1.Hydraulic Generation Refurbishment and Modernization (2019-2020)

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador DAVE ROYLE SIGNATURE 7/10/2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Hydraulic Generation Refurbishment and Modernization

July 2018

newfoundland labrador hydro
a nalcor energy company

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 2018 with the 2019 Capital Budget Application, 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 Overvie*w" (please see 2019 Capital Budget Application, Volume II, Tab 1).[1] In the 2019 Capital Budget Application (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. Turbine Major Refurbishment;
3. Upgrade Units 1-6 Generator Bearing Cover Seals;
4. Refurbish Generator Rotor; and
5. Replace/Improve Unit Metering, Monitoring, Protection, and Control Assets.

Hydraulic Structures Program

1. Refurbish Hydraulic Structure.

Reservoirs Program

1. Upgrade Public Safety Around Dams.

[1] Originally submitted as part of the 2018 Capital Budget Application.

Site Buildings and Services Program

1. Refurbish Draft Tube Deck (Phase 1)

Common Auxiliary Equipment Program

1. Replace cooling water pump and strainer;
2. replace drainage pump; and
3. refurbish sump level system.

Six activities are scheduled for a one-year execution period and five activities are scheduled for two-year execution periods. The estimated project cost for all activities in 2019 and 2020 for the proposed 2019 Hydraulic Generation Refurbishment and Modernization Project is $15,838,900[2].

[2] $9,093,700 in 2019 and $6,745,200 in 2020.

Table of Contents

Summary i

Hydraulic Generating Units Program i

Hydraulic Structures Program i

Reservoirs Program i

Site Buildings and Services Program ii

Common Auxiliary Equipment Program ii

1 Hydraulic Generation Refurbishment and Modernization Program 1

2 2019 Hydraulic Generation Refurbishment and Modernization Projects 1

2.1 Hydraulic Generating Units Program 2

2.1.1 Turbine and Generator Six-Year Overhauls 2

2.1.2 Turbine Major Refurbishment 8

2.1.3 Upgrade Units 1 to 6 Generator Bearing Cover Seals 13

2.1.4 Refurbish Generator Rotor 17

2.1.5 Replace/Improve Unit Metering, Monitoring, Protection and Control Assets 21

2.2 Hydraulic Structures Program 26

2.2.1 Control Structure Refurbishments 26

2.3 Reservoirs 34

2.3.1 Upgrade Public Safety around Dams 34

2.4 Site Buildings and Services 36

2.4.1 Refurbish Draft Tube Deck (Phase 1) 37

2.5 Common Auxiliary Equipment 41

2.5.1 Replace Cooling Water Pump and Strainer at Hinks Lake Generating Station 41

2.5.2 Replace Drainage Pump at Hinds Lake and Paradise River Generating Stations 45

2.5.3 Refurbish Sump System at Bay d'Espoir Powerhouse 1 49

3 Summary 54

3.1 Project Estimate 54

1 Hydraulic Generation Refurbishment and Modernization Program

Hydro has 10 hydraulic electric 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 makes up the individual programs within this proposal. The assets have been grouped into the following categories:

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

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 2019 Hydraulic Generation Refurbishment and Modernization Projects

With the 2019 Capital Budget Application, Hydro also submits a document titled "*Hydraulic Generation Asset Management Overview*", Version 2 (the Overview), which 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 C and D of the Overview. With this combined approach, for ease of presentation, Hydraulic Generation infrastructure has been divided into five programs. Asset management philosophies relating to each program are detailed in Section 4 of the Overview.

The programs 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 refurbishments for Hydraulic Generating Units are proposed for 2019/2020:

- Turbine and generator six-year overhauls;
- turbine major refurbishment;
- upgrade Units 1 to 6 generator bearing cover seals;
- refurbish generator rotor; and
- replace/improve unit metering, monitoring, protection, and control assets.

2.1.1 Turbine and Generator Six-Year Overhauls

Description of Equipment

The turbine and generator are the two major components that comprise a hydroelectric generating unit. Water is used to rotate the turbine, which is connected to the generator to convert the mechanical energy into electricity. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview".*

The Granite Canal unit is a 40.0 MW Kaplan Hydraulic Generating Unit commissioned in August 2003. Bay d'Espoir Unit 1 is a 76.5 MW Francis Hydraulic Generating Unit that was commissioned in June 1967.

A preventive maintenance (PM) 9, Six-Year Overhaul, is performed on the units with more detailed inspections than those in a PM 6 Annual Inspection. The PM 9 inspections incorporate the PM 6 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 "*Hydraulic Generation Asset Management Overview.*"

Existing State

Granite Canal and Bay d'Espoir Unit 1 are scheduled for PM 9 overhauls in 2019. Both Units are currently in an operational condition and available for service except during maintenance or forced outages. In comparison to annual maintenance inspections (PM6), an overhaul includes activities that determine the possibility of failure between overhauls and activities to refurbish the condition of the unit to allow it to continue to operate reliably.

A list of major works or upgrades is listed in Table 1 for the Granite Canal unit and a list of major works or upgrades for Bay d'Espoir Unit 1 are listed in Table 2.

Table 1: Major Work or Upgrades – Granite Canal Unit

Year	Major Work/Overhaul	Comments
2008	Right Hand Servo Motor Shaft Replacement	
2003	Installed Frazil Ice Monitoring System	

Table 2: Major Work and Upgrades – Bay d'Espoir

Year	Major Work/Overhaul	Comments
2015	Auto Grease System Replaced	
2015	Excitation Transformer Replaced	
2015	Thrust/Guide Bearing Coolers Replaced	
2015	Replaced Thrust Bearing and Spring Bed	
2015	Turbine Bearing Replaced	
2015	Carbon Seal Replaced	
2013	Air Gap Monitoring & Continuous PDA Installed	Part of Rewind Project.
2013	Relay Protection Replaced	
2013	Generator Rotor Poles Refurbished	Part of Rewind Project.
2013	Generator Stator Rewind	

Year	Major Work/Overhaul	Comments
2008	Cooling Water Piping Replaced	
2002	Unit Dismantled to Repair Primary Seals (Grouting)	
2003	Spherical Valve No. 2 controls upgrade to include automated control	
2000	Generator Bearing Cooling coil installation	
1999	Replace Generator Bearing oil level system	
1999	Unit Removed to Replace Head-cover and Bottom Ring Bushings	
1999	Turbine Bearing Cooling coil installation	
1998	Exciter Replacement	Existing equipment at end of its useful life.
1997	Unit Removed Due to the Loss of Thrust Bearing. Bearing was Replaced.	
1996	Runner Replacement, Voith	Increased turbine efficiency; Increased maximum plant output; Reduced vibration and power swings caused by draft tube surges; and Reduced maintenance downtime caused by cavitation and corrosion.
1979	Trabon greasing modified to make the wicket gate intermediate and bottom bushings independent of the rest of the system; they can now receive required amount of lubrication without causing excess grease in the pit.	

Justification

This work is required to maintain reliable operation of the Granite Canal and Bay d'Espoir Unit 1 turbine and generator.

Project Description

The project has a planned execution in 2019 and has an estimated cost of $764,200. Refer to Table 3 and Table 4 for the project estimate breakdown for each location. This project involves the partial dismantling of the Granite Canal and Bay d'Espoir Unit 1 turbine/generator unit to inspect, test, clean, refurbish, and replace defective components. This work includes the normal PM 9 testing activities related to but not limited to the following:

Mechanical

- Generator breaks;
- generator thrust and guide bearing;
- surface air coolers;
- rotor
- governor oil pumps;
- distributor valve;
- sump and accumulator
- turbine guide bearing;
- wicket gates;
- spiral case door;
- servomotors
- bottom ring; and
- headcover.

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;
- break 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 the 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.

1 ***Project Estimates***

2 Table 3 and Table 4 show the project estimates for the Turbine and Generator Six-Year
3 Overhauls for Granite Canal and Bay d'Espoir Unit 1 respectively.

Table 3: Granite Canal - Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	50.0	0.0	0.0	50.0
Labour	308.3	0.0	0.0	308.3
Consultant	50.0	0.0	0.0	50.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	38.8	0.0	0.0	38.8
Interest and Escalation	25.7	0.0	0.0	25.7
Contingency	89.4	0.0	0.0	89.4
Total	**562.2**	**0.0**	**0.0**	**562.2**

Table 4: Bay d'Espoir Unit 1 - Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	34.0	0.0	0.0	34.0
Labour	123.9	0.0	0.0	123.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.6	0.0	0.0	2.6
Interest and Escalation	9.4	0.0	0.0	9.4
Contingency	32.1	0.0	0.0	32.1
Total	**202.0**	**0.0**	**0.0**	**202.0**

4 ***Project Schedule***

5 The anticipated project schedules are shown in Table 5 and Table 6.

Table 5: Granite Canal - Project Schedule

Activity		Start Date	End Date
Planning	Detail plan for the overhaul outage	Feb 2019	May 2019
Procurement	Special material requirements	Mar 2019	May 2019
Construction	Perform the Major Inspection/Overhauls	Jun 2019	Jun 2019
Commissioning	Return Unit to Service	Jul 2019	Jul 2019
Closeout	Closeout the project	Jul 2019	Jul 2019

Table 6: Bay d'Espoir Unit 1 - Project Schedule

Activity		Start Date	End Date
Planning	Detail plan for the overhaul outage	Feb 2019	Jun 2019
Procurement	Special material requirements	Mar 2019	Jun 2019
Construction	Perform the Major Inspection/Overhauls	Jul 2019	Jul 2019
Commissioning	Return Unit to Service	Aug 2019	Aug 2019
Closeout	Closeout the project	Aug 2019	Aug 2019

2.1.2 Turbine Major Refurbishment

Description of Equipment

A turbine is a rotary machine that converts kinetic energy and potential energy of water into mechanical work. Major components of the turbine include a runner, draft tube, guide bearings, auto-greasing system, turbine shaft and coupling, scroll case, headcover assembly, and wicket gates and linkages. Together, these components along with the concrete substructure are necessary for the operation of the hydraulic generating units' turbine.

Bay d'Espoir Unit 7 is a 154 Megawatt vertical Francis turbine unit, commissioned in 1977. The runner of a Francis turbine is designed to rotate in the scrollcase. Water passes through the vanes that are directed in a way that hits the blades of the runner causing it to turn. Seals (primary) on the top and bottom of the runner prevent water loss and maintain efficiency. The top seal is mounted in the turbine head cover and inhibits full scroll case pressure being applied on the turbine shaft main seal. The lower seal is located in the draft tube to prevent water losses entering the discharge of the unit without going through the runner. Both seals have a clearance (gap) between moving and stationary parts. The clearance has maximum and minimum tolerances to prevent water loss for machine efficiency and to prevent contact between the parts that could result in serious damage and a forced outage. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview.*"

Background

One of the tasks in Hydro's Asset Management Program for hydraulic turbines is the measurement of the upper and lower primary seal clearances. The seal clearances are designed to ensure turbine efficiency and hydraulic balance, prevent rubbing due to misalignment and imbalance, and allow for cooling between the runner and stationary wear rings. The actual design clearance depends on both the size and speed of the unit. Clearances can change because the wear rings deteriorate due to cavitation, corrosion, erosion, distortion, or the runner incurs axial movement due to bearing wear or misalignment. A failure of the turbine due to contact between the stationary and rotating seals would result in the generating unit being unavailable for six to eight months depending on the extent of the damage. During preventive maintenance, measurements, including the seal clearances, are compared against previous measurements and the design clearances. Depending on the results of the measurements, Hydro may consult with external turbine experts to determine if intervention is required to correct seal clearances. Therefore, the actual timing of turbine overhauls is not at a set chronological frequency, rather the overhauls are performed when conditions necessitate them.

In 2016, the lower primary seal clearance measurements taken on Bay d'Espoir Unit 4 revealed an unacceptable reduction in the amount of clearance between the stationary and rotating parts. As outlined in the June 2016 Supplemental Capital Budget Application *"Turbine Rehabilitation of Bay d'Espoir Unit 4"* the Turbine Major Overhaul for Unit 4 was advanced by three years. Upon disassembly of the turbine, it was discovered the wicket gate bushings, discharge ring, and grouting had to be replaced. Based upon the state of deterioration of various components of Unit 4 and the fact that Bay d'Espoir Units 1 to 6 have the same design and manufacturer and have been subjected to the similar operating conditions, a decision was made to advance the Turbine Major Overhaul for the other units, and to include Unit 7 in Powerhouse 2. Hydro completed the Unit 3 Turbine Major Overhaul in 2017, as outlined in the Supplemental Capital Budget Application "*Refurbishment of Bay d'Espoir Penstock 2 and Bay d'Espoir Unit 3 Turbine Major Overhaul".* In 2018, Unit 2 is scheduled for the Turbine Overhaul as outlined in the Capital Budget Application "*Hydraulic Generation Refurbishment and Modernization (2018-2019)*."

Existing State

Bay d'Espoir Unit 7 has been identified as the next unit in the Bay d'Espoir Hydroelectric Generating Facility to be rehabilitated, based on the condition of the unit. Unit 7 is located in Powerhouse 2 and is experiencing similar conditions to Units 1 to 6 in Powerhouse 1 for seal clearance readings.

Trending of Bay d'Espoir Unit 7 turbine lower primary seal clearance readings between rotating and stationary parts shows that the clearance has reduced to the level where a planned intervention is required. Design clearance is .090" to .104" diametrically between the runner and seal. Currently, Bay d'Espoir Unit 7 has .106" clearance on the lower primary seal at Axis 1-Axis-2 and .039" at the Upstream Downstream diameter. The turbine bearing clearance (i.e. the amount the runner can move) is .023" leaving just .008" clearance at each axis. This clearance has been worsening each year. It is critical that the rotating components of a hydraulic unit are free to turn and have clearance. For the bearings to perform properly the shaft needs to be free to rotate in its preferred axis.

Hydro is a participant with the Center for Energy Advancement through Technological Innovation (CEATI). This group is a conglomerate of hydro owners that collaborate on technical issues within the hydro industry. A study performed by CEATI, in which Hydro was a participant, determined that if the discharge ring has a doubling or a reduction of 50% of the nominal design value of the radial clearance this should be considered as the critical value.[3]

Table 7 lists the major works or upgrades on Unit 7 since commissioning of the unit in 1977.

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

Year	Major Work/Upgrade
2015	BDE #7 Carbon Seal
2015	BDE #7 Turbine Base Plate
2009	Service Water Upgrades
2014	Excitation Transformer Unit 7
2004	Generator Field Breaker
2004	Exciter Replacement
1998	Replace Sync. Condense Compressor
1998	Install air gap monitoring system
1991	Blower, Unit #7 Sync Condenser
1990	PDA Partial Discharge Monitor
1982	New Set of Rotor Brake Plates Installed
1982	All Guide Bearing Segments Replaced

Justification

This work is required to maintain the reliable operation of Bay d'Espoir Unit 7 turbine.

Project Description

Hydro is proposing to complete a Turbine Major Overhaul on Bay d'Espoir Unit 7 in 2019 at an estimated cost of $4,179,000. The scope of work in the turbine refurbishment project to address the reduced seal clearances include:

- Dismantling of Unit 7;
- grouting and machining of the lower primary seals to design clearance; and

[3] Critical Value as defined by CEATI: Machines with a key parameter that exceeds the critical value are considered to be at risk of damage if the operation is continued in that condition. An intervention is recommended.

- inspection of the upper primary seal to be machined if required.

The remaining turbine refurbishment tasks include:

- Inspection of the head cover and bottom ring/bushings and the replacement or refurbishment of worn components;
- inspection of the operating ring bearings and linkage bushings. Worn components will be replaced where practical, and refurbished otherwise;
- replacement of all wicket gate stem "V" packing;
- refurbishment of runner cavitation as close to its original condition as practical;
- inspection of the concrete behind the scroll case and draft tube, with concrete refurbishment where required;
- machining of other unit surfaces as required based on condition assessment;
- replacement of the Turbine main shaft seal;
- reassembly of the unit;
- realignment; and
- commissioning.

Project Estimate

Table 8 presents the project estimate for Turbine Major Refurbishment project for Bay d'Espoir Unit 7.

Table 8: Turbine Major Refurbishment Bay d'Espoir Unit 7 – Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	550.0	0.0	0.0	550.0
Labour	1053.7	0.0	0.0	1053.7
Consultant	350.0	0.0	0.0	350.0
Contract Work	1250.0	0.0	0.0	1250.0
Other Direct Costs	68.6	0.0	0.0	68.6
Interest and Escalation	252.2	0.0	0.0	252.2
Contingency	654.5	0.0	0.0	654.5
Total	**4,179.0**	**0.0**	**0.0**	**4,179.0**

Project Schedule

The execution of the work on-site for Unit 7 will take approximately 16 weeks to complete. The anticipated project schedule is shown in Table 9.

Table 9: Turbine Major Refurbishment Bay d'Espoir Unit 7 – Project Schedule

Activity		Start Date	End Date
Planning	Contract development and Award	Feb 2019	Mar2019
Procurement	Engineering and Material Procurement	Feb 2019	Apr 2019
Mobilization	Contractor Mobilize	May 2019	May 2019
Construction	Seal refurbishment	May 2019	Aug 2019
Commissioning	Unit reassembly, and start-up	Jul 2019	Aug 2019
Closeout	Project Closeout	Oct 2019	Oct 2019

2.1.3 Upgrade Units 1 to 6 Generator Bearing Cover Seals

Description of Equipment

For a bearing to work properly, the shaft surface must be moving at a sufficient speed to draw in the cool lubricant, pressurize it to form a hydrodynamic layer and expel it with any debris formed during the process. When a generator thrust/guide bearing assembly reaches normal operating temperature the bearing discharge oil creates an oil mist inside the bearing oil sump just below the generator top covers. The cooling air that flows throughout the generator housing and ventilation slots in the rotor and stator contains other contaminants such as carbon dust, brake dust, and insects. These contaminants mix with the oil producing a partially conductive coating that is distributed throughout the unit by the cooling air.

The generator bearing felt seal is designed to prevent vaporized oil emissions from escaping the bearing oil sump. It is a double layer seal located in the generator top bearing covers. These covers are stationary and the shaft rotates in the center of them. A 0.020" clearance between shaft and seal is required to keep the two from making contact. Due to turbine/generator design and the requirement to keep the shaft as short as possible, the generator bearing is located three inches below the felt seal that should prevent the mist from escaping the bearing oil sump. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview.*"

Existing State

Oil mist created from the operation of the bearing escapes through the clearance between the seal and shaft on Bay d'Espoir nits 1 to 6. It contaminates the unit's main bracket, brake assembly, rotor and stator. Attempts have been made to reduce the oil emissions; however, it has been an issue since the units were installed. The first attempt in 1970 involved the installation of air baffles and oil mist catchment containers. This was a major modification of the generator covers and it did not solve the emissions problem. Other attempts have been made that involved adjustments of the felt seal that have resulted in making contact with the shaft and causing vibration issues. If the felt seal prevents the generator shaft from revolving in its preferred axis it generates heat on the journal and causes vibration. The latest attempt on Unit 2 in 2014 resulted in a 10 degree increase in the bearing operating temperature. It involved a modification of the generator guide bearing, installation of baffles, and changing the way that oil was discharged from the bearing. Some of internal ports that were used to supply the bearing with oil were plugged to reduce flow. This change in oil flow caused a temperature increase that was unexpected by the Original Equipment Manufacturer and the plan to continue on with other units was cancelled. The bearings are required to maintain as cool a temperature as possible to allow for reliable operation.

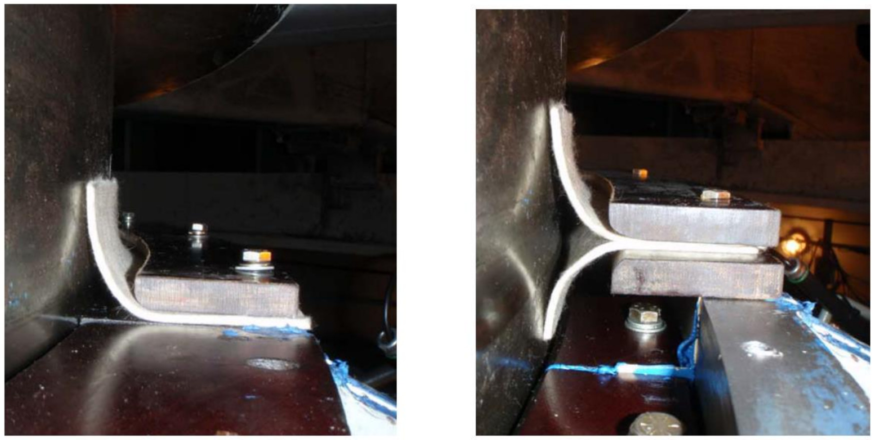
Any mist that escapes through the required clearance eventually ends up contaminating the generator components. Oil is one of the most damaging chemical exposures that can affect the life and performance of electrical insulation. It can inflict molecular damage on the components used for coil insulation and cable jacketing. This oil contamination will etch stator windings and dissolve the ground-wall insulation, reducing the strength of insulation, and lead to partial discharge. Insulation failures begin with and are characterized by small releases of electrical energy called Partial Discharge. Contamination also leads to accelerated thermal aging of the generator windings due to blocked ventilation slots. When the rotor is removed to perform a manual cleaning on both the rotor and stator every six years, only the surface contaminants are removed, a great deal of the oil contamination remains embedded in stator and rotor.

This oil also coats the floors located inside the unit creating a hazard for personnel completing maintenance on the unit internal components. In the event of a stator fault, this oil increases the possibility of having a fire.

Justification

This project is necessary to eliminate oil emissions and leaks from the generators on Units 1 to 6 at Bay d'Espoir to ensure reliable operation of the generators. As well, with Hydro's commitment to the environment, this project is justified environmentally. Hydro strives to be an environmental leader and is committed to continuously improving equipment operation. Any oil that is released from Units 1 to 6 in Bay d'Espoir is channeled into the sumps in Powerhouse 1 where it is captured. However, there is potential to release this oil to the environment so the only way to ensure no release to the environment is to eliminate the misting.

This project involves the modification of the existing felt seals design on Unit 3 in 2019 with construction on Unit 3 planned for 2020. The project will incorporate a newly designed felt seal that has been used at another utility and has proven to reduce both oil emissions and the possibility of the seal causing vibration issues. This seal is designed to lie on the generator shaft without disturbing the rotating axis and does not require clearance between shaft and seal (see Figure 1).



Franklin Flip **Double Reverse Franklin Flip**

Figure 1: New Seal Types

Project Description

This is a two-year project with engineering and design to be completed in the first year and installation of the new seal on Unit 3 to be completed in the following year to align with the major six-year inspection, PM 9, of the unit.

The scope of this project consists of:

- Completion of the engineering and design of the new seal;
- fabrication of the new seal;
- removal of existing seal and generator covers;
- modification of the covers to accommodate the new seals; and
- installation of the new seals.

Project Estimate

Table 10 presents the project estimate for Upgrade Generator Bearing project for Bay d'Espoir Units 1 to 6, with Unit 3 the first unit to be upgraded.

Table 10: Upgrade Bay d'Espoir Units 1 to 6 Generator Bearing Cover Seals Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	100.0	0.0	100.0
Labour	43.9	67.3	0.0	111.2
Consultant	200.0	0.0	0.0	200.0
Contract Work	0.0	77.1	0.0	77.1
Other Direct Costs	3.3	5.0	0.0	8.3
Interest and Escalation	16.4	44.4	0.0	60.8
Contingency	0.0	99.3	0.0	99.3
Total	**263.6**	**393.1**	**0.0**	**656.7**

Project Schedule

The first year of this project is the engineering design of the seal with the installation on Unit 3 to be in the second year, 2020. The anticipated schedule for the project is in Table 11.

Table 11: Upgrade Bay d'Espoir Units 1 to 6 Generator Bearing Cover Seals Project Schedule

Activity		Start Date	End Date
Planning	Contract development and Award for engineering design services and field services.	Feb 2019	Mar 2019
Design	Consultant will require a site visit to design the new seals for Units 1 to 6, once complete the design will be reviewed by Hydro engineering services.	May 2019	Oct 2019
Construction	Seal refurbishment	May 2020	Jun 2020
Commissioning	Unit reassembly, and start-up	Jun 2020	Jun 2020
Closeout	Project Closeout	Oct 2020	Oct 2020

2.1.4 Refurbish Generator Rotor

Description of Equipment

The Hinds Lake unit is a 75 MW Hitachi vertical generating unit with a Francis turbine. The generator of this hydroelectric unit converts the mechanical energy of the turbine into electrical energy. The two major components of the generator are the rotor and the stator. The rotor is the rotating assembly to which the mechanical torque of the turbine shaft is applied. By magnetizing or "exciting" the rotor, a voltage is induced in the stationary component, the stator. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview.*"

This unit has three guide bearings. Above the rotor there is an upper generator guide bearing, below the rotor there is a lower generator guide bearing, and above the turbine there is a turbine guide bearing. The unit uses two Rotor fans to circulate air and keep the windings cool during operation (see Figure 2).

Figure 2: Hinds Lake Rotor – The rotor fans that circulate air to cool the Rotor and Stator are bolted to the top and bottom of the rotor

The rotor is directly bolted to the hydraulic turbine and is energized by the excitation system through slip rings and carbon brushes. Slip rings and carbon brushes enable the transfer of electric power between a rotating and non-rotating surface. Contact is established by stationary brushes that press against a metal rotating ring (See Figure 3).

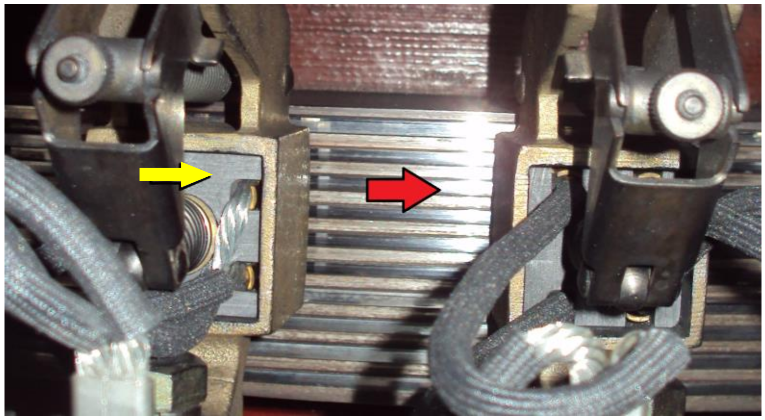


Figure 3: Slip ring (red arrow); Brushes (yellow arrow). There are 26 brushes and two rings

Existing State

Carbon dust is generated by a constant rotation of the rotor slip ring while spring loaded stationary carbon brushes press against the face of the slip ring. A portion of this carbon dust is drawn into the unit through the clearance between rotating and non-rotating parts.

Any oil leaks or oil misting from the upper guide bearing assembly during operation ultimately ends up on the rotor. This mixture of oil and carbon dust embeds in the rotor causing deterioration of the rotor pole winding insulation. Regular cleaning of the rotor and stator completed during the unit overhauls on the Hinds Lake Unit have proven to be ineffective in achieving acceptable rotor test readings. Typically the readings should be above 500 Mohms[4]. When the reading is below 0.1 Mohms it will be unsafe to operate the unit. Table 12 lists test results that indicate a trend that the unit is approaching a critical operating state.

[4] Mohms – A unit of resistance equal to one million ohms. An ohm is the SI unit of electrical resistance, expressing the resistance in a circuit transmitting a current of one ampere when subjected to a potential difference of one volt.

Table 12: Test Results

Year	Annual Test Results
2017	An inconsistent reading was listed during the outage. A work order has been entered to recheck as soon as possible.
2016	0.65 Mohms @ 500V
2015	1.28 Mohms @ 500V
2014	2.42 Mohms @ 500V
2013	5.50 Mohms @500V

Justification

This project is justified to maintain reliable operation of the Hinks Lake Generating Station. If this unit is not refurbished, failure of pole winding insulation will occur resulting in a rotor ground fault. The unit will have to be removed from service for repairs. This will require a complete dismantle of the top end of the unit, removal of the rotor, removal of the shorted pole from the rotor, repair, and reassembly of the unit, causing an extended unit outage that would take four to six weeks to complete.

Project Description

This project is required to refurbish the Hinds Lake generator rotor. In 2019, planning and engineering will be completed and the rotor will be refurbished in conjunction with the PM-9 major inspection in 2020.

The scope of work includes:

- Dismantle of the top of the unit to expose rotor;
- removal of rotor;
- removal of poles to transport to refurbishment site;
- refurbishment of poles (rewind/replace insulator);
- testing of poles to ensure quality;
- reassembly of rotor;
- installation of the rotor on the unit;

- reassembly of the top of unit; and
- commissioning of the rotor.

Project Estimate

Table 13 presents the project estimate for the Refurbish Generator Rotor project for Hinds Lake Generating Station.

Table 13: Refurbish Generator Rotor for Hinds Lake Generating Station Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	12.5	0.0	12.5
Labour	98.0	208.4	0.0	306.4
Consultant	0.0	30.4	0.0	30.4
Contract Work	0.0	595.7	0.0	595.7
Other Direct Costs	15.0	94.2	0.0	109.2
Interest and Escalation	7.4	106.8	0.0	114.2
Contingency	0.0	210.8	0.0	210.8
Total	**120.4**	**1,258.8**	**0.0**	**1,379.2**

Project Schedule

The anticipated schedule for the project is in Table 14.

Table 14: Refurbish Generator Rotor for Hinds Lake Generating Station Project Schedule

Activity		Start Date	End Date
Planning	Open project	Feb 2019	Nov 2019
Construction	Disassemble unit, refurbish roto poles	Jul 2020	Sep 2020
Commissioning	Unit reassembly, and start-up	Sep 2020	Sep 2020
Closeout	Project Closeout	Dec 2020	Dec 2020

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

Replace Condition Monitoring Equipment

<u>*Description of Equipment*</u>

The data acquisition system uses various electronic modules to collect generating unit parameters such as temperature, vibration, flows and oil levels and displays these parameters at a monitoring console in the control room. This information is used to monitor the condition of the generating unit and allow for proactive actions when abnormal conditions arise. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview.*"

The current system consists of XM121 (vibration), XM361 (temperature), and XM360 (process) electronic modules that take inputs from various instrumentation. The individual modules communicate to the data acquisition database through network communication infrastructure using DeviceNet protocol. The data in each DeviceNet network is converted to Ethernet through an XM500 Gateway. The Gateway is assessed by the data acquisition software in the Control Room.

Existing State

The data acquisition system has the ability to store and display data for up to six hours, but does not have the capability to store and display long-term, historical data of the units. This system for Bay d'Espoir Units 1 to 5 uses Allen-Bradley equipment that has been discontinued, with spare parts no longer available for some components. Failure of one of the modules will result in a portion of data for the unit associated with the failed module being lost. Units 6 and 7 have up-to-date collecting equipment.

The existing communications DeviceNet protocol is obsolete. Should a component of the system fail, it is unlikely that Hydro will be able to obtain a replacement component to work with DeviceNet protocol, which will result in a loss of the ability to track and trend long-term data for a generator or turbine. This data is required for investigating issues and identifying developing problems with the equipment.

Justification

Replacements of the condition monitoring equipment listed in this project are required to maintain investigating issues and identifying developing problems with the generating units.

Failure of the modules will result in loss of monitoring capability with resulting in an increase in the risk of generation equipment failure due to undetected problems. This is the second year of a three-year program to replace all the condition monitoring equipment listed in this project in Bay d'Espoir.

Project Description

The project will remove all the XM modules and associated infrastructure. The project will install ControlLogix PLC and PanelView Plus for Units 1 to 5 and Unit 6 will have a local HMI and a processor added to the electrical cabinet on the generating unit. The system will provide capability of measuring vital unit parameters such as the vibration levels, temperature, flows and oil levels for Units 1 to 6.

A differential pressure transducer capable of integrating with a PLC based system will be used in all units to collect scroll case pressure data. This configuration will allow the PLC to be used for alarms. A shielded Ethernet cable will be connected from the Ethernet switch in the control room to the electrical cabinets and a dedicated DC feed for each cabinet will be provided from the DC distribution panels. This will help decentralize the power supply for each unit.

Replace Control Cables

Description of Equipment

Control cables are used for carrying signals for generator 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 "*Hydraulic Generation Asset Management Overview.*"

Existing State

The 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 breakdown 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 is required to maintain reliable operation of the generating units. This is the second year of a five-year program to replace all the control cables in Bay d'Espoir.

Project Description

The scope of this project includes:

- Replacement of the 600V unit control cables; and
- replacement of associated oil contaminated junction boxes and terminal blocks.

Project Estimates

Table 15 and Table 16 present the project estimates for the Replace Condition Monitoring Equipment and Replace Control Cables, respectively.

Table 15: Replace Condition Monitoring Equipment – Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	70.0	0.0	0.0	70.0
Labour	139.4	0.0	0.0	139.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	84.0	0.0	0.0	84.0
Other Direct Costs	6.0	0.0	0.0	6.0
Interest and Escalation	23.4	0.0	0.0	23.4
Contingency	59.9	0.0	0.0	59.9
Total	**382.7**	**0.0**	**0.0**	**382.7**

Table 16: Replace Control Cables – Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	90.2	0.0	0.0	90.2
Labour	224.5	0.0	0.0	224.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	10.0	0.0	0.0	10.0
Interest and Escalation	26.0	0.0	0.0	26.0
Contingency	64.9	0.0	0.0	64.9
Total	**415.6**	**0.0**	**0.0**	**415.6**

Project Schedules

Replacement of the control cables and vibration equipment will be completed during the annual maintenance of the hydro units. The anticipated project schedule is shown in Table 17 and Table 18 for both activities.

Table 17: Replace Condition Monitoring Equipment – Project Schedule

Activity		Start Date	End Date
Planning	Detail plan for the replacement	Feb 2019	Jun 2019
Procurement	Special material requirements	Mar 2019	Jul 2019
Construction	Perform the Replacements	Aug 2019	Aug 2019
Commissioning	Commission the new equipment	Aug 2019	Aug 2019
Closeout	Closeout the project	Oct 2019	Oct 2019

Table 18: Replace Control Cables – Project Schedule

Activity		Start Date	End Date
Planning	Detail plan for the cable replacement	Feb 2019	Jun 2019
Procurement	Special material requirements	Mar 2019	Jun 2019
Construction	Perform the replacement	Aug 2019	Aug 2019
Commissioning	Commission the new equipment	Aug 2019	Aug 2019
Closeout	Closeout the project	Oct 2019	Oct 2019

2.2 Hydraulic Structures Program

The following equipment upgrades and/or refurbishment for Hydraulic Structures are proposed for 2019/2020:

- Refurbish Hydraulic Structures

2.2.1 Control Structure Refurbishments

Background

This work is a continuation of a program to refurbish all hydraulic structures within Hydro's generating system. The program began in 2010 with refurbishment work in Burnt Dam. The last submission for this program to the Board was included in the 2018 Hydraulic Generation Refurbishment and Modernization Proposal in Section 2.3 Hydraulic Structures.

The structures identified for the 2019 Hydraulic Generation Refurbishment and Modernization Proposal are Bay d'Espoir Intake 2 and the Ebbegunbaeg Control Structure.

Bay d'Espoir Intake 2

Description of Equipment

The Bay d'Espoir Intake 2, which was constructed in 1965, supplies water to Bay d'Espoir Penstock 2 which in turn supplies water to Generating Units 3 and 4. 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 an image of Intake 1 in Bay d'Espoir, which is the same as Intake 2. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview.*"

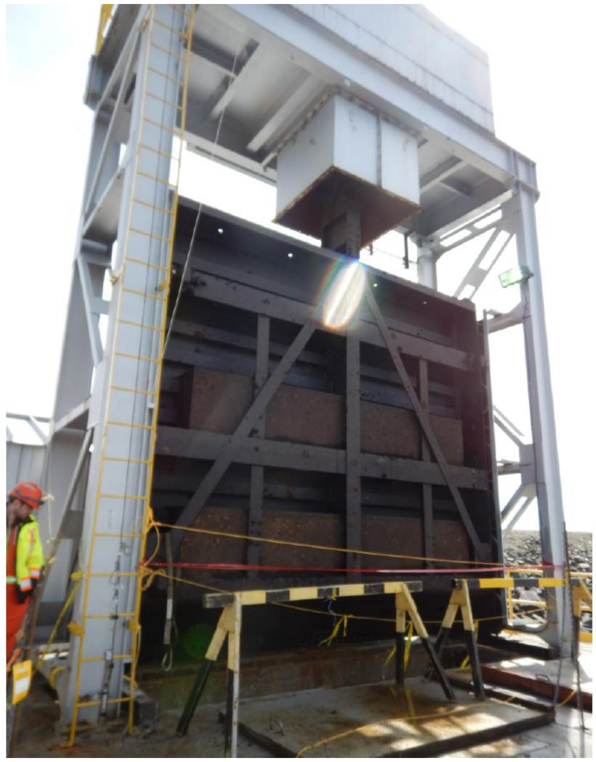


Figure 4: Bay d’Espoir Intake Gate 1

<u>Existing State</u>

A detailed assessment of Bay d’Espoir Intake 1 was completed in 2016 and 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/ gate components. Critical components that have shown deterioration include main rollers, roll paths, side-rollers and seals. It was also noted that the deterioration of these components is creating extra stress on the hoist system. As these intakes are the same vintage, with similar operating conditions and in the same environment, Hydro expects that the state of Intakes 2 and 3 are similar to the state of Intake 1 identified in 2016. Also, in 2013 Intake gate 2 failed to close due to issues related to those identified for the Intake 1. Figure 5 and Figure 6 are images of the side and main rollers on Intakes 2 and 1.

Figure 5: Bay d'Espoir Intake 2 Side Rollers - 2013

Figure 6: Pitting Corrosion on Main Rollers – Intake 1 2016

Ebbegunbaeg Control Structure

<u>*Description of Equipment*</u>

The Ebbegunbaeg Control Structure was built in 1967 as a part of the Bay d'Espoir hydroelectric project. The structure is a critical water control structure on the Bay d'Espoir system that controls water from the Meelpaeg Reservoir and discharges into Crooked Lake and eventually through the Upper Salmon and Bay d'Espoir powerhouses. The structure consists of three remotely operated gates (two screw hoists and one wire rope hoist) with a total flow discharge capacity of 338 cubic meters per second. Figure 7 shows a picture of Ebbegunbaeg Control Structure. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview.*"

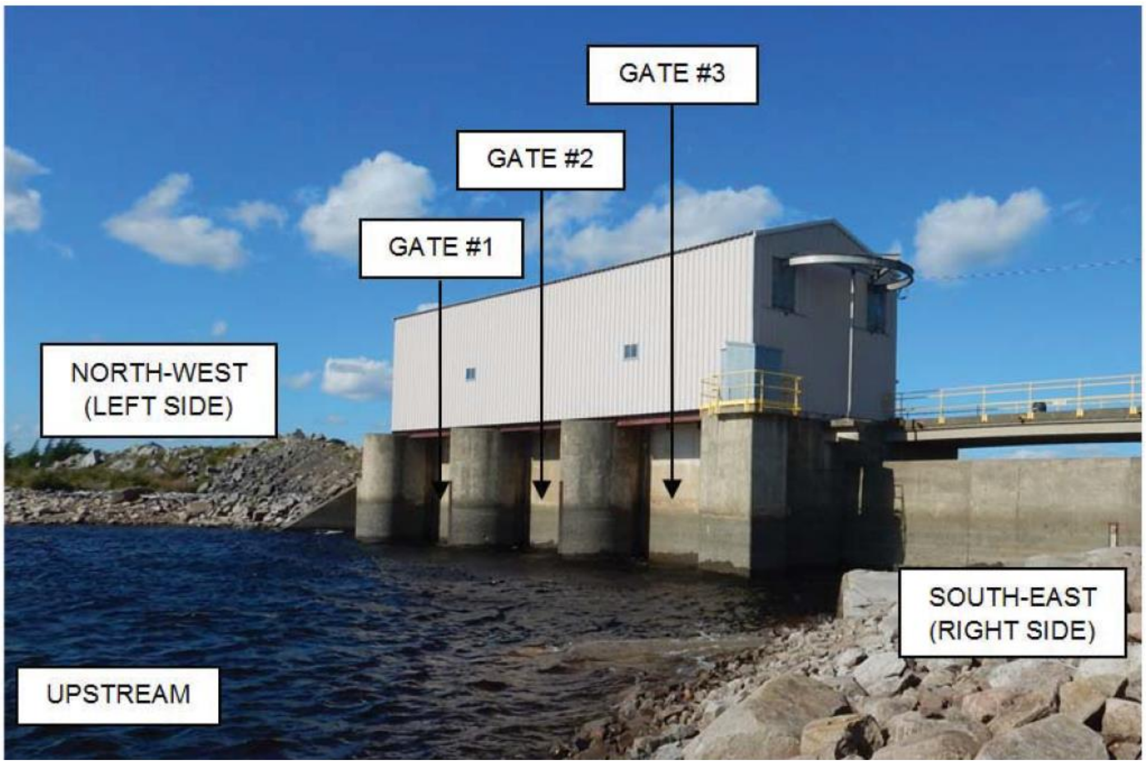


Figure 7: Ebbegunbaeg Control Structure

<u>*Existing State*</u>

In 2017, a detailed condition assessment of the Ebbegunbaeg control structure was completed. The assessment revealed operational issues with the gates, which include damage to the main rollers, embedded parts and lifting systems. The assessment also identified concrete deterioration on the piers, decking, and around the embedded parts. Figure 8, Figure 9, and Figure 10 show some of the deteriorated conditions.

