newfoundland labrador hydro

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April 25, 2023

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

Attention: Cheryl Blundon
Director of Corporate Services and Board Secretary

Re: Transmission System and Terminal Station Asset Management Execution Report

In its correspondence dated October 13, 2016,[1] the Board of Commissioners of Public Utilities ("Board") required Newfoundland and Labrador Hydro ("Hydro") file annual reports on transmission system and terminal station asset management execution, including the status of completion of activities in relation to the annual plan and the following year's plan.

Attached please find Hydro's annual report on transmission system and terminal station asset management ("Report"). The Report includes the completion status of activities in relation to the 2022 annual work plan and information relating to Hydro's 2023 planned activities.

In preparation for this and other filings, Hydro has identified that much of the information provided in this Report is either repetitive and has not changed from year to year, or is duplicative of information already found on the record. Hydro provides information regarding transmission system and terminal station asset management execution within its Capital Budget Application ("CBA"), including but not limited to the Five-Year Capital Plan, Asset Management Overview and specific program proposals and the Wood Pole Line Management.[2] Hydro also reports on variances with terminal station projects in its annual CBA,[3] as well as its Capital Expenditures and Carryover Report.[4]

The annual work plan completion information provided in the Report, is also duplicated elsewhere in other routine filings. For example, the Winter Readiness Report filed in the fourth quarter of each year provides status on the completion of annual work plan items to mid-December of the applicable year. Further, results for the full calendar year of annual work plan activities are provided in the Quarterly Regulatory Report for the Quarter Ended December 31.[5]

Hydro believes that the information provided in other routine filings, including but not limited to the Capital Budget Application, Winter Readiness Report and Quarter Regulatory Report, give substantive visibility to the Board regarding Hydro's transmission system and terminal station asset management

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[1] Board of Commissioners of Public Utilities, "Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Directions further to the Board's Phase One Report," letter, October 13, 2016.
[2] Includes a summary of the work completed under the Wood Pole Line Management Program in the prior year.
[3] "2023 Capital Budget Application," Newfoundland and Labrador Hydro, July 13, 2022, vol. I, sch. 4, sec. 1.4.
[4] "Capital Expenditures and Carryover Report for the Period Ended December 31, 2022," Newfoundland and Labrador Hydro, March 31, 2023, sec. 4.4 and sec. 9.0.
[5] "Quarterly Regulatory Report for the Quarter Ended December 31, 2022," Newfoundland and Labrador Hydro, February 15, 2023, tab 1, sec. 6.3.

execution and provide the Board with the opportunity to review and ask questions on both the status and the execution of the work. In the interest of regulatory efficiency and reducing duplication of information already found on the record, Hydro respectfully requests that the Board consider the discontinuation of the Report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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

Encl.

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Board of Commissioners of Public Utilities
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Dean A. Porter, Poole Althouse

Transmission System and Terminal Station Asset Management Execution Report

April 25, 2023

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 requested that Newfoundland and Labrador Hydro ("Hydro") provide an annual report on Hydro's transmission system and terminal station asset management execution, including the status of the completion of activities in relation to the Annual Work Plan ("AWP") and information relating to the current year's planned activities.[1]

Transmission system and terminal station assets provide the means by which generated electricity is delivered to high-voltage customers and the distribution system that serves the remaining customers. Hydro maintains 4,432 km of transmission lines and 69 terminal stations for the Island and Labrador Interconnected Systems, composed of numerous types of assets. Through the application of asset management activities during the life cycle of these assets, Hydro's asset management personnel utilize a balanced approach to maintain the reliability of the electrical system while managing costs. Hydro's asset management activities include:

- Refurbishment or replacement of existing assets as required;
- Execution of preventative maintenance ("PM") and corrective maintenance ("CM") activities to support reliable operations;
- Asset assessments to monitor asset health; and
- Installation of new assets to support system growth.

These activities are conducted within an asset management system by personnel in the Long-Term Asset Planning ("LTAP"), Short-Term Planning and Scheduling, and Work Execution functions within Hydro.

This report provides:

- Background on transmission system and terminal station equipment and asset management practices;
- Completion status of 2022 AWP maintenance activities and capital transmission system and terminal station projects; and

[1] Board of Commissioners of Public Utilities, "Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Directions further to the Board's Phase One Report," letter, October 13, 2016.

- Planned 2023 AWP maintenance activities and capital transmission and terminal station projects.

Hydro has developed its 2023 AWP in consideration of the lessons learned during the COVID-19 pandemic and continues to closely monitor supply chain and execution risk.

2.0 Terminal Stations Asset Management

Hydro has 69 terminal stations on the Island and Labrador Interconnected Systems, with some having assets dating back to the late 1960s. 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. They act as transition points within the transmission system and interface points with the lower voltage distribution and generation systems.

Appendix A outlines Hydro's PM program for the various major asset classes within terminal stations.

Attachment 1 provides information regarding Hydro's asset management philosophies and replacement and refurbishment criteria. This overview document is updated as required to reflect changes to Hydro's asset management approach as it evolves and improves.

2.1 Asset Criticality and Spares

Hydro has developed a terminal station asset criticality ranking for selected asset classes based on factors such as available mitigation (e.g., parallel transformers), environmental impact, customer impact, likelihood of breakdown, and cost of repairs. This is considered in prioritizing maintenance and capital work. Hydro uses these factors as well as other equipment-specific factors to establish asset criticality rankings for power transformers, circuit breakers, battery banks and chargers, and disconnect switches. In 2022, Hydro developed asset criticality rankings for terminal stations as a whole. In 2023, Hydro will develop asset criticality rankings for instrument transformers.

In 2023, Hydro plans to continue and complete the procurement of spares for Wabush Terminal Station synchronous condensers and spare power transformer bushings. Hydro reviews its spare terminal station equipment on a routine basis and establishes plans to achieve the appropriate level of spares based on the outcome of those reviews.

3.0 Transmission Line Asset Management

Hydro owns approximately 648 km of 69 kV, 1,538 km of 138 kV, and 2,246 km of 230 kV transmission lines as part of the Island and Labrador Interconnected Systems, for a total line length of approximately 4,432 km. Hydro also owns approximately 30 km of 46 kV sub-transmission lines in Labrador West.

Hydro's 69 kV class lines are of wood pole construction and the 138 kV class lines are primarily comprised of wood pole and aluminum lattice structures. The 230 kV class lines are a combination of wood pole and steel lattice construction. Over half of these assets were constructed in the 1960s and early 1970s.

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, allowing for the transmission of electricity across the bulk electrical system. A transmission line consists of structures, conductors, insulators, grounding system, and rights-of-way.

The primary subcomponents of a steel structure are the legs, cross members, and grillage foundations, which are typically fabricated from structural angle steel. These subcomponents are hot-dip galvanized to ensure extended life. A typical lattice steel structure can last in excess of 70 years.

The primary subcomponents of a wood pole structure are the poles, crossarms, and cross braces. These subcomponents are treated with preservatives to ensure extended life. A typical treated wood pole can last in excess of 60 years. Typically, treated crossarms and cross braces can last in excess of 30 years.

3.1 Wood Pole and Steel Structure Line Management Programs

Wood Pole and Steel Structure Line 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 inspections of conductors, guying, and foundations. LTAP personnel establish condition-based assessments to identify and prioritize capital work and CM activities 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 respective line management programs, separate capital projects are placed into the long-term plan for line upgrades. On April 21, 2023, Hydro filed its Wood Pole Line Management ("WPLM") progress report,[2] following two complete inspection cycles. This report demonstrates that Hydro's WPLM Program has been successful in improving the reliability of Hydro's wood-pole transmission assets, while achieving cost savings. Hydro intends to continue this program going forward.

3.2 Helicopter Patrols

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

3.3 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 which 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.

3.4 Infrared Inspections

As required, Hydro completes infrared scanning of connections on dead end structures on all transmission lines. Any deficiencies are documented and scheduled for corrective work.

3.5 Wood Pole Treatment

Preservative treatment is added to the poles to extend their service life through the WPLM Program.

3.6 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,

[2] "Wood Pole Line Management Program – Progress Report (2018–2022)," Newfoundland and Labrador Hydro, April 21, 2023.

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 rights-of-way. Hydro performs vegetation control on approximately 10% of its rights-of-way per year with approximately 60% of the annual program involving vegetation cutting and the remaining 40% of the vegetation sprayed with herbicide.

3.7 Asset Criticality and Spares

Hydro has developed a transmission line asset criticality ranking based on the health of asset, available mitigation (e.g., backup generation), environmental impact, customer impact, likelihood of breakdown, and cost of repairs. These factors 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 these reviews, action is taken or plans are established to achieve appropriate levels of spares.

4.0 Status of Planned 2022 Transmission System and Terminal Station Activities

The year-end 2022 completion status of the AWP and Winter Readiness ("WR") activities for transmission system and terminal station facilities on the Island and Labrador Interconnected System is summarized in the following sections.

4.1 Transmission System

As shown in Figure 1 to Figure 4, Hydro completed 98% and 100% of its 2022 Island and Labrador Transmission AWPs respectively, and 100% of planned transmission WR activities.

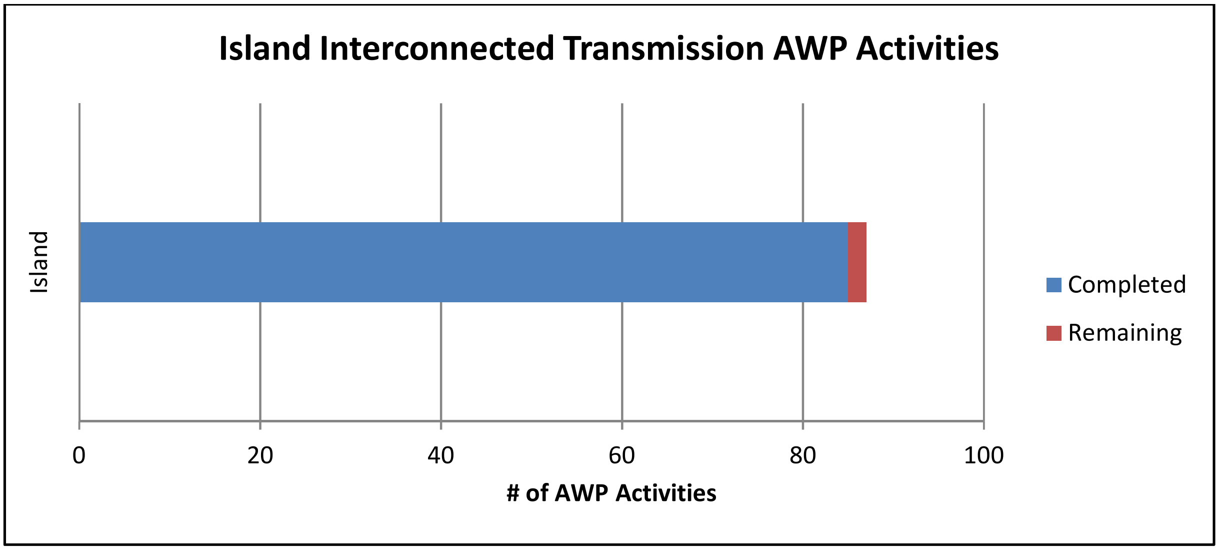

Figure 1: 2022 Transmission System AWP Activities for the Island Interconnected System (December 31, 2022)

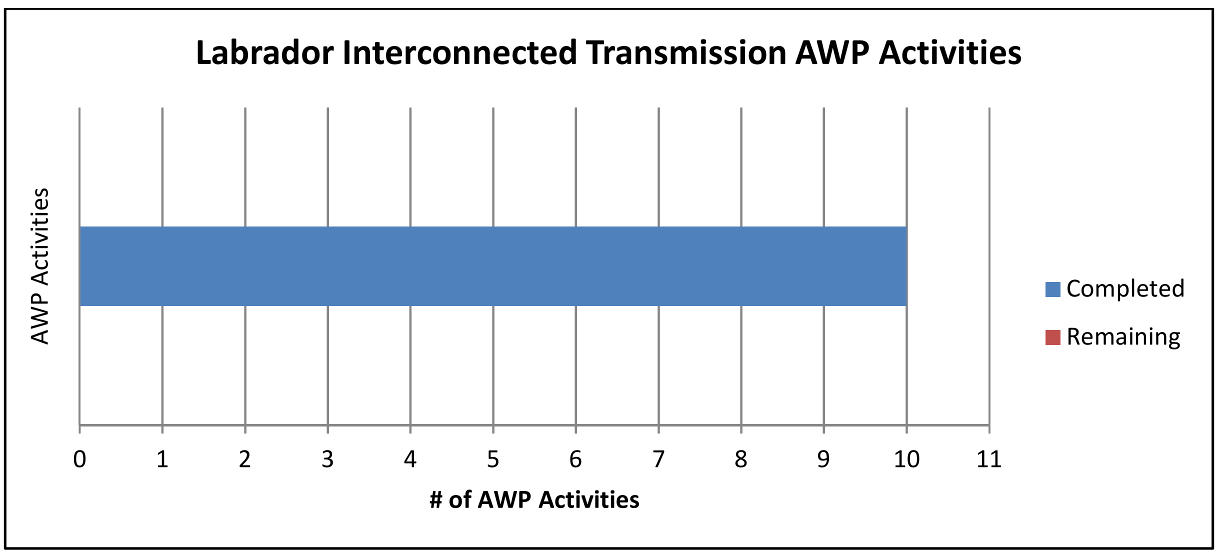

Figure 2: 2022 Transmission System AWP Activities for the Labrador Interconnected System (December 31, 2022)

