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April 11, 2018

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

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

Dear Ms. Blundon:

Re: Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - Transmission System and Terminal Station Asset Management Execution Report

Further to the Board's correspondence dated October 13, 2017, attached please find Hydro's annual report on transmission system and terminal station asset management including the status of completion of activities in relation to the 2017 annual plan and information relating to Hydro's 2018 planned activities.

We trust the foregoing is satisfactory. If you have any questions or comments, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoff P. Young
Corporate Secretary and General Counsel
GPY/skc

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

ecc: Denis Fleming- Cox & Palmer
Roberta Frampton Benefiel – Grand Riverkeeper® Labrador
Larry Bartlett – Teck Resources Ltd.

Newfoundland and Labrador Hydro's

Transmission System and Terminal Station Asset Management Execution Report

April 11, 2018

A Report to the Board of Commissioners of Public Utilities

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1.0 Introduction

On October 13, 2016, the Board of Commissioners of Public Utilities (the Board) requested Newfoundland and Labrador Hydro (Hydro) provide an annual report on Hydro's transmission system and terminal station asset management execution, including the status of completion of activities in relation to the annual plan and information relating to the following year's planned activities.

Transmission and terminal station assets provide the means by which generated electricity can be delivered directly to high voltage customers and to the distribution system, which then delivers to the attached customers. Hydro maintains equipment for 3,668 km of transmission lines and 57 terminal stations for the Island Interconnected System. This infrastructure is composed of numerous types and quantities of assets. Through the application of asset management activities during the lifecycle of these assets, Hydro works to provide reliable electricity delivery at the least cost. Within these activities, Hydro:

- installs new assets;
- refurbishes existing infrastructure and equipment to meet expected operating conditions;
- executes maintenance activities to maintain reliable operations; and
- conducts asset assessments to provide appropriately timed refurbishment and replacement activities of infrastructure and equipment.

These activities are conducted within an Asset Management System by Long Term Asset Planning, Short Term Planning and Scheduling, and Operations and Work Execution personnel.

This report provides:

- Hydro's Asset Management Life Cycle Model;

- roles and activities of the Long Term Asset Planning, Short Term Planning and Scheduling, and Work Execution (and Operations) personnel;
- background on Transmission and Terminal Station equipment function and asset management practices;
- background on capital related interactions;
- completion status of 2017 Annual Work Plan Maintenance activities and Capital Transmission and Terminal Station projects; and
- planned 2018 Annual Work Plan Maintenance activities and Capital Transmission and Terminal Station projects.

2.0 Life Cycle of Hydro Asset

At Hydro, new assets are brought into the system through reviews of load growth and new customer requests, configuration changes for improved reliability, and asset refurbishment, or renewal based upon condition and/or reduced reliability. The assets are maintained until condition assessments or asset management practices deem that they are no longer fit for service, or that the assets are no longer of use for Hydro's electrical system. Assets are disposed as per Hydro's established practices.

3.0 Roles of Asset Management Personnel

3.1 Long Term Asset Planning

Long Term Asset Planning (LTAP) personnel focus on an asset over its entire life cycle to achieve reliable, least cost service, and to implement replacement or refurbishment of the asset in a manner which optimizes its service life while avoiding unacceptable failures. To accomplish this objective, LTAP works with Hydro's Engineering Services to establish standards and practices for equipment and infrastructure installations to meet operating conditions and provide reliable service, as well as to review the commissioning results of newly installed equipment. LTAP personnel develop, monitor, and improve maintenance programs and procedures. They implement and monitor condition assessment techniques and incorporate results into asset maintenance regimes or the timing of capital plans for replacement or refurbishment. LTAP personnel also incorporate failure analysis corrective actions into the above activities to improve asset reliability. LTAP is also responsible for establishing and monitoring spare equipment requirements.

To begin an asset's life cycle, LTAP will ensure assets are entered and configured correctly inside of the computerized maintenance management system, ensure the correct Preventive Maintenance cycle is communicated to Short Term Planning and Scheduling (STPS) personnel, and ensure the correct check sheet for the maintenance is used. If required, LTAP personnel will update the maintenance manual to reflect any new maintenance tactics that may be required.

3.2 Short Term Planning and Scheduling

Based upon the maintenance procedures and frequencies determined by LTAP personnel, STPS personnel develop the annual work plan to execute the asset maintenance activities and schedule execution of the planned and required corrective maintenance work. STPS undertake the detailed efforts required to schedule and execute this work by determining the human resources, tools, procedures and equipment that are required and, subsequently, requisition necessary materials, tools and equipment.

3.3 Operations and Work Execution

Operations Management (Operations) reviews corrective maintenance work orders to determine the priority of the work. When approved by Operations, Short Term Planning and Scheduling will plan and schedule the work order, as appropriate.

Work Execution personnel focus on the execution of work orders from STSP weekly scheduling activities. Work Execution assigns human, tool, and equipment resources to have the work completed and is responsible for ensuring the work is completed properly. The work order is updated with information on activities performed and any completed check sheets are attached. This information is incorporated into the Asset Management System and used by LTAP and SPTS to improve maintenance practices and to assess the condition of assets.

4.0 Capital Related Interactions

System Planning identifies new infrastructure required due to load growth, new major customer requests, and electrical system reliability improvements. LTAP personnel identify asset renewal or refurbishment based upon asset condition assessments, asset management practices, and/or reduced reliable operation. Condition assessment is normally determined by a review of completed Preventive Maintenance (PM) and Corrective Maintenance (CM) work orders as well as formal condition assessments, original equipment manufacturer recommendations, and other asset-specific criteria or legislative criteria.[1] Once capital work is identified, it is placed in the long-term plan in the appropriate year for refurbishment or replacement. LTAP monitors the asset condition and adjusts execution timing, as required.

For each annual Capital Budget Application submitted for Board approval, the long-term plan preliminary scope statements, justifications, and estimates prepared have detailed justifications, detailed scopes and estimates developed. Each project is reviewed by various groups within Hydro, including Engineering Services, Asset Owners, LTAP, Regulatory Affairs, and Finance.

Once the Capital Budget is approved, Project Execution teams (as part of Hydro's Engineering Services Group) are assigned to execute the projects. The teams ensure appropriate design standards are followed, all necessary equipment is procured within the right specifications, equipment and infrastructure is properly installed, commissioning and energization plans are

[1] An example would include PCB Management.

developed, spare parts are identified for new assets, as-built drawings are completed, and Operation and Maintenance manuals are made available to LTAP, STPS, and Work Execution.

Once the assets from the project are commissioned and placed into service, the assets are transitioned to regional staff for operation and maintenance.

5.0 Terminal Stations Asset Management

Hydro maintains assets in 57 Terminal Stations as part of the Island Interconnected System, with some having assets dating back to the late 1960's. These stations contain electrical equipment, such as transformers, circuit breakers, instrument transformers, disconnect switches, arresters, and associated protection and control relays and equipment required to protect, control, and operate Hydro's electrical system.

Terminal Stations play a critical role in the transmission and distribution of electricity. Stations act as transition points within the transmission system and interface points with the lower voltage distribution and generation systems.

The following sections provide a summary of the maintenance, refurbishment and replacement criteria Hydro uses for Terminal Station assets. Appendix A, *Terminal Station Asset Management Overview*, which was included in the *Terminal Station Refurbishment and Modernization* project in Hydro's 2018 Capital Budget Application, provides additional terminal station asset management information. Appendix B provides additional information on the maintenance program for various major asset classes for terminal stations.

5.1 Power Transformers and Oil Filled Shunt Reactors

Power transformers are critical components of the power system. Transformers allow the cost-effective production, transmission, and distribution of electricity by converting the electricity to an appropriate voltage for each segment of the electrical system to allow economic construction and operation. On the Island Interconnected System, Hydro has 111 power transformers and three oil-filled shunt reactors, which are 46 kV and above, as well as several station service transformers at voltages lower than 46 kV.

Electrical insulation aging is directly related to transformer operating temperatures and, therefore, it is critical that transformers operate as cool as possible. Higher operating temperatures affect the characteristics of the oil, which in turn lowers the strength of the insulation within the transformer. As a result, critical cooling is checked regularly. Additionally, it is important for the transformer oil to be tested to ensure acceptable oil quality, strength of insulation, and acceptable levels of dissolved gases. Doble Tests[2] are performed to measure the overall insulation of the transformer, as well as the bushings, and helps provide an overall condition of the unit. A winding resistance test is used to determine if there are any loose connections or shorted turns inside the transformer. Other important tests are also completed for the transformer protective devices such as gas relay, winding, and oil temperature relays. In the event of a low level problem within the transformer, these devices provide a warning alarm. For more severe conditions, these protective devices can cause breakers to trip, which will remove the unit from service.

Hydro's current replacement criterion for 46 kV (and greater) power transformers is based upon one of the following:

1. Degree of polymerization (DP) less than 400 for network transformers and less than 500 for generator step up transformers (in Asset Criticality A);
2. Uncontrollable gassing, which is an indication of an internal fault;
3. Forecasted replacement based upon DP value and rate of change of DP; or

[2] Doble Tests are high voltage insulation tests that examine the overall integrity of high voltage equipment through power factor and capacitance measurements.

4. Requirement for major refurbishment in the near-term (to maintain/restore reliability), but replacement is a lower cost alternative.

Due to the aging nature of the transformer fleet in a maritime environment, Hydro has developed an ongoing refurbishment program to cover bushing replacements, radiator replacements, oil refurbishment, moisture reduction, on-load tap changer overhaul and leak repair, transformer leak repair, protective device replacement, transformer painting, and installation of on-line Dissolved Gas Analysis monitors.

5.2 Circuit Breakers

Circuit breakers operate to complete, maintain, or interrupt current flow under normal or fault conditions. The failure of a breaker to operate properly may affect reliability and safety of the electrical system, resulting in failure of other equipment and electrical outages to customers. Hydro has 179 terminal station circuit breakers in service, 69 kV and greater, on the Island Interconnected System. Hydro has three types of circuit breakers utilized throughout the system. They are Sulphur Hexafluoride (SF_6), air blast, and oil-filled circuit breakers.

To ensure reliable operation, breaker operating mechanisms are inspected, lubricated, and tested to ensure low contact resistance and contact opening and closing timing is within manufacturer's guidelines.

SF_6 circuit breakers, 138 kV and 230 kV, are planned for overhaul at 20 years and replacement at 40 years. SF_6 breakers from 69 to 230 kV are replaced after 40 years or sooner if their condition dictates. Oil circuit breakers are not overhauled and all are planned for replacement by 2025 due to the bushings being suspected of containing PCBs greater than 50 parts per million (ppm). There is also a Federal Government environmental mandate to remove such bushings by 2025. Air blast circuit breakers are no longer overhauled due to execution of a project to have all air blast circuit breakers replaced by the end of 2020.

5.3 Instrument Transformers

Instrument transformers convert high voltage and high current into low voltages and currents for use in protection, control, and metering equipment.

The majority of Hydro's high voltage instrument transformers are filled with oil for electrical insulation purposes. If the oil leaks from the device, it could fail. Therefore, visual inspections are required to find oil leaks and Doble Testing is also used to confirm the high voltage insulation integrity of the unit.

It is also common that junction boxes experience corrosion. The older designed junction boxes were constructed of mild steel and contain secondary wiring and terminal blocks connected to protection, control, and metering equipment. Severe rusting of these junction boxes could result in water leaking into the junction box, causing corrosion of electrical terminals and affecting the reliability of the protection circuits. Transformers with severely corroded junction boxes are replaced. Replacement units use either aluminum or stainless steel junction boxes.

