Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 | f. 709.737.1800
nlhydro.com

May 21, 2025

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Re: Newfoundland and Labrador System Operator Annual Assessments

The Newfoundland and Labrador System Operator ("NLSO") Transmission Planning process involves the execution of power system studies to demonstrate that the power system meets Transmission Planning Criteria necessary for maintaining the reliability of the Newfoundland and Labrador ("NL") transmission system. These power system studies are performed by the NLSO and include an annual assessment of the NL transmission system, which is comprised of transmission infrastructure operating at a voltage level of 230 kV or higher and includes the Labrador-Island Link, the Labrador Transmission Assets, the Labrador Interconnected System, and Island Interconnected System. The NLSO also performs, on behalf of Newfoundland and Labrador Hydro ("Hydro"), an assessment of all other transmission system facilities with a rated voltage of 46 kV and above that are under its operational control.

Two reports were generated as a result of these power system studies:

1) TP-R-092: "NLSO Report – 2025 Annual Planning Assessment," Newfoundland and Labrador Hydro, March 31, 2025; and
2) TP-R-093 "NL Hydro Report – 2025 Annual Planning Assessment," Newfoundland and Labrador Hydro, May 13, 2025.

Details of the assessments are provided to the Board of Commissioners of Public Utilities for its information as committed in Hydro's response to PUB-NLH-025 of the *Reliability and Resource Adequacy Study Review* proceeding, filed May 24, 2019.

Should you have any questions, please contact the undersigned.

Yours truly,

SWalsh

NEWFOUNDLAND AND LABRADOR HYDRO

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

Encl.

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
Board General

Consumer Advocate
Dennis M. Browne, KC, Browne Fitzgerald Morgan & Avis
Stephen F. Fitzgerald, KC, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis

Labrador Interconnected Group
Senwung F. Luk, Olthuis Kleer Townshend LLP
Nicholas E. Kennedy, Olthuis Kleer Townshend LLP

Newfoundland Power Inc.
Dominic J. Foley
Douglas W. Wright
Regulatory Email

Island Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Glen G. Seaborn, Poole Althouse

NLSO Report - 2025 Annual Planning Assessment

Doc # TP-R-092

Date: 2025/05/06

Executive Summary

A key function of the Newfoundland and Labrador System Operator ("NLSO") is to ensure the coordinated development of a safe, reliable and economical transmission system for transmission customers.

The NLSO Transmission Planning Process involves the execution of power system studies to demonstrate that the power system meets Transmission Planning Criteria. An annual assessment of the transmission system is utilized to determine the timing of system additions/modifications to ensure long-term safe, reliable, and economical operation.

This report addresses the Newfoundland and Labrador ("NL") Transmission System, which is comprised of transmission facilities located in NL, operating at a voltage level of 230 kV or higher, including, the Labrador-Island Link ("LIL"), the Labrador Transmission Assets ("LTA"), the Labrador Interconnected System ("LIS") and Island Interconnected System ("IIS").[1,2]

Conclusions of the 2025 Annual Planning Assessment are stated as follows:

- The NL Transmission System includes Radial and Local Networks where outages to system elements may result in customer impacts. Transmission Planning Criteria are not strictly applied in these cases. Rather, these systems are designed to meet customer reliability and cost requirements.
- The Transmission Planning Criteria are strictly applied to the Primary Transmission System ("PTS").[3] Steady state analyses were performed and the following conditions were confirmed for the long-term horizon:
    - There are no pre-contingency transmission equipment overloads or voltage violations
    - **The following are single contingency events that result in a violation of the Transmission Planning Criteria, but may be addressed based on the outcome of future studies:**
        - **Loss of Wabush Synchronous Condenser. Further detail is provided in Section 5.2.1.**
        - **Loss of TL236 and TL266. Further detail is provided in Section 5.3.3.**
- The short circuit analyses were performed and it was confirmed that there are no issues with circuit breaker ratings in the near-term or long-term planning horizons.
- Transient stability analysis is currently in progress as part of ongoing operational studies in support of the Lower Churchill Project ("LCP") integration effort. These studies are expected to be completed by Q2 2025. The final operational study will be provided as part of the 2026 Annual Assessment. The NLSO will also provide a plan for future transient stability analysis, as it is expected it may not be required on an annual basis or will be triggered based on material changes to the IIS or LIS.

---

[1] A separate annual assessment is performed by Newfoundland and Labrador Hydro ("Hydro"), which includes all system elements 46 kV and above that are under its operational control and not included in the NLSO assessment.

[2] The Churchill Falls (Labrador) Corporation ("CFLCo") 735 kV transmission facilities are currently not included in the NLSO assessment.

[3] All transmission elements with a voltage rating greater than or equal to 230 kV. A power transformer must have a primary and secondary voltage rating of ≥230kV to be considered part of the PTS.

Table of Contents

1 Introduction

The NLSO Transmission Planning Process involves the execution of power system studies to ensure compliance with Transmission Planning Criteria and to determine the timing of system additions and modifications.

The 2025 Annual Planning Assessment covers the period extending to 2034. Cases are assessed to investigate the capability of the transmission system to meet peak load and to meet firm export commitments of 250 MW over the Maritime Link.

This report addresses the NL Transmission System, which is comprised of transmission facilities located in NL, operating at a voltage level of 230 kV or higher, including, the LIL, LTA, the LIS and IIS.[4] Analysis is performed to ensure compliance with the NLSO's Transmission Planning Criteria.

The maps of the IIS and LIS are provided in Appendix A.

[4] The CFLCo 735 kV transmission facilities are currently not included in the NLSO assessment.

2 Selection of Study Cases

System models have been developed to reflect the latest load forecast with completed system changes including proposed additions/modifications for future years ranging to 2034. The following system additions/assumptions are applied to the 2034/2035 study cases:

- The Final Under Frequency Load Shedding ("UFLS") Scheme is implemented to allow for increased power transfer over the LIL.[5]
- The Muskrat Falls Generating Station ("MFAGS") has four 206 MW generating units in service.
- The LIL is operating in Bipole Mode up to its rated capacity of 900 MW (Rdc = 19.29 ohm).
    - All filter banks are available at each of Muskrat Falls and Soldiers Pond Converter Stations.
    - Electrode lines and electrode sites are in service.
- Churchill Falls recall power (less Labrador loads) is available to send to the Island.
- There are two 60 MVAr line reactors installed on the Muskrat Falls end of 315 kV lines L3101 and L3102.
- There are two Soldiers Pond 175 MVAr synchronous condensers in service for analysis (the third unit is available).
- The ML exports are set at 250 MW at Bottom Brook Terminal Station 2 – ("BBKTS2") in both the peak and light load cases.
- Holyrood Thermal Generating Station ("Holyrood TGS") is out of service with Unit 3 operating in synchronous condenser mode.
- Holyrood combustion turbine G4 is in-service.
- Proposed Bay d'Espoir Unit 8 (154.4 MW) and new Avalon Combustion Turbine Plant ("ACT") in Holyrood (3 x 56.1 MW)[6] are in-service, per the recommendation of the 2024 Resource Adequacy Plan, in order to meet forecasted load growth in the study cases.
- 100 MW of proposed new wind generation was added to meet forecasted load growth in the study cases per the recommendation of the 2024 Resource Adequacy Plan.
- Stephenville ("SVL") gas turbine is in-service as a synchronous condenser (no longer available as a generator).[7]
- Hardwoods ("HWD") gas turbine is in-service as a synchronous condenser (no longer available as a generator).[8]

The following load flow plots for the Year Ten (2034/35) cases are provided in Appendix B:

- 2034/35 Peak Load Conditions
- 2034 Light Load Conditions

[5] Hydro and Newfoundland Power are currently in the process of designing the final UFLS scheme.

[6] The rating of the ACT units has not been finalized, but will be approximately 50 MW per unit. 3 x 56.1 MW was used for ease of modelling with the understanding a slight variation in ratings would have no material impact on the results. The PSSE models will be updated once the ratings are finalized and specifications have been provided by the successful vendor.

[7] Hydro is expected to complete a life-extension study for the SVL Gas Turbine by end of 2025.

[8] Hydro is expected to complete a life-extension study for the HWD Gas Turbine by end of 2025.

3 Special Consideration

Special considerations for this study period are discussed in the sections below.

3.1 Operational Studies

Hydro is currently conducting a set of operational studies as part of the integration effort of the LCP assets into the NL Transmission System. The objective of these studies is to identify operating limits or guidelines to allow for the development of instructions to be used by the NLSO. These operational studies include assessments of the transient stability of the IIS and LIS with all LCP assets fully integrated. Transient stability considerations will therefore be outside of the scope of annual assessments until the operational studies are complete. The final operational study is expected to be completed by the end of Q2 2025, with a summary of results provided in the 2026 Annual Assessment.

3.2 Labrador Incremental Load

Hydro is currently undertaking a process to investigate large incremental customer load requests in Labrador. These incremental requests are beyond the baseline forecast and outside of the scope of any Annual Assessment.

Transmission system expansion requirements to serve incremental customers in Labrador East was assessed in a standalone study in 2024 in accordance with Hydro's Network Addition Policy. The study concluded that additional transformation[9] is required at the Happy Valley Terminal Station by the winter of 2029/2030 to facilitate the firm load requests in Labrador East.

Hydro has received a number of large load requests in Western Labrador for new potential mining expansions/projects that total approximately 2,000 MW. Hydro is currently working with external consultants in conducting a Transmission Feasibility Study to determine the transfer capacity and cost for multiple transmission upgrade options between Churchill Falls and Labrador West to support various load scenarios. Hydro is also working with Hydro Quebec ("HQ") to assess potential solutions involving an interconnection between Labrador West and the HQ transmission system to serve the firm load requests in Labrador West.

Hydro continues to assess the availability of non-firm supply to Labrador East and West for potential customers willing to be interruptible.

[9] The replacement of an existing transformer (25 MVA) with a 50 MVA transformer

4 Load Forecast

The 2025 Annual Planning Assessment is based upon the following load forecasts prepared by the Market Analysis and Load Forecasting Section, Resource and Production Planning (RPP) Department, Hydro:

- IIS Peak Demand Forecast System – prepared in June 2024; and
- LIS Long Term Load Forecast – prepared in June 2024.

The IIS and LIS P90 forecasted peaks are summarized in Table 1.

Table 1 – Peak Load Forecasts (P90) - IIS and LIS

Forecasted Demand (MW)[10]			
Year[11]	Island Interconnected System (IIS)	Labrador Interconnected System (LIS)	
		Lab East	Lab West
2024/25	1,767	79.1	383.4
2025/26	1,802	80.4	384.3
2026/27	1,817	81.9	384.6
2027/28	1,838	82.8	385.0
2028/29	1,867	83.5	385.4
2029/30	1,878	102.3	385.8
2030/31	1,897	103.0	386.3
2031/32	1,914	103.7	386.8
2032/33	1,941	104.6	387.5
2033/34	1,962	105.5	388.2
2034/35	1,987	106.6	389.1

[10] These forecasts do not include NLH system transmission losses or station service load requirements.

[11] The peak is assumed to occur sometime between December and March of the following year.

5 Steady State Analysis

The NL Transmission System consists of Radial Networks, Local Networks as well as the Primary Transmission System. Radial Network and Local Networks allow for the delivery of electricity to specific customers and Transmission Planning Criteria are not strictly applied. These systems are designed to meet customer reliability and cost requirements. In such a network, the loss of a transmission system element may result in a customer impact. This is in contrast to the Primary Transmission System, where all Transmission System Criteria are strictly enforced.

Steady state analysis is performed on all systems when fully intact (pre-contingency) and following the loss of each single transmission element (single contingency). The pre-contingency analysis is performed to ensure that with all equipment in service under normal operation, power flow through all elements does not exceed their designed rating and voltages are within normal limits (0.95 and 1.05 pu). Similarly, the single contingency analysis assesses the system impact following the loss of each individual transmission element, where voltage levels are acceptable within a larger range, or the emergency limits (0.9 pu and 1.1 pu).

The ratings of each type of transmission element are defined as per TP-S-001 - NLSO Facilities Rating Guide. The results of the steady state analysis are described in the sections below.

Load flow plots during normal operation of the NL Transmission System for Year Ten (2034/35) are provided in Appendix B.

5.1 Radial Networks

5.1.1 Supply to Vale

Vale is supplied by radial transmission line TL208. There are no overloads to this transmission line under normal operation. In the event of an outage to this transmission line, there will be an interruption of electrical supply which is deemed acceptable by Vale.

5.2 Local Networks

5.2.1 The Labrador West System

The transmission system in western Labrador is considered a local network and consists of two 230 kV transmission lines that connect Churchill Falls Terminal Station #1 to the Wabush Terminal Station. These transmission lines are designated as L23 and L24. This network also includes three synchronous condensers at the Wabush Terminal Station (SC1, SC2, and SC3[12]).

Criteria for this local network were defined as part of Hydro's LIS Transmission Expansion Study that was completed in 2018. Criteria were defined to ensure that there shall be no customer interruption for the

[12] SC3 is owned by IOC.

loss of a synchronous condenser, a capacitor bank, or a power transformer. Loss of load is permitted for a transmission line outage.

For the purposes of the NLSO annual assessment, analysis was performed to assess the impact of a transformer, a synchronous condenser, or a capacitor bank. The power transfer capacity to Labrador West is currently set at 385 MW, which is defined based on voltage violations following the loss of a synchronous condenser. **According to Table 1, the load forecast exceeds 385 MW by the winter of 2028/2029.** Transient stability analysis is currently underway to determine if minor system adjustments could increase the transfer capacity, deferring the violation beyond 2034. This analysis is expected to be completed by Q3 2025 with the objective of deferring capital investment until a long-term plan is established to accommodate significant new mining load in Labrador West, as described in Section 3.2.

5.3 Primary Transmission System

Analysis was performed to assess steady state contingencies for the PTS. The PTS includes all transmission elements[13] within the IIS and LIS with a voltage rating greater than or equal to 230 kV. Transmission Planning Criteria are applied to the network to ensure that no system events result in the interruption of load or firm imports or export commitments.

5.3.1 Bay d'Espoir System

The Bay d'Espoir System consists of a network of 230 kV transmission lines that includes the following:

- TL234 between Bay d'Espoir Terminal Station #2 and Upper Salmon Terminal Station
- TL263 between Upper Salmon Terminal Station to Granite Canal Terminal Station
- TL269 between Granite Canal Terminal Station to Bottom Brook Terminal Station #2

This network also includes hydraulic generating facilities at Bay d'Espoir, Upper Salmon and Granite Canal Generation Stations. The Bay d'Espoir Generation Station is the largest plant on the Island Interconnected System with a total capacity of approximately 613 MW. The largest unit at the Bay d'Espoir Generation Station is Unit #7 (154.4 MW), which can also operate as a synchronous condenser.

Future expansion is assumed for Bay d'Espoir Generation Station with the addition of Unit #8 (154.4 MW) upgrading the total capacity to approximately 767 MW.

This network also includes a 15 MVAR reactor at Granite Canal Tap Terminal Station.

[13] A power transformer must have a primary and secondary voltage rating of ≥230kV to be considered part of the PTS.

Steady state analysis indicates that within the long-term horizon, there are no violations within this network under normal operation or any contingency event involving the loss of any 230 kV line, generator, reactor or synchronous machine.

In the event of an outage to the Granite Canal Tap Shunt Reactor, TL269 would be removed from service in accordance with NLSO operating instructions. There are no violations to Transmission Planning Criteria associated with this scenario.

5.3.2 Bay d’Espoir - Western Avalon Corridor

Bay d’Espoir Terminal Station is interconnected to Western Avalon Terminal Station through a network of 230 kV transmission lines that includes the following:

- TL202 between Bay d’Espoir Terminal Station #1 and Sunnyside Terminal Station
- TL206 between Bay d’Espoir Terminal Station #2 and Sunnyside Terminal Station
- TL267 between Bay d’Espoir Terminal Station #2 and Western Avalon Terminal Station
- TL203 between Sunnyside Terminal Station and Western Avalon Terminal Station
- TL207 between Sunnyside Terminal Station and Come by Chance Terminal Station
- TL237 between Come by Chance Terminal Station and Western Avalon Terminal Station

This network also includes four 38.45 MVAR capacitor banks at Come by Chance Terminal Station.

Steady state analysis indicates that within the near and long-term horizons there are no violations in this corridor under normal operation or any contingency event involving the loss of a transmission line or capacitor bank.

There are transmission constraints on the 230 kV lines[14] to the Avalon Peninsula during a LIL bipole outage (N-2 contingency), but it is outside the scope of the annual assessment and is currently being investigated as part of another study.

Operating limits in this corridor are defined in accordance with NLSO guidelines. Transient stability limits for this transmission corridor are currently being assessed as part of the operational studies mentioned in Section 3.1.