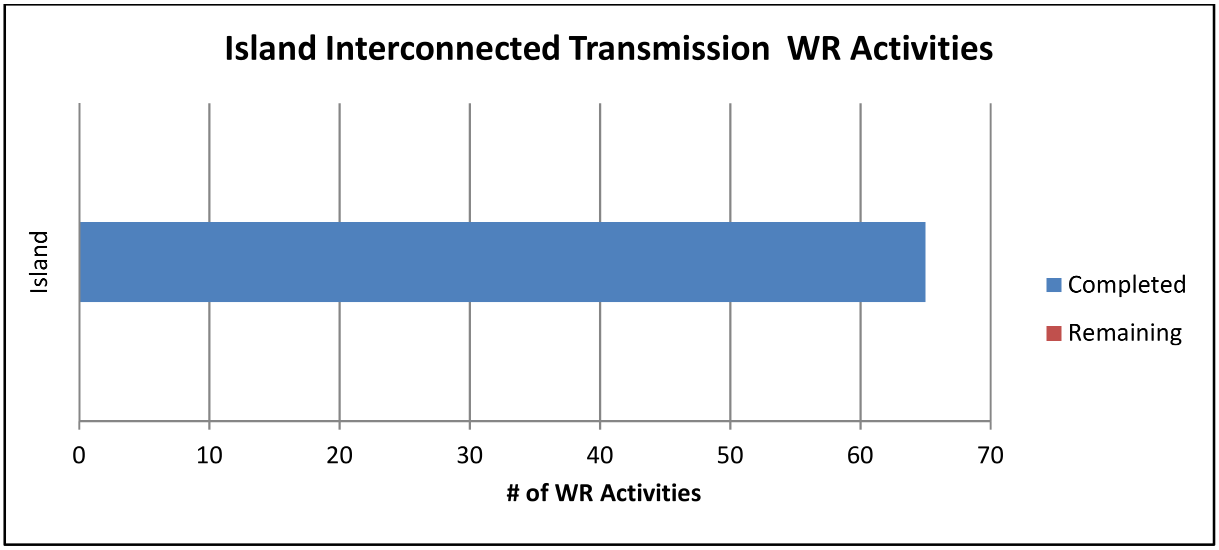

Figure 3: 2022 Transmission System WR Activities for the Island Interconnected System (December 31, 2022)

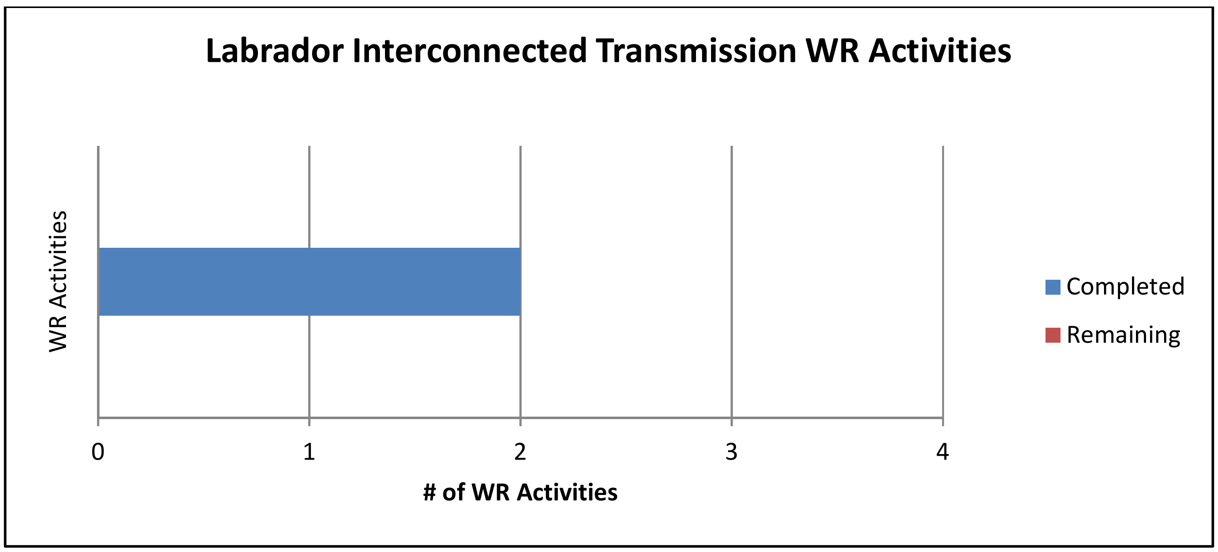

Figure 4: 2022 Transmission System WR Activities for the Labrador Interconnected System (December 31, 2022)

The following is a summary of the transmission system activities completed in 2022:

- Commenced construction of new Transmission Line TL271 between Star Lake Terminal Station and Marathon Gold's proposed new Valentine Terminal Station.
- Replaced TL219 structures #392, #393, #394, and #395 as a result of damage from the February 2022 ice storm.

- Repaired TL203 structure #77 as a result of damage from the February 2022 ice storm.
- Replaced TL215 failed structures #24 and #160 as a result of broken guy wire attachments.
- Replaced TL215 guy hook and eyebolt attachments on 24 structures with robust tee-plate arrangements.
- Completion of the following WPLM inspections and refurbishments; and
    - Inspection on TL201, TL210, TL221, TL233, TL234, TL239, TL259 and TL260; and
    - Refurbishment on L1303, TL201, TL210, TL215, TL219, TL222, TL232, TL239, TL241, TL250, TL251 and TL259.
- Completion of Steel Line Inspection Program inspections, as referenced in Table 1.

Table 1: 2022 Steel Line Climbing/Ground Inspections Completed

Line #	Climbing Inspection (Structures)	Ground Patrol (Structures)
TL202	157-172, 263-280	69-102, 247-282
TL204	91-101, 248-264	23-44, 174-204
TL205	189-208	84-125
TL206	157-172, 271-287	69-102, 250-287
TL207	1-15	1-30
TL208	1-25	1-46
TL211	127-140	56-83
TL212	74-147	74-147
TL214	229-274, 275-355	111-166
TL217	51-75	104-155
TL228	127-144, 226-233	75-112, 189-219
TL231	33-43, 266-278	64-84, 176-210
TL236	53-56	1-56
TL237	91-108	73-108
TL242	29-35	29-42
TL247	298-334, 417-430	225-299, 372-410
TL248	148-166	76-112
TL265	21-25	N/A
TL268	21-25	N/A
L23	34-44, 67-77, 85-98, 227-240, 370-383	
L24	34-44, 67-77, 85-98, 227-240, 370-383	

4.2 Terminal Stations

As shown in Figure 5 to Figure 8, Hydro completed 96% and 100% of its planned 2022 terminal station Island Interconnected System and Labrador Interconnected System AWPs respectively, and 100% of its planned 2022 terminal station WR activities as of December 31, 2022. The incomplete activities were assessed and mitigated to ensure there was no significant risk to reliable operation for the winter season.

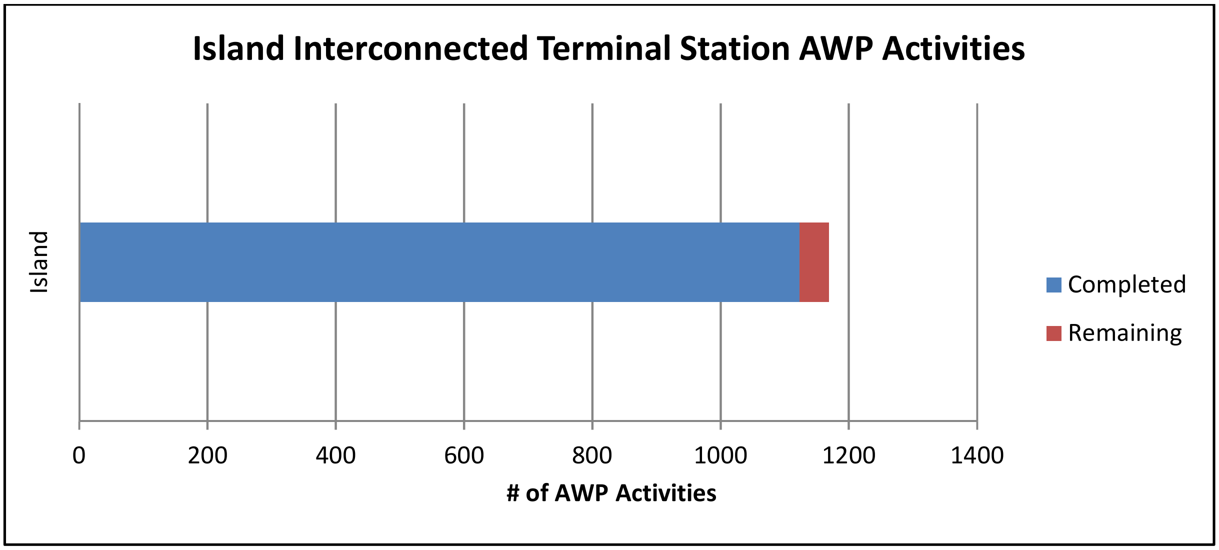

Figure 5: 2022 Terminal Station AWP Activities for the Island Interconnected System (December 31, 2022)

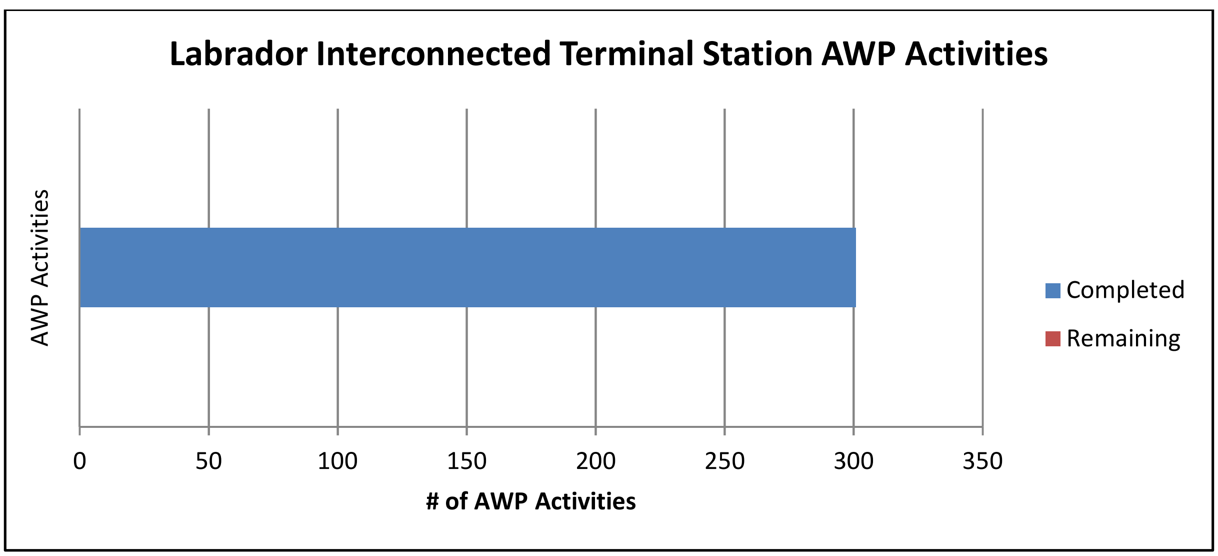

Figure 6: 2022 Terminal Station AWP Activities for the Labrador Interconnected System (December 31, 2022)

