventilation system does not provide adequate cooling of the engine hall. During the summer the gensets have operated in ambient plant temperatures of 40°C and higher. These temperatures are above the equipment design specifications required to ensure reliable unit performance as well as ensure that service life is not negatively impacted. The manufacturer advises that for engine hall temperatures exceeding 40°C the generators must be de-rated as per the generator de-rate schedule. In the summer months, the doors to the engine hall often need to be left open to help cool the area. Leaving doors open leads to dust and dirt entering the building, negatively affecting unit performance when drawn into the generators.

The existing ventilation system includes belt driven roof mounted exhaust fans that require frequent belt and bearing replacements. In addition exposure to severe wind gusts has caused damage to fan hoods (see Figure 4).

Figure 4: Nain Plant Ventilation Damaged Weather Hoods

3.0 Alternatives and Analysis

Consideration was given to two alternatives:

1) Industrial Air Conditioning and Ventilation System: This alternative would utilize refrigeration technology. It would include new evaporator and condenser units along with associated fans, pumps, piping, and controls to provide increased cooling to the engine hall. New air conditioning components are large and installation would require significant renovations to the plant. In addition the existing ventilation system would remain, but would require modification.

2) Upgrade Existing Ventilation System: This alternative would consist of an upgrade to the existing ventilation system and expansion of the overall capacity by installing new higher capacity supply and exhaust fans. The hot air and fumes/odors produced in the engine hall would be discharged through wall mounted exhaust fans.

The estimated cost of Alternative 1 would be in excess of double that of Alternative 2, the maintenance cost would be higher, and Alternative 1 would require more electricity to operate. Hydro is recommending Alternative 2.

4.0 Project Description

The scope of work for this project includes:

- Partial removal of the existing ventilation system and roof repairs after the exhaust fans have been removed; and
- Supply and installation of new fans, louvers, dampers, hoods, motor starters, thermostats, and other associated equipment.

The project estimate is provided in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	78.7	91.9	0.0	**170.6**
Consultant	50.0	30.0	0.0	**80.0**
Contract Work	0.0	425.0	0.0	**425.0**
Other Direct Costs	5.7	8.1	0.0	**13.7**
Interest and Escalation	8.2	52.2	0.0	**60.4**
Contingency	20.2	83.2	0.0	**103.4**
Total	**162.7**	**690.4**	**0.0**	**853.1**

The project schedule is provided in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules.	January 2020	March 2020
Engineering: Site visit, design for ventilation system and specification tender/procurement.	March 2020	Sept 2020
Procurement: All the required materials for supply and installation, contract development, and publish tender.	October 2020	February 2020
Construction: Remove old ventilation system and install new ventilation system.	July 2021	August 2021
Commissioning: Run up the new ventilation system, confirm operation, and release to operations.	August 2021	August 2021
Closeout: Close work order, complete all documentation, and complete lessons learned.	September 2021	September 2021

5.0 Conclusion

The operating temperatures within the Nain Diesel Plant generator hall are above the criterion recommended by the diesel manufacturer, risking accelerated deterioration and derating of the equipment. Upgrades are required to the plant ventilation system to ensure maximum generating capacity and continued reliable operation of the generating units.

17. Additions for Load – Distribution System – Makkovik and Hopedale

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July 29/19
DATE
NEWFOUNDLAND & LABRADOR

2020 Capital Budget Application
Additions for Load – Distribution System
Makkovik and Hopedale

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

The peak demand in both Makkovik and Hopedale is growing and an analysis of the most recent forecast has indicated that in 2020, during peak load, voltage levels that violate Newfoundland and Labrador Hydro's ("Hydro") Distribution Planning Criteria[1] are expected to occur.

A number of upgrade alternatives were considered to address the expected low voltages on each system. The least-cost alternative for both systems is to upgrade the primary conductor along the main section (trunk) of the distribution line from 1/0 AASC[2] to 477 ASC[3] so as to ensure distribution systems adequately supply the projected load growth in both communities.

The Hopedale portion of the project will involve reconductoring 1.8 km of the feeder trunk, beginning at the diesel plant. The Makkovik portion of the project will involve reconductoring 1.3 km of the feeder trunk, beginning at the diesel plant, as well as upgrading 500 m of single-phase distribution line to three-phase distribution line.

The estimated project cost is approximately $846,100 with planned completion in 2020.

[1] Hydro's Distribution Planning Criteria are a set of criterion that ensures an adequate supply of power to customers served on Hydro's distribution systems. These criteria are described and explained in Appendix A to this report. Hydro's Distribution Planning Assumptions are attached in Appendix B.
[2] Aluminum alloy stranded conductor.
[3] Aluminum stranded conductor.

Contents

List of Appendices

1.0 Introduction

As new customers are added to distribution systems and existing customers use more electrical power, both the peak demand and energy requirements of communities grow. To support additional peak demand and energy requirements, Hydro must at times upgrade and add new infrastructure to ensure the continued supply of quality power.

1.1 Existing System

1.1.1 Hopedale

The Hopedale Distribution System is comprised of a single 4.16 kV distribution line ("feeder") that connects customers to the diesel generating station. This feeder serves the entire coastal Labrador town of approximately 574 residents.[4] The primary and neutral conductors of the Hopedale system mainly consist of 1/0 AASC. The layout of the distribution system and expected area of load growth can be seen in Figure 1.

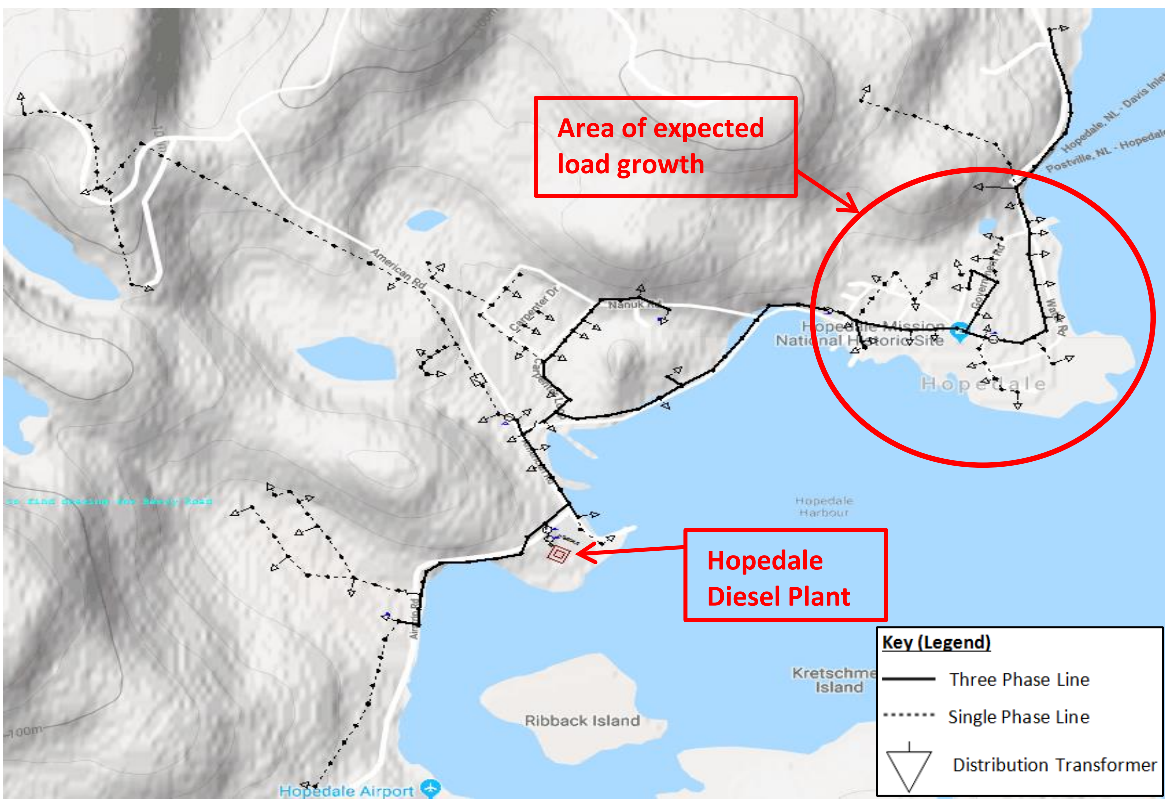

Figure 1: Layout of Hopedale Distribution System

[4] Statistics Canada–2016 Canadian Census Data.

1.1.2 Makkovik

The Makkovik Distribution System is comprised of a single 4.16 kV distribution line that connects customers to the diesel generating station. This feeder serves the entire coastal Labrador town of approximately 377 residents.[5] The primary and neutral conductors of the Makkovik Distribution System mainly consist of 1/0 AASC. The layout of the distribution system and expected area of load growth can be seen in Figure 2.