Instrument transformers are currently replaced for any of the following reasons:

1. Severe rusting;
2. Oil leaks;
3. Doble Testing indicate failing electrical insulation;
4. Unit is suspect to contain PCBs greater than 50 parts per million (ppm);
5. Secondary voltages outside of ratio;

6. Current transformer is a 230 kV Asea IMBA; or[3] [4]
7. Unit 40 years old.

5.4 Surge Arrestors

Surge arrestors provide overvoltage protection for equipment resulting from lightning strikes or switching surges. Arrestor failure is likely to result in a fault. To ensure the devices are reliable, arrestors are visually inspected for contamination or cracking of the insulator. Arrestors also undergo Doble Testing to confirm overall condition.

Arresters are replaced if:

- Doble Testing has indicated a failed unit;
- visual inspection identifies severe contamination or insulator cracking;
- the arrester type is prone to failure;
- a transformer with aged arresters is being replaced (consideration will be given to installing arrester replacement); or
- arresters are 40 years old.

5.5 Disconnect Switches

Disconnect switches are used as isolating devices to enable other equipment to be removed from service and restored to service safely. It is critical when a switch is required to open or close that all electrical contacts open or close properly. When high voltage disconnect contacts

[3] IMBA is a model of current transformer manufactured by Asea AB.

[4] The failure of a 230 kV, IMBA type current transformer (CT) at the Holyrood Terminal Station in 2010 prompted the engagement of a consultant to provide a CT tear down investigation. One recommendation from the consultant's report was to remove all 230 kV IMBA type CTs within Hydro's system in a planned approach. Following the consultant's recommendation, all IMBA type CTs were identified and included in the instrument transformer replacement program (http://www.pub.nf.ca/applications/nlh2013capital/files/application/NLH2013Application-VolumeII-Report14.pdf).

do not close properly a high resistance connection can occur resulting in overheating of the contacts. This heating can melt the contacts and damage the switch resulting in breakers to operate and, depending on the terminal station configuration, cause a customer outage. To ensure disconnects function, both manually and electrically, visual inspection and infrared scans are performed. Switches are also lubricated and functionally tested.

Replacement of disconnects is primarily decided based upon its condition, identified operating problems, issues determined during maintenance, and requirement for excessive corrective maintenance. Secondary prioritization for the long-term plan is based on equipment age of 50 years.

5.6 Protection and Control Relays

The terminal station protection and control system automatically monitors, analyzes and causes action by other equipment in the terminal station to occur, such as opening of breakers, to ensure the safe, reliable operation of the electrical system, or to initiate operation of equipment when a command is issued by system operators. The protection and control system also provide indications of system conditions and alarms, and allows the recording of system conditions for analysis.

To ensure protective relays operate correctly, relays are tested and recalibrated. As well, during 230 kV breaker PMs, breakers are operated from the protection to ensure the overall system is verified. After a protection operation on the system, engineering personnel review the occurrence to ensure protective relaying operated correctly. If there was a malfunction of the relaying, corrective actions are implemented.

There are two types of relays used throughout Hydro’s system, digital solid state (new and older vintage) and the older electromechanical design.

Historically, protective relays were replaced based on performance, obsolescence, age, and the inability to provide the desired protection functionality and information required for fault analysis. Hydro has a protective relay replacement program for electromechanical and obsolete solid state relaying. Hydro plans to complete the 230 kV related replacement by 2026 and will develop the plan further to replace the 138 kV and 69 kV related relaying. As well, there are programs to upgrade alarm systems and breaker failure protection in major terminal stations. Starting in 2019, Hydro plans to start a program to replace deteriorating transformer tap changer paralleling controllers.

The electromechanical and older digital solid state type relays lack features, such as data storage and event recording capability, therefore modern digital multifunction relays are used to replace these older style relays. The modern digital multifunctional relays have increased setting flexibility, fault disturbance monitoring, communications capability, and metering functionality, and offer greater dependability and security, thus enhancing system reliability.

5.7 Battery Banks and Chargers

Battery banks and chargers provide direct current power supply to protection and control equipment, circuit breakers, and disconnect switches. Battery banks are visually inspected for leaks and contact corrosion, and are tested annually for contact conductance. Discharge testing is completed for battery banks during factory acceptance testing and is scheduled on critical A and B flooded cell banks after 10 years of service and every 5 years thereafter.

Based upon experience, Hydro plans replacement of Flooded Cell battery banks after 20 years of service and Valve Regulated Lead Acid batteries after 10 years of service. Equipment condition and operating problems are also considered and equipment is replaced sooner, if required.

5.8 Capacitor Banks

Capacitor banks are required at various locations on the system to provide voltage control for different system conditions. These banks are typically made up of capacitor modules in series and parallel. Capacitor banks are visually inspected for insulating oil leaks or insulator cracking. Preventive maintenance, which is conducted on a six-year cycle, will clean the capacitor bank and execute capacitance testing.

Hydro replaces capacitor banks based upon condition and will also consider replacement after the capacitor bank has been in service for 35 years.

5.9 Air Systems

Air systems consist of both compressors and air dryers. They are used mainly to supply dry air-to-air blast circuit breakers. For air blast circuit breakers to operate correctly, air must be available and dry. Maintenance for compressors and dryers ranges from monthly visual inspections and cleaning to annual performance and function testing. Overhauls are undertaken as warranted by equipment condition.

With the existing condition of the air systems and an on-going program to replace air blast circuit breakers by 2020, Hydro is not planning to replace air dryers or compressors needed for those breakers.

Some SF_6 and Oil-Filled Circuit Breakers use compressed air in the operating mechanism. Any remaining compressors used for those breakers will be assessed for replacement.

5.10 Grounding

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, bonding wiring connecting the structure and equipment metal components to the ground grid and a crush stone layer. 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.

Hydro will continue with its grounding upgrade program, in which disconnect gradient control mats have been replaced and grounding systems are upgraded in accordance with IEEE Standard 80 *IEEE Guide for Safety in AC Substation Grounding*.

5.11 Insulators

Insulators provide electrical insulation between energized equipment and ground. When an insulator fails and a fault occurs, a safety hazard to personnel and customer outage may occur. Terminal stations contain solid core, cap and pin, multi-cone, and suspension type insulators.

For insulators using porcelain, cement is used in mating the porcelain and metal hardware. Some older insulators have failed by a phenomenon known as “cement growth”.[5] In such situations, pieces of falling porcelain are a hazard to personnel and equipment below the insulator. Also, when an insulator failure causes a fault customer outages may occur. Hydro replaces identified cement growth insulators in its capital program.

5.12 Steel Structure and Foundations

Reinforced concrete foundations support high voltage equipment, structures, and bus work. The majority of these foundations were installed during the original station construction and most are in excess of thirty-five years of age. Exposure to freeze/thaw cycles and other weather

[5] Cement growth is a phenomenon where cement grout expands due to moisture egress, which leads to radial cracks of porcelain suspension insulators.

and age can cause deterioration and impact the foundations structural integrity. When routine visual inspections identify significant damage, refurbishment or replacement of the foundation is included in Hydro's capital program.

As well, there is a refurbishment program scheduled to be completed in 2018 to address corrosion, which could lead to structure failure, between aluminum structures and the concrete foundations at Holyrood Terminal Station.

5.13 Control Buildings

The control buildings house protection, control, and Supervisory Control and Data Acquisition (SCADA) equipment, as well as battery banks and chargers. Control buildings are inspected for leaks, and general building and life safety condition during 120-day terminal station inspections. Hydro has an on-going program to address capital deficiencies.

5.14 Asset Criticality and Spares

Hydro has developed a terminal station asset criticality ranking, based on the health of each piece of equipment, available alternatives (i.e. parallel transformers), environmental impact, customer impact, likelihood of breakdown, and cost of repairs, which is considered in prioritizing maintenance and capital work. Hydro uses similar factors for establishing rankings for power transformers, circuit breakers, battery banks and chargers, disconnect switches, and instrument transformers. In 2018, Hydro will continue development of asset criticality rankings for protection and control assets.

In 2018 Hydro plans to identify any new terminal station spares for power transformer tap changers, synchronous condensers at Wabush, and protection and control relays. Procurement of any identified spares will be completed in 2018 and 2019. Also, Hydro reviews its spare terminal station equipment on a routine basis and takes action or establishes plans to achieve appropriate spares levels based on the outcome of those reviews.

6.0 Transmission Line Asset Management

Newfoundland and Labrador Hydro owns and maintains approximately 583 km of 69 kV; 1264 km of 138 kV; and 1821 km of 230 kV transmission line as part of the Island Interconnected System, for a total line length of approximately 3668 km. Its 69 kV class lines are of wood pole construction and its 138 kV class lines are primarily of wood pole and aluminum lattice construction. The 230 kV class lines are a combination of wood pole and steel lattice construction. Over half of these assets were constructed in the 1960's and early 1970's.

Transmission lines are a set of conductors supported by structures that carry electrical power from generation plants to terminal stations and link terminal stations together, which allows for the distribution of electricity to customers. A transmission line consists of structures, conductors, insulators, grounding system, and right-of-ways.

The subcomponents of a steel structure are the legs, cross-members, and grillage foundations which are typically fabricated from structural steel angle. These subcomponents are hot-dip galvanized to ensure extended life. A typical lattice steel structure can last in excess of 70 years. The subcomponents of a wood pole structure are the poles, cross-arms, and cross braces. These subcomponents are treated with preservatives to ensure extended life. A typical treated pole can last in excess of 60 years. Typically treated cross-arms and braces can last in excess of 30 years. The summary of the maintenance, refurbishment, and replacement criteria Hydro uses for its transmission line assets follows.

6.1 Wood Pole and Steel Structure Line Management Programs

These management programs are the primary means by which Hydro maintains and refurbishes its transmission lines. These cyclical programs include structure-climbing inspections, wood pole Resistograph® readings and shell thickness measurements, and visual inspection of conductors, guying, and foundations. LTAP establish condition-based assessments to identify and prioritize capital and maintenance corrective activities so as to extend line life expectancy. The condition based data collected is also used to determine when a total line replacement is required. As component replacement quantities increase beyond the budgetary framework of the pertinent line management program, separate capital projects are placed into the long term plan for line upgrades.

6.2 Helicopter Patrols

Helicopter patrols are carried out twice a year on transmission lines. This is a visual inspection of the transmission line from the air looking for visible defects and right-of-way deficiencies, such as danger trees. Hydro video records all helicopter patrols, which allows for further assessment after completion of the patrol. All deficiencies are documented and scheduled for corrective work.

6.3 Ground Patrols

Ground patrols are generally carried out as part of the Wood Pole and Steel Structure Line Management Programs. Lines exposed to high loading conditions have annual ground patrols. Patrols conduct visual inspection from the ground to identify, assess, and prioritize deficiencies to a transmission line and its right-of-way. Identified deficiencies are documented and scheduled for corrective work.

6.4 Infrared Inspections

Hydro's completes infrared scanning of connections on dead-end structures on all transmission lines. All deficiencies are documented and scheduled for corrective work.

6.5 Wood Pole Treatment

Preservative treatment is added to the poles to extend their service life through the Wood Pole Line Management Program.

6.6 Right-of-Way Maintenance

A transmission line runs along a corridor typically referred to as a "right-of-way". The width of the right-of-way depends on the voltage class of the transmission line, or if several lines run through the same corridor. Uncontrolled vegetation growth may eventually lead to outages due to conductor contact, or travel access restrictions on the right-of-way due to thick brush. During transmission line inspections, tree height and vegetation growth are noted in addition to areas that need repairs, such as washouts. The work to control vegetation is prioritized based on condition. Hydro utilizes a combination of cutting and spraying to control vegetation growth on its right of ways. Hydro performs vegetation control on approximately 10% of its right-of-ways per year with 60% of the annual program involving vegetation cutting, and the remaining 40% of the vegetation sprayed with herbicide.