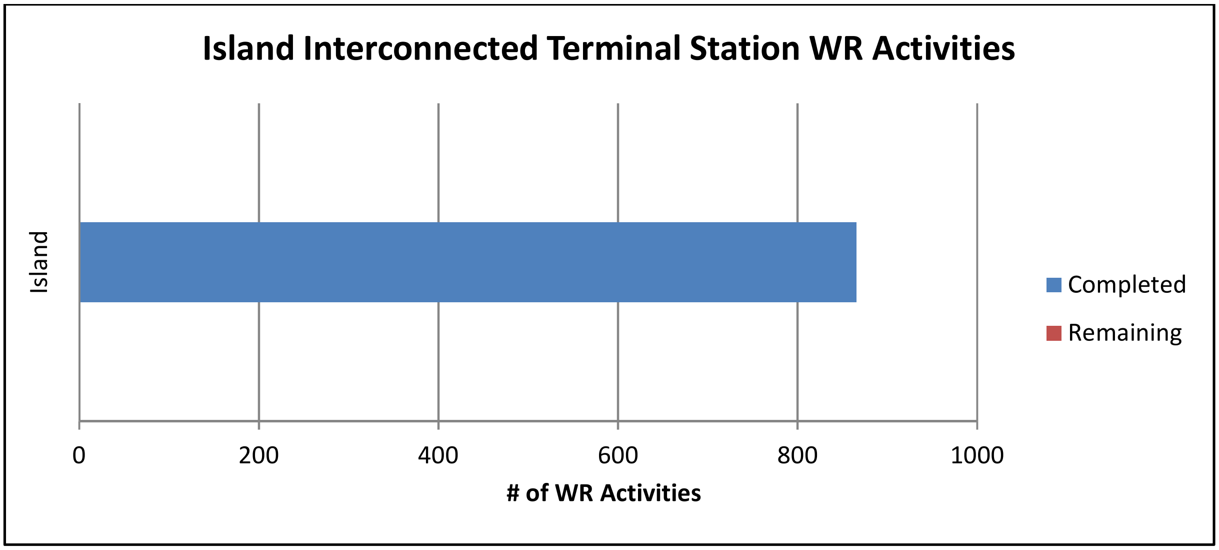

Figure 7: 2022 Terminal Station WR Activities for the Island Interconnected System (December 31, 2022)

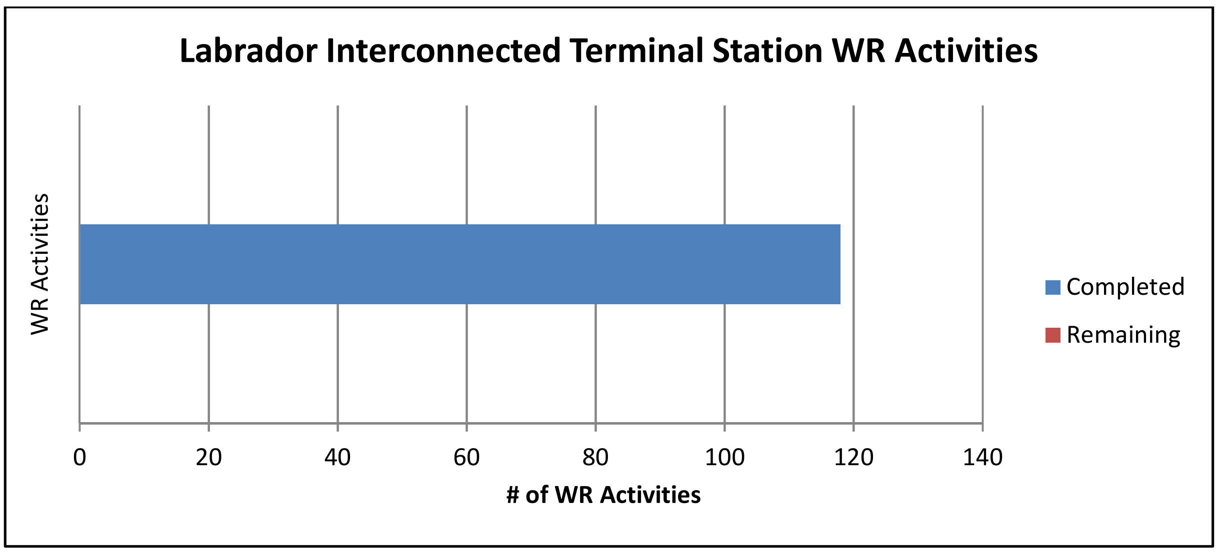

Figure 8: 2022 Terminal Station WR Activities for the Labrador Interconnected System (December 31, 2022)

The following is a summary of the terminal station activities completed in 2022:

- Completed 40 six-year breaker PM procedures;
- Operated all 69 kV and above circuit breakers once throughout the year;
- Completed 16 trip from protection breaker maintenance procedures;

- Completed 24 six-year power transformer maintenance procedures and 26 six-year power transformer Doble maintenance procedures;
- Completed Oil Quality and Dissolved Gas Analysis Program for power transformers and tap changers;
- Completed 102 disconnect switch PM procedures;
- Completed six-year protection and control maintenance procedures at six stations;
- Completed 73 six-year instrument transformer maintenance procedures;
- Completed 70 six-year instrument transformer Doble maintenance procedures;
- Completed infrared scans at all terminal stations;
- Completed annual battery maintenance at all terminal stations;
- Replaced two battery banks;
- Replaced eight circuit breakers;
- Refurbished five circuit breakers;
- Power Transformers: completed two oil refurbishments, two radiator replacements, and 31 bushing replacements on seven transformers; installed seven online gas monitors and one online oil dehydrator;
- Replaced five surge arrestors;
- Replaced 13 disconnect switches;
- Replaced eight instrument transformers;
- Replaced one data alarm system;
- Replaced protective relays for five transmission line protection schemes, three transformer protection schemes, and two bus protection schemes; and
- Installed/upgraded seven breaker failure protection schemes.

4.3 Status of 2022 Terminal Station and Transmission Line Capital Projects

Appendix B identifies the capital projects that included planned construction completion in 2022 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 2022

Asset Category	Complete	Partially Complete/ Deferred	Incomplete	Total
Transmission Lines	3	2	-	5
Terminal Stations	6	4	3	13
Total	**9**	**6**	**3**	**18**

Where elements of work in the transmission lines and terminal station asset categories have been deferred to 2023, Hydro assessed the risk and determined that these deferred activities would not significantly impact the reliability of the Island and Labrador Interconnected Systems for winter 2022–2023. Further project details are provided in Appendix B.

5.0 Planned 2023 Transmission System and Terminal Station Activities

Hydro has established its AWP scope of work for 2023, including identification of WR activities. The charts below provide an overview of work progress and a summary of key activities is also provided for each area.

5.1 Transmission System

As shown in Figure 9 to Figure 12, Hydro has completed approximately 47% of its planned 2023 transmission system AWP activities and approximately 46% of its 2023 WR activities for the Island Interconnected System as of April 8, 2023. For the Labrador Interconnected System, 50% of AWP and WR activities are complete as of April 8, 2023.

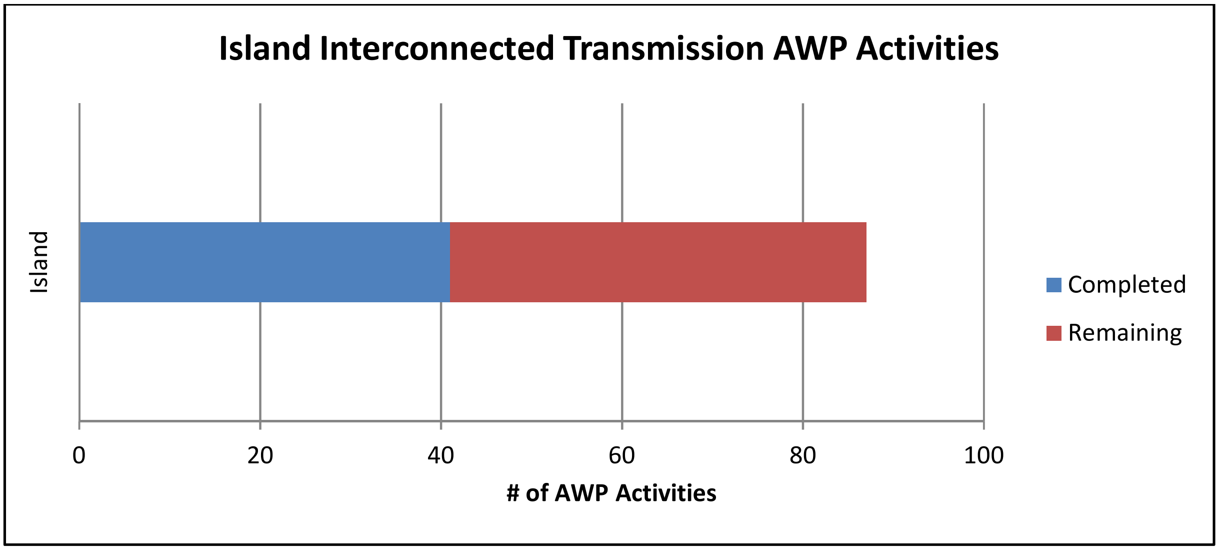

Figure 9: 2023 Transmission System AWP Activities for the Island Interconnected System (April 8, 2023)

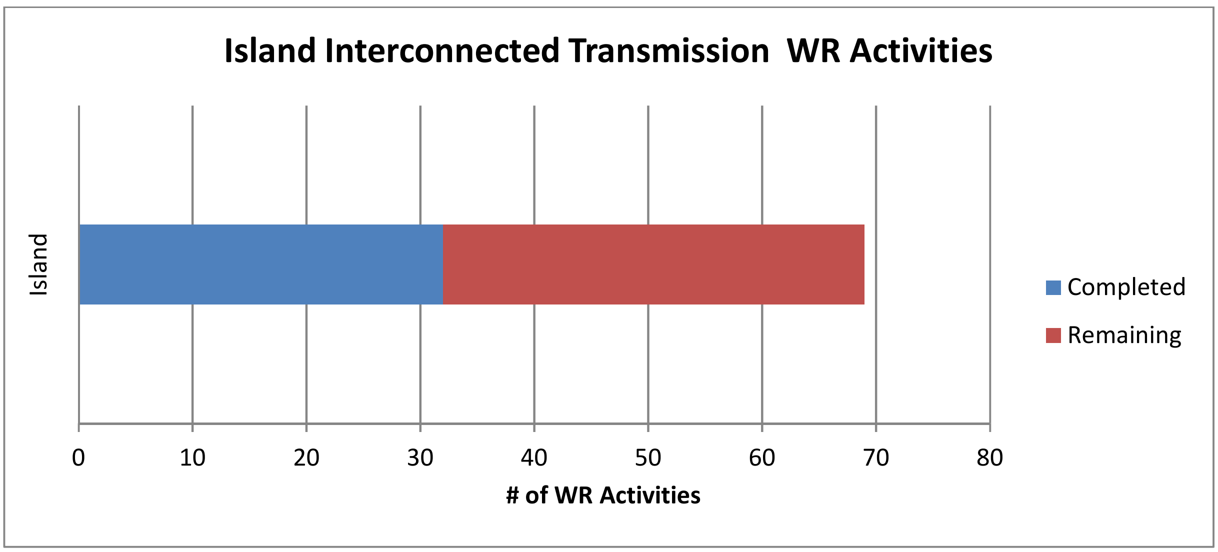

Figure 10: 2023 Transmission System WR Activities for the Island Interconnected System (April 8, 2023)

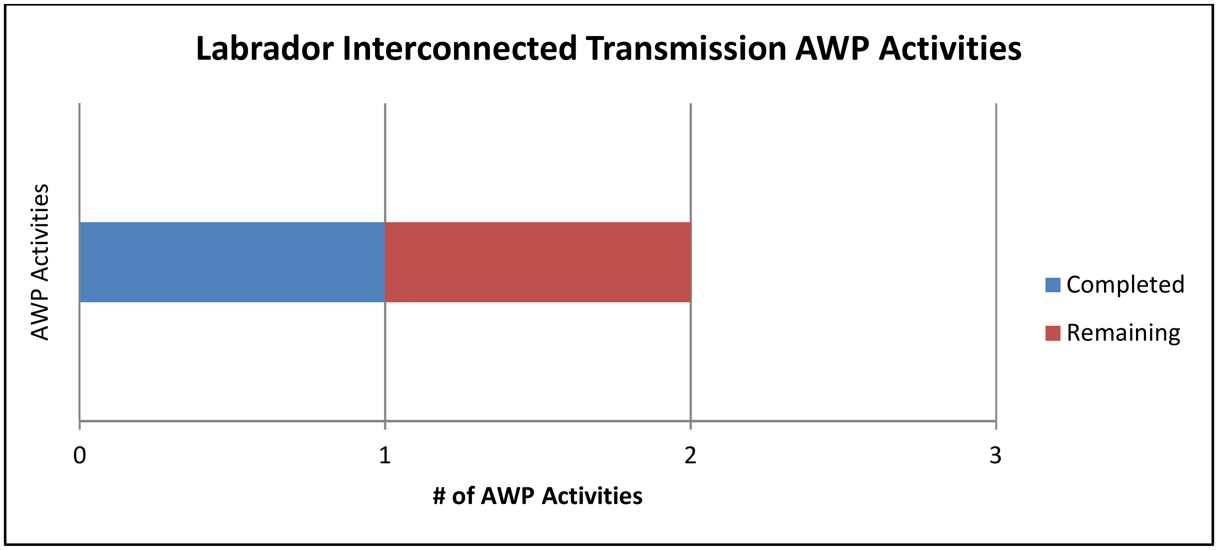

Figure 11: 2023 Transmission System AWP Activities for the Labrador Interconnected System (April 8, 2023)