[14] TL201, TL202, TL203, TL206, TL207, TL217, TL237 and TL267

5.3.3 Avalon Peninsula System

The Avalon Peninsula is the largest load center on the Island Interconnected System that is comprised of a network of 230 kV transmission lines that include the following:

- TL201 and TL217 between Western Avalon Terminal Station and Soldiers Pond Terminal Station
- TL265 and TL268 between Soldiers Pond Terminal Station and Holyrood Terminal Station
- TL242 and TL266 between Soldiers Pond Terminal Station and Hardwoods Terminal Station
- TL236 between Hardwoods Terminal Station and Oxen Pond Terminal Station
- TL218 between Oxen Pond Terminal Station and Holyrood Terminal Station

This network also includes synchronous condensers at Soldiers Pond as well as Unit 3 at Holyrood Generating Station and the Combustion Turbines at Holyrood and Hardwoods Terminal Station.

Steady state analysis indicates that within the near and long-term horizons there are two violations within the Avalon Peninsula System following a contingency event involving the loss of a transmission line. These violations include the following:

Table 2 - Avalon Violations

Contingency	Violation	Year of Violation
Loss of TL236	Overload of HWD-T1	2031
	Overload of HWD-T2	2034
	Overload of HWD-T3	2031
	Overload of HWD-T4	2031
Loss of TL266	Overload of TL-242	2031

The advancement of these violations is driven by load growth in the St. John's Area and the planned retirement of the HWD Gas Turbine as a generating source in 2030.[15] Hydro is in the process of conducting a life-extension study for the HWD Gas Turbine, which is expected to be completed by Q4 2025. Depending on the outcome of this study, the violations in Table 2 may be deferred beyond 2031 if it is determined that the life extension of the HWD Gas Turbine is cost effective.

There are transmission constraints on the 230 kV lines[16] to the Avalon Peninsula during a LIL bipole outage (N-2 contingency), but it is outside the scope of the annual assessment and is currently being investigated as part of various studies in support of the RRA.

Operating limits on the Avalon Peninsula are defined in accordance with NLSO operating limits.

[15] The HWD GT would continue to serve as synchronous condenser.

[16] TL201, TL202, TL203, TL206, TL207, TL217, TL237 and TL267

5.3.4 Western Island Interconnected System

The Western Island Interconnected system consists of a network of 230 kV transmission lines that include the following:

- TL204 between Bay d'Espoir Terminal Station #1 and Stony Brook Terminal Station
- TL231 between Bay d'Espoir Terminal Station #2 and Stony Brook Terminal Station
- TL205 and TL232 between Stony Brook Terminal Station and Buchans Terminal Station
- TL233 between Buchans Terminal Station and Bottom Brook Terminal Station #2
- TL211 between Bottom Brook Terminal Station #2 and Massey Drive Terminal Station
- TL228 between Buchans Terminal Station and Massey Drive Terminal Station
- TL248 between Massey Drive Terminal Station and Deer Lake Terminal Station
    - Loss of this line isolates Cat Arm generation
- TL247 between Deer Lake Terminal Station and Cat Arm Terminal Station
    - Loss of this line isolates Cat Arm generation

This network also includes three hydro generating facilities, Cat Arm, Hinds Lake and Deer Lake Generation Stations. The two units at the Cat Arm Generating Station can also operate in synchronous condenser mode.

Steady state analysis indicates that within the near and long-term horizons, there are no violations on this network under normal operation or the loss of any 230kV line or generator. Operating limits for the Western Island Interconnected System are defined in accordance with NLSO operating limits. Transient stability considerations are being investigated as part of operational studies, as addressed in Section 7.

Considerations associated with outages to TL248 are defined in accordance with NLSO operating instructions.

5.3.5 The Exploits System

This network only includes the 230 kV line from Stony Brook Terminal Station to the Grand Falls Terminal Station (TL235). The loss of this line isolates Exploits Generation from the rest of the Island Interconnected System, which results in no violations.

5.3.6 The Labrador 315 kV System

The Labrador Interconnected System consists of two 315 kV transmission lines between Churchill Falls Terminal Station #2 and Muskrat Falls Terminal Station #2. These two lines are designated as L3101 and L3102.

Table 3 provides a summary of the pre-contingency transformer loading levels across the planning horizons for transformers located on the Labrador Interconnected System that fall under the planning authority of the NLSO.

Table 3 – Transformer Peak Loads

Transformer	2034/2035	
	MVA	%
CHFTS2-T1	82.13	9.8%
CHFTS2-T2	81.90	9.7%

Table 4 provides the transformer loading with the largest transformer out of service.

Table 4 – Transformer Peak Loads – Loss of Largest Transformer[17]

Transformer	2034/2035	
	MVA	%
CHFTS2-T1	152.62	18.2%
CHFTS2 T2	***Out of Service***	

There are no thermal overloads on the 315 kV lines in a pre-contingency state for any generation dispatch scenario on the LIS. With a 315 kV line out of service, the remaining line is limited to avoid under or over frequency if that line trips. The 315 kV transfer limits with a prior line outage are provided in the relevant operating instruction.

5.3.7 The Labrador-Island Link

The LIL is an HVdc bipole that electrically connects the IIS and LIS, which terminates at the Muskrat Falls Converter Station and the Soldiers Pond Converter Station. Steady state analysis indicates that within the near and long-term horizons, there are no violations under normal operation or any single contingency event involving the loss of a pole or an ac filter at the Muskrat Falls or Soldiers Pond terminal stations. The LIL transfer limits are a function of the following:

- Island Demand (MW)
- LIL Mode of Operation (Bipole or Monopole)

[17] The following are two scenarios in which higher flow on the 315 kV system could be experienced:

1. Minimum MFA generation and high LIL flow
2. LIL is offline and full MFA generation is dispatched

In both cases, the transformers and 315 kV lines would not be overloaded.

- Available frequency response from the Maritime Link[18]
- Muskrat Falls Generation Dispatch
- Soldiers Pond Synchronous Condenser Dispatch
- Status of the Labrador 315 kV System
- Accepted[19] amount UFLS following a LIL Bipole Trip

5.3.8 The Maritime Link

The ML is an HVdc bipole that electrically connects the Island Interconnected System to Nova Scotia via two 170 km subsea cables. The link terminates at Bottom Brook Terminal Station #2 in Newfoundland and at Woodbine Terminal Station in Nova Scotia. Steady state analysis indicates that within the near and long-term horizons, there are no violations under normal operation or any contingency event involving the loss of a single pole or an ac filter at Bottom Brook Terminal Station #2. There is currently a firm export commitment of 158 MW[20] to Nova Scotia that must not be interrupted unless there is a LIL pole or bipole outage, at which time the firm exports would be pro-rated based on LIL available capacity. The study cases were all setup with the total firm export commitment on the ML of 250 MW. The ML is capable of operating within its full import (320 MW) and export (500 MW) capacity range with LIL Power Demand Overrides ("PDOs")[21] enabled.

The ML import and export limits are provided in the applicable operating procedure.

6 Short Circuit Analysis

Short circuit analysis is required to ensure that the prospective short circuits for equipment locations do not exceed the interrupting capacity of the circuit breakers used to protect the equipment. All circuit breakers with known asset information were assessed.[22] Short circuit analysis was performed and the results indicate that there are no circuit breaker rating violations.

---

[18] Frequency Controller Capacity or Status of ML Runbacks/PDOs.

[19] Once the LIL bipole is proven reliable though testing/commissioning, the amount of acceptable UFLS will increase as a LIL bipole trip should be less probable.

[20] At Bottom Brook Terminal Station

[21] HVdc PDOs are used to help regulate system frequency on the Island Interconnected System following a HVdc contingency on another link and can be defined as follows:

Runback: a coordinated instantaneous reduction of the power order (imports or exports) on an HVdc link in an attempt to avoid an under or over frequency event

Run-up: a coordinated instantaneous increase of the power order (imports or exports) on an HVdc link in an attempt to avoid an under or over frequency event

[22] Planned outages are required to gather the unknown asset information, but will eventually be collected during scheduled maintenance to avoid any unnecessary customer impact.

7 Stability Analysis

As discussed in previous sections, Hydro is undertaking operational studies to assess the transient stability of the NL Transmission System. Until these studies are complete, the dynamic analysis of the NL Transmission System shall remain outside of the scope of the annual assessment process. The final operational study is currently in progress as the LCP assets have been fully integrated into the NL Transmission System, and is expected to be completed by Q2 2025. The NLSO will provide a plan for future transient stability analysis, as it is expected it may not be required on annual basis or will be triggered based on material changes to the IIS or LIS.

8 Conclusions

The 2025 Annual Planning Assessment focuses on the planning horizon to 2034/35. Conclusions of the 2025 Annual Planning Assessment are stated as follows:

- The NL Transmission System includes Radial and Local Networks where outages to system elements may result in customer impacts. Transmission Planning Criteria are not strictly applied in these cases. Rather, these systems are designed to meet customer reliability and cost requirements.
- The steady state contingency analysis on the Labrador West Local Network indicates that for all pre-contingency and single contingency conditions, there are no transmission equipment overloads or voltage violations in the near-term or long-term planning horizons provided that approved upgrades will be implemented.
- Transmission Planning Criteria are strictly applied to the Primary Transmission System. Steady state analyses were performed and the following conditions were confirmed for the long-term horizon:
  - There are no pre-contingency transmission equipment overloads or voltage violations.
  - **The following are single contingency events that result in a violation of the Transmission Planning Criteria, but may be addressed based on the outcome of future studies:**
    - **Loss of Wabush Synchronous Condenser.**
    - **Loss of TL236 and TL266.**
- The short circuit analyses were performed and it was confirmed that there are no issues with circuit breaker ratings.
- Transient stability analysis is currently in progress as part of ongoing operational studies in support of the LCP integration effort. These studies are expected to be completed by Q2 2025. The final operational study will be provided as part of the 2026 Annual Assessment. The NLSO will also provide a plan for future transient stability analysis, as it is expected it may not be required on an annual basis or will be triggered based on material changes to the IIS or LIS.

9 Reference Documents

1. Operational Study - Stage 4C: Labrador Transfer Analysis (TP-R-034)
2. Labrador Interconnected System - Expansion Study (TP-R-019)
3. TP-S-001 NLSO Standard – Facilities Rating Guide
4. TP-S-003 NLSO Standard – Annual Planning Assessment
5. TP-S-007 NLSO Standard – Transmission Planning Criteria

APPENDIX A

Island and Labrador Interconnected Systems

Figure 1 – Island Interconnected System

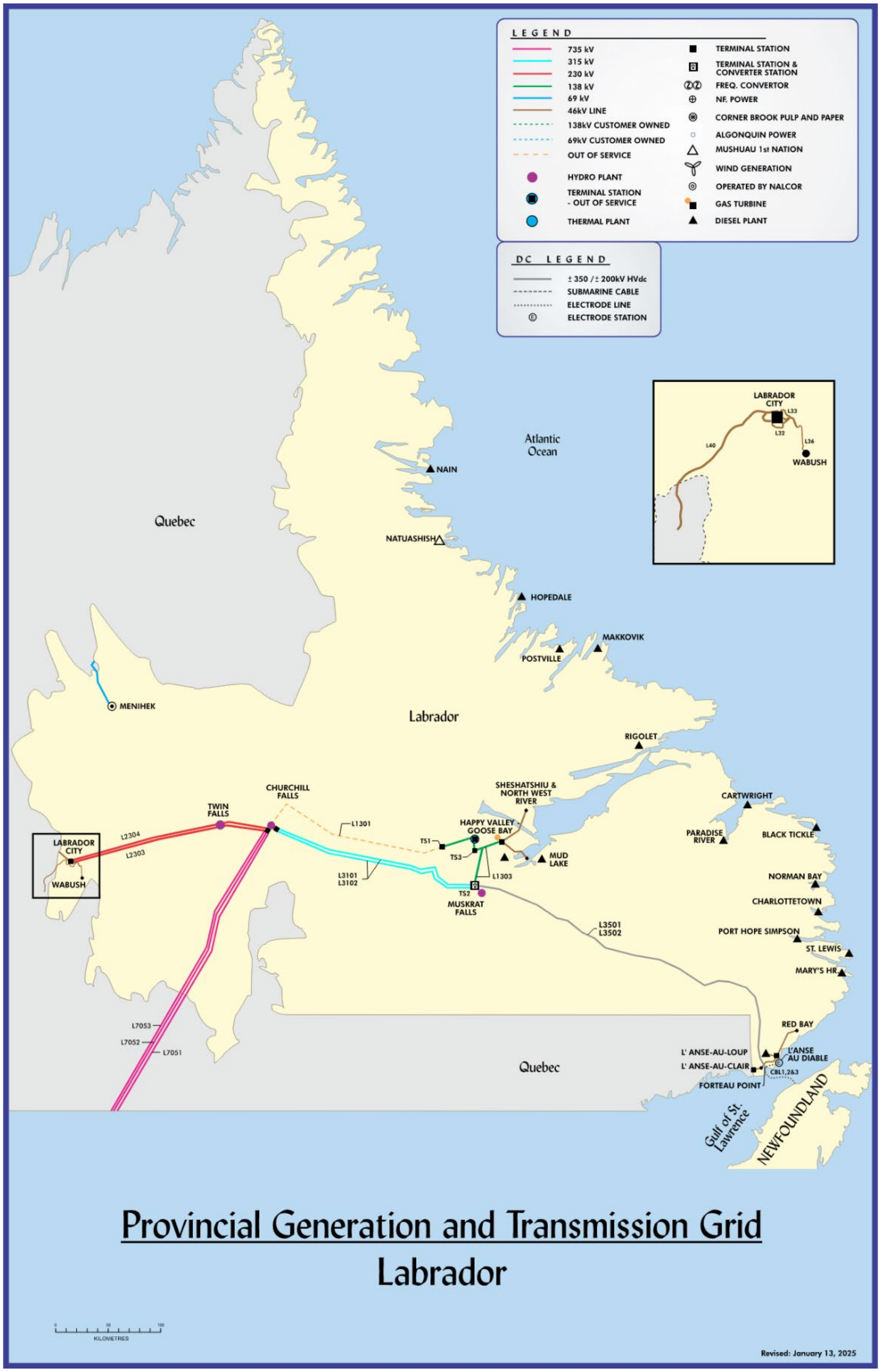


Figure 2 – Labrador Interconnected System

APPENDIX B

Load Flow Plots Primary Transmission System Year Ten (2034/2035) – Peak and Light Case

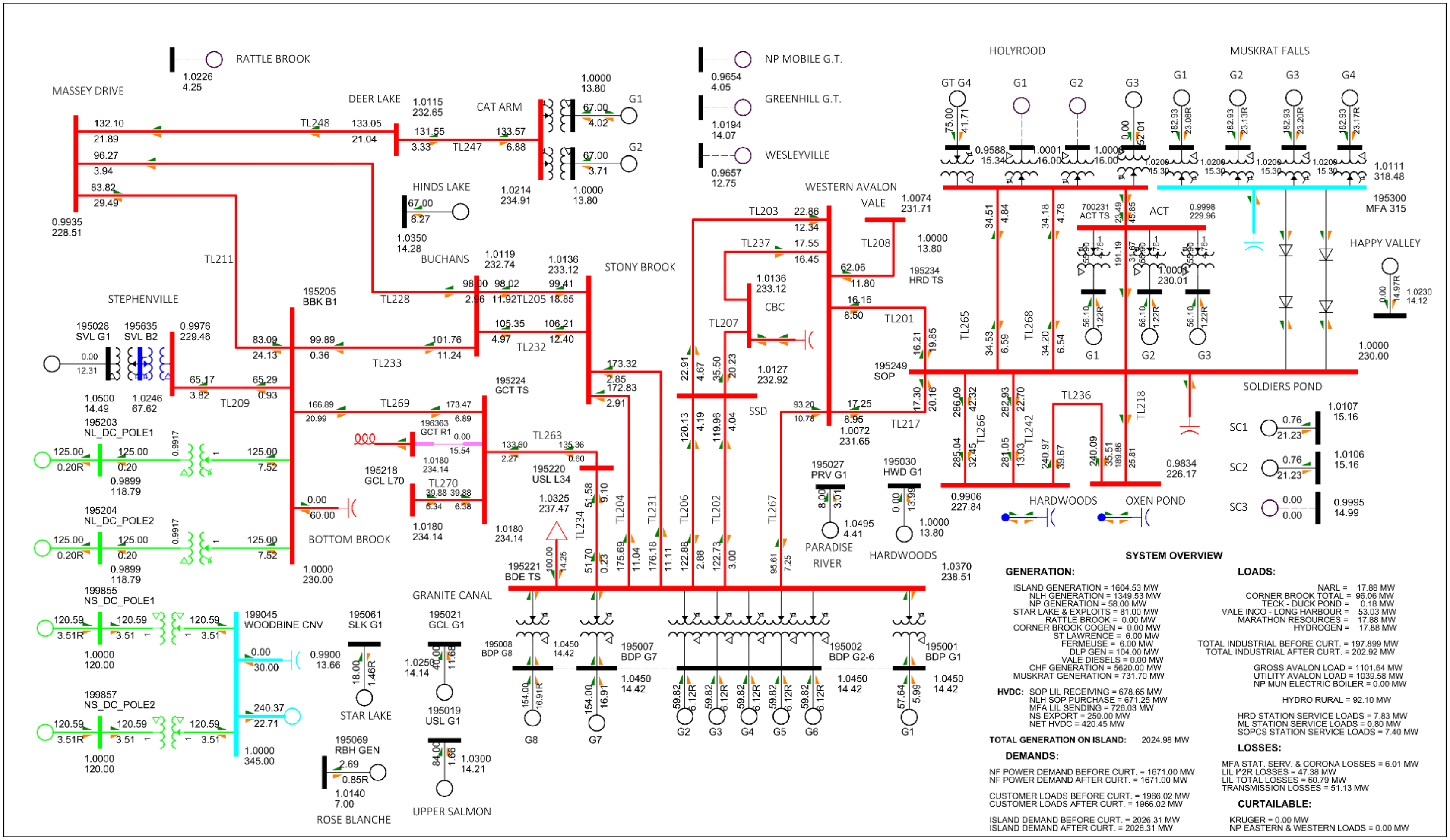


Figure 3 – IIS (2034/35 Peak Conditions – ML Exports (Emera Block – 250 MW))