6.7 Asset Criticality and Spares

Hydro has developed a transmission line asset criticality ranking based on the health of each piece of equipment, available alternatives (i.e. radial lines), environmental impact, customer impact, likelihood of breakdown, and cost of repairs, which are considered in prioritizing maintenance and capital work. Rankings have been established for all transmission lines using this approach.

Hydro reviews its spare transmission materials on a routine basis. From those reviews it takes action or establishes plans to achieve appropriate spares levels.

7.0 Status of Planned 2017 Transmission and Terminal Station Activities

The completion status of the Annual Work Plan (AWP) and Winter Readiness (WR) activities for transmission and terminal station facilities on the Island Interconnected System is summarized in the sections to follow.

7.1 Transmission

As shown in Figures 1 and 2, Hydro completed 100% of its planned 2017 transmission AWP and WR activities.

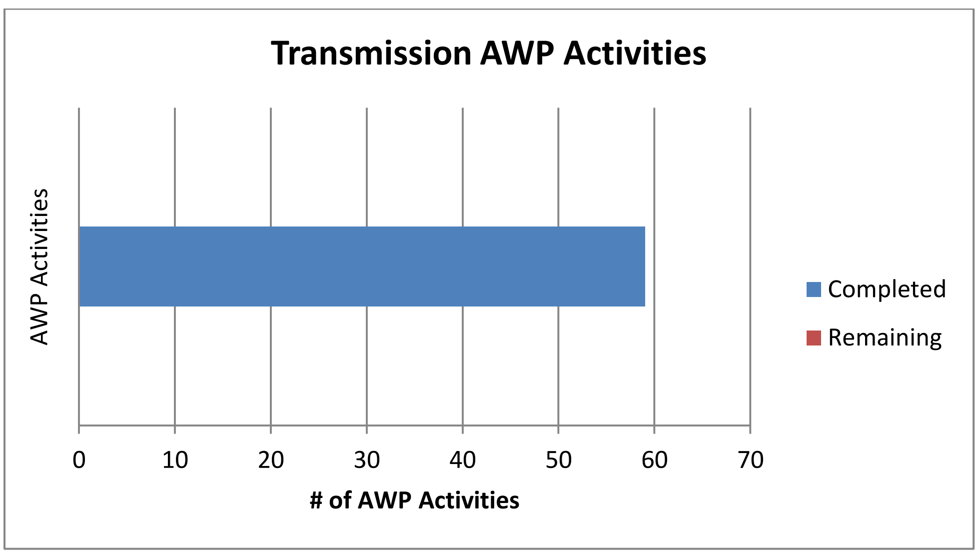

Figure 1: Transmission – AWP Activities (December 31, 2017)

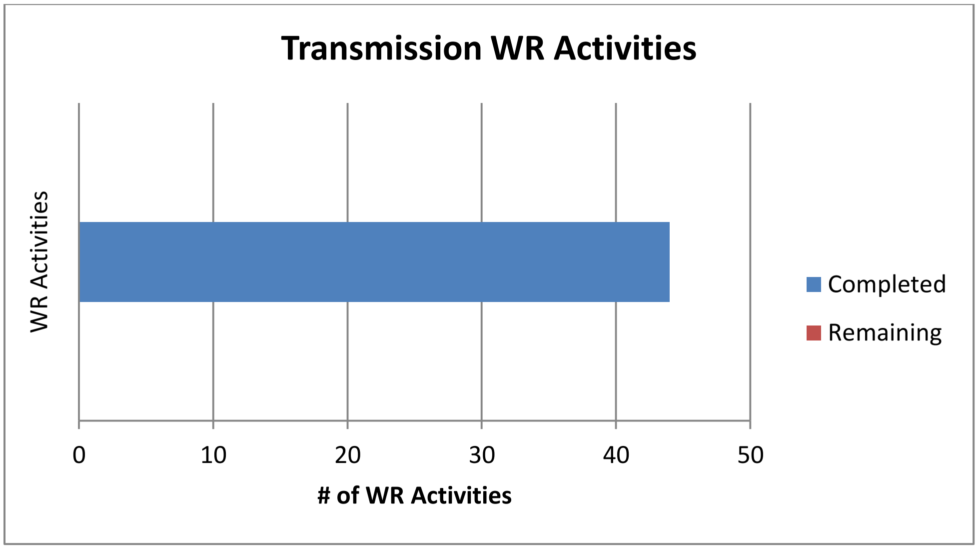

Figure 2: Transmission – WR Activities (December 31, 2017)

The following is a summary of the Transmission activities completed in 2017:

- Completion of TL 267 (in-service) from Bay d'Espoir to Western Avalon.
- Completed the interconnection of TL 269 from Granite Canal to Bottom Brook.
- Completed the interconnection of TL 270 from Granite Canal Plant to Granite Canal Station.
- Relocation of section of TL 227 as a result of the landslide near Sally's Cove (year two).
- Replaced Aircraft Markers at Grand Lake Crossing on TL 228.
- Completed the following Wood Pole Line Management Inspections and Refurbishments.
    - Inspection on lines TL 203, TL 212, TL 219, TL 220, TL 227, TL 241, TL 250, TL 251, TL 252, TL 261 and L 1301
    - Refurbishment on lines TL 201, TL 203, TL 212, TL 219, TL 232, TL 244, TL 250, TL 251, and L 1301.
- Steel Line Inspection Program Inspections completed in 2017.

Table 1: 2017 Steel Line Climbing/Ground Inspections Completed

Line #	Climbing Inspection (Structures)	Ground Patrol (Structures)
TL 202	70-87, 173-190	70-87
TL 204	41-50, 166-187	41-50, 174-204, 23-44
TL 205	84-104	84-125
TL 206	70-87, 174-191	70-87
TL 207	16-30	1-30
TL 208	26-46	
TL 211	57-70	57-70
TL 212	1-73	1-73
TL 214	184-228, 275-355	184-228, 275-355
TL 217	181-210	113-168
TL 228	37-54	
TL 231	44-54, 161-177	44-54, 64-84, 176-210
TL 236	24-29	1-56
TL 237	1-18	73-108
TL 242	49-60	50-74
TL 247	417-430, 112-148	
TL 248	55-72	55-72

7.2 Terminal Stations

As shown in Figures 3 and 4, Hydro completed 97.9% of its planned 2017 terminal station AWP and 99.7 % of its WR activities as of December 31, 2018.

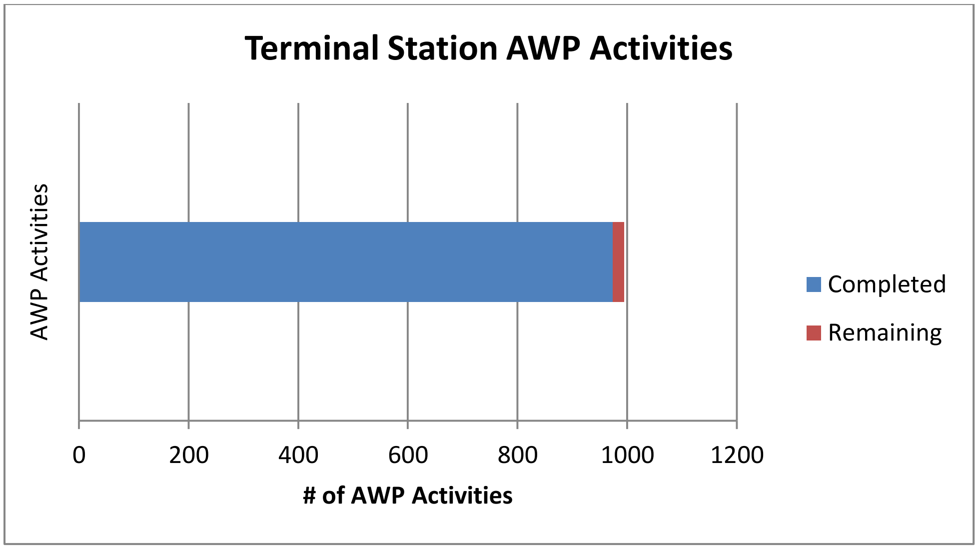

Figure 3: Terminal Stations – AWP Activities (December 31, 2017)

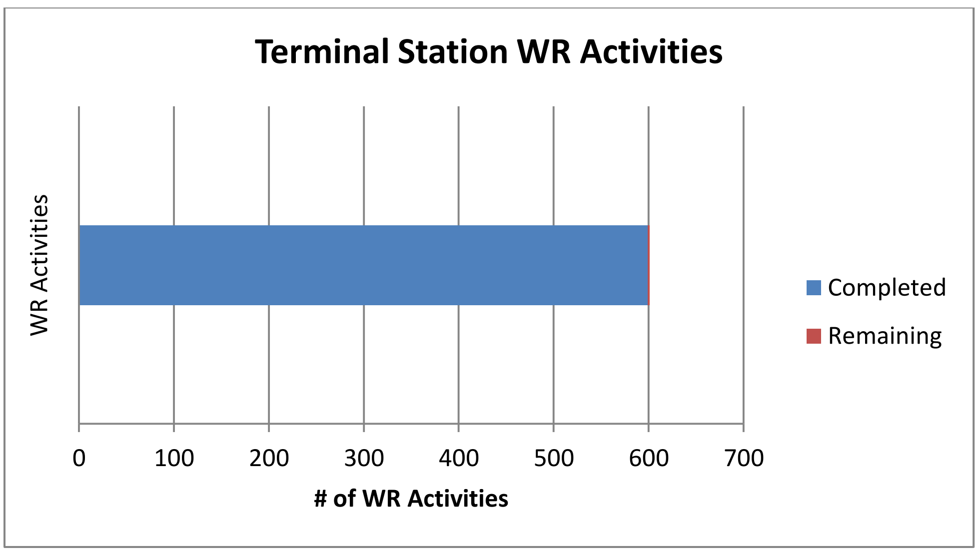

Figure 4: Terminal Stations – WR Activities (December 31, 2017)

The following is a summary of the Terminal Station activities completed in 2017:

- Interconnection of new transmission line TL 267 (in-service) at Bay d'Espoir and Western Avalon.

- Splitting and interconnection of lines (TL 242, TL 217, and TL 201) to place Soldiers Pond Terminal Station in service for Lower Churchill Project.
- Interconnection of a new 230 kV AC stations at Bottom Brook and Granite Canal to accommodate new TL 269 and Emera DC link.
- Completed 24 Six-Year Breaker Maintenance procedures.
- Operated all 69 kV and above circuit breakers once throughout the year and operated from the protection system during 11 Six Year 230 kV Breaker Maintenance procedures.
- Completed 23 Six-Year Power Transformer Maintenance procedures and 23 Six-Year Power Transformer Doble Maintenance procedures.
- Completed Oil Quality and Dissolved Gas Analysis Program for power transformers and tap changers.
- Completed 101 Disconnect Switch Preventive Maintenance procedures
- Completed Six-Year Protection and Control Maintenance procedures at 9 stations.
- Completed 67 Six-Year Instrument Transformer Doble Maintenance procedures.
- Completed infrared scans at all terminal stations.
- Completed annual battery maintenance at all terminal stations.
- Replaced seven circuit breakers with two being air blast circuit breakers replacements. Also removed four air blast breakers at Bottom Brook due to being replaced by the new Emera breakers in the new 230 kV AC station. Four new breakers were installed in Bay d'Espoir and a new Gas-Insulated Substation (GIS) was installed at Western Avalon for the interconnection of TL 267.
- Completed for power transformers: two oil refurbishments, one radiator replacement, 48 bushing replacements on eight transformers, four corrosive sulfur remediations, installation of six online gas monitors, and 39 arrestor replacements.
- Replaced 12 disconnect switches.
- Replaced 15 instrument transformers.
- Replaced protective relays for eight transmission lines.