Figure 8: Roller Corrosion - Ebbegunbaeg

Figure 9: Seized Side Roller - Ebbegunbaeg

Figure 10: Concrete Deterioration - Ebbegunbaeg

Justification

This project is required to maintain the reliable operation of Bay d'Espoir Intake 2 and the Ebbegunbaeg hydraulic structures.

Bay d'Espoir Intake #2

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 catastrophic failure, damage to the penstock and other downstream components is likely to occur.

Ebbegunbaeg Control Structure

The deterioration of the gates, main rollers, embedded parts and lifting systems heavily impacts the reliable operation of this structure. If left unmitigated, the deficiencies identified will continue to worsen and lead to gate failures. Without properly functioning gates, it will be difficult to control the water being released from the Meelpaeg reservoir which could lead to spilling or potentially dam related issues such as overtopping[5].

Project Description

Bay d'Espoir Intake 2

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.

[5] The overtopping occurs when water flows over the top of a dam. Overtopping may result in failure of the dam.

<u>Ebbegunbaeg Control Structure</u>

The scope of the Ebbegunbaeg refurbishment project is as follows:

- Rehabilitate screw hoist brake systems;
- complete a structural analysis of the structure bracing/connections;
- complete a constructability analysis to determine approach to required repairs;
- fabricate a second master-log;
- refurbish major embedded parts;
- refurbish second stage concrete;
- replace main rollers/side rollers/springs;
- replace seals; and
- replace the wire ropes.

Project Estimate

Table 19 and Table 20 present the project estimates for the Bay d'Espoir Intake 2 and Ebbegunbaeg Control Structure, respectively.

Table 19: Bay d'Espoir Intake 2 Refurbishment – Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	90.2	0.0	0.0	90.2
Labour	224.5	0.0	0.0	224.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	10.0	0.0	0.0	10.0
Interest and Escalation	26.0	0.0	0.0	26.0
Contingency	64.9	0.0	0.0	64.9
Total	**415.6**	**0.0**	**0.0**	**415.6**

Table 20: Ebbegunbaeg Control Structure Refurbishment – Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	60.0	0.0	60.0
Labour	165.5	189.0	0.0	354.5
Consultant	32.0	32.0	0.0	64.0
Contract Work	300.0	1,385.9	0.0	1,685.9
Other Direct Costs	26.4	58.6	0.0	85.0
Interest and Escalation	30.6	223.0	0.0	253.6
Contingency	0.0	449.9	0.0	449.9
Total	**554.5**	**2,398.4**	**0.0**	**2,952.9**

Project Schedule

The anticipated project schedule is shown in Table 21 and Table 22 for Bay d'Espoir Intake 2 Refurbishment and Ebbegunbaeg Control Structure Refurbishment, respectively.

Table 21: Bay d'Espoir Intake 2 Refurbishment – Project Schedule

Activity		Start Date	End Date
Planning	Detail plan for the refurbishment	Feb 2019	May 2019
Procurement	Special material requirements	Mar 2019	Jun 2019
Construction	Perform the refurbishment	Jun 2019	Aug 2019
Construction	Perform the refurbishment	May 2020	Aug 2020
Commissioning	Commission the new equipment	Aug 2020	Aug 2020
Closeout	Closeout the project	Oct 2020	Nov 2020

Table 22: Ebbegunbaeg Control Structure Refurbishment – Project Schedule

Activity		Start Date	End Date
Planning	Detail plan for the refurbishment	Feb 2019	May 2019
Procurement	Special material requirements	Mar 2019	Jun 2019
Construction	Perform the refurbishment	Jun 2019	Aug 2019
Construction	Perform the refurbishment	May 2020	Aug 2020
Commissioning	Commission the new equipment	Aug 2020	Aug 2020
Closeout	Closeout the project	Oct 2020	Nov 2020

2.3 Reservoirs

The following equipment upgrades and/or refurbishment for Reservoirs are proposed for 2019-2020:

- Upgrade Public Safety around Dams

2.3.1 Upgrade Public Safety around Dams

Description of Equipment

Dams and waterways are critical assets for the generation of hydroelectric 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. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview.*"

In the past decade, an increase in noted public interactions with hydroelectric structures including access by recreational vehicles and boating near spilling gates has prompted the development of this program in accordance with Canadian Dam Association Public Safety around Dams Guidelines issued in 2011. Canadian Dam Association Public Safety around Dams 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. Areas included in this proposal include the following locations:

- The Paradise River system consists of a reservoir, dams, and an intake structure;
- the Upper Salmon reservoir consists of dams, spillway structures, a power canal and an intake; and
- the Cat Arm reservoir also consists of dams, a spillway structure and an intake.

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

Existing State

The Paradise River system has some minor public control measures installed; however, a public safety risk assessment has not been completed.

The Upper Salmon reservoir has few public safety control measures installed. The risk assessment and action plan completed in 2017 outlines areas that need to be addressed.

The Cat Arm reservoir has few public safety control measures. The risk assessment and action plan was completed in 2016 and Year 1 items are to be implemented in 2018.

Justification

This project is justified to increase public safety for Paradise River, Upper Salmon and Cat Arm facilities around dams and associated waterways.

Project Description

The scope of this project includes:

- Paradise River Public Safety Risk Assessment;
- Upper Salmon Year 1 implementation - Year 1 will consist of fencing, boom anchor design and the installation of half of the required signage; and
- Cat Arm Year 2 implementation - Year 2 work will consist of fencing, gate installation, anchor boom design and remaining signage.

Project Estimate

The project estimate for the Upgrade Public Safety around Dams project in 2019 is presented Table 23.

Table 23: Upgrade Public Safety around Dams Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	129.5	0.0	0.0	129.5
Labour	159.7	0.0	0.0	159.7
Consultant	70.0	0.0	0.0	70.0
Contract Work	200.0	0.0	0.0	200.0
Other Direct Costs	20.6	0.0	0.0	20.6
Interest and Escalation	40.7	0.0	0.0	40.7
Contingency	58.0	0.0	0.0	58.0
Total	**678.5**	**0.0**	**0.0**	**678.5**

Project Schedule

The anticipated project schedule for the Upgrade Public Safety around Dams project in 2019 is presented Table 24.

Table 24: Upgrade Public Safety around Dams Project Schedule

Activity		Start Date	End Date
Planning	Detail plan for each location; open projects in JDE; review schedule.	Feb 2019	May 2019
Procurement	Special material requirements	Mar 2019	Jun 2019
Construction	Installation of public safety devices and assessment of Paradise River.	May 2019	Sep 2019
Closeout	Closeout the project	Oct 2019	Nov 2019

2.4 Site Buildings and Services

The following equipment upgrades and/or refurbishment for Site Buildings and Services are proposed for 2019-2020:

- Refurbish Draft Tube Deck (Phase 1)

2.4.1 Refurbish Draft Tube Deck (Phase 1)

Description of Equipment

The draft tube deck[6] is located on the discharge side of the Bay d'Espoir Hydro Generating Station and spans between shore lines along the Powerhouse 1 wall (see Figure 11). The 97 m long draft tube deck is made up of reinforced concrete columns, pre-cast deck beams and pre-cast deck slabs, topped with a 15 cm concrete distribution slab and finished with 50 mm of asphalt. The deck was constructed in two stages. The first stage, which consisted of Units 1 to 4, was completed in 1966. The second stage, which consisted of Unit 5 and 6, was completed in 1968. The draft tube deck also provides vehicular access to BDE Unit 7 in Powerhouse 2 and the north end of Bay d'Espoir Powerhouse 1. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview".*

Figure 11: Bay d'Espoir Draft Tube Deck

Existing State

The draft tube deck has not received any major refurbishment since it was originally constructed. In recent years, problems have been experienced when installing draft tube gates. The gates often stick in the guides and are not always able to seal properly. An improper seal

[6] The draft tube deck includes the substructure underneath the deck leading to the draft tube of the hydro unit. The substructure includes columns, beams, and structural slabs which are used to support the deck and channel the water from the hydro unit to the tailrace.

will not allow dewatering of the units draft tubes and prevents access to the draft tube and scroll case, refer to the Overview for asset descriptions.

In 2012, a condition assessment determined that if deterioration progresses much further it may impact the load carrying capacity of the structure, which could impact access as well as operation of the draft tube gates. The assessment also determined the proposed repairs are required to prevent continued deterioration of the structure, and failure to complete the repairs may result in increased life cycle cost. The structure will continue to deteriorate beyond repair and may require a pre-mature structure replacement which would be much more costly. Figure 12 to Figure 15 highlight some of the concrete deterioration.

Figure 12: Deterioration on the Draft Tube Deck

Figure 13: Deterioration on the Draft Tube Deck

Figure 14: Deterioration on the Draft Tube Deck

Figure 15: Deterioration on the Draft Tube Deck

Justification

This project is justified to maintain reliable operation of the draft tube gate system for Bay d'Espoir Units 1 to 6 in Powerhouse 1. Not undertaking this project will result in continued deterioration of the draft tube deck and the possible pre-mature structure replacement

Project Description

This is the first of a three phases to address the deterioration of the draft tube deck gates. The scope includes:

- Removal of existing asphalt wear surface and concrete topping;
- removal and reinstatement of steel railing, as required to facilitate the work;

- removal and replacement of concrete fascia for exterior deck slabs along southern portion of the structure;
- supply and installation of new deck drains;
- installation of new concrete topping and curbs;
- supply and installation of deck waterproofing membrane; and
- supply, placement and compaction of new asphalt wear surface.

Hydro currently plans to complete Phase 2 in 2020 and Phase 3 in 2022 and will seek separate Board approvals for these phases.

Project Estimate

The project estimate for the Refurbish Draft Tube Deck (Phase 1) project in 2019 is presented Table 25.

Table 25: Refurbish Draft Tube Deck (Phase 1) – Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	113.7	0.0	0.0	113.7
Consultant	125.0	0.0	0.0	125.0
Contract Work	568.2	0.0	0.0	568.2
Other Direct Costs	6.7	0.0	0.0	6.7
Interest and Escalation	56.1	0.0	0.0	56.1
Contingency	162.7	0.0	0.0	162.7
Total	**1,032.4**	**0.0**	**0.0**	**1,032.4**

Project Schedule

The anticipated project schedule for the Refurbish Draft Tube Deck (Phase 1) project in 2019 is presented in Table 26.

Table 26: Refurbish Draft Tube Deck (Phase 1) – Project Schedule

Activity		Start Date	End Date
Planning	Open project in JDE; review schedule. Prepare tender documents for consultant and contract work.	Feb 2019	Jun 2019
Procurement	Special material requirements.	May 2019	Jun 2019
Construction	Refurbish phase one items.	Aug 2019	Sep 2019
Closeout	Closeout the project	Oct 2019	Nov 2019

2.5 Common Auxiliary Equipment

The following equipment upgrades and/or refurbishment for Common Auxiliary Equipment are proposed for 2019-2020:

- Replace cooling water pump and strainer at Hinks Lake Generating Station;
- replace drainage pump at Hinds lake and Paradise River Generating Stations; and
- refurbish sump level system at Bay d'Espoir Powerhouse 1.

2.5.1 Replace Cooling Water Pump and Strainer at Hinks Lake Generating Station

Description of Equipment

The cooling water pump and strainer supplies tail race water to the various cooling water and water lubricating systems used on the turbine/generator. The pump is a 600 V centrifugal twin volute and the strainer is 600 V rotary type with automatic backwash. The emergency "Y" strainer is a basket type manual strainer (See Figure 16 and Figure 17). For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview.*"

Figure 16: Rotary Strainer

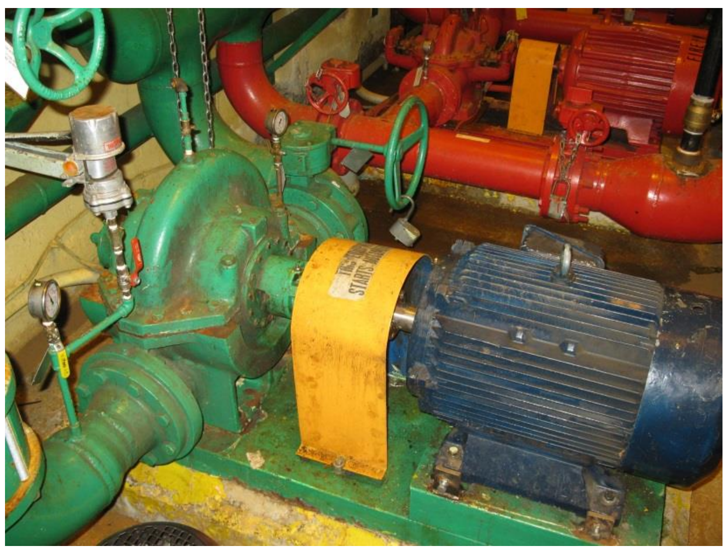


Figure 17: Cooling Water Pumps

Existing State

The cooling water pump, rotary strainer, and emergency Y strainer[7] are original equipment and have been operating throughout the life of the plant since commissioning in 1980.

[7] Y strainers are devices for mechanically removing unwanted solids from liquid, gas or steam lines by means of a perforated or wire mesh straining element.

The pump-motor has experienced bearing temperature issues on several occasions, which have resulted in replacement of the bearings. These bearing failures are a result of excessive axial thrusting caused by the worn components in the pump. A previous failure of this motor caused a forced outage in 2000 when the emergency supply from the fire header also failed. The overloads that protect the motor have tripped off the pump on several occasions (2014 and 2016) and this issue has been investigated but not resolved. Corrosion and wear of internal components (wear rings, mechanical seals, and impellor) on the pump have reduced the pump's efficiency. Corroded and blocked internal pump passages are causing fluid turbulence that result in cavitation and further inefficiencies.

The Hinds Lake plant has a history of pipe and component fouling due to the water conditions at the plant and the inefficient strainers that supply it. Most recently (2016), the piping outside the generator was replaced due to fouling. The piping inside the generator was previously replaced (2007) also due to fouling.

The rotary strainer backwash system used to clean the strainer elements has failed in-service and has components that are not reliable. The actuator and valves are leaking and the system does not effectively clean the strainer element as it should. The strainer has been dismantled and cleaned on numerous occasions and parts have become worn, corroded, and leaks have developed. Corrosion and build-up on the internal parts of the strainer are adding to the reliability issues. On occasion, both the emergency "Y" and rotary strainer have to be put in service at the same time to maintain sufficient supply to the service water system. Sensing lines, used for service water control circuits at the plant, have become blocked from debris are getting through these strainers. This blockage results in dirty cooling water causing piping to foul and reducing cooling capacity.

The emergency "Y" strainer element is damaged from repeated cleanings. It is deformed and does not seat properly.

Justification

This project is required to maintain reliable operation of the Hinds Lake Generating Unit. When minimal flows, as defined by the original equipment manufacturer, are not maintained, bearing and stator temperatures increase subjecting the equipment to failure and premature wear.

Corrosion and build up can reduce cooling water flow to levels which will cause the unit not to start remotely or can trip the generator. Staff must then investigate, which will cause delays in getting the unit back on-line.

Project Description

The scope of work consists of the replacement of Hinds Lake generating station cooling water pump and rotary strainer which entails:

- Replacement of the cooling water pump complete with controls and motor;
- replacement of the rotary strainer complete with controls and motor;
- modifications to the existing equipment mounting bases to install equipment;
- replacement of electrical feed from starters to motors;
- replacement of the emergency "Y" strainer; and
- modifications of piping required to install new equipment;

Project Estimate

The project estimate for the Replace Cooling Water Pump and Strainer project in 2019/2020 is presented Table 27.

Table 27: Replace Cooling Water Pump and Strainer at Hinds Lake Generating Station Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	40.0	45.0	0.0	85.0
Labour	54.0	57.4	0.0	111.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	105.5	0.0	105.5
Other Direct Costs	5.8	3.6	0.0	9.4
Interest and Escalation	6.5	28.4	0.0	34.9
Contingency	0.0	62.3	0.0	62.3
Total	**106.3**	**302.2**	**0.0**	**408.5**

Project Schedule

The anticipated project schedule for the Replace Cooling Water Pump and Strainer project in 2019-2020 is presented Table 28.

Table 28: Replace Cooling Water Pump and Strainer at Hinds Lake Generating Station Project Schedule

Activity		Start Date	End Date
Planning	Open project in JDE; review schedule. Prepare tender documents for contract work.	Feb 2019	Jun 2019
Procurement	Special material requirements.	May 2019	Nov 2019
Construction	Replace strainers, and pump	Oct 2020	Oct 2020
Closeout	Closeout the project	Oct 2020	Nov 2020

2.5.2 Replace Drainage Pump at Hinds Lake and Paradise River Generating Stations

Description of Equipment

In a hydraulic generating station, water is used to cool bearings and lubricate the turbine shaft seal. The discharge water from these systems then flows through a system of drains to the waste water sump. Any oil or water leaks not captured at the source is also collected by this drain system and directed to the sump. Sump water is then pumped directly to the tailrace with a pump controlled by an automatic water level control system. The automatic level system prevents the discharge of oil to the environment by ensuring the water level in the sump is maintained at acceptable levels so that an overflow does not occur. As there is typically a small amount of oil in the sumps, it is regularly removed to prevent contamination of the environment. For further information on the equipment, refer to Appendix A in the "*Hydraulic Generation Asset Management Overview.*"

At Paradise River, pumps, motors, piping and guide rails are submerged and located at the bottom of the sump, see Figure 18. At Hinds Lake, the drainage pump is a vertical turbine pump; the bottom column and pump are submerged in water, see Figure 19.

Figure 18: Corroded Component in the Paradise Sump

Figure 19: The drainage pump, motor, and column at Hinds Lake

Existing State

These pump systems are in near continuous operation at Paradise River and Hinds Lake. The drainage pump at Hinds Lake is experiencing longer run times indicating that the pump has worn internal parts resulting in the loss of efficiency. The pump has been in service since 1980. The turbine pump impellors and bowls are made of bronze and wear over time. This wear causes the pump to lose efficiency. The impellers on the pump have had to be adjusted closer to the bowls to increase flow on several occasions when the pump has not effectively pumped down the sump. This adjustment adds to the clearance below the impellors and has, over time, further worn the bronze components. The column and pump are located below floor level and submerged in water and are corroded. The line shaft bearings are made of rubber and are worn causing increased vibration when running. Rougher starts are being experienced. All bores and shafts need to be concentric to avoid vibration and failures down the length of the column. This corrosion and wear is severe, therefore replacement is the only option.

At Paradise River the pumps are experiencing longer run times, which indicate that the discharge flow rate is decreasing due to worn internal parts. Being submerged in water, all components in this sump are corroded and require replacement, including pumps, pump guide rails, and piping. This corrosion is severe and replacement is the only option.

The submerged piping at Paradise River was repaired in 2016 due to corrosion. Salt water from the tailrace was entering the sump due to failed piping and a failed check valve. An inspection completed on the piping in 2017 indicated that the corrosion of this piping has worsened since the repairs were completed in 2016. The sump pumps at Paradise River have been in service since the commissioning of the plant in 1989.

Also, the starter internal components are worn from numerous daily starts and stops at both sites.

Justification

This project is required to maintain reliable operation of the generating units at Hinds Lake and Paradise River.

A failure of these pumps will result in powerhouse flooding if the units are not shut down and thus causing a forced outage. The importance of the reliable operation of these pumps is high considering they are located in remotely operated plants. Response time for personnel to reach the plants is between two and six hours due to the geographic location of the plants. A high sump level alarm will require the unit be shut down from the Energy Control Centre until an operator could investigate. There is also a possibility that during a high sump level alarm event, oil could be discharged into the environment.

Project Description

The scope of work consists of the replacement of the two sump pumps at Paradise River and the drainage pump at Hinds Lake generating stations, which entails:

- Replacement of the two submerged sump pumps, pump guide rails, and controls/starters at Paradise River;
- replacement of the two discharge check valves and any corroded piping and fittings at Paradise River;
- addition of a stainless steel check valve on the powerhouse discharge at Paradise River;
- replacement of the drainage pump and controls/starter at Hinds Lake;
- replacement of the discharge check valve at Hinds Lake; and
- base and piping modifications (if required) to install pump at Hinds Lake;

Project Estimate

The project estimate for the Replacement of Drainage Pump equipment in Hinds Lake and Paradise River project in 2019-2020 is presented Table 29.

Table 29: Replace Cooling Water Pump and Strainer at Hinds Lake and Paradise River Generating Stations – Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	0.0	151.0	0.0	151.0
Labour	33.0	128.0	0.0	161.0
Consultant	33.4	37.0	0.0	70.4
Contract Work	10.0	155.0	0.0	165.0
Other Direct Costs	6.0	36.5	0.0	42.5
Interest and Escalation	5.2	60.9	0.0	66.1
Contingency	0.0	118.0	0.0	118.0
Total	**87.6**	**686.4**	**0.0**	**774.0**

Project Schedule

The anticipated project schedule the Replacement of Drainage Pump equipment in Hinds Lake and Paradise River project in 2019-2020 is presented Table 30.

Table 30: Replace Cooling Water Pump and Strainer at Hinds Lake and Paradise River Generating Stations – Project Schedule

Activity		Start Date	End Date
Planning	Open project in JDE; review schedule. Prepare tender documents for consultant and contract work.	Feb 2019	May 2019
Procurement	Special material requirements.	Jul 2019	Sept 2019
Construction	Replace drainage pumps and commission.	Jun 2020	Aug 2020
Closeout	Closeout the project	Oct 2020	Nov 2020

2.5.3 Refurbish Sump System at Bay d’Espoir Powerhouse 1

Description of Equipment

For each generating unit in Bay d’Espoir Powerhouse 1, water is used to lubricate the turbine shaft seal and operate the main inlet valves. Discharge water from these systems and any water leaking from turbine components flow through a system of drains to waste water sumps. Sumps are large concrete pits at the lower elevation of the building that act as collection basins for fluids leaking from plant equipment and consists primarily of water but also may contain small amounts of lubricating oil. Oil leaks not captured at the source are also collected by the drain system and directed to the sump.

In Powerhouse 1, there are six generating units and three sump pits. Waste water drainage from generating Units 1 and 2 flows into Sump 1. Units 3 and 4 flow into Sump 2 and Units 5 and 6 flow into Sump 3. Sump 1 is connected to Sump 2 at the bottom of each sump by a 12 inch diameter pipe and Sump 2 is similarly connected to Sump 3. Each pipe has a valve installed that is normally open. Fluids can migrate from one sump to others through the 12 inch pipes.

A pump is installed in each sump for removing water when it exceeds a specific level. The pumps are controlled such that when fluid elevation reaches a specified level one pump will start and discharge fluid to the tailrace and on to the outside natural waterway. If the fluid continues to rise a second pump will also start and, ultimately, a third pump will start if fluid levels continue to rise. The pumping system is designed so that one or two pumps can maintain required sump fluid levels. An automatic control system starts and stops the pumps as required utilizing a system of floats that operate electric switches.

Any oil that drains to a sump floats on water collected in the sumps. The sumps are visually inspected twice weekly and any excessive drainage oil floating on the water is removed manually so that sufficient volume does not collect that would allow it to enter the pumping system and be discharged to the environment.

In general, each sump system consists of the following (see Figure 20):

- A 6’ X 8’ X 33’ deep interconnected concrete sump pit;
- a 600 V vertical turbine pump and discharge piping;
- sump water level control system – floating electrical switches; and
- pump starter and electromechanical relays.

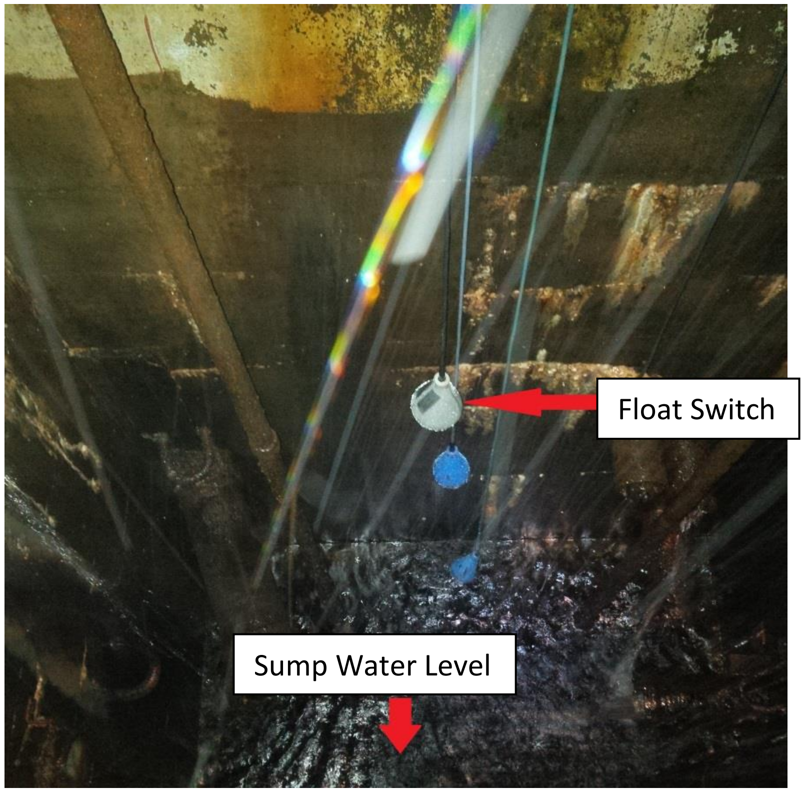


Figure 20: Sump Pump 1 in Bay d'Espoir

Note: Visual representations of the sumps are difficult due to the location and accessibility of the sumps

Existing State

The level control system has been in operation since commissioning in 1967. Floating switches have become tangled and unanchored and have malfunctioned causing the sump levels to go above or below the pre-set levels. There is no alarm system to indicate that the level is too low, only an extreme low cut off switch to ensure the pump is not damaged by running dry. Sump levels are monitored manually and regularly with an aim to ensure proper operation with respect to water level and oil presence. Due to the design of the sump, both the detection of oil in the water and an accurate assessment of the water level visually at the sump opening are impossible. Any oil collected and trapped by this system is manually skimmed from the water surface, approximately three to five meters down, by entering the sump on regular intervals.

In February 2018 there was a malfunction of the sump system for Units 1 and 2. The low level float switch failed and the extreme low level switch on the pump did not activate. The pump continued to operate pumping sump water to the tailrace until the pump was shut down by operational staff. If intervention did not occur the pump would have burned out.

The sump system to Units 1 and 2 was repaired by replacing the float switches and a new automatic oil skimmer was added to this sump, which allows for only one person to check water levels and check for hydrocarbons from the sump opening. The pump on Sump 1 also needs to be replaced, due to age and condition, and this pump has been ordered and will be installed later in 2018. The pump replacement will be performed under the Hydraulic Generation In-Service Failure project for 2018.

Currently, workers are entering the Sumps 2 and 3 twice a week to check for hydrocarbons and clean the sumps as required. To enter the sump, confined space permits are required and a stand-by worker is required in case of emergency. The addition of skimmers for Sump 2 and 3 would allow for one person check the system visually from the sump opening eliminating the need to enter the sumps.

Justification

This project is required to reduce the risk of discharging prohibited fluids into the environment.

Project Description

This project will refurbish and upgrade current sump level control system with a better stainless anchorage and floats with fixed attachment pivot points. This project will add an alarm that will be annunciated in the control room if the sump water level is too low to allow operations be able to react to low level situations. As well, the addition of an automatic oil skimmer to the sump system will ensure that oil trapped by the system is removed regularly as it enters the sump and workers will no longer have to enter the sump pit on a regular basis. The automatic system will skim the sump pit and workers can then look in the collection drum to determine if there is oil present in the sump.

The scope of this project for Sumps 1, 2, and 3 includes:

- Installation of a stainless steel anchorage system to anchor the float switches to the sides of the sumps;
- replacement of all existing float switches with floats that have fixed attachment pivot points;
- installation of low level sump alarm that is annunciated in the control room and shuts down the pump;
- modifications of the sumps structural steel to accommodate new components; and
- installation of oil skimmers in Sumps 2, and 3 only.

Project Estimate

The project estimate for the Refurbish Sump System in Bay d'Espoir Project in 2019 is presented Table 31.

Table 31: Refurbish Sump System at Bay d'Espoir Powerhouse 1 – Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	51.0	0	0	51.0
Labour	48.7	0	0	48.7
Consultant	0.0	0	0	0.0
Contract Work	0.0	0	0	0.0
Other Direct Costs	2.9	0	0	2.9
Interest and Escalation	8.5	0	0	8.5
Contingency	20.5	0	0	20.5
Total	**131.6**	**0.0**	**0.0**	**131.6**

Project Schedule

The anticipated project schedule for the Refurbish Sump System project in 2019 is presented Table 32.

Table 32: Refurbish Sump System at Bay d'Espoir Powerhouse 1 – Project Schedule

Activity		Start Date	End Date
Planning	Open project in JDE; review schedule. Prepare tender documents for consultant and contract work.	Feb 2019	May 2019
Procurement	Special material requirements.	May 2019	Jun 2019
Construction	Replace anchorage system, floats, and install skimmers in all three sumps.	Jun 2019	Aug 2019
Closeout	Closeout the project	Oct 2019	Nov 2019

3 Summary

This report in conjunction with the "*Hydraulic Generation Asset Management Overview*" defines the 2019-2020 capital budget submission for all Hydraulic Generation assets.

3.1 Project Estimate

Individual project estimates for each activity are provided in Section 2 of this report. The project estimate for all activities described in the 2019 Hydraulic Generation Refurbishment and Modernization Project is shown in Table 33.

Table 33: Hydraulic Generation Refurbishment and Modernization – Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	1014.7	428.5	0.0	1443.2
Labour	2729.3	836.0	0.0	3565.3
Consultant	892.4	131.4	0.0	1023.8
Contract Work	2562.2	3247.5	0.0	5809.7
Other Direct Costs	223.6	222.9	0.0	446.5
Interest and Escalation	529.5	621.2	0.0	1150.7
Contingency	1142.0	1257.7	0.0	2399.7
Total	**9,093.7**	**6,745.2**	**0.0**	**15,838.9**

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 the first year. Typically, one-year projects have short material lead times and shorter construction requirements.

All activities in this proposal will be completed before December 2020.

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador DAVE ROYLE SIGNATURE 7/10/2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Hydraulic Generation Asset Management Overview

July 2018

newfoundland labrador hydro
a nalcor energy company

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 were 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 projects included those that do not meet the definition of a program. Hydro had as many as 80 separate program-type projects in its Capital Budget Applications over the past five years, with each stand-alone project tailored to a specific asset.

Starting with the 2018 Capital Budget Application, Hydro implemented a change to the hydraulic generation programs submissions and 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 allows for opportunities to realize efficiencies by improving the coordination of capital and maintenance work on the Hydraulic Generation assets.

With the 2019 Capital Budget Application, Hydro submits this revised Hydraulic Generation Asset Management Overview (Overview) to provide an update of Hydro's hydraulic generation asset maintenance philosophies. The annual proposed projects reflect the philosophies contained within.

Table of Contents

Summary i
1 Introduction 1
1.1 Changes in Version 2 2
2 Hydraulic Generation Background 2
2.1 Hydraulic Generating Stations 2
2.2 Infrastructure Classifications 3
3 Hydraulic Generation Capital Projects 4
3.1 Historical Hydraulic Generation Capital Projects 4
3.2 Hydro's Approach to Hydraulic Generation Capital Projects 4
3.3 Benefits of the Approach 5
4 Asset Management Programs 6
4.1 Condition Assessment Practices 6
4.2 Program Types and Timing 7
4.3 Asset Classification Description 9
4.4 Hydraulic Generating Units Asset Classification 9
4.4.1 Turbine and Generator Six Year Overhauls Program 11
4.4.2 Turbine Major Refurbishment Program 11
4.4.3 Generator Refurbishment Program 12
4.4.4 Spherical Valve By-Pass Refurbishment Program 12
4.4.5 Exciter Replacement and Refurbishment Program 13
4.4.6 Automate Generator Deluge Systems Program 13
4.4.7 Refurbish Generator Bearings Program 13
4.4.8 Replace Auto Greasing Systems Program 13
4.4.9 Replace Unit Metering, Monitoring, Protection, SCADA & Control Assets Program 13
4.4.10 Other Sustaining Activities 14
4.5 Hydraulic Structures Asset Classification 14
4.5.1 Refurbish and Replace of Control Gates Infrastructure Program 17
4.5.2 Refurbish Surge Tanks Program 18
4.5.3 Other Sustaining Activities 18
4.6 Reservoirs Asset Classification 18
4.6.1 Upgrade Public Safety around Dams and Waterways Program 20
4.6.2 Other Sustaining Activities 21
4.7 Site Buildings and Services Asset Classification 21

4.7.1 Access Road Refurbishment Program 23
4.7.2 Diesel Fuel Storage Refurbishment and Replacement Program 23
4.7.3 Draft Tube Deck Refurbishment Program 23
4.7.4 Other Sustaining Activities 23
4.8 Common Auxiliary Equipment Asset Classification 24
4.8.1 Station Service Refurbishment and Replacement Program 26
4.8.2 Service/Cooling Water Refurbishment and Replacement Program 26
4.8.3 Air Conditioning Refurbishment and Replacement Program 27
4.8.4 Standby Generator Refurbishment and Replacement Program 27
4.8.5 Ancillary AC/DC Electrical System Refurbishment and Replacement Program 27
4.8.6 Other Sustaining Activities - Common Auxiliary Equipment Program 28

Appendices

Appendix A Full Asset Description

Appendix B Operational Hour and Time-Based Activity Background

Appendix C Overhaul Timing Background

1 Introduction

Newfoundland and Labrador Hydro (Hydro) has 10 hydraulic electric generating stations. There are over 3,000 assets involved in the operation of these stations.

Hydro's Asset Management Program 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 (e.g. turbine overhauls are performed on each hydraulic generating unit).

Part of Hydro's Annual Capital Program is a sustaining effort to ensure the safety and reliability of generation assets. Combining these projects into Hydraulic Generation Asset Management Project provides an opportunity to increase regulatory efficiency and provide a more focused presentation of Hydro's sustaining efforts for hydraulic generation.

This document, Hydraulic Generation Asset Management Overview (Overview), serves as a reference for annual projects. It provides supporting 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 revise and resubmit the Overview, where appropriate, as changes are implemented to asset management practices.

1.1 Changes in Version 2

This document reflects Version 2 of the Overview and is being submitted with the 2019 Capital Budget Application. All material changes in this revision are shaded in grey and are summarized in Section 4.7, updated to include the Draft Tube Deck refurbishment program.

Minor changes to syntax have been made to improve reading and to reflect that this document has been previously submitted and is no longer a newly established approach. These minor changes have not been highlighted.

2 Hydraulic Generation Background

2.1 Hydraulic Generating Stations

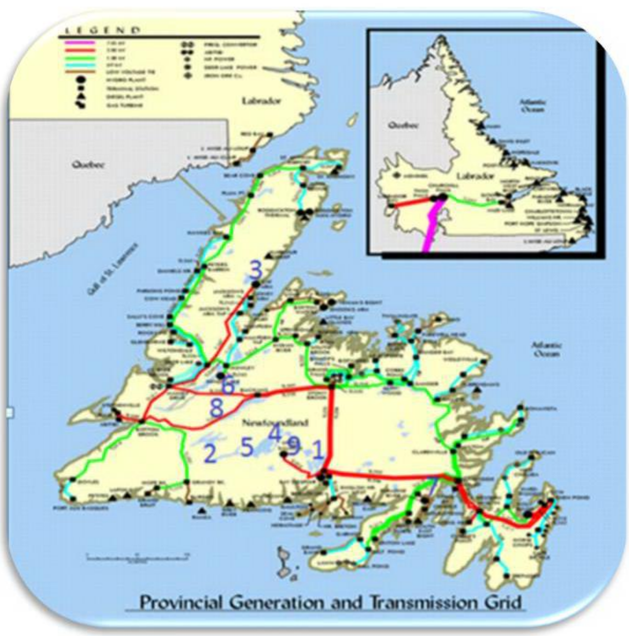
The location, number of generators at each location, and the total rated generating capacity of Hydro's 10 generating stations is as follows:

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
1a	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
1b	Bay d'Espoir Powerhouse 2	Unit 7 - December 1977
2	Cat Arm	Unit 1 - February 1985
		Unit 2 - February 1985
3	Upper Salmon	January 1983
4	Hinds Lake	December 1980
5	Granite Canal	August 2003
6	Paradise River	February 26, 1989
7	Snook's Arm	September 1957 (Acquired in 1968)
8	Venams Bight	April 1957 (Acquired in 1968)
9	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 3,000 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 Hydraulic Generation Capital Projects

3.1 Historical Hydraulic Generation Capital Projects

In the 2017 Capital Budget Application, there were 14 individual Hydraulic Generation projects, which accounted for $13.1 million, or 5% 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 Capital Budget Applications 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 will be proposed separately include:

- Activities that cannot be scheduled for inclusion in the annual Capital Budget Application - these projects will be submitted as either a supplementary capital budget application or executed in the *"Hydraulic Generating Stations In-Service Failures Project";*

- Activities in response to additional load or reliability requirements - these projects generally have unique justifications and will be proposed separately; and
- Activities in response to significant isolated issues in a particular station (e.g. replacement of a damaged turbine) - these projects generally have unique justification and will be proposed separately.

Hydro will continue 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.

3.3 Benefits of the Approach

Supporting information, such as asset descriptions change infrequently, referencing the 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.

Hydro has a proactive Asset Management Program to anticipate future failures so that refurbishment or replacement can be incorporated into an Application. However, there are situations were immediate refurbishment or replacement, which has not been included in an Application, 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 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.

[1] If the work undertaken in the 2017 "*Hydraulic Generation Refurbishment and Modernization Project"* had been submitted as 13 individual projects, it is estimated preparation would be approximately $10,000 per project.

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 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, 1,000 or 2,000-hour preventive maintenance procedures. More information on calendar-based or equipment operating time-based activities is presented in Appendix B.

Capital overhauls and refurbishments are conducted on differing timeframes depending upon the asset and 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 the determination of timing is presented in Appendix C.

The more frequent calendar-based and equipment operating time-based maintenance procedures consist of visual inspection of the equipment 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 Overview.

4.2 Program Types and Timing

The programs in this 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 this 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 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 Capital Budget Application, 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 the determination of timing is presented in Appendix C. Execution of capital corrective actions which align with philosophies and practises outlined in this 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 that 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.

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.