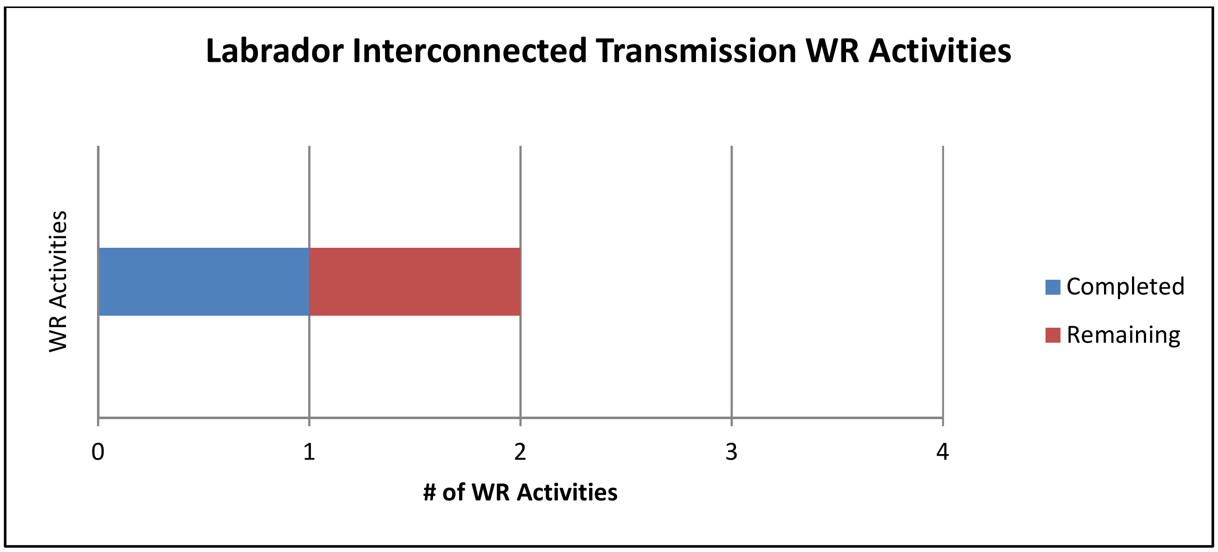

Figure 12: 2023 Transmission System WR Activities for the Labrador Interconnected System (April 8, 2023)

The following is a summary of the transmission system work plan activities scheduled for 2023:

- Continue decommissioning of Transmission Line L1301, Churchill Falls to Muskrat Falls;
- Complete construction of Transmission Line TL271, Star Lake Terminal Station to Marathon Gold's Valentine Terminal Station;
- Transmission line in-service failure related work;

- Transmission Line TL215 upgrade guying attachments on 46 structures;
- WPLM inspections and refurbishments:
    - Inspect: L1303, TL212, TL214, TL221, TL222, TL226, TL227, TL234, and TL245; and
    - Refurbish: TL201, TL209, TL210, TL215, TL219, TL222, TL233, TL234, TL241, TL259 and TL260; and
- Steel Line Inspection Program inspections, as referenced in Table 3.

Table 3: 2023 Steel Line Climbing/Ground Inspections

Line #	Climbing Inspection (Structures)	Ground Patrol (Structures)
TL202	1-17, 281-298	103-136, 283-319
TL204	1-10, 102-117	45-66, 142-173
TL205	1-20	126-167
TL206	1-17, 288-308	103-136, 288-325
TL207	16-30	1-30
TL208	26-46	1-46
TL211	1-13	84-111
TL212	1-73	1-73
TL214	184-228, 275-355	167-222
TL217	76-100	156-207
TL228	145-162, 234-243	113-150, 220-249
TL231	1-10, 106-126	43-63, 141-175
TL236	1-12	1-58
TL237	109-126	109-144
TL242	1-8	46-60
TL247	335-371, 403-416	150-224, 411-445
TL248	167-185	113-150
TL265	31-40	1-50
TL268	32-41	1-52
L23	99-112, 241-254, 384-397, 513-526, 537-540	
L24	99-112, 241-254, 384-397, 513-526, 537-540	

5.2 Terminal Stations

As shown in Figure 13 and Figure 14, Hydro has completed approximately 22% of its planned 2023 terminal station AWP activities and approximately 26% of its 2023 WR activities for the Island Interconnected System as of April 8, 2023. As shown in Figure 15 and Figure 16, Hydro has completed approximately 19% of its planned 2023 terminal station AWP activities and approximately 17% of its 2023 WR activities for the Labrador Interconnected System as of April 8, 2023.

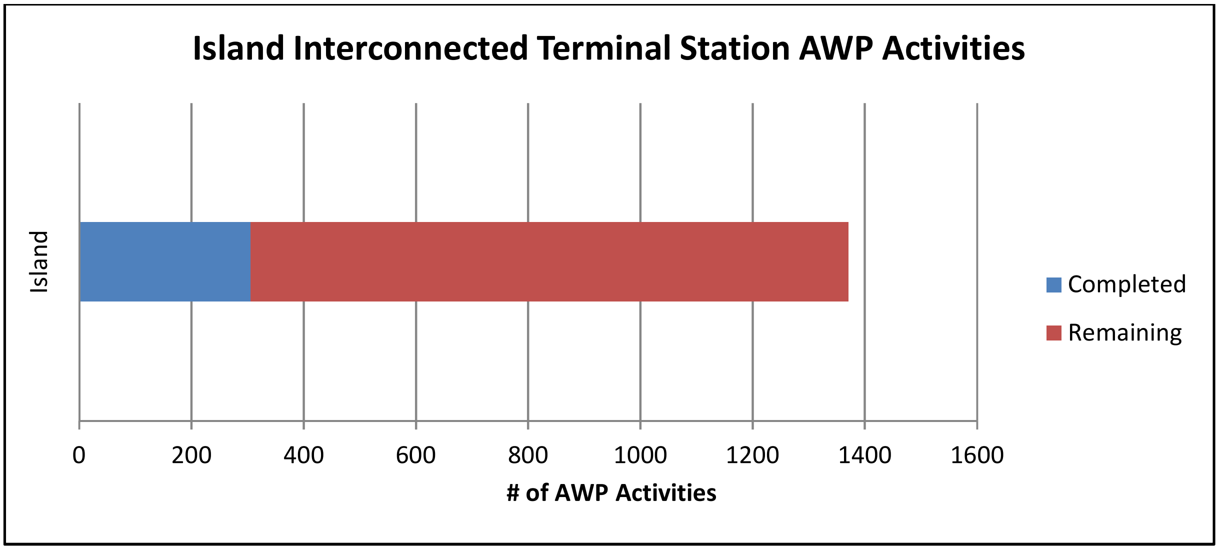

Figure 13: 2023 Terminal Station AWP Activities for the Island Interconnected System (April 8, 2023)

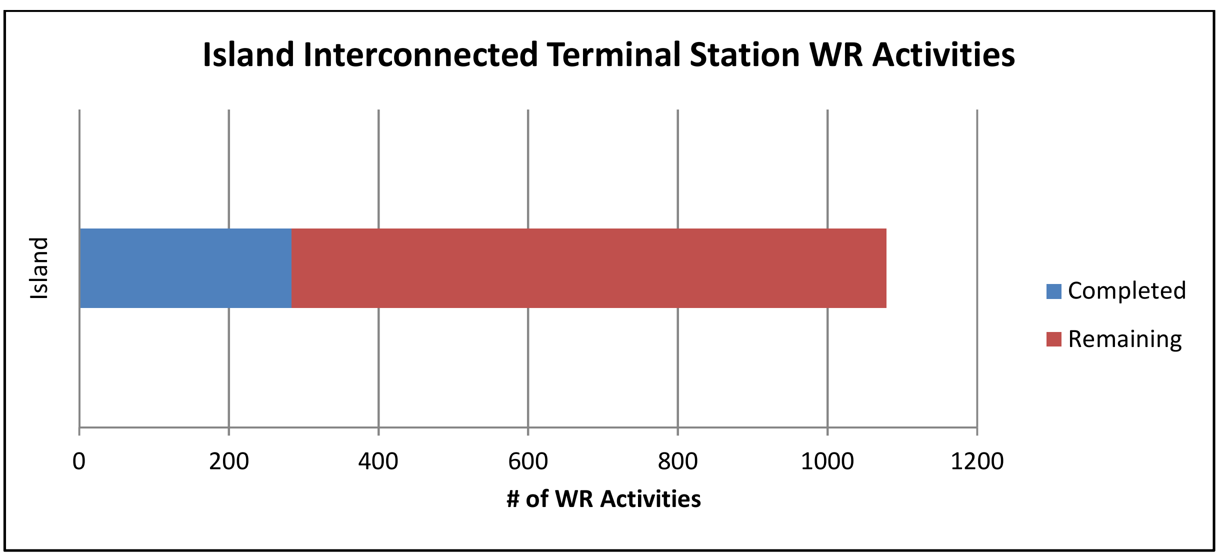

Figure 14: 2023 Terminal Station WR Activities for the Island Interconnected System (April 8, 2023)

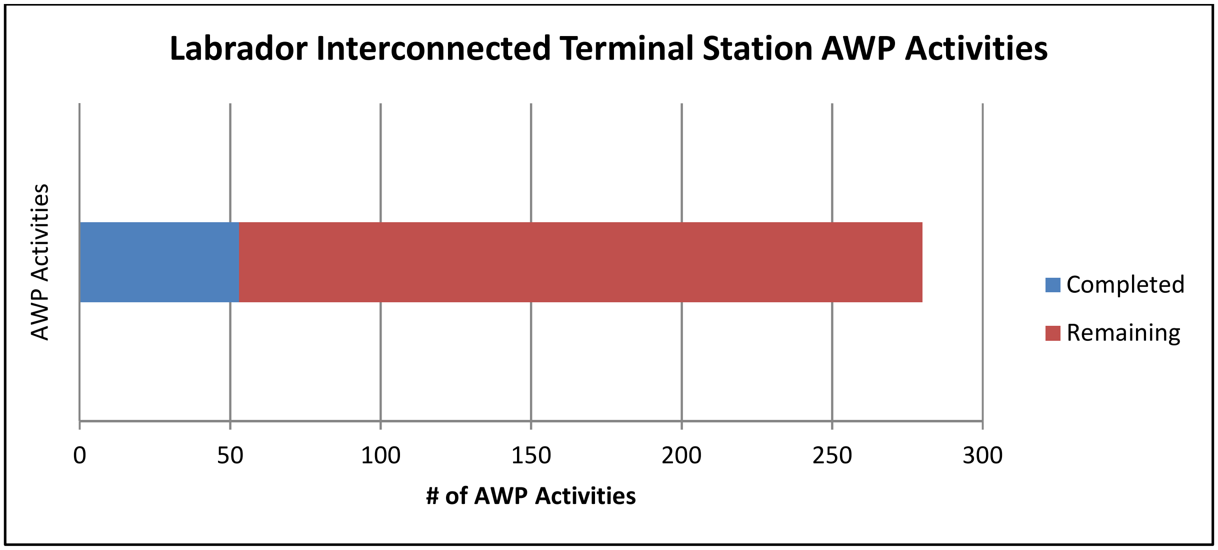

Figure 15: 2023 Terminal Station AWP Activities for the Labrador Interconnected System (April 8, 2023)