The following is also an update on planned 2017 maintenance items shown as not completed in Hydro's January 19, 2018 Winter Readiness update to the Board regarding *The Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnection System —Winter Readiness Planning Report —Update*.

1. Corrective maintenance on B2B3-1 230 kV Disconnect Switch in Bay d'Espoir is deferred until 2018 because systems conditions at the time the job was originally scheduled did not allow for the work on the disconnect switch. These system conditions still persist. The work will be rescheduled in 2018 when the system loading and conditions allow for the work to be completed.

   The motor operator does not work but this disconnect switch can still be operated manually.

2. Work to replace the copper braids on Disconnect Switch B2B3 at Bottom Brook is deferred until 2018 because the work could not be completed as planned due to switching requirements during energization of transformers T3 and T1. The work will be rescheduled in 2018 when the system loading and conditions allow for the work to be completed.

   Infrared scans have been performed on the braid connections and no issues were reported. If this normally open disconnect is closed again during the winter, a second infrared scan, and additional scans, if required, will be completed to ensure no issues with the braid connections.

   These two items will be completed in the 2018 AWP.

7.3 Status of 2017 Terminal Station and Transmission Line Capital Projects

Appendix C identifies the capital projects that included planned construction completion in 2017 for assets in terminal stations and on transmission lines, and indicates the completion status of each. Table 2 summarizes the completion status of these projects by asset category.

Table 2: Status of Capital Projects with Planned Construction Completion in 2017

Asset Category	Complete	Partially Complete/Deferred	Incomplete	Total
Transmission Lines	2	1	0	**3**
Terminal Stations	11	11	0	**22**
Total	**13**	**12**	**0**	**25**

Some elements of work in the Terminal Station and Transmission Line Asset Categories have been deferred to 2018. These are mostly a result of unforeseen events including reprioritization of work to accommodate the major projects (TL 267, Labrador-Island Link, and the Maritime Link), availability of internal Engineering and Construction resources and unavailability or shortening of outage windows required to execute work. The deferred work included two poles, two cross arms and one cross brace on TL 203, the installation of frequency monitors at three locations, transformer refurbishments at five of 16 terminal stations, two of 18 breaker replacements, four of eight protection upgrades, three of 15 disconnect switch replacements, data alarm upgrades at Stony Brook, breaker fail protection at three sites, fire suppression system at Bay d’Espoir and three of 19 instrument transformers. While this work has been deferred, Hydro determined that these deferred activities would not significantly impact reliability of the Island Interconnected System for winter 2017-2018. Details regarding the cause of the deferrals, as well as the risk and mitigation through the winter are provided in the Notes Section of Appendix C.

8.0 Planned 2018 Transmission and Terminal Station Activities

8.1 Transmission

As shown in Figures 5 and 6, Hydro has completed 44% of its planned 2018 transmission AWP activities and 0% of its 2018 WR activities as of March 24, 2018.

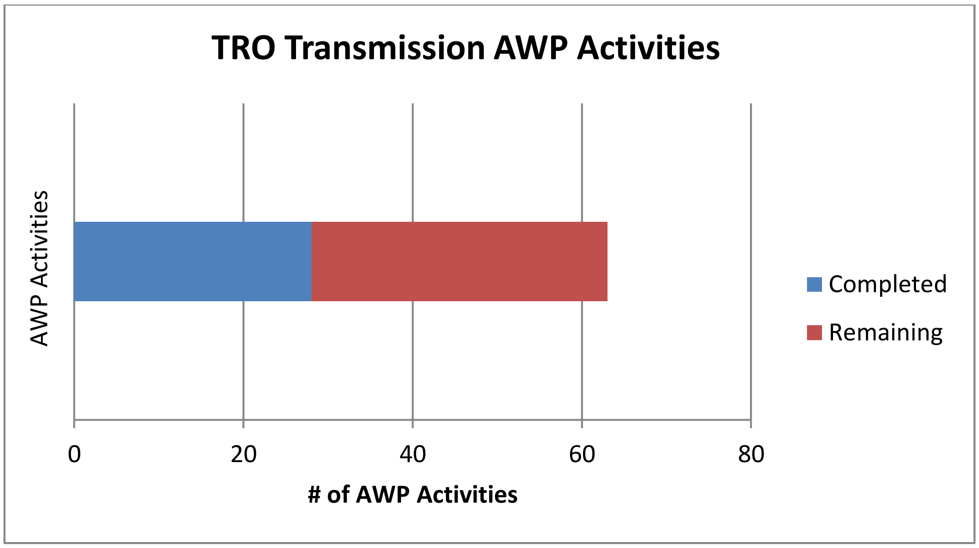

Figure 5: Transmission – AWP Activities (March 24, 2018)

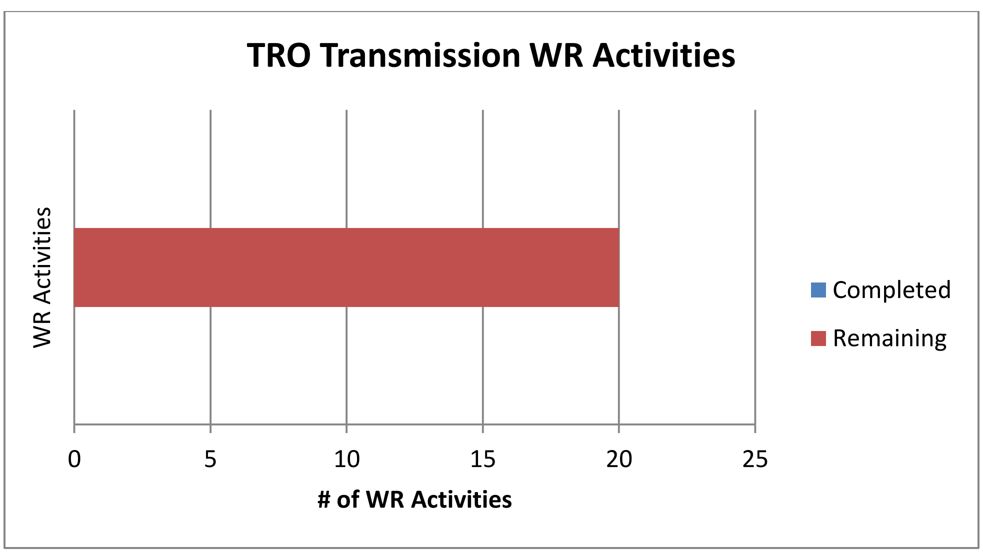

Figure 6: Transmission – WR Activities (March 24, 2018)

The following is a summary of the Transmission work plan activities scheduled for 2018:

- Complete TL 267 (environmental rehabilitation and project close-out) from Bay d'Espoir to Western Avalon.
- Replace Insulators TL 227
- Wood Pole Line Management Inspections and Refurbishments.
  - Inspection on lines TL 219, TL 252, TL 253, TL 223, TL 220, TL 225, TL 241, TL 239, TL 256, and L1301
  - Refurbishment on lines TL 203, TL 212, TL 219, TL 220, TL 227, TL 234, TL 241, TL 250, TL 251, TL 261, and L 1301
- Steel Line Inspection Program Inspections.

Table 3: 2018 Steel Line Climbing/Ground Inspections

Line #	Climbing Inspection (Structures)	Ground Patrol (Structures)
TL 202	88-103, 191-208	103-136, 70-87
TL 204	51-60, 182-197	45-66, 142-173
TL 205	105-125	126-167
TL 206	88-103, 192-211	103-136, 288-325
TL 207	1-15	1-30
TL 208	1-25	1-46
TL 211	71-84	84-111
TL 212	370-436	
TL 214	1-45, 275-355	167-222, 275-355
TL 217	201-225	156-207
TL 228	55-72, 189-200	113-150, 250-278
TL 231	55-65,195-211	43-63, 141-175
TL 236	30-35	1-56
TL 237	19-36	109-144
TL 242	64-71	43-57
TL 247	403-416, 149-185	150-224, 372-410
TL 265	1-5	
TL 268	1-5	
TL 248	73-90	113-150

8.2 Terminal Stations

As shown in Figures 7 and 8, Hydro has completed 23% of its planned 2018 terminal station AWP activities and 0% of its 2018 WR activities as of March 24, 2018.

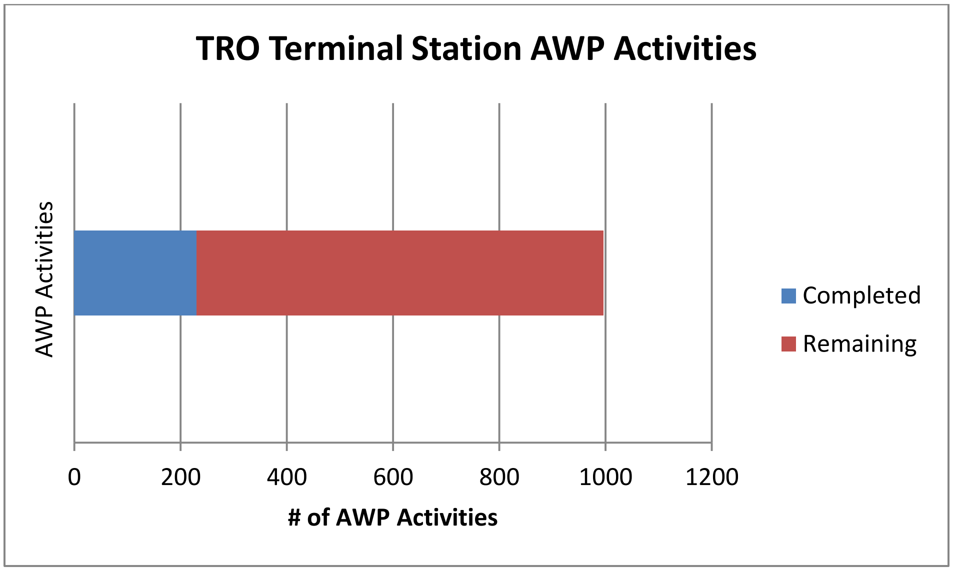

Figure 7: Terminal Stations – AWP Activities (March 24, 2018)

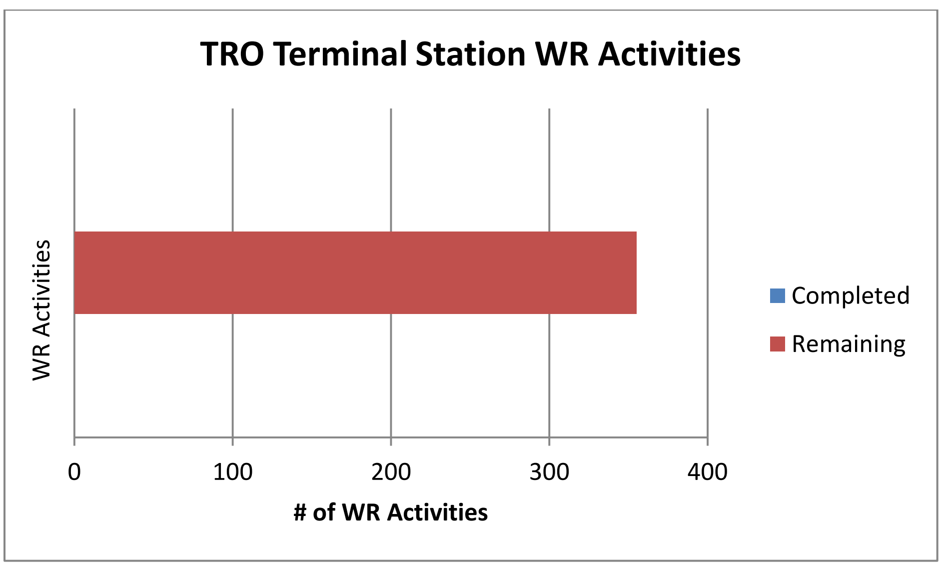

Figure 8: Terminal Stations – WR Activities (March 24, 2018)