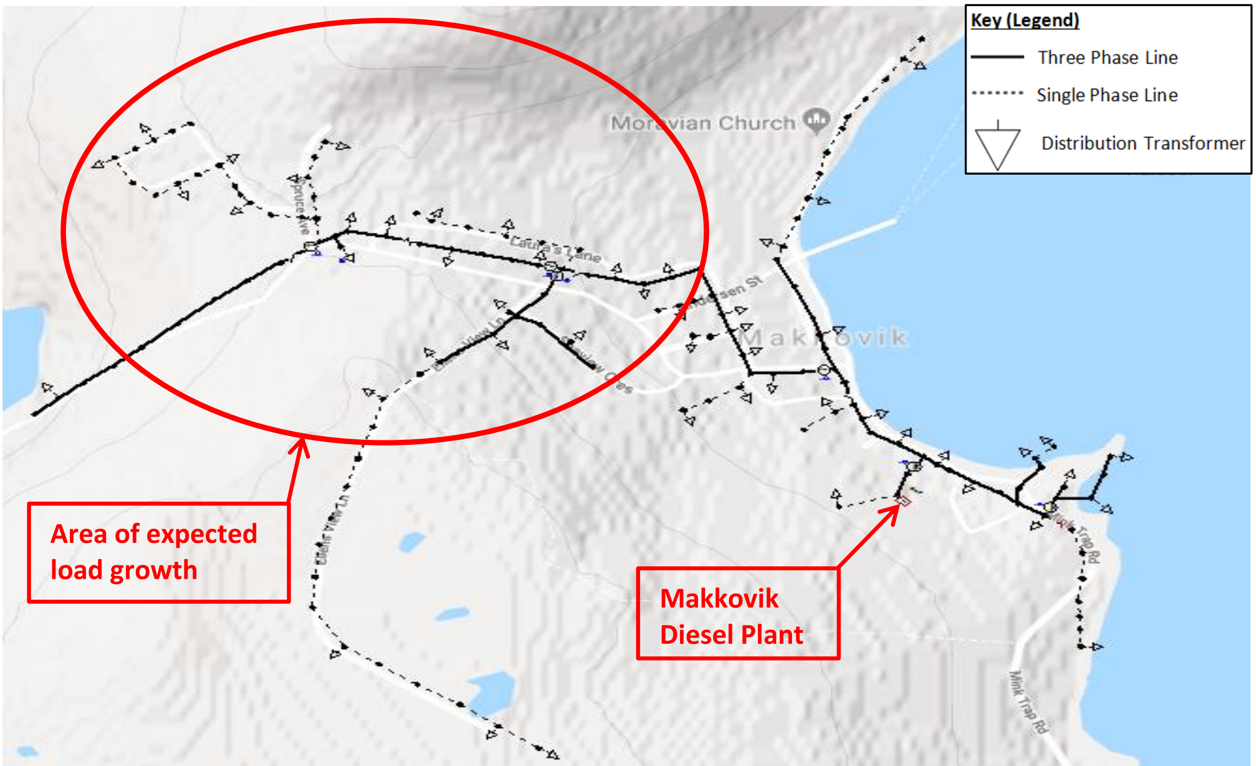

Figure 2: Layout of Makkovik Distribution System

1.2 Operating Experience

1.2.1 Hopedale

The Hopedale Distribution System has experienced continued load growth over the last decade. This load growth is due to new services like the multi-purpose facility connected in 2015 as well as existing residential and general service buildings converting from oil or wood to electric heat. The historic peak load and energy consumption of the Hopedale Distribution System from 2014 to 2018 is shown in Figure 3.[6]

[5] Statistics Canada - 2016 Canadian Census Data.
[6] The values in Figure 3 and Figure 4 are the system's gross peak loads recorded at the diesel plant and include the power used by the plant's station service load in addition to the community load.

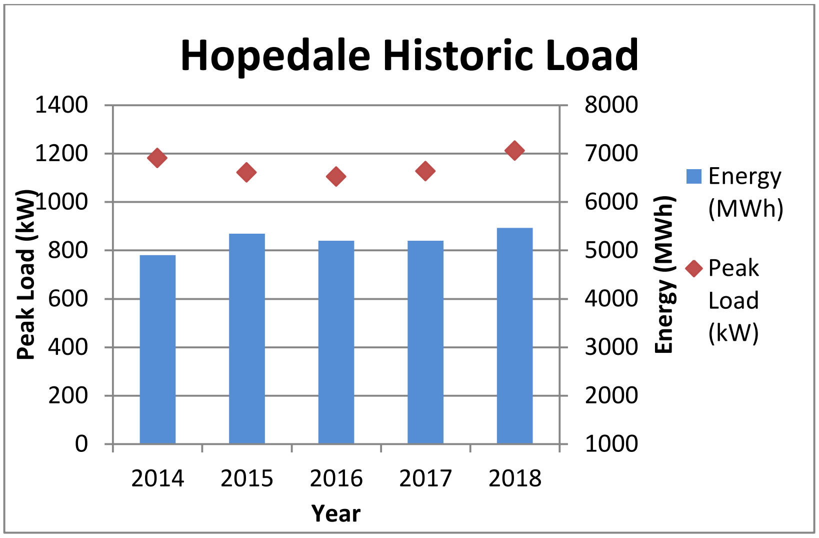

Figure 3: Hopedale Historic Load

1.2.2 Makkovik

The Makkovik Distribution System has experienced continued load growth over the last decade. This load growth is due to new services like the recreation facility and ice rink connected in 2017 as well as existing residential and general service buildings converting from oil or wood to electric heat. The historic peak load and energy consumption of the Makkovik Distribution System from 2014 to 2018 is shown in Figure 4.

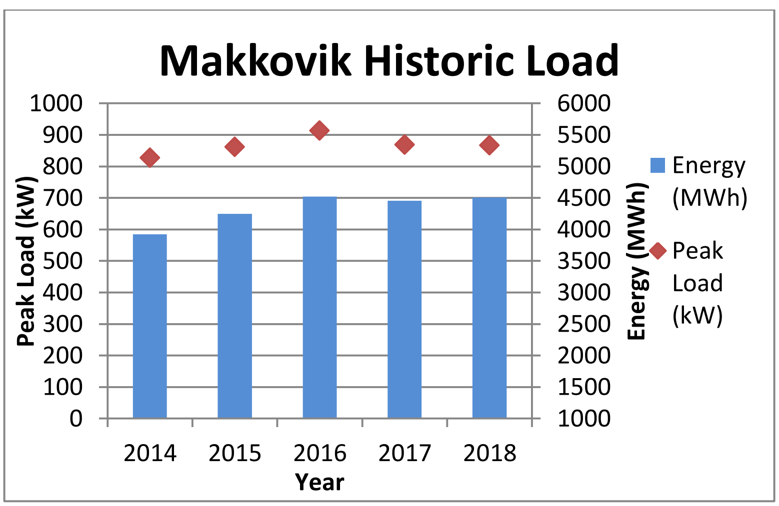

Figure 4: Makkovik Historic Load

2.0 Analysis

2.1 Forecasted Load Growth

Hydro has prepared base case and high growth forecasts for the anticipated loads in Makkovik and Hopedale to 2040.

The base case forecast includes the existing load in each community and the expected load growth over the next 20-plus years and is used to determine when upgrades to the distribution system are required.

The high growth forecast includes the base case load and additional load for growth that may occur up to 2040. The high growth forecast is used in a sensitivity analysis to test the robustness of the alternatives for each system. The 2018 base case and high growth peak load forecasts for the Hopedale and Makkovik Distribution Systems are presented in Table 1 and Table 2, respectively.

Table 1: Hopedale Distribution System Peak Load Forecast

Year	Gross Peak (kW)	
	Base Case	High Growth
2018	1,210	1,285
2019	1,259	1,338
2020	1,304	1,383
2021	1,334	1,413
2022	1,342	1,421
2023	1,350	1,429
2024	1,383	1,443
2025	1,418	1,469
2026	1,439	1,521
2027	1,461	1,540
2028	1,475	1,559
2029	1,490	1,579
2030	1,505	1,603
2031	1,520	1,619
2032	1,535	1,634
2033	1,551	1,650
2034	1,566	1,699
2035	1,574	1,718
2036	1,582	1,732
2037	1,590	1,746
2038	1,598	1,760
2039	1,606	1,772
2040	1,614	1,784

Table 2: Makkovik Distribution System Peak Load Forecast

Year	Gross Peak (kW)	
	Base Case	High Growth
2018	988	1,068
2019	1,003	1,086
2020	1,015	1,097
2021	1,024	1,107
2022	1,030	1,113
2023	1,034	1,117
2024	1,067	1,152
2025	1,096	1,173
2026	1,120	1,185
2027	1,135	1,197
2028	1,150	1,210
2029	1,159	1,241
2030	1,165	1,249
2031	1,172	1,257
2032	1,178	1,268
2033	1,185	1,299
2034	1,191	1,310
2035	1,198	1,321
2036	1,201	1,327
2037	1,204	1,352
2038	1,207	1,359
2039	1,211	1,367
2040	1,214	1,375

2.2 Identification of Alternatives

Whenever distribution planning criteria violations are forecasted to occur on a distribution system, Hydro investigates various technical options to prevent the violations from occurring. The common technical options studied by Hydro are:

- Load transfers;
- Single-phase to three-phase line conversion;
- Installation of voltage regulators;
- Replace existing equipment with equipment that has higher ratings;
- Increase conductor size (Reconductor);
- Voltage conversion;
- Relocate equipment; and
- Construct a new distribution feeder.

2.2.1 Hopedale

For Hopedale, the common technical options were evaluated resulting in four technically viable alternatives as follows:

1) Replace existing analog voltage regulators with digital voltage regulators on the diesel generators to provide operation with more stable source voltage allowing the use of higher voltages on the distribution system;
2) Upgrade 1,800 m of the feeder's main section in Hopedale from 1/0 AASC primary and neutral to a larger 477 ASC primary and 4/0 AASC neutral;
3) Construction of a second distribution feeder from the Hopedale substation to the area of the load growth (as shown in Figure 1) combined with upgrading 1,400 m of the existing feeder trunk with a larger conductor; and
4) Convert the Hopedale Distribution System operating voltage from 4.16 kV to 25 kV.

2.2.2 Makkovik

For Makkovik the common technical options were evaluated resulting in three technically viable alternatives as follows:

1) Upgrade 1,300 m of the feeder's main section in Makkovik from 1/0 AASC primary and neutral to a larger 477 ASC primary and 4/0 AASC neutral. Also includes converting 500 m of single-phase 1/0 AASC distribution line to three-phase 477 ASC distribution line;
2) Construction of a second distribution feeder out of the Makkovik substation to the area of the load growth (as seen in Figure 2). Also includes converting 500 m of single-phase 1/0 AASC distribution line to three-phase 477 ASC distribution line; and
3) Convert the Makkovik Distribution System operating voltage from 4.16 kV to 25 kV. Also includes converting 500 m of single-phase 1/0 AASC distribution line to three-phase 477 ASC distribution line.

2.3 Evaluation of Alternatives for Hopedale

2.3.1 Hopedale Alternative 1: Install New Automatic Voltage Regulators

This alternative involves replacing the automatic voltage regulators at the diesel plant with new digital technology that would make the source voltage more stable and allow the voltage set point to be increased. However, this project is only a temporary solution since voltages on the distribution system would fall below the normal operating limits in 2029 for the base case loads or in 2023 for the high growth loads. Further capital work would be required to address these voltage concerns. For the purpose of economic analysis it was assumed that in 2029 Hydro would reconductor, as per alternative 2, to supply adequate distribution voltages for the study period. The capital cost to install the new voltage regulators is $120,600. This alternative results in no significant reduction in electrical losses and therefore there are no savings associated with displaced fuel consumption related to energy loss savings.