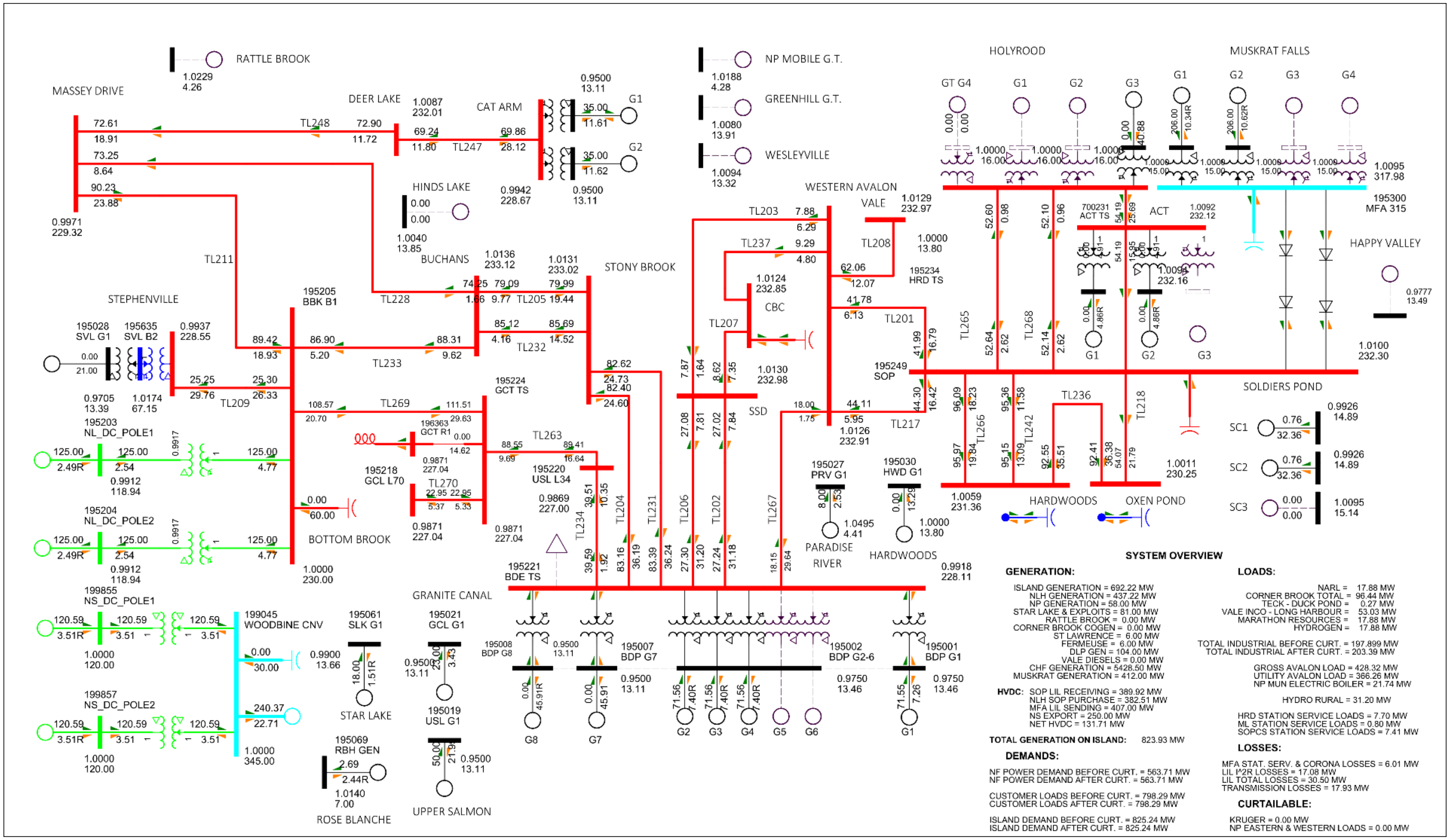


Figure 4 – IIS (2034 Light Conditions – ML Firm Exports (250 MW))

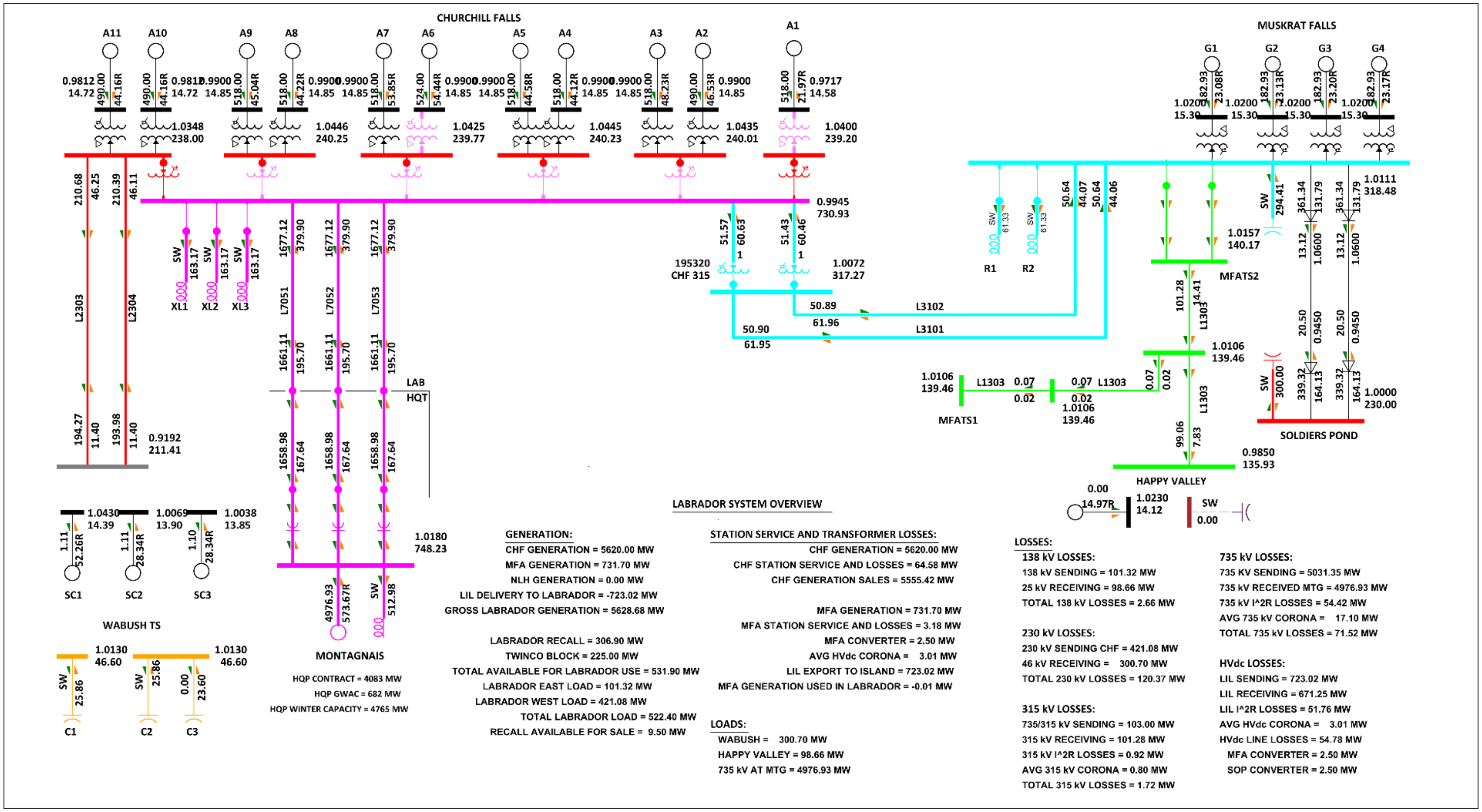


Figure 5 – LIS (2034/35 Peak Conditions)

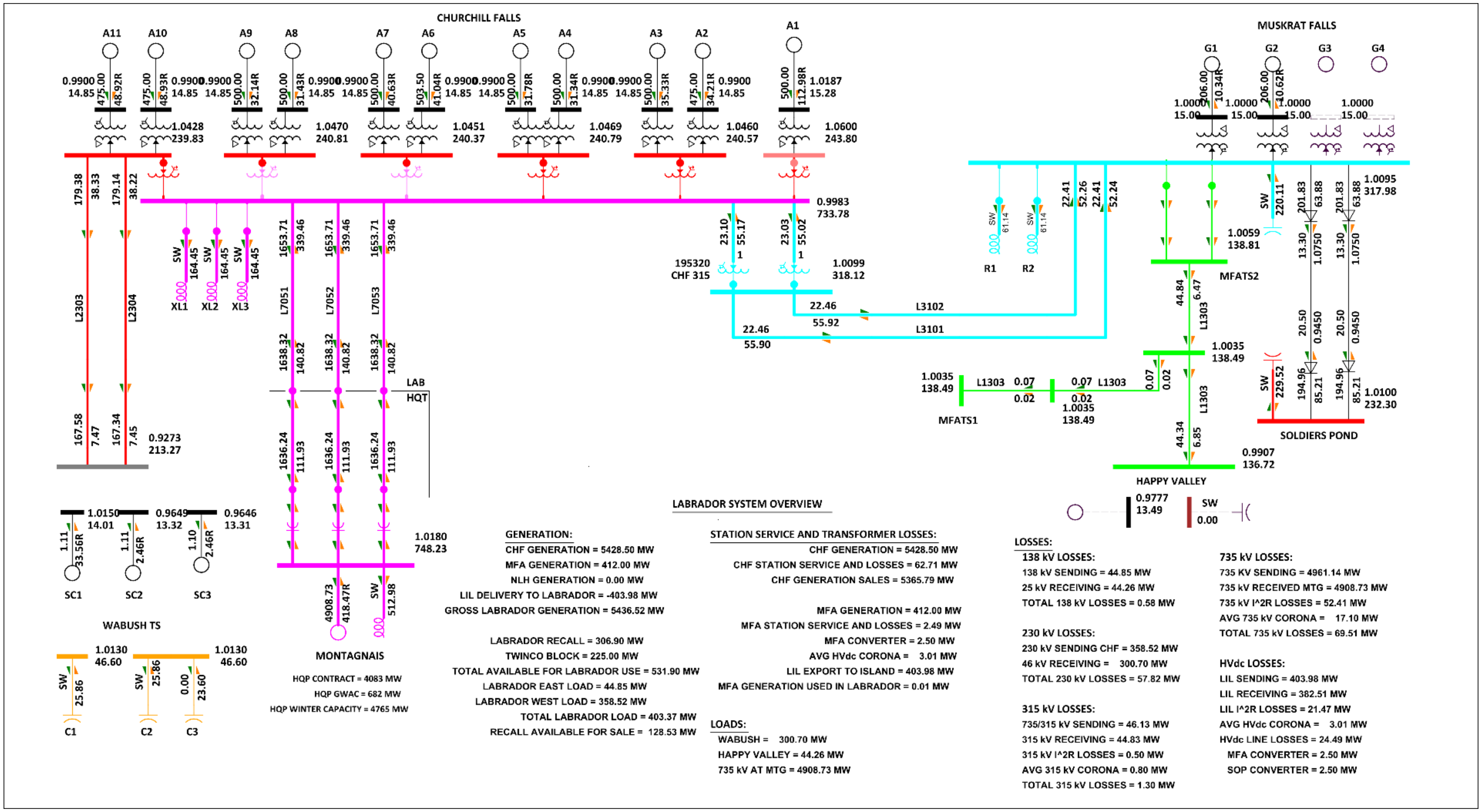


Figure 6 – LIS (2034 Light Conditions)

Document Summary

Document Owner:	Transmission Planning
Document Distribution:	NLSO

Revision History

Revision	Prepared by	Reason for change	Effective Date
0		Original Issue	2025/03/31
1		Corrected Lab East forecast in Table 1	2025/05/06

Document Approvers

Position	Signature	Approval Date
Sr. Manager of Transmission and Rural Planning		2025/05/06

Document Control

Regarding NLSO documents: The electronic version of this document is the CONTROLLED version. Please check the NLSO Document Management System SharePoint site for the official copy of this document. This document, when downloaded or printed, becomes UNCONTROLLED.

NL Hydro Report - 2025 Annual Planning Assessment

Doc # TP-R-093

Date: 2025/05/13

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") ensures the coordinated development of a safe, reliable and economical transmission system for the benefit of users within the Province of Newfoundland and Labrador ("NL"). The Hydro transmission planning process involves the execution of power system studies to ensure compliance with Transmission Planning Criteria and to determine the timing of system additions and modifications.

The annual assessment of the NL Transmission System is performed by the Newfoundland and Labrador System Operator ("NLSO") and is summarized in a separate document.[1] The NL Transmission system is comprised of transmission facilities located in NL operating at a voltage level of 230 kV or higher within the Island Interconnected System ("IIS") and Labrador Interconnected System ("LIS") including the Labrador-Island Link ("LIL") and the Labrador Transmission Assets ("LTA"). This document provides an overview of Hydro's assessment, which addresses all other transmission system facilities with a rated voltage of 46 kV and above that are under the operational control of Hydro. The 2025 Annual Planning Assessment revealed the following:

- Steady state analyses were performed and the following violations were identified for the long-term planning horizon:
    - There was one pre-contingency transmission equipment overload:
        - **South Brook Transformer T1 is expected to be overloaded by 2031/2032.** Hydro will perform further analysis with a more detailed load forecast to verify the timing of the violation.
    - There were three contingency transmission equipment overloads:
        - **Loss of transmission line L32 (46 kV) to Labrador City results in an overload on line L33 in the year 2029.** Hydro is currently investigating low-cost options to increase the thermal rating of L33.
        - **Loss of transmission line L33 (46 kV) to Labrador City results in an overload on line L32 in the year 2025.** Hydro is currently preparing an operational procedure to address a potential short-term overload this coming winter in the rare event of an unplanned outage of line L33 during peak conditions. Low-cost options to increase the thermal rating of L32 are also being investigated.
        - **Loss of transformer T1 or T5 at the Happy Valley Terminal Station will result in an overload on transformers T2 and T4 by 2033/34.** The forecast does not include all the Network Addition Customers (See Section 3.2), which if connected, will advance the violation to 2029/30. This overload violation can be mitigated on an interim basis by dispatching the Happy Valley ("HVY") gas turbine for capacity support. The long-term solution would be to replace Transformer T2 with a 50 MVA transformer.
- There were no voltage violations identified as part of the pre-contingency and contingency analysis summarized in Section 5.

[1] NLSO Annual Transmission Assessment (2025) – TP-R-092

- The key takeaways from the 2025 Newfoundland Power ("NP") Loop Assessment include:
  - **Sunnyside/Stoney Brook ("SSD"/"STB") Loop:** The loss of SSD-T4 results in an overload on SSD-T1. This is mitigated by dispatching NP gas turbines at Wesleyville ("WES") and Greenhill ("GRH"), however, these gas turbines are approaching their end of life.
  - **Hardwoods/Oxen Pond ("HWD"/"OPD") Loop:** The loss of OPD-T1 results in HWD-T3 being loaded to 99.4% of its rating with all mitigating measures applied.

  Hydro and NP will conduct a joint study to establish a long-term plan for both loop systems. The results of the joint study will be provided as part of the 2026 Annual Assessment.
- The short circuit analysis reveals no issues with circuit breaker ratings. All circuit breakers with known asset information were assessed.[2]
- Transient stability analysis is currently in progress as part of ongoing operational studies,as the LCP assets have been fully integrated into the NL Transmission System. These studies are expected to be completed by Q2 2025. The final operational study will be provided as part of the 2026 Annual Assessment. The NLSO will also provide a plan for future transient stability analysis, as it is expected it may not be required on an annual basis or will be triggered based on material changes to the IIS or LIS.