The following is a summary of the Terminal Station work plan activities scheduled for 2018:

- Relocate transmission line TL 231 from Bay d'Espoir Terminal Station 1 to Bay d'Espoir Terminal Station 2.
- Relocate transmission line TL 208 to new Gas-Insulated Substation (GIS) at Western Avalon Terminal Station.
- Complete 23 Six-Year Breaker Maintenance procedures.
- Replace 12 breakers; nine of which are to replace air blast circuit breakers. The Western Avalon and Bay d' Espoir Terminal Stations will be reconfigured to eliminate two air blast breakers.
- Operate all 69 kV and above breakers once and operate six 230 kV breakers from the protection during Six-Year Breaker Maintenance.
- Complete 18 Six-Year Power Transformer Maintenance procedures and Six-Year Power Transformer Doble Maintenance procedures.
- Complete Oil Quality and Dissolved Gas Analysis Program for power transformers and tap changers.
- Complete for power transformers: four oil Refurbishments, five radiator replacements, three tap changer upgrades, 43 bushing replacements on seven transformers, three leak refurbishments, and install seven online gas monitors.
- Complete annual maintenance on all terminal station battery banks.
- Replace 15 arrestors on power transformers.
- Complete PMs on 141 disconnect switches.
- Replace 13 disconnect switches.
- Replace 30 instrument transformers.
- Replace protective relays for three power transformer, two transmission lines, and two buses and install breaker failure protection at four stations.
- Complete Six-Year Protection and Control Maintenance procedures at six terminal stations.

1 • Complete 77 Six-Year Instrument Transformer Doble Maintenance procedures.

2 • Complete infrared scans at all terminal stations.

Appendix A

Terminal Station Asset Management Overview

LICENSED PROFESSIONAL ENGINEER 08906 MATTHEW P. HALLORAN SIGNATURE 2017-07-21 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Terminal Station Asset Management Overview

Revision 1

July 2017

A Report to the Board of Commissioners of Public Utilities

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.

Before 2017, Hydro's terminal station projects could be 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, such as disconnects or instrument transformers, and have similar justification each year. Stand alone would include projects that do not meet the definition of a program. Hydro had 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 of Commissioners of Public Utilities (the Board). Hydro has consolidated the programs into the *Terminal Station Refurbishment & Modernization Project*, thereby improving regulatory efficiency and easing the administrative effort for both the Board and Hydro and allowing Hydro to look for opportunities to realize efficiencies by improving coordination of capital and maintenance work in terminal stations.

In 2018, Hydro submitted a revised *Terminal Station Asset Management Overview* to provide an updated overview of Hydro's asset maintenance philosophies in one document. For each Capital Budget Application in the *Terminal Station Refurbishment & Modernization Project*, Hydro submits required terminal station work, referencing this Overview document.

TABLE OF CONTENTS

1.0 Introduction

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

Hydro 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 to equipment specification, placement, maintenance, refurbishment, replacement and disposal. These practices mean that the monitoring, assessments, action justifications for capital refurbishment and replacement for asset sustaining projects are consistent. Hydro established programs which enact these practices for groups or sub groupings of assets, for example High Voltage Switch Replacements.

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

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

Hydro will revise, and resubmit, the Overview as it implements changes to its asset management philosophies appropriate for inclusion in the Overview.

1.1 Changes in Revision 1

Hydro is submitting Revision 1 of this document with the 2018 Capital Budget Application. All material changes in this revision are shaded in grey, and are summarized below:

- Section 3.2 has been modified to include the Breaker Bypass Switch Installation program;
- Section 4.19 Install Breaker Bypass Switch Installation has been added.

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.

2.0 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, such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment, required to protect, control, and operate the Hydro's electrical grid. Stations act as transition points within the transmission system, and interface points with the lower voltage distribution and generation systems. Hydro 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
- Battery Banks

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

3.0 Terminal Station Capital Projects

3.1 Historical Terminal Station Capital Projects

In 2016 Capital Budget Application, there were 22 individual terminal station projects, which accounted for $30 Million, or 16% of the Capital Budget. Historically, Hydro’s terminal station projects were divided into two categories; Stand-alone and Programs. Programs include projects that are proposed year after year to address the required refurbishment or replacement of assets such as disconnects or instrument transformers, and have similar justification and other information presented each year. Of the 22 individual terminal station projects proposed in 2016, 15 were program-type projects. In the 2017 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. Upgrade Control Buildings
7. Upgrade Terminal Station for Mobile Substation
8. Install Breaker Bypass Switches
9. Protection and Control Refurbishment and Upgrades[1]

The Terminal Station Refurbishment and Modernization project excludes:

- Transformer Replacement & Spares – Although transformer replacement fits within the description of a terminal station program, these projects often have unique justification and a high project cost, and therefore are proposed separately.
- Accelerated Circuit Breaker Replacement – Hydro proposed the accelerated replacement of 230kV Circuit Breakers as part of the 2016 Capital Budget Application "Upgrade Circuit Breakers" project. This project involves the replacement of high-

[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 the Protection and Control Refurbishment and Upgrades Program.

voltage circuit breakers through the year 2020. As this project has already been approved, it is not included in the Terminal Station Upgrades and Modernization Program. 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 which 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, the projects will be proposed separately.
- Activities in response to significant isolated issues in a particular station, such as replacement of a failed power transformer. As these projects generally have unique justification, the projects will be proposed separately.

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

This document is submitted to the Board as part of the 2018 Application. Hydro will annually submit *Terminal Station Refurbishment and Modernization Project* and *Terminal Station In-Service Failures Project proposal*s 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 situations were immediate refurbishment or replacement, which has not be 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 Station assets unanticipated failures may increase. This increase will require additional future efforts to provide and review regulatory documentation. By introducing a *Terminal Station In-Service Failures* project, there will be a reduced need for that documentation and change management processes. Each year, Hydro will provide a concise summary of the previous year's work.

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

4.0 Asset Management Programs

4.1 Electrical Equipment

4.1.1 High Voltage Instrument Transformer Replacements

The metering protection, and control devices, such as protective relaying, power quality monitors, 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

[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.

(CT) and a potential transformer (PT) respectively. CT and PT are collectively known as instrument transformers (IT). Hydro has approximately 900 individual high voltage instrument transformers within the Island and Labrador Interconnected Systems.

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

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

Hydro's manages planned budgeted IT replacements in three categories:

1. Condition
2. PCB Compliance Replacements
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 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 IT to determine if replacement is required. Hydro monitors IT for physical and electrical deterioration by conducting regular visual inspections of the units as part of its station inspection program plus regularly scheduled station IR inspections and electrical insulation testing.

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

Figure 2: Rusting PT

Electrical deterioration is identified by conducting Power Factor testing at intervals which is used to establish the rate and level of insulation degradation. Hydro uses a world recognized testing company, Doble Engineering Company, to provide an assessment of the test results

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

PCB Compliance Replacements

Environment Canada's PCB Regulations requires that by 2025 all ITs will not have a PCB concentration greater that 50ppm. Instrument transformers are sealed oil filled units, where the oil , which acts as an electrical insulator, has been known to contain PCBs for equipment prior to 1985 Due to the age of the units and the risk of introducing contamination such as air into the unit, which could impact the electrical integrity of 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 IT replacement program

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

4.1.2 High Voltage Switch Replacements

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

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

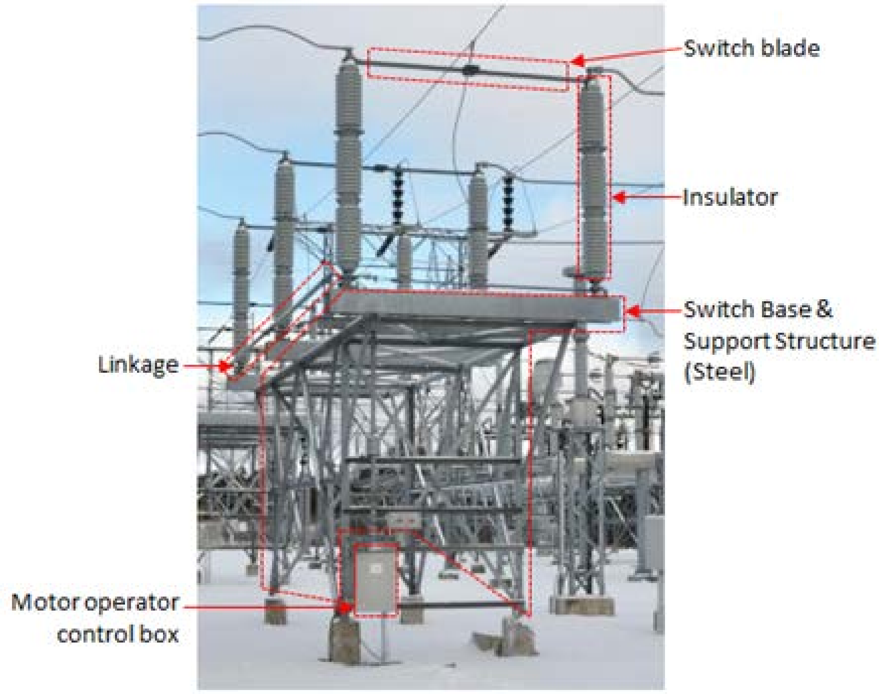

Figure 3: The various components of a high-voltage disconnect switch

Hydro monitors the condition of its switches by conducting regular visual inspections of the units as part of its station inspection program and its IR inspection program and by reviewing reports from the JDE work order system or staff who operate the switch, outlining problems such as inoperable mechanical linkages, misalignment of switch blades, broken insulators, and seizing of moving parts. Asset management personnel determine the timing of corrective maintenance or switch replacement. If the required parts are available then repairs are undertaken as part of on-going maintenance. Switches that have no replacement parts available due to obsolescence, damaged beyond repair or cannot be economically repaired and do not require immediate replacement are designated for replacement under this program.

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

Figure 4: Broken insulator on 69 kV disconnect switch

4.1.3 Surge 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 could damage the equipment's insulation. The surge arrestors act to maintain the voltages within acceptable levels. Without surge arrestors, equipment insulation could be damaged and faults could result during 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 230kV Surge Arresters

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

Hydro’s surge 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.
4. If transformers are being planned for maintenance or other Capital work, consideration is given to changing aged arresters on a common outage.

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. 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 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. Sometime ago insulator manufacturers identified and researched cement growth problems, and have improved their cement quality to eliminate this problem.

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

4.1.5 Grounding Refurbishment and Upgrades

The grounding system in a terminal station or distribution substation consists of copper wire used in the ground grid under the station, gradient control mats for high voltage switches, and bonding wiring connecting the structure and equipment metal components to the ground grid. In the event of a 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.

Figure 7: Typical grounding connection on terminal station fence

To determine whether grounding upgrades are required, Hydro performs a step and touch potential analysis of the terminal station or distribution substation. Step and touch potential analysis involves the gathering of field data and conducting analysis in order to determine if ground grid modifications are required to eliminate step and touch potential hazard. This engineering is conducted in accordance with the Institute of Electrical and 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 repairing damage or replacing missing infrastructure. Upgrades and refurbishments are made in accordance with Hydro's Terminal Station Grounding Standard.