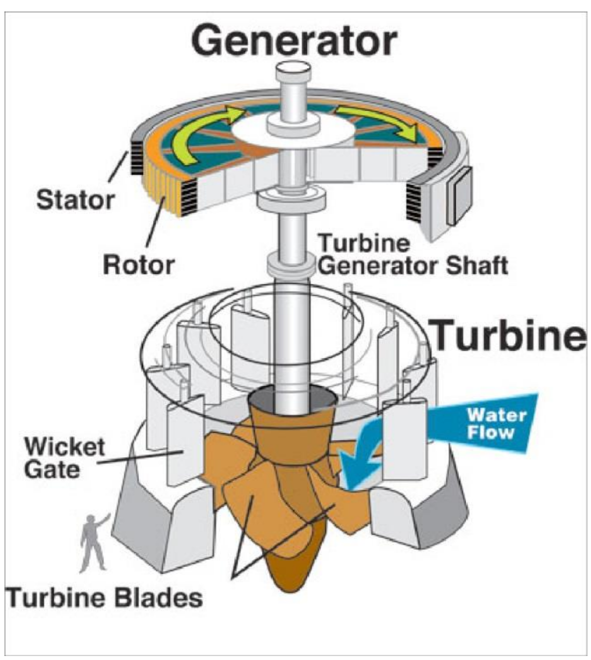


Figure 2: Hydraulic Generating Units

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 and, as such, 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.

[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.

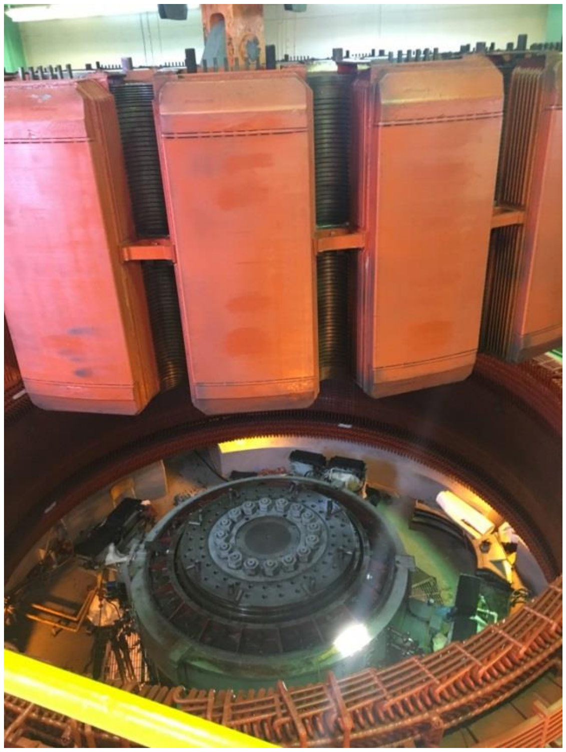


Figure 3: Dismantled Generator

4.4.1 Turbine and Generator Six Year Overhauls Program

The Six-Year Overhaul involves a partial dismantling 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 such activities as are 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 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 reaches its end of 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 ongoing maintenance issues. This program will be used to undertake future work of this nature.

4.4.9 Replace Unit Metering, Monitoring, Protection, SCADA & 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 due to the monitors being 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.

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.

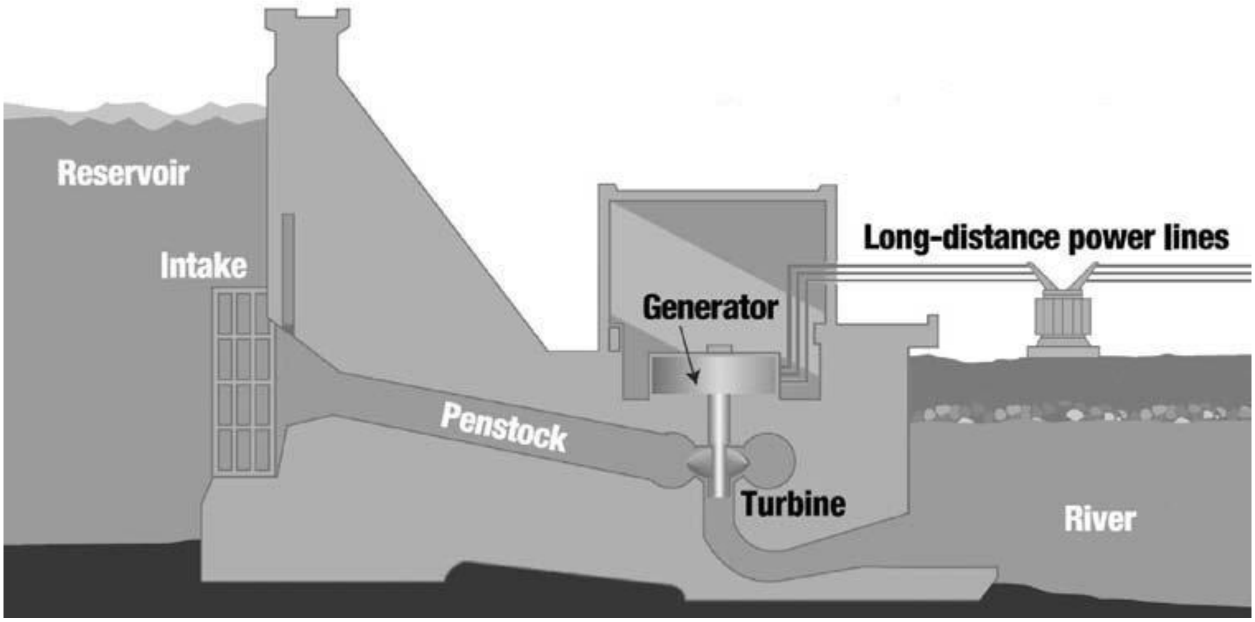


Figure 4: Cross-section of intake

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 undertaken 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 (Figure 5). 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 a 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 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. Hydro has eight steel and one wood stave penstock serving the hydraulic units and three arrangements with penstock/power tunnel combinations.

Hydraulic generating stations with high head designs have surge tanks 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).

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

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

4.5.1 Refurbish and Replace 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. A failed 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, causing inoperability. 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 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:

- ams;
- 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.

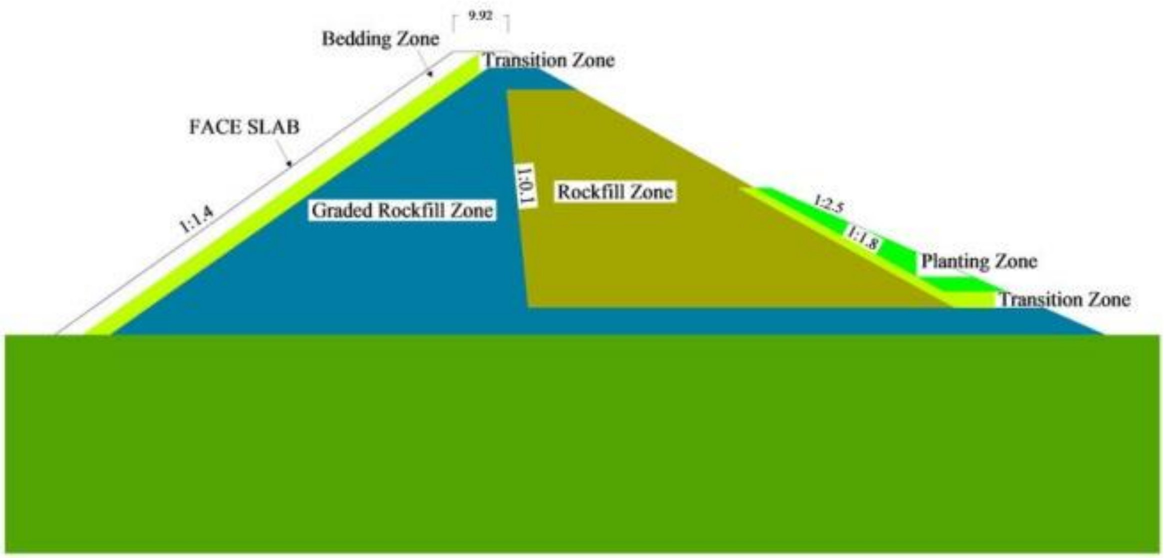


Figure 7: Dam cross-section

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 63 m 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 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 a hydraulic generating unit(s) and the unit's auxiliary mechanical and electrical equipment. Service buildings are other buildings required for a hydraulic generating station, which include warehouses, maintenance buildings, training facilities, site accommodations, and security offices. Helicopter pads allow helicopters to use relatively flat, clearly marked, obstacle-free hard surfaces 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 site access. Deterioration was a result of insufficient drainage, washouts, or the normal wear/loss of 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 (e.g. reduced wall thickness, corrosion) which is detected during routine tank inspections. Tanks are also subject to 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 a portion 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. 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 depicts the Bay d'Espoir Station Service Transformers, 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 as back-up at locations that require electricity for operations. 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 2,000 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, are prone to insulation breakdown and other deterioration as they reach the end of their 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 of this nature to 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 attaches 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.

Stator Assembly

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

Thrust and Guide Bearing

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

Cooling Water System

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

Governor

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

Governor Speed Generators

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

Governor Pump

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

Governor Piping System

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

Accumulator Tank

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

Servomotor Assembly

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

Isolated Phase Bus

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

Disconnect Switch

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

Grounding Switch

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

Buswork

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

Main Inlet Valve

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

Turbine

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

Runner

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

Draft Tube

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

Guide Bearing

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

Auto-greasing System

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

Turbine Shaft and Coupling

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

Scroll Case

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

Headcover Assembly

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

Wicket Gates and Linkages

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

Excitation

Excitation Transformer

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

Field Breaker

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

Metering, Monitoring, Protection, SCADA and Control

Ground Cubicle

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

Auto Control Panel

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

Synchronizing Panel

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

Temperature and Frequency Control Panel

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

Time and Frequency Clock

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

Oscillogragh

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

Voltage and Megawatt Panel

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

Recorder

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

Control Cables and Junction Boxes

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

Vibration Monitoring System

Hydro Unit Systems

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

Handheld Units

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

Data Acquisition System

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

Hydraulic Structure

Substructure

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

Superstructure

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

Gates

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

Stoplogs/Master logs

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

Gate Hoist

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

Gate Rollers, seals, and embedded parts

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

Heating Systems

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

Control Systems

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

De-icing Systems

In conjunction with the heating systems other systems are strategically employed to combat ice around gates. Water 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 cannot 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 to contain water for electricity generation. The majority of Hydro's dams are embankment type structures with the highest structure being 63 m 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 implemented 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 door 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 comes to site to empty the tank. PCB waste oil has to be disposed of properly outside of the province, thus the reason for 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; and
- PM 9: 6 Year Checks.

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

Operational Hour Activities

Operational Hour Preventive 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;
- 1,000 Hour PM; and
- 2,000 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 Protection and Control. On each check sheet, there are specific checks and duties that have to be completed. If abnormalities (e.g. unexpected wear on a runner) are found, a report is made to the Long-Term

Asset Planning group for condition assessment and, if required, determination of the corrective action and timing. This work may or may not require capital expenditures.

Appendix C

Overhaul Timing Background

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; and
- 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 Long Term Asset Planners 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 an inspection 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 preventive 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 centre 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.

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 preventive 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 centre 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. Overhaul Unit 3 Turbine Valve – Holyrood

REGISTERED PROFESSIONAL ENGINEER PEGNL MOHAMED KHALIFA SIGNATURE July 19, 2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Overhaul Unit 3 Turbine Valves

Holyrood

July 2018

newfoundland labrador hydro
a nalcor energy company

Summary

This project is for the scheduled overhaul of Generating Unit 3 Turbine Valves at the Holyrood Thermal Generating Station (Holyrood). The generating units at Holyrood experience numerous system faults and swings in load during system events, which increases the forces and load induced upon the turbine control valve. Completing scheduled overhauls at the correct times are required to ensure reliable operation.

The report illustrates the primary reasons why the turbine valves are overhauled on a three year schedule. It also emphasizes consultant reviews of the system and their recommendations and findings. Important factors that support the conclusions made by this report include, but are not limited to, age of equipment, major work and/or upgrades, anticipated useful life, maintenance history, and historical information.

The estimated project cost is approximately $3,290,500 with planned completion in 2019.

Table of Contents

Summary i
1 Introduction 1
2 Project Description 1
3 Justification 2
3.1 Existing System 2
3.2 Operating Experience 3
3.2.1 Historical Information 3
4 Conclusion 4
4.1 Project Estimate 4
4.2 Project Schedule 4

1 Introduction

Hydro's Holyrood Thermal Generating Station (Holyrood) is a critical part of the Island Interconnected System (IIS). The three oil-fired generating units provide an installed capacity of 490 MW. As part of the generation process, numerous valves in the system control different functions such as controlling the main steam flow into the high compression stage of the turbine and releasing steam from the turbine in the event of a unit trip. All of the valves are required to operate reliably during steam production and are overhauled on a standard three-year cycle.

2 Project Description

This project is required to complete a scheduled turbine valves overhaul for Unit 3 at Holyrood.

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

- Two main stop valves;
- Two combined reheat stop/intercept valves;
- Four control valves; and
- Auxiliary valves (blowdown valve and non-return valves).

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

The work required for this project can be classified into three categories:

1. Routine standard work defined by the equipment manufacturer;
2. Defined work, which is extra to the standard work and identified prior to the overhaul; and
3. Unforeseen work, which may result from examination of the equipment during the internal inspection.

The schedule to complete the standard and defined work is within the specified overhaul period. Action by the contractor on unforeseen work is determined in consultation with Hydro staff. The valve overhaul will take approximately 12 weeks to complete, and any unforeseen work, particularly if components need to be sent off site for refurbishment, could alter the schedule and have an impact on the overall cost.

3 Justification

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

Since the installation of Unit 3 in 1979, valves overhauls of the turbine and auxiliaries have been performed on a scheduled basis that reflected industry standards. The turbine valves manufacturer recommended that a three-year cycle should be maintained for turbine valve overhauls to minimize unplanned corrective maintenance. In January 2010, AMEC Americas Limited (AMEC) was contracted by Newfoundland and Labrador Hydro to conduct a Phase 1 Condition Assessment and Life Extension Study of the Holyrood Generating facility. The study agreed with the three-year cycle for turbine valve overhauls. Hydro has maintained this cycle since the generating units were put into service. Also, the Holyrood Turbine Service Provider, GE, provided engineering recommendations to complete the scheduled turbine valve overhaul to avoid the risk of turbine overspeed and forced outages.

The Unit 3 turbine valves were last overhauled in 2016 and will be due for an overhaul in 2019.

3.1 Existing System

The three major components of the thermal generating units are the power boiler, turbine, and generator. Through combustion of No. 6 fuel oil, the power boiler provides high energy steam to the turbine. The turbine is directly coupled to the generator and provides the rotating energy necessary for the generator to produce rated output power.

The Unit 3 turbine was manufactured by Hitachi in 1978. The turbine was supplied with major turbine valves including control valves, stop valves, intercept valves, a blowdown valve, and extraction steam non-return valves.

The control valves control the flow of steam to the turbine to rotate the generator rotor for electricity production. These valves open and close to vary the flow rate of the steam, thus varying the production of electrical energy. These valves also perform the vital function of protecting the turbine from overspeed failure during emergency shut down. The stop, intercept, and blowdown valves protect the turbine from overspeed failures in emergency conditions. The extraction non-return valves allow steam to flow from the turbine to the feedwater heaters to preheat the boiler feedwater for thermal efficiency gains. These valves are designed to slam shut during emergencies such as sudden loss of load to protect the turbine from water induction and overspeed failure.

3.2 Operating Experience

Turbine valves have operated reliably and safely, with no forced outages, under the current maintenance practices since the 2016 overhaul.

3.2.1 Historical Information

Since the commissioning of Unit 3 in 1979, turbine valve overhauls have been performed on a three-year frequency that matches industry standards. Table 1 details the costs incurred for the last three overhauls.

Table 1: Unit 2 Overhaul Maintenance History ($000s)

Year	Unit	Type of Overhaul	Costs
2016	3	Major[1]	5,869
2013	3	Valves	1,003[2]
2010	3	Valves	909[2]

[1] A major overhaul also includes a Valves Overhaul.

[2] It should be noted that the costs in 2010 and 2013 were Operating Budgets. Also, in 2013 the work was done in parallel with the Unit 1 turbine rebuild and as such there were shared overhead costs.

4 Conclusion

The purpose of the Unit 3 turbine valve overhaul is to restore their capabilities to ensure that the valves perform safely, efficiently, and reliably until the next overhaul. This project will contribute to ensuring the reliable operation of Holyrood Unit 3 generating unit.

4.1 Project Estimate

The estimate for this project is shown in Table 2.

Table 2: Project Estimate ($000s)

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

4.2 Project Schedule

The anticipated project schedule is provided in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Open Project, prepare work breakdown structure and scope statement	Jan 2019	Jan 2019
Procurement	Order parts	Jan 2019	Feb 2019
Construction	Perform pre-shutdown checks and isolations	Jun 2019	Jun 2019
	Remove, dismantle and inspect valves	Jul 2019	Jul 2019
	Overhaul and re-assemble valves	Jul 2019	Aug 2018
Commissioning	Perform operational checks	Sep 2019	Sep 2019
Closeout	Prepare closeout documentation	Sep 2019	Dec 2019

1, Amlbgrgml ?qqcqqkclr _lb Kgqacjj_lcmsq Snep_bcq - Fmjwpmmb

REGISTERED PROFESSIONAL ENGINEER PEG MOHAMED KHALIFA Mohamed Khalifa SIGNATURE July 19, 2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Condition Assessment and Miscellaneous Upgrades

Holyrood

July 2018

newfoundland labrador hydro
a nalcor energy company

Summary

The project is the last year of a three-year program at Holyrood Thermal Generating Station (Holyrood) that was started in 2017 and proposed for completion in 2019. It includes a Level 2 condition assessment related to internal components of the main steam generators (boilers) and also associated external high energy piping. In addition to the condition assessment work, various refurbishments and replacements will take place related to several pieces of equipment and other infrastructure.

Holyrood has exceeded the normal life expectancy for thermal generating stations. In order to maintain reliable operation of the station, this project proposal is to execute a detailed investigation to determine the appropriate timing of refurbishment and replacement work, correct deficiencies identified during plant operation, and complete work on assets that are required on a regular basis.

The estimated project cost is approximately $1,968,800 with the majority of the inspection and testing work to be performed during the planned outage for each generating unit in 2019.

Table of Contents

Summary i
1 Introduction 1
2 Project Description 1
3 Justification 1
3.1 Existing System 2
3.2 Operating Experience 2
3.2.1 Historical Information 4
3.2.2 Anticipated Useful Life 4
4 Conclusion 4
4.1 Project Estimate 4
4.2 Project Schedule 5

Appendices

Appendix A Holyrood Level II Condition Assessment - 2017

1 Introduction

This project is the last year of a three-year program, outlined in the 2017 Capital Budget Application, for the Holyrood Thermal Generating Station (Holyrood) that was started in 2017 and will continue to 2019. The 2017 project was approved by the Board under Board Order No. P.U. 45(2016) and the 2018 project was approved by the Board under Board Order No. P.U. 43(2017). The scope for the 2019 project includes a Level 2 condition assessment related to internal components of the main steam generators (boilers) and associated external high energy piping. Additionally, Hydro is proposing to complete various upgrades and replacements, as outlined in the following sections.

2 Project Description

The project includes a Level 2 condition assessment on internal components of the main steam generators (boilers) and associated external high energy piping to detail refurbishment or replacement work to be completed in succeeding years. Additionally, the following miscellaneous upgrades will be completed:

- Replacement of boiler expansion joints and boiler refractories.
- Upgrade of site security.
- Replace back-up control center building air conditioning system.

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

3 Justification

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

3.1 Existing System

Each generating unit at Holyrood has an oil-fired boiler. Each boiler generates steam with high flow rate at high pressure. The steam is transferred from each boiler through high energy piping and passes through a steam turbine. The steam spins the turbine that drives a generator to produce electricity.

After the Muskrat Falls development is brought into service, Holyrood assets can be separated into two classes:

1. Assets that will remain in service for a standby generation period and will be shut down at the end of this period as electricity generation will be no longer required at Holyrood. These assets such as boilers and auxiliary systems will require condition assessments to ensure short term reliability; and
2. Assets that will be required to remain reliable for more than 20 years to support synchronous condenser operation. Some assets such as the waste water treatment plant and basins require condition assessments to ensure long term reliability.

3.2 Operating Experience

The existing main steam generators (boilers) and associated high energy piping (main steam piping, hot reheat piping, cold reheat piping and high pressure feed water piping) are subjected to high temperatures, corrosion and erosion deterioration mechanisms. For this reason, continued Level 2 condition assessments are required to ensure reliable operation, and these components have been a focus of the condition assessment projects since 2012. Through previous condition assessments, issues were identified with piping wall thinning, thermal cracking of boiler internal headers, and weld deficiencies. The consequence of operating with these issues would result in operating the equipment at less than the design criteria with increased likelihood of failure.

As deficiencies are discovered, upgrades ensure safe and reliable operation. Recommended interventions from previous condition assessments are included in the scope of subsequent projects. For example, the 2018 condition assessment project currently being executed was guided by the results of the 2017 project. Background assessment information and recommendations from the 2017 project are provided in Appendix A. The 2019 project scope will be guided by the results of the 2018 work completed this year.

Level 2 condition assessments are required to identify required work and to allow for planned interventions to avoid failures and unplanned outages.

The Holyrood gated site covers approximately 286,000 square meters. The current security system was installed in 2007-2008. Since then, there have been changes to the site and operations, including the addition of the Gas Turbine in 2015-2016. Currently, many occupied zones are not monitored via security cameras due to outdated and non-functioning cameras. For example, the contractor parking lot, main parking lot, marine terminal, and site access gates are unmonitored. The current security system is outdated, often malfunctions, and is no longer reliable.

The Backup Control Center (BCC) must be readily available and properly maintained to ensure its capability. The BCC contains essential operating equipment that can control Hydro's generating systems in the event that the Energy Control Center (ECC), located at Hydro Place, becomes inoperable. The BCC building, constructed in 2006, has an air conditioning unit in the control room installed at the time of construction. The existing air conditioning unit is at the end of its useful service life. For safe and reliable operation of the BCC equipment, proper cooling is required to avoid overheating. In addition, the existing air conditioning unit is not linked to the BCC emergency generator. If power is lost to the BCC building, the emergency generator will automatically start providing power to the BCC computer equipment but not the cooling system. Without having the cooling system linked to the emergency generator, the control room equipment is at risk of overheating during a power outage.

3.2.1 Historical Information

Hydro is presently working on the activities outlined in the 2018 project of this program.

3.2.2 Anticipated Useful Life

It is anticipated that Holyrood will continue reliable operation as a thermal generating station until the Muskrat Falls development is brought into service and thereafter as a Synchronous Condenser station.

4 Conclusion

Holyrood has exceeded the normal life expectancy for thermal generating stations.

This project is the last year of a three year program that was started in 2017 and proposed for completion in 2019. It includes a condition assessment and various sustaining refurbishments and replacements related to several major pieces of equipment and infrastructure.

This program is required to ensure a reliable operation for Holyrood as a power generating station until the Muskrat Falls development is brought into service.

4.1 Project Estimate

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000s)

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

4.2 Project Schedule

The anticipated project schedule is provided in Table 2.

Table 2: Project Schedule

Activity	Start Date
Initiation	Feb 2019
Condition Assessment Contract	Mar 2019
Inspection Contracts	Apr 2019
Site Investigations and Inspections	Apr-Oct 2019
Replacement and Refurbishment	Jun-Jul 2019
Condition Assessment Report	Nov 2019
Close Out	Dec 2019

Appendix A

Holyrood Level II Condition Assessment - 2017

Amec Foster Wheeler
4th Floor, 393 University Avenue
Toronto, Ontario, Canada. M5G 1E6
Tel: (416) 592-7000 Fax: (416) 592-8284
www.amecfw.com

December 20, 2017

Jamie Curtis
Project and Quality Assurance Engineer
Holyrood Thermal Generating Station
Newfoundland and Labrador Hydro

Re: Holyrood Thermal Generating Station Level II Condition Assessment
2017 NDE Inspections

Dear Mr. Curtis,

Amec Foster Wheeler prepared a Level II condition assessment for Holyrood Thermal Generating Station (HTGS), based on the results of the Level I assessment [1]. The Level II focused on major boiler components and high-energy piping, including pipe support systems. Since then, follow-up inspections have been conducted based on the recommendations provided in the condition assessments [2][3][4][5].

The scope of the 2017 inspections was:

1. Flow Accelerated Corrosion (FAC)
    a. Unit 2 Economizer Inlet Header Piping,
    b. Unit 2 Boiler Feed Pump Piping at Flow Element (FE) 554,
    c. Unit 2 Repaired area on Bend 4 upstream of the No. 6 High Pressure Feedwater (HPFW) Heater,
    d. Unit 3 Repaired Area above the No. 6 HPFW Heater.
    e. Unit 3 Emergency Reheat Attemperator Refill Line Piping at FE 3595,
2. NDE Data collection
    a. Unit 1 Phased Array Ultrasonic Testing (PAUT) of lower vestibule feeder tubes
    b. Unit 1 and Unit 2 Boroscope inspection of economizer inlet headers
    c. Unit 3 Replica and UT inspections of the main steam turbine terminal

3. Unit 3 Boiler Tube Inspections

The findings from these 2017 activities are summarised in the attached table. The FAC Analysis Report is attached as an Appendix to this summary letter. The NDE reports are provided in the 2017 reference Binder [6].

FAC Inspection Results

FAC inspections were recommended based on previous findings with low re-inspection intervals and areas showing degradation in similar locations in other units. All the recommended locations were inspected. The FAC analysis report is included as an attachment to this letter. The previously repaired areas were found to be in good condition for continued operation. The Unit 3 Emergency Reheat Attemperator Refill Line Piping at FE 3595 was replaced [7]. There was no FAC assessment at this location.

Two locations on Unit 2 had measurements below the ASME calculated pressure-based minimum wall thickness [8]: Piping to the Economizer inlet header and FE 554. A temporary weld buildup was applied to FE554 and replacement was planned for September 2017 [9].

The economizer inlet header piping thinned area was too large to apply a National Board Inspection Code compliant weld repair. Instead this location was dispositioned through analysis. Replacement was planned for September 2017 and analysis using the guidance in EPRI NP-59911-SP [10] and the ASME B31.1 standard was applied to allow operation until replacement [11]. Both locations were replaced in the fall 2017 Unit 2 outage.

As part of an effort to disposition the low FAC inspection findings, re-rating of the feedwater piping in the Holyrood units was considered. The FAC inspection results and piping replacements demonstrate that the burden for remediation and analysis will increase with advancing plant age. In particular, areas adjacent to welds, where the machined counter-bore contributes to the reduced margin on wall thickness, will necessitate repairs on otherwise acceptable pipe segments. In an attempt to address this concern, an investigation into the necessary steps to reduce the registered design pressure was undertaken [12], however the effort for re-rating was significant and therefore this option was not pursued. It is recognized that the expectation is for an increasing number of piping replacements on the feedwater system in future outages.

Boiler Tube Inspection Deferral

Boiler tubes in Holyrood TGS experience fireside corrosion and erosion. Reliable operation to 2021 was concluded in a previous assessment with the exception of Unit 3. Specific sections of Unit 3 had lower margins on minimum acceptance criteria and were recommended for re-inspection in 2017. Due to outage limitations only accessible areas were inspected. With the exception of one location, the wall thicknesses were above the minimum acceptable and showed minimal change. The one location on the south bend at the 9th floor Reheater tubes, found a significant wall thickness difference from the 2016 inspection. Weld repairs were applied. Deferral of the remainder of the inspections to 2018 was deemed acceptable but procurement of spare tubing and inspection of locations near furnace wall lugs were recommended [13].

Other NDE Inspections

PAUT was completed on bends in the lower vestibule feeder pipes on Unit 1 to determine if there was evidence of corrosion fatigue cracking on the feeder ID on the bends. The inspections would follow-up on work performed in 2013 to support the conclusion that cracking in the lower feeder pipes was not an active mechanism [5]. The 2017 PAUT inspection did not find any indications of cracking in the feeder pipes. Internal pitting was noted in one location (minimum wall thickness of 0.325"). Similar indications of pitting were observed in previous inspections [3] but were found to be inactive. The wall loss is not considered an operability concern.

Internal video inspection of the Unit 1 and Unit 2 economizer inlet headers was planned but only the Unit 1 inspection could be completed. The inspection report did not note any concerning indications, e.g. extension of the existing thermal fatigue cracking. The report did mention that the colour of the scale appeared to have changed. Images from the inspection video also show small dark spots. These do not appear to be an integrity concern but other changes to the internal scale should be noted in the next scheduled inspection in 3 years.

A Replica and PAUT inspection of the Unit 3 main steam piping at the West Upper turbine terminal point weld was performed in accordance with the recommended 3-year cycle. Although the wall thickness measured was slightly lower than previously reported [4] this does not pose an integrity concern. The volumetric inspection, the replication and magnetic particle inspection found no indications of creep damage. It was also found that the wall thicknesses on both side of the weld were above the pressure based minimum requirements identified in Appendix C of the 2014 report [4]. Despite these findings monitoring on a 3-year cycle should continue as a lead indicator of end of creep life.

Conclusion

The HTGS piping is in good condition considering its age. FAC requires continued monitoring. Weld repairs and replacements were required to maintain compliance with the power piping code at the system design pressure. More repairs and replacements should be expected as the margin to minimum wall thickness is further reduced during operation. Piping sections that have been replaced are expected to be fit for service to end of life with no further inspection required. Inspections should continue at their recommended frequency in order to ensure reliable operation.

The current assessments consider operation to an end of life of 2021.

Inspection Recommendations

Based on a review of the 2017 inspection results and previous condition assessments the following inspections should be carried out in 2018.

1. Unit 1 – Inspection of Steam Drum Downcomer Penetration.
2. Unit 3 – Economizer Inlet Header - internal visual inspection to monitor ligament cracking. PAUT Inspection to characterise and size the ligament cracks should be reconsidered, though the difficulties in inspecting ligaments have been previously noted.
3. Unit 3 – Boiler Tube Inspection (deferred from 2017 scope and additional):
    a. High temperature superheater, 8.5th floor, overhead, tube (nested tubes adjacent to outlet header),
    b. Reheater, 9th floor, overhead, tube (nested tubes adjacent to outlet header),
    c. Reheater and Superheater tube bends at furnace wall lug connections.

4. FAC Inspections – where available previous year of inspection and location index provided.

   a. Unit 3 Boiler Feed Pump Discharge - Low Flow Line Connection to Main Run. Elbow and Pipe (2014, 3-4).

   b. Unit 3 West Boiler Feed Pump Discharge. (Repaired 2015, 3-3).

   c. Unit 3 High Pressure (HP) Heater No. 6 ByPass – 1st Elbow D/S of Tee bypass branch (left bend). (2015, 3-1).

   d. Unit 3 High Pressure (HP) Heater No. 6 ByPass – last Bypass elbow (vertical to horizontal bend). (2015, 3-2).

   e. Unit 3 Boiler Feed Pump Discharge Flow Element 3554.

   f. Unit 1 West BFP discharge elbow and reducer (Repaired 2015, 1-3).

If operation beyond 2021 is anticipated it is recommended that a review of the Level II condition assessments and maintenance program be completed. A similar review is recommended if there is a significant change in operating patterns, e.g. to 2-shifting.

REFERENCES

[1] T. Mahmood, T. Ogundimu, "HTGS Condition Assessment and Life Extension Study," Amec Foster Wheeler File No. AM060/RP/001 R01, January 2015.

[2] A. Valsalan, Holyrood Thermal Generating Station 2016 NDE Inspections, Amec Foster Wheeler File No. BW018/002/000001 R00, February 17, 2017.

[3] T. Ogundimu, "Holyrood Level II Condition Assessment Follow-Up Inspections – 2015," File No. BW016/RP/003 R00, December 24, 2015.

[4] T. Ogundimu, "2014 Level II Condition Assessment Boiler and Steam Piping, Flow Accelerated Corrosion, Units 1 and 3 Generators, Civil Structures," File No. AM160/RP/002 R01, December 5, 2014.

[5] D. McNabb, "Holyrood Thermal Generating Station Condition Assessment and Life Extension Study –Phase 2, 2012/13 Level II Condition Assessment Boiler and High-Energy Piping," File No. AM132/RP/005 R03, November 13, 2013.

[6] NDE Reference Binder, Amec Foster Wheeler File No. AM231/RE/004 R00, December 15, 2017.

[7] J Curtis, "Re: Unit 3 FE 3595 (Reheat Attemperator refill line), E-mail to T Ogundimu AmecFW file AM231/RE/006, July 10, 2017

[8] Power Piping Code, ASME B31.1 1967.

[9] T. Ogundimu, "Flow Accelerated Corrosion Screening Report", Amec Foster Wheeler File No. AM231/RE/001 Part 2, June 13, 2017.

[10] "Acceptance Criteria for Structural Evaluation of Erosion- Corrosion Thinning in Carbon Steel Piping", EPRI Technical Report NP-5911-SP, July 1988.

[11] T. Ogundimu, "Holyrood Unit 2 Economiser Inlet Piping Wall Thinning Disposition", Amec Foster Wheeler File No. AM231/CN/001 R00, May 31, 2017.

[12] D. McNabb, "Re: Analysis for Re-Rating the HP Feedwater Piping", E-mail Record AM231/RE/005, 15 June 2017.

[13] D. McNabb, "Unit 3 Boiler Tube Inspection – Primary Assessment of Results", Amec Foster Wheeler File No. AM231/004/000001 R01, September 6, 2017.

Prepared by:
Tolulope Ogundimu
Senior Analyst
Inspection and Maintenance Engineering

Verified by:
Alia El-Rashidi
Associate Analyst
Life Cycle and Asset Management

Approved and Reviewed by:
David McNabb
Manager
Life Cycle and Asset Management

REGISTERED PROFESSIONAL ENGINEER
D. D. McNABB
20/12/17
PROVINCE OF ONTARIO

Appendix A

Table A1 Results and Recommendations from the 2017 NDE Inspections

Unit	Component/Location	Inspection	Findings	Recommendations
Unit 1	Economiser Inlet Header	Internal Visual	Borehole cracking unchanged. Discolouration of internal surface noted.	No re-inspection required to end of life. Or re-inspect in 3 years.
Unit 1	Lower Vestibule Feeder Tubes	Phased Array Ultrasonic Testing	No cracking found. Minor internal pitting noted	No re-inspection required to end of life.
Unit 2	Feedwater - BFP Discharge: Economizer Inlet Header Piping	UT Grid for Flow Accelerated Corrosion	Measurements below minimum wall thickness found. Assessed for continued operation. Bend replaced in fall 2017.	No re-inspection required to end of life.
Unit 2	Feedwater - BFP Discharge: Flow Element 554	UT Grid for Flow Accelerated Corrosion	Measurements below minimum wall thickness found. Pad weld applied. FE replaced in fall 2017.	No re-inspection required to end of life.
Unit 2	Feedwater – Heater No.6 Bypass Piping	UT Grid for Flow Accelerated Corrosion	Re-inspection of 2016 pad weld. All locations were above minimum wall thickness. Adjacent pipe is limiting.	Re-inspection of bend in 2 years.
Unit 3	Feedwater – Heater No.6 Discharge Piping	UT Grid for Flow Accelerated Corrosion	Re-inspection of 2014 pad weld. All locations were above minimum wall thickness. Adjacent pipe is limiting.	Re-inspection of bend in 4 years.
Unit 3	Main Steam Turbine Terminal	Replica, PAUT, UT, Magnetic Particle	No indications of creep found. Microstructure shows high-temperature creep damage consistent with previous findings. Wall thickness noted to be slightly lower than previously report.	Continue recommended monitoring in 3 years.

<table>
<tr><td colspan="2">FLOW ACCELERATED CORROSION ANALYSIS REPORT</td><td rowspan="2">amec foster wheeler</td></tr>
<tr><td colspan="2">Client: Amec FW Newfoundland, Holyrood Thermal Generating Station</td></tr>
<tr><td>Unit:</td><td>Systems:</td><td>Date:</td></tr>
<tr><td>2, 3</td><td>Feedwater</td><td>December 20, 2017</td></tr>
<tr><td colspan="2">Operating Years:</td><td>Amec Foster Wheeler File Number:</td></tr>
<tr><td>Total:</td><td>Unit 2 – 46 years
Unit 3 – 38 years</td><td rowspan="2">AM231/003/000001 Attachment</td></tr>
<tr><td>Since Last Inspection:</td><td>1 year</td></tr>
<tr><td>Inspection Method:</td><td>Inspection Procedure/Technique:</td><td>Inspection Date:</td></tr>
<tr><td>☒ Ultrasonic (U/T)</td><td></td><td>May-June</td></tr>
<tr><td>☐ Pulse Eddy Current (Incotest)</td><td></td><td></td></tr>
<tr><td>☐ Radiography</td><td></td><td></td></tr>
<tr><td>☐ X-Ray Fluorescence (Material Testing)</td><td></td><td></td></tr>
</table>

SCOPE (Locations and Component Summary):

Amec Foster Wheeler Nuclear Canada recommended follow-up inspections in 2017 based on previous Flow Accelerated Corrosion (FAC) inspections. The recommendations considered the findings for previous years which were reaching the noted re-inspection time (half of the remaining wall thickness margin in most case) and similar locations that saw degradation in other units. All recommended locations were inspected. A correction was made to the 2017 FAC inspection report which reduced the inspection/repair scope. The remaining inspections were executed. The location numbers below are consistent with the 2016 numbering.

Unit 2

2-1: BFP Discharge - Piping to Economiser Inlet Header

- Double bend upstream of economizer inlet header
- (see drawing 238-10-6022-028 R4)

2-2: BFP Discharge Flow Element 554

- Piping upstream and downstream of flow element
- (see drawing 238-10-0210-024 R1)

2-3: BFP Discharge - No. 6 Heater Bypass (area repaired in 2016)

- First lower bend after tee connection from outlet of heater no. 5, straight section after tee connection, first bend, straight section, second bend, straight section upstream and downstream of valve, straight section, third bend
- (see drawing E-343-M-001 R19 and 238-10-6022-028 R4)

Unit 3

3-2: BFP Discharge - No. 6 Heater Discharge (area repaired in 2014)

- Downstream of FE3595, on straight pipe sections around valves TV3623B and ZS3623
- Immediately adjacent to the FE, upstream and downstream on straight pipe sections and on straight pipe sections of the connecting 1" lines
- Upstream of FE3595, on straight pipe sections between valves and reducers off BFP P1
- (see drawing E-343-M-001 R19)

Piping in the Reheat Attemperator Fill Line at FE 3595 was replaced. No FAC assessment was done.

RESULTS AND COMMENTS:

This report is a follow up of the preliminary assessment and recommendations made during the 2017 outage, based on the NDE data received. All the locations inspected were either previous pad weld repairs or re-inspections of areas recommended for revisit due to low margin. Measurements were only taken in areas of interest and not around the entire pipe circumference. As such, the EPRI band method could not be applied. Where the minimum measured wall thickness remained above the ASME minimum, the wall loss rate from the last inspection was applied and a re-inspection interval determined. When the minimum wall thickness was below the ASME minimum, repair, replacement or disposition was completed.

Locations that had been marginally above the ASME minimum wall thickness the year before (2-1, 2-2), were found to be below in the 2017 inspection. A Weld repair was required for the FE 554 location (2-2) and replacement was executed in the fall of 2017. A disposition to demonstrate fitness for service was prepared for the economizer inlet piping (2-1) and the replacement was executed in Fall 2017.

Locations Below Code Minimum Wall:

- 2-1: BFP Discharge - Piping to Economiser Inlet Header
- 2-2: BFP Discharge Flow Element 554

Results and Recommendations:

2-1: BFP Discharge - Piping to Economiser Inlet Header

A small area was recommended for re-inspection based on the 2016 inspection analysis. Wear rate analysis was performed using the UT data from a grid layout. Some locations were below the calculated pressure based minimum wall thickness. Analysis was performed to support operation until replacement of elbow could be executed in the Fall of 2017. Replacements was completed. No re-inspection for the remaining plant operating life is necessary.