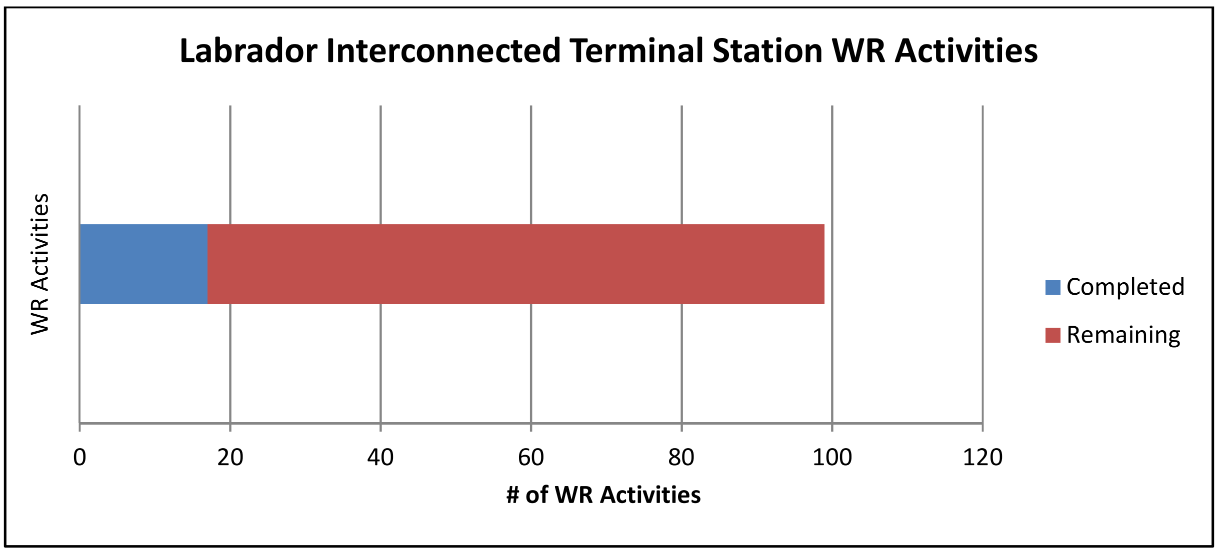

Figure 16: 2023 Terminal Station WR Activities for the Labrador Interconnected System (April 8, 2023)

The following is a summary of the terminal station work plan activities scheduled for 2023:

- Complete 31 six-year breaker maintenance procedures;
- Replace ten breakers, two of which are air blast circuit breakers;
- Refurbish six breakers;
- Operate all 69 kV and above breakers once;

- Complete 12 trip from protection breaker maintenance procedures;
- Complete 37 six-year power transformer maintenance procedures and 36 six-year power transformer Doble maintenance procedures;
- Complete Oil Quality and Dissolved Gas Analysis Program for power transformers and tap changers;
- For power transformers, complete: three oil refurbishments, one radiator replacement, 39 bushing replacements on eight transformers, refurbish four on-load tap changer, and install one online oil dehydrator and five online gas monitors;
- Install three power transformers;
- Complete annual maintenance on all terminal station battery banks;
- Replace one battery bank and one battery charger;
- Complete PM activities on 103 disconnect switches;
- Replace eight disconnect switches;
- Replace eight instrument transformers;
- Install one capacitor bank;
- Replace protective relays for three transmission lines and seven power transformers;
- Install/upgrade one breaker failure protection scheme;
- Upgrade two breaker reclosing protection schemes;
- Install one digital fault recorder;
- Complete 46 six-year protection and control maintenance procedures;
- Complete 100 six-year instrument transformer maintenance procedures;
- Complete 104 six-year instrument transformer Doble maintenance procedures;
- Install one control building;
- Install fire protection in one terminal station;
- Replace lighting in three terminal stations;

- Perform one synchronous condenser major inspection; and
- Complete infrared scans at all terminal stations.

Appendix A

Details of Terminal Station Preventive Maintenance Activities

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Introduction

The following outlines Hydro's PM criteria for the various major asset classes within terminal stations.

Power Transformers and Shunt Reactors

- 120-day PM: cooling fan function testing, operational data collection, and visual inspection;
- Oil Sample PM (one year by default, more frequently as needed): dissolved gas analysis, oil quality, and moisture;
- Furan PM (four years by default, one year as needed): to test the degree of polymerization ("DP") of the paper;
- Six-year PM: 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; and
- Hydro's current replacement criteria for power transformer replacement (46 kV and above) is based upon one of the following:
  - Condition based upon DP <400 for network transformers and <500 for generator step-up transformers in Asset Criticality A;
  - Uncontrollable gassing which is an indication of an internal fault; or
  - Requirement for major refurbishment in the near term (to maintain/restore reliability) but replacement is a lower-cost alternative.

Circuit Breakers

- 120-day PM: visual inspection, check pressures for air and/or SF_6, record heater amps;
- Annual: operate breaker PM is completed to confirm operation once per year;
- Oil sample from oil circuit breakers 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 SF_6 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; and
- Every six years the following is completed for oil circuit breakers: 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 D877 of the oil; perform megger of each phase to ground with breaker; and perform doctor and timing.

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: 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; and
- Every six years function test 230 kV circuit breakers from the protection during the scheduled 230 kV breaker PM.

Current Transformers

- On 120-day general inspection, the following is checked: bushings; tanks; oil leaks; rust/paint condition; concrete base; primary connections; conduits; cabinets; and grounding; and
- Every six years the following is completed:
    - Wiring connections checked;

- Secondary connections checked;
- Heater amperage checked;
- Touch-up painting done, as required; and
- Doble test performed.

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; installed heater amperages; conduits; cabinets; voltages at each secondary winding; and grounding; and
- Every six years the following is completed:
  - Connections for position and tightness checked;
  - Grounding device checked;
  - Coupler box internally inspected;
  - Gaskets and gap clearances checked;
  - Heater amperage checked;
  - Touch-up painting, as required;
  - Perform Doble test;
  - Surge protection device in capacitor voltage transformer junction box checked/tested, if fitted for wave-trap;
  - Ground switches cleaned and lubricated; and
  - Surge gap checked.

Surge Arresters

- 120-day power transformer inspection, a visual inspection is performed; and
- Every six years, a visual inspection and a Doble test are performed.

Disconnect Switches

- 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	One-week
3	20°C to 50°C	One-month
4	Below 20°C	One-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 disconnect switches the motor operation is checked and if load break, interrupter modules are checked.

Batteries and Chargers

- 120-day inspection includes: voltmeter checks; ammeter checks; alarm function testing; and visually checking battery condition as well as electrolyte levels for flooded cells. Distilled water may be added to flooded cells and completion of equalize charge procedure if required;
- Batteries and chargers are inspected and cleaned annually. During this inspection a conductance test is performed on all the cells and straps with a Midtronics battery tester. For flooded cells the specific gravity is also checked on all cells; and
- 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. Criticality A and B VRLA[1] banks are discharge tested every two years.

[1] Valve-regulated lead acid ("VRLA").

Air Systems

- Compressor annual PM: change deteriorated disposable parts; cleaning; record operational data; performance testing; protective device function testing, and visual inspection;
- Monthly air system PM: cleaning; record operational data; performance testing; protective device function testing; and visual inspection; and
- 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.

Grounding

- 120-day PM: visual inspection; and
- Grounding is upgraded as a result of visual inspections and grounding analysis completed in accordance with IEEE[2] 80-2013.

Capacitor Banks

- 120-day PM: record operational data, blown fuse replacement, and visual inspection; and
- Six-year PM: record operational data, electrical testing (capacitance, insulation resistance), blown fuse replacement, cleaning, and visual inspection.

Synchronous Condensers

- Minor inspections, performed on year one and year two of a three-year cycle, include:
    - Check/monitor operating parameters (bearing temperatures, vibration, etc.) prior to unit coming offline and after inspection (prior to being released back to service);
    - Drain oil system and sumps. Inspect oil sump, replace filters and refill. Run oil through filter press when refilling. Repair and/or report any issues. Replace any required gaskets;

[2] Institute of Electrical and Electronic Engineers (“IEEE”).

- Remove and visually inspect outer end covers and inner baffles including mounting hardware. Repair or note any issues;
- Take oil samples before and after oil filtering;
- Remove the bearing pedestal cap and top half of the bearing. Inspect and check clearance and cap pinch;
- Inspect piping connections, oil fittings, oil flinger rings, bearing cap, upper half of the bearings;
- Inspection of the fan blades and shrouds;
- Check high pressure lift system. Take shaft lift measurements at start and after inspection before returning unit to service and check oil filters. Replace filters if required;
- Verify speed sensor clearance by rotating unit by hand before returning to service;
- Replace intake air filters;
- Complete electrical tests on stator, rotor, and bearing pedestals including insulation resistance, polarization index and rotor field pole voltage drop;
- Visually inspect rotor V-blocks, pole windings and collars;
- Inspection of damper winding ring assembly for signs of movement, bolts loosening, or copper cracking;
- Tap-test stator wedges;
- Inspect surge caps and lightning arrestors;
- Inspect slip rings. Disassemble brush rigging and inspect and cleaning. Install new brushes, as required;
- Complete general cleaning and maintenance of components;
- Perform any required maintenance items identified for follow up on previous inspection; and
- Reassemble unit, test-run and complete vibration and other operational checks.

- Major inspections, performed on year three of a three-year cycle, include:
  - Complete items performed as part of the scope of the minor inspection;

- Pull rotor and inspect the rotor and stator (further details below);
- Remove bottom halves of bearings and complete set of checks;
- Clean inside bearing pedestals;
- Replace thrust bearing and install new seals/gaskets; and
- Drain oil from reservoir and check screens, replace if required.

Stator and rotor inspections, performed as part of the scope of the major inspections, include the following checks, as well as any additional items identified for follow up on previous inspections:

- Stator:
  - Complete a thorough inspection of stator including windings, frame, end covers, etc. Tap-test stator wedges;
  - Inspect frame hold down bolts, soleplates, grout and dowels for looseness or evidence of movement;
  - Check oil coolers for mechanical damage to tubes, corrosion and leakage;
  - Check for any evidence of fretting on stator frame;
  - Visually inspect stator core for damage and looseness to laminations, dirt, oil, foreign obstacles, overheating and corona activity. Note findings and clean stator as required; and
  - Clean stator core.
- Rotor:
  - Check rotor V-blocks, coil braces and coil tightness. Check for damage and erosion;
  - Check rotor field poles for insulation fretting and migration;
  - Check rotor field coils for damage and signs of overheating;
  - Check damper bars and resistance rings for damage and tightness;
  - Clean rotor; and
  - Check for looseness, vibration, or movement of assembling hardware. Check for improper locking or peening of locking devices.

Appendix B

2022 Terminal Station and Transmission Line Project Status

Table B-1: Terminal Station Projects

Project Description	Status of 2022 Planned Construction Completion
In-Service Failures – Various Sites	Complete (See Note 1)
Replace Transformer T7 – Holyrood (CO23)[1]	(See Note 2)
Refurbish 230 kV Wabush Terminal Station (MY23)[2]	(See Note 3)
Upgrade Circuit Breakers (CO23) – Various	(See Note 4)
Upgrade Circuit Breakers (MY23) – Various	(See Note 15)
Additions for Load – Wabush Substation (MY23)	Complete
Replace Transformer T2 – Holyrood Generating Station	Complete
Wabush L34/L35 Line Protection Upgrades	Complete (See Note 5)
Upgrades for Future Retirement of Stephenville Gas Turbine (MY23)	(See Note 6)
Terminal Station Refurbishment and Modernization Various Sites (Multi-Year 2020)	
• Replace Protective Relays	Complete (See Note 7)
• Upgrade 230kV Terminal Station – Wabush	Complete
• Upgrade Data Alarm Systems – Holyrood	Complete
• Upgrade Reclosing Circuit Breakers – Holyrood	Complete
Terminal Station Refurbishment and Modernization Various Sites (Multi-Year 2021)	
• Refurbish and Upgrade Power Transformers	Complete
• Install Fire Protection in 230kV Stations – Stony Brook	Complete
• Replace Instrument Transformers	Complete
• Upgrade Breaker Failure Protection	Complete
• Install Fault Recorders – Happy Valley	Complete
• Upgrade 230kV Terminal Station Part 2 – Wabush	Complete (See Note 5)
• Upgrade Data Alarm Systems – Massey Drive	Complete
• Replace Disconnects	Complete
• Insulator Replacement – Various Sites	Complete
• Upgrade Station Lighting – Holyrood	Complete

[1] CO23 represents a project that has been carried over to 2023.
[2] MY23 represents a multi-year project ending in 2023.