2.3.2 Hopedale Alternative 2: Reconductor 1,800 m of Feeder Trunk

This alternative involves replacing 1,800 m of the feeder trunk that currently uses a 1/0 AASC primary and neutral with a larger 477 ASC primary and 4/0 AASC neutral. The reconductoring will begin at the diesel plant and continue along American Road before turning onto Water Road. A map of this alternative is show in Figure 5. The capital cost to reconductor 1,800 m of three-phase distribution line is $357,000. This alternative will reduce electrical losses on the system, which will save approximately $21,900 worth of fuel each year.

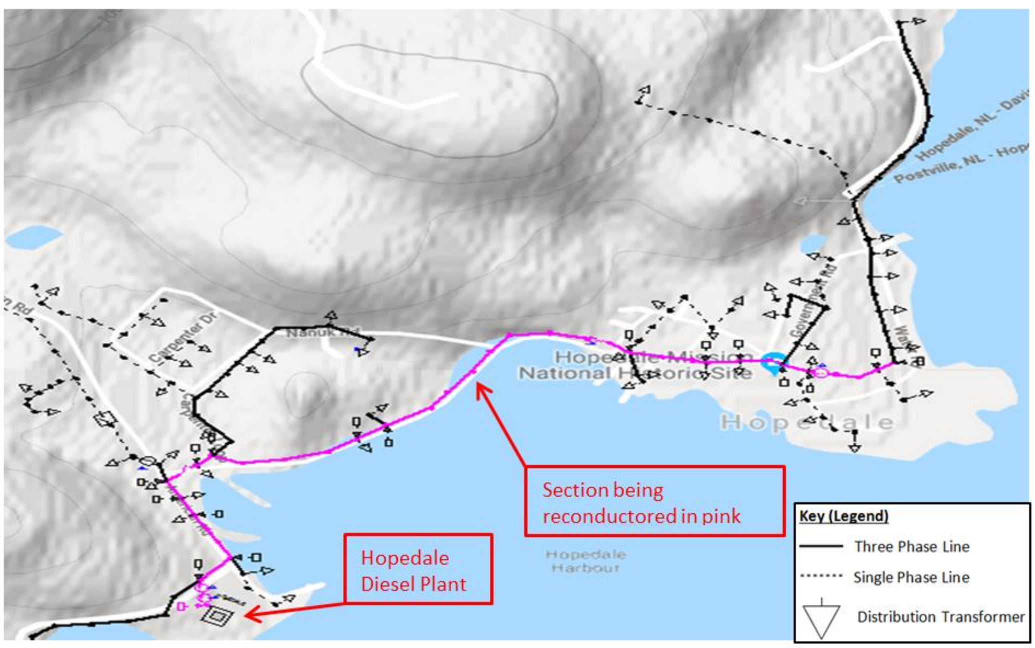

Figure 5: Map of Hopedale Alternative 2

2.3.3 Hopedale Alternative 3: New Distribution Feeder from Diesel Plant and Reconductor

This alternative involves constructing a second distribution feeder from the Hopedale Diesel Plant to serve the east side of the town. The new line will be 400 m long, constructed with 477 ASC primary and 4/0 AASC neutral and run parallel to the existing feeder to Water Road where load on the east side of the town will be transferred to the new feeder. The feeder trunk along Water Road, similar to Alternative 2, will have 1,400 m of existing 1/0 AASC primary and neutral replaced with a larger 477 ASC primary and 4/0 AASC neutral. A map of this alternative is show in Figure 6. The capital cost to construct a new feeder and perform reconductoring is $480,500. This alternative will reduce electrical losses on the system, which will save approximately $21,800 worth of fuel each year.

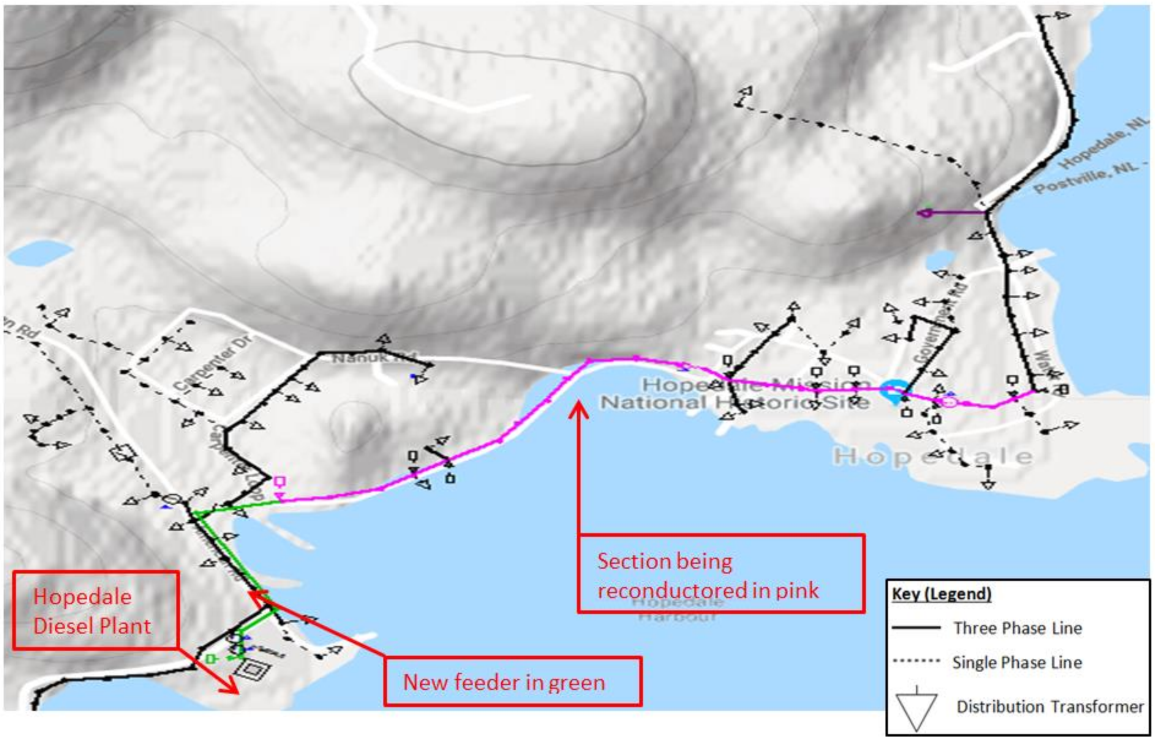

Figure 6: Map of Hopedale Alternative 3

2.3.4 Hopedale Alternative 4 for Voltage Conversion

This alternative involves converting the Hopedale Distribution System operating voltage from 4.16 kV to 25 kV. A voltage conversion would involve replacing the substation transformers as well as all customer transformers on the system with dual voltage transformers. This alternative provides extra capacity, as compared to the other alternatives, allowing for growth beyond both the base case and high growth 20-year forecast. The initial capital cost to perform a voltage conversion in Hopedale is $1,132,600. This alternative will reduce electrical losses, which will save approximately $32,400 worth of fuel each year.

2.3.5 Comparison of Hopedale Alternatives

All of the alternatives considered are technically viable and would prevent any distribution planning criteria violations within the next 20 years for both load forecasts. As such, a 20 year economic analysis was conducted to determine the most cost-effective alternative. This analysis included all capital costs required for load growth as well as the fuel costs associated with electrical losses.

Table 3 and Table 4 present the cumulative present worth ("CPW") of each alternative and the difference in CPW between each alternative for the base case forecast and the high growth forecast, respectively, to determine the least-cost alternative.

Table 3: CPW of Hopedale Alternatives Using Base Case Forecast

	CPW ($000)	CPW Difference between Alternative and the Least-Cost Alternative ($000)
Alternative 1: Voltage Regulators	700.4	117.7
Alternative 2: Reconductoring	582.7	0.0
Alternative 3: New Feeder and Reconductoring	793.6	210.9
Alternative 4: Voltage Conversion (4.16 kV to 25 kV)	1,208.6	625.9

Table 4: CPW of Hopedale Alternatives Using High Growth Forecast

	CPW ($000)	CPW Difference between Alternative and the Least-Cost Alternative ($000)
Alternative 1: Voltage Regulators	732.1	115.6
Alternative 2: Reconductoring	616.5	0.0
Alternative 3: New Feeder and Reconductoring	947.7	331.3
Alternative 4: Voltage Conversion (4.16 kV to 25 kV)	1,224.4	607.9

2.4 Recommended Alternatives for Hopedale

Based on the economic analysis shown in Table 3 and Table 4, Hydro is recommending Alternative 2 for Hopedale since it has the lowest CPW for both load forecasts.

2.5 Evaluation of Alternatives for Makkovik

2.5.1 Makkovik Alternative 1: Reconductor 1,800 m of Feeder Trunk

This alternative involves replacing 1,300 m of the 1/0 AASC feeder trunk with larger 477 ASC primary and 4/0 AASC neutral. The reconductoring will begin at the diesel plant and continue along Moravian Street before turning onto Andersen Street. This alternative also includes upgrading 500 m of single-phase 1/0 AASC distribution line to three-phase 477 ASC distribution line. A map of this alternative is shown in Figure 7. The initial capital cost to upgrade the 1,300 m of primary conductor and convert 500 m of single-phase distribution line to three-phase distribution line is $489,100. This alternative will reduce electrical losses on the system, which will save approximately $17,500 worth of fuel each year.