[2] Planned outages are required to gather the unknown asset information, but will be collected during scheduled maintenance to avoid any unnecessary customer impact.

Table of Contents

1 Introduction

The Hydro Transmission Planning Process involves the execution of power system studies to ensure compliance with Transmission Planning Criteria and to determine the timing of system additions and modifications. The 2025 Annual Planning Assessment covers the period extending to the winter of 2034/35. Cases are assessed to investigate the capability of the transmission system to meet peak load and firm transmission commitments of 250 MW.

This report addresses the NL Interconnected Transmission Systems, which are comprised of transmission facilities located in NL, operating at a voltage level of 46 kV or higher, but less than 230 kV. It is noted that NL Transmission System facilities, operating at a voltage level of 230 kV or higher, are addressed separately as part of the NLSO 2025 Annual Planning Assessment.[3] Analysis is performed to ensure compliance with appropriate criteria, including those defined in TP-S-007 - NLSO Standard – "Transmission Planning Criteria".

The maps of the IIS and LIS are provided in Appendix A.

[3] The NLSO 2025 Annual Planning Assessment addresses the NL Transmission System, which is comprised of transmission facilities located within the IIS and LIS, operating at a voltage level of 230 kV or higher, including, the LIL and LTA.

2 Selection of Study Cases

System models have been developed to reflect the latest load forecast with completed system changes including proposed additions/modifications for future years ranging to 2034. The following system additions are included in the 2034/35 study cases:

- The Final Under Frequeney Load Shedding ("UFLS") Scheme is implemented to allow for increased power transfer over the LIL.[4]
- The Muskrat Falls Generating Station (MFAGS) has four 206 MW generating units in service
- The LIL is operating in Bipole Mode up to its rated capacity of 900 MW (Rdc = 19.29 ohm)
    - All filter banks are available at each of Muskrat Falls and Soldiers Pond Converter Stations
    - Electrode lines and electrode sites are in service
- Churchill Falls recall power (less Labrador loads) is available to send to the Island
- There are two 60 MVAr line reactors installed on the Muskrat Falls end of 315 kV lines L3101 and L3102
- There are two Soldiers Pond 175 MVAr synchronous condensers in service for analysis (the third unit is available)
- The ML exports are set at 250 MW at Bottom Brook Terminal Station 2 – ("BBKTS2") in both the peak and light load cases
- Muskrat Falls TS3 T1 has been disconnected
- Holyrood Thermal Generating Station ("Holyrood TGS") is out of service with Unit 3 operating in synchronous condenser mode
- Holyrood Combustion Turbine G4 is in-service
- Proposed Bay d'Espoir Unit 8 (154.4 MW) and new Avalon Combustion Turbine Plant ("ACT") in Holyrood (3 x 56.1 MW)[5] are in-service, per the recommendation of the 2024 Resource Adequacy Plan in order to meet forecasted load growth in the study cases.
- 100 MW of proposed new wind generation was added to meet forecasted load growth in the study cases per the recommendation of the 2024 Resource Adequacy Plan.
- Stephenville ("SVL") gas turbine is in-service as a synchronous condenser (no longer available as a generator)[6]
- Hardwoods ("HWD") gas turbine is in-service as a synchronous condenser (no longer available as a generator)[7]
- A new curtailable electric boiler load has been installed at MUN (both Light and Peak load cases), which is curtailed in Peak load cases
- Valentine Terminal Station is in service, with the following configuration (both Light and Peak load cases):
    - Phase 2: 6 MVAr capacitor bank on 6.6 kV bus VLN T1, and 4 MVAr capacitor bank on 6.6 kV bus VLN T2

[4] Hydro and Newfoundland Power are currently in the process of designing the final UFLS scheme.

[5] The rating of the ACT units has not been finalized, but will be approximately 50 MW per unit. 3 x 56.1 MW was used for ease of modelling with the understanding a slight variation in ratings would have no material impact on the results. The PSSE models will be updated once the ratings are finalized and specifications have been provided by the successful vendor.

[6] Hydro is expected to complete a life-extension study for the SVL Gas Turbine by Q4 2025.

[7] Hydro is expected to complete a life-extension study for the HWD Gas Turbine by Q4 2025.

- Wind Hydrogen loads have been connected at the following locations:
  - Stephenville TS 230 kV bus
  - Voisey's Bay Nickel TS 230 kV bus
- Wabush Terminal Station upgrades include:
  - Addition of a 23 MVAr capacitor bank C3
  - Transformers T4 and T5 have been replaced with 125 MVA units
- Wabush Substation has been renamed to Jean Lake Terminal Station. Upgrades include:
  - Transformers T3, T4, T5 and T6 have been removed from service
  - New 20/26.7/33.3 MVA transformers T1 and T2 have been installed
  - A 12.5 kV bus tie has been added, which is normally open

The following load flow plots for the Year Ten (2034/35) cases are provided in Appendix B:

- 2034/35 Peak Load Conditions
- 2034 Light Load Conditions

3 Special Consideration

Special considerations for this study period are discussed in the sections below.

3.1 Operational Studies

Hydro is currently conducting a set of operational studies as part of the integration effort of the LCP assets into the NL Transmission System. The objective of these studies is to identify operating limits or guidelines to allow for the development of instructions to be used by the NLSO. These operational studies include assessments of the transient stability of the IIS and LIS with all LCP assets fully integrated. Transient stability considerations will therefore be outside of the scope of annual assessments until the operational studies are complete. The final operational study is expected to be completed by the end of Q2 2025, with a summary of results to be provided in the 2026 Annual Assessment.

3.2 Labrador Incremental Load

Hydro is currently undertaking a process to investigate large incremental customer load requests in Labrador. These incremental requests are beyond the baseline forecast and outside of the scope of any Annual Assessment.

Transmission system expansion requirements to serve incremental customers in Labrador East was assessed in a standalone study in 2024 in accordance with Hydro's Network Addition Policy. The study concluded that additional transformation[8] is required at the HVY Terminal Station by the winter of 2029/2030 to facilitate the firm load requests in Labrador East.

Hydro has received several large load requests in Western Labrador for new potential mining expansions/projects that total approximately 2,000 MW. Hydro is currently working with external consultants in conducting a Transmission Feasibility Study to determine the transfer capacity and cost for multiple transmission upgrade options between Churchill Falls and Labrador West to support various load

[8] The replacement of an existing transformer (25 MVA) with a 50 MVA transformer

scenarios. Hydro is also working with Hydro Quebec ("HQ") to assess potential solutions involving an interconnection between Labrador West and the HQ transmission system to serve the firm load requests in Labrador West.

Hydro continues to assess the availability of non-firm supply to Labrador East and West for potential customers willing to be interruptible.

4 Load Forecast

The 2025 Annual Planning Assessment is based upon the following load forecasts prepared by the Market Analysis and Load Forecasting Section, Resource and Production Planning Department of Newfoundland and Labrador Hydro:

- IIS Peak Demand Forecast System – prepared in June 2024; and
- LIS Long Term Load Forecast – prepared in June 2024.

The IIS and LIS P90 forecasted peaks are summarized in Table 1.

Table 1 – Peak Load Forecasts (P90) - IIS and LIS

Forecasted Demand (MW)[9]			
Year[10]	Island Interconnected System (IIS)	Labrador Interconnected System (LIS)[11]	
		Lab East	Lab West
2024/25	1,767	79.1	383.4
2025/26	1,802	80.4	384.3
2026/27	1,817	81.9	384.6
2027/28	1,838	82.8	385.0
2028/29	1,867	83.5	385.4
2029/30	1,878	102.3	385.8
2030/31	1,897	103.0	386.3
2031/32	1,914	103.7	386.8
2032/33	1,941	104.6	387.5
2033/34	1,962	105.5	388.2
2034/35	1,987	106.6	389.1

[9] These forecasts do not include NLH system transmission losses or station service load requirements.

[10] The peak is assumed to occur sometime between December and March of the following year.

[11] The Labrador Interconnection Forecast does not include the Network Addition Requests mentioned in Section 3.2, with the exception of the largest request in Lab East (added in 2029/30).

5 Steady State Analysis

The steady state analysis consists of pre-contingency and contingency analysis. The pre-contingency analysis is performed to ensure that with all equipment in service under normal operation, power flows in all elements are at or below normal rating and voltages are within acceptable limits. The contingency analysis performs the same checks, but with each major transmission element removed from service. The ratings are defined as per TP-S-001 - NLSO Facilities Rating Guide. The results of the steady state analysis are described in the sections below.

Load flow plots during normal operation of the NL Transmission System for Year Ten (2034/35) are provided in Appendix B.

5.1 Summary of Pre-Contingency Transformer Peak Loads

Table 2 provides a summary of the pre-contingency transformer loading levels in Year Ten (2034/35). A review of the pre-contingency peak cases for long-term horizons indicates that there is one violation at the South Brook Terminal Station.

Table 2 – Pre Contingency Transformer Load Levels[1]

Station	Unit	Rating (MVA)	2034/35	
			MVA	%
Barachoix	T1	10/13.3/16.7	7.46	44.7%
Bay d'Espoir	T10	15/20/25	10.16	40.6%
	T11	10/13.3/16.7	6.50	38.9%
	T12	15/20/25	10.08	40.3%
Bear Cove	T1	10/13.3/16.7	5.22	31.3%
Berry Hill	T1	15/20/25	2.10	8.4%
Bottom Brook	T1	25/33.3/41.7	27.17	65.2%
	T3	25/33.3/41.7	14.02	33.6%
Bottom Waters	T1	10/13.3/16.7	6.21	37.2%
Buchans	T1	40/53.3/66.6	6.51	9.9%
	T2	5/6.6/8.3	3.03	36.5%
Coney Arm	T1	2.5/3.3/4	0.12	3.0%
Conne River	T1	2.5/3.3	2.60	78.9%
Corner Brook Converter	T1	21/28	9.00	32.2%
	T2	21/28	9.37	33.5%
Cow Head	T1	5/6.7/8.3	2.04	24.6%
Daniel's Harbour	T1	1/1.3	0.57	43.5%
	T2	1/1.3	0.56	43.1%
Deer Lake	T1	25/33.3/41.7	9.82	23.6%
	T2	45/60/75	23.79	31.7%
Doyles	T1	25/33.3/41.7	29.04	69.6%
English Harbour West	T1	5/6.7	2.96	44.1%
Farewell Head	T1	10/13.3/16.7	7.32	43.8%
Glenburnie	T1	2.5/3.3	2.92	88.4%
Grand Falls Frequency Converter	T1	30/40/50	22.97	45.9%
	T2	30/40/50	24.13	48.3%

	T3	30/40/50	20.36	40.7%
Grandy Brook	T1	7.5/10/12.5	5.31	42.5%
Hampden	T1	2.5/3.3/4	1.81	45.2%
Happy Valley	T1	30/40/50	34.77	69.5%
	T2	15/20/25//28	19.39	69.2%
	T4	15/20/25//28	19.39	69.2%
	T5	30/40/50	33.97	67.9%
Hardwoods	T1	75/100/125	107.37	85.9%
	T2	40/53.3/66.6	54.79	82.1%
	T3	40/53.3/66.6	59.16	88.7%
	T4	75/100/125	106.52	85.2%
Hawke's Bay[2]	T1	5/6.7	***NOTE 2***	
	T2	2.5/3.3		
Holyrood	T5	15/20/25	21.47	85.9%
	T10	15/20/25	20.91	83.6%
	T6	25/33.3/41.7	10.94	26.2%
	T7	75/100/125	30.98	24.8%
	T8	75/100/125	31.76	25.4%
Howley[3]	T2	7.5/10/12.5	3.41	27.3%
Jackson's Arm	T1	5/6.6/8.3	1.46	17.7%
Main Brook	T1	1.5	0.69	46.1%
Massey Drive	T1	75/100/125	58.23	46.6%
	T2	40/53.3/66.7	39.65	59.4%
	T3	75/100/125	70.27	56.2%
Muskrat Falls TS1	T1	2	0.07	3.7%
Muskrat Falls TS2	T5	75/100/125	56.17	44.9%
	T6	75/100/125	54.99	44.0%
Oxen Pond	T1	150/200/250	176.45	70.6%
	T2	75/100/125	85.09	68.1%
	T3	150/200/250	176.45	70.6%
Parson's Pond	T1	1/1.3	0.70	53.9%
Peter's Barren	T1	15/20/25	2.25	9.0%
Plum Point	T1	10/13.3/16.7	3.69	22.1%
Quartzite	T1	15/20/25	18.27	73.1%
	T2	15/20/25	18.15	72.6%
Rocky Harbour	T2	5/6.6/8.3	4.81	57.9%
Roddickton Woodchip	T2	5	2.77	55.3%
South Brook	T1	5/6.6/8.3	**8.31**	**100.1%**
Stephenville	T3	40/53.3/66.7	56.66	84.9%
Stony Brook	T1	75/100/125	106.74	85.4%
	T2	75/100/125	105.46	84.4%
St. Anthony Airport[4]	T1	15/20/25	15.76	63.1%
St. Anthony Diesel Plant[4]	T1	15/20/25	11.49	47.7%
Sunnyside	T1	75/100/125	91.66	73.3%
	T4	75/100/125	92.32	73.9%
	T5	15/20/25	10.18	40.7%
Vanier	T1	15/20/25	13.92	55.7%
	T2	15/20/25	14.13	56.5%
Wabush Terminal Station[5]	T1	35/47/65	37.21	57.2%
	T2	35/47/65	38.37	59.0%

	T3	35/47/65	37.77	58.1%
	T4	75/100/125	79.46	63.6%
	T5	75/100/125	79.00	63.2%
	T6	35/47/65	36.57	56.3%
	T7	50/66.6/83.3	52.98	63.6%
	T8	50/66.6/83.3	52.88	63.5%
Wabush Substation (AKA Jean Lake)[6]	T1	20/26.7/33.3	11.23	33.7%
	T2	20/26.7/33.3	14.87	44.7%
Western Avalon	T1	15/20/25	15.94	63.8%
	T2	15/20/25	16.24	64.9%
	T3	25/33.3/41.7	16.19	38.8%
	T4	25/33.3/41.7	16.10	38.6%
	T5	75/100/125	47.19	37.7%
Wiltondale	T1	1.5	0.07	4.9%

Notes:

1. Generator step up transformers and converter transformers are not included as these units have been sized for the full unit capability.
2. The Hawke's Bay system has a transformer peak of 6.34 MW and is typically supplied by the 15 MVA mobile transformer during the winter season.
3. Rattle Brook hydro generator G1 is not in-service, but is available for capacity support at 4 MW.
4. St. Anthony Diesel Plant is not in-service, but is available for capacity support.
5. WABTS transformers T4 and T5 will both be replaced with 125 MVA units prior to Year 10 (2034/35).
6. An additional 33.3 MVA transformer (WABSUB T2) will be installed prior to Year 10 (2034/35).

Violation: The South Brook transformer T1 will exceed 100% loading in 2033/34. Hydro will perform further analysis with a more detailed load forecast to confirm the timing of the transformer overload.

5.2 Review of Radial Systems

Radial systems that are impacted by loss of a transmission line are summarized in Table 3.

Table 3 – Radial Transmission Systems and Impact of Line Loss

TL #	kV	From	To	Impact
214	138	Bottom Brook	Doyles	Loss of load in Doyles/Port-aux-Basques area. Newfoundland Power owns mobile gas turbine and mobile diesel located at Grand Bay as well as Rose Blanche hydro site which can supply limited load in area.
215	66	Doyles	Grand Bay	Loss of load in Port-aux-Basques area. Newfoundland Power owns mobile gas turbine and mobile diesel located at Grand Bay as well as Rose Blanche hydro site which can supply limited load in area.
220	69	Bay d'Espoir	Barachoix	Loss of load on the Connaigre Peninsula
221	66	Peter's Barren	Hawke's Bay	Loss of load in the Hawke's Bay/Port Saunders area. Hydro maintains a 5 MW diesel plant at Hawke's Bay that provides limited back up.
226	66	Deer Lake	Berry Hill	Loss of load in Bonne Bay. TL226 can be isolated in various locations such that Bonne Bay area loads can be supplied from Berry Hill following line switching.
227	66	Berry Hill	Daniel's Harbour	Loss of load from Sally's Cove to Parson's Pond. TL227 can be isolated in various locations such that loads from Sally's Cove to Daniel's Harbour can be supplied from either Berry Hill or Peter's Barren following line switching.