Project Description	Status of 2022 Planned Construction Completion
Terminal Station Refurbishment and Modernization Various Sites (Multi-Year 2022)	
• Refurbish and Upgrade Power Transformers	Complete
• Install Fire Protection in 230kV Stations – Massey Drive	(See Note 8)
• Replace Instrument Transformers	Complete (See Note 9)
• Upgrade Breaker Failure Protection	Complete (See Note 10)
• Perform Grounding Upgrades	Complete
• Upgrade Data Alarm Systems – Oxen Pond	Complete
• Replace Disconnects	(See Note 11)
• Replace Protective Relays	(See Note 12)
• Upgrade Terminal Station Foundation (SY21)	Complete
• Upgrade Transformer Paralleling – Hardwoods	Complete
• Upgrade Station Lighting – Stony Brook	Complete
• Replace Surge Arresters (SY21)	Complete
• Replace Terminal Station Battery Banks and Chargers	Complete
• Upgrade Fault Recorders – Howley	Complete
• Upgrade Cables (SY21)	Complete
Terminal Station Refurbishment and Modernization Various Sites (Multi-Year 2023)	
• Refurbish and Upgrade Power Transformers	Complete
• Install Fire Protection in 230kV Stations – Buchans	(See Note 13)
• Replace Instrument Transformers	Complete
• Upgrade Breaker Failure Protection – Deer Lake	(See Note 14)
• Replace Disconnects	(See Note 13)
• Replace Protective Relays	(See Note 13)
• Upgrade Terminal Station Foundation (SY22)	Complete
• Upgrade Station Lighting – Buchans and Hardwoods	(See Note 13)
• Replace Terminal Station Battery Banks and Chargers – Various	Complete
• Upgrade Fault Recorders – Wabush	(See Note 13)
• Upgrade Reclosing For Circuit Breakers – Various	(See Note 13)

Table B-2: Transmission Line Projects

Project Description	Status of 2022 Planned Construction Completion
Perform WPLM	(See Note 18)
TL271 Construct New Transmission Line	(See Note 19)
TL215 Guying Attachment Upgrades	Complete
TL215 Replace Structures	Complete
TL219 and TL203 Ice Storm Damage	Complete

Notes

1) In 2022, the Terminals In-Service Failures project executed: one transformer refurbishment, one transformer oil remediation, one transformer bushing replacement, two synchronous condenser spare bearing overhauls, and fifteen power transformer protective device replacements. The project also initiated procurement of one set of isolated-phase bus duct kits and a spare distribution transformer, with the balance of procurement to be completed in 2023.

2) In 2022, the transport of the transformer from Churchill Falls to Holyrood could not proceed due to logistical issues related to the height of the transformer and its proposed transportation route. The route proposed by the contractor included the Marine Atlantic ferry service from North Sydney, Nova Scotia to Port Aux Basques, Newfoundland and Labrador. The contractor's proposal had been based on Hydro-supplied manufacturer's as-built drawing for the maximum height of the transformer. The transportation subcontractor discovered at site that the transformer height exceeded that shown on the as-built drawing and the transformer could not be transported on the ferry. After investigating several other options for transporting the transformer in the fall of 2022, it was decided to delay to a more favourable time of year in 2023 and allow further investigation of more economical options.

3) Over allocation of engineering resources led to an engagement of a contractor to complete the civil design. The delay associated with establishing this engagement pushed the subsequent construction schedule past the seasonal timeframe to complete the work in 2022. This work is now planned for 2023.

4) Eight circuit breaker replacements and five circuit breaker refurbishments were completed in 2022. The project has been extended to 2023 to allow one 69 kV breaker replacement at Holyrood to be deferred one year, from 2022 to 2023, and one 138 kV breaker replacement to be changed to a refurbishment and deferred one year from 2022 to 2023.

5) The project was closed in 2022. The commissioning of the differential line protection aspect of the overall line protection scheme was delayed to 2023 to align with the customer's installation schedule. All other associated line protection was placed in service.

6) The scope items planned at Bottom Brook Terminal Station in 2022 were, as follows: upgrade protection system; relocate and install one power transformer; and install two disconnect switches. The project was carried over to 2023 and all items were deferred to 2023, to align with the decision to keep Stephenville Gas Turbine in place for another year.

7) The project was closed in 2022, with the following scope item transferred to a new project in 2023: one transformer protection upgrade due to extension of a previous related upgrade which pushed the start of this item too late in the year for an outage.

8) Fire protection system construction was delayed until 2023 due to an equipment supply chain disruption associated with a warehouse fire. Work completion is planned by mid 2023.

9) The project was closed in 2022, with the following scope transferred to a new program in 2023: 12 instrument transformer replacements, due to extended lead times from suppliers and metering regulatory approvals. These are all planned for completion in 2023.

10) The project was closed in 2022, with the following scope transferred to a new program in 2023: two breaker failure protection installations. These are both planned for completion in 2023.

11) The project was closed in 2022, with the following scope transferred to a new program in 2023: two disconnect replacements. These are both planned for completion in 2023.

12) The project was closed in 2022, with the following scope transferred to a new program in 2023: two backup line protection upgrades, due to a manufacturer's recall. These are both planned for completion in 2023.

13) No planned 2022 construction.

14) Construction was advanced from 2023 and was completed in 2022 due to resource availability and coordination with other related work.

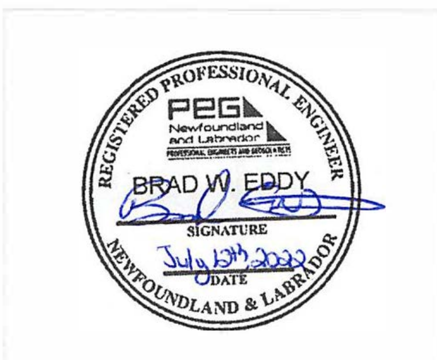
15) Construction of one breaker was deferred to 2023 due to late delivery from supplier.

16) The 2022 scope of work for the WPLM included: the inspection and treatment of 2,653 poles and the replacement of: 14 poles, and 3 crossarms. No replacements of sets of kneebraces or cross braces were required in 2022. Work that carried over into 2023 included: one pole, three sets of kneebracing, one crossarm and one set of crossbracing – TL234; one crossarm and two sets of eyebolts – TL241.

17) Construction of new Transmission Line TL271 between Star Lake Terminal Station and Marathon Gold's Valentine Terminal Station is planned to be completed in the fall of 2023.

Attachment 1

Terminal Station Asset Management Overview



Terminal Station Asset Management Overview Version 7

July 2022

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro

Executive Summary

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

The following asset classes are terminal station infrastructure:

- Instrument transformers;
- Disconnect switches;
- Surge arresters;
- Insulators;
- Grounding;
- Power transformers;
- Circuit breakers;
- Station services;
- Battery banks and chargers;
- Circuit breaker bypass switches;
- Lighting;
- Synchronous condensers;
- Equipment foundations;
- Fire protection;
- Control buildings; and
- Protection and control.

Each asset class of infrastructure has a section complete with eligibility criteria (i.e., the requirements that a piece of equipment must meet to be eligible for the planned capital work). Each section consists of an introduction and a description. Each introduction describes the high-level function and/or construction of the equipment in that asset class.

Each description details the associated capital program, including each asset class' eligibility criteria, which are typically a combination of some of the following factors: age, usage, condition, and reliability improvements.

Contents

1.0 Introduction

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

Hydro's Asset Management System governs the life cycle of its terminal station assets. The Asset Management 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 breakers, transformers, grounding systems, buildings, and sites. This allows the asset managers to establish consistent practices for equipment specification, placement, maintenance, refurbishment, replacement, and disposal. These practices mean that the monitoring, assessments, and action justifications for capital refurbishment and replacement for asset-sustaining projects are consistent. Hydro established programs that enact these practices for groups or sub-groupings of assets, for example, high-voltage switch replacements.

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[] This document provides information as to the assets involved, an overview of each asset program, and how this document will be updated in the event of changes to Hydro's asset management philosophies.

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

1.1 Changes in Version 7

Version 7 of this document, is included as part of Hydro's 2023 Capital Budget Application ("CBA"). All material updates in this version are shaded in grey, and are summarized below:

- Executive Summary: Replaced in its entirety;
- Section 1.0: Paragraph 3 was removed in its entirety; text was also removed from Paragraph 4;
- Section 3.0 and all sub-sections: Removed in their entirety;
- Section 4.1.1, Program Description and Justification: Updates to text throughout;
- Section 4.1.1, Manufacturer and Model: Sub-section removed in its entirety;

- Section 4.1.1, Age: Updates to text;
- Section 4.1.6, Transformer Oil Deterioration: Updates to text;
- Section 4.1.7: Removal of text in Paragraph 3;
- Section 4.2.3: Paragraph 3 was replaced in its entirety; and
- Section 4.3.1, Equipment Alarm Upgrades: Addition of Paragraph 4.

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

2.0 Background

2.1 Hydro's Terminal Stations

Terminal stations play a critical role in the transmission and distribution of electricity. Terminal stations contain electrical equipment, such as transformers, circuit breakers, instrument transformers, disconnect switches, and associated protection and control relays and equipment required to protect, control, and operate the Hydro's electrical grid. Stations act as transition points within the transmission system and interface points with the lower-voltage distribution and generation systems. Hydro has 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 arresters;
- Grounding;
- Buswork;
- Steel structures and foundations;

- Insulators
- Control buildings;
- Protection and control relays;
- Yards, fences, and access roads;
- Battery banks;
- Terminal station lighting; and
- Synchronous condensers.

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

3.0 []

4.0 Asset Management Programs

4.1 Electrical Equipment

4.1.1 High-Voltage Instrument Transformer Replacements

Introduction

The protection, control, and metering devices, such as protective relaying, power quality monitors, and kWh meters used in generation and transmission systems are not manufactured to handle the currents and voltages inherent to those systems. Measurement of the electricity's currents and voltages are provided to these devices through a current transformer ("CT") and a potential transformer ("PT"), respectively. CTs and PTs, as shown in Figure 1, are collectively known as instrument transformers ("IT"). Hydro has approximately 900 individual high-voltage ITs within the Island and Labrador Interconnected Systems.

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

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

Program Description and Justification

Hydro manages planned budgeted Instrument Transformer replacements in four categories:

1) Condition;
2) Polychlorinated biphenyl ("PCB") compliance replacements;
3) []
4) Age; and
5) System concern

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. In some situations, pieces of the IT may be forcibly projected resulting in safety risks to 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 with mobile equipment. Upon such incidents, Hydro assesses the electrical and physical integrity of the IT to determine if replacement is required.

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

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

Figure 2: Rusting PT

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

On an ongoing basis, Hydro’s asset management personnel review the unit deterioration information and determine when corrective maintenance or unit replacement is required. Hydro conducts minor 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 require that by 2025 all ITs will not have a PCB concentration greater than 50 mg/kg. ITs 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 ITs, 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 mg/kg. Thus Hydro has a program to replace all suspect oil-filled ITs before 2025.

[]

Age

Hydro targets replacement at 40 years of age to reduce the risk of in-service failures and minimize service interruptions. Original equipment manufacturers ("OEM") recommend that the life of an IT is approximately 30 to 40 years. In the last five years (i.e., 2017–2021), 56% of failed ITs were at least 30 years old at the time of their failure.

System Concern

System concern refers to a transient response of a specific make and model of IT to a specific system transient condition that can contribute to over-stressing (and possibly damage) equipment connected nearby. For example, following four 230 kV circuit breaker failures at Bay d'Espoir Terminal Station 1 from 2018–2019, a transient study identified three ITs with a system concern that likely contributed to overstressing these circuit breakers and thereby contributed to their failure.

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

Introduction

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 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 insulators and mounts to a metal frame support structure. The operating mechanism is operated manually by using a handle at ground level to open and close the blade, or by a motor-operated device, in which case the switch is known as a motor-operated disconnect. A disconnect and its associated components are shown in Figure 3.