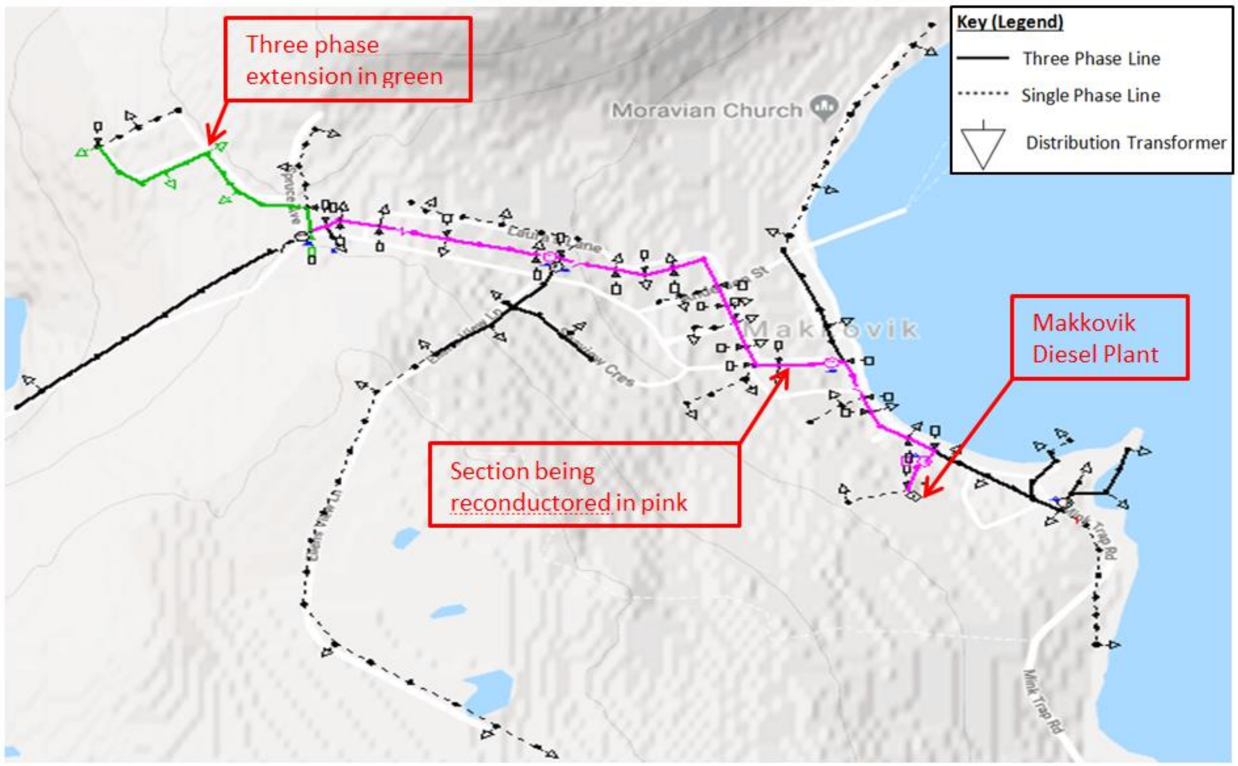

Figure 7: Map of Makkovik Alternative 1

2.5.2 Makkovik Alternative 2: New Distribution Feeder from Diesel Plant and Reconductor

This alternative involves constructing a second distribution feeder from the Makkovik Diesel Plant to serve the west side of the town. The new line will be 600 m long, constructed with 477 ASC primary and 4/0 AASC neutral and run from the diesel plant to Seaview Crescent where load on the west side of the town will be transferred to the new feeder. This alternative also includes upgrading 500 m of single-phase 1/0 AASC distribution line to three-phase 477/ASC distribution line. A map of this alternative is shown in Figure 8. The initial capital cost to construction a new feeder and convert 500 m of single-phase distribution line to three-phase distribution line is $583,400. This alternative will reduce electrical losses on the system, which will save approximately $14,100 worth of fuel each year.

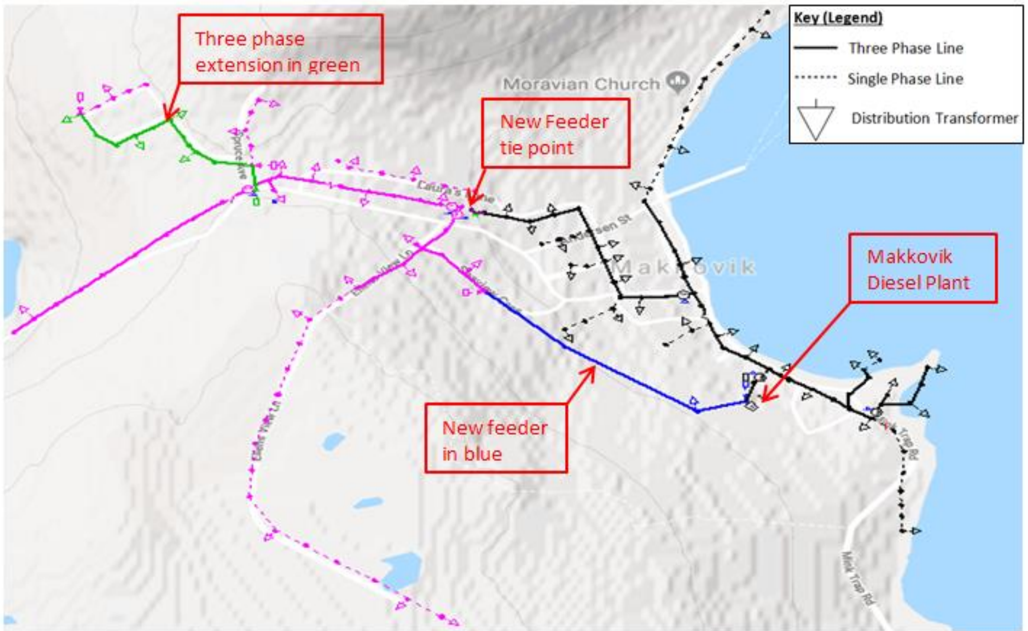

Figure 8: Map of Makkovik Alternative 2

2.5.3 Makkovik Alternative 3: Voltage Conversion

This alternative involves converting the Makkovik Distribution System operating voltage from 4.16 kV to 25 kV. A voltage conversion would involve replacing all customer transformers on the system with dual voltage transformers; the substation transformers in place already have dual windings. This alternative also includes upgrading 500 m of single-phase 1/0 AASC distribution line to three-phase 477 ASC distribution line. This alternative provides extra capacity, as compared to the other alternatives allowing for growth beyond the 20-year base case and high growth forecasts. The initial capital cost to perform a voltage conversion in Makkovik and convert 500 m of single-phase distribution line to three-phase distribution line is $972,400. This alternative will reduce electrical losses on the system, which will save approximately $21,800 worth of fuel each year.

2.5.4 Comparison of Makkovik Alternatives

All of the alternatives considered are technically viable and would prevent any distribution planning criteria violations within the next 20 years. As such, a 20-year economic analysis was conducted to determine the most cost-effective alternative. This included analyzing the capital costs required for load growth as well as the fuel costs associated with electrical losses.

Tables 5 and 6 present the CPW of each alternative and the difference in CPW between each alternative for the base case forecast and the high growth forecast, respectively, to determine the least cost alternative.

Table 5: CPW of Makkovik Alternatives using Base Case Forecast

	CPW ($000)	CPW Difference between Alternative and the Least-Cost Alternative ($000)
Alternative 1: Reconductoring	564.7	0.0
Alternative 2: New Feeder	686.9	122.2
Alternative 3: Voltage Conversion (4.16 kV to 25 kV)	975.5	410.8

Table 6: CPW of Makkovik Alternatives using High Growth Forecast

	CPW ($000)	CPW Difference between Alternative and the Least-Cost Alternative ($000)
Alternative 1: Reconductoring	577.4	0.0
Alternative 2: New Feeder	701.9	124.4
Alternative 3: Voltage Conversion (4.16 kV to 25 kV)	983.0	405.6

2.6 Recommended Alternatives for Makkovik

Based on the economic analysis shown in Table 5 and Table 6, Hydro is recommending Alternative 1 for Makkovik since it has the lowest CPW for both load forecasts.

3.0 Project Description

The project being proposed in Hopedale consists of replacing 1.8 km of existing 1/0 AASC three-phase distribution line with 477 ASC primary and 4/0 AASC neutral. In Makkovik the scope consists of replacing of 1.3 km of existing 1/0 AASC three-phase distribution line with 477 ASC primary and 4/0 AASC neutral as well as upgrade 500 m of single-phase distribution line to three-phase distribution line. Table 7 shows the estimated cost for the entire project.

Table 7: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	171.5	0.0	0.0	**171.5**
Labour	376.3	0.0	0.0	**376.3**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	120	0.0	0.0	**120**
Other Direct Costs	72.3	0.0	0.0	**72.3**
Interest and Escalation	32.0	0.0	0.0	**32.0**
Contingency	74.0	0.0	0.0	**74.0**
Total	**846.1**	**0.0**	**0.0**	**846.1**

The estimated capital cost of the proposed scope in Makkovik is $489,100 and in Hopedale is $357,000.

Table 8 shows the schedule for the project.

Table 8: Project Schedule

Activity	Start Date	End Date
Planning: Open job, develop project scope statement, and baseline schedule.	January 2020	February 2020
Design: Detailed design.	January 2020	March 2020
Procurement: Procure materials and construction tender.	March 2020	May 2020
Construction: Phase conversion and reconductoring.	July 2020	August 2020
Commissioning: Acceptance inspection.	September 2020	September 2020
Closeout: Close out project.	October 2020	October 2020

4.0 Conclusion

System analysis indicates that the current distribution systems in Makkovik and Hopedale are unable to support their forecasted load growth due to voltage conditions that would violate Hydro's distribution planning criteria.

Hydro's analysis determined that the least cost alternative to accommodate the forecasted load growth for Hopedale is to replace 1.8 km of 1/0 AASC three-phase distribution line with 477 ASC primary and 4/0 AASC neutral. The estimated cost of the work in Hopedale is $357,000.

Hydro's analysis also determined that the least cost alternative to accommodate the forecasted load growth for Makkovik is to replace 1.3 km of 1/0 AASC three-phase distribution line with 477 ASC primary and 4/0 AASC neutral and to upgrade 500 m of single-phase 1/0 AASC distribution line to three-phase 477 ASC distribution line. The estimated cost of the work in Makkovik is $489,100.

The proposed project will ensure the distribution systems in Hopedale and Makkovik will operate within Hydro's Distribution Planning Criteria for the load forecasts presented in this report. The total estimated project cost is $846,100 and the project is scheduled to be completed in 2020.

Appendix A

Distribution Planning Criteria

Distribution Planning Criteria

Hydro’s distribution planning criteria was established to ensure an adequate supply of power to customers served on Hydro’s distribution systems. As a general rule to guide Hydro's planning activities the below criteria have been adopted.