2-2: BFP Discharge Flow Element 554

This location was recommended for re-inspection and repair based on the 2016 analysis results. Results from the 2017 inspection found grid points below the calculated pressure based minimum wall thickness. The 2016 analysis did not note any measurements below minimum wall thickness and this extent of wall loss is not expected to have occurred over only one operating year. The source of the discrepancy is not known though differences in the precise inspection location and the finer grid size used in the 2017 inspection likely contributed. A pad weld was applied while a replacement FE was fabricated to the original FE dimensions. The FE was replaced in the Fall of 2017. No re-inspection of this location is required for the remaining plant operating life.

2-3: BFP Discharge - No. 6 Heater Bypass (area repaired in 2016)

Weld repair was conducted in this area in 2016 to increase the wall thickness and to provide additional margin. The pad weld was re-inspected in 2017. Using the wear rate from the original wall thicknesses in 2016 analysis with the 2017 measurements, the re-inspection interval for this location is 2 years.

3-2: BFP Discharge - No. 6 Heater Discharge (area repaired in 2014)

Weld repair was conducted in this area in 2014 to when a single low wall thickness measurement was noted. The pad weld was re-inspected in 2017. The 2017 inspection area does not appear to be centred on the pad weld but provides measurements on a portion of both the pad weld and the adjacent pipe material. The pad welded area showed significant margin on the minimum wall thickness. Areas adjacent to the pad weld, with the original pipe material showed lower margin to minimum wall thickness. Using the wear rate from the original wall thicknesses in 2014 analysis with the 2017 measurements, the re-inspection interval for this location is 3.9 years.

References:

1. AM231/RE/001 Flow Accelerated Corrosion Screening Report Part 2, June 13, 2017.
2. A. Ali, "Flow Accelerated Corrosion Analysis Report", BW017/RP/002 R02, June 30, 2017.
3. T. Ogundimu, "Flow Accelerated Corrosion Analysis Report", AM160/RP/001 R00, November 14, 2014.
4. G. Poon to S. Lingley, "Re: External Weld Metal Buildup Procedure – Holyrood TGS Feedwater Piping, Line # 3-HFW-09-L502", BW016/005/000002 R02, October 26, 2015.

Table 1 Summary Table – 2017 Holyrood TGS Flow Accelerated Corrosion NDE Data Analysis

Base Data							Inspection Results					Inspection Status		
						Fabricated (")	Measured (2017)		Calculated					
Location Description	Site No.	Component	NPS (Inch)	SCH	ASME Minimum Wall Thicknes s (Inch)	Nominal Wall Thickness[4] (Inch)	Band [2] t_{min} (Inch)	Band [2] t_{max} (Inch)	Maximum Wear[3] (Inch)	Band Wear rate (Inch/yr)[1]	Margin to Minimum Req'd Wall Thickness (Inch)	Re-inspecti on time[5] (years)	Potential Signs of FAC	Comments
Economizer Inlet Header Piping Bottom Bends	2-1	Bend 2	10	160	0.980	1.125	0.972	1.194	0.201	0.004	0.012	**NA**	Significant	Measured max and min wall thickness have been updated for 2017 inspection results. Calculated inspection results reference previous complete inspection (2016). Pipe was replaced Fall 2017.
Boiler Feed Pump Flow Element 554	2-2	Straight Pipe Segment	10	160	0.980	1.125	0.961	1.168	0.135	0.003	0.014	**NA**	Moderate	Measured max and min wall thickness have been updated for 2017 inspection results. Calculated inspection results reference previous complete inspection (2016). FE was replaced Fall 2017.
High Pressure Heater No. 6 Bypass Piping	2-3	Bend upstream of Heater 6 inlet	10	160	0.980	1.125	1.013	1.173	0.337	0.007	0.033	**2.2**	Significant	Re-inspection time updated with wall thickness of re-inspected area after 2016 pad weld. Max wear and wear rate reported here are the original 2016 data (pre-repair) of the pad welded area.
High Pressure Heater No. 6 Discharge Piping	3-2	2nd Elbow Downstream	10	160	0.98	1.125	1.029	1.176	0.218	0.006	0.049	**3.9**	Significant	2014 pad weld re-inspected to confirm margin. Max wear and wear rate are from the original 2014 inspection results, prior to the pad weld.

[1] Based on years of service from last full inspection (see comments).

[2] Measurements use the max and min from the re-inspected areas (since full circumference bands were not inspected in 2017).

[3] This column represents band wear.

[4] This column represents nominal wall thickness corresponding to the pipe schedule, or assumed pipe schedule if not directly available.

[5] The re-inspection time is based on margin above the required minimum wall thickness, except for repaired or previously repaired locations.

FAC	Wear
Significant	>0.200" maximum wear
Moderate	0.100" - 0.200" maximum wear
Minor	0.000" - 0.100" maximum wear

4. Overhaul Olympus Gas Generator – Stephenville

REGISTERED PROFESSIONAL ENGINEER PEG MOHAMED KHALIFA SIGNATURE July 19, 2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Overhaul Olympus Gas Generator

Stephenville

July 2018

newfoundland labrador hydro
a nalcor energy company

Summary

The 50 MW Stephenville Gas Turbine, commissioned in 1975, is operated in either generation mode to meet peak and emergency power requirements, or synchronous condenser mode to provide voltage support to the Island Interconnected System (IIS).

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

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

The estimated project cost is approximately $1,666,800, with planned completion in 2019.

Table of Contents

Summary i

1 Introduction 1

2 Project Description 1

3 Justification 1

3.1 Existing System 1

3.2 Operating Experience 3

3.2.1 Maintenance Support Arrangements 3

3.2.2 Maintenance History 3

3.2.3 Anticipated Useful Life 3

3.3 Development of Alternatives 4

4 Conclusion 4

4.1 Project Estimate 4

4.2 Project Schedule 5

1 Introduction

The 50 MW Stephenville gas turbine, which was commissioned in 1975, is operated in either generation mode to meet peak and emergency power requirements, or synchronous condenser mode to provide voltage support to the Island Interconnected System (IIS). Hydro overhauls the Stephenville gas turbine engines on a five-year cycle. The End B engine has been in service since the time of its last overhaul in 2014.

2 Project Description

This project will overhaul the Stephenville gas generator End B engine serial number 202223. The scope of work for the project includes the following:

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

3 Justification

This project is required to maintain the reliable operation of the Stephenville Gas Turbine. Without an overhaul, the risk of an End B engine in-service failure increases. In the event of an in-service failure, the gas turbine will operate on reduced capacity until a spare engine is available and installed, thus reducing the capacity to 25 MW for approximately one week until an available spare 19 MW engine was installed. In this configuration, capacity will be limited to 38 MW for approximately 20 weeks while the engine is repaired. If a spare engine is not available, the gas turbine capacity is 25 MW for 20 weeks.

3.1 Existing System

The Stephenville Gas Turbine provides backup generation and synchronous condense support to the Island Interconnected System. The gas turbine consists of two Rolls Royce Olympus C engines (End A and End B), and two Curtis Wright power turbines, connected to a single 50 MW generator by two SSS Clutches. The plant was placed in service in 1975.

Figure 1 is an image of the Stephenville Gas Turbine Plant and Figure 2 is an image of the gas generator engine.

Figure 1: Stephenville Gas Turbine Plant

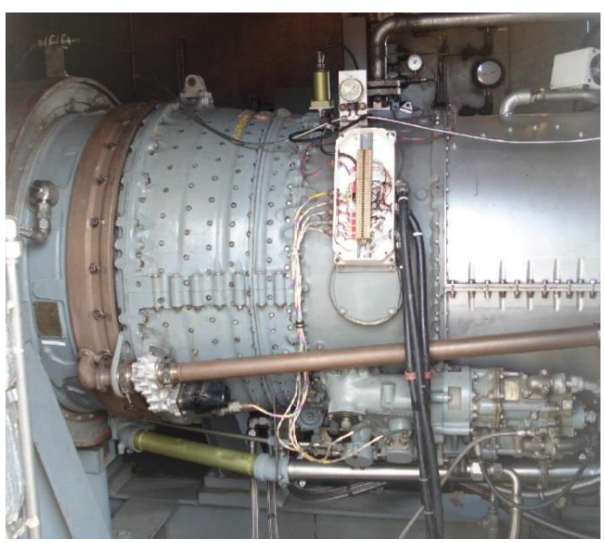


Figure 2: Gas Generator Engine

When the gas turbine operates in generation mode, at least one of the engines has to run continuously for the generator to produce power. However, when the generator runs in synchronous condensing mode only one engine is required to bring the generator up to the proper speed. At that point, the generator can operate without the engine, which is then shut down.

3.2 Operating Experience

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

3.2.1 Maintenance Support Arrangements

Normal routine maintenance work is performed by Hydro. However, gas turbine service companies such as Rolls Wood Group Ltd. and Alba Power Ltd., both located in the United Kingdom, have been contracted in the past to perform visual inspections, on-site specialty maintenance items, and major shop overhauls of gas generator engines.

3.2.2 Maintenance History

Borescope inspections for the gas generator engines were completed every two years until 2014. Considering the age and anticipated increased operation of the engines, annual borescope inspections were completed thereafter.

3.2.3 Anticipated Useful Life

As refurbished rather than new parts are used in this engine overhaul, the anticipated service life before next scheduled overhaul is five years.

3.3 Development of Alternatives

There are no alternatives to this project. Replacement, instead of overhauling the engine, is not possible as there are no new similar engines manufactured.

4 Conclusion

The Stephenville Gas Turbine provides back-up generation and synchronous condense support to the Island Interconnected System. As new internal components are not available, the service life of an engine overhaul, using refurbished parts, is five years. The End B engine has been in service since its last overhaul in 2014. Thus, the engine is nearing the end of its useful overhaul life. To maintain operational reliability of the Stephenville Gas Turbine Plant, the End B engine needs to be sent to a gas turbine service facility for a scheduled overhaul.

4.1 Project Estimate

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000s)

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

4.2 Project Schedule

The anticipated project schedule is provided in Table 2.

Table 2: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Open Project	Jan 2019	Jan 2019
Procurement and Execution	Public tender for engine overhaul	Feb 2019	Mar 2019
	Tender evaluation and award	Mar 2019	Mar 2019
	Transportation and overhaul	April 2019	Jun 2019
	Return transportation and installation	Jul 2019	Aug 2019
Commissioning	Commissioning	Aug 2019	Aug 2019
Project Closeout	Project Closeout	Sep 2019	Dec 2019

3, Snep_bc FKG $?TP - F_pbummbq

REGISTERED PROFESSIONAL ENGINEER A.C. WARREN SIGNATURE 07/24/2018 DATE PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Upgrade Human-Machine-Interface and Automatic Voltage Regulator

Hardwoods Gas Turbine

July 2018

newfoundland labrador
hydro
a nalcor energy company

Summary

This report details the upgrade of the Human-Machine-Interface (HMI) and the Automatic Voltage Regulator (AVR) at the Hardwoods Gas Turbine site. Both systems are vital to the operation of the gas turbine and need to be replaced due to obsolescence. The HMI and AVR present a risk of having to implement restrictions on the gas turbine operations in the event of failure of either system. If the HMI fails, local control is unavailable and detailed alarms, monitoring and data trending of the gas turbine stops. Without local control, the gas turbine would be unavailable until installation of the spare obsolete HMI, and after that it would run at risk of failure for three months until a new HMI was procured and installed. If the AVR fails, the gas turbine will not be available for operation as there will be no supply of voltage to the generator.

The estimated project cost is approximately $685,900 (the HMI project is approximately $368,500, and the AVR project is approximately $317,400) with a planned completion in 2019.

Table of Contents

Summary i

1 Introduction 1

2 Project Description 1

3 Justification 1

3.1 Existing System 2

3.2 Operating Experience 4

3.2.1 Maintenance or Support Arrangements 4

3.2.2 Anticipated Useful Life 4

3.3 Development of Alternatives 4

4 Conclusion 5

4.1 Project Estimate 6

4.2 Project Schedule 6

1 Introduction

The 50 MW Hardwoods Gas Turbine Human-Machine-Interface (HMI) is the infrastructure through which the local operator performs local control and monitoring of the gas turbine. The obsolete HMI software will not operate on present day computer operating systems. If the HMI computer fails, the gas turbine cannot be locally controlled and monitored until the software and computer are replaced with modern versions.

The Hardwoods Gas Turbine Automatic Voltage Regulator (AVR) is a device that uses the turbine's static excitation system to maintain acceptable generator voltage and control of reactive power flow from the generator. The AVR manufacturer has declared this model obsolete, which limits replacement components availability and could delay the return to service of the gas turbine upon failure of a component.

2 Project Description

The scope of this project includes:

- Removal and disposal of the existing obsolete HMI software and computer;
- Procurement and installation of new HMI including:
  - Provision of new HMI software and computer;
  - Provision of communications modules in the control system to facilitate new HMI interaction with the control system;
  - Conversion and integration of existing HMI graphics into the new software; and
  - Testing of HMI interaction with control system;
- Removal and disposal of existing obsolete AVR; and
- Procurement, installation, and testing of new AVR.

3 Justification

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

3.1 Existing System

The HMI is used for local control and data collection for the Hardwoods Gas Turbine. It provides detailed alarms for troubleshooting and collects trend data for historical analysis.

The HMI consists of specialized software called PCView and an operating system called QNX (not a Windows compatible product) running on an obsolete computer that is connected to the gas turbine control system. Communications modules reside in the control system cabinet that connect to the HMI computer. Interactive graphics were developed by the manufacturer for the HMI, which consist of graphics for control, monitoring, alarms, and trended data.

Figure 1 shows the HMI.

Figure 1: HMI Console

The HMI software entered Limited Lifecycle phase in July 2017 and will enter the obsolete phase in June 2018. In the obsolete phase, the manufacturer will not supply technical support or software upgrades. The last update to the software was in 2012. If the HMI computer fails, it cannot be replaced with a Windows-based computer as the HMI software and operating system will not operate within the Windows environment. The operation of the gas turbine will be significantly impaired without the HMI system as it cannot be locally controlled and monitored.

The Energy Control Centre (ECC) can operate the gas turbine with limited alarms but critical data will not be collected and there will no local monitoring of gas turbine alarms and critical operating parameters. There is insufficient remote visibility of the gas turbine's operation to run it without an HMI in-service and a local operator present to monitor it. Hydro's current operating regime is to have a local operator present while a gas turbine is generating power to monitor its operation and attend to any issues. Without an HMI, the local operator has no visibility into the condition of the gas turbine, and the gas turbine would therefore be unavailable. Although Hydro has a spare HMI of identical vintage to the operating HMI, the gas turbine would have to be shut down by the ECC for approximately one hour while the back-up unit was installed, since local monitoring would be unavailable once the HMI has failed. Subsequently, it would take approximately three months to have a new HMI prepared, installed, and tested, during which time Hydro would be exposed to a subsequent failure of the only available obsolete HMI.

The automatic voltage regulator (AVR) is a micro-processor based system that uses the turbine's static excitation system to maintain acceptable generator voltage and control of reactive power flow from the generator. It consists of a cabinet of redundant controllers and assorted electrical components as shown in Figure 2.

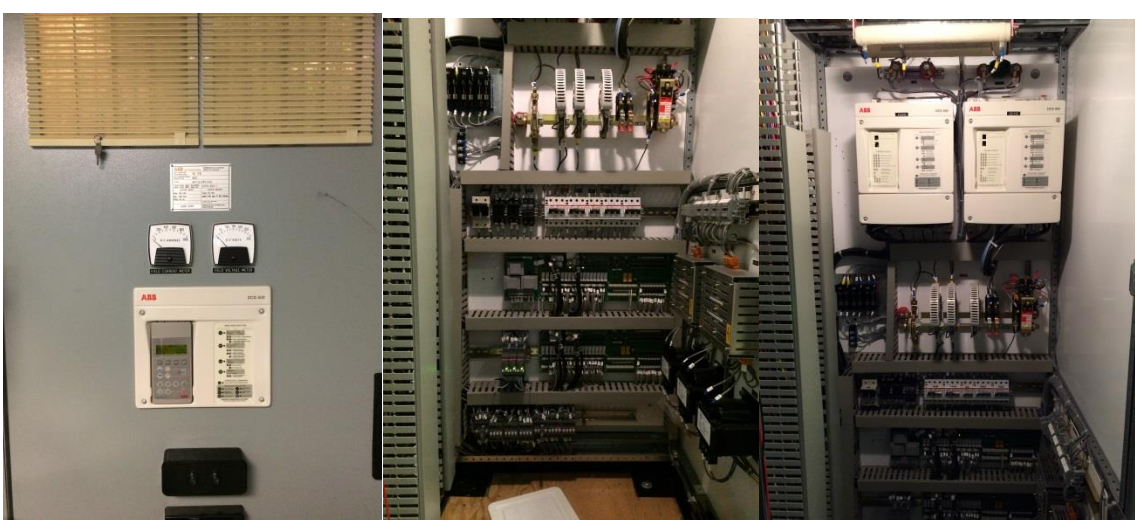


Figure 2: AVR Cabinet (Left to Right: Front, Inside Top, Inside Bottom)

This AVR was installed in 2006 and the manufacturer moved the model into the 'Limited' phase of its life cycle in the beginning of 2017. This phase means the manufacturer cannot guarantee life cycle services and support due to the scarcity of key components and technical knowledge. Therefore, a component failure may result in unavailability of the gas turbine for an extended period due to scarcity of replacement components. As well, the AVR software used for configuration and troubleshooting does not work with modern Windows operating systems, restricting the ability of Hydro personnel to use computer-based tools for troubleshooting. As a result, Hydro has to engage the manufacturer for troubleshooting activities, which increases the time to correct problems.

3.2 Operating Experience

The HMI has provided adequate service since the control system upgrade in 2000 and the AVR has provided adequate service since 2006.

3.2.1 Maintenance or Support Arrangements

Hydro has maintained an HMI software support subscription with the Original Equipment Manufacturer (OEM) for the provision of technical support and upgrades at no cost.

3.2.2 Anticipated Useful Life

The anticipated useful life of the new HMI and AVR is 18 years.

3.3 Development of Alternatives

Two alternatives for upgrading the HMI are:

1. Upgrade present OEM version to the next edition; or
2. Replace with an HMI from another manufacturer.

The first alternative requires importing and conversion of original graphics and database configuration to enable functionality in the new operating software environment. This alternative has the least requirement for development as it is from the OEM and is anticipated to be the lower cost, lower time for implementation, and least potential for mismatch of data between HMI and control system.

The second alternative requires a complete development of all graphics and database points to be used in a different software application and efforts to establish interaction between the HMI and control system from two different manufacturers. This alternative is anticipated to require the most effort to review and test and presents a higher risk of issues with interoperability between the HMI and control system.

Additional communications hardware, a new computer with a modern Windows operating system, and testing are common aspects to both alternatives and do not impact the cost differential between the two options. Therefore, Alternative 1 was selected.

The AVR is to be tendered to determine the lowest cost and functionally acceptable option to purchase.

4 Conclusion

While the HMI has performed satisfactorily to date, the HMI software cannot be transferred to a Windows-based computer if the HMI computer fails. If the HMI fails, the gas turbine cannot be locally controlled or monitored. The ECC does not have sufficient visibility to operate the gas turbine without local detailed monitoring, and in the event of failure the gas turbine operation would be through installation of the only available obsolete spare HMI. It would take approximately three months to have a new HMI prepared, installed, and tested, during which time Hydro would be exposed to a subsequent failure of the spare HMI.

While the AVR has performed satisfactorily to date, the AVR manufacturer cannot guarantee life cycle services and support due to the scarcity of key components and technical knowledge. Therefore, a component failure may result in unavailability of the gas turbine until a new AVR is purchased, installed, and tested. It is anticipated that the development and installation of a new AVR would require five months.

This project will eliminate these risks to operation of the gas turbine, providing greater confidence of reliable operations.

4.1 Project Estimate

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000s)

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

4.2 Project Schedule

The anticipated project schedule is provided in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Project launch and site visit	Feb 2019	Feb 2019
Design	Information Gathering	Mar 2019	Mar 2019
	Design work for HMI	Apr 2019	May 2019
	Design work for AVR	May 2019	Jun 2019
Procurement	Issue contract for HMI	Mar 2019	Jul 2019
	Issue contract for AVR	Mar 2019	Aug 2019
Construction	HMI	Jul 2019	Aug 2019
	AVR	Aug 2019	Aug 2019
Commissioning	Commissioning	Aug 2019	Aug 2019
Closeout	As-Built drafting	Sep 2019	Sep 2019
	Project closeout	Oct 2019	Oct 2019

4, Rcpkgl_j Qr_rgml Pcdsp`gqfkclr _lb Kmbcplgx_rgml &0./7+0.0.'

<table>
<tr><td rowspan="7">LICENSED PROFESSIONAL ENGINEER
08906
MATTHEW P. HALLORAN
Matt Hall
SIGNATURE
2018-07-19
DATE
NEWFOUNDLAND & LABRADOR</td><td>Electrical</td></tr>
<tr><td>Mechanical</td></tr>
<tr><td>Civil</td></tr>
<tr><td>Protection & Control</td></tr>
<tr><td>Transmission & Distribution</td></tr>
<tr><td>Telecontrol</td></tr>
<tr><td>System Planning</td></tr>
</table>

Terminal Station Refurbishment and Modernization

July 2018

newfoundland labrador hydro
a nalcor energy company

Summary

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*. Version 3 of this document is part of the 2019 Capital Budget Application. Changes in this revision are outlined in a new section in the document, titled "*Changes in Version 3*".

Hydro proposes the following activities under the 2019 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;
- refurbishment and upgrade of station grounding;
- refurbishment of equipment foundations;
- installation of fire suppression systems in control buildings;
- refurbishment of control buildings;
- protection, control, and monitoring replacements and modernization; and
- refurbishment of the Wabush terminal station.

Hydro will execute the majority of these activities in a multi-year approach, with all activities scheduled for completion before the end of 2020.

The total estimated project cost is approximately $29,952,900 with a planned completion of 2020.

Table of Contents

Summary i
1 Terminal Station Refurbishment and Modernization Project 1
2 2019 Project 1
2.1 Electrical Equipment 2
2.1.1 Replace Instrument Transformers 2
2.1.2 Replace Disconnect Switches 4
2.1.3 Replace Surge Arrestors 5
2.1.4 Refurbish and Upgrade Power Transformers 6
2.1.5 Replace Insulators 8
2.1.6 Upgrade Grounding 9
2.2 Civil Works and Buildings 10
2.2.1 Repair Equipment Foundations 10
2.2.2 Install Fire Suppression 11
2.2.3 Refurbish Control Buildings 12
2.3 Protection, Control, and Monitoring Refurbishment and Upgrades 15
2.4 Wabush Terminal Station Refurbishment 16
3 Project Cost 17
3.1 Project Estimate 17
3.2 Project Schedule 18

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

Hydro 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 refurbishment of control buildings has been carried out under the 'Upgrade Office Facilities and Control Buildings' project. Hydro is now carrying out such refurbishments under the Terminal Station Refurbishment and Modernization Project to provide consistency in its approach to Terminal Station assets. The 2019 Capital Budget Application does not include expenditures for Terminal Station battery banks and chargers; however, future capital expenditures will be included in the Project.

Hydro's strategy for the replacement, refurbishment, or modernization of terminal stations is outlined in the *Terminal Station Asset Management Overview, Version 3,* included with this Capital Budget Application in Volume II, Tab 6.

2 2019 Project

The projects identified in this proposal have been selected to align with Hydro's commitment to the delivery of safe, reliable, least-cost electricity in an environmentally responsible manner.

2.1 Electrical Equipment

The following electrical equipment upgrades and/or refurbishments are planned for 2019:

- replace instrument transformers;
- replace disconnect switches;
- replace surge arrestors;
- refurbish and upgrade power transformers;
- replace insulators;
- upgrade grounding; and
- install breaker bypass switches.

2.1.1 Replace Instrument Transformers

The estimate for this project is $849,900.

Table 1: Replace Instrument Transformers Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	182.8	57.1
Labour	28.3	131.8
Consultant	22.4	22.4
Contract Work	0.0	359.6
Other Direct Costs	9.7	35.8
Total Direct Costs	**243.2**	**606.7**

Project Scope

Hydro replaces instrument transformers due to physical, or electrical, deterioration, or to comply with federal regulations regarding the use of PCBs (as detailed in Section 4.1.1 of the *Terminal Station Asset Management Overview*). Hydro plans to replace the instrument transformers outlined in Table 2.

Table 2: Instrument Transformer Replacements

Station	Equipment ID	Replacement Criteria
Cow Head	TL227 CØ, PT	Failed Electrical Testing
St. Anthony	TL256 BØ, PT	Corrosion
St. Anthony	TL256 CØ, PT	Corrosion
Stony Brook	TL231 CØ, PT	Corrosion
Stony Brook	TL205 AØ, PT	Corrosion
Churchill Falls	230-22 BØ, CT	Same vintage/mfg as units leaking and being replaced in 2018
Churchill Falls	230-22 CØ, CT	Same vintage/mfg as units leaking and being replaced in 2018
Churchill Falls	230-23 CØ, CT	Same vintage/mfg as units leaking and being replaced in 2018
Churchill Falls	230-24 BØ, CT	Same vintage/mfg as units leaking and being replaced in 2018
Churchill Falls	230-24 AØ,CT (c/w PT)	Same vintage/mfg as units leaking and being replaced in 2018
L'anse au Loup	DIST308 (5871623) PT	PCB
Stony Brook	B3 CØ, PT	Failed Electrical Testing
Stephenville	L405 CØ, CT	Failed Electrical Testing
Holyrood	B6 AØ, PT	PCB
Holyrood	B6 BØ, PT	PCB
Holyrood	B6 CØ, PT	PCB
Hardwoods	T1 B-CØ, PT	PCB
Hardwoods	T2 B-CØ, PT	PCB
Hardwoods	T3 B-CØ, PT	PCB
Hardwoods	B7 AØ, CT	PCB
Hardwoods	B7 BØ, CT	PCB
Hardwoods	B7 CØ, CT	PCB
L'anse au Loup	DIST308 (5869792) PT	PCB

Occasionally, a unit in one of the diesel plants across Hydro's operating area experiences an issue that necessitate an unplanned overhaul. Where appropriate, Hydro may complete such an overhaul under this project and, if possible, defer one of the units planned for completion.

2.1.2 Replace Disconnect Switches

The estimate for this project is $1,814,900.

Table 3: Replace Disconnect Switches Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	283.0	58.0
Labour	96.3	483.3
Consultant	87.2	237.6
Contract Work	113.0	371.6
Other Direct Costs	6.5	78.4
Total Direct Costs	**586.0**	**1,228.9**

Project Scope

Hydro replaces disconnect switches when damaged beyond repair, parts required for repair are unavailable due to obsolescence, or 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 noted in Table 4.

Table 4: Disconnect Switches Replacements

Station	Equipment ID	Condition
Hampden Tap	L51-1/L51G	Alignment Issue
Hampden Tap	L52-1/L52G	Alignment Issue
Buchans	L28L32-1	Drivetrain issue
Buchans	L28L32-2/L32G	Alignment Issue
Sunnyside	L02L07-1	Age >50 yrs
Sunnyside	L06L07-1/L06G	Age >50 yrs
Sunnyside	B1L03-2/L03G	Age >50 yrs
Sunnyside	B1L02-1	Age >50 yrs
Bay D’espoir	B5B6-1	Age >50 yrs
Bay D’espoir	B1T2-1	Age >50 yrs
Churchill Falls	B25B26	Obsolescence
Churchill Falls	21B23	Obsolescence

2.1.3 Replace Surge Arrestors

The estimate for this project is $129,500.

Table 5: Replace Surge Arrestors Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	41.4	0.0
Labour	60.2	0.0
Consultant	19.1	0.0
Contract Work	0.0	0.0
Other Direct Costs	8.8	0.0
Total Direct Costs	**129.5**	**0.0**

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 noted 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 Arrestor Replacement Plan

Station	Equipment ID
Holyrood	T10 H1
Holyrood	T10 H2
Holyrood	T10 H2
Holyrood	T10 X1
Holyrood	T10 X2
Holyrood	T10 X3
Holyrood	SST-1-2 H1
Holyrood	SST-1-2 H2
Holyrood	SST-1-2 H3
Western Avalon	T4 H1
Western Avalon	T4 H2
Western Avalon	T4 H3
Western Avalon	T4 X1
Western Avalon	T4 X2
Western Avalon	T4 X3
Hardwoods	T6SX1
Hardwoods	T6SX2

Hardwoods	T6SX3

2.1.4 Refurbish and Upgrade Power Transformers

The estimate for this project is $7,302,900.

Table 7: Refurbish and Upgrade Power Transformers Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	1,300.4	1,224.7
Labour	542.0	584.9
Consultant	185.0	175.0
Contract Work	1,385.0	1,563.5
Other Direct Costs	143.0	199.4
Total Direct Costs	**3,555.4**	**3,747.5**

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 listed in Table 8.

Table 8: Power Transformer Upgrades and Refurbishments

Refurbishment Activity	Station	Equipment ID
Major Refurbishment	Bottom Brook	T3
	Deer Lake	T2
	Plum Point	R1
	Plum Point	R2
	Bottom Brook	T1
	Hardwoods	T2
	Western Avalon	T4
Oil Reclamation or Replacement	Bear Cove	T1
	Wabush	T3
Oil Dehydrator	Bay D'espoir	T1
	Holyrood	UST-3
	Paradise River	T1
	Howley	T2
	Oxen Pond	T2
	St Anthony	T1
Radiator Replacement	Bottom Brook	T3 SST
	Bay d'Espoir	T6
	Grandy Brook	T1
Tap Changer Refurbishment	Happy Valley	T2
	Sunnyside	T1
	Sunnyside	T4
	Hardwoods	T1
Tap Changer Oil Replacement	Sunnyside	T4
Bushing Replacement	Daniels Harbour	T1
	Daniels Harbour	T2
	Granite Canal	T1 LV
	Main Brook	T1
	Wabush Ts	T1 HV
	Churchill Falls	T31S
	English Harbour West	T1
	Hawkes Bay	T3
	Howley	T2
	Stephenville	T1
	Upper Salmon	T2 HV,N

Refurbishment Activity	Station	Equipment ID
Online Dissolved Gas Analysis	Come By Chance	T1
	Come By Chance	T2
	Churchill Falls	T31
	Sunnyside	T1
	Sunnyside	T4
	Wabush Terminal Station	T11
	Wabush Terminal Station	T12
	Hardwoods	T6S
	Bottom Brook	T1
	Hardwoods	T6
	Hardwoods	T7
	Howley	T2
	Hardwoods	T3
	Massey Drive	T3

2.1.5 Replace Insulators

The estimate for this project is $768,500.

Table 9: Replace Insulators Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	0.0	318.0
Labour	11.8	280.6
Consultant	24.0	83.2
Contract Work	0.0	0.0
Other Direct Costs	4.8	46.1
Total Direct Costs	**40.6**	**727.9**

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). Hydro plans to replace such insulators in the following stations:

- Wabush Terminal Station;

- Happy Valley;
- Parsons Pond;
- Glenburnie;
- St. Anthony;
- Main Brook;
- Roddickton; and
- Churchill Falls.

2.1.6 Upgrade Grounding

The estimate for this project is $1,423,000.

Table 10: Upgrade Grounding Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	0.0	5.0
Labour	66.6	101.9
Consultant	477.8	398.1
Contract Work	0.0	304.0
Other Direct Costs	35.8	33.8
Total Direct Costs	**580.2**	**842.8**

Project Scope

Hydro analyzes terminal station grounding systems to identify hazardous step and touch potentials, and upgrades station grounding to eliminate these hazards (as detailed in Section 4.1.5 of the Asset Management Overview). Hydro plans to analyze and upgrade the stations noted in Table 11.

Table 11: Stations Designated for Grounding Upgrades

Station
Bottom Brook
Bear Cove
Buchans
Cat Arm
Farewell Head
Granite Canal
Grand Falls
Glenburnie
Hinds Lake
Howley
Massey Drive
Roddickton
Stony Brook
Stephenville

2.2 Civil Works and Buildings

The following civil works and buildings activities are proposed for 2019:

- repair equipment foundations;
- install fire suppression; and
- refurbish control buildings.

2.2.1 Repair Equipment Foundations

The estimate for this project is $243,400.

Table 12: Repair Equipment Foundations Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	0.0	0.0
Labour	80.6	0.0
Consultant	49.0	0.0
Contract Work	109.0	0.0
Other Direct Costs	4.8	0.0
Total Direct Costs	**243.4**	**0.0**

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 and shown in Figure 1). Hydro plans to repair equipment foundations in the following stations:

- Deer Lake;
- Massey Drive; and
- Buchans.

Figure 1: Compromised Foundation at Buchan's Terminal Station

2.2.2 Install Fire Suppression

The estimate for this project is $684,900.

Table 13: Install Fire Suppression Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	0.0	10.0
Labour	43.4	27.1
Consultant	24.0	26.4
Contract Work	0.0	550.0
Other Direct Costs	1.0	3.0
Total Direct Costs	**68.4**	**616.5**

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:

- Oxen Pond.

2.2.3 Refurbish Control Buildings

The estimate for this project is $517,600.

Table 14: Refurbish Control Buildings Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	0.0	10.0
Labour	43.4	27.1
Consultant	24.0	26.4
Contract Work	0.0	550.0
Other Direct Costs	1.0	3.0
Total Direct Costs	**68.4**	**616.5**

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 2019:

<u>*Holyrood Terminal Station*</u>

- Replace Roof System (Figure 2): Roof has reached end of expected service life, and is displaying significant surface cracking. Evidence of leaking present.
- Exterior Doors (Figure 3): Exterior doors are heavily rusted and deteriorated.
- Other Upgrades: Hydro will address other issues such as failed HVAC equipment, battery room ventilation, obsolete low voltage distribution equipment, and corroded water service entry.

Figure 2: Leaking Roof at Holyrood

Figure 3: Rusted Doors at Holyrood

Come By Chance

- Replace Roof System (Figure 4): Roof has reached end of expected service life, and is displaying significant surface cracking.
- Exterior Metal Cladding (Figure 5): Exterior cladding is severely rusted, and must be replaced to prevent deterioration of building structure and maintain weather-tightness.
- Other Upgrades: Hydro will address other issues, such as heaters, battery room

1 ventilation, station service automatic transfer switch, low voltage distribution panel, and
2 domestic plumbing.

Figure 4: Roof Surface Cracking at Come By Chance

Figure 5: Rusting Exterior Cladding at Come By Chance

2.3 Protection, Control, and Monitoring Refurbishment and Upgrades

The estimate for this project is $5,967,400

Table 15: Protection, Control, and Monitoring Refurbishment and Upgrades Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	780.5	347.8
Labour	788.9	1,110.4
Consultant	865.8	440.4
Contract Work	0.0	1,419.0
Other Direct Costs	52.0	162.6
Total Direct Costs	**2,487.2**	**3,480.2**

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 plans to replace the protective relays noted in Table 16.

Table 16: Protective Relay Replacement Plan

Station	Equipment ID	Relay Type
Bay d'Espoir	TL 206	Electromechanical
Sunnyside	TL 206	Electromechanical
Cat Arm	TL 247, BUS 1	Electromechanical
Deer Lake	TL 247	Electromechanical
Hinds Lake	G1, T1,T2	Electromechanical
Western Avalon	T1,T2,T4	Electromechanical
Holyrood	B12L65 and B2L68 Reclosing	Electromechanical
Western Avalon	T1,T2,T3,T4, and T5 Paralleling	Obsolete Solid-State, heightened risk of failure

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. Hydro plans to implement breaker failure protection in the following stations:

- St. Anthony; and
- Stony Brook.

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

- Holyrood.

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

- Berry Hill.

2.4 Wabush Terminal Station Refurbishment

The estimate for this project is $3,835,700.

Table 17: Wabush Terminal Station Refurbishment Project Estimate ($000s)

Project Cost	2019	2020
Material Supply	385.0	5.0
Labour	388.8	634.9
Consultant	0.0	0.0
Contract Work	180.0	1,909.9
Other Direct Costs	75.8	256.3
Total Direct Costs	**1,029.6**	**2,806.1**

Project Scope

On August 5, 2016, Hydro applied to the Board for approval to acquire the Wabush Terminal Station and was subsequently approved in Board Order No. P.U. 37(2016). It was identified within the application 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 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 were proposed and approved in Hydro's 2018 Capital Budget Application. Hydro plans to continue the refurbishment of the Wabush Terminal Station, proposing the following work for this 2019 Capital Budget Application:

- protection upgrades of transformers T1 and T2;
- procurement and replacement of two 46kV circuit breakers (46-1 & 46-2) and associated foundations, cables, and protection;
- procurement and installation of three 46kV disconnect switches; and
- major inspection of synchronous condenser SC1.

In 2017, Hydro acquired the electrical equipment in the Churchill Falls Switchyard dedicated to serving Labrador West. As part of the Wabush Terminal Station Refurbishment activities, Hydro plans to replace four Current Transformers and one Current Transformer/Capacitive Voltage Transformer combination units in the Churchill Falls Switchyard, which are included in the instrument transformer section of this project.

3 Project Cost

3.1 Project Estimate

The project estimate for the terminal station refurbishment and modernization program is shown in Table 18.

Table 18: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	2,973.1	2,025.6	0.0	4,998.7
Labour	2,202.8	3,354.8	0.0	5,557.6
Consultant	1,870.3	1,383.2	0.0	3,253.5
Contract Work	2,087.0	6,477.5	0.0	8,564.5
Other Direct Costs	347.9	815.5	0.0	1,163.4
Interest and Escalation	421.6	1,382.9	0.0	1,804.5
Contingency	988.4	3,622.3	0.0	4,610.7
Total	**10,891.1**	**19,061.8**	**0.0**	**29,952.9**

3.2 Project Schedule

Due to the large number of individual activities enveloped in this project, it is not practical to provide individual project schedules. Detailed project schedules will be developed at project initiation. However, 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 have a planned completion of 2020.

LICENSED PROFESSIONAL ENGINEER 08906 MATTHEW P. HALLORAN SIGNATURE 2018-07-19 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Terminal Station Asset Management Overview

Version 3

July 2018

newfoundland labrador
hydro
a nalcor energy company

Summary

Hydro has developed an ongoing capital program to replace or refurbish assets as the end of design life is reached or the assets require attention due to obsolescence or anticipated failure.

Prior to 2017, Hydro's terminal station projects were divided into two categories: stand-alone and programs. Programs included projects that are proposed year after year to address the upgrade or replacements of deteriorated equipment (e.g. disconnects or instrument transformers) and have similar justification each year. Stand-alone projects do not meet the definition of an annual program. Hydro typically had as many as 15 separate program-type projects in its Capital Budget Application, with each program based upon a particular type of asset.

Starting with the 2017 Capital Budget Application, Hydro implemented a change to how the terminal station programs are submitted for consideration by the Board. The programs have been consolidated into the Terminal Station Refurbishment and Modernization Project resulting in improved regulatory efficiency and easing the administrative effort for the Board and Hydro. This approach also allows Hydro to realize efficiencies by improving coordination of capital and maintenance work in terminal stations.

In the 2019 Capital Budget Application, Hydro has submitted a revised Terminal Station Asset Management Overview – Version 3, with changes noted in Section 1.1 to provide an updated overview of Hydro's Terminal Station asset maintenance philosophies in one document. The Terminal Station Refurbishment and Modernization Project, included in this Capital Budget Application, includes proposals for required terminal station work, referencing specific section and following the philosophies of this Overview document.