229	66	Wiltondale	Glenburnie	Loss of load on western arm of Bonne Bay to Woody Point
239	138	Deer Lake	Berry Hill	Loss of load on Great Northern Peninsula north of Bonne Bay. Hydro maintains 5 MW diesel plant at Hawke's Bay and 9.7 MW diesel plant at St. Anthony. With TL239 out switching on the 66 kV will permit up to 25 MVA to be supplied from Deer Lake on the 66 kV TL226 to Berry Hill and then through the Berry Hill 138/66 kV transformer to the 138 kV system via TL259.
241	138	Peter's Barren	Plum Point	Loss of load on Great Northern Peninsula north of Daniel's Harbour. Hydro maintains 9.7 MW diesel plant at St. Anthony that provides limited back up.
244	138	Plum Point	Bear Cove	Loss of load on Great Northern Peninsula Bear Cove and north. Hydro maintains 9.7 MW diesel plant at St. Anthony that provides limited back up.
250	138	Bottom Brook	Grandy Brook	Loss of load in Burgeo
251	69	Howley	Hampden	Loss of load in White Bay
252	69	Hampden	Jackson's Arm	Loss of load Jackson's area of White Bay
254	66	Boyd's Cove	Farewell Head	Loss of load Fogo and Change Islands
256	138	Bear Cove	St. Anthony Airport	Loss of load St. Anthony – Roddickton area. Hydro maintains 9.7 MW diesel plant at St. Anthony that provides limited back up.
257	69	St. Anthony Airport	Roddickton	Loss of load Main Brook and Roddickton
259	138	Berry Hill	Peter's Barren	Loss of load on Great Northern Peninsula north of Parson's Pond. Hydro maintains 5 MW diesel plant at Hawke's Bay and 9.7 MW diesel plant at St. Anthony. With TL259 out switching on the 66 kV will permit up to 25 MVA to be supplied from Berry Hill on the 66 kV TL227 to Peter's Barren and then through the Peter's Barren 138/66 kV transformer to the 138 kV system via TL259.
260	138	Seal Cove	Bottom Waters	Loss of load on the Baie Verte Peninsula
261	69	St. Anthony Airport	St. Anthony Diesel	Loss of load in the St. Anthony area. Hydro maintains 9.7 MW diesel plant at St. Anthony that provides limited back up.
262	66	Peter's Barren	Daniel's Harbour	Loss of load in Daniel's Harbour area. Switching on the 66 kV results in supply of Daniel's harbour via TL227
264	66	Buchans	Duck Pond	Loss of industrial customer load
271[12]	69	Star Lake	Valentine	Loss of industrial customer load
L1303	138	Muskrat Falls	Happy Valley	The system is being reconfigured as part of the Muskrat Falls – Happy Valley interconnection, but will remain a radial system. Loss of load upper Lake Melville area. Hydro maintains a 25 MW gas turbine in Happy Valley that provides limited back up.

5.3 Review of Steady State Contingencies

5.3.1 Line Out Contingencies

A review of the steady state line out contingency analysis concluded that there are two violations to the Transmission Planning Criteria following the loss of the following Hydro owned equipment:

- All transmission lines (46 kV to 138 kV)
- All Shunt Device (Capacitor Banks and Reactors)
- All generation units

[12] Future industrial customer load

Violations:

Table 4 – Line Out Contingencies – Violations		
Contingency	**Violation**	**Year of Violation**
Loss of L32 (46 kV)	Overload of L33 (46 kV)	2029
Loss of L33 (46 kV)	Overload of L32 (46 kV)	2025

Transmission L32 and L33 are both 46 kV lines that supply the Quartzite ("QTZ") and Vanier ("VAN") Terminal Stations in Labrador City. The QTZ and VAN Terminal Stations are also connected forming a 46 kV loop. The advancement of these violations is due to an increase in the peak load forecast of the Labrador City area that was the result of an update to the coincident factor that was derived from more recent historical load data.

Hydro is currently preparing an operational procedure to address any potential short-term overload this coming winter in the rare event of an unplanned outage of line L33 during peak load conditions. Hydro will also investigate low-cost options to increase the thermal rating of L32 and L33. A plan to address these violations will be provided as part of the 2026 Annual Assessment.

5.3.2 Summary of Multi Transformer Station Contingency Loading

Table 5 provides the transformer loading for each multi transformer station with the largest transformer out of service.

Table 5 – Multi Transformer Contingency Load Levels[1]				
Station	**Unit**	**Rating MVA**	**2034/2035**	
			MVA	**%**
Bay d'Espoir	T10	15/20/25	*Out-of-Service*	
	T12	15/20/25	20.68	82.7%
Bottom Brook[2,3]	T1	25/33.3/41.7	35.14	87.6%
	T3	25/33.3/41.7	*Out-of-Service*	
Daniel's Harbour	T1	1/1.3	*Out-of-Service*	
	T2	1/1.3	1.13	86.6%
Grand Falls Frequency Converter	T1	30/40/50	*Out-of-Service*	
	T2	30/40/50	30.36	60.7%
	T3	30/40/50	34.71	69.4%
Happy Valley[4]	T1	30/40/50	*Out-of-Service*	
	T2	15/20/25//28	**28.42**	**101.5%**
	T4	15/20/25//28	**28.42**	**101.5%**
	T5	30/40/50	49.80	99.6%
Hawke's Bay[5]	T1	5/6.7	*Note 4*	
	T2	2.5/3.3		
Holyrood[6]	T5	15/20/25	6.52	26.1%
	T10	15/20/25	*Out-of-Service*	
Massey Drive[7]	T1	75/100/125	*Out-of-Service*	
	T2	40/53.3/66.7	57.38	92.0%

	T3	75/100/125	101.7	82.5%
Muskrat Falls TS2[8]	T5	75/100/125	*Out-of-Service*	
	T6	75/100/125	111.54	89.2%
Wabush Terminal Station[9]	T1 (bus B3)	35/47/65	54.98	84.6%
	T2 (bus B3)	35/47/65	56.69	87.2%
	T3 (bus B3)	35/47/65	55.80	85.9%
	T8 (bus B3)	50/66.6/83.3	*Out-of-Service*	
	T4 (bus B4)	75/100/125	*Out-of-Service*	
	T5 (bus B4)	75/100/125	118.38	94.7%
	T6 (bus B4)	35/47/65	54.79	84.3%
	T7 (bus B4)	50/66.6/83.3	79.38	95.3%
Wabush Substation (AKA Jean Lake)[10]	T1	20/26.7/33.3	*Out-of-Service*	
	T2	20/26.7/33.3	26.10	78.4%
Western Avalon[11]	T1	15/20/25	*Out-of-Service*	
	T2	15/20/25	23.88	95.5%

Notes:

1. The loading provided is with the largest transformer in the station removed from service and back up generation online where applicable.
2. There are a few transformers which must be derated due to their active tap position.
3. Bottom Brook 138 kV bus tie switch B2B3 closed.
4. The Happy Valley GT is not in-service as a generator but is available for capacity support.
5. The Hawke's Bay system is typically supplied by 15 MVA mobile transformer during the winter season.
6. The 66kV loop between Holyrood and Hardwoods must be opened at 52L to avoid the overload of transformer T5. It is noted that opening the loop leads to Hardwoods transformer T3 being loaded to 95%.
7. MDR 66 kV bus tie B2B4-1 closed.
8. MFATS2 25 kV bus tie B1B2 closed.
9. WABTS transformers T4 and T5 will both be replaced with 125 MVA units prior to Year 10 (2034/35). Due to the split bus configuration of the WABTS, the transformer capacity is evaluated on a per-bus basis (i.e. bus tie B3B4 remains open).
10. WABSUB 46 kV bus tie B2B3 closed.
11. There is generation available downstream for capacity support.

Violation: The loss of transformer T1 or T5 at the Happy Valley Terminal Station will result in an overload on transformers T2 and T4 by 2033/34. The forecast does not include all the Network Addition Customers mentioned in Section 3.2, which if connected, will advance the violation to 2029/30.

This overload violation can be mitigated on an interim basis by dispatching the HVY gas turbine for capacity support.

5.3.3 Summary of Looped System Transformer Contingency Loading

Island Looped Systems

Newfoundland Power executed a 10-year assessment (2025-2034) of Island looped systems that are supplied by Hydro's power transformers (Appendix C).[13] This loop assessment evaluated a load forecast of P90 + 4.25% to allow for potential demand growth. The following are the key takeaways for the 2025 NP Loop Assessment:

- **SSD/STB Loop:** The loss of SSD-T4 results in an overload on SSD-T1. This is mitigated by dispatching NP gas turbines at WES and GRH, however, these gas turbines are approaching their end of life. Therefore, additional transformer capacity, transmission system reinforcements or gas turbine replacements may be required to address this transformer overload. **Hydro and NP will conduct a joint study to establish a long-term plan to address this overload violation. The results of this study will be provided as part of the 2026 Annual Assessment.**
- **HWD/OPD Loop:** The loss of OPD-T1 results in HWD-T3 being loaded to 99.4% of its rating with all mitigating measures applied. **Hydro and NP plan to conduct a joint study to establish a long-term plan for the HWD/OPD 66 kV loop. The results of this study will be provided as part of the 2026 Annual Assessment.**

Labrador City Looped System

The Labrador City ("Lab City") loop is comprised of 46 kV sub-transmission between the Quartzite and Vanier Terminal Stations. There are tie switches on the 25 kV distribution system which allows for the load to be transferred between these two stations.

Table 6: Transformer Capacity – Lab City Loop

Transformer	Transformer Rating (MVA)
QTZ-T1	25
QTZ-T2	25
VAN-T1	25
VAN-T2	25
Transformer Capacity (N-0)	**100**
Firm Transformer Capacity (N-1)	**75**

The total Lab City load for 2034/2035 is 63.81 MVA, or 85.1% of the firm transformer capacity of the looped system.

5.3.4 Generator and Synchronous Condenser Contingency Analysis

There are no violations to the Transmission Planning Criteria following the loss of any single generator or synchronous condenser. The NLSO has developed maximum generator unit guidelines to prevent UFLS

[13] NP 138kV/66kV Loop Assessments: 2025-2034

for loss of a unit. These limits have become less restrictive with the addition of the LIL and ML frequency controllers.

5.3.5 Shunt Contingency Analysis

There are no violations to the Transmission Planning Criteria following the loss of any other shunt device.

6 Short Circuit Analysis

Short circuit analysis is required to ensure that the prospective short circuits for equipment locations do not exceed the interrupting capacity of the circuit breakers used to protect the equipment. All circuit breakers with known asset information were assessed.[14] Short circuit analysis was performed, and the results indicate that there are no circuit breaker rating violations.

7 Stability Analysis

As discussed in previous sections, Hydro is undertaking operational studies to assess the transient stability of the NL Transmission System. Until these studies are complete, the dynamic analysis of the NL Transmission System shall remain outside of the scope of the annual assessment process. The final operational study is currently in progress and is expected to be completed by Q2 2025. The NLSO will provide a plan for future transient stability analysis, as it is expected it may not be required on annual basis or will be triggered based on material changes to the IIS or LIS.

[14] Planned outages are required to gather the unknown asset information, but will be collected during scheduled maintenance to avoid any unnecessary customer impact.

8 Conclusions

The conclusions for the 2025 Annual Planning Assessment are stated as follows:

- Steady state analyses were performed and the following violations were identified for the long-term planning horizon:
  - There was one pre-contingency transmission equipment overload:
    - **South Brook Transformer T1 is expected to be overloaded by 2031/2032.** Hydro will perform further analysis with a more detailed load forecast to confirm the timing of the violation.
  - There were three contingency transmission equipment overloads:
    - **Loss of transmission line L32 (46 kV) to Labrador City results in an overload on line L33 in the year 2029.** Hydro is currently investigating low-cost options to increase the thermal rating of L33.
    - **Loss of transmission line L33 (46 kV) to Labrador City results in an overload on line L32 in the year 2025.** Hydro is currently preparing an operational procedure to address a potential short-term overload this coming winter in the rare event of an unplanned outage of line L33 during peak conditions. Hydro is currently investigating low cost options to increase the thermal rating of L32. Low-cost options to increase the thermal rating of L32 are also being investigated.
    - **Loss of transformer T1 or T5 at the Happy Valley Terminal Station will result in an overload on transformers T2 and T4 by 2033/34.** The forecast does not include all the Network Addition Customers (See Section 3.2), which if connected, will advance the violation to 2029/30. This overload violation can be mitigated on an interim basis by turning on the HVY gas turbine for capacity support. The long-term solution would be to replace transformer T2 with a 50 MVA transformer.
- There were no voltage violations identified as part of the pre-contingency and contingency analysis summarized in Section 5.
- The key takeaways from the 2025 Newfoundland Power ("NP") Loop Assessment include:
  - **SSD/STB Loop:** The loss of SSD-T4 results in an overload on SSD-T1. This is mitigated by dispatching NP gas turbines at Wesleyville and Greenhill , however, these gas turbines are approaching their end of life.
  - **HWD/OPD Loop:** The loss of OPD-T1 results in HWD-T3 being loaded to 99.4% of its rating with all mitigating measures applied.

  Hydro and NP will conduct a joint study to establish a long-term plan for both loop systems. The results of the joint study will be provided as part of the 2026 Annual Assessment.

- The short circuit analysis reveals no issues with circuit breaker ratings. All circuit breakers with known asset information were assessed.[15]
- Transient stability analysis is currently in progress as part of ongoing operational studies in support of the LCP integration effort. These studies are expected to be completed by Q2 2025. The final operational study will be provided as part of the 2026 Annual Assessment. The NLSO will also provide a plan for future transient stability analysis, as it is expected it may not be required on an annual basis or will be triggered based on material changes to the IIS or LIS.

9 Reference Documents

1. 2025 NLSO Annual Assessment (TP-R-092)
2. Labrador Interconnected System - Expansion Study (TP-R-019)
3. NLSO Standard – Transmission Facilities Rating Guide (TP-S-001)
4. TP-S-003 NLSO Standard – Annual Planning Assessment
5. TP-S-007 NLSO Standard – Transmission Planning Criteria
6. Newfoundland Power 138kV/66kV Loop Assessment: 2024 - 2033

[15] Planned outages are required to gather the unknown asset information, but will be collected during scheduled maintenance to avoid any unnecessary customer impact.

APPENDIX A

Island and Labrador Interconnected Systems

Figure 1 – Island Interconnected System

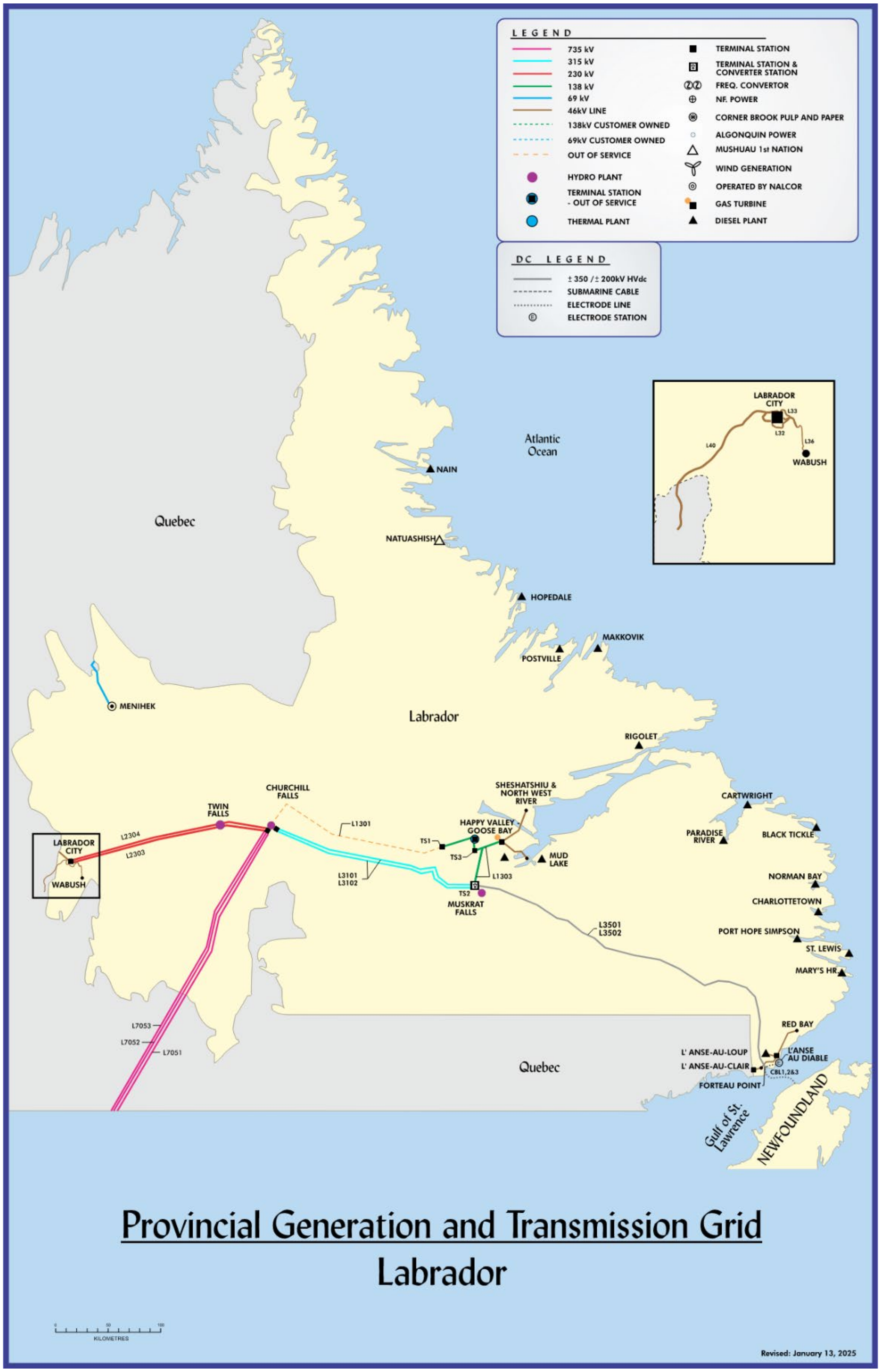


Figure 2 – Labrador Interconnected System

APPENDIX B

Load Flow Plots Primary Transmission System Year Ten (2034/35) – Peak and Light Case