Voltage Levels

- The range of normal operating voltage is based on the Canadian Standard CSA CAN3-C235-83 ("Preferred Voltage Levels…") and the Canadian Electricity Association "Distribution Planner's Guide".
- Voltage balance: maximum 2% voltage unbalance.
- Voltage flicker limit: maximum of 5% voltage flicker.
- Temporary overvoltage: maximum 110% overvoltage.

Hydro uses the CSA standard *CAN3–C235–83–Preferred Voltage Levels for AC Systems 0–50,000 V* as the guide for determining acceptable steady-state voltage limits at customers’ service entrances. This is a National Standard of Canada that establishes a guideline for voltage standards for ac systems in Canada. It was adopted by Hydro as its standard for the range of acceptable voltages that will be provided to customers and is used by utilities across Canada. A standard for voltage levels is necessary because the devices connected to the electrical system are designed to operate within a certain range of voltages. When voltages supplied to the device deviate from this acceptable range, the device can be damaged or fail to function properly. The standard is meant to ensure that the devices connected to the electrical system will receive voltage within their normal operating range so that they function normally and damage does not occur.

The standard refers to two separate operating conditions, normal and extreme. The normal operating condition is applied when the distribution system is operating as designed and not experiencing continuous operation outside design limits. The extreme operating condition is applied during continuous operation of a power system outside of design limits and planned capital or operating work is scheduled to be carried out to correct the issue. In this situation, the system is operating within normal operating conditions most of the time and only operates within extreme operating conditions at times of peak demand. These conditions do not include voltage levels experienced during fault conditions or heavy starting loads.

Under normal operating conditions where there are no operational anomalies and the feeder is performing as designed, the customer service entrance voltage must be held between a minimum of 110 V for single-phase customers and 112 V for three-phase customers and a maximum of 125 V for a nominal 120 V service.

Table A-1 displays the normal and extreme operating condition nominal voltage ranges for many types of electrical services.

Table A-1: Recommended Voltage Variation Limits for Circuits up to 1000 V, at Service Entrances[7]

Nominal System Voltages	Voltage Variation Limits Applicable at Service Entrances			
	Extreme Operating Conditions			
		Normal Operating Conditions		
Single-phase (V)	**Lower Limit**		**Upper Limit**	
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
Three-phase Four-Conductor (V)				
120/208Y	110/190	112/194	125/216	127/220
240/416Y	220/380	224/338	250/432	254/440
277/480Y	245/424	254/440	288/500	293/508
347/600Y	306/530	318/550	360/625	367/635
Three-Phase Three-Conductor (V)				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

The standard also states that primary service voltages are to be supplied within six percent of the nominal system voltage. Under extreme operating conditions the distribution system is operating outside of the normal operating voltage limits and an operational anomaly has been identified on the

[7] CSA standard CAN3–C235–83 (R2006) –Preferred Voltage Levels for AC Systems 0–50,000 V, Table 3: Recommended Voltage Variation Limits for Circuits up to 1000 V, at Service Entrances.

system. In this case, work must be planned to correct the deficiency so that voltages remain within the normal operating condition limits. During extreme operating conditions, the customer service entrance nominal voltage must range from a minimum of 106 V for single-phase customers and 110 V for three-phase customers to a maximum of 127 V for a nominal 120 V service (single-phase and three-phase).

If the customer service entrance nominal voltage falls outside of the extreme voltage range as outlined in the CSA standard, emergency work must be completed as soon as possible to rectify the issue. If not, damage to customer equipment is likely. Hydro is responsible for ensuring voltage levels up to the service entrance (i.e., the weatherhead) are within stated limits.

The above CSA standard has been adopted by Hydro to ensure customer service entrance voltages remain within the stated limits. However, planning engineers complete system design and analysis using nominal voltages on primary distribution feeders. To relate the two, the System Planning Department references the Canadian Electricity Association Distribution Planners Manual. The manual provides estimates of the average voltage drop that can be anticipated between the primary and the service entrance to define a minimum and maximum planning voltage on a 120 V base for the primary distribution line.

Table A-2 and Table A-3 outline the Hydro standard voltage drop for each line section and transformer between the primary conductor and the service entrance for single-phase and three-phase customers, respectively.

Table A-2 Preferred Voltage at the Primary for Single-phase Customers

		Voltage (120 V Base)	
		Heavy Load	**Light Load**
Service Entrance Voltage[8]		110	125
Voltage Drop at:	Service Drop Wire	1	0.375
	Secondary Conductor	2	-
	Distribution Transformer	3	1.125
Total Voltage Drop from Primary to Service Entrance		**6**	**1.5**
Voltage at Primary		116	126.5
Note: Some customers are supplied from express service drops. Therefore, no secondary voltage drop occurs under the light load condition.			

[8] Hydro is responsible for voltage up to the service entrance.

Table A-3: Preferred Voltage at the Primary for Three-phase Customers

		Voltage (120 V Base)	
		Heavy Load	**Light Load**
Service Entrance Voltage[9]		112	125
Voltage Drop at:	Service Drop Wire	1	0.375
	Secondary Conductor	-	-
	Distribution Transformer	3	1.125
Total Voltage Drop from Primary to Service Entrance		**4**	**1.5**
Voltage at Primary		116	126.5

Note: Three-phase General Service Customers are normally supplied from express drops off their own transformer bank. Therefore, no secondary voltage drop occurs.

Therefore, Hydro uses a planning voltage range of 116 V to 126.5 V on distribution primary lines, assuming a 120 V base.

Voltage unbalance occurs when loads are not equally distributed across all three-phases of a distribution feeder. The percentage voltage unbalance is calculated as the maximum phase voltage deviation from the average voltage, divided by the average voltage, multiplied by 100%. It is common on many Hydro distribution systems to have long single-phase lines with large end of line loads that can increase voltage unbalance. A feeder experiencing a high percentage of voltage unbalance can cause excessive motor heating, increasing the likelihood of failure.

Voltage flicker is a transient phenomenon that occurs when large loads are switched on the system causing an instantaneous change in voltage. Usually this is experienced during motor starting or pick-up of a large customer load. In these cases, a dip in voltage is experienced due to the increase in current flow, causing lights to flicker. This can dim lighting and interrupt motor operation. Hydro will allow a maximum of 5% voltage flicker before work must be initiated to correct the problem. If voltage flicker worsens, the problem becomes much more noticeable and pronounced. Hydro addresses flicker at the operational level by setting limitations on the amount of current the system can supply to a customer without causing disturbances to other customers on the system.

Temporary overvoltage is an increase in ac voltage greater than 1.1 pu for a duration longer than 1 min. Overvoltages can be the result of load switching (e.g., switching off a large load) or of variations in the

[9] Hydro is responsible for voltage up to the service entrance.

reactive compensation on the system (e.g., switching on a capacitor bank). Poor system voltage regulation capabilities or controls can cause overvoltages.

Loading

Equipment loading is no greater than 100% of its continuous rating.

- Conductor ampacity is seasonally adjusted for appropriate temperature during the peak.
- Short-term overloading on transformers is permitted.

Loading of equipment should not exceed nameplate ratings and the conductor ampacity must be adjusted for the ambient temperature during periods of peak loading. Distribution power transformers, however, are permitted to be loaded to 110% of nameplate rating for short durations. This is due to the cooling effect of the oil surrounding the transformer core and windings during short periods of overloading.

Increases in customer load on distribution feeders can lead to overloading of overhead conductor and/or related equipment. A detailed load flow analysis will indicate areas that are experiencing current overloads during periods of peak loading. Equipment affected by overloads includes transformers, circuit breakers, reclosers, voltage regulators and switches.

Overloads on bare overhead conductor are identified during load flow analysis for the particular distribution feeder. Hydro has adopted the IEEE738[10] method for calculating the ampacity of overhead conductor based on ambient temperatures and uses a 100% ampacity rating for all planning related design and analysis.

Hydro has two standard types of switches, group operated switches ("gang switch") and single-phase cutouts. Group operated switches are rated for load breaking and are operated by a single handle to break all phases at the same time. These switches do not use any fuses for line protection. Single-phase cutouts are used for isolating sections of line once they have been de-energized, as they are not rated to break load. Cutouts, however, can be fused to a number of ratings depending on the protection requirements. For planning and analysis purposes, the System Planning Department uses 100% of the

[10] IEEE738–IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors.

continuous current rating for switches. Gang switches are rated for 600A per phase, where solid blade ("no fuse") cutouts are rated for 300A. If the cutout is fused, the rating then becomes the rating of the installed fuse.

The planning rating for reclosers is 100% of the rated continuous and interrupting current of the unit. Circuit breaker planning ratings are the same for reclosers; 100% of the rated continuous and interrupting current rating of the unit.

Overloads on power transformers in distribution substations are identified during the feeder load flow analysis. Hydro uses a planning rating of 110% of the nameplate rating of the transformer. Voltage regulators on the Hydro system are analyzed using a planning rating of 100% of the continuous current rating of the series winding of the device. Table A-4 contains a list of the planning loading limits for all distribution system equipment.

Table A-4: Planning Limits for Loading of Distribution System Equipment

Equipment Type	Nominal (%)	Planning (%)	Comments
Breaker	100	100	
Recloser	100	100	
Fuse	100	100	
Sectionalizer	100	100	
Switch	100	100	
Aerial Conductor	100	100	Seasonally adjusted for temperature.
Insulated Cable	100	100	Adjusted for installation location and type.
Regulator	100	100	
Transformer	100	110	Where overload is short term.

Load imbalance occurs when customer loads are not equally distributed across all three-phases of a distribution feeder. The percentage of load imbalance is calculated as the maximum phase load deviation from the average load, divided by the average load, multiplied by 100%. A highly unbalanced load on a feeder can lead to a high degree of voltage unbalance along the feeder due to varying voltage drop on the phase conductors. An unbalanced feeder will experience higher losses due to currents flowing in the neutral circuit.

By comparing the planning ratings to the forecast load, Hydro determines the required timing of capacity additions.

Appendix B

Distribution Planning Assumptions

Distribution Planning Assumptions

To maintain a consistent approach to all distribution system design and analysis, Hydro has developed a set of assumptions for all systems. No equipment, including transformers, regulators, reclosers, circuit breakers, or switches is de-rated. Therefore all equipment is assumed to be capable of operating within design limits.