Table of Contents

Summary i
1 Introduction 1
1.1 Changes in Version 3 2
2 Terminal Stations Background 2
2.1 Newfoundland and Labrador Hydro's Terminal Stations 2
2.2 Terminal Station Infrastructure 3
3 Terminal Station Capital Projects 3
3.1 Historical Terminal Station Capital Projects 3
3.2 Hydro's Approach to Terminal Station Capital Project Proposals 4
3.3 Benefits of this Approach 6
4 Asset Management Programs 6
4.1 Electrical Equipment 6
4.1.1 High Voltage Instrument Transformer Replacements 6
4.1.2 High Voltage Switch Replacements 10
4.1.3 Surge Arrestors Replacements 12
4.1.4 Insulator Replacements 14
4.1.5 Grounding Refurbishment and Upgrades 15
4.1.6 Power Transformer Upgrades and Refurbishment 17
4.1.7 Circuit Breaker Refurbishment and Replacements 22
4.1.8 Station Service Refurbishment and Upgrades 24
4.1.9 Battery Banks and Chargers 26
4.1.10 Install Breaker Bypass Switches 27
4.2 Civil Works and Buildings 28
4.2.1 Equipment Foundations 28
4.2.2 Fire Protection 29
4.2.3 Control Buildings 30
4.3 Protection, Control, and Monitoring 32
4.3.1 Protection and Control Upgrades and Refurbishment 32

1 Introduction

Newfoundland and Labrador Hydro has 69 terminal stations that contain electrical equipment (e.g. 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 has an Asset Management System that 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 result in a consistent approach to monitoring, assessments, and action justifications for capital refurbishment and replacement for asset sustaining projects. Hydro established programs that enact these practices for groups or sub-groupings of assets (e.g. High Voltage Switch Replacements).

Part of Hydro's annual capital program is a sustaining effort to ensure the safety and reliability of terminal station assets. As submitted in its 2017 application, Hydro has consolidated its terminal station sustaining work into one project, the *Terminal Station Refurbishment and Modernization Project* (the Project), in an effort to streamline the capital budget process and to ensure opportunities for synergies across projects are realized. Additionally, Hydro submitted the Terminal Station In-Service Failures Project to cover the replacement or refurbishment of failed equipment or incipient failures. Hydro is utilizing this document, *Terminal Station Asset Management Overview* (the Overview), as a reference for both projects to streamline and focus information submitted. The Overview provides supporting information that was historically presented, on an annual basis, for similar classification projects in the Application. The remainder of this document provides information on the assets involved, an overview of each asset program, and updates in the event of changes to Hydro's asset management philosophies.

Hydro will revise and resubmit the Overview as required in future Capital Budget Applications as it implements changes to its asset management philosophies appropriate for inclusion in the Overview.

1.1 Changes in Version 3

Hydro has submitted Version 3 of this document with the 2019 Capital Budget Application. All material changes in this version are shaded in grey, and are summarized below:

- Addition of section 4.1.9 – Battery Banks and Chargers;
- Addition of section 4.2.3 – Control Buildings; and
- Addition of 'Digital Fault Recorders' to section 4.3.1 – Protection and Control Upgrades

In 2016, Hydro submitted its 'Upgrade Office Facilities and Control Buildings Condition Assessment and Refurbishment Program Asset Management Strategy Plan' in its 2017 Capital Budget Application, which outlined Hydro's approach to address aging and failing building infrastructure. Beginning with the 2019 Capital Budget Application, Hydro will undertake the refurbishment of terminal station control buildings under the Terminal Station Refurbishment and Modernization Program.

Minor changes to syntax have been made to improve reading and to reflect that this document has been previously submitted, and is no longer a newly established approach. These minor changes have not been highlighted.

2 Terminal Stations 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 (e.g. 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 owns and operates 69 terminal stations throughout Newfoundland and Labrador.

2.2 Terminal Station Infrastructure

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

- transformers;
- circuit breakers;
- instrument transformers;
- disconnect, bypass and ground switches;
- surge arrestors;
- grounding;
- buswork;
- steel structures and foundations;
- insulators;
- control buildings;
- protection and control relays;
- yards, fences and access roads; and
- battery banks.

Many of Hydro's terminal stations were constructed in the 1960's. Annual capital commitment is required to sustain terminal station assets, ensuring the provision of reliable electrical service.

3 Terminal Station Capital Projects

3.1 Historical Terminal Station Capital Projects

In the 2016 Capital Budget Application, there were 22 individual terminal station projects, accounting for approximately $30,000,000 or 16% of the capital budget. Historically, Hydro's terminal 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 (e.g. disconnects or instrument transformers) and have similar justification and other information presented each year. Stand-alone projects do not meet the definition of an annual program and are not included in this project. Of the 22 individual terminal station projects proposed in 2016, 15 were program-type projects. In the 2017 Capital Budget Application, Hydro consolidated the historical station projects into the Terminal Station Refurbishment and Modernization Project.

3.2 Hydro's Approach to Terminal Station Capital Project Proposals

The programs now included in the Project are:

1. Upgrade Circuit Breakers (Beyond 2020);
2. Replace Disconnect Switches;
3. Install Fire Protection;
4. Replace Surge Arrestors;
5. Upgrade Terminal Station Foundations;
6. Replace Battery Banks and Chargers;
7. Refurbish Control Buildings;
8. Upgrade Terminal Station for Mobile Substation;
9. Install Breaker Bypass Switches; and
10. Protection and Control Refurbishment and Upgrades.[1]

The Terminal Station Refurbishment and Modernization 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;

[1] As noted in the 2017 edition of this document, 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 Overview and Project as Protection and Control Refurbishment and Upgrades Program.

- Accelerated Circuit Breaker Replacement: Hydro proposed the accelerated replacement of 230kV Circuit Breakers as part of the 2016 Capital Budget Application Upgrade Circuit Breakers project. This project involves the replacement of high-voltage circuit breakers through the year 2020. As this project has already been approved, it is not included in the Terminal Station Refurbishment and Modernization Project. However, future breaker replacements not captured in the 2016 Upgrade Circuit Breakers project will be included in future Capital Budget Applications and, therefore, the justification for such programs is included in this report;
- Activities that cannot be scheduled for inclusion in a Capital Budget Application as these will be submitted as either a supplementary capital budget application 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; and
- Activities in response to significant isolated issues in a particular station (e.g. replacement of a failed power transformer) as these projects generally have unique justification and will be proposed separately.

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

This document is submitted to the Board as part of the 2019 Capital Budget Application. Hydro will annually submit proposals for the '*Terminal Station Refurbishment and Modernization Project'* and the '*Terminal Station In-Service Failures Project'* referencing the most recent Overview. Future Applications will not include a copy of the Overview unless Hydro revises its contents. When the Overview is revised, Hydro will clearly denote such changes for review and approval by the Board.

3.3 Benefits of this Approach

As supporting information for programs changes infrequently, referencing the 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.

Hydro has a proactive Asset Management System that strives to anticipate future failures so that refurbishment or replacement can be incorporated into an Application. However, there are instances in which projects are not included in an Application as immediate refurbishment or replacement is required (i.e. occurrence of an unanticipated failure or the recognition of an incipient failure) to maintain the delivery of safe, reliable electricity at least cost. These situations seldom include extenuating or abnormal circumstances and costs. With aging 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 for relatively minor failure correction. Each year, Hydro will provide a concise summary of the previous year's work.

As personnel look to further coordinate work by location, Hydro expects the Terminal Station Refurbishment and Modernization Project will provide opportunities whereby Hydro can further optimize the coordination of capital and maintenance work to minimize outages to customers and equipment.

4 Asset Management Programs

4.1 Electrical Equipment

4.1.1 High Voltage Instrument Transformer Replacements

The metering protection and control devices (e.g. protective relaying, power quality monitors,

[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.

and kilowatt-hour meters) used in generation and transmission systems are not manufactured to handle the electricity involved in those systems. Measurement of the electricity's currents and voltages are provided to these devices through a current transformer (CT) and a potential transformer (PT), respectively. CTs and PTs are collectively known as instrument transformers (IT) (Figure 1). Hydro has approximately 900 individual high voltage ITs within the Island and Labrador Interconnected Systems.

A high-voltage IT consists of a tank, bushing, and an insulated electrical primary and secondary winding. 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 Current Transformer (left) and Potential Transformer (Right)

Hydro's manages planned IT replacements in three categories:

1. Condition;
2. PCB compliance replacements; and
3. manufacturer and model.

Condition

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

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

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

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

Figure 2: Rusting on Potential Transformer

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 a world recognized testing company, Doble Engineering Company, to provide an assessment of the test results

Unit deterioration information is reviewed regularly by Asset Management personnel to determine when corrective maintenance or unit replacement is required. Hydro conducts minor IT corrective maintenance, such as painting and small bushing chip treatment; however, major corrective maintenance or unit refurbishments are not undertaken as economical options for this type of work have not been found. Units requiring major corrective maintenance or refurbishments are replaced.

PCB Compliance Replacements

Environment Canada's PCB Regulations requires that by 2025 all ITs are not to have a PCB concentration greater that 50ppm. ITs are sealed, oil-filled units, in which the oil acts as an electrical insulator. Equipment manufactured prior to 1985 has been known to contain PCBs. Due to the age of the units and the risk of introducing contamination (e.g. air) that could impact the electrical integrity of an IT, Hydro does not sample ITs. Therefore, establishing the actual PCB concentration in an IT is not possible. Hydro, in consultation with manufacturers, has established that units manufactured before 1985 are suspected to contain PCBs in concentration levels greater than or equal to 50 ppm. Thus, Hydro has a program to replace all suspect oil-filled ITs 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.

Exclusions from the IT Replacement Program

Modern day circuit breaker technology includes CTs embedded in the circuit breaker bushings.

Therefore, where possible, external CTs will be displaced by bushing CTs as circuit breakers are replaced and, as 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 system operation and control (e.g. 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 with an open switch) 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, while 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 (MOD). A disconnect and its associated components are shown in Figure 3.

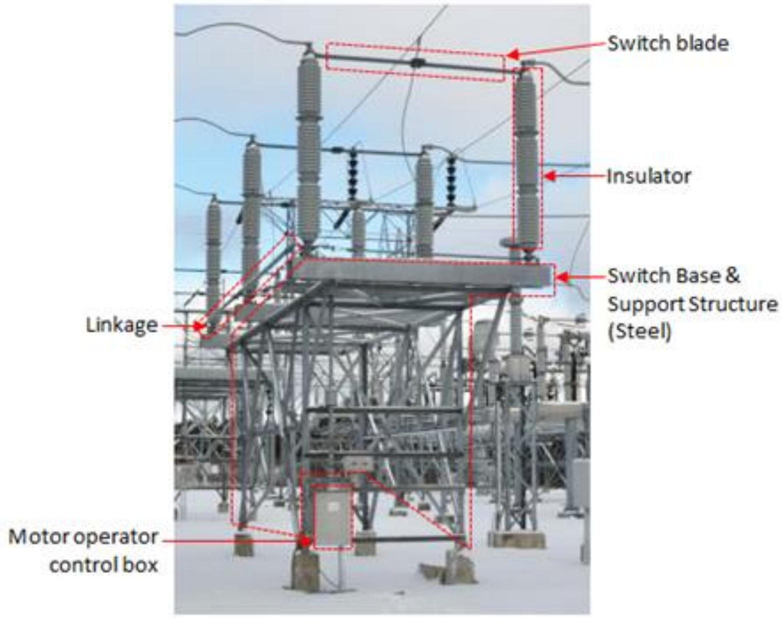


Figure 3: Various Components of a High Voltage Disconnect Switch

Hydro monitors the condition of its switches by conducting regular visual inspections of the units (through station inspection and Infrared inspection programs) and reviewing reports from the work order system and staff. Issues commonly reported include 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 ongoing maintenance. Switches that have operating deficiencies and have reached a service life of 50 years or greater are designated for replacement. Switches that have no replacement parts available due to obsolescence, are damaged beyond repair, or cannot be economically repaired and do not require immediate replacement are designated for replacement under this program.

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

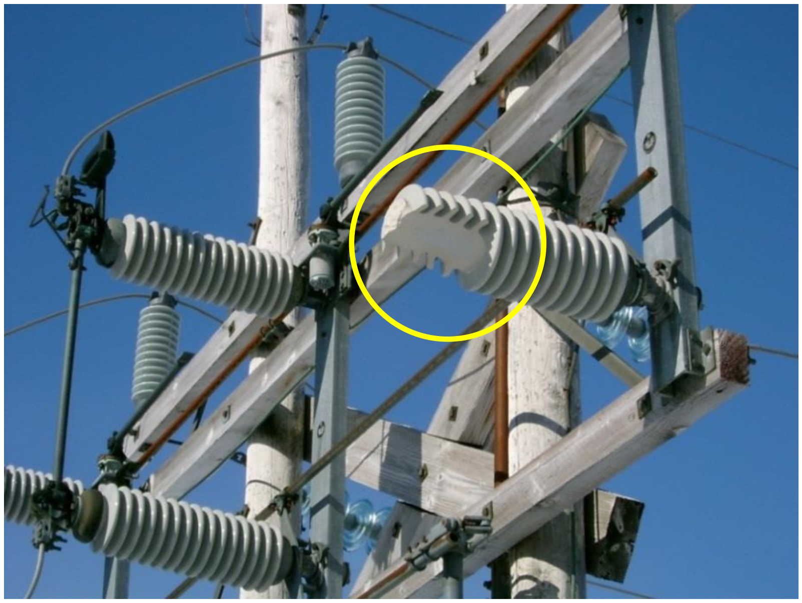


Figure 4: Broken Insulator on 69 kV Disconnect Switch

4.1.3 Surge Arrestors Replacements

Surge arresters (also known as lightning arrestors) 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 can damage the equipment's insulation. The surge arrestors act to maintain the voltages within acceptable levels. Without surge arrestors, equipment insulation can be damaged and faults can result during overvoltages. Hydro typically has surge arresters installed on the high side and low voltage sides of it 46 kV and above power transformers.

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

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

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

Hydro's surge arrestor asset management program replaces surge arrestors based upon the following criteria:

1. Removal of gapped type arresters with Zinc Oxide design due to enhanced performance;
2. Replace units due to a condition identified through visual inspections for chips or cracks or electrical testing such as Power Factor testing;
3. 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
4. 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 Replacements

Insulators provide electrical insulation between energized equipment and ground. When an insulator fails and a fault occurs, a safety hazard to personnel and 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 (e.g. post, cap and pin, suspension). An example of a suspension insulator is shown in Figure 6.

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

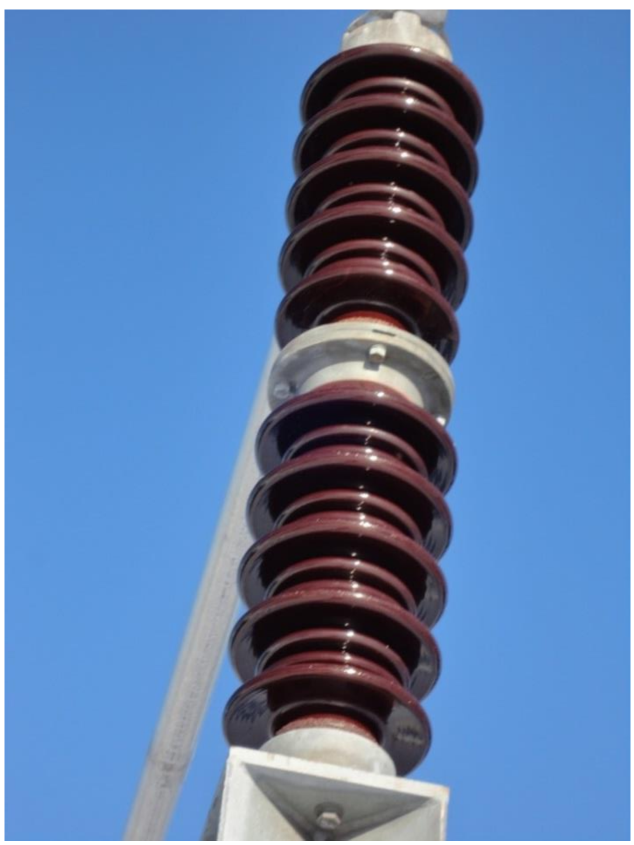


Figure 6: A Multi-cone type insulator prone to failure due to cement growth

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 causing swelling of the cement during freeze/thaw cycles, 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[3]. Insulator manufacturers have 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 (Figure 7). In the event of a line to 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.

[3] Flashover is an electrical arc between the electrified end and the un-electrified (ground) end of an insulator due to insulator failure.

Figure 7: Typical Grounding Connection on Terminal Station Fence

To determine whether grounding upgrades are required, Hydro performs a step and touch potential analysis of the terminal station or distribution substation. A step and touch potential analysis involves the gathering 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 Electronic 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 correcting 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 for 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 136 power transformers 46kV and above, as well as several station service transformers at voltages lower than 46kV.

The basic components of a power transformer are:

- Transformer steel tank, which contains the metal core and paper insulated windings responsible for voltage conversion, oil which is part of the insulating system, and a gasket system that keeps the oil from penetrating the environment;
- Bushings mounted to the top of the transformer tank that connect the windings to the external electrical conductors;
- Radiators and cooling fans that remove heat for the transformer's internal components;
- Load tap changer, which is attached internally or externally and is the device through which transformer's voltage is 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 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 transformers 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 transformer's condition such as:

1. Insulating oil and paper deterioration;
2. oil moisture content;
3. oil leaks;
4. tank, radiators and other component rusting/corrosion;
5. tap changer component wear or damage;
6. damaged/Deteriorated and PCB contaminated bushings;

7. failure of the protective devices; and
8. 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 the oil in a transformer is of acceptable quality, Hydro has an oil monitoring program through which oil samples are 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 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 install an online molecular sieve dry-out system, which circulates and dries the transformer oil without requiring 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, perforated 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 (e.g. small repairs, patching and minor painting) is undertaken as part of the maintenance. Work requiring major refurbishments and replacements (e.g. radiator or bushing replacements, gasket replacements, and tank rusting refurbishment) are undertaken under this program.

Load Tap Changer

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 that provide assessments of the condition of the parts and oil. Oil samples are obtained annually from each load tap changer to perform a Tap Changer Activity Signature Analysis (TASA) by the laboratory. This analysis provides a condition assessment of the tap changer oil and components, along with recommendations for implementation by Hydro. Recommendations can range from continued or increased annual sampling, planned refurbishment, or to immediately remove from service, inspect 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 for compliance with the latest PCB Regulations, as well as bushings with degraded electrical properties.

The latest regulations state that all equipment bushings in-service beyond 2025 must have a PCB concentration of less than 50 mg/kg. Hydro has approximately 500 sealed bushings that were manufactured prior to 1985 which are suspected to contain PCBs greater than 50 mg/kg and possibly greater than 500 mg/kg. Some sealed bushings have sampling ports to allow sampling; however, Hydro does not sample due to small quantity of oil in bushings and the risk of contamination during sampling. Bushings that are known or suspected of having unacceptable PCB levels are replaced.

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.

On-line 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. The online gas in oil monitoring continuously monitors the transformer and provides early fault detection. Continuous data is also a useful tool for personnel to trend gases for the scheduling of 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 is being 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"*. Hydro has identified 50 transformers for installation of online DGA devices through 2024.

4.1.7 Circuit Breaker Refurbishment and Replacements

The circuit breaker is a critical component of the power system. Located in a terminal station, each circuit breaker performs switching actions to complete, maintain, and interrupt current flow under normal or fault conditions. The reliable operation of circuit breakers through its fast response and complete interruption of current flow is essential for the protection and stability of the power system. The failure of a breaker to operate as designed may affect the reliability and safety of the electrical system resulting in failure of other equipment and the occurrence of an outage affecting more end users. Hydro has 195 terminal station circuit breakers with voltage rates greater than 66kV in service.

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 typically are at least 38 years old at replacement. In the 2016 Capital Budget Application *"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 Overview.

2. Oil Circuit Breakers (OCB) - use oil to interrupt currents and typically are at least 36 years old at replacement. In the 2016 Capital Budget Application "Upgrade Circuit Breakers – Various Sites (2016-2020)" project, approval was obtained for the replacement of 10 OCBs up to 2020 that were not compliant with Environment Canada PCB regulations. The remaining non-compliant breakers will be replaced before 2025. From 2017 forward, any replacements not previously approved in the 2016-2020 project will be included in the work conducted under this section of the Overview; and
3. Sulphur Hexafluoride (SF_6) Circuit Breakers - use SF_6 gas to interrupt current and installation of these breakers started in 1979, including all new installations. In the 2016 Capital Budget Application "Upgrade Circuit Breakers – Various Sites (2016-2020)" 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 forward, any SF_6 replacements and refurbishments not previously approved in the 2016-2020 project will be included in the work conducted under this section of the Overview.

Figure 9: Circuit Breakers – ABCB (left), Oil (middle), and SF_6 (right)

As presented in the 2016 Capital Budget Application, "Upgrade Circuit Breakers – Various Sites (2016-2020)" project, SF_6 circuit breakers rated at 138 kV and above are required to be refurbished after 20 years of service. 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 capital budget application "Upgrade Circuit Breakers –

Various Sites (2016-2020)" project. Select 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 Capital Budget Application, "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.

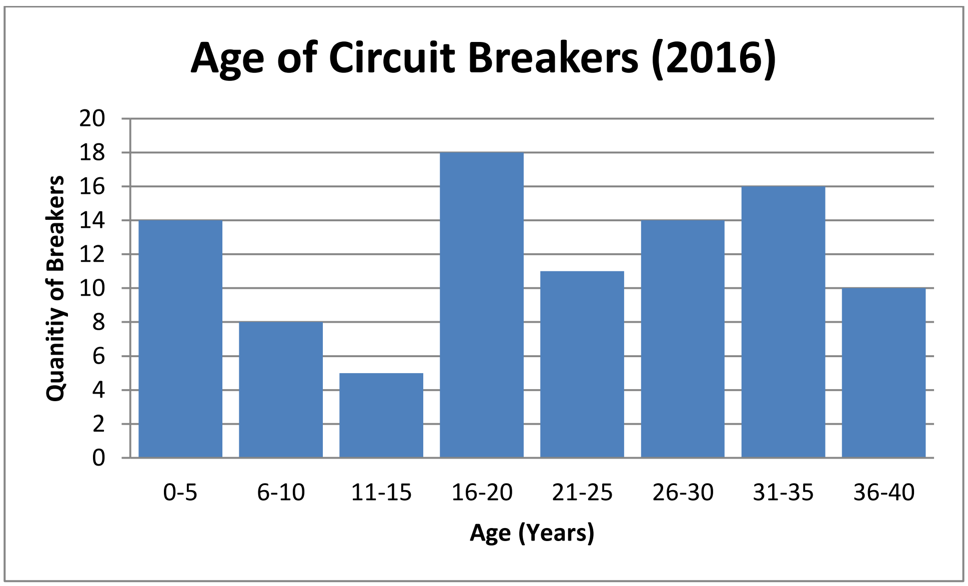


Figure 10: Age of Circuit Breakers Not Included in Ongoing Replacement Program

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 (Alternating Current) and DC (Direct Current) power to operate the equipment in a station.

The AC station service is generally supplied by one or more transformers in the station. Due to their criticality, 230 kV terminal stations have a redundant station service feed, fed either through a redundant transformer tertiary winding, 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 charging motors;
- digital relays;
- emergency lighting;
- disconnect switch motor operators; 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 Application, under the *Replace Power Transformers* project.

4.1.9 Battery Banks and Chargers

Battery banks and chargers supply direct current (DC) power to critical station infrastructure such as circuit breakers, protection and control relays, disconnect switch motor operators, and telecontrol equipment (Figure 11). 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, which have deteriorating capacity over time. Hydro adheres to IEEE 450 and 1188, which recommends replacements of a battery if its capacity has fallen to 80% or less of its rated capacity. The service life of flooded cell batteries is 18 to 20 years while valve regulated lead acid (VRLA) batteries have a service life of 7 to 10 years.

Hydro regularly carries out testing on its battery banks to determine bank capacity and will replace banks and chargers with insufficient capacity under this program.

Figure 11: 125 V Direct Current 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 (Figure 12). When a breaker is removed 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.

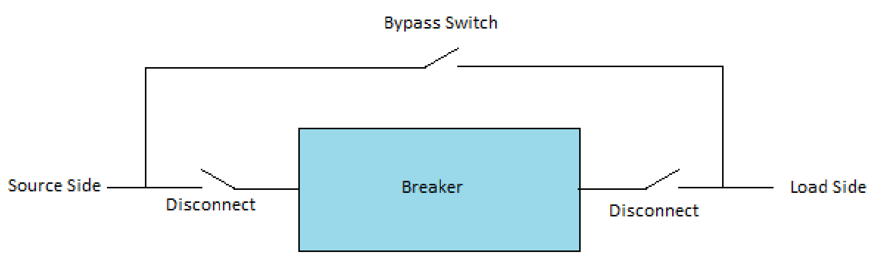


Figure 12: Example of Bypass Switch Installation

Listed in Table 1 are six radial systems, servicing multiple customers, where breakers are installed without bypass switches. To ensure service continuity during breaker downtime, Hydro will install breaker bypass switches in these locations.

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 Basque, and Long Lake area Newfoundland Power customers.
Howley B1T2	773 Hampden and Jackson's Arm area customers and 665 Newfoundland Power Howley area customers (Approved Project Ongoing)
Peter's Barren B1L41	1900 Great Northern Peninsula customers north of Daniel's Harbor
South Brook L22T1	2340 South Brook area customers.

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

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. These foundations range in age from one to forty-five years. Terminal station foundations support equipment and bus work. The majority of these structures formed part of the original station construction and are in excess of thirty-five years of age.

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. Degraded structure foundations are shown in Figure 13 and Figure 14.

Figure 13: Structure B1T1 Bottom Terminal Stations

Figure 14: 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 a terminal station severely damaged by fire to normal operation could take months.

Hydro is installing gaseous 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 Capital Budget Application "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, battery banks, 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, siding, and doors 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).

Figure 15 and Figure 16 show deterioration at different control building locations.

Figure 15: Terminal Station Control Buildings (Come By Chance and Sunnyside) showing cracking and deterioration of the roof membrane systems.

Figure 16: Building exterior cladding and 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 h 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, preventing hazardous conditions from damaging electrical equipment, or preventing harm to 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 greater dependability and security, thus enhancing system reliability. Digital and electromechanical relays are shown in Figure 17.

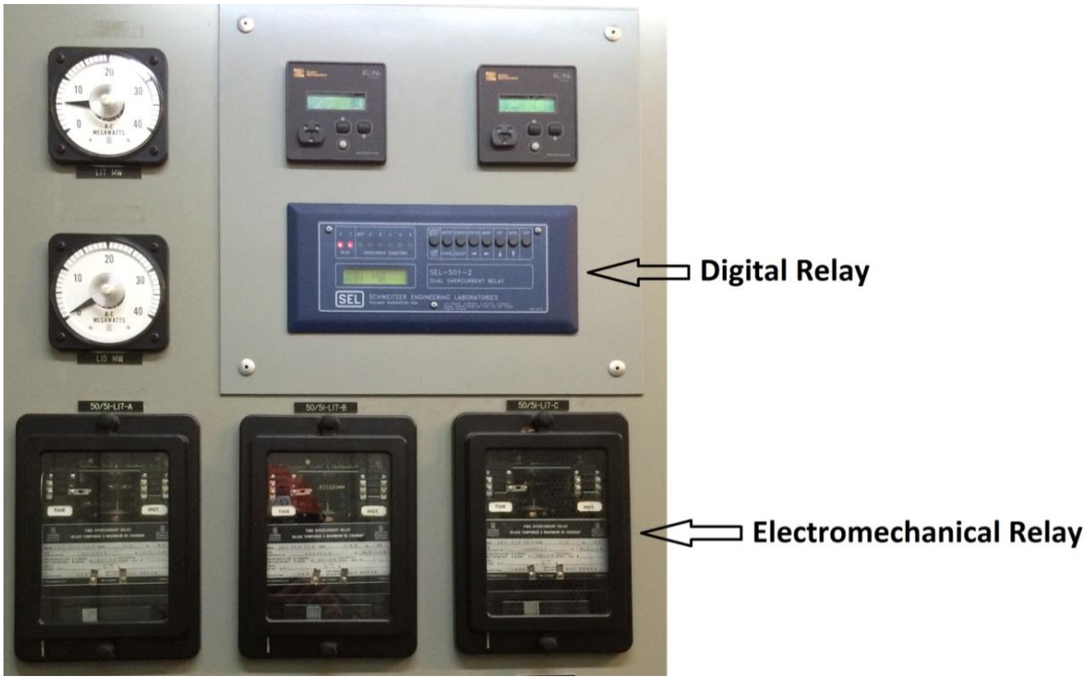


Figure 17: Digital and Electromechanical Relays

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, "Review of Updates and Changes to Existing Digital Relay Program" 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 request for information CA-NLH-037 of the 2016 Capital Budget Application, 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 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. Circuit breaker protective relaying is designed to recognize a breaker failure and to initiate action to surrounding breakers to minimize damage to equipment and the spread of the impact of a breaker failure. This breaker protection feature is called Breaker Failure Protection.

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 the Hydro’s 2016 Capital Budget Application, 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.

Tap Changer Paralleling Control Replacement

Tap changer paralleling controls are designed to:

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

Current tap changer controls are of similar vintage as the power transformers, dating back to the late 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 observed by Hydro staff at numerous sites during review, which indicated that a high number of operations were experienced at various 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 Center and operating personnel that equipment and relaying requires attention and are communicated to the Energy Control Centre and/or displayed locally on the station annunciator (Figure 18).

Figure 18: An annunciator commonly found in Hydro's 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 for five 230 kV terminal stations to the Energy Control Centre. 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 Capital Budget Application "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 applications.

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 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.

Digital Fault Recorders

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

Protection and Control Cable and Panel Modifications

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

7. Diesel Genset Replacements (2019-2020)

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador FORHAD AHMAD f. ahmad SIGNATURE 24/07/2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Diesel Genset Replacement

Cartwright

July 2018

newfoundland labrador
hydro
a nalcor energy company

Summary

This project is for the replacement of diesel generator set Unit 2052 in the Cartwright Diesel Generating Station.

Gensets have an expected average service life of 100,000 operating hours. Hydro's asset management strategy is to replace gensets when they reach approximately 100,000 operating hours to ensure reliable operation. This is consistent with other utilities in Canada with prime power diesel plants. Cartwright's Unit 2052 has accumulated approximately 107,909 hours as of March 31, 2018.

To avoid significant risk associated with overhauling this unit past its expected lifespan and to maintain reliable operations in Cartwright, Unit 2052 requires replacement.

The project is estimated to cost approximately $3,947,400 with planned completion in 2020.

Table of Contents

Summary i
1 Introduction 1
2 Project Description 1
3 Justification 3
  3.1 Existing System 3
  3.2 Operating Experience 3
  3.3 Load Forecast 3
  3.4 Development of Alternatives 4
  3.5 Cost Benefit Analysis 4
4 Conclusion 6
  4.1 Project Estimate 6
  4.2 Project Schedule 6

1 Introduction

Cartwright is located on the east coast of Labrador. Hydro provides electrical service to approximately 330 customers in the community from the Cartwright diesel generating plant consisting of four gensets; two rated at 450 kW, one at 600 kW, and one at 720 kW.

Electricity in each community is supplied solely by a diesel generating plant owned and operated by Hydro. Figure 1 is a map of a Labrador showing the location of Cartwright.

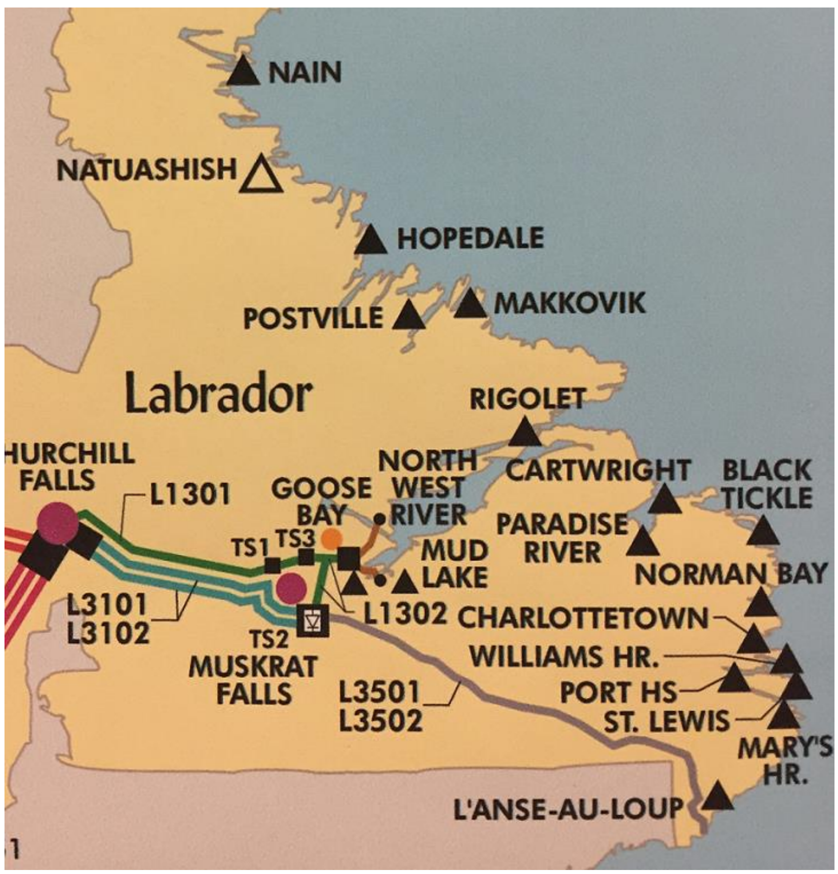


Figure 1: Map of Southern Labrador - Cartwright

2 Project Description

This proposed project is for the replacement of Unit 2052, a 720 kW unit at the Cartwright generating plant, with a 925 kW unit. The estimated project cost includes all costs associated with the procurement and installation of the new genset. To fit the new unit in the plant, Unit

2036 will be moved to the location of 2052 and the new 925 kW unit will be put in Unit 2036's place (please refer to Figure 2). Piping modifications to the existing cooling system will be required to accommodate the new unit and a new exhaust system installed with the new unit.

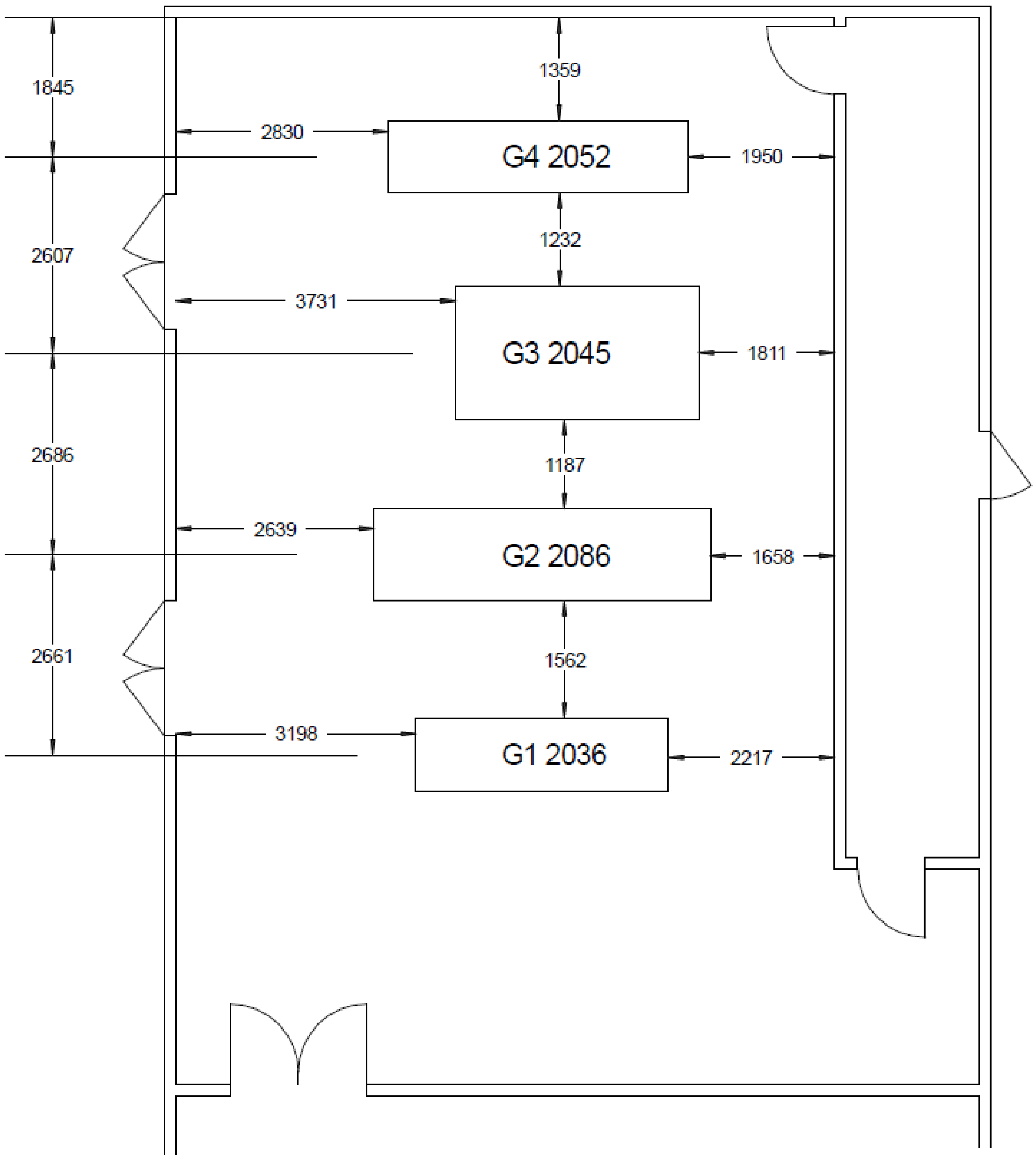


Figure 2: Layout of Cartwright Plant (Existing)

3 Justification

This project is justified on the requirement to satisfy Hydro's current asset management strategy to replace gensets when they approach 100,000 operating hours to ensure reliable power supply. Cartwright Unit 2052 is past end of life and need to be replaced.

3.1 Existing System

The Cartwright Diesel Generating Plant consists of four gensets with an installed capacity of 2,220 kW. The genset arrangement includes two 450 kW gensets, one 600 kW genset, and one 720 kW genset. The facility is the sole source of power for the community of Cartwright and is required to provide electricity to customers on a continuous basis. The unit breakdown is shown in Table 1.

Table 1: Cartwright Diesel Units

Unit	kW	Year Installed	Operating Hours
2036	450	1992	58,753
2086	600	2009	28,879
2045	450	1993	75,993
2052	720	1998	107,909
Total kW	**2,200 (1500 Firm)**		

3.2 Operating Experience

Unit 2052 has been in service for 20 years. The 720 kW unit has had four overhauls since installation. The last overhaul was performed in 2016 after incurring 94,778 operating hours. The unit had accumulated approximately 107,909 operating hours as of March 30, 2018 and is due for replacement in 2020 based on 20,000 operating hours since its last overhaul and exceeding 100,000 operating hours, which is the normal replacement criteria.

3.3 Load Forecast

Table 2 contains the projected load forecast for Cartwright for the next 5 years.

Table 2: 5-Year Projected Load Forecast for Cartwright

Year	2018	2019	2020	2021	2022	2023
Forecasted Peak	1025	1025	1027	1027	1028	1032

The load in Cartwright is not expected to increase dramatically in the next six years; however, the project to replace the unit is not justified on load growth but rather Hydro's replacement criteria. The proposed increase in unit capacity to 925 kW is the least cost option based on a full cost benefit analysis.

3.4 Development of Alternatives

Several alternatives were considered for Cartwright and a cost benefit analysis was completed to determine the most economic unit for the lifespan. Unit 2052 is a 1200 rpm unit that has proven to be very reliable throughout its lifespan. The options include:

- Alternative 1: Replace Unit 2052 with a larger unit rated at 925 kW, 1200 rpm;
- Alternative 2: Replace Unit 2052 with a larger unit rated at 925 kW, 1800 rpm; and
- Alternative 3: Replace Unit 2052 with existing rated unit at 725 kW, 1800 rpm.[1]

3.5 Cost Benefit Analysis

The economic analysis for this proposal uses a comparison of the cumulative present worth (CPW) of each alternative to determine the least cost alternative. The CPW analysis considered a study period of 25 years. The discount rate used in the study is 5.9 percent, which reflects Hydro's current long term weighted cost of capital.

The CPW analysis for each alternative was performed using the following information:

- Estimated capital costs;
- forecasted fuel costs;
- estimated unit overhaul costs and intervals;

[1] There are no 725 kW, 1200 rpm units available.