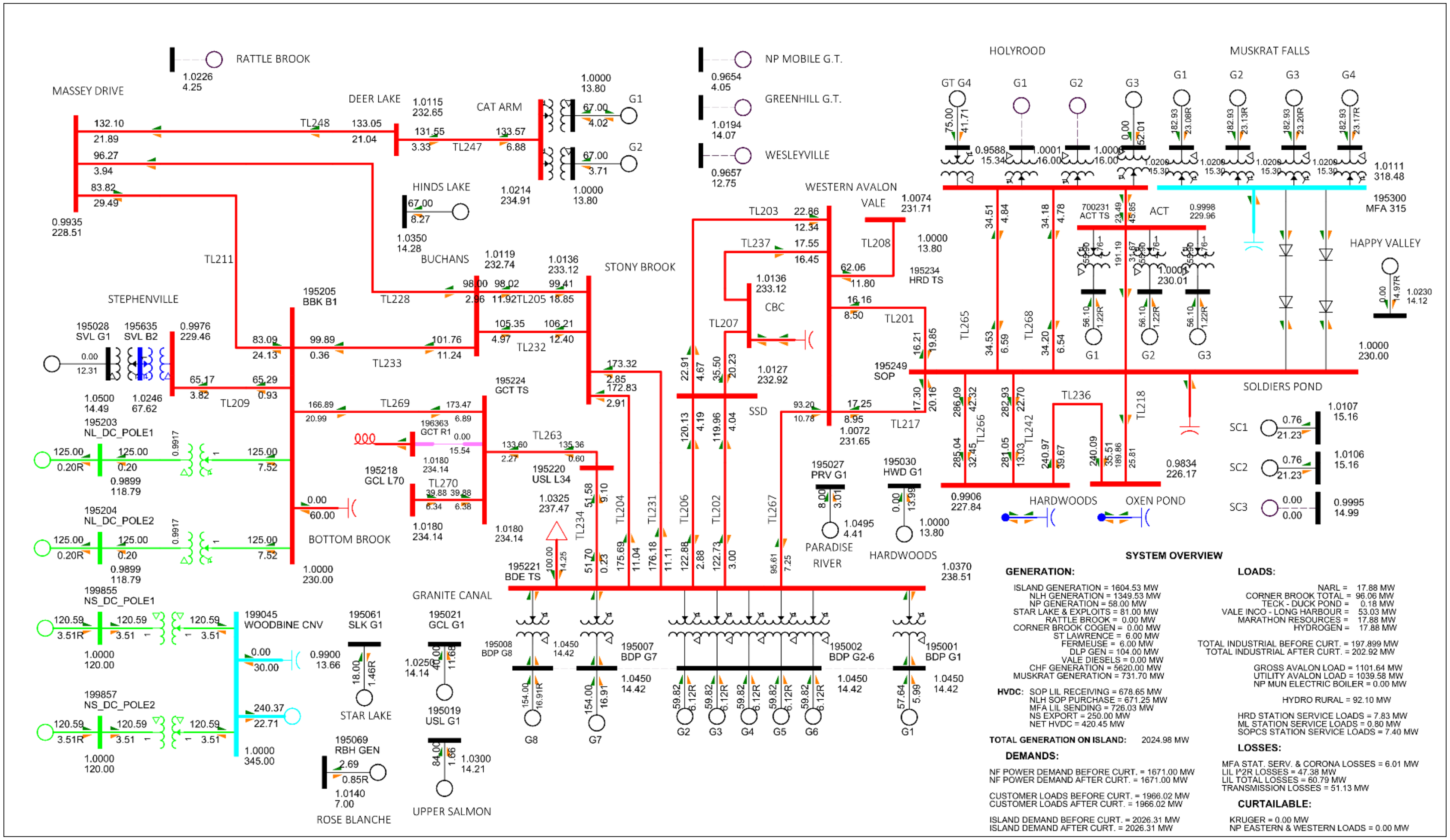


Figure 3 – IIS (2034/35 Peak Conditions – ML Exports (Emera Block – 250 MW))

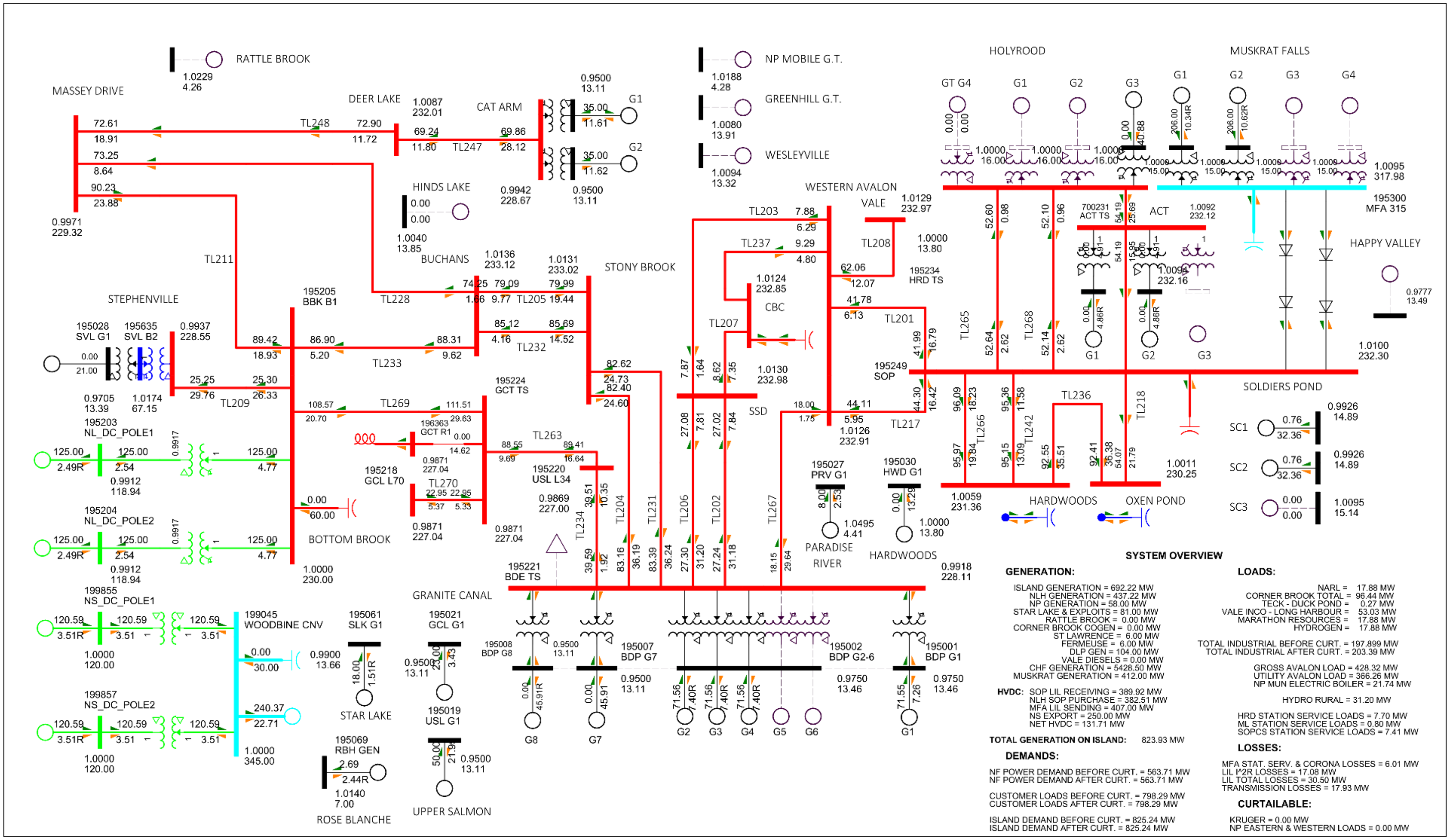


Figure 4 – IIS (2034 Light Conditions – ML Firm Exports (250 MW))

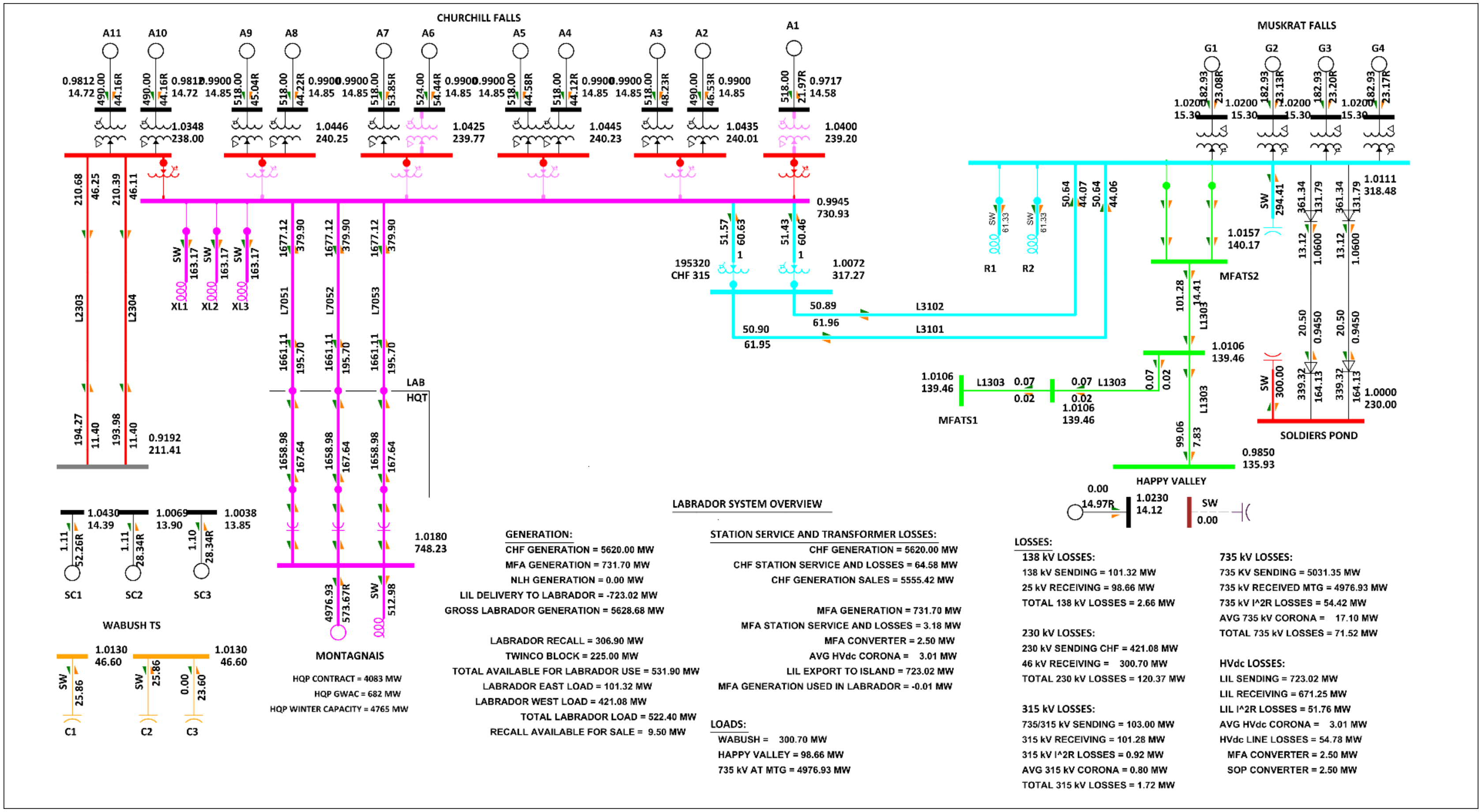
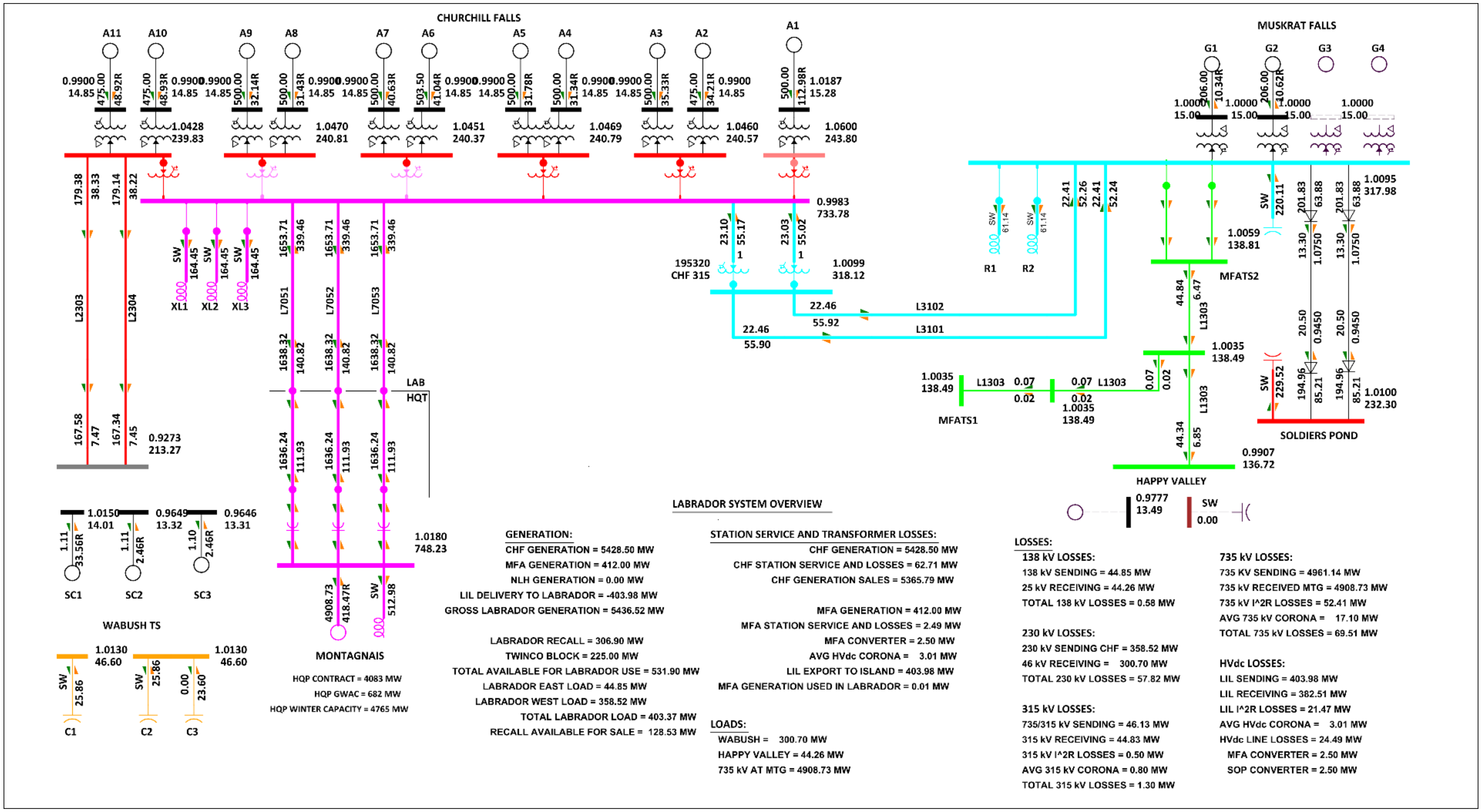


Figure 5 – LIS (2034/35 Peak Conditions)