A number of assumptions are made to obtain the ampere rating of a particular sized conductor depending on its construction and geographic location. Generally, the rated capacity of the lines is based on the maximum allowable operating temperature, which is affected by climate. Hydro has adopted the IEEE738–IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors, which outlines the method used to determine the current-temperature of a particular cable. Hydro assumes a maximum conductor rating of 75°C, a temperature rise of 45°C, and a 30°C ambient temperature. The operating temperature of an overhead conductor is affected by the heating effects of solar radiation and the cooling effects of wind as well as geographic location. A new overhead conductor is shiny, which reflects solar radiation and is less susceptible to additional heating than that of a weathered conductor, which is dull and absorbs more solar energy. Hydro assumes all conductors to have 50% emissivity and 50% solar absorption, which reflects a weathered (greyed) conductor in full sunshine and a clear atmosphere, located at 50° north latitude at sea level. Cooling of the conductors during normal operation due to light cross winds is assumed. All conductors are assumed to be orientated east to west.

Distribution line ampere ratings are further based on the time of the year in which the peak load occurs on that particular feeder and its location; whether it is located on the Island or in Labrador. For a winter peaking system in Labrador, the ambient temperature is assumed to be -20°C, where the same system on the Island is assumed to experience an ambient temperature of 0°C. A summer peaking system is assumed to experience an ambient temperature of 30°C across all distribution systems. For emergency and temporary situations conductors may be rated based on lower temperatures then indicated above. This depends on the specific location and expected weather during peak conditions.

During load flow analysis, unless all the loads are known, all loads are scaled and power factor adjusted so that the substation bus sending power and power factor matches the peak loading EMS data. Furthermore, loads are modelled, unless known, to have a power factor of 0.90 lag if it is primarily a motor load and a power factor closer to unity if the load s primarily electrical resistance heating. The voltage on the substation bus is assumed to be set at its lowest EMS value (if available) during peak loading as a worst case scenario.

18. Upgrade Line Depots - Various

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2020 Capital Budget Application
Upgrade Line Depots
Various

July 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Fogo Island and Burgeo Line Depot facilities are utilized by Newfoundland and Labrador Hydro ("Hydro") personnel as a base of operations and storage facility to support local transmission and distribution operations. Aspects of the facilities such as roofs, windows, siding, support members, plumbing, lighting, and concrete slabs are deteriorated.

This project will refurbish the facilities thereby maintaining the operational capability of the buildings and extend their life span.

The project is estimated to cost approximately $648,300 with scheduled completion in 2020

Contents

1.0 Introduction

Hydro's line depot buildings are utilized by personnel as a base of operations and storage facility to support local transmission and distribution operations. Aspects of these facilities have degraded over time and require intervention to maintain them in acceptable condition.

2.0 Background

2.1 Existing System

The Fogo Island Line Depot is located on Fogo Island and Burgeo is located on the South Coast of Newfoundland (See Figure 1).

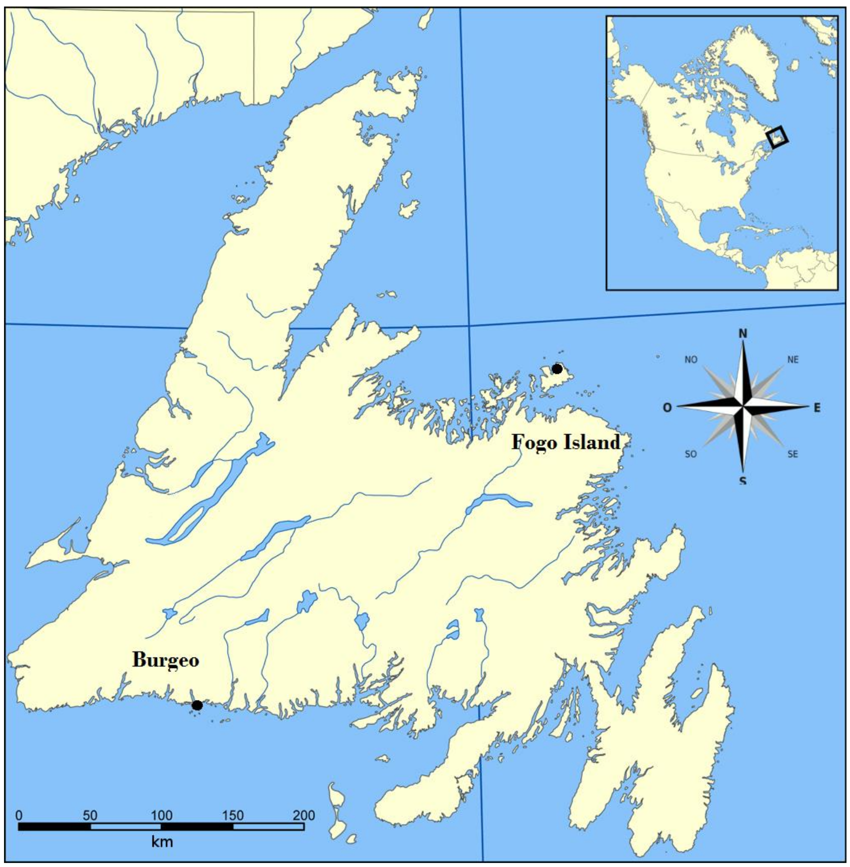

Figure 1: Location of Fogo Island and Burgeo Line Depot

2.1.1 Fogo Island Line Depot

The Fogo Island Line Depot is a single-level wood frame building that is constructed on top of a concrete slab. The building is approximately 53 m² (575 ft²) with an 83 m² (900 ft²) storage shed. The building consists of one office, a washroom, a utility room, and a workshop. The building is cladded with vertical metal siding and a sloped roof finished with asphalt shingles (See Figure 2). The storage shed (see Figure 3) is a wood structure complete with a wood floor supported on pressure-treated wood sleepers on a graded gravel bed.

Figure 2: Fogo Island Line Depot Building

Figure 3: Fogo Island Storage Shed

2.1.2 Burgeo Line Depot

The Burgeo Line Depot (see Figure 4) is a single-level building constructed on top of a concrete foundation wall with a concrete slab floor. The building is approximately 140 m^2 (1500 ft^2). The building is constructed of load bearing masonry block exterior walls and a gable-style roof with fully adhered EPDM[1] roofing.

Figure 4: Burgeo Line Depot Building

Also at the Burgeo Line Depot site there is a single level 32m^2 (350 ft^2) storage shed. The storage shed is a single-room equipment storage shed. The shed is constructed of load-bearing masonry block wall with a gable-style wood roof with asphalt shingles (See Figure 5).

There is a wire storage ramp located on the side of the line depot building. The ramp consists of round timber pole girders on similar round timber pole sleepers.

[1] Ethylene Propylene Diene Monomer ("EPDM")

Figure 5: Burgeo Storage Shed

2.2 Operating Experience

2.2.1 Fogo Island Line Depot Building

The Fogo Island Line Depot has an asphalt-shingled roof that was installed in the early 1980s when the building was originally constructed. The single-pane windows are old and deteriorated. The wooden window frame is in poor condition with limited paint and window sealant. These issues will cause water to seep into the window and building frame (See Figure 6).

Figure 6: Existing Windows

The vertical metal siding is damaged in locations and sharp edges at the base are exposed and can be a hazard and an entry point for water into the building. (See Figure 7)

Figure 7: Damaged Siding

Upgrades to mechanical and plumbing throughout the building are required in order to extend the life of the existing building. A new heat recovery ventilator ("HRV") unit, complete with ducts, will reduce the humidity and moisture buildup within the building.

The exterior building lighting is in poor condition, broken, and inoperable.

2.2.2 Fogo Island Storage Shed

The plywood floor is in poor condition from settlement and heaving due to shifting of the pressure treated sleepers (See Figure 8).

Figure 8: Pressure Treated Sleepers

The storage shed's roof structure is sagging in locations. The existing roof framing is undersized to current codes and snow-loading requirements. Roof shingles are in poor condition and lifting in locations which will result in leaks (See Figure 9).

Figure 9: Deteriorated and Lifting Roof Shingles

2.2.3 Burgeo Line Depot Building

The Burgeo Line Depot's roof system is deteriorated with the seams and edges delaminated (see Figure 10 and Figure 11). These failures will result in roof leaks.

Figure 10: Roof Seam Cracking

Figure 11: Roof Seams Cracking and Damage to Existing Roof

Multiple exterior concrete pads/ramps are deteriorated and contain cracks throughout the concrete pads and require replacement (See Figure 12). Additionally, various locations in the concrete building foundations are being undermined (See Figure 13).

Figure 12: Deteriorated Concrete Ramps

Figure 13: Undermining of Concrete Foundations

Upgrades to mechanical and plumbing system throughout the building are required in order to extend the life of the existing building. A new HRV unit, complete with associated piping and ducts, will reduce the humidity and moisture buildup within the building.

2.2.4 Burgeo Storage Shed

Burgeo Storage shed has wooden double doors and frames that are in deteriorated condition (See Figure 14).

Figure 14: Storage Shed Doors

2.2.5 Burgeo Wire Storage Ramp

The wire storage ramps contain girders and sleepers that are rotted throughout (see Figure 15).

Figure 15: Burgeo Wire Storage Ramp

3.0 Project Justification

This project will refurbish the deteriorated infrastructure at the Fogo Island and Burgeo Line Depots and maintain the operational capability of the buildings, extending the lifespan of these facilities.

4.0 Project Description

The project is for the refurbishment of the Fogo Island and Burgeo Line Depots. The scope of work includes:

- Fogo Island Line Depot Refurbishments:
  - Replacement of windows;
  - Replacement of damaged metal siding;
  - Installation of a new HRV Unit;
  - Mechanical and plumbing upgrades to the building;
  - Replacement of exterior lighting; and,
  - Replacement of a storage shed.
- Burgeo Line Depot Refurbishments:
  - Replacement of the EPDM Roof;
  - Replacement of concrete pads;
  - Refurbishments of concrete building foundations;
  - Installation of a new HRV unit;
  - Mechanical and plumbing upgrades to the building;
  - Replacement of storage shed doors; and,
  - Replacement of the wire storage ramp.