4.1.6 Power Transformer Upgrades and Refurbishment

Power transformers are a critical component of the power system Transformers allow the cost effective production, transmission and distribution of electricity by converting the electricity to an appropriate voltage for each segment of the electrical system 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 which does the voltage conversion; oil which is part of the insulating system and a gasket system which keeps the oil from getting into the environment
- Bushings mounted to the top of the transformer tank which connects the windings to the external electrical conductors.
- Radiators and cooling fans which remove heat for the transformer’s internal components.
- Load tap changer is a device attached internally or externally through which transformer’s voltage are maintained at acceptable levels.
- 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 its transformer by regularly assessing their condition, executing regularly schedule maintenance and testing and undertaking refurbishment or corrective actions as required. Transformers regularly undergo visual inspection as part of Hydro's terminal station inspection, and scheduled preventative 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
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 on acceptable quality, Hydro has an oil monitoring program, in which an oil samples are obtained annually from each transformer and then the samples are analyzed by a professional laboratory. The test results are assessed to determine the level of deterioration. If an unacceptable level of deterioration is identified required corrective action is identified by asset management personnel. This action entails either the refurbishment of the oil to improve its quality or the replacement of the oil.

Moisture Content

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

Oil Leaks & 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, tanks piping and other steel components. Transformers are visually inspected for leaks as part of the regularly scheduled terminal station inspection program and assessed by asset management personnel to determine the level of corrective action. Minor action, such as small repairs, patching and minor painting is undertaken as part of the maintenance. Work requiring major refurbishments and replacements such as radiator or bushing replacements, gasket replacements and tank rusting refurbishment are undertaken under this program.

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 which 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. Hydro implements the laboratories recommendations. This ranges from continued or increased annual sampling, planned refurbishment to immediate removal from service, inspection and repair. The later 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 to have PCB levels not compliant with the latest PCB Regulations, as well as bushings with degraded electrical properties.

The latest regulations state that all equipment remaining in service beyond 2025 must have a PCB concentration of less than 50 mg/kg. Hydro has approximately 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 which are known or suspected of having unacceptable PCB levels are replaced.

Hydro performs Power Factor testing on bushings every six (6) years as part of the transformer preventative 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 preventative 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 GSUs, to allow real-time, continuous monitoring of dissolved gases in oil. The on line gas in oil monitoring continuously monitors the transformer and provides early fault detection. Continuous data is also a useful tool for personnel to use to trend gases to help schedule repairs or replacement prior to in-service failures, improving the overall reliability of the Island Interconnected System. Continuous monitoring enables Hydro to reduce unplanned outages and lessen the probability of equipment in-service failure.

This program 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 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), which use high pressure air to interrupt currents and will be 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), which use oil to interrupt currents and will be at least 36 years old at replacement. In the 2016 Capital Budget Application "Upgrade Circuit Breakers – Various Sites" project, approval was obtained for the replacement of 10 OCBs up to 2020 which not compliant with Environment Canada PCB regulations. The remaining non-compliant breakers will be replaced before 2025. From 2017, any replacements not previously approved in the 2016 Application will be included in the work conducted under this section of the Overview.
3. Sulphur Hexafluoride (SF_6) Circuit Breakers, which use SF_6 gas to interrupt current and installation of these breakers started in 1979 and is used for all new installations. In the 2016 Capital Budget Application "Upgrade Circuit Breakers – Various Sites" project, approval was obtained, until the end of 2020, for the mid-life refurbishment and replacement of SF6 circuit breakers with voltage rates 66 KV and above. From 2017, any SF_6 replacements and refurbishments not previously approved in the 2016 Application 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" project, SF_6 circuit breakers rated at 138kv and above are required to be refurbished after 20 years of service. Replacement of SF_6 circuit breakers rated at 66kV 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" project. Some

SF_6 circuit breakers may require replacement before the 40-year service life period based upon their condition and operational history. Hydro expects to replace up to six breakers per year beyond 2020 and an average of five breakers and overhaul one breaker per year for 2022 and 2023 and not require overhauls again until beginning 2030. As per the 2016 Capital Budget Application, “Upgrade Circuit Breakers – Various Sites” project, Hydro does not currently overhaul breakers rated below 138kV.

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

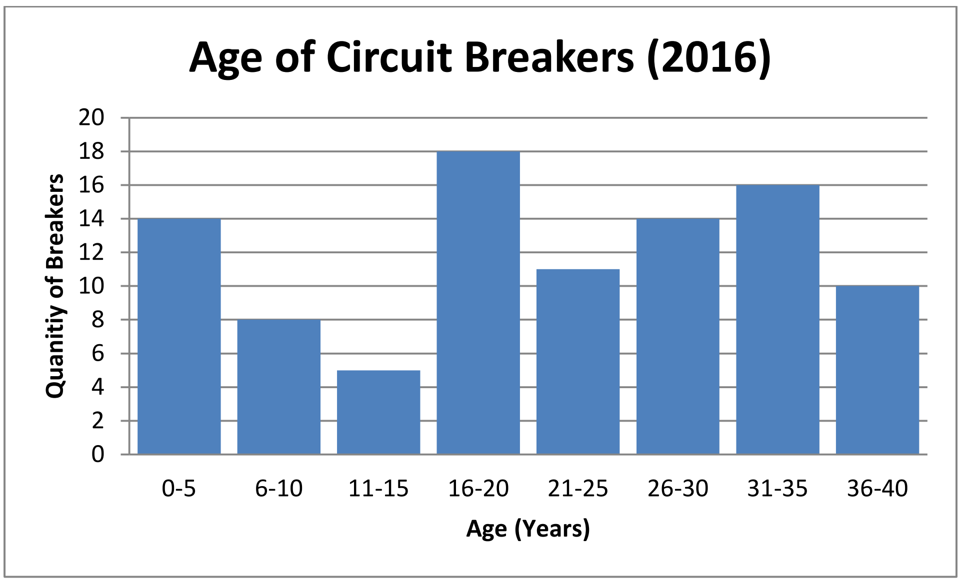

Figure 10: Age of Circuit Breakers Not Included in Ongoing Replacement Program

4.1.8 Station Service Refurbishment & 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, feed either through a redundant transformer tertiary, supplied from Newfoundland Power's electrical system where available, or by a diesel generator. Common AC station service loads are:

- Transformer Cooling fans
- Anti-Condensation Heaters
- Station Lighting
- Control building HVAC
- Control building lighting
- Air Compressors
- Battery Chargers

The DC station service is supplied by a battery bank, with 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 125V system in the majority of the stations with some lower voltage stations and telecommunications equipment having 48V systems. Common DC station service loads are:

- Circuit Breaker Charging Motors
- Digital Relays
- Emergency Lighting
- Disconnect Switch Motor Operators
- 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 and battery banks and chargers are not included in this program, as they are addressed separately in the Application, under the *Replace Power Transformers* and *Replace Battery Banks and Chargers* projects.

4.19 Install Breaker Bypass Switches

High voltage circuit breakers, with their associated protection and control equipment, are used to control the flow of electrical current to ensure safe and reliable operation of the electrical system. When a breaker is removed for service for maintenance, troubleshooting, refurbishment, or replacement, an alternate electrical path must be implemented to avoid customer outages. On radial systems[3], this alternate path is accomplished using a bypass switch. When closed, the bypass switch permits electricity to flow around the breaker allowing the breaker to be safely de-energized, while maintaining service continuity.

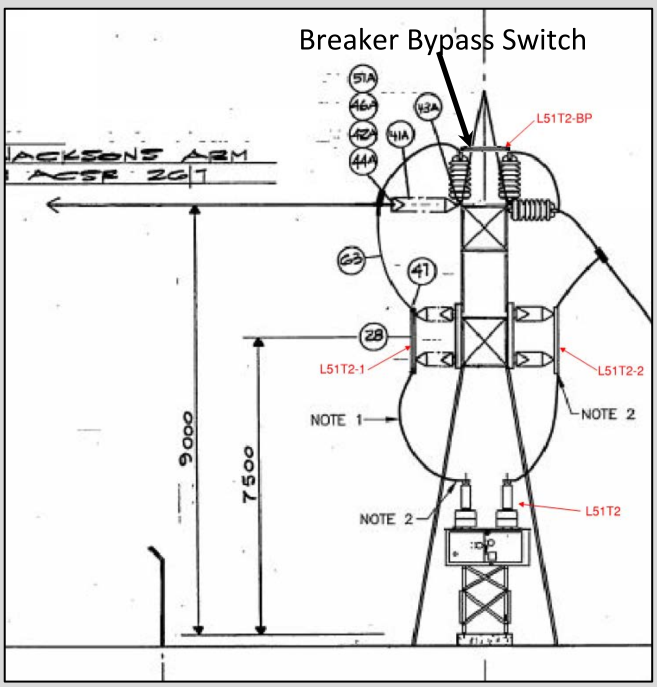

Figure 11: Example of Bypass Switch Installation

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

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

breaker B1T2.

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
Peter's Barren B1L41	1900 Great Northern Peninsula customers north of Daniel's Harbor
South Brook L22T1	2340 South Brook area customers.

Hydro expects the program to be completed in 2023

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 buswork. 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 figures 11 and 12.

Figure 12: Structure B1T1 Bottom Brook Terminal Station

Figure 13: Structure L01L37-1 Western Avalon Terminal Station

1 To ensure foundations perform as per the original design intent, severely deteriorated concrete

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

4.2.2 Fire Protection

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

Hydro is installing 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 230kV terminal stations.

4.3 Protection, Control, and Monitoring

4.3.1 Protection and Control Upgrades and Refurbishment

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

- Protective Relays
- Breaker Failure Protection
- Tap Changer Controls
- Data Alarm Systems
- Frequency Monitors
- Cables and Panels

Electromechanical & 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 harming personnel.

Older relays existing on Hydro's system are the electromechanical and older solid state types, and lack features such as data storage and event recording capability. Modern digital multifunction relays are used to replace these older style relays, as they have increased setting flexibility, fault disturbance monitoring, communications capability and metering functionality, and offer greater dependability and security, enhancing system reliability. Digital and electromechanical relays are showing in Figure 14.

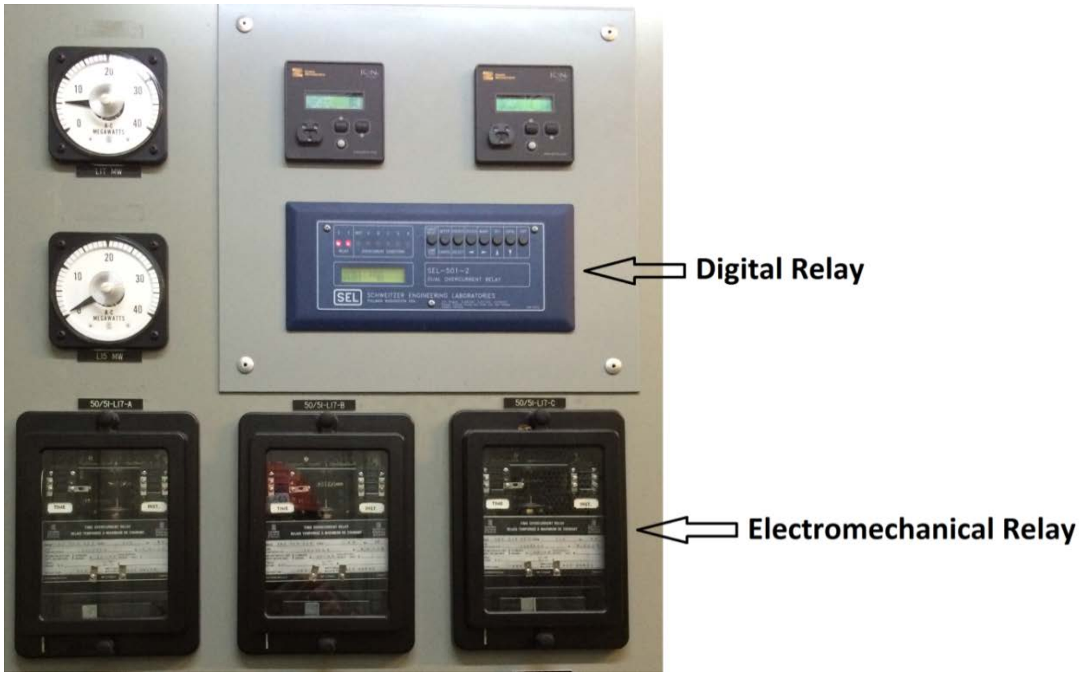

Figure 14: Digital and Electromechanical Relays

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.
- 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 2016 RFI CA-NLH-037, Hydro is installing redundant multifunction transformer protection relays in 2016 for transformers rated above 10 MVA. Under this program Hydro will continue to install these upgrades.