- estimated unit replacements and years; and
- remaining book values.

Using Diesel Plant Simulator software, the total operating hours, fuel consumption and production (kWh) per unit for each alternative was determined for every year of the study period. The main inputs to this simulator included load forecasts, load duration curves and diesel unit specifications. By analyzing the annual operating hours for each unit the overhaul and replacement intervals could be projected. Cost estimates for overhauls and unit replacements were developed. Replacing Unit 2052 with a larger unit would result in greater plant efficiency with fewer units online at certain times. The units online would be operating with higher load, which is more efficient. For example, instead of running two units in the summer for a load of 800 kW, the new larger unit could be operated solely and burn less fuel in the process. The Cumulative Net Present Value analysis results are presented in Table 3.

Table 3: Analysis Summary

Cartwright Unit 2052 Replacement			
Alternative Comparison Cumulative Net Present Value To The Year 2018			
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**	**Up front Cost**
925 kW - 1200 PM	22,379,624	0	3,812,500
925 kW - 1800 PM	23,381,274	1,001,649	3,448,900
725 kW - 1800 PM	24,080,061	1,700,437	3,330,400

As shown in Table 3, Alternative 1 - replacing Unit 2052 (725 kW) with a 925 kW 1200 rpm unit, is the least cost alternative, based on the total operating hours, fuel consumption, number of replacements and the number of overhauls. This is based on 20,000 hour overhaul for both 1800 rpm and 1200 rpm units, which is current practice. Hydro is undergoing an internal study that may push 1200 rpm unit overhauls past 20,000 hours to 30,000 hours. This would further justifies the larger up-front capital cost of a 1200 rpm unit versus a 1800 rpm unit as there would more operating hours between overhauls and also extend the lifespan past 100,000 hours. However, this cost benefit analysis still favors the 1200 rpm unit even with the 20,000 hour overhaul interval.

4 Conclusion

By 2020, Unit 2052 at Cartwright Diesel Plant will have operated more than 115,000 hours, reaching the end of its lifespan and needing to be replaced to maintain acceptable reliability for power generation. Replacing Cartwright Unit 2052 (725 kW) with a 925 kW 1200 rpm unit, is the least cost alternative.

4.1 Project Estimate

The estimate for this project is shown in Table 4.

Table 4: Project Estimate ($000s)

Project Cost	2019	2020	Beyond	Total
Material Supply	10.0	1,059.3	0.0	1,069.3
Labour	221.6	662.5	0.0	884.1
Consultant	243.3	549.6	0.0	792.8
Contract Work	0.0	50.0	0.0	50.0
Other Direct Costs	20.0	187.6	0.0	207.6
Interest and Escalation	30.8	312.0	0.0	342.8
Contingency	0.0	600.8	0.0	600.8
Total	**525.6**	**3,421.8**	**0.0**	**3,947.4**

4.2 Project Schedule

The anticipated project schedule is provided in Table 5.

Table 5: Project Schedule

Activity		Start Date	End Date
Planning	Open project and develop design transmittal.	Jan 2019	Feb 2019
Design	Finalize size and output requirements of new unit.	Mar 2019	Jun 2019
	Complete mechanical.	Jul 2019	Sep 2019
	Complete electrical design.	Jul 2019	Sep 2019
	Complete protection and control design.	Jul 2019	Sep 2019
Procurement	Order genset.	Oct 2019	May 2020
	Order switchgear.	Oct 2019	May 2020
Construction	Disconnect and remove Unit 2052.	Jul 2020	Jul 2020
	Install new genset.	Jul 2020	Aug 2020
	Modify cooling system.	Aug 2020	Aug 2020
Commissioning	Commission genset.	Aug 2020	Aug 2020
Closeout	Project closet out.	Sep 2020	Oct 2020

6, Bgqrpg`srgml Qwqrck Snep_bcq &0./7+0.0.'

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador PROFESSIONAL ENGINEERS AND GEOSCIENTISTS Paul Dillon Paul Dillon SIGNATURE 25-July-2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Distribution System Upgrades 2019

Various Sites

July 2018

newfoundland labrador hydro
a nalcor energy company

Summary

Historically, Hydro used a component condition assessment based approach to identify parts of its distribution system that needed to be refurbished to ensure reliable operation. With the 2019 Capital Budget Application, Hydro is enhancing this on-going effort to increase distribution reliability by focusing on refurbishment of distribution feeders that have poor reliability performance.

A brief description of work Hydro proposes to undertake in this project is:

1. Bottom Waters (L3, L6 and L7) - Replace poles, insulators, conductor, transformers, cribs, crossarms, reroute feeder and install a three-phase recloser;
2. Barachoix (L1 and L4) - Replace poles, insulators, conductor, transformers, cribs and crossarms; and
3. Hawke's Bay (L3) - Replace poles, insulators, transformers, cribs and crossarms.

In this project Hydro is also proposing to replace inefficient area lighting fixtures with energy efficient LED fixtures in the isolated diesel generation communities of Hopedale, Postville, Makkovik, Rigolet, Black Tickle, Charlottetown, Port Hope Simpson, St. Lewis, Mary's Harbour, L'Anse au Loup, Grey River, Francois, McCallum, St. Brendan's, and Little Bay Islands.

The estimated project cost is approximately $5,880,900 with planned completion in 2020.

Table of Contents

Summary i
1 Introduction 1
2 Project Description 2
3 Justification 2
3.1 Existing System 3
3.2 Operating Experience 4
3.3 Alternative Analysis 10
4 Conclusion 12
4.1 Project Estimate 12
4.2 Project Schedule 12

1 Introduction

Through its distribution system, Hydro provides electricity to customers in many rural communities. Historically, Hydro used a component condition assessment based approach to identify parts of its distribution system that needed to be refurbished to ensure reliable operation. With the 2019 Capital Budget Application, Hydro is enhancing this on-going effort to increase distribution reliability by focusing on refurbishment of distribution feeders that have poor reliability performance. These feeders were identified through the examination of the Worst-Performing feeders. To identify those feeders, 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 worst performing feeders that should receive capital expenditures for refurbishment and upgrade. This process includes:

(i) Calculating reliability indices for all distribution feeders based on data for 2013-2017. 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;

(ii) Ranking the feeders based on CHI, and SAIFI/SAIDI[4];

(iii) Analysing the reliability data for the top twenty worst performing feeders to identify the root cause of the poor performance; and

(iv) Where work is required to address reliability performance, performing a feeder study, which includes such activities as inspection data review, system design review and recommendations for corrective actions.

[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.

Hydro continues to replace high pressure sodium and mercury vapour area lights with more energy efficient LED lights in isolated diesel communities

2 Project Description

An overview of the reliability related work to be completed in this project is:

1. Bottom Waters (L3, L6 and L7), Central Interconnected
   - Replace distribution structures, conductor, insulators, transformers, cribs, crossarms, anchors and downguys;
   - Install a three-phase recloser; and
   - Reroute feeder.
2. Barachoix (L1 and L4), Central Interconnected
   - Replace distribution structures, conductor, transformers, cribs, crossarms, anchors and downguys.
3. Hawke's Bay (L3), Northern Interconnected
   - Replace distribution structures, transformers, cribs, crossarms, anchors and downguys.

The project will also install LED area lighting fixtures to replace high pressure sodium and mercury vapour street lights in the communities of Hopedale, Postville, Makkovik, Rigolet, Black Tickle, Charlottetown, Port Hope Simpson, St. Lewis, Mary's Harbour, L'Anse au Loup, Grey River, Francois, McCallum, St. Brendan's, and Little Bay Islands.

3 Justification

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

3.1 Existing System

3.1.1 Bottom Waters

Feeders to be addressed (L3, L6 and L7) are three-phase and total 39.4 km in length. Communities serviced include La Scie, Brent's Cove, Harbour Round, Tilt Cove and Round Harbour. The total number of customers in the communities serviced is 811.

3.1.2 Barachoix

Feeders to be addressed (L1 and L4) are three-phase and total 50 km in length. Communities serviced include Hermitage, Harbour Breton, Furby's Cove, Sandyville and Seal Cove. The total number of customers in the communities serviced is 1,274.

3.1.3 Hawke's Bay

Feeder to be addressed (L3) is three-phase and total 23 km in length. Communities serviced include Eddies Cove West, Port Saunders and Port au Choix. The total number of customers in the communities serviced is 971.

3.1.4 Communities for LED Streetlights

The number of streetlights to be replaced, by community, are:

- Hopedale - 54 streetlights;
- Postville - 33 streetlights;
- Makkovik - 43 streetlights;
- Rigolet - 49 streetlights;
- Black Tickle - 14 streetlights;
- Charlottetown - 47 streetlights;
- Port Hope Simpson - 28 streetlights;
- St. Lewis - 18 streetlights;
- Mary's Harbor - 41 streetlights;
- L'Anse au Loup - 206 streetlights;
- Grey River - 10 streetlights;

- Francois - 16 streetlights;
- McCallum - 15 streetlights;
- St. Brendan's - 26 streetlights; and
- Little Bay Islands - 42 streetlights.

3.2 Operating Experience

Appendix A contains the Worst Performing Feeder list and a summary of data analysis for these feeders.

Feeder Study Reports for Bottom Waters L3, L6 and L7, Barachoix L1 and L4 and Hawke's Bay L3 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.

3.2.1 Outage Statistics

Table 1 lists five-year average distribution reliability data excluding loss of supply, planned outage, customer request and major events for Bottom Waters - L3, L6 and L7, Barachoix - L1 and L4, Hawke's Bay - L3 and compares those data to corporate values.

Table 1: Outage Statistics

Feeder	CHI	SAIFI	SAIDI
Bottom Waters L3	1,737	3.18	9.13
Bottom Waters L6	1,298	2.45	6.45
Bottom Waters L7	4,815	3.73	10.93
Barachoix L1	3,428	2.25	7.51
Barachoix L4	7,614	2.91	9.43
Hawke's Bay L3	4,269	3.43	4.39
Hydro Corporate	957	1.86	3.83

3.2.2 Major Work or Upgrades

Table 2, Table 3, and Table 4 show the major work or upgrades performed on the Bottom Waters, Barachoix, and Hawke's Bay lines in recent years.

Table 2: Bottom Waters – Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2017	$44,931	Replace poles, conductor, transformers, insulators, crossarms, anchors and downguys, relocate poles
2016	$57,553	Replace transformers and crossarms, relocate poles
2015	$69,430	Replace transformers and meters
2014	$59,671	Replace poles, conductor, transformers and rotten platforms

Table 3: Barachoix – Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2017	$101,387	Replace poles, conductor, transformers, insulators, crossarms, anchors and downguys, bond downguys
2016	$64,396	Replace poles, conductor, transformers, insulators, anchors and downguys
2015	$63,123	Replace poles, transformers, anchors and downguys, repair neutral conductor
2014	$90,956	Replace poles, conductor, transformers, insulators, crossarms, anchors and downguys

Table 4: Hawke's Bay – Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2017	$74,210	Install poles, insulators and conductor. Replace insulators, crossarms, and conductor
2016	$54,417	Install poles, insulators and conductor. Replace insulators and crossarms
2015	$101,263	Install poles, insulators and conductor. Replace insulators and crossarm
2014	$65,299	Install poles, insulators and conductor. Replace insulators

3.2.3 Maintenance History

The five-year maintenance histories for the distribution lines in this report are shown in Table 5 to Table 10.

Table 5: Bottom Waters L3 Five-Year Maintenance History ($000s)

Year	Preventive Maintenance	Corrective Maintenance	Total Maintenance
2017	39.8	5.3	40.1
2016	0.0	9.2	9.2
2015	0.0	12.4	12.4
2014	0.0	5.4	5.4
2013	2.2	3.0	5.2

Table 6: Bottom Waters L6 Five-Year Maintenance History ($000s)

Year	Preventive Maintenance	Corrective Maintenance	Total Maintenance
2017	0.0	0.1	0.1
2016	0.0	0.8	0.8
2015	0.0	0.3	0.3
2014	1.4	2.8	4.2
2013	0.0	0.4	0.4

Table 7: Bottom Waters L7 Five-Year Maintenance History ($000s)

Year	Preventive Maintenance	Corrective Maintenance	Total Maintenance
2017	0.0	1.0	1.0
2016	0.0	0.7	0.7
2015	3.4	6.7	10.1
2014	0.0	1.2	1.2
2013	0.0	12.9	12.9

Table 8: Barachoix L7 Five-Year Maintenance History ($000s)

Year	Preventive Maintenance	Corrective Maintenance	Total Maintenance
2017	0.2	10.9	11.1
2016	21.7	51.0	72.7
2015	16.3	14.2	20.5
2014	1.7	18.0	19.7
2013	19.1	15.5	34.6

Table 9: Barachoix L4 Five-Year Maintenance History ($000s)

Year	Preventive Maintenance	Corrective Maintenance	Total Maintenance
2017	0.0	14.3	14.3
2016	25.0	8.7	33.7
2015	8.0	8.5	16.5
2014	0.0	12.7	12.7
2013	0.0	5.5	5.5

Table 10: Hawke's Bay L3 Five-Year Maintenance History ($000s)

Year	Preventive Maintenance	Corrective Maintenance	Total Maintenance
2017	1.0	21.2	22.2
2016	1.0	23.0	24.0
2015	1.2	11.5	12.7
2014	1.0	7.1	8.1
2013	0.5	27.7	28.2

3.2.4 Historical Information

Table 11 lists budgeted and actual costs for distribution upgrades in the last five years as well the amounts budgeted for 2018.

Table 11: Historical Information ($000s)

Year	Project Description	Budget	Actuals
2018F	Upgrade Distribution System – Cartwright (Year 1 of 2)	32.0	
	Upgrade Distribution System – English Harbour West (Year 1 of 2)	255.7	
	Upgrade Distribution System – Farewell Head (Year 1 of 2)	42.7	
	Upgrade Distribution System – Rocky Harbour (Year 1 of 2)	53.4	
	Upgrade Distribution System – Grandy Brook (Year 2 of 2)	643.2	
	Upgrade Distribution System – Ramea (Year 2 of 2)	487.7	
2017	Upgrade Distribution System – Grandy Brook (Year 1 of 2)	32.1	0.0
	Upgrade Distribution System – Ramea (Year 1 of 2)	32.1	0.0
	Upgrade Distribution System – Farewell Head (Year 2 of 2)	856.4	860.0
	Upgrade Distribution System – Paradise River (Year 2 of 2)	621.1	604.9
	Upgrade Distribution System – Happy Valley (Year 2 of 2)	738.8	820.0
	Upgrade Distribution System – King's Point (Year 2 of 2)	737.9	770.0
	Upgrade Distribution System – Sally's Cove (Year 2 of 2)	199.9	211.0
	Upgrade Distribution System – L'Anse au Loup (Year 2 of 2)	1,666.0	1730.0
	Upgrade Distribution System (Reclosers) – Coney Arm and Grandy Brook (Year 2 of 2)	623.4	700.3
	Upgrade Distribution System (Milltown) – Bay d'Espoir (Year 2 of 2)	906.8	940.0
2016	Upgrade Distribution System – Farewell Head (Year 1 of 2)	31.9	109.1
	Upgrade Distribution System – Paradise River (Year 1 of 2)	32.1	0.0
	Upgrade Distribution System – Happy Valley (Year 1 of 2)	32.0	0.0
	Upgrade Distribution System – King's Point (Year 1 of 2)	32.0	5.1
	Upgrade Distribution System – Sally's Cove (Year 1 of 2)	15.4	0.0
	Upgrade Distribution System – L'Anse au Loup (Year 1 of 2)	74.2	2.9
	Upgrade Distribution System (Reclosers) – Coney Arm and Grandy Brook (Year 1 of 2)	36.0	0.3
	Upgrade Distribution System (Milltown) – Bay d'Espoir (Year 1 of 2)	32.0	0.0
	Upgrade Distribution Feeder & Voltage Conversion – Happy Valley	593.7	582.6
	Upgrade Distribution Feeder – Line 1, 3, 4, 6, and 7 Bottom Waters (Year 2 of 2)	818.8	446.1

Year	Project Description	Budget	Actuals
2015	Upgrade Distribution Feeder – Line 1, 3, 4, 6 and 7 Bottom Waters (Year 1 of 2)	42.7	0.0
	Pole Replacements – Pinsent’s Arm and Labrador City	593.4	524.4
	Insulator Replacements – Farewell Head	500.0	181.3
	Relocate Voltage Regulators – Hawke’s Bay	166.4	103.4
	Install Second Distribution Feeder - Nain	1050.3	1,113.1
	Upgrade Distribution Feeder - Line 1 Nain (Year 2 of 2)	261.0	348.8
	Upgrade Distribution Feeder - Line 1 Daniel’s Hr. (Year 2 of 2)	877.8	964.9
	Upgrade Distribution Feeder - Line 1 and 2 Main Brook (Year 2 of 2)	837.1	855.8
	Upgrade Distribution Feeder - Line 1 Plum Point (Year 2 of 2)	1,440.9	1,324.4
	Upgrade Distribution Feeder - Line 1 Hampden (Year 2 of 2)	733.2	738.4
2014	Upgrade Distribution Feeder - Line 1 Nain (Year 1 of 2)	43.0	10.0
	Upgrade Distribution Feeder - Line 7 Happy Valley (Year 1 of 2)	64.3	26.6
	Upgrade Distribution Feeder - Line 1 Daniel’s Hr. (Year 1 of 2)	69.7	14.9
	Upgrade Distribution Feeder - Line 1 and 2 Main Brook (Year 1 of 2)	64.3	104.7
	Upgrade Distribution Feeder - Line 1 Plum Point (Year 1 of 2)	75.3	6.4
	Upgrade Distribution Feeder - Line 1 Hampden (Year 1 of 2)	53.6	30.5
	Upgrade Distribution Feeder - Line 1 McCallum	359.1	320.1
	Upgrade Distribution Feeder - Line 1, 2, 4 and 5 Barachoix	583.7	553.8
	Upgrade Distribution Feeder - Line 1 Bay d’Espoir	692.6	632.3
	Upgrade Distribution Feeder - Line 1 Conne River	494.2	443.2
	Upgrade Distribution Feeder - Line 1 St. Lewis (Year 2 of 2)	908.1	740.5
	Upgrade Distribution Feeder - Line 1 and 3 Roddickton (Year 2 of 2)	1,259.5	1,366.7
	Upgrade Distribution System - Charlottetown (Year 2 of 2)	365.0	269.2
	Upgrade Distribution System - South Brook (Year 2 of 2)	975.8	846.2
	Upgrade Distribution Feeder - Line 1 Grey River (Year 2 of 2)	487.1	410.8

Year	Project Description	Budget	Actuals
2013	Upgrade Distribution Feeder - Line 1 St. Lewis (Year 1 of 2)	76.9	23.3
	Upgrade Distribution Feeder - Line 1 and 3 Roddickton (Year 1 of 2)	98.4	106.5
	Upgrade Distribution System - Charlottetown (Year 1 of 2)	27.8	22.8
	Upgrade Distribution System - South Brook (Year 1 of 2)	76.3	108.5
	Upgrade Distribution Feeder - Line 1 Grey River (Year 1 of 2)	32.5	111.9
	Upgrade Distribution Feeder - Line 1 Cow Head	665.6	658.4
	Upgrade Distribution Feeder - Line 1 St. Brendan’s	330.2	310.7
	Upgrade Distribution Feeder - Line 1 Holyrood	632.4	372.1
	Upgrade Distribution Feeder - Line 11 Wabush	400.8	513.2
	Upgrade Distribution Voltage - Line 6 St. Anthony	641.9	648.6
	Upgrade Distribution Feeder - Line 6 Farewell Head	961.9	980.0
	Upgrade Distribution Feeder - Line 5 Farewell Head	1,110.1	1,184.9
	Upgrade Distribution Feeder - Line 2 Plum Point (Year 2 of 2)	1,110.5	1,276.2

3.3 Alternative Analysis

3.3.1 Line Upgrades

Three alternatives were considered for each feeder. Constructing an entirely new distribution line and retiring the existing line (Alternative 1), allowing the existing line components to remain in service until failure (Alternative 2), replacing deteriorated line components and utilizing existing non-deteriorated line components (Alternative 3).

Alternative 1: New Distribution Line

There are existing line components that are still operable such as poles, conductor, insulators, and cross arms, and the construction of an entirely new line would lose the benefit of this existing and functional equipment. This alternative requires spending that is unnecessary for the continuation of reliable provision of electricity.

Alternative 2: Line Components Remain in Service until Failure

Allowing existing line components to remain in service until failure is not viable as it negatively affects the reliability of electrical service provided to Hydro’s customers, and the lines already show signs of decreasing reliability.

Alternative 3: Replace Deteriorated Line Components and Use Non-Deteriorated Components

Replacing deteriorated line components reduces the chance of outages due to deteriorated line components, while utilizing existing non-deteriorated line components means Hydro doesn't incur the cost to replace line components before end of life.

Alternative 3 has been deemed the most acceptable of the three alternatives.

3.3.2 Installation of LED Lighting

Two alternatives that were considered were continuing with the status quo (Alternative 1) and replacing existing streetlights with new LED fixtures (Alternative 2).

A Cumulative Present Worth Analysis (CPW) determined the cost effectiveness of installing LED lighting. The CPW analysis considered a study period of 20 years. The discount rate used in the study was 5.9 percent, which reflects Hydro's current long term weighted cost of capital. The CPW analysis evaluated the savings in fuel costs offset by the capital investment of installing LED lighting. It is anticipated that Hydro will recover the costs of the installation of LED lighting within six years. Table 12 shows costs savings of $396,577 over a period of 20 years.

Table 12: CPW Analysis

2019 Distribution Upgrades – LED Replacement		
Alternative Comparison Cumulative Net Present Value To The Year 2018		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
LED Replacement	1,532,377	0
Status Quo	1,928,954	396,577

4 Conclusion

Hydro needs to maintain reliable energy supply is to customers serviced by its distribution. By executing the work detailed in this proposal, Hydro expects to improve the overall reliability of the distribution systems. Also, the installation of LED lighting in the 15 identified isolated distribution systems yielded cost savings for ratepayers.

4.1 Project Estimate

The estimate for this project is shown in Table 13.

Table 13: Project Estimate ($000s)

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

4.2 Project Schedule

The anticipated project schedule is provided in Table 14: Project Schedule

Table 14: Project Schedule

Activity		Start Date	End Date
Planning	Resource Planning	Jan 2019	Jan 2020
Design	Assessment Completed	Sep 2017	Nov 2017
Procurement	Materials Ordered	Jan 2020	Mar 2020
Construction	Monitor Construction Activities	May 2020	Oct 2020
Commissioning	Inspection Preformed by Local Operations Crews	Aug 2020	Sep 2020
Closeout	Project Closeout	Sep 2020	Nov 2020

Appendix A

Worst Performing Feeder List and Summary of Data Analysis

Worst Performing Feeders Sorted by CHI

Rank	Feeder	CHI	Comments
1	Farewell Head, L5	8491	In 2013, poor reliability statistics were driven by a defective terminator of the Farewell Head submarine cable. This will be addressed through the proposed 2019 capital project- "Condition Assessment for Submarine Cable". In 2016, line hardware failures during adverse weather contributed to poor reliability statistics. This feeder was upgraded in 2017 as part of the 2016-2017 distribution system upgrades project. No additional work is required at this time.
2	Bottom Waters, L1	7918	Poor reliability statistics in 2013 were due to mainly vegetation issues and several weather-related events. This line experienced a significant amount of tree cutting in 2013-2016. 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 poor reliability statistics were driven by tree related events. Tree cutting work has been planned for 2018 and no additional work is required at this time.
3	English Harbour, L1	7912	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. All these issues will be addressed through the 2018-2019 distribution upgrade project.
4	Barachoix, L4	7614	Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents, and other defective line hardware incidents during the 2013-2017 period. A capital project is required to complete the required work to improve the reliability performance of Barachoix, L4.
5	Happy Valley, L16	6690	Reliability statistics were driven by a broken overhead pole incident in 2013. 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 part of the 2016-2017 distribution upgrades project. No additional work is required at this time.

Rank	Feeder	CHI	Comments
6	Roddickton, L1	6371	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 upgrades project. Since then reliability has generally been good. No additional work is required at this time.
7	Farewell Head, L4	5781	In 2013, poor reliability statistics were driven by a defective terminator of the Farewell Head submarine cable. This will be addressed through 2019 capital project- Condition Assessment for Submarine Cable. In 2016, primary conductor failures during adverse weather contributed to poor reliability statistics. This will be addressed through 2018-2019 distribution upgrades project (Replace primary conductor for FHD, L4). No additional work is required at this time
8	Bottom Waters, L7	4815	Poor reliability statistics were driven by several insulator failures in 2016 and 2017. Overall reliability was impacted due to broken line hardware i.e. cross arm, primary conductor, overhead transformer. A capital project is required to mitigate all the issues.
9	South Brook, L5	4799	A lightning-related event resulted in poor overall reliability statistics in 2013. In 2014 reliability was impacted by a broken pole caused by third party. In 2017, poor reliability statistics were driven by a broken pole incident and a damaged disconnect switch. This feeder will continue to be monitored to determine if it should be considered for upgrading in a future capital budget.
10	Farewell Head, L6	4702	This feeder performed poorly in 2013 period due to broken hendrix insulator incidents. As a remedial action, problematic hendrix insulators were replaced with porcelain insulators during the 2013-2015 Period. Since 2014, this feeder has been performing well. No additional work is required at this time.
11	Kings Point, L1	4572	Poor reliability statistics were driven by mainly tree-related events in 2013 and 2017. Tree cutting work has been scheduled for 2019 and no additional work is required at this time.
12	Hawke's Bay, L3	4269	During the 2013-2016 period, poor reliability statistics were driven by several incidents of line components failure (insulators, overhead splice, conductor, cross arms). In 2017 there was a significant broken conductor incident due to galloping. A capital project is required to address these concerns.
13	Bay D'Espoir, L1	4268	This feeder was down several times due to several tree related events during the 2013-2017 period. Vegetation issues were addressed and no additional work is required at this time.

Rank	Feeder	CHI	Comments
14	Bottom Waters, L4	3612	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 and overhead connector failures in 2016. This feeder will continue to be monitored to determine if it should be considered for upgrading in a future capital budget.
15	Bear Cove, L6	3535	During 2013-2015, this feeder had numerous power outages due to unnecessary/faulty operations of reclosers caused by feeder unbalance. Work was completed in 2016 to address the unbalanced load issue. No additional work is required at this time.
16	Barachoix, L1	3428	Poor reliability statistics in 2014 were caused by a broken cross arm. The feeder performed poorly in 2016 due to several broken primary conductors. Overall reliability statistics on this feeder have been impacted by primary conductor and other line hardware issues during the 2013-2017 period. Work is required to mitigate the above issue.
17	Happy Valley, L7	3286	An equipment overload event resulted in poor overall reliability statistics in 2015. In addition, a tree contacted the line in late 2015. No work is required at this time.
18	Rocky Harbour, L2	2786	In 2013 reliability was impacted by a broken pole caused by third party. In 2017 a prolonged power outage due to a tree contacts impacted the reliability. This feeder will be addressed for danger trees during 2018-2019 distribution system upgrades project (Upgrade Rocky Hr. System).
19	L'Anse-Au-Loup, L2	2753	In 2014 poor reliability statistics were driven by primary conductor failures. This feeder had significant upgrades in 2017 as part of the 2016-2017 distribution upgrade project. No additional work is required at this time.
20	Glenbernie, L1	2553	The poor reliability statistics were driven by tree contacts in 2015 and 2017. Tree cutting work has been scheduled for 2019-2020. No additional work is required at this time.

Worst Performing Feeders Sorted SAIFI and SAIDI based Feeder Score[5]

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI based list	Comments
1	Bottom Waters, L1	3.397	20.756	12.076	Yes	See comments in CHI table.
2	Burgeo, L5	2.167	16.816	9.491	No	In 2016-2017, 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.
3	Farewell Head, L4	3.969	14.272	9.12	Yes	See comments in CHI table.
4	Farewell Head, L5	3.964	13.244	8.604	Yes	See comments in CHI table.
5	Farewell Head, L1	1.637	15.485	8.561	No	In 2013, poor reliability statistics were driven by a defective terminator of the Farewell Head submarine cable. This will be addressed through 2019 capital project- “Condition Assessment for Submarine Cable”. 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. No additional work is required at this time.

[5] Feeder Score= (.5* SAIFI) + (.5*SAIDI)

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI based list	Comments
6	Barachoix, L5	1.5	13.45	7.475	No	This feeder is a 2.4 KV 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.
7	Bottom Waters, L7	3.732	10.927	7.33	Yes	See comments in CHI table.
8	Burgeo, L1	1.945	12.707	7.326	No	Poor reliability statistics in 2015 were due to three defective disconnect switch incidents, one defective recloser and one lightning strike. In 2017, line hardware failures contributed to poor reliability statistics. A capital project (distribution upgrades project, GBK, 2017-2018) is ongoing in this area. All the above issues will be addressed through the capital project.
9	Kings Point, L2	2.865	11.294	7.079	No	Poor reliability statistics were principally driven by multiple tree-related incidents in 2017. Tree cutting work has been scheduled for 2019. No additional work is required at this time.
10	Roddickton, L1	2.363	11.51	6.937	Yes	See comments in CHI table.
11	Main Brook, L2	2.555	11.308	6.931	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

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI based list	Comments
						constructed. In 2013 the power line was down several times due to transformer failures. 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. No additional work is required at this time
12	English Harbour, L1	3.827	9.752	6.79	Yes	See comments in CHI table.
13	Burgeo, L4	2.499	10.865	6.682	No	Poor reliability statistics in 2014 were due to defective recloser issues. In 2017, line hardware failures contributed to poor reliability statistics. A capital project (distribution upgrades project, GBK, 2017-2018) is ongoing in this area. All the line hardware concerns will be addressed through the capital project.
14	Farewell Head, L6	2.928	9.441	6.185	Yes	See comments in CHI table.
15	Barachoix, L4	2.913	9.425	6.169	Yes	See comments in CHI based list.
16	Bottom Waters, L3	3.181	9.13	6.155	No	Overall reliability statistics on this feeder have been impacted by several weather events, tree related incidents and broken line component issues during the 2013-2017 period. Work is required to mitigate all the issues.
17	Kings Point, Line 1	2.263	8.351	5.307	Yes	See comments in CHI table.
18	Roddickton, L4	1.393	8.811	5.102	Yes	See comments in CHI table.

Rank	Feeder	SAIFI	SAIDI	Feeder Score	Included in CHI based list	Comments
19	Happy Valley, L16	3.62	6.556	5.088	Yes	See comments in CHI table.
20	Seal Cove Road, L2	1.622	8.448	5.035	No	Reliability statistics were driven by a broken conductor incident in 2017 due to adverse weather. The primary and neutral conductors had ice build-up and high wind caused the conductors to slap together. No additional work is required at this time.

Appendix B

Feeder Study Reports

Bottom Waters (L3, L6 and L7)

Bottom Waters, L3

Bottom Waters L3 is a three-phase distribution line and total 34 km in length. Communities serviced include Shoe Cove, Tilt Cove and Round Harbour. The total number of customers in the communities serviced is 181. This feeder also supplies power to L6 and L7 of Bottom Waters distribution system.

Table B1 summarizes the reliability data and Figure B1 shows the reliability trends for Bottom Waters L3 for 2013-2017 period. All the reliability indices are calculated excluding loss of supply outages, planned outages, customer requests and major events.

Table B1: Five Year Average (2013-2017) Reliability Data for Bottom Waters L3

Location	CHI	SAIFI	SAIDI
Bottom Waters L3	1,737	3.18	9.13
Hydro Corporate	957	1.86	3.83

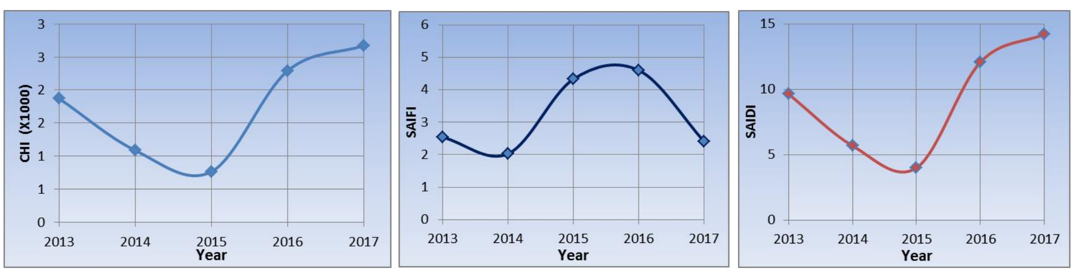


Figure B1: Reliability Trends for Bottom Waters L3

Feeder Analysis

Overall reliability statistics on this feeder have been impacted by several weather events and broken line component incidents during the 2013-2017 period. In addition the poor reliability statistics are also driven by tree contacts in 2014, 2016 and 2017. Tree cutting work for this feeder was started in 2017 and planned for completion in 2018.

From the inspection record, this line has deteriorated line components - 10 poles, 16 transformers, and 4 cross arms. It also has a section where existing conductor is substandard.

The distance from the recloser, BW3-R1 (located at Bottom Waters terminal station) to the recloser, LS7-R1 (located at La Scie Substation) is approximately 18 km. This 18 km section is highly exposed to deep forest and any fault on this segment will cut power for all the customers of L3 including L6 and L7. To minimize the power outage, this long radial circuit should be sectionalized by installing another recloser in the proposed location (Figure B2). This will reduce the number of affected customers and improve the power restoration time in the event of a fault downstream of the new recloser.

In addition, a section of L3 near Armchair Pond is required to be rerouted to roadside for better access (Figure B3). 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 Bottom Waters L3:

- Replace pole, insulators, transformers, cribs, crossarms, anchors and downguys;
- replace any substandard or deteriorated primary conductors;
- install a three-phase recloser, and
- re-route feeder.

As a part of the preparation of the project, the engineering team will review the feeder to identify any additional deficiencies that need to be addressed.

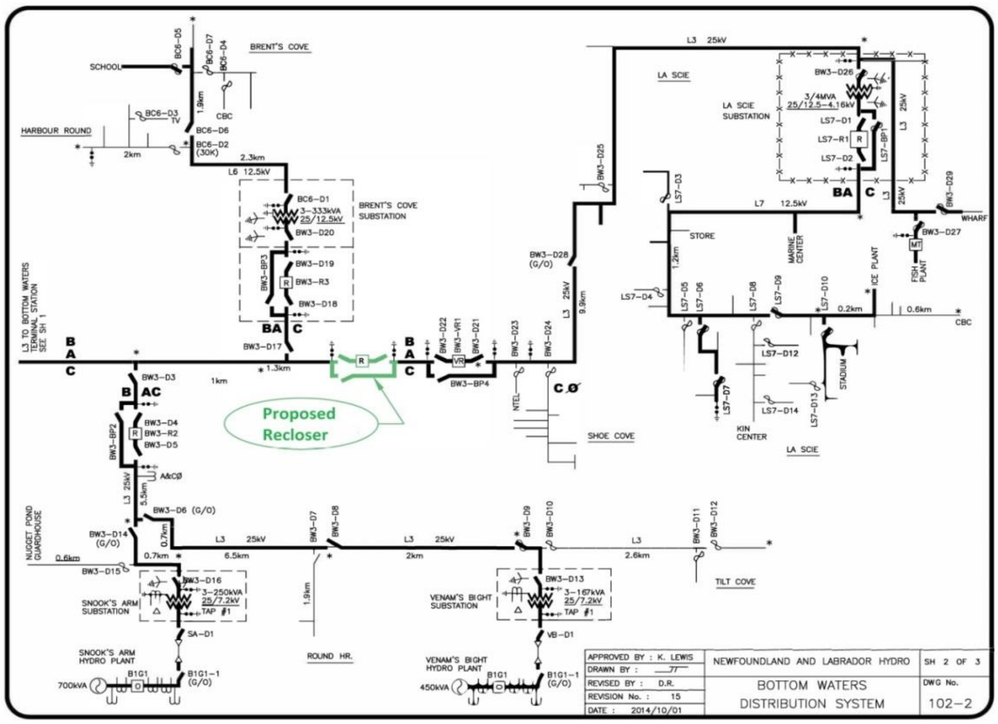


Figure B2: New Recloser Location, Bottom Waters, Line 3

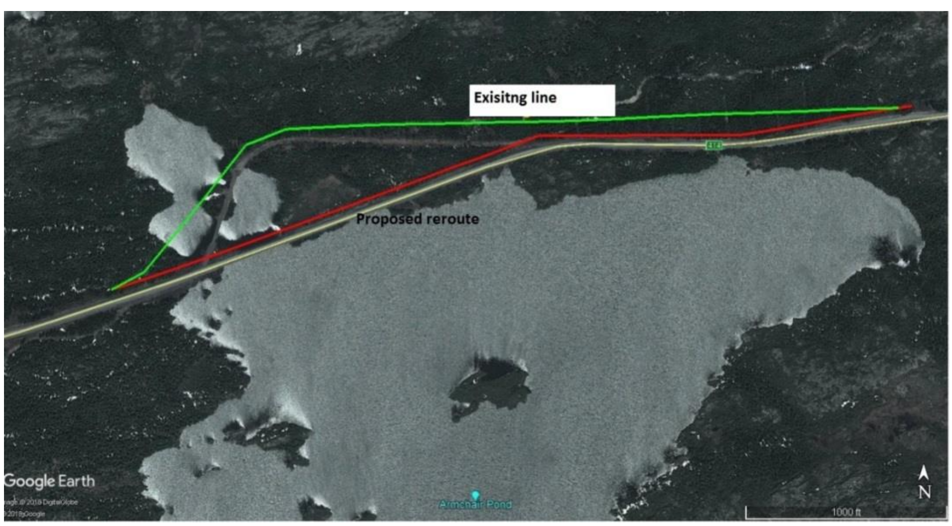


Figure B3: Proposed Reroute for Bottom Waters, Line 3

Bottom Waters L7

Bottom Waters L7 is a three-phase distribution feeder and total 1.4 km in length. This feeder serves La Scie Community and the total number of customers in the community is 435.

Table B2 summarizes the reliability data and Figure B4 shows the reliability trends for Bottom Waters L7 for 2013-2017 period. All the reliability indices are calculated excluding loss of supply outages, planned outages, customer requests and major events.

Table B2: Five Year Average (2013-2017) Reliability Data for Bottom Waters L7

Location	CHI	SAIFI	SAIDI
Bottom Waters L7	4,815	3.73	10.93
Hydro Corporate	957	1.86	3.83

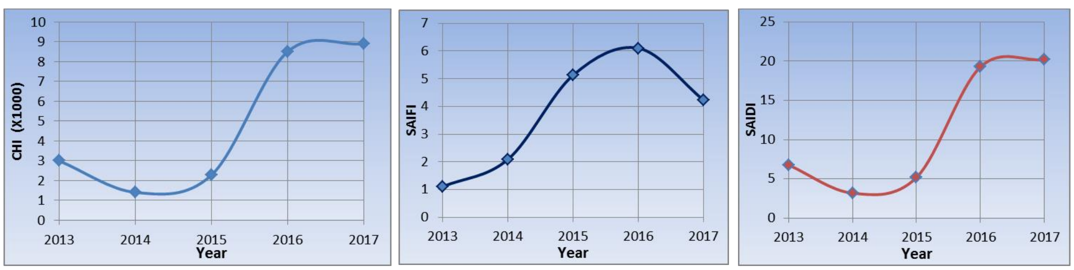


Figure B4: KPI Trends for Bottom Waters L7

Feeder Analysis

Poor reliability statistics were driven by several insulator failures in 2016 and 2017. Overall reliability was impacted due to broken line hardware (cross arm, primary conductor, and transformer).

From the pole line inspection record, this line has 70 deteriorated poles and 30 rusty transformers. Inspections have also identified substandard conductor and obsolete insulators on the main trunk section of this feeder.

Recommendations

The following work is required to improve reliability performance of Bottom Waters L7:

- Replace poles, transformers, cribs, cross arms, insulators, anchors and downguys.
- Replace any substandard or deteriorated primary conductors.

As a part of the preparation of the project, the engineering team will review the feeder to identify any additional deficiencies that need to be addressed.