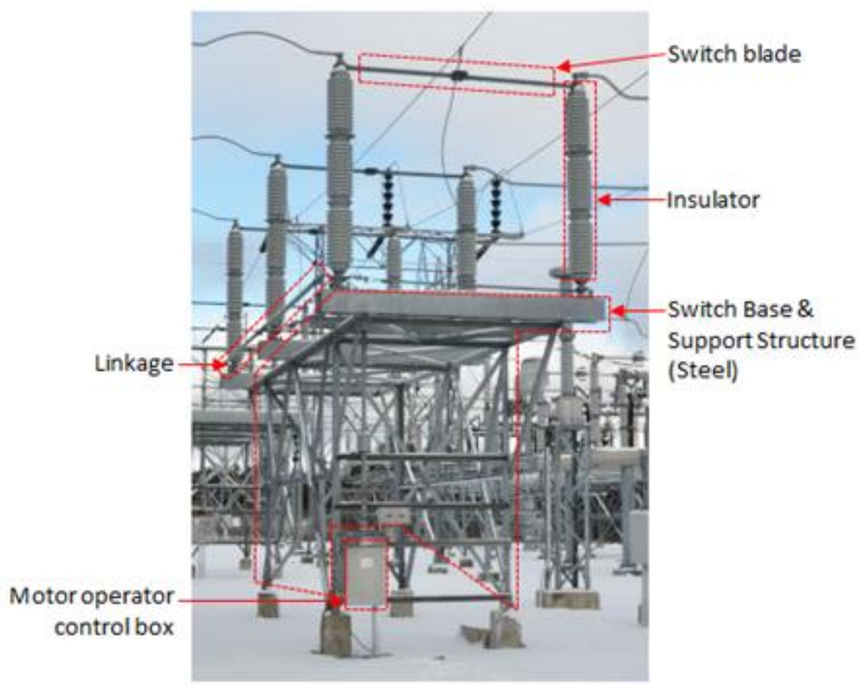

Figure 3: Various Components of a High-Voltage Disconnect Switch

Program Description and Justification

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

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

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

Figure 4: Broken Insulator on 69 kV Disconnect Switch

4.1.3 Surge Arrester Replacement

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

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

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

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

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

- Removal of gapped type arresters with zinc oxide design due to enhanced performance;
- Replacement of units due to a condition identified through visual inspections for chips or cracks or electrical testing such as power factor testing;
- If failures occur on a given transformer, all arresters on both the high and low side are considered for replacement either immediately or in a planned fashion; and

- If transformers are being planned for maintenance or other capital work, consideration is given to changing aged arresters on a common outage. Hydro targets replacement at 40 years of age, to reduce the risk of in-service failures and minimize service interruptions.

4.1.4 Insulator Replacement

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

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

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

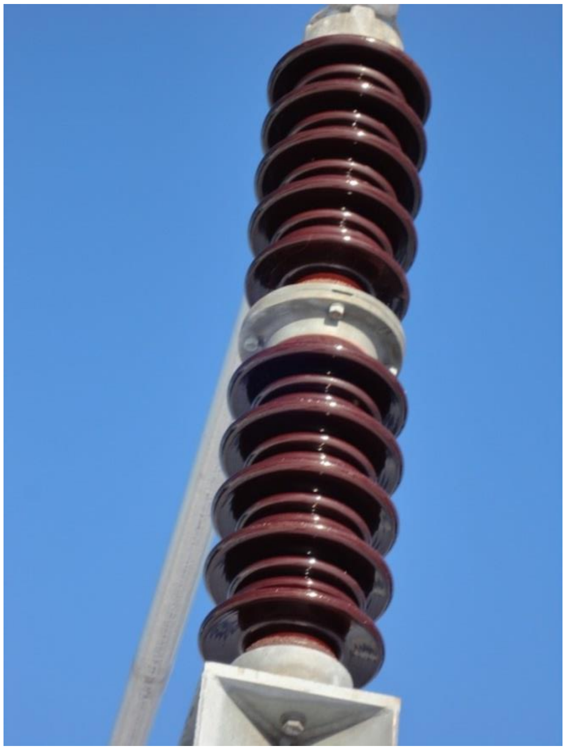

Figure 6: Multi-Cone Type Insulator Prone to Failure due to Cement Growth

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

Hydro carries out detailed insulator surveys by geographical area. Hydro identifies any insulator types that are 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, as shown in Figure 7. In the event of a ground fault, electrical potential differences will exist in the grounding system. If the grounding system is inadequate or deteriorated these differences 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. A step and touch potential analysis involves the gathering and analyzing of field data to determine if ground grid modifications are required to eliminate step and touch potential hazards. This engineering is conducted in accordance with IEEE[1] Standard 80-2000.[2] 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

Introduction

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

Hydro has 118 power transformers and 3 oil-filled shunt reactors 46 kV and above, as well as several station service transformers at voltages lower than 46 kV.

The basic components of a power transformer are:

- Transformer steel tank containing the metal core and paper insulated windings; oil, which is part of the insulating system; and a gasket system, which keeps the oil from getting into the environment;
- Bushings mounted to the top of the transformer tank, which connects the windings to the external electrical conductors;
- Radiators and cooling fans, which remove heat for the transformer's internal components;

[1] Institute of Electrical and Electronics Engineers ("IEEE").
[2] *Guide for Safety in AC Substation Grounding*, IEEE Standard 80, 2000.

- On-load tap changer, which is a device attached internally or externally through which transformer voltages are maintained at acceptable levels; and
- Protective devices to ensure the safe operation of the transformer, such as gas detector relays, oil level and temperature relays, and gauges.

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

Figure 8: Power Transformer

Program Description and Justification

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

- Insulating oil and paper deterioration;
- Oil moisture content;
- Oil leaks;
- Tank, radiators, and other components rusting/corrosion;
- Tap changer component wear or damage;
- Damaged/deteriorated and PCB-contaminated bushings;
- Failure of the protective devices; and
- Cooling fan failures.

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

Transformer Oil Deterioration

The insulating oil in a transformer and its tap changer diverter switch is a critical component of the insulation system. The normal operation of a transformer will cause its oil to deteriorate. Deterioration results from several causes, such as heating, internal arcing of electrical components, or ingress of water moisture into the transformer. Deterioration of the oil will affect its function in the insulation system and may damage the paper component of the insulation system. Unacceptable levels of deterioration can affect the reliable operation of the transformer. To ensure that the oil in a transformer is of acceptable quality, Hydro has an oil-monitoring program, in which an oil sample is obtained annually from each transformer and analyzed by a professional laboratory. The test results are assessed to determine the level of deterioration. If an unacceptable level of deterioration is identified, required corrective action is identified by asset management personnel. This action entails either the refurbishment of the oil to improve its quality or the replacement of the oil. The oil that is PCB contaminated (i.e., > 2 ppm PCB), whose refurbishment requires oil reclamation, will be replaced.

Moisture Content

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

Oil Leaks and Corrosion

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

On-Load Tap Changer

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

Bushings

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

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

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

Protective Devices and Cooling Fans

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

Online Oil Analysis

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

This program was extended to non-GSU transformers in 2017, with online DGA being installed on critical power transformers on the Island Interconnected System. The factors used to determine the criticality score were submitted to the Board of Commissioners of Public Utilities in the June 2, 2014 "Transformers Report."[3] Hydro has identified 49 transformers for the installation of online DGA devices between 2019 and 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 their fast response and complete interruption of current flow is essential for the protection and stability of the power system. The failure of a breaker to operate as designed may affect the reliability and safety of the electrical system, resulting in the failure of other equipment and the occurrence of an outage affecting more end users. Hydro has over 230 terminal station circuit breakers in service with a voltage rating of 46 kV or greater.

Currently, Hydro maintains three different types of high-voltage circuit breakers, as shown in Figure 9:

1) Air-blast circuit breakers ("ABCB") use high-pressure air to interrupt currents and will be at least 38 years old at replacement. In the 2016 CBA project Upgrade Circuit Breakers – Various Sites, approval was obtained to replace ABCBs on an accelerated schedule by the end of 2020.[4] This work is covered under a separate project and is not part of the work outlined in the Asset Management Overview. Hydro has since modified this program and is targeting completion in 2023.

2) Oil circuit breakers ("OCB") use oil to interrupt currents and will be at least 36 years old at replacement. In the 2016 CBA project Upgrade Circuit Breakers – Various Sites, approval was obtained for the replacement of ten OCBs up to 2020 that were not compliant with Environment

[3] "Report to the Board of Commissioners of Public Utilities Regarding Work to be Performed on Transformers," Newfoundland and Labrador Hydro, June 2, 2014.
[4] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol II, tab 8 was approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

Canada's PCB Regulations. Hydro has since modified this program and is targeting completion of that scope in 2022. The remaining non-compliant breakers will be replaced before 2025. From 2017, any replacements not previously approved in the 2016 CBA will be included in the work conducted under this section of the Asset Management Overview.

3) Sulphur hexafluoride ("SF_6") circuit breakers use SF_6 gas to interrupt current. The installation of these breakers started in 1979 and continues for all new installations.

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

As presented in the 2016 CBA project Upgrade Circuit Breakers – Various Sites, SF_6 circuit breakers rated at 138 kV and above are required to be refurbished after 20 years of service. In 2018, Hydro added 66 kV-rated breakers to also be refurbished after 20 years. Replacement of SF_6 circuit breakers rated at 66 kV and above will be planned after 40 years of service. However as SF_6 circuit breakers come due, a further condition assessment will be completed to determine if life extension can be achieved through refurbishment. Some SF_6 circuit breakers may require replacement before the 40-year service life period based on their condition and operational history.[]

4.1.8 Station Service Refurbishment and Upgrades

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

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

Common ac station service loads are:

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

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

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

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

4.1.9 Battery Banks and Chargers

Introduction

Battery banks and their chargers supply dc power to critical station infrastructure, such as circuit breakers, protection and control relays, disconnect switch motor operators, and telecontrol equipment. Battery banks are designed to provide a minimum of eight hours of auxiliary power to critical infrastructure in the event of a loss of ac station service supply. The majority of Hydro's battery banks consist of lead-acid flooded-cell type batteries, whose capacity deteriorates over time.

Program Description and Justification

Hydro currently completes discharge testing on criticality A and B battery banks after 10 years and then every 5 years for flooded cell and every 2 years for valve regulated. If the battery bank's capacity has fallen to 80% or less of its rated capacity, Hydro will plan replacements. In addition, due to the critical nature of battery banks, flooded cell batteries are replaced after 20 years while valve-regulated lead-acid batteries are replaced after 10 years. An example of a 120 Vdc battery bank is shown in Figure 10.

Figure 10: 125 Vdc Terminal Station Battery Bank

4.1.10 Install Breaker Bypass Switches

High-voltage circuit breakers, with their associated protection and control equipment, are used to control the flow of electrical current to ensure safe and reliable operation of the electrical system. When a breaker is removed from service for maintenance, troubleshooting, refurbishment, or replacement, an alternate electrical path must be implemented to avoid customer outages. On radial systems,[5] this alternate path is accomplished using a bypass switch. When closed, the bypass switch allows electricity

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

to flow around the breaker allowing the breaker to be safely de-energized, while maintaining service continuity, as shown in Figure 11.

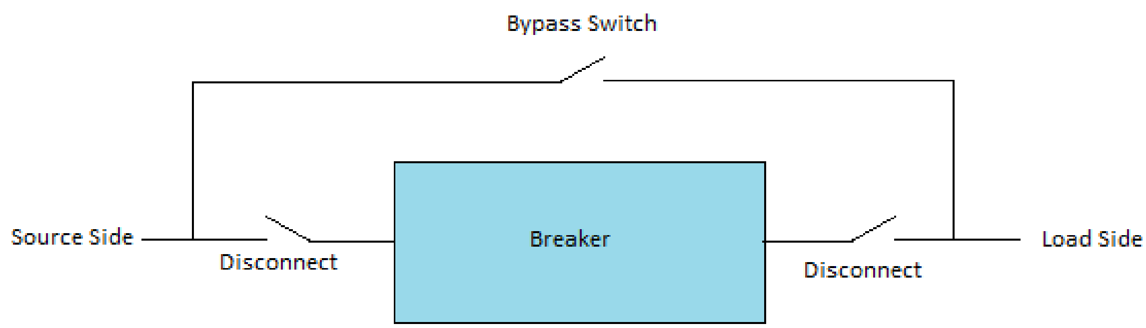

Figure 11: Example of Bypass Switch Installation

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

Table 1: Circuit Breakers without Bypass Switches

Breaker Location	Customers Affected
Bottom Waters L60T1	2,253 Bottom Waters area customers
Buchans B2T1	665 Buchans area Newfoundland Power customers and Duck Pond Mine
Howley B1T2	773 Hampden and Jackson's Arm area customers and 665 Newfoundland Power Howley area customers
Peter's Barren B1L41	1,900 Great Northern Peninsula customers north of Daniel's Harbor
South Brook L22T1	2,340 South Brook area customers

Hydro placed a hold on this program in 2018 and is looking closer at doing this work only when other major terminal station work is planned or if there is a low-cost solution. For example, Doyles B1L15 had a low-cost bypass installed in the first quarter of 2020 through an in-service failure project to facilitate the topping up of an ongoing leak in Breaker B1L15.