Breaker Failure Protection

Protective relaying is designed to trip a breaker during fault conditions to remove the fault from the electrical system so as to minimize equipment outages and maintain system stability and safe, reliable operation. When a breaker does not properly isolate a fault, other breakers will be commanded to trip to isolate the fault. This will result in larger outages but will ensure isolation of the original fault in a time to minimize damage to equipment and minimize impact to the system. The failure of a breaker to isolate a fault when commanded is called a Breaker Failure. 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 (3) 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:

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

Current tap changer controls are of similar vintage as the power transformers dating back to the late 1960's, and require replacement. Recent feedback from the tap changer paralleling control supplier indicated older equipment has capacitors that will dry out over time resulting in control issues. Additionally, it was recommended the same controller model be applied to all transformers to optimize tap changing control. The control issues as described by the supplier have been seen by Hydro staff at numerous sites through review, which indicated a high number of operations 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 15: An annunciator commonly found in Hydro terminal stations

Hydro's review of Alarms, Event Recording Devices and Digital Relays found that by providing more detailed alarm schemes, the ECC and local operators are able to troubleshoot system events more accurately and quickly.

Hydro's internal study identified required increases to alarm detail for five 230kV terminal stations to the ECC. 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 in 2018 and beyond.

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.

Protection and Control Cable and Panel Modifications

This program will cover protection and control panels and wiring 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.

Appendix B

Details of Terminal Station Preventive Maintenance, Overhaul and Replacement Criteria

Details of Terminal Station Preventive Maintenance, Overhaul and Replacement Criteria

1.0 Introduction

The following outline's Hydro's the preventive maintenance (PM) program and Hydro's overhaul and replacement criteria for the various major asset classes within Terminal Stations.

2.0 Power Transformers & Shunt Reactors

- 120-Day PM (120 days): cooling fan function testing; operational data collection; and visual inspection.
- Oil Sample PM (one year by default, more frequently as needed): DGA; oil quality; and moisture.
- Furan PM (four years by default, one year as needed): to test Degree of Polymerization (DP) of the paper.
- Six-Year PM (six years): electrical testing (Doble Testing, winding resistance, winding insulation resistance, protective device insulation resistance, surge arrester grounding continuity); protective device function testing; tap changer function testing; cooling fan function testing; and visual inspection.
- Hydro's current replacement criteria for Power Transformer Replacement (46 kV and above**)** is based upon one of the following:
    1. Condition based upon DP (degree of polymerization) <400 for network transformers and <500 for Generator Step Up transformers in Asset Criticality A).
    2. Uncontrollable gassing which is an indication of an internal fault.
    3. Forecasted based upon DP value and rate of change of DP.
    4. An economic evaluation for a given transformer for refurbishment versus replacement three to five years prior to the unit becoming 55 years old.

Due to Hydro's aging transformer fleet Hydro has developed an ongoing refurbishment program to cover bushing replacements, radiator replacements, oil refurbishment, moisture reduction, on load tap changer overhaul and leak repair, transformer leak repair, protective device replacement , transformer painting, and installation of on line DGA monitors. The following will provide the details for each.

3.0 Power Transformer Bushing Replacement

Hydro's current replacement criterion is based upon one of the following:

1. Condition (bad Doble Test results as identified by Doble Engineering OR unobservable oil level OR non removable tap caps OR visual damage allowing moisture ingress).
2. Suspected of containing PCB-contaminated oil (All sealed equipment containing $\geq$50ppm must be removed from service by 2025).

Prioritization: poor condition first (by condition severity), PCB-contaminated next.

4.0 Power Transformer Radiator Replacement

Hydro's replacement criterion is based upon the condition of the radiator (rust) from a visual inspection and ranking by an Asset Specialist.

5.0 Power Transformer Oil Refurbishment

Hydro's oil refurbishment criteria is based upon oil being IEEE Class III. Class III units will have their oil either reclaimed or replaced. If the oil has a PCB content greater than 2 ppm the oil will be replaced, otherwise it will be reclaimed to improve the oil quality.

6.0 Power Transformer Moisture Reduction

Hydro's moisture reduction criteria is based upon having paper >3.5% moisture OR paper is ≥2.5% AND inferred DP is <1100)), AND replacement not forecasted within ten years of current year.

Prioritization: equal weighting of paper moisture severity and asset criticality.

7.0 Power Transformer On-Load Tap Changer Leak Repair

Hydro's criteria to complete leak repair for on On-Load Tap changers is based upon having stable acetylene and other combustible gases in the transformer, and a proven leak test. Units testing positive to leak tests are planned for refurbishment.

8.0 Power Transformer On-Load Tap Changer Overhaul

Hydro's criteria for tap changer overhaul is based upon

1. An annual oil sample to measure dissolved gases and particle count. Hydro uses a Tap Changer Analysis Signature Assessment (TASA) to provide a ranking of very good (1) to very poor (4). A rank >3; or
2. Stenestam Ratio > 5.0; or
3. Number of operations (based upon OEM recommendation for contact maintenance).

9.0 Power Transformer Leak Repair

Hydro's criteria to complete leak repairs is based upon:

1. Identified leaks.
2. Major refurbishment will include gasket replacements to prevent future leaks.

10.0 Power Transformer Protective Device Replacement

Hydro will complete transformer protective relay replacements if condition warrants as determine by 120-Day or Six-Year PM. Protective devices and associated cabling is also changed as required during other transformer refurbishment work.

11.0 Power Transformer Online DGA Monitors

Hydro's criteria for on-line DGA monitors is to install full monitoring of all combustible gases for Criticality A and B transformers (GE TransFix) and install GE Hydran units on criticality C and D units. All data is and will be brought back to a GE Perception Software that is remotely accessible by engineers and asset specialist.

12.0 Power Transformer Painting

Hydro's criterion for rust removal and painting is based upon a visual inspection for rust. As well transformers undergoing major refurbishment will have painting considered.

13.0 Circuit Breakers

- 120-Day PM: visual inspection, check pressures for Air and/or SF6, record heater amps.
- Annual Operate breaker PM is completed to confirm operation once per year.
- Oil sample from OCBs every three years.
- Every four years the following is completed for Air Blast Circuit Breakers - Conductor, timing, trip coil measurement, check auxiliary contact, check pressure switches, function test breaker, and measure trip coil resistance.
- Every six years the following is completed for SF_6 Circuit Breakers: check SF6 pressure; check operating mechanism pressure; check conductor; measure trip coil resistance; check pressure settings; check primary connections; lubricate mechanism; and measure timing and function test breaker.

- Every six years the following is completed for Oil Circuit Breakers (OCB): change oil in compressor; check dash pot oil level, breaker in open position; check pressure switches and record, if applicable; inspect contactors; lubricate operating mechanism; measure and record run time of compressor from cut-in to cut-out; measure interrupter resistors (138 kV KSO only), check bushings and wipe down, if required; complete a dielectric test ASTM 877 of the oil; perform megger of each phase to ground with breaker; and perform doctor and timing.
- 138 and 230 kV SF6 breakers are planned for overhaul at mid-life (20 years) and replaced at 40 years or sooner if condition dictates. 69 kV SF6 circuit breakers are not overhauled but are planned to be replaced at 40 years or sooner if condition dictates.
- Oil circuit breakers are not overhauled and are being planned for replacement by 2025 due to the bushings being suspect to contain PCBs $\geq$ 50 ppm.
- Air blast circuit breaker are no longer overhauled and a plan is in place to have all air blast circuit breakers removed from service at the end of 2020.

14.0 Protective Relays

- Six-Year PM Inspection: Function test each protective relay one at a time: clean, dust, and inspect connections; connect the relay test equipment to the relay; configure the relay test equipment settings to those required for the relay; function test each in-service function of the relay using the relay test equipment; troubleshoot the relay if it fails any function tests; record and save the results in the relay testing software; and return relay to service.
- For Electromechanical Relays, perform the additional steps of: remove glass and clean inside and out; pull biscuit(s) and check for oxidation (tarnished); clean with a white eraser; unlock relay and gently pull out of case; check for Iron filings on operating disc, if equipped; clean contact surfaces with a burnishing tool; and manually move disc to look for smooth operation and to ensure it resets properly.

- Every six years, Function Test 230 kV circuit breakers from the protection during the scheduled 230 kV breaker PM.
- Historically protective relays were replaced based on age, performance, obsolescence, and their inability to provide the desired protection functionality and information required for fault analysis. Following the events of January 2014, Hydro formalized a protective relay replacement plan which will see protective relay systems (which had not already been previously replaced) replaced for all major equipment on the 230 kV system during the period from 2015 to 2026. Further plans will be developed for 138 and 69 kV equipment. As well, as a result of the events of January 2014 plans have been put in place to upgrade alarm systems and breaker failure protection in major terminal stations.

15.0 Current Transformers

- 120-Day General Inspection, the following is checked: bushings; tanks; oil leaks; rust/paint condition; concrete base; primary connections; conduits; cabinets; and grounding.
- Every six years the following is done:
  - Wiring connections checked;
  - Secondary connections checked;
  - Heater amperage checked;
  - Touch-up painting done, as required; and
  - Doble Test performed.
- Current transformers are currently replaced based upon either :
  1. Condition as determined visual inspection for rust and leaks.
  2. If the unit is suspect to contain PCBs $\geq$ 50 ppm.
  3. If the unit is a 230 kV IMBA.

16.0 Potential Transformers/Capacitive Voltage Transformers

- On 120-Day General Inspection, the following is checked: bushings; tanks; oil leaks; rust/paint condition; concrete base; primary connections; conduits; cabinets; voltages at each secondary winding; and grounding.
- Every six years the following is done:
  - connections for position and tightness checked;
  - grounding device checked;
  - coupler box internally inspected;
  - gaskets and gap clearances checked;
  - heater amperage checked;
  - touch-up painting done, as required;
  - perform Doble Test;
  - surge protection device in CVT junction box checked/tested, if fitted for wave-trap;
  - ground switches cleaned and lubricated; and
  - surge gap checked
- Potential transformers and capacitive voltage transformers are currently replaced based upon either:
  1. Condition as determined visual inspection for rust and leaks.
  2. Condition as determined by Doble Testing.
  3. If the unit is suspect to contain PCBs $\geq$ 50 ppm.

17.0 Surge Arresters

- 120-Day Power Transformer inspection, a visual inspection is performed.
- Every six years, a visual inspection and a Doble Test are performed.
- Arresters are replaced based upon:
  1. Doble Testing indicates a failed unit;
  2. Visual inspection identifies severe commination or insulator cracking;

3. Arrester type is prone to failure;
4. A transformer is being replaced (consideration will be given to installing arrester replacement).