Bottom Waters L6

Bottom Waters L6 is an approximately 4 km three-phase branch feeder extending from the main line L3. This feeder serves Brent's Cove and Harbour round communities and the total number of customers in the communities serviced is 195.

Although L6 is not in the twenty worst performing feeder list, several line components (8 poles, 14 transformers and 2 cross arms) have been found to be deteriorated and are required to be replaced soon. It is cost effective to complete the refurbish work for Bottom Waters L6 within this project as L6 is located in the same general geographical region. This close proximity to L3 will reduce or eliminate mobilization costs of refurbishing L6.

Barachoix (L1 and L4)

Barachoix L1

Barachoix L1 is a three-phase distribution feeder and total 26 km in length. Communities serviced include Hermitage, Furby's Cove, Sandyville and Seal Cove. The total number of customers in the communities serviced is 462.

Table B3 summarizes the reliability data and Figure B5 shows the reliability trends for Barachoix L1 for 2013-2017 period. All the reliability indices are calculated excluding loss of supply outages, planned outages, customer requests and major events.

Table B3: Five Year Average (2013-2017) Reliability Data for Barachoix L1

Location	CHI	SAIFI	SAIDI
Barachoix, Line 1	3,428	2.25	7.51
Hydro Corporate	957	1.86	3.83

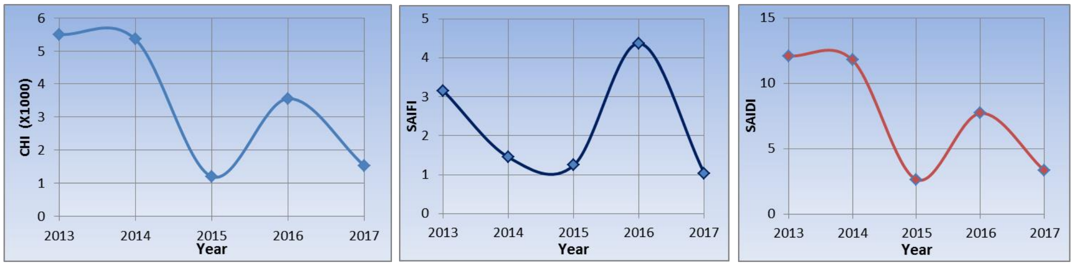


Figure B5: KPI Trends for Barachoix L1

Feeder Analysis

Poor reliability statistics in 2014 were caused by a broken cross arm. The feeder performed poorly in 2016 due to several broken primary conductors. Overall reliability statistics on this feeder have been impacted by primary conductor and other line hardware failure incidents during the 2013-2017 period. Work is required to mitigate the above issues.

From the pole line inspection record, this line has several deteriorated line components - 90 poles, 80 cross arms, 10 cribs and 4 transformers. It has also been identified that the existing primary conductor on numerous sections of this feeder is substandard and or deteriorated.

Recommendations

Based on the feeder analysis and inspections of the Barachoix L1, the following upgrade is required:

- Replace poles, transformers, cribs, cross arms, anchors and downguys.
- Replace any substandard or deteriorated conductor

As a part of the preparation of the project, the engineering team will review the feeder to identify any additional deficiencies that need to be addressed.

Barachoix L4

Barachoix L4 is a three-phase distribution feeder and total 24 km in length. This feeder serves Harbour Breton Community and the total number of customers in the community is 812.

Table B4 summarizes the reliability data and Figure B6 shows the reliability trends for Barachoix, Line 4 for 2013-2017 period. All the reliability indices are calculated excluding loss of supply outages, planned outages, customer requests and major events.

Table B4: Five Year Average (2013-2017) Reliability Data for Barchoix L4

Location	CHI	SAIFI	SAIDI
Barachoix L4	7,614	2.91	9.43
Hydro Corporate	957	1.86	3.83

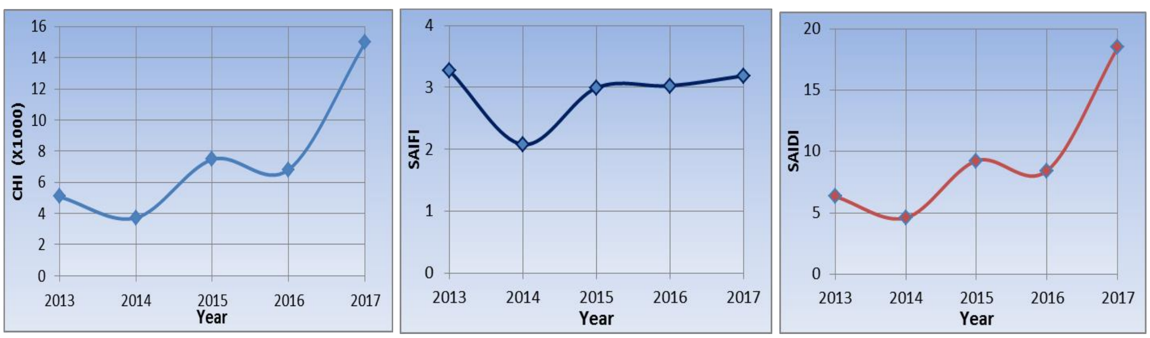


Figure B6: KPI Trends for Barachoix L4

Feeder Analysis

Overall reliability statistics on this feeder have been impacted by several broken primary conductor incidents, and other defective line hardware incidents for 2013-2017 period.

Inspections have identified that there are numerous locations where the primary conductor is substandard or deteriorated on this feeder. It has also been identified that this line has 105 deteriorated poles and 100 decayed or damaged cross arms. There are also several deteriorated transformers and cribs on this feeder.

Recommendations

To improve the reliability performance of Barachoix L4, the following work is required:

- Replace poles, transformers, cribs, cross arms, anchors and downguys.
- Replace any substandard or deteriorated conductor

As a part of the preparation of the project, the engineering team will review the feeder to identify any additional deficiencies that need to be addressed.

Hawke's Bay (L3)

Hawke's Bay L3

Hawke's Bay L3 is a three-phase distribution line and total 23 km in length. Communities serviced include Eddies Cove West, Port Saunders and Port au Choix. The total number of customers in the communities serviced is 971.

Table B5 summarizes the reliability data and Figure B7 shows the reliability trends Hawke's Bay L3 for 2013-2017 period. All the reliability indices are calculated excluding loss of supply outages, planned outages, customer requests and major events.

Table B5: Five Year Average (2013-2017) Reliability Data for Hawke's Bay, Line 3

Location	CHI	SAIFI	SAIDI
Hawke's Bay, L3	4,269	3.43	4.39
Hydro Corporate	957	1.86	3.83

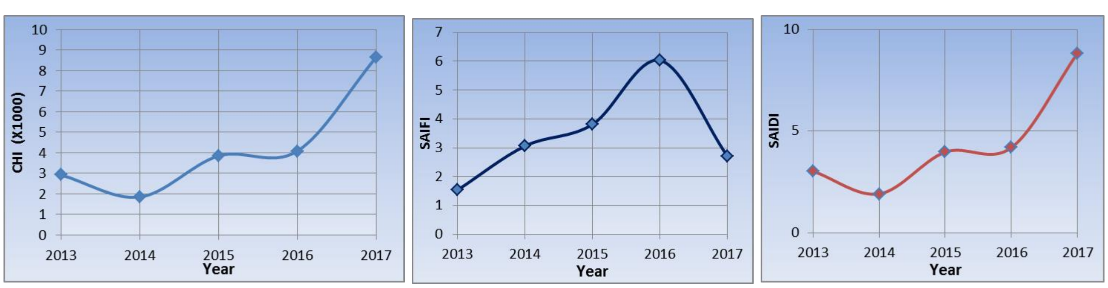


Figure B7: KPI Trends for Hawke's Bay L3

Feeder Analysis

During the 2013-2016 period, poor reliability statistics were driven by several incidents of line components failure (insulators, overhead splice, conductor, cross arms). In 2017 there was a significant broken conductor incident due to galloping.

Inspection has identified deteriorated line components consisting of 200 poles, 11 transformers, 4 cribs, 40 cross arms. There are a number of locations where the existing conductor or the insulators are obsolete. Due to the age and condition of the insulators, conductor, and other line hardware, this feeder is becoming more prone to damage when exposed to severe wind, ice and snow loading.

Recommendations

To improve the reliability performance of Hawke's Bay L3, the following work is required:

- Replace poles, transformers, cribs, cross arms, insulators, anchors and downguys; and
- Replace any substandard or deteriorated conductor.

As a part of the preparation of the project, the engineering team will review the feeder to identify any additional deficiencies that need to be mitigated.

9. Overhaul Diesel Units – Various

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador DAVE ROYLE SIGNATURE 7/10/2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Overhaul Diesel Engines

Various Sites

July 2018

newfoundland labrador hydro
a nalcor energy company

Summary

This report presents the capital budget proposal for diesel engine overhauls that are performed on a usage-based schedule, at an interval of 20,000 operating hours. Each overhaul is required to ensure each engine is able to meet its expected life of 100,000 hours. The estimated project cost for the overhaul of ten diesel engines and four alternators is approximately $2,511,300 with planned completion in 2019. The projection of future overhauls forecasts 45 overhauls over the 2019 to 2023 period.

Table of Contents

Summary i
1 Introduction 1
2 Project Description 2
3 Justification 4
3.1 Existing System 4
3.2 Operating Experience 5
3.2.1 Reliability Performance 7
3.2.2 Safety Performance 10
3.2.3 Environmental Performance 10
3.2.4 Industry Experience 10
3.2.5 Vendor Recommendations 11
3.2.6 Maintenance or Support Arrangements 11
3.2.7 Maintenance History 11
3.2.8 Historical Information 12
3.2.9 Anticipated Useful Life 12
3.3 Development of Alternatives 12
3.4 Evaluation of Alternatives 12
3.5 Economic Analysis 12
4 Conclusion 13
4.1 Project Estimate 13
4.2 Project Schedule 13

Appendices

Appendix A Diesel Engine Overhaul Five Year Plan

1 Introduction

Hydro's Diesel Engine Overhaul plan has been developed to ensure the reliability of diesel engines at each of Hydro's diesel generating stations. Hydro has 24 diesel generating stations, 20 of which are prime power stations serving a total of approximately 4,400 customers. Prime power means that diesel is the primary (or, in some cases, sole) power source. These generating stations are the primary source of electricity in the community that they are located, which means that if the station cannot meet the load then customer outages will occur. The reliability of the prime power diesel generating stations are designed such that each station can withstand a single contingency, meaning that each plant is designed to be able to provide maximum load in the event of the unavailability of any single diesel unit (due to failure). While the failure of a single unit will not result in customer outages, the failure of an additional unit before the initially failed unit is returned to service may result in customer outages. This highlights the importance of the reliability of these diesel generating stations. In addition, the prime power diesel generating stations are normally the only power source for a community and require major overhauls to achieve the expected service lives, while providing reliable power.

The four generating stations that are not prime power stations are Hawke's Bay, St. Anthony, Mud Lake and Happy Valley. These stations provide emergency backup generation. Both Hawke's Bay and St. Anthony provide emergency backup to the Island Interconnected System, and Happy Valley and Mud Lake provide emergency backup to the customers served by the Happy Valley Distribution System.

Figure 1 is of Ramea Unit 2077 prior to its installation in the Ramea Diesel Plant.

Figure 1: Ramea Unit 2077

2 Project Description

This project is required in order to overhaul the diesel engines at various diesel generating stations. Hydro's five year plan for overhauls, which can be found in Appendix A, consists of the overhaul of 45 engines during the 2019-2023 five-year period. The 2019 proposed project consists of overhauling ten diesel engines and four alternators. Diesel engine overhauls are planned based on each engine requiring overhauls every 20,000 hours of operation. This criterion is being used for diesel engine overhauls and is also the criteria recommended in 2003, following a comprehensive internal maintenance review (subsequently referred to in this report as the asset maintenance strategy review). Prior to this maintenance review, overhauls were performed at an interval of 15,000 operating hours.

The planned overhaul schedule is based on an estimate of when each engine will reach 20,000 operating hours, based on its in-service or last overhaul date. A typical unit will accumulate 20,000 operating hours in 7.2 years, but this depends on individual plant utilization factors and the subsequent usage of the diesel engines in that plant. As such, this schedule is subject to change and the year for which an engine is projected to require an overhaul can vary, depending on plant conditions and the actual hours accumulated. While the specific diesel engines projected to be due for overhauls in a given year can vary, the number of engines projected to be due for overhauls in a given year tends to be consistent.

An overhaul consists of replacement of specific critical parts, including pistons, liners, main bearings, connecting rod bearings, fuel injectors, oil cooler, turbo charger, water pump, oil pump, cylinder heads, fuel lines, and all necessary gaskets. Also included in an overhaul is a bench top overhaul of the fuel pump and in every second overhaul the fuel lines are replaced. An overhaul of the alternator is typically completed once in the unit's lifetime, at approximately 40,000 operating hours or when identified as required through maintenance checks. The fuel pump and alternator overhauls were added to the overhaul scope in recent years as a result of a formal asset maintenance strategy review, which considered Hydro's experience, other utility experience, other utility practice, and manufacturer recommendations. With the exception of the fuel lines, the replacement parts are remanufactured parts.

The unit overhauls involved in this project includes those that are projected to become due during 2019. The ten units to be overhauled in 2019 include:

- Francois 588;
- Little Bay Island 2058;
- McCallum 2063;
- Normans Bay 584;
- Charlottetown 2089;
- Nain 576;
- Nain 2085;
- Black Tickle 579;
- Nain 591; and
- Makkovik 3033.

In addition, the following units will have their alternators overhauled:

- McCallum 2063;
- Nain 576;
- Nain 2085; and
- Black Tickle 579.

Occasionally, a unit in one of the diesel plants across Hydro's operating area experiences an issue that necessitate an unplanned overhaul. Where appropriate, Hydro may complete such an overhaul under this project and, if possible, defer one of the units planned for completion.

3 Justification

3.1 Existing System

Hydro's existing system of diesel generating stations consists of 24 diesel generating stations, 20 of which are prime power generating stations and four of which are emergency backup generating stations. The number of diesel generating units at each generating station ranges from three to six generators and the rated output of the units range from 40kW to 2,600kW. The diesel engines across the system range in age from less than one year to 66 years of age and currently range in operating hours from less than 288 hours to over 117,880 hours (as of the end of 2017). The oldest engine in a prime power station is 33 years old.

Table 1 lists, for each engine in this proposal, the number of operating hours left before the engine becomes due for an overhaul and the forecasted time when that overhaul will become due.

Table 1: 2019 Overhaul Forecasts

Engine	Remaining Operating Hours Before Due for Overhaul (as of December 31, 2017)	Forecasted Overdue Due Date
Francois 588	5,388	Q3 2019
Little Bay Islands 2058	10,699	Q4 2019
McCallum 2063	4,387	Q3 2019
Norman Bay 584	3,381	Q3 2018
Charlottetown 2089	5,405	Q4 2019
Nain 2085	12,226	Q3 2019
Nain 576	4,379	Q2 2019
Black Tickle 579	4,540	Q3 2019
Nain 591	4,539	Q4 2018/Q1 2019
Makkovik 3033	9,500	Q4 2019

3.2 Operating Experience

An isolated diesel generation plant operates continuously because it provides the primary source of electricity to communities isolated from the Province's electrical grid. A given diesel generation unit is not in service continually since the number of units in service varies based on customer demand. Emergency backup diesel generation plants operate only in emergency situations, which are rare but critical. In automated plants the engine mix is automatically controlled by a control system to maximize fuel efficiency, while in a manual plant this is controlled by the operator.

In all plants, the operator has the flexibility to shut down the engines for planned maintenance provided there is another engine available to supply the load for that time. As a result, planned outages to engines can occur without customer outages.

Table 2 provides details concerning the overhaul work completed during the previous five years and the work planned for the current year.

Table 2: Overhauls Completed in Last Five Years

Year	Unit
2018	
	Paradise River 324
	Paradise River 585
	Postville 2084
	Hopedale 2054
	Hopedale 590
	Charlottetown 2087
	Norman Bay 583
	St. Anthony 521 (Alternator O/H only)
	St. Anthony 522 (Alternator O/H only)
	Little Bay Islands 586
	Ramea 2047
	McCallum 589
2017	
	Grey River 2067
	Hopedale 2053
	Rigolet 2081
	St. Brendan’s 2056
	St. Lewis 2080
	Ramea 2077
	Port Hope Simpson 2073
	Rigolet 2065
	Black Tickle 582
	Rigolet 2051
	St. Anthony 523 (Alternator O/H only)
	St. Anthony 525 (Alternator O/H only)
2016	
	Makkovik 2059
	Little Bay Islands 2058
	Mary’s Harbour 2037
	Mary’s Harbour 2083
	Mary’s Harbour 2090 (Mobile Unit) (Alternator O/H ONLY)
	Nain 2085
	Postville 577
	Postville 573
	Rigolet 2051

	St. Brendan's 578
	St. Lewis 2039
	Francois 587
	Ramea 2045
	Cartwright 2052
	Charlottetown 2088 (Mobile Unit)
	Norman Bay 581
2015	
	Cartwright Unit 2086
	Gray River Unit 2062
	Hopedale Unit 2074
	Makkovik Unit 2059
	Makkovik Unit 3033
	Port Hope Simpson Unit 2042
	St. Brendan's 2055
	William's Harbour 2057
2014	
	Charlottetown 2087
	Francois 570
	L'Anse-au-Loup 2041
	McCallum 2064
	Paradise Unit 324
	Port Hope Simpson 2043
	Port Hope Simpson 2073
	Postville Unit 2084
	Postville 573
	William's Harbour Unit 580

3.2.1 Reliability Performance

A consequence of not completing this project is an increase in the frequency and duration of customer outages as a result of increases in diesel unit failures.

Outage Statistics

Loss of Supply is defined by the Canadian Electricity Association (CEA) as:

> *Customer interruptions due to problems in the bulk electricity supply system such as under frequency load shedding, transmission system transients, or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle.*

For this analysis, the definition is applied to the loss of diesel generation.

Hydro tracks all distribution system outages using industry standard indexes, SAIDI and SAIFI which are explained as follows:

- ***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.
- ***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.

Table 3 lists the SAIDI loss of supply outage statistics for the prime power diesel generating stations for the previous five years. Table 4 lists the SAIFI loss of supply outage statistics for the same diesel generating stations for the previous five years.

Table 3: 2013 to 2017 Outage Statistics (SAIDI Loss of Supply)

System	SAIDI (Loss of Supply)				
	2013	**2014**	**2015**	**2016**	**2017**
Central					
Francois	0.00	0.08	0.08	0.35	0.00
Grey River	0.17	0.08	0.00	0.08	5.20
Little Bay Islands	0.25	0.25	0.58	0.25	0.33
McCallum	0.00	0.00	0.00	0.00	2.83
Ramea	0.12	0.08	0.03	0.21	0.50
St. Brendan's	6.04	0.37	0.37	0.30	0.08
Northern					
Charlottetown	0.846	1.367	0.870	1.02	0.00
L'Anse au Loup	2.033	3.567	7.240	0.93	0.23
Mary's Harbour	2.517	1.767	1.360	5.60	0.42
Norman Bay	0.167	0.167	0.070	0.00	0.00
Port Hope Simpson	0.450	4.367	1.630	3.93	0.00
St. Lewis	0.167	0.283	0.320	0.00	0.18
Labrador					
Black Tickle	1.50	0.667	4.130	7.62	2.33
Cartwright	0.499	0.583	0.960	21.37	1.00
Hopedale	9.309	10.383	7.270	5.13	0.78
Makkovik	4.027	1.883	1.620	2.78	0.35
Nain	1.334	10367	1.350	5.77	0.17
Paradise River	0.583	0.667	0.500	1.83	0.00
Postville	4.748	2.250	0.330	0.20	0.17
Rigolet	2.738	0.100	0.283	26.580	9.71

Table 4: 2013 to 2017 Outage Statistics (SAIFI Loss of Supply)

System	SAIFI (Loss of Supply)				
	2013	**2014**	**2015**	**2016**	**2107**
Central					
Francois	0.0	1.0	1.0	5.0	0.00
Grey River	2.0	1.0	0.0	1.0	3.00
Little Bay Islands	2.0	2.0	3.0	2.0	2.00
McCallum	0.0	0.0	0.0	0.0	1.00
Ramea	1.6	1.0	0.6	1.5	3.00
St. Brendan's	8.0	3.0	2.7	2.0	1.00

System	SAIFI (Loss of Supply)				
	2013	**2014**	**2015**	**2016**	**2107**
Northern					
Charlottetown	1.1	6.0	9.0	5.9	0.00
L'Anse au Loup	2.0	5.0	7.0	4.0	1.00
Mary's Harbour	0.8	4.0	2.8	14.0	2.00
Norman Bay	2.0	1.0	1.0	0.0	0.00
Port Hope Simpson	3.0	5.0	3.0	3.0	0.00
St. Lewis	1.0	2.0	4.0	0.0	2.00
Labrador					
Black Tickle	9.0	3.0	7.0	2.0	5.01
Cartwright	3.0	5.0	4.0	5.0	4.00
Hopedale	10.0	18.0	14.0	7.0	1.99
Makkovik	12.0	4.0	3.0	9.0	2.00
Nain	4.0	3.0	3.0	3.0	0.99
Paradise River	5.0	10.0	1.0	3.0	0.00
Postville	10.0	9.0	2.0	2.0	1.00
Rigolet	2.0	2.0	8.0	6.0	10.00

3.2.2 Safety Performance

This is a reliability-based project. If this project is not executed, there is a higher risk of diesel engine failure and diesel engine failure can result in extended customer outages, which would negatively impact reliability and public safety. In addition, diesel engines can fail catastrophically creating possible hazards for the employees in the vicinity. The risk of this occurring increases if overhauls are not completed.

3.2.3 Environmental Performance

This project is being justified from a reliability perspective, but if overhauls are not completed failures could result in oil and glycol being released into the environment.

3.2.4 Industry Experience

Manufacturers of diesel engines will provide recommended overhaul intervals, which typically are in the 15,000 hour range. Hydro adopted this philosophy for many years, but completed a comprehensive review of its maintenance practices in 2003 and extended the overhaul period to 20,000 hours.

3.2.5 Vendor Recommendations

The diesel engine manufacturers generally recommend an overhaul interval of 15,000 hours but as a result of a review of maintenance practices and failure history it was decided to extend Hydro's overhauls to 20,000 hours.

3.2.6 Maintenance or Support Arrangements

Generally, a routine annual inspection is performed by internal resources. The annual inspection checks the fuel, coolant, exhaust systems, and engine structure. Problems identified during the inspection are also typically corrected during the inspection. If an engine fails prematurely, the manufacturer is typically consulted to help with a failure analysis.

To help manage the service of the parts for diesel engines, blanket orders are created with the engine original equipment manufacturers (OEMs) or their authorized distributor. Compared to purchase orders, blanket orders allow for quicker procurement of diesel engine parts by virtue of the fact that approval is given up front and therefore isn't required for each of the multiple parts orders that are placed. Such arrangements are necessary to ensure lead times on parts are acceptable and Hydro does not have to incur the cost of stocking diesel parts in inventory.

3.2.7 Maintenance History

The five-year maintenance cost history for the prime power diesel engines is shown in Table 5.

Table 5: Five-Year Maintenance Cost History ($000)

Year	Preventative Maintenance	Corrective Maintenance	Total Maintenance
2017	103.3	494.7	**598.0**
2016	105.3	827.0	**932.3**
2015	141.6	690.1	**837.7**
2014	85.1	805.2	**890.3**
2013	49.8	458.6	**508.5**

3.2.8 Historical Information

Table 6 provides the five year historical diesel engine overhaul costs.

Table 6: Overhaul Diesel Engines Historical Cost

Year	2014	2015	2016	2017	2018B
Per Engine Average (Actual)	$96,845	$149,875	$128,502	$130,991	$219,415
Number of Engines	10	8	16	12	13
Total	**$968,450**	**$1,199,000**	**$2,506,035**	**$1,571,900**	**$2,852,400**

3.2.9 Anticipated Useful Life

The actual life of a diesel engine depends primarily on the operating hours of the unit and overhauls are scheduled for every 20,000 operating hours to ensure continued reliability.

3.3 Development of Alternatives

One alternative that was considered for this overhaul project was to overhaul the engines at the manufacturer-recommended interval, which is typically 15,000 operating hours. A review completed in 2003 recommended changing the interval to 20,000 operating hours to improve the balance between least-cost and reliability and Hydro adopted this recommendation.

3.4 Evaluation of Alternatives

The recommended alternative was analyzed as part of the review completed by Hydro in 2003. The review considered Hydro's experience, other utility experience, other utility practice, and manufacturer recommendations. The recommendation on diesel engine overhauls made as part of this review states that *"parts being removed from the units have sustained very little wear and the overhaul can very easily be extended to 20,000 hours."*

3.5 Economic Analysis

Economic analysis shows that the selected alternative of completing overhauls at an interval of 20,000 operating hours reduces lifetime overhaul costs by one-third compared to the 15,000 operating hour interval alternative. This is a result of the selected alternative having one-third less overhauls, six overhauls verses four overhauls over the life of the engine, without increasing the cost of an overhaul or increasing the running maintenance on the units.

4 Conclusion

This project is necessary in order to provide least cost, reliable electrical service to the customers served by diesel generation. Overhauling diesel engines is a necessity in operating this type of equipment.

4.1 Project Estimate

The estimate for this project is shown in Table 7.

Table 7: Project Estimate ($000s)

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

4.2 Project Schedule

The anticipated project schedule is provided in Table 8.

Table 8: Project Schedule

Activity		Start Date	End Date
Planning	Schedule annual overhauls	Feb 2019	Sep 2019
Procurement	Purchase overhaul components	Mar 2019	Oct 2019
Installation	Complete overhaul	Apr 2019	Nov 2019
Commissioning	Testing after overhaul	Apr 2019	Nov 2019
Closeout	Release for service and Asset Assignment	Dec 2019	Dec 2019

Appendix A

Diesel Engine Overhaul Five Year Plan

Table A1: Diesel Engine Overhaul Five Year Plan

Planned Year	Unit
2019	
	Black Tickle 579
	Nain 2085
	Nain 576
	Charlottetown 2089
	Norman Bay 584
	Francois 588
	Little Bay Islands 2058
	McCallum 2063
	Nain 591
	Makkovik 3033
2020	
	Cartwright 2036
	Charlottetown 2092
	L'anse au Loup 2012
	Mary's Harbour 2093
	Port Hope Simpson 2073
2021	
	Francois 587
	Grey River 2062
	Grey River 2067
	McCallum 2064
	Black Tickle 582
	Cartwright 2045
	Cartwright 2086
	Nain 574
	Rigolet 2081
	Mary's Harbour 2090
	Port Hope Simpson 2042
	St. Lewis 2080
2022	
	Ramea 2077
	Hopedale 2074
	Hopedale 590
	Makkovik 2029
	Makkovik 2059

	Nain 2085
	Nain 591
	Paradise River 324
	Postville 2084
	Postville 2096
	Charlottetown 2087
	Norman Bay 581
	Port Hope Simpson 2043
2023	
	Little Bay Islands 586
	Ramea 2047
	Cartwright 2052
	Charlottetown 2034
	Mary’s Harbour 2083

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador ANDRE C. MARSHALL SIGNATURE July 19, '18 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Wood Pole Line Management Program 2019

July 2018

newfoundland labrador hydro
a nalcor energy company

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 Hydro personnel and for the general public could also result from issues with weakened structure integrity.

The project is estimated to cost approximately $2,467,000 with a planned completed in 2019.

[1] Reliability centered maintenance (RCM) is a corporate-level maintenance strategy that is implemented to optimize the maintenance program of a company or facility.

Table of Contents

Summary i
1 Introduction 1
2 Project Description 3
3 Justification 4
3.1 Existing System 5
3.2 Operating Experience 5
3.2.1 Historical Expenditures 5
3.2.2 Historical Replacement Information... 6
3.2.3 Anticipated Useful Life 7
3.2.4 Review of 2017 WPLM Program 7
3.2.5 Update of 2018 WPLM Program 9
3.3 Development of Alternatives 10
4 Conclusion 10
4.1 Project Estimate 10
4.2 Project Schedule 11

Appendices

Appendix A WPLM Inspection Schedule 2018-2023 (with Average Age of Transmission Lines and Estimates Pole Rejection Rates)

1 Introduction

Hydro maintains approximately 2,500 km of wood pole transmission lines operating at voltages of 69, 138, and 230 kV. These lines consist of approximately 26,000 poles of varying ages, with the maximum age being 53 years. As of 2018, approximately 95% of the transmission pole assets are more than 20 years old and about 55% of these poles are at least 40 years old.

As wood poles age, their preservative retention levels decrease and the poles become increasingly subjected to deterioration by different agents, including fungi and insects. Wood poles must be regularly inspected and treated in-situ[2] to proactively identify and assess any deterioration. 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 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.

[2] Latin meaning "in place".

Figure 1: WPLM Inspection Techniques, Clockwise from Bottom Left: 1) Typical Field Data Collector; 2) Cavity Measuring; 3) Climbing Inspection; 4) Destructive Testing at MUN

Figure 2: Sample Wood Pole Inspection Results

Hydro first initiated the Wood Pole Line Management (WPLM) program as a pilot study in 2003. It was determined that the program should continue as a long-term asset management and life extension program. The program was presented to the Board of Commissioners of Public Utilities (the Board) in October 2004 as part of Hydro's 2005 Capital Budget Application and was entitled *"Replace Wood Poles – Transmission".* The proposal was supported in the application by Hydro's internal report titled *"Wood Pole Line Management Using RCM Principles"* by Asim Haldar, PhD, P. Eng.

The Board found that:

> *This approach (by Hydro) 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.*

The Board approved the project submitted in the 2005 Capital Budget in Order No. P.U. 53(2004). 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. Hydro has reviewed the program and has included an update in Appendix C of the *"2019-2023 Capital Plan"* (Volume 1)

2 Project Description

The WPLM program is a condition-based program that uses the basic principles and strategies of reliability centered maintenance. Under the program, line inspection data is analyzed each year and appropriate recommendations are made for necessary refurbishment or replacement of deteriorated line components (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 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, then 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.

The WPLM program is based on a ten 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 to be completed by 2023. In the absence of this long term data, an analysis of recent ice storms, such as in March 2008 and March 2010, can provide an indication of how the transmission lines are performing. On March 18-19, 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 which were not structurally sound had already been replaced during the first WPLM inspection cycle between 2003 and 2007. This was again supported 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 request to pursue the continued proactive condition-based management program.

3 Justification

The WPLM program detects deteriorated poles and other line components early to avoid safety hazards and to identify poles that are at early stages of decay to ensure that corrective measures can be taken to extend the average life of these poles. This is a least cost strategy in the long term through the deferring of rebuilding lines and avoiding forced outages.

3.1 Existing System

As stated previously, Hydro maintains approximately 2,500 km of wood pole transmission lines operating at voltages of 69, 138 and 230 kV. These lines consist of approximately 26,000 transmission size poles of varying ages.

3.2 Operating Experience

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.

3.2.1 Historical Expenditures

The five-year historical cost information for the WPLM program as well as the budget for 2018 is provided in Table 1. No units or cost per unit is available since the work is not defined into individual units, such as a 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 cross arm or an insulator replacement). The same is true for a breakdown by individual transmission line, where the cost will be affected by the configuration and voltage of the line, its age and geographical location.

Table 1: Historical Wood Pole Line Management Program Expenditures ($000s)

Year	Budget	Actuals
2018B	3,532.9	-
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
2013	2,466.7	2,380.1

3.2.2 Historical Replacement Information

Table 2 provides the annual 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	Poles	Cross Arms	Knee Bracing	Cross Bracing	Comments
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
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	**1,243**	**420**	**457**	**446**	

Year	Poles	Cross Arms	Knee Bracing	Cross Bracing	Comments
1999-2003	357	135	62	150	5 years before WPLM
2004-2017	917	317	431	372	14 years since WPLM

3.2.3 Anticipated Useful Life

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 ten years or more.

Extension of the life of the transmission line is evidenced when considering Hydro's current system. 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 53 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, refer to Appendix C of the *"2019-2023 Capital Plan"* (Volume 1).

3.2.4 Review of 2017 WPLM Program

The first objective of the 2017 program was to inspect, test and treat 2,363 poles and associated line components.

Table 3 summarizes the inspection accomplishments for 2017. In the spring of 2017, planned inspections on TL 219 were deferred to 2018 to inspect and treat TL 203 in 2017.

Table 3: 2017 Inspections Completed

Regions	Line Name	Year In Service	Voltage Level	Planned Number of Poles to Inspect	Actual Number of Poles Inspected	Percent Complete
Eastern	TL 203	1965	230 kV	0	431	-
	TL 212	1966	138 kV	59	69	117%
	TL 219	1990	138 kV	350	0	0%
Central	TL 220	1970	69 kV	111	109	98%
	TL 251	1981	69 kV	291	178	61%
	TL 252	1981	69 kV	200	199	99%
Western	TL 250	1987	138 kV	356	368	103%
Northern	TL 241	1983	138 kV	240	240	100%
	TL 227	1970	69 kV	195	195	100%
	TL 261	1996	69 kV	261	259	99%
Labrador	TL 240	1976	138 kV	300	294	98%
Totals				**2,363**	**2,342**	**99%**

Another objective of the 2017 program was the refurbishment of defective components identified in inspections. A summary of the work completed in 2017 is given in Table 4.

Table 4: Summary of 2017 Refurbishment

Component	**Region**					**Total**
	Eastern	**Central**	**Western**	**Northern**	**Labrador**	
Poles	20	9	1	1	1	**32**
Cross arms	15	11	0	0	6	**32**
Cross bracing	5	71	0	0	0	**76**
Knee bracing	20	16	0	0	0	**36**
Foundations	0	0	1	3	0	**4**
Miscellaneous (Insulators, hardware, etc.)	30	15	7	0	0	**52**

The total expenditure of $3.2 million was approximately $831,000 or 34.5% over the budget estimate of $2.4 million. This can be partially attributed to an unforeseen quantity of refurbishment work required on L1301 (TL 240) and TL 232. Critically damaged cross arms and a critical pole were identified during helicopter patrols on L1301, and these items were refurbished when the line was de-energized in November 2017. On TL 232, an unforeseen number of critically deteriorated cross braces were identified and replaced. Prior to the 2016 inspection program, it was estimated that three poles would require replacement on TL 232 in 2017. However, upon completion of the 2016 inspections, it was determined that seven poles and seventy-one sets of cross bracing required replacement. The cost of this refurbishment work was approximately $650,000

3.2.5 Update of 2018 WPLM Program

The proposed inspection and treatment work for 2018 is summarized in Table 5. This work will be executed between mid-April and October 2018.

Table 5: 2018 Inspection Plan

Region	Line No.	Year Built	Age of Line	Target Number of Poles to Inspect
Eastern	TL 219	1990	28	598
Central	TL 220	1970	48	235
	TL 223	1966	52	175
	TL 252	1981	37	202
	TL 253	1982	36	192
Western	TL 225	1970	48	46
Northern	TL 239	1982	36	352
	TL 241	1983	35	198
	TL 256	1995	23	249
Labrador	TL 240	1976	42	500
Totals				**2,747**

As a result of the 2017 inspection program, a refurbishment program will occur in the spring and summer months of 2018 and continue into the fall. This will include the replacement of approximately 59 poles, 22 cross arms, 11 sets of cross bracing, 6 sets of knee bracing, and other components.

A list of the refurbishment work to be completed in 2018 is provided in Table 6.

Table 6: 2018 Refurbishment Plan

Component	Region				Total
	Eastern	Central	Western	Northern	
Poles	17	31	8	3	**59**
Cross arms	16	5	1	0	**22**
Cross bracing	10	0	0	1	**11**
Knee bracing	6	0	0	0	**6**
Foundations	8	0	2	2	**12**
Miscellaneous (Insulators, hardware, etc.)	47	4	47	25	**123**

3.3 Development 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 expenditures as submitted in the 2005 Capital Budget in Board Order No. P.U. 53(2004).

This current submission to the Board provides an update of the program work, which includes both a progress report of the work completed as well as a forecast of the future program objectives.

4 Conclusion

In conclusion, the major objectives for the 2017 program were achieved.

4.1 Project Estimate

The WPLM project estimate shown in Table 7 includes the complete inspection of the stated lines, including the visual inspection supported by inspecting each pole using non-destructive evaluation tools and full treatment of the pole as required. The project estimate for 2020 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 curves (Appendix A) depending on their age and group.[3] 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 2012 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 2018 to 2023 is provided in Appendix A of this proposal. The table also provides the average age and anticipated pole rejection rate for each year.

Table 7: Project Estimate ($000)

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

4.2 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.

[3] 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.

Appendix A

WPLM Inspection Schedule 2018-2023
(with Average Age of Transmission Lines and Estimates Pole Rejection Rates)

Table A1: WPLM Inspection Schedule and Expected Pole Rejection Rates (Summary)

Year	Age of Lines	No. of Poles Inspected	Estimated Approximate Pole Rejection Rate	No. of Poles Rejected
2018	34.0	2,747	0.8%	23
2019	36.6	2,655	2.17%	58
2020	41.6	2,641	1.9%	49
2021	38.1	2,659	3.4%	92
2022	42.6	2,701	7.2%	194
2023	47.3	2,406	3.6%	87

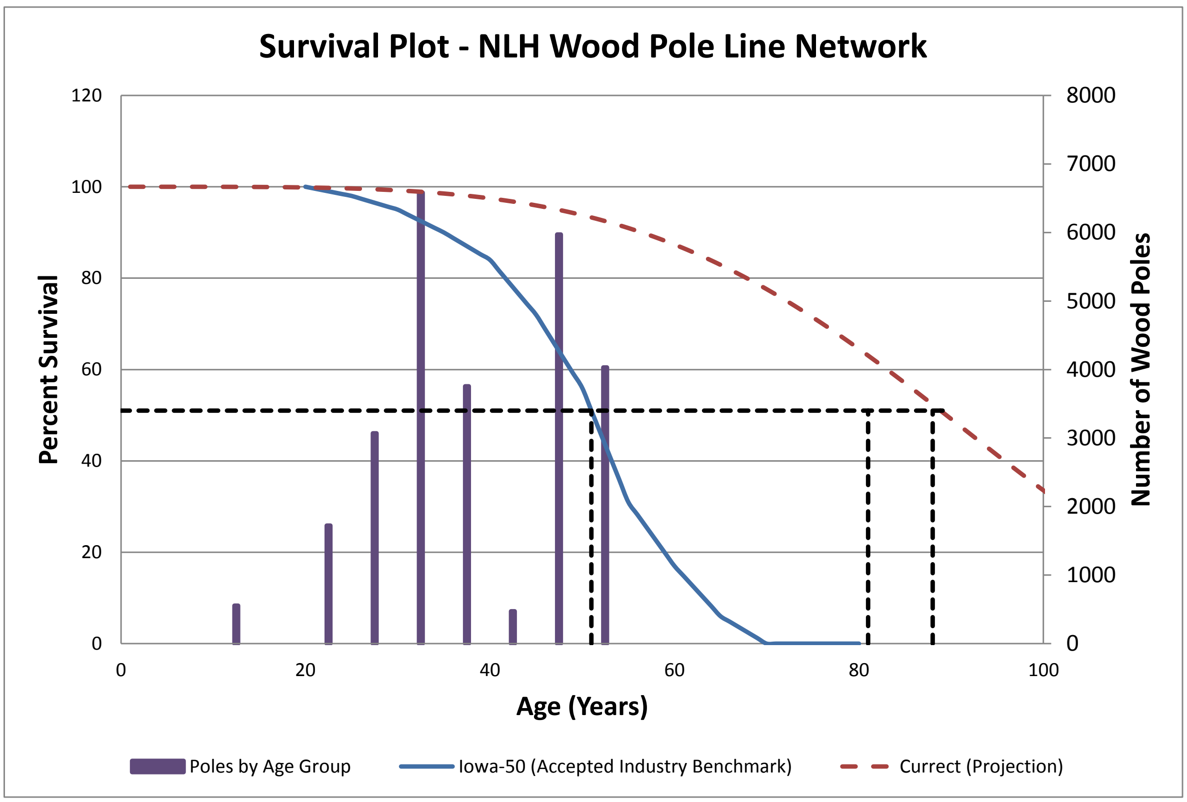


Figure A1: IOWA Curve

1 For detailed IOWA curves refer to Appendix C of the *"2019-2023 Capital Plan"* (Volume 1).

11. Additions for Load - Isolated Generation Systems

LICENSED PROFESSIONAL ENGINEER 09214 Scott L. Henderson [signature] SIGNATURE July 23/18 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Additions for Load Growth – Isolated Systems

Makkovik

July 2018

newfoundland labrador hydro

a nalcor energy company

Summary

The peak demand and energy use in the isolated community of Makkovik is growing and the most recent forecast has indicated that the winter fuel requirements in Makkovik will exceed the available fuel storage in 2020. To ensure that there is enough fuel storage to contain the required amount of fuel for the winter of 2020, Hydro is proposing a two-year project to replace two existing 68,000 L horizontal fuel tanks that are approaching the end of their useful life with one 400,000 L vertical tank. This alternative is the least cost of two alternatives considered in a cumulative present worth analysis.