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	88.9	0.0	0.0	**88.9**
Consultant	172.0	0.0	0.0	**172.0**
Contract Work	286.0	0.0	0.0	**286.0**
Other Direct Costs	11.5	0.0	0.0	**11.5**
Interest and Escalation	24.4	0.0	0.0	**24.4**
Contingency	65.5	0.0	0.0	**65.5**
Total	**648.3**	**0.0**	**0.0**	**648.3**

The project schedule is provided in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning:		
Design transmittal, project schedule, etc.	January 2020	February 2020
Design:		
Develop tender documents.	August 2020	March 2020
Procurement:		
Tender and award construction contract.	April 2020	May 2020
Construction:		
Construction at Fogo Island Line Depot	July 2020	August 2020
Construction at Burgeo Line Depot	August 2020	September 2020
Commissioning:		
Final inspection and acceptance	September 2020	September 2020
Closeout:		
Close out project.	October 2020	December 2020

5.0 Conclusion

The Fogo Island and Burgeo Line Depot buildings and other site infrastructure are utilized by Hydro personnel as a base of operations and storage facility to support local transmission and distribution operations. This infrastructure is deteriorated.

This project is proposed to refurbish the deteriorated infrastructure at the Fogo Island and Burgeo Line Depots to maintain the operational capability of the buildings and extend the lifespan of these facilities.

2020 Capital Budget Application
Replace Light and Heavy Duty Vehicles (2020-2021)
Various

July 2019

A report to the Board of Commissioners of Public Utilities

Executive Summary

Newfoundland and Labrador Hydro (”Hydro”) operates a fleet of vehicles comprised of approximately 270 light-duty vehicles (cars, pick-ups, and vans) and 65 heavy-duty trucks (aerial devices, material handlers, and boom trucks). The fleet is 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.

This project provides for the replacement of light-duty and heavy-duty vehicles that meet the established replacement criteria. This project will contribute to the reliable operation of Hydro’s Light and Heavy Duty Vehicle Fleet.

This project is estimated to cost approximately $3,209,000, with scheduled completion in 2021.

Contents

List of Appendices

1.0 Introduction

Hydro operates a fleet of vehicles comprised of approximately 270 light-duty vehicles (cars, pick-ups, and vans) and 65 heavy-duty trucks (aerial devices, material handlers, and boom trucks). The fleet is 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.

2.0 Background

Hydro's Transportation section maintains a close liaison with other Canadian utilities through participation on the Canadian Utility Fleet Council. Hydro has established vehicle replacement criteria that consider the operating regime for the vehicles and the average replacement criteria used by other Canadian utilities.

Hydro's replacement criteria for light duty and heavy duty vehicle replacement are provided in Table 1, and for similar utilities in Table 2.

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 Number 1	
Light Duty Vehicles	5 years or 200,000 km
Heavy Duty Vehicles:	8 years or 300,000 km
Utility Number 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 Number 3	
Light Duty Vehicles	5 years or 150,000 km
Heavy Duty Vehicles	10 years or 250,000 km

2.1 Existing System

Please refer to Appendix A for a detailed equipment listing, as of January 2019. The listing includes age at retirement, projected kilometers at retirement, and maintenance costs of the vehicles being replaced under this proposal.

2.2 Operating Experience

Table 3 provides the five-year purchase history for vehicle and aerial devices and the budgets for 2018 and 2019.

Table 3: Vehicle and Aerial Device Purchases

Vehicle and Aerial Device Purchases 2015-2019

Year	Units Purchased		Budget ($000)	Actuals ($000)
	Vehicles	Aerial Devices		
2019-2020B	27	5	1,843.0	-
2018-2019B	36	10	2,420.9	2044.3
2017	36	10	2,400.2	2,173.4
2016	40	4	1,977.5	1,977.5
2015	39	6	2,602.0	2,878

2.3 Maintenance History

Please refer to Appendix A for the life-to-date maintenance costs for vehicles proposed to be replaced under this project.

3.0 Analysis

3.1 Identification of Alternatives and Analysis

Replacement of these vehicles is the only viable option based on Hydro’s established replacement criteria and industry best practice.

4.0 Project Justification

This project will contribute to the reliable operation of Hydro’s Light and Heavy Duty Vehicle Fleet.

5.0 Project Description

This project will replace 29 light-duty vehicles and 10 heavy-duty vehicles. The project estimate is provided in Table 4.

Table 4: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	1,467.9	1,282.3	0.0	**2,750.2**
Labour	3.0	2.0	0.0	**5.0**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	0.0	0.0	**0.0**
Other Direct Costs	2.0	2.0	0.0	**4.0**
Interest and Escalation	152.6	159.2	0.0	**311.8**
Contingency	0.0	138.0	0.0	**138.0**
Total	**1,625.5**	**1,583.5**	**0.0**	**3,209.0**

This is a two year project as the majority of the larger vehicles that are requisitioned in the first year will not be delivered until the second year of the project. Hydro plans to replace all proposed vehicles by 2021.

6.0 Conclusion

Hydro has established vehicle replacement guidelines based upon its participation on the Canadian Utility Fleet Council. These guidelines consider the operating regime for the vehicles and average replacement criteria used by other Canadian utilities.

This project will contribute to the reliable operation of Hydro’s Light and Heavy Duty Vehicle Fleet.

Appendix A

List of Vehicles and Aerial Devices Scheduled for Replacement

Table1: Vehicles and Aerial Devices Scheduled for Replacement

Type	Description	Age at retire	Projected kms	Age	kms	Condition	Life To Date Maint. Cost
Mini Van	V1347, 2012 DODGE CARAVAN	8.0	162,399	X	X		**$11,929.16**
Car	V1350, 2012 DODGE AVENGER	8.0	179,391	X	X		**$32,224.05**
Car	V1354, 2013 DODGE AVENGER	7.1	167,827	X	X		**$8,171.76**
Car	V1355, 2013 DODGE AVENGER	7.1	185,051	X	X		**$12,122.05**
Pick Up	V2741, 2011 GMC SIERRA 1500	9.2	135,749	X		engine Hrs	**$17,812.00**
Pick Up	V2755, 2011 GMC SIERRA 1500	8.9	227,993	X	X		**$4,234.66**
Pick Up	V2770, 2011 GMC SIERRA	8.4	179,118	X	X		**$2,523.85**
SUV	V2771, 2012 GMC TERRAIN	8.2	161,044	X	X		**$12,076.56**
Pick Up	V2793, 2012 F150 EXT CAB	8.0	190,320	X	X		**$13,356.68**
Pick Up	V2803, 2013,CHEV EXT CAB 4X4	7.2	159,233		X		**$10,608.48**
Van	V2810, 2014, CHEV AWD VAN	6.8	167,025	X	X		**$12,055.26**
SUV	V2813, 2014 CHEVROLET EQUINOX	6.2	141,089	X	X		**$7,247.42**
SUV	V2814, 2014 CHEVROLET EQUINOX	6.2	197,376	X	X		**$9,874.39**
Pick Up	V2820, 2014 CHEV 2500 4X4 C CAB	6.1	177,928	X	X		**$12,361.01**
Pick Up	V2823, 2014 F150 4X4 EXT CAB	5.9	275,218	X	X		**$14,704.00**
Pick Up	V2825, 2014 F150 4X4 EXT CAB	5.9	174,387	X	X		**$13,206.90**
Pick Up	V2827, 2014 F150 4X4 EXT CAB	5.9	207,394	X	X		**$11,958.98**
Pick Up	V2828, 2014 F150 4X4 EXT CAB	5.9	209,906	X	X		**$15,170.00**
Pick Up	V2831, 2014 F150 4X4 EXT CAB	5.9	158,961	X	X		**$11,372.32**
Van	V2839, 2014 CHEV EXPEDITION 2500	5.9	162,455	X	X		**$16,064.00**

Type	Description	Age at retire	Projected kms	Age	kms	Condition	Life To Date Maint. Cost
Van	V2840, 2014 CHEV EXPEDITION 2500	5.9	201,460	X	X		**$13,889.19**
SUV	V2846, 2015 DODGE JOURNEY	5.3	188,034	X	X		$8,520.39
SUV	V2847, 2015 DODGE JOURNEY	5.3	180,471	X	X		**$9,284.55**
Pick Up	V2853, 2014 GMC SIERRA DBL CAB	5.1	190,641	X	X		**$7,930.13**
Pick Up	V2854, 2014 GMC SIERRA DBL CAB	5.1	220,661	X	X		**$9,315.35**
Pick Up	V2861, 2015 F150 EXT CAB 4X4	5.0	212,954	X	X		**$8,101.96**
Pick Up	V2864, 2015 F150 EXT CAB 4X4	5.0	276,867	X	X		**$8,839.58**
Pick Up	V2874, 2015 CHEVROLET SILVERADO	5.0	197,531	X	X		**$6,080.30**
Pick Up	V2895, 2016 Chev Silverado	4.1	227,857	X	X		**$9,528.38**
Line Body	V4505, 2008, IHC C CAB 7500	13.0	191,488	X	X	Maint	**$97,504.35**
Aerial Device	V4508, 2008 GMC 5500 4X4 W MHAD	12.7	161,615	X		Maint	**$208,910.00**
Boom Truck	V4514, 2008 STERLING ACTERRA	12.6	92,014	X		Rust	**$167,873.00**
Boom Truck	V4515, 2008 STERLING ACTERRA	12.6	32,920	X		Rust	**$103,162.00**
Boom Truck	V4519, 2009 IHC DURASTAR 4400	11.3	94,779	X		Maint	**$208,107.00**
Knuckle Boom	V4521, 2010 HINO 358 W STAKE	11.0	104,873	X		Maint	**$100,096.00**
Boom Truck	V4524, 2009 INTERNATIONAL 4400	10.6	136,512	X		Maint	**$188,442.00**
Aerial Device	V4526, 2010 F550 4X4 W AD & SB	9.9	169,398	X		Rust	**$115,131.00**
Boom Truck	V4531, 2011 FREIGHTLINER M2 106	9.5	245,416	X	X	Maint	**$121,778.00**
Material Handler	V4543, 2013 FREIGHTLINER M2 106	7.6	256,913	X	X		**$78,033.00**

20. Replace Elevator Motors and Control Equipment – Hydro Place

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2020 Capital Budget Application
Replace Elevator Motors and Controls Equipment
Hydro Place

July 2019

newfoundland labrador
hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

Executive Summary

Hydro Place located in St. John's, Newfoundland and Labrador, serves as the corporate headquarters for Newfoundland and Labrador Hydro ("Hydro") and was constructed in 1988. It is a six story office building that utilizes two elevators for access to all levels. The elevator motors and control equipment are original to the building and are approaching the end of their life expectancy. In recent years, the elevators have been out of service many times due to controls and mechanical failures.