4.1.11 Replace Station Lighting

Terminal station lighting is essential to provide adequate illumination for a safe working environment, as well as for deterring theft and vandalism in terminal stations. Hydro utilizes a variety of lighting technologies and configurations, depending on the application and vintage of the lighting system. Over time, exposure to the elements can cause physical deterioration, such as corrosion (as shown in Figure 12 and Figure 13), leading to moisture ingress that impacts the function of the lighting system. Additionally, some legacy lighting technologies have become obsolete.

Under this program, Hydro will replace deteriorated lighting systems as they become unable to provide adequate illumination of the terminal station and have become obsolete or beyond repair. Hydro will replace legacy lighting systems with modern, efficient lighting technologies whenever possible.

Figure 12: Corroded Ballast Requiring Replacement

Figure 13: Light Fixture Showing Perforations due to Corrosion, Enabling Moisture Ingress

4.1.12 Synchronous Condensers

Hydro maintains two synchronous condensers located at the Wabush Terminal Station. Each condenser undergoes major and minor inspections on a three-year rotating cycle, with minor inspections performed on both Year One and Year Two of the cycle, and a major inspection performed on Year Three. Each involves a standard list of checks, tests and general maintenance as well as any additional items that have been identified for follow-up based on the results of previous inspections.

The minor inspections involve function testing, vibrations checks, lube oil system maintenance and oil sampling, disassembly and inspection of the top half of bearings, clearance checks, electrical tests, visual inspections, as well as cleaning and general maintenance including replacement of various gaskets, filters, and hardware.

The major inspections expand on the same activities performed under the minor inspections by also rotor and stator inspection, disassembly, and inspection of the bottom half of the bearings and replacement of the thrust bearings.

4.2 Civil Works and Buildings

4.2.1 Equipment Foundations

Reinforced concrete foundations support high-voltage equipment and structures in Hydro's terminal stations. The majority of these structures formed part of the original station construction and support critical terminal station equipment and buswork.

The service life of galvanized steel structures varies depending on the operating environment but can exceed 100 years, outliving the foundations on which they are built. A number of the foundations in Hydro terminal stations have deteriorated significantly due to repeated exposure to damaging freeze/thaw cycles, weathering, and age, leading to concerns over their integrity. Examples of degraded structure foundations are shown in Figure 14 and Figure 15.

Figure 14: Structure B1T1 Bottom Brook Terminal Station

Figure 15: Structure L01L37-1 Western Avalon Terminal Station

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

4.2.2 Fire Protection

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

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

In the 2015 and 2016 CBAs Install Fire Protection projects, Hydro received approval to install fire protection in the Holyrood and Bay d'Espoir Terminal Stations.[6,7] Due to their criticality, Hydro intends to continue its program to install fire suppression systems in all 230 kV terminal stations.

4.2.3 Control Buildings

Terminal station control buildings contain critical station infrastructure such as protection, control, and monitoring equipment; telecontrol equipment; station service equipment; and compressed air systems. Many control buildings also contain offices, breakrooms, and washroom facilities, for use by Hydro crews when working in the station. As the equipment in control buildings is critical to the function of the terminal station, it is imperative that Hydro ensures the structural integrity, weather tightness, and security of its control buildings. While addressing these issues, Hydro also ensures that building auxiliaries such as electrical, plumbing, and HVAC systems function properly to ensure reliable and safe operation and use of the terminal station and the control building.

Typical refurbishment activities for control building involve replacement of the roof membrane (Figure 16), siding, and doors (Figure 17), and may also include replacement of electrical equipment (such as distribution panels, transfer switches, or low-voltage disconnects), plumbing (such as water service entries and internal plumbing), and HVAC (such as intake and exhaust fans, louvers, heaters, and air conditioning equipment).

[]

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

[6] "2015 Capital Budget Application," Newfoundland and Labrador Hydro, August 1, 2014, approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 50(2014), Board of Commissioners of Public Utilities, December 2, 2014.
[7] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

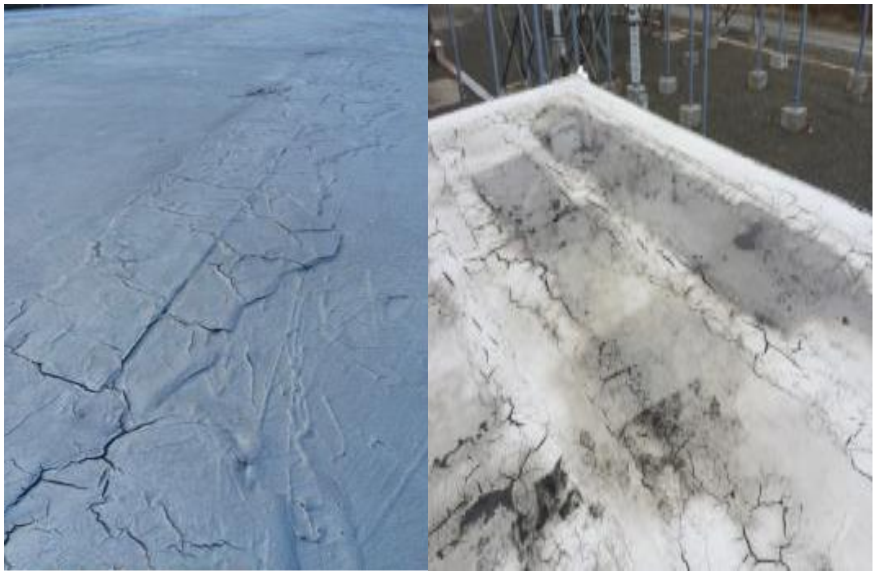

Figure 16: Terminal Station Control Buildings (Come by Chance and Sunnyside) Showing Cracking and Deterioration of the Roof Membrane System

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

4.3 Protection, Control, and Monitoring

4.3.1 Protection and Control Upgrades and Refurbishment

Introduction

The terminal station protection and control system automatically monitors, analyzes, and causes action by other equipment, such as breakers, to ensure the safe, reliable operation of the electrical system, or to initiate action when 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;
- Circuit breaker reclosing controllers;
- Tap changer controls;
- Data alarm systems;
- Digital fault recorders; and
- Cables and panels.

Program Description and Justification

Electromechanical and Solid State Protective Relay Replacement

Protective relays monitor and analyze the operation conditions of the electrical system. When a relay identifies unacceptable operating conditions, such as a fault, it will initiate an action to isolate the source of the condition by commanding high-voltage equipment, such as breakers, to operate. Protective relays play a crucial role in maintaining system stability and preventing hazardous conditions from damaging electrical equipment or harming personnel.

Older, obsolete 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 18.

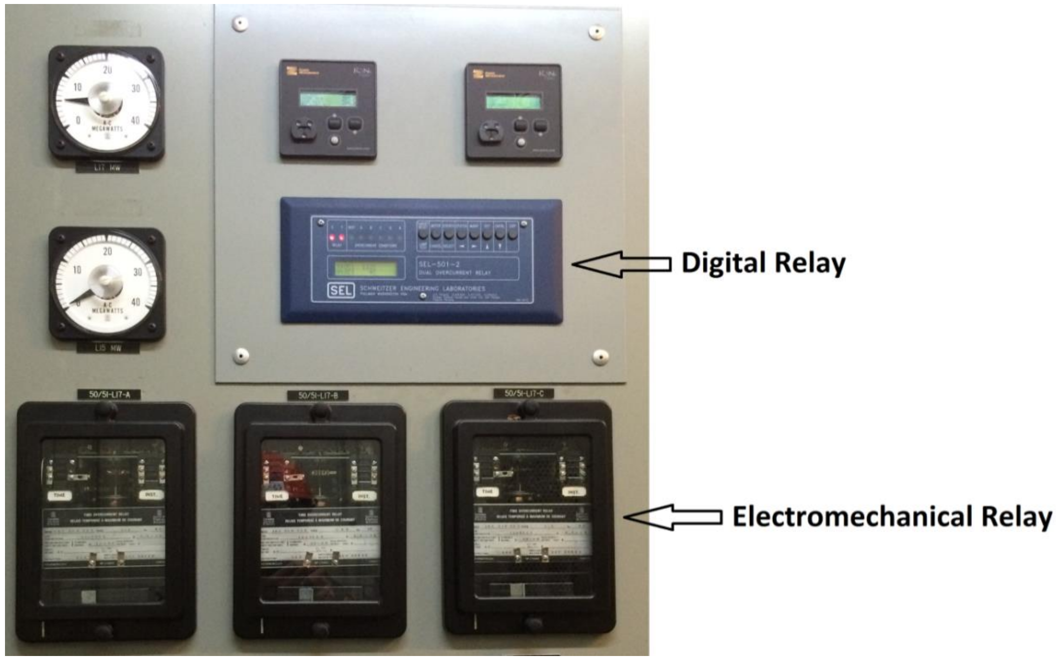

Figure 18: Digital and Electromechanical Relays

In a 2014 report, Hydro stated it " . . . 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."[8] To fulfill this commitment, Hydro completed the following:

- A review of all transformer, bus, and line protection on 230 kV, 138 kV, and 69 kV systems, including data storage and fault recording capabilities; and
- A plan to replace all existing electromechanical transformer, bus, timer, and line protection relays with modern digital relays. The 230 kV relays are the priority for the first phase of the plan, with 138 kV and 69 kV to follow.

As part of its annual Terminal Station Renewal Program,[9] Hydro will continue to execute the replacement of 230 kV electromechanical and obsolete solid-state generator, transformer, line, and bus relays with modern digital multifunction relays, which began in 2016 under the Replace Protective Relays – Various Sites project.[10] Additionally, in line with Hydro's response to CA-NLH-037, filed as part

[8] "Report to the Board of Commissioners of Public Utilities Related to Alarms, Event Recording Devices, and Digital Relays," Newfoundland and Labrador Hydro, August 1, 2014, s 3.1.
[9] Formerly known as the "Terminal Station Refurbishment and Modernization" project.
[10] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol III, tab 19.

of the 2016 CBA, Hydro installed redundant multifunction transformer protection relays in 2016 for transformers rated above 10 MVA. Under this program, Hydro will continue to install these upgrades.

Furthermore, continuing in 2023 as part of the annual Terminal Station Renewal Program, Hydro plans to replace protection relays in the Wabush Terminal Station on 46 kV feeders. Each replacement is currently planned to coincide with the replacement of the circuit breaker associated with that protection.

Breaker Failure Protection

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

Prior to 2014, breaker failure protection was implemented only in Hydro's 230 kV terminal stations. In 2014, Hydro completed a review of breaker failure protection in 66 kV and 138 kV terminal stations. Hydro also developed a protection and control standard, Application of Breaker Failure Relaying, calling for breaker failure protection on transmission breakers rated at 66 kV and above. From this review, Hydro identified 20 terminal stations requiring breaker failure protection.

As part of Hydro's 2016 CBA, Hydro proposed and received Board approval for the installation of breaker failure protection in three terminal stations.[11] As part of the annual Terminal Station Renewal Program, Hydro will continue its plan to execute the installation of breaker failure protection in the remaining terminal stations. As well, Hydro has identified concerns with the reliability of legacy breaker failure in 230 kV stations and will be replacing as necessary under this program.

[11] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

Tap Changer Paralleling Control Replacement

Tap changer paralleling controls are designed to:

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

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

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

Equipment Alarm Upgrades

Alarms inform the Energy Control Centre ("ECC") and operating personnel that equipment and relaying requires attention and are communicated to the ECC, and/or displayed locally on the station annunciator, as shown in Figure 19.

Figure 19: Annunciator Commonly Found in Hydro Terminal Stations

Hydro's review of alarms, event recording devices, and digital relays found that by providing more detailed alarm schemes, the ECC and local operators are able to troubleshoot system events more accurately and quickly.

Hydro's internal study identified required increases to alarm detail to the ECC for five 230 kV terminal stations. Stony Brook, Holyrood, Sunnyside, Oxen Pond, and Massey Drive Terminal Stations were assessed. Hydro proposed and received approval to implement the proposed upgrades at the Stony Brook Terminal Station as part of the 2016 CBA project Upgrade Data Alarm Systems – Stony Brook.[12] Hydro will continue its plan to install improved data alarm management as part of the Terminal Station Renewal Program, with the remaining stations being addressed in future CBAs.

Deterioration of an annunciator can result in the failure of individual alarms or the whole unit and these failures may negatively affect the safe and reliable operation of the generation and transmission systems. For this reason, Hydro also replaces deteriorated obsolete annunciators.

[12] "2016 Capital Budget Application," Newfoundland and Labrador Hydro, July 31, 2015, vol. I, s D, pp. D-374 to D-394, approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2015), Board of Commissioners of Public Utilities, December 2, 2015.

Digital Fault Recorders

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

Protection and Control Cable and Panel Modifications

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