18.0 Disconnects

- 120-Day inspection is completed which includes: visual check for alignment and signs of overheating; insulator conditions; and heater.
- Annual Infrared scans to look for hot spots. The following guidelines shows temperature difference between phases and outlines response time required to address identified hot spots:

Priority	Temp. Difference (ΔT Phase to Phase)	Respond Within
1 (Emergency)	Visually Hot	24 Hours
2	Above 50°C	1 week
3	20°C to 50°C	1 month
4	Below 20°C	1 year

- Every six years (one or three years as well if located in severe environmental contamination) the following is checked: All connections and contacts; switch operation; contacts are greased; and linkages and operating mechanism are lubricated. On motor operated disconnects the motor operation is checked and if load break, interrupter modules are checked.
- Disconnects are replaced mainly based primarily on: condition and operating problems and issues as determined by issues found during PM's; problems encountered during operation; excessive corrective maintenance required; etc. Secondary prioritization for the long term plan is based on equipment age.

19.0 Batteries and Chargers

- 120-Day inspection includes: voltmeter checks; ammeter checks; and visually checking battery condition as well as electrolyte levels for flooded cells. Distilled water may be added to flooded cells and equalize charge given if required.
- Annually the batteries and chargers are inspected and cleaned. Also included in this is a conductance test performed on all the cells and straps with a Midtronics battery tester. For flooded cells the specific gravity is also checked on all cells.
- Discharge testing is completed for all battery banks during factory acceptance testing and is scheduled to be completed on Criticality A and B flooded cell banks after ten years of being in service and then every five years thereafter.
- Battery banks and chargers are recommended to be replaced after 20 years and VRLA batteries after ten years. Equipment condition and operating problems are also considered and equipment is replaced sooner if required.

20.0 Air Systems

- Compressor Annual PM (one year): change deteriorated disposable parts; cleaning; record operational data; performance testing; protective device function testing, and visual inspection
- Monthly Air System PM (monthly): cleaning; record operational data; performance testing; protective device function testing; and visual inspection
- Compressor overhauls: overhauls are based on the inspections performed, as well as experience. Factors considered for compressor overhauls are: excessive oil consumption; change in inter-stage pressure/back pressure; excessive time to bring system up to pressure; oil leaks; broken valve spring/overheating; excessive noise; and vibration, etc.
- Many of the air systems have been upgraded prior to the decision to replace all air blast circuit breakers and as a result there is no longer a plan in place to replace air dryers or

compressors. Any remaining compressors used in a different application will be assessed by the each for replacement.

21.0 Grounding

- 120-Day PM (120 days): visual inspection.
- Grounding is upgraded as a result of visual inspections and grounding analysis completed in accordance with IEEE Standard 80.

22.0 Capacitor Banks

- 120-Day PM (120 days): record operational data, blown fuse replacement, visual inspection.
- Six-Year PM (six years): record operational data, electrical testing (capacitance, insulation resistance), blown fuse replacement, cleaning, visual inspection.

Hydro will plan replacement of capacitor banks based upon condition or consider replacement as banks approach 35 years in service.

Appendix C

2017 Terminal Station and Transmission Line Project Status

Hydro Island Interconnected System - 2017 Capital Projects Status
Transmission System and Terminal Station Assets

Asset Category	Project Description	Status of 2017 Planned Construction Completion
Transmission	Rerouting of Transmission Line and Distribution Line - Sally's Cove	Complete
Transmission	Structures Replacement and Restoration - TL 212 and TL 201	Complete
Transmission	Perform Wood Pole Line Management Program	See Note 1
Terminal Stations	In-Service Failures - Various Sites	See Note 2
Terminal Stations	Purchase Capital Spares - Terminal Stations	Complete
Terminal Stations	Upgrade Aluminum Support Structures - Holyrood	Complete
Terminal Stations	Purchase Backup Diesel For Station Service - Grand Falls and Buchans	Complete
Terminal Stations	**Terminal Station Refurbishment and Modernization - Various Sites**	
Terminal Stations	- Install Frequency Monitors - Various Sites	See Note 3
Terminal Stations	- Upgrade Equipment Foundations - Various Sites	Complete
Terminal Stations	- Replace Surge Arrestors - Various Sites	Complete
Terminal Stations	- Upgrade Power Transformers - Various Sites	See Note 4
Terminal Stations	- Cable Upgrades - Various Sites	Complete
Terminal Stations	Upgrade Circuit Breakers - Various Sites (2016-2020)	See Note 5
Terminal Stations	Replace Protective Relays - Various Sites	See Note 6
Terminal Stations	Replace Disconnect Switches - Various Sites (2016-2017)	See Note 7
Terminal Stations	Upgrade Digital Fault Recorders - Various Sites	Complete
Terminal Stations	Upgrade Data Alarm Systems - Various Sites	See Note 8
Terminal Stations	Install Breaker Failure Protection - Various Sites	See Note 9
Terminal Stations	Install Fire Protection in 230 kV Stations - Bay d'Espoir	See Note 10
Terminal Stations	Upgrade Terminal Station for Mobile Substation - Cow Head	Complete
Terminal Stations	Replace Instrument Transformers - Various Sites	See Note 11
Terminal Stations	Replace Battery Banks and Chargers - Various Sites (2017-2018)	Complete
Terminal Stations	Interconnection of new transmission line TL 267 at Bay d'Espoir and Western Avalon	Complete
Terminal Stations	Interconnection and splitting of lines to place Soldiers Pond Terminal Station in service for Lower Churchill Project	Complete
Terminal Stations	Interconnection of a new 230 kV AC station at Bottom Brook and Granite Canal to accommodate new TL 269 and Emera DC link	See note 12

NOTES

1 - The 2017 scope of work for the Wood Pole Line Management Program included the inspection and treatment of 2,363 poles and the replacement of approximately 43 poles, 38 crossarms, 78 sets of crossbracing, 41 sets of knee bracing and many other smaller components. Work on TL 203 that carried over into 2018 included the replacement of two poles, two crossarms and one crossbrace. This work was completed on February 1st, 2018.

2 - In 2017, In-Service Failures executed one Interrupter replacement, four Sure Arrestor replacements, one station transformer replacement, 32 transformer protective device replacements, one breaker fail protective circuit upgrade, one mobile transformer refurbishment and one 138 kV Breaker Replacement. Three (3) spare breakers (one 230 kV, one 138 kV and one 69 kV) for the stand-by equipment pool were ordered with delivery on February 15, 2018.

3 -The 2017 scope of work for Install Frequency Monitors - Various Sites was to install frequency monitoring equipment at three sites: Hydro Place Test Room; Bay d'Espoir Terminal Station 2 (Central); and Massey Drive (West). Due to high demands on engineering resources in 2017 resulting in late ordering and delivery of equipment, the construction work was deferred to 2018. Work which was deferred was deemed low risk to the Island Interconnected System and is scheduled to be completed in 2018.

4 - The 2017 scope of work for transformer refurbishments included transformer refurbishments at 16 terminal stations, with work on multiple transformers at seven of these sites. The type of work completed included bushing replacement, oil replacement and/or reclamation, radiator replacement, tap changer overhauls, transformer rust removal and painting, transformer leak assessments, transformer leak repairs, tap changer oil replacement and/or reclamation and the addition of transformer online gas monitors on six transformers at five sites . The planned work at Hinds Lake included removal of rust and painting of Hinds Lake T1, and addition of radiator fans to T1 and T2. This was was not completed in 2017 due to late delivery of parts for the fan addition and internal resource availability for painting. The planned work at Stony Brook included a T2 tap changer overhaul, which was not completed due to unavailability of the tap changer Original Equipment Manufacturer representative. The planned work at Bay d'Espoir included replacement of T1 radiators, which was not completed due to late delivery of the radiators. The removal of rust and painting of transformers T1 at Hawke's Bay and GT1 at Roddickton was not completed due to internal resource availability. Work which was deferred was deemed low risk to the Island Interconnected System and is scheduled to be completed in 2018. Late delivery components have been received and Hydro is construction ready in the unlikely event of a failure.

5 - The 2017 scope of work for Upgrade Circuit Breakers - Various Sites (2016-2020) included the assessment, replacement, or refurbishment of 18 circuit breakers. Sixteen were completed. Two breaker replacements at Bay d'Espoir (B3B4, B5B6) were deferred to 2018 due to the impacts of higher priority work including the integration of TL 267, Labrador-Island Link, and Maritime Link on their timely completion. Work which was deferred was deemed low risk to the Island Interconnected System and is scheduled to be completed in 2018.

6 - The 2017 scope of work for Replace Protective Relays - Various Sites included the Protection Upgrade at eight locations. Four were completed. Review of the overall work plan for 2017 led to recommendations to defer lower priority work in order to achieve success for higher priority work including the integration of TL 267, Labrador-Island Link, and Maritime Link. As a result of this review construction and installation of the protection upgrade for Bay d'Espoir Transformer T6 and Generating unit G6 were deferred. Line protection upgrade for Holyrood 39L was deferred to 2018 to coincide with the replacement of breaker B8L39 that was moved from 2019 to 2018. Holyrood T5 was deferred to 2018 due to lack of construction resources (Internal and Contract) available to perform the work. All materials have been procured and engineering is complete for these scopes of work. The deferral of this work did not pose any risk to the operation of the Island Interconnected System.

7 - The 2017 scope of work for Replace Disconnect Switches - Various Sites included the installation of disconnect switches at 15 locations. 12 were completed. Review of the overall work plan for 2017 led to recommendations to defer lower priority work in order to achieve success for higher priority work including the integration of TL 267, Labrador Island Link, and Maritime Link. As a result of this review construction and installation of the disconnect switches B1B2-1, B3B4-1 at Bay d'Espoir and B1L02-2/L02G at Sunnyside were deferred. All materials have been procured and engineering is complete for these scopes of work. The deferral of this work did not pose any risk to the operation of the Island Interconnected System.

8 - The 2017 scope of work for Upgrade Data Alarm Systems - Various was to upgrade the data alarm systems in Stony Brook. Due to high demands on Protection and Control Resources in 2017, the majority of the construction work for this project has been deferred, with the remainder of the construction work starting in February 2018, with completion by April 2018. The deferral of this work did not pose any risk to the operation of the Island Interconnected System.

9 - The 2017 scope of work for Install Breaker Failure Protection - Various Sites was to complete breaker fail protection at three terminal stations. Due to high demands on Protection and Control Resources in 2017 and outage restrictions , the construction work was partially deferred to 2018. Construction work at Howley and Hinds Lake is substantially complete and requires an outage for final terminations and commissioning, scheduled for September 2018. Work at Indian River is scheduled to start in April 2018 with expected completion by July 2018. The deferral of this work did not pose any risk to the operation of the Island Interconnected System.

10 - The 2017 scope of work for Install Fire Protection in 230kV Stations - Bay d'Espoir included the installation of a clean agent fire detection and suppression system in Terminal Station 2. The entire construction work scope was deferred to 2018 due to dependency on the completion of TL 267 building extension and ventilation modifications. The deferral of this work did not pose any risk to the operation of the Island Interconnected System.

11 - The 2017 scope of work for Replace Instrument Transformers - Various Sites included the replacement of 19 Instrument Transformers in the Island Interconnected System. Fifteen Instrument Transformers were completed as planned in 2017. One Instrument Transformer in Peter's Barren was cancelled as it was previously replaced in 2008 and in good condition, three Instrument Transformers in Oxen Pond were deferred to 2018 due late delivery and ouatge availability. The deferral of this work did not pose any risk to the operation of the Island Interconnected System.

12 - The 2017 scope of work included modification of five transmission line protection relays and two transformer protection relays, telecommunication system modifications, and decommissioning of the 230 kV ac station in Bottom Brook. All work was substantially complete in 2017 and the interconnection to Emera's new stations in Bottom Brook and Granite Canal was commissioned and energized. There were minor deficiencies outstanding on the project, some of which have already been completed in early 2018. These deficiencies do not affect the operation of the new Emera infrastructure.