CHURCHILL FALLS
MUSKRAT FALLS
A11
A10
A9
A8
A7
A6
A5
A4
A3
A2
A1
G1
G2
G3
G4
L2303
L2304
L7051
L7052
L7053
XL1
XL2
XL3
LAB
HQT
CHF 315
R1
R2
L3102
L3101
MFATS2
MFATS1
L1303
SOLDIERS POND
HAPPY VALLEY
SC1
SC2
SC3
WABUSH TS
C1
C2
C3
MONTAGNAIS
HQP CONTRACT = 4083 MW
HQP GWAC = 682 MW
HQP WINTER CAPACITY = 4765 MW
LABRADOR SYSTEM OVERVIEW
GENERATION:
CHF GENERATION = 5428.50 MW
MFA GENERATION = 412.00 MW
NLH GENERATION = 0.00 MW
LIL DELIVERY TO LABRADOR = -403.98 MW
GROSS LABRADOR GENERATION = 5436.52 MW
LABRADOR RECALL = 306.90 MW
TWINCO BLOCK = 225.00 MW
TOTAL AVAILABLE FOR LABRADOR USE = 531.90 MW
LABRADOR EAST LOAD = 44.85 MW
LABRADOR WEST LOAD = 358.52 MW
TOTAL LABRADOR LOAD = 403.37 MW
RECALL AVAILABLE FOR SALE = 128.53 MW
STATION SERVICE AND TRANSFORMER LOSSES:
CHF GENERATION = 5428.50 MW
CHF STATION SERVICE AND LOSSES = 62.71 MW
CHF GENERATION SALES = 5365.79 MW
MFA GENERATION = 412.00 MW
MFA STATION SERVICE AND LOSSES = 2.49 MW
MFA CONVERTER = 2.50 MW
AVG HVdc CORONA = 3.01 MW
LIL EXPORT TO ISLAND = 403.98 MW
MFA GENERATION USED IN LABRADOR = 0.01 MW
LOADS:
WABUSH = 300.70 MW
HAPPY VALLEY = 44.26 MW
735 kV AT MTG = 4908.73 MW
LOSSES:
138 kV LOSSES:
138 kV SENDING = 44.85 MW
25 kV RECEIVING = 44.26 MW
TOTAL 138 kV LOSSES = 0.58 MW
230 kV LOSSES:
230 kV SENDING CHF = 358.52 MW
46 kV RECEIVING = 300.70 MW
TOTAL 230 kV LOSSES = 57.82 MW
315 kV LOSSES:
735/315 kV SENDING = 46.13 MW
315 kV RECEIVING = 44.83 MW
315 kV I^2R LOSSES = 0.50 MW
AVG 315 kV CORONA = 0.80 MW
TOTAL 315 kV LOSSES = 1.30 MW
735 kV LOSSES:
735 KV SENDING = 4961.14 MW
735 kV RECEIVED MTG = 4908.73 MW
735 kV I^2R LOSSES = 52.41 MW
AVG 735 kV CORONA = 17.10 MW
TOTAL 735 kV LOSSES = 69.51 MW
HVdc LOSSES:
LIL SENDING = 403.98 MW
LIL RECEIVING = 382.51 MW
LIL I^2R LOSSES = 21.47 MW
AVG HVdc CORONA = 3.01 MW
HVdc LINE LOSSES = 24.49 MW
MFA CONVERTER = 2.50 MW
SOP CONVERTER = 2.50 MW

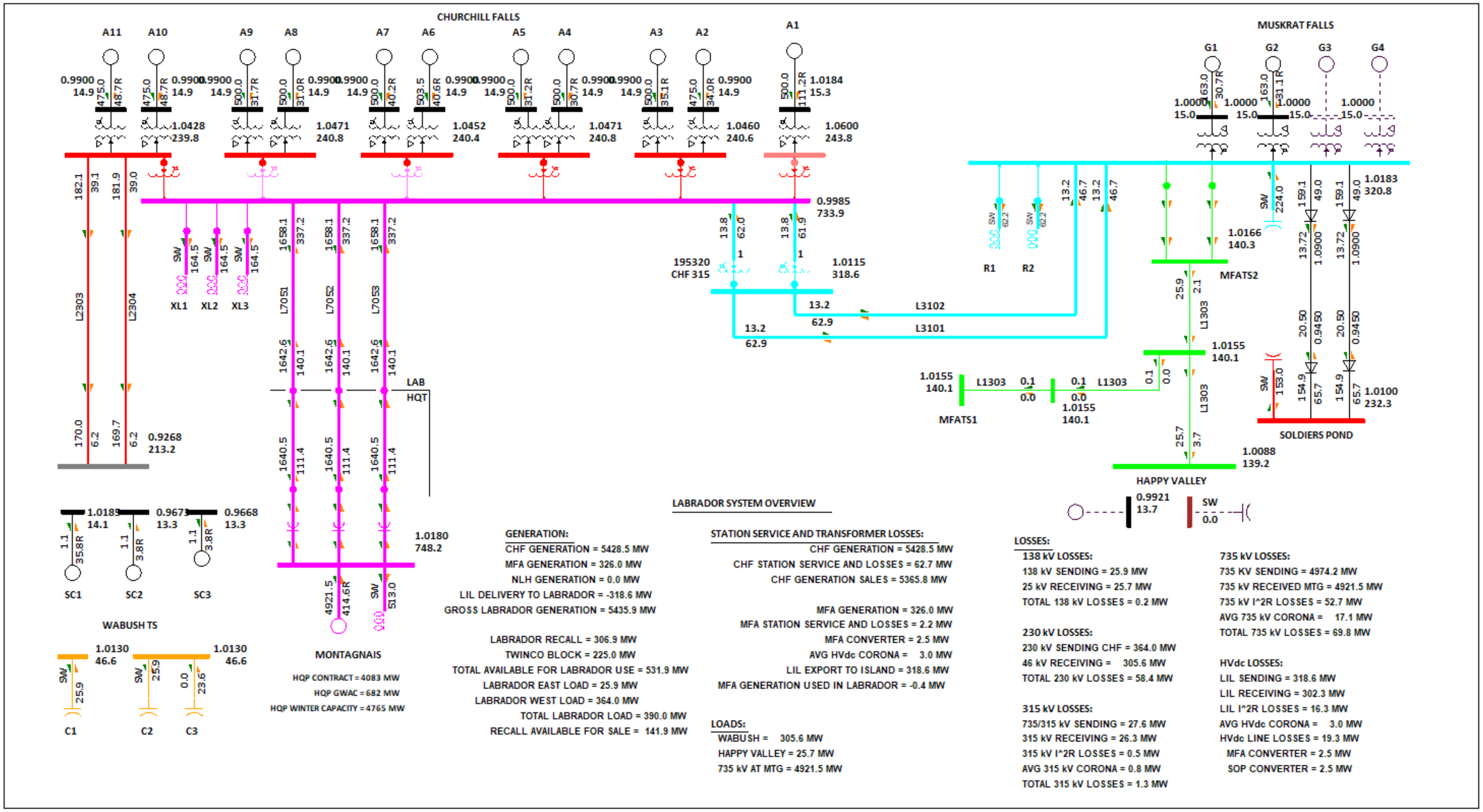


Figure 6 – LIS (2034 Light Conditions)

APPENDIX C

Newfoundland Power's 138/66 kV Loop Assessments 2025-2034

SEE ATTACHMENT A

Document Summary

Document Owner:	Transmission Planning
Document Distribution:	Newfoundland and Labrador Hydro

Revision History

Revision	Prepared by	Reason for change	Effective Date
0	Transmission Planning	Original Issue	2025/05/13

Document Approvers

Position	Signature	Approval Date
Sr. Manager of Transmission and Rural Planning		2025/05/13

Document Control

Regarding NLSO documents: The electronic version of this document is the CONTROLLED version. Please check the NLSO Document Management System SharePoint site for the official copy of this document. This document, when downloaded or printed, becomes UNCONTROLLED.

Attachment A

138kV & 66kV Loop Assessments

Rev. 3

2025–2034

138kV & 66kV Loop Assessments

2025-2034

Revision 3

Prepared by: Tony Jones, P. Eng.

May 5, 2025

Revision History

Rev. #	Comments	Date
3	-Revised Section 6.0.	May 5, 2025
2	-Minor edits.	April 28, 2025
1	-Incorporated Hydro's comments. -Added Appendix A and modified results to reflect generation values provided by Hydro.	April 18, 2025
0	Initial draft for comments.	March 10, 2025

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

The purpose of this report is to assess 138kV and 66kV transmission loop systems based on forecast data for 2025 – 2034. This report aims to summarize the findings of simulating various equipment outage scenarios during peak conditions and to provide recommendations to minimize customer impacts and equipment overloads for each transmission loop. The results of this report will be shared with both Newfoundland Power ("NP") and Newfoundland & Labrador Hydro ("Hydro") power system operators to inform any potential operating procedures or capital upgrades that may be required to minimize outages under the contingency scenarios herein.

2.0 Overview of Methodology

CYME was used to model load flows assuming worst-case peaks forecasted for 2025 – 2034. Modeling was based on NP's five-year P90 In-Feed Forecast provided to Hydro in December 2024 which forecasts peak demand through to 2030. Load data was scaled an additional 4.8% to allow for potential demand growth through to 2034 based on correspondence with Hydro in early 2025. Potential equipment overloading, as well as any observed voltages outside of either NP's or Hydro's planning criteria limits[1] based on P90 + 4.8% load scenarios for each loop are presented in the following sections. De-ratings of transformer capacities due to tap changer positions were also considered when appropriate. All NP hydraulic generation units in the loops were also modeled as 'on' unless otherwise stated. NP generator outputs for the pre-contingency scenarios were consistent with Hydro's own modeling assumptions which are provided in Appendix A. For post-contingency scenarios that require increased generation output up to a unit's full rating, the specified dispatched amount is provided when applicable.

Load flows were analyzed for various single outages to transmission lines and system transformers to provide an assessment of potential N-1 contingency scenarios for each 138kV or 66kV loop. It should be noted that analyzing the effect of multiple outages occurring simultaneously resulting in contingency scenarios beyond N-1 is beyond the scope of this report. Curtailable loads were connected in all load flows unless otherwise specified.

3.0 Hardwoods – Oxen Pond 66kV Loop

The Hardwoods – Oxen Pond Loop ("HWD-OPD") is comprised of numerous 66kV transmission lines that supply the St. John's area from Hydro's Hardwoods Terminal Station ("HWD") and Oxen Pond Terminal Station ("OPD"). The following sections outline load flow results for the pre-contingency scenario, as well as for various N-1 contingency scenarios due to single outages to transmission lines and system transformers within the loop. It should be noted that load flows were completed assuming the gas turbine in HWD is unavailable.[2]

---

1 Pre-contingency voltage limits for Hydro and NP transmission lines are 0.95-1.05pu; post-contingency limits on transmission lines are 0.90-1.10pu for Hydro and 0.90-1.06pu for NP.

2 Hydro is currently performing a study to assess the life expectancy of the HWD combustion turbine.

3.1 Pre-Contingency

Load flow results for 2034 for the current pre-contingency system configuration are shown in Table 1. [3]

Table 1
HWD-OPD 66kV Loop
System Transformer Loading for 2034

Station	Unit	Max Rating (MVA)	P90 + 4.8%	
			MVA	%
Hardwoods	T1	125	107.7	86.2
	T2	66.6	54.9	82.5
	T3	66.6	59.5	89.3
	T4	125	106.9	85.5
Oxen Pond	T1	250	182.6	73.0
	T2	125	88.1	70.5
	T3	250	182.7	73.1

All voltages in this loop were observed to be within acceptable planning limits and as shown in Table 1, no transformer overloads were observed.

3.2 Single Line Outages (N-1)

Each 66kV transmission line within the HWD-OPD loop was individually disconnected in CYME to observe effects during peak. The results are provided in Table 2.

[3] The results in this section include loads associated with the electrification of Memorial University of Newfoundland ("MUN").

Table 2 HWD-OPD 66kV Loop Effect of Transmission Line Contingency Events	
Transmission Line(s)	**Planning Criteria Violations?**
	P90 + 4.8%
4L / 25L	No
12L / 14L	No
13L	No
15L / 19L	No
16L / 74L	No
18L / 72L / 73L	No
30L / 32L / 67L	Yes
31L / 70L	Yes
34L / 58L	No
33L / 35L	No
49L / 79L	No
54L	No
69L	No

3.2.1 Loss of 30L

A loss of 30L during the P90 + 4.8% peak resulted in an overload to 14L. Disconnecting 14L results in additional power flow over adjacent lines all within winter ampacity limits and therefore resolves the loss of 30L contingency.

3.2.2 Loss of 31L / 70L

A loss of either 31L or 70L during the P90 + 4.8% peak resulted in an overload to the other transmission line. Disconnecting 14L results in additional power flow over adjacent lines all within winter ampacity limits and therefore resolves the loss of the 31L or 70L contingency.

3.3 Single Transformer Outages (N-1)

In addition to assessing various transmission line outages, the effect of single system transformer outages within the loop were also analyzed for 2034. In substations with multiple system transformers and bus voltages, the largest transformer per bus was removed. In cases where there were multiple transformers of the same size at a particular substation bus, the transformer with the smallest impedance was removed. Load flow results for the simulated outages during the P90 + 4.8% case are found in Table 3.

Table 3 HWD-OPD 66kV Loop System Transformer Loading Following XFMR Loss P90 + 4.8% Scenario						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 4.8% (No HWD-T1)**		**P90 + 4.8% (No OPD-T1)**	
			MVA	**%**	**MVA**	**%**
Hardwoods	T1	125	*Out-of-service*		120.3	96.2
	T2	66.6	70.7	106.1	61.4	92.1
	T3	66.6	76.5	114.8	66.4[4]	99.7
	T4	125	137.4	109.9	119.4	95.5
Oxen Pond	T1	250	200.0	80.0	*Out-of-service*	
	T2	125	96.5	77.2	140.1	112.1
	T3	250	200.1	80.1	290.4	116.2

As shown in Table 3, transformer overloads were observed with either HWD-T1 or OPD-T1 out-of-service. To mitigate these overloads, the system was re-modeled to consider a 25MW load curtailment associated with MUN's electric boilers. Furthermore, voltage management schemes were implemented as follows, and additional Newfoundland Power hydraulic generation was dispatched.[5]

For the HWD contingency, all Newfoundland Power area generation was dispatched at their full ratings and HWD 66kV was reduced to 0.98pu. To avoid overloads to Holyrood Substation ("HRD") transformers as described in Section 7.3, the HRD 66kV bus was also reduced to 1.0pu. For the OPD contingency, all local NP generation was dispatched, OPD 66kV was reduced to 0.97pu and HWD 66kV was reduced to 0.98pu.[6] This effectively resolved the overloaded transformer contingencies, as shown in Table 4.[7]

---

4 At the modeled tap position for the post-contingency scenario, HWD-T2 and HWD-T3 are effectively de-rated to 64.9MVA, and HWD-T4 is effectively de-rated to 122MVA.

5 As per Appendix A, base case models assumed approximately 34MW of NP generation in the St. John's area, out of a total capacity of approximately 52MW.

6 Pre-contingency load flows were modeled with OPD and HWD 66kV busses set to 1.025pu.

7 A curtailable load agreement associated with the addition of MUN's electric boilers is currently being developed and will be finalized prior to energization of the new load.

Table 4 HWD-OPD 66kV Loop: System Transformer Loading Following XFMR Loss P90 + 4.8% Scenario (MITIGATED via Voltage Management and MUN Curtailment)						
Station	**Unit**	**Max Rating (MVA)**	**(No HWD-T1) 25MW MUN Curtail, HWD 66kV@ 0.98pu, HRD 66kV @ 1.00pu, Maximum NP Generation Dispatched**		**(No OPD-T1) 25MW MUN Curtail, OPD 66 @ 0.97pu, HWD 66 @ 0.98pu, Maximum NP Generation Dispatched**	
			MVA	**%**	**MVA**	**%**
Hardwoods	T1	125	*Out-of-service*		119.8	95.9
	T2	66.6	61.5	92.4	63.6	95.4
	T3	66.6	65.8	98.8	66.2	99.4
	T4	125	118.3	94.6	118.9	95.1
Oxen Pond	T1	250	201.0	80.4	*Out-of-service*	
	T2	125	97.0	77.6	118.4	94.7
	T3	250	201.2	80.5	245.3	98.1

As shown in Table 4, the observed transformer overloads resulting from a loss of HWD-T1 or OPD-T1 may be mitigated by implementing a contingency voltage management scheme at HWD and OPD, in conjunction with dispatching additional NP generation along with a load curtailment at MUN. CYME results show that in either case, transmission voltages may be maintained within emergency limits.

4.0 Holyrood – Western Avalon 138kV/66kV Loop

The Holyrood – Western Avalon Loop ("HRD-WAV") is comprised of 138kV and 66kV transmission lines that run through the Avalon Peninsula between Hydro's Holyrood Terminal Station ("HRD") and the Western Avalon Terminal Station ("WAV"). The following sections outline load flow results for the pre-contingency scenario, as well as for various N-1 contingency scenarios due to single outages to transmission lines and system transformers within the loop.

4.1 Pre-Contingency

Load flow results for the 2025-2034 pre-contingency system configuration are shown in Table 5. It was found that no transformer overloads nor system voltage criteria violations were observed in the pre-contingency configuration.