The project is estimated to cost approximately $2,182,500 with a planned completion in 2020.

Table of Contents

Summary i
1 Introduction 1
2 Project Description 1
3 Justification 1
3.1 Existing System 2
3.2 Operating Experience 2
3.3 Historic Load Information 2
3.4 Forecast Customer Growth 3
3.5 Analysis 4
3.6 Development of Alternatives 5
3.6.1 Alternative 1 5
3.6.2 Alternative 2 5
3.6.3 Conservation and Demand Management (CDM) 6
3.7 Economic Evaluation of Alternatives 6
4 Conclusion 6
4.1 Project Estimate 7
4.2 Project Schedule 7

1 Introduction

As new customers are added to distribution systems and as 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 continued reliable power.

In isolated communities, the electrical power is provided through the combustion of diesel fuel. As the energy usage of the community increases so will the amount of fuel consumed by the diesel plant.

Due to the freeze-up of the ocean in winter, Makkovik is not able to be resupplied with fuel for part of the year. In Makkovik, energy usage is growing and the winter fuel requirement forecast has indicated that the available bulk fuel storage is not adequate to supply the required nine-month winter fuel storage beyond 2020. This poses a risk to the ability to supply the community load for the full winter period. If the fuel supply on hand was to be depleted over the winter before tanker delivery became available, the plant would require expensive emergency fuel delivery to prevent running out of fuel.

2 Project Description

To increase the amount of bulk fuel storage in Makkovik, Hydro is proposing to replace two existing 68,190 L horizontal fuel tanks that are approaching the end of their useful life with one 400,000 L vertical tank.

3 Justification

This project is justified on the requirement to meet the growing electricity needs of Hydro's customers in Makkovik.

3.1 Existing System

The Makkovik Diesel Generating Station consists of three diesel generating units with a combined capacity of 1,650 kW[1] and a firm capacity of 1,015 kW. The facility is the sole source of electrical power for the community of Makkovik and supplies electrical energy to approximately 234 customers on a continual basis[2].

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

The two horizontal tanks are approaching the end of their useful life

3.2 Operating Experience

An internal tank inspection of all fuel tanks in Makkovik was completed in October 2017. The inspection results indicated that the horizontal fuel tanks have weld corrosion on the interior of the tank and the inspector recommended repairing the welds before returning the tanks to service. Internal expertise along with third-party consultation determined that there was a low risk of a tank failure within the next two years and that the risk did not warrant a supplemental Capital Budget Application. Instead, it was decided to continue using these tanks and, given the additional issue regarding installed fuel capacity, propose to replace them in 2019-2020 as part of the 2019 Capital Budget Application. It should be noted that these fuel tanks cannot be field repaired because they would lose the ULC certification according to GAP regulations.

3.3 Historic Load Information

Makkovik is a winter peaking system that has historically experienced steady growth in peak load and electricity sales.

---

[1] By the end of 2018 the firm capacity for Makkovik will be 1,130 kW. Please refer to Hydro's 2018 Capital Budget Application (Revision 3), Volume 2, Tab 15, for more information.

[2] Customer count is based on 2017 Rural Sales Ledger.

Since 2012, there have been Conservation and Demand Management (CDM) programs in Makkovik every second year. It is estimated that these programs saved a total of 162 MWh or 46,400 L of fuel annually, resulting in a decrease in required winter fuel storage of 34,800 L.

Figure 1 shows the historical load and gross energy use in Makkovik.

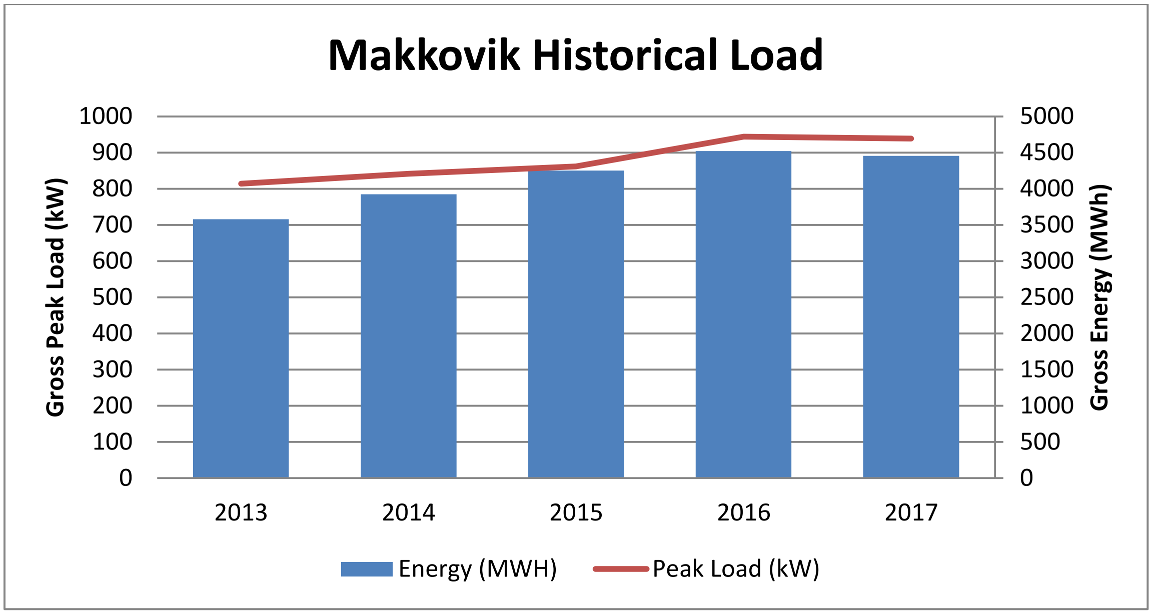


Figure 1: Makkovik Historical Load

3.4 Forecast Customer Growth

Hydro annually projects the peak winter fuel requirements for each isolated system. The Winter Fuel Requirement Forecast for Makkovik is presented in Table 1.

Table 1: Makkovik Winter Fuel Requirements

Year	Fuel Forecast (9 Months)(L)	Deficit (L)
2017	1,048,200	
2018	1,060,600	
2019	1,075,400	
2020	1,086,500	8,120
2021	1,094,100	15,720
2022	1,105,700	27,320
2023	1,119,000	40,620
2024	1,132,400	54,020
2025	1,146,000	67,620
2026	1,159,800	81,420
2027	1,169,700	91,320
2028	1,178,500	100,120
2029	1,187,300	108,920
2030	1,196,200	117,820
2031	1,205,200	126,820
2032	1,214,200	135,820
2033	1,223,300	144,920
2034	1,232,500	154,120
2035	1,241,800	163,420
2036	1,251,100	172,720

The Winter Fuel Requirement Forecast is used to determine the required amount of fuel storage that must be available at a diesel plant to ensure there will be enough capacity available to store the fuel required for the winter season.

3.5 Analysis

Hydro maintains long-term bulk fuel storage at its remote diesel plants in Labrador and has established a criterion that sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for nine consecutive months.[3] This criterion ensures the plant will continue to support the load during the winter months when fuel delivery is not possible or impractical.

As can be seen in the forecast in Table 1, the present bulk fuel storage in Makkovik is not adequate to supply the required nine month winter fuel storage beyond 2020.

3.6 Development of Alternatives

To increase the amount of fuel storage available at the diesel plant in Makkovik, two alternatives were considered. Hydro also investigated delaying the need for additional fuel storage through additional conservation and demand management programs.

3.6.1 Alternative 1

The first alternative involves replacing the two existing 68,190 L horizontal tanks that are approaching the end of their useful life with one new 400,000 L vertical tank in 2020, including modifications to the dyke and fuel piping systems. This alternative will provide total fuel storage of over 1,300,000 L and will meet the forecasted needs of Makkovik beyond the 20-year forecast.

3.6.2 Alternative 2

The second alternative involves installing one new 45,000 L tank in 2020, replacing the two existing 68,190 L tanks with four 45,000 L tanks in 2024, and adding two more 45,000 L tanks in both 2027 and in 2032. This alternative includes a yard extension to fit the additional tanks.

[3] This 9 month criterion is considered conservative for some diesel plants, which allows for some flexibility. Typically, from last fill up in early November to ice breaking up in mid-June, the 7-7.5 months winter season causes Makkovik to be inaccessible by ocean. However, occasionally the ice breaking up can be up to a month later. As well, the fuel required can vary due to changing engine efficiencies that could result from the most efficient diesel unit breaking down, an extra cold winter, or an unexpected load increase. Therefore, the 9 month criterion is used to account for the possibility of these variances.

3.6.3 Conservation and Demand Management (CDM)

Additional CDM may delay the requirement for additional fuel storage in Makkovik by one or two years. However, there is currently a general service customer investigating conversion from oil fired to electric heat, which would further increase the winter fuel storage requirement[4] in Makkovik. Hydro plans to reserve the saving from CDM to offset the energy growth associated with this proposed conversion.

3.7 Economic Evaluation of Alternatives

A cumulative net present value analysis was completed to determine which alternative was the least cost preferred alternative. This analysis included the up front capital, future required capital, and operations and maintenance costs. The results of the analysis are shown in Table 2.

Table 2: Additions for Load Growth (Isolated) – Makkovik Fuel Storage Increase

Alternative Comparison
Cumulative Net Present Value To the Year 2018

Alternatives		Cumulative Net Present Value (CPW)	CPW Difference between Alternative and Least Cost Alternative
1	New Vertical Tank Option	1,455,174	0
2	45,000 L Tanks Option	1,592,692	137,518

Table 2 shows that Alternative 1 has the least cumulative net present value.

4 Conclusion

In Makkovik, the existing amount of fuel storage is not adequate to support the future energy needs of the community. The forecasted winter fuel requirements are expected to exceed the existing amount of storage in 2020. Therefore, to maintain reliable electricity supply, fuel stor-

[4] Hydro estimates that another two years of CDM (including a street light LED replacement project) could allow a potential savings of 119 MWh a year. If the customer in Makkovik proposing to switch from oil heat to electric heat does so, the energy usage in the community would increase by more than the 119 MWh.

age capacity must be increased by 2020. To increase the capacity, Hydro is proposing to replace two 68,190 L fuel tanks that are approaching the end of their useful life with a new 400,000 L vertical fuel tank, which is the alternative with lease cumulative net present value.

4.1 Project Estimate

The estimate for this project is shown in Table 3.

Table 3: Project Estimate ($000)

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

4.2 Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Project Start-Up, Scope Statement, Schedule	Jan 2019	Jan 2019
Design	Engage Consultant	Jan 2019	Feb 2019
	Detailed Engineering Design	Feb 2019	April 2019
Procurement	Procure Plate Steel	Apr 2019	Jun 2019
Construction	Field Fabricate Tank	Jul 2019	Oct 2019
	Apply Exterior Coating System	Jul 2020	Aug 2020
Commissioning	Commission Tank & Return to Service	-	Oct 2019
	Final Inspection and Acceptance of Exterior Coating	-	Aug 2020
Closeout	Certificate of Completion, Interest Cut-Off, PIR	-	Oct 2020

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador FORHAD AHMAD f.ahmad SIGNATURE 19/07/2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Diesel Plant Fire Protection

Black Tickle

July 2018

newfoundland labrador hydro
a nalcor energy company

Summary

Hydro owns and operates 25 diesel powered generation plants. Most are located in remote coastal areas of Newfoundland and Labrador and are not staffed 24 hours per day. There have been six serious fires at several of these plants resulting in the loss of equipment and facilities. Starting in 2014, Hydro has had multi-year program-like projects to install automatic fire protection systems in diesel generating plants. Details were presented most recently in the 2018 Capital Budget Application in Diesel Plant Fire Protection, Volume II, Tab 29. To date installations have been completed in three plants. In 2018, automatic fire protection will be installed in the Postville Diesel Generating Station.

In the 2019, Hydro proposes the continuation of the program in Black Tickle Plant. Engineering will start in 2019 for the 2020 installation of automatic fire suppression in the Black Tickle Generating Station. The estimated cost of this project is $1,917,400.

It is anticipated that Hydro will submit other proposals to the Board in subsequent years to have automatic fire suppression installed under other proposed projects to be completed at remote diesel plants.

Table of Contents

Summary i
1 Introduction 1
2 Project Description 2
3 Justification 3
3.1 Existing System 3
3.2 Operating Experience 3
3.3 Development of Alternatives.. 4
3.4 Operating Experience 4
3.4.1 Maintenance Support Arrangements 4
3.4.2 Maintenance History 4
3.4.3 Anticipated Useful Life 5
3.5 Development of Alternatives.. 5
4 Conclusion.. 5
4.1 Project Estimate... 5
5 Project Schedule 6
6 Future Plans 6

1 Introduction

In 21 communities, Hydro's diesel plants are the only source of electric power as the communities are isolated from the interconnected electrical grid. Out of 21 diesel plants 17 plants do not have fire suppression system. Continuous operation of the generating units, or their availability in the case of standby plants, is critical to each community.

There have been six serious fires at these plants resulting in the loss of equipment and facilities. Starting in 2014, Hydro has had multi-year program-like projects to install automatic fire protection systems in diesel generating plants. Details of the program were presented in the 2014 Capital Budget Application in the Install Fire Protection System proposal (Volume II, Tab 22). To date installations have been completed in three plants. In 2017, automated fire protection was installed in Nain Diesel Generating Station. In 2018, Hydro is installing automated fire protection in the Postville Diesel Generation Plant. In 2019, Hydro proposes the continuation of the program with installation of an automated fire protection system in Black Tickle (Figure 1).

Figure 1: Black Tickle – Diesel Generating Plant

2 Project Description

The project will install a water mist fire protection system at the Black Tickle Generating Station. The system sprays water and nitrogen, which produces a blanket of atomized water particles that absorb heat and smother the fire. This system will be used in the diesel generator main hall area (Figure 2) and other interior spaces requiring fire protection including the transformer room and the lube and coolant storage room.

Figure 2: Black Tickle – Diesel Generators in Powerhouse

The scope of work includes design, procurement, installation, and commissioning of the new equipment. A new storage shelter for nitrogen cylinders, water cylinders and associated equipment will be supplied and installed outside the powerhouse, which includes required foundations, electrical work and ventilation.

The majority of the work, including detailed design, will be completed by the external contractor supplying the systems, with support from Hydro personnel.

3 Justification

This project is justified by the requirement to protect critical assets at the diesel plant in Black Tickle from fire.

3.1 Existing System

The diesel plant at Black Tickle is not staffed 24 hours per day and does not have a fire protection system. The 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 (ECC) 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. If there is a fire, extinguishing the fire is either done by plant personnel or by the local volunteer fire department.

3.2 Operating Experience

Major outages that were the result of fires in diesel plants include:

- Fire in Rencontre East, on September 2, 2002, when the plant was destroyed and resulted in a power outage of 42.5 hours;
- Fire in the Nain diesel plant that occurred on September 7, 2008, resulted in a power outage of 35.5 Hours. In addition, a second major outage occurred at Nain diesel plant on November 19, 2008, due to a fault in the temporary bus work used to interconnect the temporary mobile diesels to the main diesel plant. This outage lasted 29.5 hours for 50% of the customers and 52 hours for the remaining customers; and
- Fire in Black Tickle, on March 14, 2012, when the engine hall was damaged resulting in a power outage of 40 hours.

3.3 Development of Alternatives

There are no viable alternatives to this project. The powerhouse does not have adequate space to install fire walls between the diesel generators.

When the gas turbine operates in generation mode, at least one of the engines has to run continuously for the generator to produce power. However, when the generator runs in synchronous condensing mode only one engine is required to bring the generator up to the proper speed. At that point, the generator can operate without the engine, which is then shut down.

3.4 Operating Experience

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

3.4.1 Maintenance Support Arrangements

Normal routine maintenance work is performed by Hydro. However, gas turbine service companies such as Rolls Wood Group Ltd. and Alba Power Ltd., both located in the United Kingdom, have been contracted in the past to perform visual inspections, on-site specialty maintenance items, and major shop overhauls of gas generator engines.

3.4.2 Maintenance History

Borescope inspections for the gas generator engines were completed every two years until 2014. Considering the age and anticipated increased operation of the engines, annual borescope inspections were completed thereafter.

3.4.3 Anticipated Useful Life

As refurbished rather than new parts are used in this engine overhaul, the anticipated service life before next scheduled overhaul is five years.

3.5 Development of Alternatives

There are no alternatives to this project. Replacement, instead of overhauling the engine, is not possible as there are no new similar engines manufactured.

4 Conclusion

The Black Tickle plant has no automatic fire protection systems to permit early intervention in the event of a fire. As a continuation of Hydro's Fire Protection projects, this project will address the risk of damage resulting from a fire by installing automatic fire protection systems in the Black Tickle diesel generator plant main hall area and other interior spaces requiring fire protection.

4.1 Project Estimate

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

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

5 Project Schedule

The anticipated schedule for this project is provided in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open Project	Jan 2019	Jan 2019
Tendering	Issue and evaluate request for proposal’s (RFP)	Feb 2019	Apr 2019
Design	Site Visit Prepare conceptual designs	May 2019	Jun 2019
	Contract Awards Prepare detailed design and shop drawings	Jun 2019	Jul 2019
Installation	Installation of Storage Facility for Nitrogen Cylinders	Jul 2019	Sep 2019
Procurement	Supply fire protection equipment	Jul 2019	Sep 2019
Installation	Install fire protection equipment	Jul 2020	Aug 2020
Commissioning	Perform testing and commissioning of fire protection systems	Aug 2020	Sep 2020
Closeout	Prepare closeout package	Nov 2020	Nov 2020

6 Future Plans

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

13. Replace Vehicles and Aerial Devices - Hydro System (2019-2020) – Various

Replace Vehicles and Aerial Devices

Various Sites (2019-2020)

July 2018

Summary

This project provides for the replacement of light-duty and heavy-duty vehicles that meet the established replacement criteria.

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

The project is estimated to cost approximately $1,843,000 with planned completion in 2020.

Table of Contents

Summary i
1 Introduction 1
2 Project Description 1
3 Justification 2
3.1 Existing System 2
3.1.1 Operating Regime 3
3.1.2 Age of System or Equipment 3
3.1.3 Operating Experience 3
3.1.4 Industry Experience 3
3.1.5 Maintenance History 4
3.1.6 Historical Information 4
4 Conclusion 4
4.1 Project Estimate 4
4.2 Project Schedule 5

Appendices

Appendix A Diesel Engine Overhaul Five Year Plan

1 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[1], material handlers and boom trucks).

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

The Transportation section of Hydro maintains a close liaison with other Canadian Utilities through participation on the Canadian Utility Fleet Council and has established vehicle replacement guidelines, which consider the operating regime for the vehicles, as well as average replacement criteria used by other Canadian utilities.

2 Project Description

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

Table 1: Replacement Criteria - Hydro

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

[1] An aerial device or elevated work platform, also known as a 'cherry picker' or 'bucket truck', is a mechanical device used to provide temporary access for people or equipment to inaccessible areas, usually at height.

Table 2: Replacement Criteria – Other Utilities

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

Occasionally, a unit in one of the diesel plants across Hydro's operating area experiences an issue that necessitate an unplanned overhaul. Where appropriate, Hydro may complete such an overhaul under this project and, if possible, defer one of the units planned for completion.

3 Justification

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

3.1 Existing System

This project proposes the replacement of 27 light-duty vehicles and five heavy-duty vehicles in accordance with the established replacement criteria for vehicle age and kilometers. All vehicles that meet the criteria are being replaced.

3.1.1 Operating Regime

As this project relates to the replacement of vehicles and aerial devices, there is no relevant data related to operating regime. Typically, the units do not move from region to region so that they can provide reliable service in the assigned areas. However, a unit may be relocated to another area if operational commitments demand it.

3.1.2 Age of System or Equipment

This project is being justified from a reliability perspective, but if overhauls are not completed failures could result in oil and glycol being released into the environment.

3.1.3 Operating Experience

Failure to replace units in accordance with the replacement policy will lead to increasing maintenance costs and less reliable vehicles. Hydro employees maintain the electrical system 24 hours a day, 7 days a week and require dependable and safe vehicles for their work. As vehicles age, they experience increasing downtime, which could negatively affect response times for emergency outages or planned maintenance.

3.1.4 Industry Experience

Vehicle replacement criteria across the Canadian Utility Industry vary depending on location, exposure to harsh environmental conditions, and the severity of the service hours for the vehicle. While some variances exist, vehicle replacement criteria in other utilities are generally consistent with the replacement criteria utilized by Hydro (please see Section 2.0).
Hydro's Transportation section maintains a database of the vehicle fleet, which tracks individual unit history including acquisition date, kilometers, and maintenance history. The Fleet Specialist updates this information on an ongoing basis and uses current data to determine annual vehicle replacements.

Prior to the preparation of the capital budget proposal, a review of the latest version of the database is performed to select the units that meet the replacement criteria for age or kilometers, and to verify those that should be included in the capital budget proposal based on their maintenance history or ongoing maintenance issues.

3.1.5 Maintenance History

Please see Appendix A for the life to date maintenance costs for vehicles being replaced under this proposal.

3.1.6 Historical Information

Table 3 provides the five-year purchase history for vehicle and aerial device, as well as the budgets for 2017 and 2018.

Table 3: Vehicle and Aerial Device Purchases

Year	Units Purchased		Budget	Actuals
	Vehicles	Aerial Devices	($000)	($000)
2018-2019B	27	7	2,421	-
2017-2018B	43	3	2,400	-
2016	37	3	1,978	1,977
2015	40	4	2,602	2,602
2014	32	9	2,900	2,815

4 Conclusion

This project provides for the replacement of light-duty and heavy-duty vehicles that are approaching the end of their useful lives and are no longer dependable.

4.1 Project Estimate

The estimate for this project is shown in Table 4.

Table 4: Project Estimate ($000)

Project Cost	2019	2020	Beyond	Total
Material Supply	1,194.5	479.9	0.0	1,674.0
Labour	7.0	0.5	0.0	7.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	1.0	0.0	3.0
Interest and Escalation	44.6	29.3	0.0	73.9
Contingency	0.0	84.2	0.0	84.2
Total	**1,248.1**	**594.9**	**0.0**	**1,843.0**

4.2 Project Schedule

This project is scheduled to be completed by December 31, 2020.

Appendix A

Replace Vehicles and Aerial Devices Hydro System (2019)

Table A1: Diesel Engine Overhaul Five Year Plan

Type	Unit Number	Age at retirement	Projected kms	Age	Kms	Condition	Life to Date Maintenance Cost
Car	V1339	7.9	168976	X	X		$12,100
Car	V1340	7.7	136265	X		Body Condition	$11,428
Car	V1351	7.0	177466	X	X		$12,630
Car	V1355	6.1	168473	X	X		$10,868
Car	V1356	6.1	164543	X	X		$10,440
Car	V1357	6.1	168696	X	X		$9,527
Mini Van	V1358	5.9	179715	X	X		$8,362
Pick Up	V2715	9.0	176992	X	X		$13,451
Pick Up	V2756	7.9	178809	X	X		$9,174
Pick Up	V2775	7.0	170927	X	X		$10,244
Pick Up	V2785	7.0	162422	X	X		$33,889
Pick Up	V2796	6.8	171791	X	X		$18,770
Pick Up	V2800	6.2	188051	X	X		$9,934
Pick Up	V2801	6.2	180188	X	X		$9,361
Pick Up	V2815	5.2	232946	X	X	Hi mileage	$7,350
Pick Up	V2816	5.2	196485	X	X	Hi mileage	$7,193
Pick Up	V2817	5.1	176689	X	X		$7,169
Pick Up	V2818	5.1	173876	X	X		$15,027
Pick Up	V2821	5.0	219377		X	Hi mileage	$1,252
Pick Up	V2823	4.9	288957		X	Hi mileage	$11,614
Pick Up	V2824	4.9	185912		X	Hi mileage	$8,234
Pick Up	V2826	4.9	190727		X	Hi mileage	$3,874
Pick Up	V2834	4.9	207536		X	Hi mileage	$10,693
SUV	V2814	5.2	170700	X	X		$7,559
Van	V2809	5.7	185051	X	X		$6,607
Van	V2838	4.9	228830		X	Hi mileage	$13,383
Van	V2841	4.9	192258		X	Hi mileage	$8,271
Dump Truck	V4485	15.7	140079	X		Rusty	$124,594
Boom Truck	V4521	10.0	92207	X		Hi Engine Hours	$58,795
Material Handler	V4528	8.7	207441	X	X	Hi Engine Hours	$107,532
Material Handler	V4529	8.7	253739	X	X	Hi Engine Hours	$162,036
Aerial Device	V4539	6.3	205546	X	X	Hi Engine Hours	$75,951

14. Upgrade Telecontrol Facilities - Gull Pond Hill and Bay d'Espoir Hill

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador RYAN FURLONG SIGNATURE 19/07/2018 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Upgrade Telecontrol Facilities

Gull Pond Hill and Bay d'Espoir Hill

July 2018

newfoundland labrador
hydro
a nalcor energy company

Summary

The telecontrol facilities at Bay d'Espoir Hill and Gull Pond Hill, located near the Bay d'Espoir Hydroelectric Generation Plant, are essential for effective and continued communications and SCADA control of the Island Interconnected System. Both sites include a microwave shelter that houses the communications equipment and a backup generator and enclosure that provides power to the communications equipment in the event of a power outage on the distribution system.

Both microwave shelters are between 35 and 40 years old and are in a deteriorated condition. To provide continued weather protection to the communications equipment, refurbishments are required to the shell and foundation of each shelter.

This report outlines a proposed project to refurbish the microwave shelters at the Bay d'Espoir Hill and Gull Pond Hill telecommunications sites to ensure continued reliability of communications and SCADA control.

This estimated project cost is approximately $673,900 with planned completion in 2020.

Table of Contents

Summary i

1 Introduction 1

2 Project Description 1

3 Justification 1

3.1 Existing System 2

3.2 Operating Experience 4

3.2.1 Siding, Wall sheathing and Insulation, Roof Ice Guard, and Door 16

3.2.2 Concrete Foundations 16

3.2.3 Porch Structure 16

3.2.4 Ground Rods and Ground Grid 16

3.2.5 Building Metal Floor Frame 17

3.3 Anticipated Useful Life 17

3.4 Alternative Analysis 17

4 Conclusion 17

4.1 Project Estimate 18

4.2 Project Schedule 18

1 Introduction

The Bay d'Espoir Hill (BDH) and Gull Pond Hill (GPH) telecontrol sites are repeater[1] sites and are vital in the provision of secure and reliable telecommunications for the operation of the Island Interconnected System (IIS). Hydro employees identified the condition of the building during regular site visits. These site visits prompted Hydro to make an assessment of the telecontrol facilities.

This report outlines a proposed project to refurbish the existing microwave shelters at the Bay d'Espoir Hill and Gull Pond Hill sites.

2 Project Description

This two year project proposes to refurbish the shelters at Gull Pond Hill and Bay d'Espoir Hill. The scope of the work includes:

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

3 Justification

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

[1] A repeater is an electronic device in a communication channel that increases the power of a signal and retransmits it, allowing it to travel further.

3.1 Existing System

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

The equipment at these sites transmits operational data from the generating sites to the ECC over the microwave system. The ECC uses the microwave system to remotely control that equipment. Examples of microware communication are commands for opening and closing a circuit breaker; providing generation telemetry; and, monitoring generating frequency data to the ECC. The link to the ECC also includes communication traffic such as telephone, email and video conferencing. These shelters protect microwave equipment from water, ice and wind damage. Refer to Figure 1 for the site locations on the SCADA system connection map.

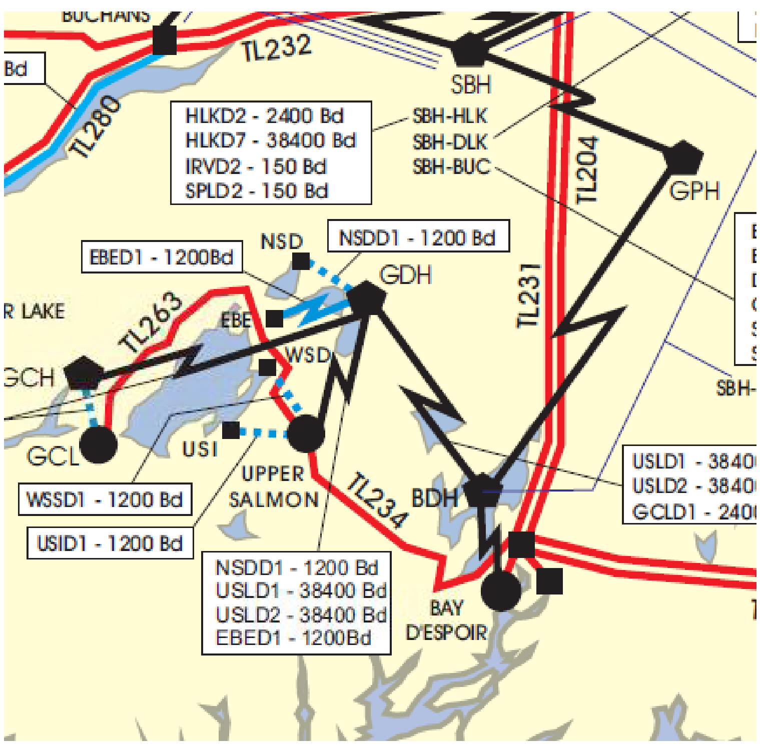


Figure 1: Portion of SCADA System Connection Map

The shelters are metal clad wooden structures anchored to concrete foundations. After the shelters were constructed, small porches were attached to provide storage and protect the main door.

Figure 2 and Figure 3 are images of the site locations.

Figure 2: Gull Pond Hill Telecommunications Site

Figure 3: Bay d'Espoir Hill Telecommunications Site

3.2 Operating Experience

The telecommunications shelters at Bay d'Espoir Hill and Gull Pond Hill were constructed in the late 1970's. The buildings are between 35 and 40 years old and have not had a significant upgrade since they were built. A condition assessment was completed in 2014 and a follow up site visit was completed in May 2018. The following deficiencies were identified:

- Siding and roof protection are beyond its useful life and show signs of dents, damage and water infiltration (see Figures 4, 5, 6, and 7 for Gull Pond Hill and Figures 8A and 8B for Bay d'Espoir Hill).
- Cracks in foundation (see Figures 9A and 9B for Gull Pond Hill and Figures 10A & 10B for Bay d'Espoir Hill).
- Porch separating from building (see Figures 11A and 11B for Gull Pond Hill and Figures 12A and 12B for Bay d'Espoir Hill).
- Ground rods and wire above yard surface (see Figures 13 for Gull Pond Hill and Figures 14A and 14B for Bay d'Espoir Hill).
- Building metal frame shows signs of rust and deterioration (see Figures 15A and 15B for Gull Pond Hill).

Figure 4 to Figure 15 illustrate the deteriorated state of the buildings.

Figure 4: Gull Pond Hill – exterior metal siding – weathered, damaged, and separating from building

Figure 5: Gull Pond Hill – Temporary patching of metal roof to help prevent water entry

Figure 6: Gull Pond Hill – Damaged siding and exposed sheeting

Figure 7: Gull Pond Hill – Exterior Door

Figure 8A and 8B: Bay d'Espoir Hill – Deteriorated siding and rusted metal roof

Figure 9A and 9B: Gull Pond Hill: Cracked and deteriorated building foundations

Figure 10A and 10B: Bay d'Espoir Hill – cracked and deteriorated building foundations

Figure 11A and 11B: Gull Pond Hill – porch separating from main shelter

Figure 12A and 12B: Bay d'Espoir Hill – porch separating from main building

Figure 13: Gull Pond Hill – ground rod and wire above surface

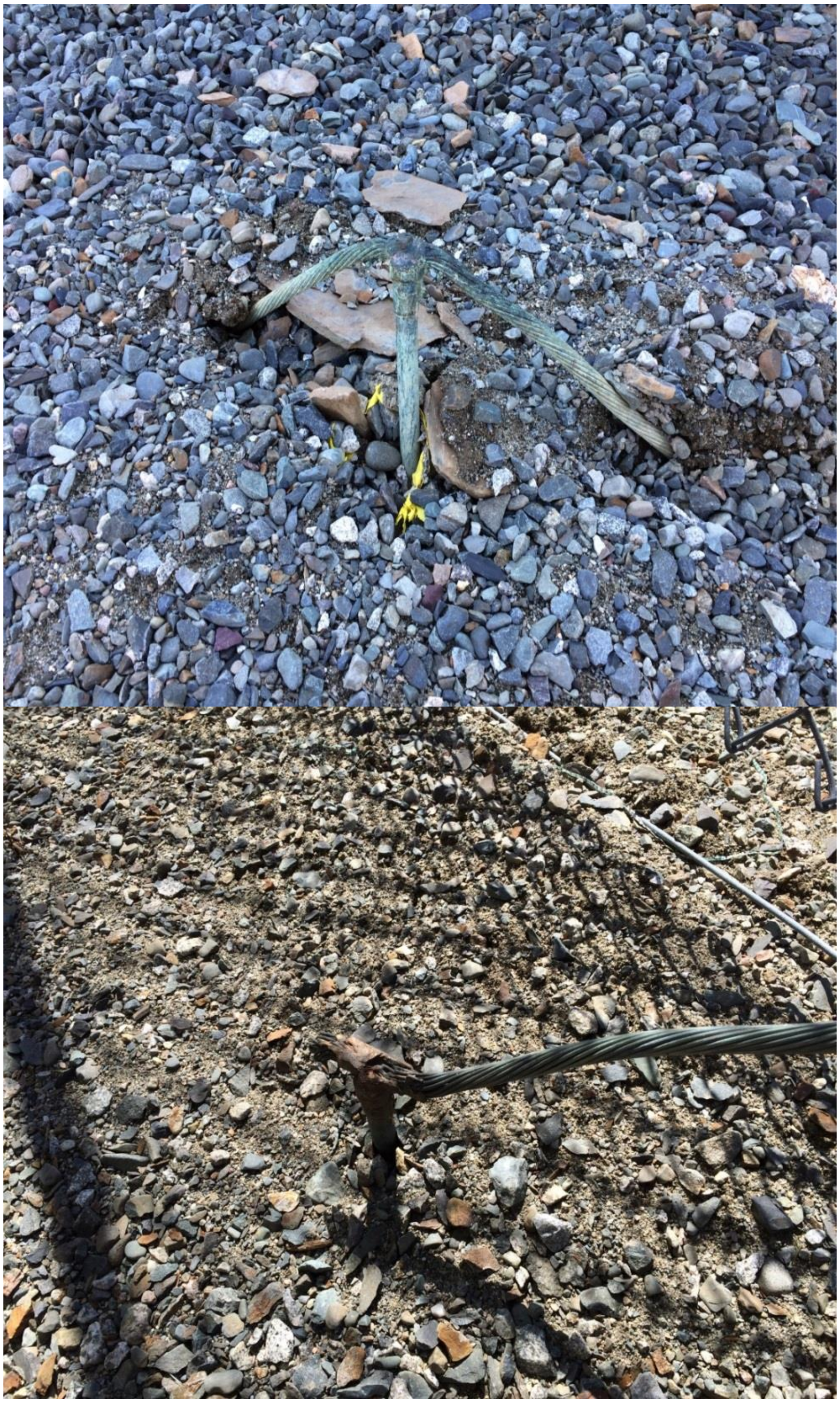


Figure 14A and 14B: Bay d'Espoir Hill – ground rods and wire migrating above the surface

Figure 15A and 15B: Bay d'Espoir Hill – building metal floor frame rusting

3.2.1 Siding, Wall sheathing and Insulation, Roof Ice Guard, and Door

At both sites, the siding and door are original to the buildings and are beyond their useful lives and show signs of deterioration. Based on experience from similar sites, water has filtered through the siding and damaged the wood sheathing and insulation. Water infiltrating into the building structures will continue to deteriorate the buildings. The roof ice guard protects the building's roof from ice falling off the telecommunication tower. The ice collects during the winter months and falls on the building roof during the warm periods. The roof ice guard is to be replaced due to the amount of damage that has occurred throughout the years with this falling ice.

3.2.2 Concrete Foundations

Both buildings concrete foundations have cracks that allow water to penetrate the concrete making them susceptible to freeze/thaw cycles resulting in structural damage to the foundations. Continuing foundation deterioration jeopardizes the function of the internal equipment if the foundation fails.

3.2.3 Porch Structure

The porch foundations are inadequate and the porch structure is settling as a result of an inadequate porch foundation. As shown in the included images, this settlement is causing the metal siding to separate and allow water to penetrate the siding.

3.2.4 Ground Rods and Ground Grid

To ensure the protection of equipment and the safety of personal, especially during lightning conditions, an extensive ground grid was installed at both sites in the late 1990s. Due to the natural settling of the ground and the freeze thaw cycles, this ground grid has started to protruded above the surface of the yard at many locations and presents a safety hazard to personal working at the sites. This project will allow the site yard to be excavated and the grounding and re-installed as per Hydro's specifications.

3.2.5 Building Metal Floor Frame

The telecommunications buildings at both sites are a prefabricated structure mounted on a steel floor frame. This steel frame is integral to the structural integrity of the building. At the Bay d'Espoir Hill site, the frame is showing severe rusting and requires refurbishment before the frame deteriorates to a point of failure. This project will allow for the refurbishment of the steel frame to prolong the life of the existing building. The Gull Pond Hill site does not exhibit the same deterioration as the Bay d'Espoir Hill site, most likely due to the fact that the site is further inland than the Bay d'Espoir Hill site and is not affected by salt contamination.

3.3 Anticipated Useful Life

The anticipated useful lives of the shelter components after refurbishment are:

- Metal siding – 15 to 20 years;
- Concrete foundations – 20 years; and
- Metal roof with ice shield – 15 to 20 years.

3.4 Alternative Analysis

An alternative to refurbishment of the shelters is their replacement. The cost to replace the two shelters is approximately $1.5M compared to refurbishing them at a cost of $673,900. Replacement has been deemed a non-viable alternative.

4 Conclusion

The telecontrol facilities at Bay d'Espoir Hill and Gull Pond Hill are required for communications and SCADA control for the Island Interconnected System.

The shelters at these sites are between 35 and 40 years old and are in a deteriorated condition. To provide continued weather protection to the communications equipment, refurbishments are required to the shell and foundation of each shelter. The estimated project cost to refurbish these sites is approximately $673,900.

4.1 Project Estimate

The estimate for this project is shown in Table 1.

Table 1: Project Estimate ($000)

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

4.2 Project Schedule

The anticipated project schedule is provided in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Planning: Design transmittal, Project schedule, etc.	Jan 2019	Mar 2019
Design	Site visit	Apr 2019	Apr 2019
	Develop design	May 2019	Nov 2019
	Develop tender documents	Nov 2019	Feb 2020
Procurement	Tender/award construction contract	Feb 2020	May 2020
Construction	Construction Bay d'Espoir Hill and Gull Pond Hill	Jun 2020	Sep 2020
Commissioning	Final inspection and acceptance	Sep 2020	Sep 2020
Closeout	Project closeout	Oct 2020	Nov 2020