Hydro is proposing this project to provide reliable elevator operation at Hydro Place.

This project estimate is approximately $736,700 with planned completion in 2021.

Contents

List of Attachments

1.0 Introduction

Hydro Place, located in St. John's, Newfoundland and Labrador, serves as the corporate headquarters for Hydro. It is a six story office building constructed in 1988 that provides work space for approximately 550 employees. Two elevators in Hydro Place allow access to all levels by employees and visitors; reliable elevator service is necessary for operational requirements.

2.0 Background

The elevators must operate reliably on a year round, 24 hour basis. Outside normal business hours, elevators are required to access each level, as the stairwells are locked for security reasons.

2.1 Existing System

Two elevators were installed in 1988 during building construction. The elevator maintenance room is located in the penthouse on the roof above level six. It houses the elevator motors, pulley system, and control equipment. Figures 1 and 2 show some of this equipment.

Figure 1: Hydro Place – Elevator Motor and Pulley System at the Penthouse.

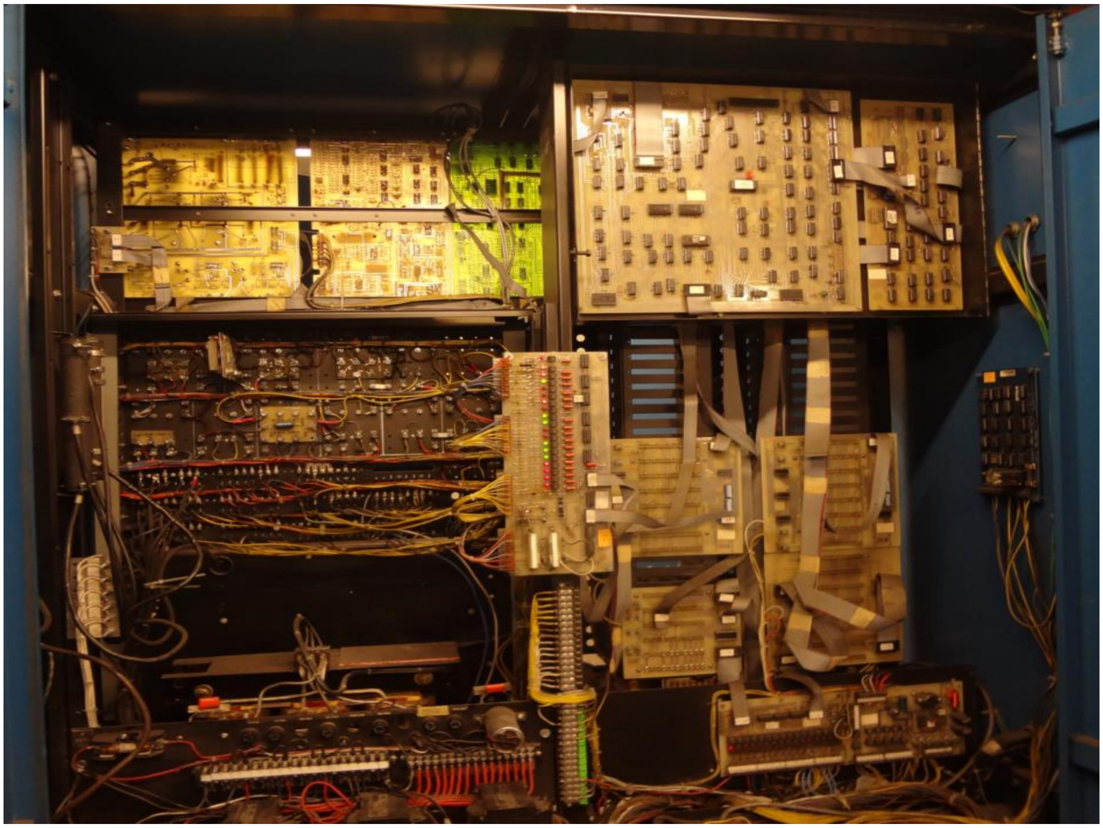

Figure 2: Hydro Place – Elevator Control System at the Penthouse.

2.2 Operating Experience

The elevators have become less reliable in recent years and there have been several occasions where they have malfunctioned and were out of service for repairs. Recently, the elevators would not stop level with the floors when the doors opened, creating a safety risk as people walk on/off the elevators. In 2018, the elevators were out of service on 12 occasions due to control/sensor and mechanical failures that needed repair.

The elevator Original Equipment Manufacturer ("OEM") was contacted for their opinion on the condition of the elevators and typical life expectancy for the equipment. The OEM provided a letter (contained in Attachment 1) indicating that the elevators are beyond the average lifespan for similar equipment. In addition, they indicated that repair costs and delays will continue to increase as many parts are becoming unavailable due to obsolescence. A delay in replacing the elevators may result in a substantial failure triggering an unplanned replacement with increased downtime. This would impact building operations including limiting building access to mobility-restricted employees and visitors.

2.3 Maintenance History

The OEM has performed regular maintenance and repairs on the elevators since their installation. From 2016 to present, planned and unplanned maintenance costs total $138,200.

3.0 Project Justification

This project is required to provide reliable elevator service at Hydro Place.

4.0 Project Description

The scope of work for this project includes:

- Replace motors;
- Replace control system hardware;
- Program new control installations;
- Test for proper functionality; and
- Complete electrical and civil temporary relocation work required to facilitate old equipment removals and installation of new.

The project estimate for this project is provided in Table 1.

Table 1: Project Estimate ($000)

Project Cost	2020	2021	Beyond	Total
Material Supply	0.0	0.0	0.0	**0.0**
Labour	77.1	86.7	0.0	**163.8**
Consultant	0.0	0.0	0.0	**0.0**
Contract Work	0.0	460.0	0.0	**460.0**
Other Direct Costs	0.0	0.0	0.0	**0.0**
Interest and Escalation	4.4	46.2	0.0	**50.6**
Contingency	7.6	54.7	0.0	**62.3**
Total	**89.1**	**647.6**	**0.0**	**736.7**

The project schedule is provided in Table 2.

Table 2: Project Schedule

Activity	Start Date	End Date
Planning: Open work order, plan and develop detailed schedules	January 2020	February 2020
Engineering/Procurement: Site Visit, Specification for Design, Supply & Installation Tender/Procurement.	March 2020	August 2020
Construction: Remove Old Motors, Control Equipment and Installation of new Equipment	June 2021	August 2021
Commissioning: Run up the new Elevator system; confirm operation and release to operations.	August 2021	August 2021
Closeout: Close work order, complete all documentation and complete lessons learned	October 2021	November 2021

5.0 Conclusion

Hydro Place serves as the main corporate headquarters for Newfoundland and Labrador Hydro. It provides work space for approximately 550 employees. Both elevators in the building are approaching the end of their useful life and have been out of service multiple times in recent years.

This project is being proposed by Hydro to provide reliable elevator service at Hydro Place.

Attachment 1

Elevator Original Equipment Manufacturer Recommendation Letter

thyssenkrupp

June 14, 2019

Newfoundland and Labrador Hydro
500 Columbus Drive
St. John's, NL A1B 4K7

Attention: Mr. John Poole

Subject: Modernization of Elevators

Dear John,

In our efforts to support you and your facility in a proactive manner, we at thyssenkrupp Elevator Canada (tkE) have continually examined and reported on the condition of your elevator. The elevator installation at Columbus Drive facility is coming upon 30 years of service (installation late in 1989). Although we have performed maintenance and replaced parts to keep the units operational, the unit is still operating with a majority of the vintage parts and systems as originally installed. Years of wear-and-tear caused by regular use will eventually impact performance and efficiency. The average lifespan of an elevator is about 20 to 25 years, at which point we will recommend modernization services. Your units have served the facility well and, by industry standards, are overdue for a substantial upgrade.

To date, we have been dedicated to keeping the units running as we are fully aware of your operational reliance on the elevators. As an elevator ages, the likelihood of a major component failure increases and unfortunately these failures are unpredictable and could result in lengthy downtimes. On occasion these unforeseen downtimes are inflated due to fact that the vintage parts are more difficult to source or in some instances unavailable due to obsolescence.

We have recommended repairs, upgrades and most recently, we have mutually discussed the modernization option. We presume you, as do we, would very much like to avoid a complete shut-down and loss of use of the unit for an unexpected period. We would much rather work in partnership to plan the shut-down, minimize the downtime and provide a substantial modernization solution that will provide reliable and safe service for another 25 years. Modernizations simply avoid obsolescence, add value, increase reliability, and enhance safety by utilizing today's technology that comply with the applicable and current codes.

To elaborate, modernizations can greatly improve operational reliability by replacing mechanical relays and contacts with solid-state electronics. Ride quality can be improved by replacing motor-generator-based drive designs with Variable-Voltage, Variable Frequency (VVVF) drives, providing near-seamless acceleration and deceleration. Passenger safety is also improved by updating systems and equipment such as redundant brake system or unintended car movement protection device on the brake system to conform to current codes.

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The following summary pertains to the replacements and/or upgrades we discussed for your facility and outlines some of the specific improvements:

Controller Replacement
- Accurate floor leveling
- Energy efficiency
- Faster response time
- Emergency fire service compliance
- Increase ride comfort
- Non-proprietary designs

Door Equipment Replacement
- Improve passenger safety
- Reduce operating noise
- Efficient door speeds
- Enhance aesthetics
- Electronic door reopening device

Signal Equipment Replacement
- ADA compliant
- Vandal resistant
- Upgrade emergency lighting and communication systems
- Update aesthetics

Traction Machine Replacement
- Boost efficiency
- Enhance ride quality
- Eliminate DC motor generator and replace with efficient AC design
- Improve braking system for added safety
- Increase up direction protection with new rope gripper
- Perform safety and governor upgrades to meet codes

We hope that this explanation assists in your capital planning and justification. We look forward to hearing from you soon regarding the project.

Regards

A. Blair Wentzell

A. Blair Wentzell,
New Construction / Modernization Estimator
thyssenkrupp Elevator (Canada) Limited

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