Table 5 HRD-WAV 138kV/66kV Loop System Transformer Loading for 2034				
Station	Unit	Max Rating (MVA)	P90 + 4.8%	
			MVA	%
Blaketown	T3	41.6	27.8	66.8
Bay Roberts	T2	41.6	24.0	57.7
	T3	41.6	23.6	56.7
Western Avalon	T1	25	15.1	60.3
	T2	25	15.4	61.5
	T3	41.7	12.5	29.9
	T4	41.7	12.4	29.7
	T5	125	36.4	29.1
Holyrood	T6	41.7	13.6	32.6
	T7	125	38.6	30.8
	T8	125	39.5	31.6

4.2 Single Line Outages (N-1)

Each 66kV and 138kV transmission line within the HRD-WAV loop were individually disconnected in CYME to observe effects during peak. The results are provided in Table 6 below.

Table 6 HRD-WAV 138kV/66kV Loop Effect of Transmission Line Contingency Events	
TL	Planning Criteria Violations?
	P90 + 4.8%
39L / 42L / 46L / 47L	No
48L	No
64L	Yes
56L / 57L / 68L	No
41L	No
80L	No
86L	No

4.2.1 Loss of 64L

A loss of 64L during the P90 + 4.8% peak resulted in an overload to 39L. Dispatching MG2 at BLK reduces power flow over 39L and therefore resolves the loss of 64L contingency.[8,9]

4.3 Single Transformer Outages (N-1)

In addition to assessing various transmission line outages, the effect of single system transformer outages within the loop were also analyzed for 2034. In substations with multiple system transformers and bus voltages, the largest transformer per bus was removed. In cases where there were multiple transformers of the same size at a particular substation bus, the transformer with the smallest impedance was removed. The transformers analyzed in this section are BLK-T3, BRB-T2, WAV-T2, WAV-T5, and HRD-T8. Loading results for the simulated outages during P90 + 4.8% peak are found in Tables 7a and 7b.

Table 7a
HRD-WAV 138kV/66kV Loop
System Transformer Loading Following XFMR Loss (HRD-T8, WAV-T2, WAV-T5)
P90 + 4.8% Scenario

Station	Unit	Max Rating (MVA)	P90 Load + 4.8% (No HRD-T8)		P90 Load + 4.8% (No WAV-T5)		P90 Load + 4.8% (No WAV-T2)	
			MVA	%	MVA	%	MVA	%
Blaketown	T3	41.6	25.6	61.5	24.2	58.1	30.3	72.8
Bay Roberts	T2	41.6	23.5	56.6	23.8	57.1	24.8	59.7
	T3	41.6	23.1	55.6	23.3	56.1	24.4	58.6
Western Avalon	T1	25	15.9	63.4	16.9	67.5	23.0	92.0
	T2	25	16.1	64.6	17.2	68.8	*Out-of-Service*	
	T3	41.7	14.6	35.0	28.9	69.4	14.5	34.9
	T4	41.7	14.5	34.8	28.8	69.0	14.5	34.7
	T5	125	42.5	34.0	*Out-of-service*		42.4	33.9
Holyrood	T6	41.7	20.8	50.0	14.1	33.8	13.1	31.4
	T7	125	59.1	47.3	39.9	31.9	37.2	29.7
	T8	125	*Out-of-service*		40.9	32.7	38.1	30.5

8 MG2 is a mobile 5MW combustion turbine typically stationed at BLK Substation.
9 Transmission lines 39L, 42L and 47L are currently de-rated to 560A. Newfoundland Power intends to conduct a protection coordination review of the HRD-WAV 138kV network to determine whether these ampacities can be increased.

Table 7b HRD-WAV 138kV/66kV Loop System Transformer Loading Following XFMR Loss (BRB-T2, BLK-T3) P90 + 4.8% Scenario						
Station	**Unit**	**Max Rating (MVA)**	**P90 Load + 4.8% (No BRB-T2)**		**P90 Load + 4.8% (No BLK-T3)**	
			MVA	**%**	**MVA**	**%**
Blaketown	T3	41.6	29.7	71.4	*Out-of-service*	
Bay Roberts	T2	41.6	*Out-of-service*		28.0	67.3
	T3	41.6	43.1	103.6	27.5	66.1
Western Avalon	T1	25	16.6	66.6	23.9	95.6
	T2	25	17.0	67.8	24.4	97.4
	T3	41.7	14.4	34.4	10.4	24.9
	T4	41.7	14.3	34.2	10.3	24.8
	T5	125	41.8	33.5	30.3	24.2
Holyrood	T6	41.7	12.3	29.5	12.4	29.7
	T7	125	34.9	27.9	35.2	28.1
	T8	125	35.8	28.6	36.0	28.8

As shown in Tables 7a and 7b, an overload condition exists for an N-1 contingency scenario analyzed during the P90 + 4.8% load scenario. Specifically, with BRB-T2 out of service, BRB-T3 is overloaded. This can be mitigated by opening 48L at BRB.[10] Load flow results for the mitigated scenario are presented in Table 8.

[10] With BRB-T2 and 48L out of service, further contingency scenarios could result in loss of supply to the entire loop system.

Table 8 HRD-WAV 138kV/66kV Loop MITIGATED Scenarios Following XFMR Loss				
Station	Unit	Max Rating (MVA)	P90 + 4.8% No BRB-T2 48L Open	
			MVA	%
Blaketown	T3	41.6	36.5	87.8
Bay Roberts	T2	41.6	*Out of Service*	
	T3	41.6	39.0	93.8
Western Avalon	T1	25	16.4	65.7
	T2	25	16.7	66.9
	T3	41.7	10.5	25.3
	T4	41.7	10.5	25.1
	T5	125	30.7	24.6
Holyrood	T6	41.7	15.8	37.9
	T7	41.7	44.8	35.8
	T8	125	45.9	36.7

5.0 Sunnyside – Stony Brook 138kV Loop

The Sunnyside-Stony Brook loop ("SSD-STB") is comprised of numerous 138kV transmission lines that run through Central Newfoundland between Hydro's Sunnyside Terminal Station ("SSD") and Stony Brook Terminal Station ("STB"). All modeling for the SSD-STB Loop was completed with NP's new 138kV transmission line 148L in service, as well as transmission line 146L rebuilt.[11] The SSD-STB Loop also supplies the 138kV Burin Peninsula Loop system through the 138kV supply at SSD. As a result, a transmission contingency analysis of the Burin Peninsula System is included in this section.

5.1 Pre-Contingency

Load flow results for the 2034 pre-contingency configurations are shown in Table 9. The results indicate no transformer overloads or planning criteria violations.[12]

[11] Transmission Line 148L is a new 138kV line between NP's Lewisporte ("LEW") and Boyd's Cove ("BOY") substations, which was filed and approved as part of Newfoundland Power's 2025 Capital Budget Application. The line is expected to be in service in 2027. Transmission Line 146L was approved to be rebuilt as part of Newfoundland Power's 2024 Capital Budget Application and is expected to be completed later in 2025.

[12] Presently, a transmission voltage violation affects the 66kV supply to the following substations: BOY, Summerside ("SUM"), and Twillingate ("TWG"). The construction of Transmission Line 148L in 2027 will resolve these voltage violations and they are therefore omitted from the 2034 pre-contingency results.

Table 9 SSD-STB 138kV Loop System Transformer Loading for 2034				
Station	**Unit**	**Max Rating (MVA)**	**P90 + 4.8%**	
			MVA	**%**
Sunnyside	T1	125	92.2	73.7
	T4	125	92.6	74.0
Stony Brook	T1	125	91.9	73.5
	T2	125	92.8	74.3

5.2 Single Line Outages (N-1)

The following 138kV transmission lines within the SSD-STB loop were disconnected in CYME to observe effects during peak: 100L/109L, 121L 124L, 144L, 146L, 130L/132L/133L, 136L/137L/147L, 148L and TL-210. The following 138kV transmission lines within the Burin Peninsula loop were also assessed: TL-212, TL-219, 300L and 308L. The results are provided in Table 10.

Table 10 SSD-STB 138kV Loop Effect of Transmission Line Contingency Events	
Transmission Line(s)	**Planning Criteria Violations?**
	P90 + 4.8%
100L / 109L	No
121L	No
124L	Yes
146L	No
144L	Yes
130L / 132L / 133L	No
136L / 137L / 147L	Yes
148L	No
TL-210	Yes
TL-212 (Burin System)	Yes
TL-219 (Burin System)	Yes
300L (Burin System)	No
308L (Burin System)	No

5.2.1 Loss of 124L

Transmission line 124L is a 138kV transmission line that runs between NP's Clarenville Substation ("CLV") and Glovertown Substation ("GLV"). CYME analysis shows that disconnecting 124L at CLV during the P90 + 4.8% load scenario results in undervoltage conditions as low as 0.83pu along the 138kV network near NP's Gander ("GAN"), Gambo ("GAM") and GLV substations.
To mitigate this effect, NP's existing combustion gas turbine unit at NP's Wesleyville ("WES") Substation ("WES-GT") was dispatched at 8MW, resulting in acceptable post-contingency transmission voltages of 0.955pu at the lowest levels along GAN-GAM.[13] No transformer overloads were observed during the contingency scenario.

5.2.2 Loss of 144L

Transmission line 144L is a 138kV transmission line that runs between NP's Cobb's Pond Substation ("COB") and Gander Substation ("GAN"). CYME analysis shows that disconnecting 144L during the P90 + 4.8% load scenario results in undervoltage conditions as low as 0.815pu along the 138kV network near GAN and GAM substations.

To mitigate this effect, WES-GT was dispatched at 8MW, resulting in acceptable post-contingency transmission voltages of 0.963pu at the lowest levels along GAN-GAM. No transformer overloads were observed during the contingency scenario.

5.2.3 Loss of 137L

Transmission line 137L is a 138kV transmission line that runs between NP's Rattling Brook ("RBK") and LEW substations. CYME analysis shows that disconnecting 137L during the P90 + 4.8% load scenario results in an undervoltage condition of 0.89pu along 148L.

To mitigate this effect, WES-GT was dispatched at 8MW, resulting in acceptable post-contingency transmission voltages of 0.92pu along 148L. No transformer overloads were observed during the contingency scenario.

5.2.4 Loss of TL-210

Transmission line TL-210 is a 138kV transmission line operated by Hydro that runs between STB Terminal Station and NP's Glenwood ("GLN") and GAN substations. CYME analysis shows that disconnecting TL-210 during the P90 + 4.8% scenario results in an undervoltage condition as low as 0.867pu along the 138kV network near GAN and GAM substations. To mitigate this effect, WES-GT was dispatched at 8MW, resulting in acceptable post-contingency transmission voltages of 0.952pu at the lowest levels along GAN-GAM. No transformer overloads were observed during the contingency scenario.

---

[13] WES-GT is a 16MW combustion turbine originally commissioned in 1969 and is currently de-rated to 8MW. While the unit remains operational, it is nearing the end of its service life. Newfoundland Power and Hydro are currently assessing options to address its eventual retirement.

5.2.5 Loss of TL-212 or TL-219

Hydro's 138 kV transmission line TL-212 runs between SSD, and NP's Monkstown ("MKS"), Bay L'Argent ("BLA") and Linton Lake ("LLK") substations on the Burin Peninsula, while Hydro's 138kV transmission line TL-219 runs between SSD and NP's Salt Pond ("SPO") Substation. CYME analysis shows that disconnecting TL-219 during the P90 + 4.8% scenario results in an undervoltage condition as low as 0.791pu at SPO. Similarly, by disconnecting TL-212 between MKS and BLA, an undervoltage condition as low as 0.852pu at SPO was observed.

To mitigate this effect, the existing combustion gas turbine unit at Greenhill ("GRH") Substation ("GRH-GT") was dispatched at 20MW, resulting in acceptable post-contingency SPO transmission voltages of 0.925pu following the TL-219 outage, and 0.944 following the TL-212 outage.[14]

No transformer overloads were observed during the contingency scenario.

5.3 Single Transformer Outages (N-1)

In addition to assessing various transmission line outages, the effect of single system transformer outages within the loop were also analyzed for 2034. In substations with multiple system transformers and bus voltages, the largest transformer per bus was removed. In cases where there were multiple transformers of the same size at a particular substation bus, the transformer with the smallest impedance was removed. The transformers analyzed in this section are SSD-T4 and STB-T2; loading results for the simulated outages for the P90 + 4.8% case are found in Table 11.

Table 11
SSD-STB 138kV Loop
System Transformer Loading Following XFMR Loss for 2034
P90 + 4.8% Scenario

Station	Unit	Max Rating (MVA)	P90 + 4.8% (No SSD-T4)		P90 + 4.8% (No STB-T2)	
			MVA	%	MVA	%
Sunnyside	T1	125	179.2	143.4	96.3	77.0
	T4	125	*Out of Service*		96.7	77.4
Stony Brook	T1	125	96.1	76.9	173.7	139.0
	T2	125	97.1	77.7	*Out of Service*	

To mitigate the STB transformer overload presented in Table 11, 16MW of generation was dispatched at WES. However, it is important to note that this is beyond the current derated capacity of the existing WES-GT unit, and the unit's current de-rating of 8MW was not sufficient to resolve the contingency. In addition, transmission line TL-245 was opened at Howley Terminal Station,

[14] GRH-GT is a 25MW combustion turbine original commissioned in 1975 and is currently de-rated to 20MW. While the unit remains operational, is its nearing the end of its service life. Newfoundland Power and Hydro are currently assessing options to address its eventual retirement.

and the following hydraulic generating stations were dispatched to their full rating: Hind's Like ("HND"), RBK, and Sandy Brook ("SBK"). To avoid de-rating STB-T1 due to its tap setting, its 138kV bus was set to 1.0pu.

To mitigate the SSD transformer overload condition, WES-GT was dispatched at 8MW and 25MW of generation was modeled at GRH. Again, it should be noted that this is beyond GRH-GT's current derated capacity of 20MW, which is not sufficient to resolve the overload condition. In addition, transmission line 124L was opened at CLV to limit SSD power flow toward Central Newfoundland.

See Table 12.

Table 12
SSD-STB 138kV Loop
System Transformer Loading Following Loss of SSD-T4 for 2034
P90 + 4.8% Scenario (MITIGATION)

Station	Unit	Max Rating (MVA)	P90 + 4.8% (No SSD-T4) 8MW at WES 25MW at GRH 124L Open at CLV		P90 + 4.8% (No STB-T2) 16MW at WES, TL245 Open at HOW, HND, SBK, RBH at Max, STB 138kV at 1.0pu	
			MVA	%	MVA	%
Sunnyside	T1	125	117.0	93.6	90.3	72.2
	T4	125	*Out of Service*		90.7	72.5
Stony Brook	T1	125	107.5	86.0	123.3	98.6
	T2	125	108.7	86.9	*Out of Service*	

Since these contingencies are not fully mitigated due to the deratings of WES-GT and GRH-GT, NP and Hydro are currently assessing alternatives to resolve the noted contingencies.

6.0 Stephenville – Bottom Brook 66kV Loop

The Stephenville – Bottom Brook Loop ("SVL-BBK") is comprised of numerous 66kV transmission lines that run through Western Newfoundland between Hydro's Stephenville Terminal Station ("SVL") and the Bottom Brook Terminal Station ("BBK"). The following sections outline load flow results for a pre-contingency scenario, as well as for various N-1 contingency scenarios due to single outages to transmission lines and system transformers along the loop. It should be noted that the previously approved project to replace BBK-T2 with a 230/66kV 66.6MVA transformer as proposed in Hydro's 2021 Capital Budget Application has been canceled, and Hydro is currently conducting a condition assessment on the 50MW SVL combustion gas turbine ("SVL-GT") and is considering extending its service life.

6.1 Pre-Contingency

Load flow results for 2034 for the current pre-contingency system configuration are shown in Table 13.[15] No overloads were observed.

Table 13
SVL-BBK 66kV Loop
System Transformer Loading for 2034

Station	Unit	Max Rating (MVA)	P90 + 4.8%	
			MVA	%
Stephenville	T3	66.6	58.5	87.9
Bottom Brook	T2	25	0.4	1.5

6.2 Single Line Outages (N-1)

Each 66kV transmission line within the SVL-BBK loop was individually opened in CYME to observe effects during peak. The results are provided in Table 14 below.

Table 14
SVL-BBK 66kV Loop
Effect of Transmission Line Contingency Events

Transmission Line	Planning Criteria Violations?
	P90 + 4.8%
400L / 404L	No
401L / 405L / 406L	No
TL-209	Yes

It was found that the loss of any one 66kV transmission line within the SVL-BBK loop resulted in no transformer overloads or voltage criteria violations. However, a loss of 230kV transmission line TL-209 resulted in a loss of supply to SVL-T3, which is discussed in the following section.

6.3 Single Transformer Outages (N-1)

In addition to assessing various transmission line outages, the effect of single system transformer outages within the loop were also analyzed for 2034. The transformers analyzed in this section are SVL-T3 and BBK-T2; loading results for the simulated outages for the P90 + 4.8% case are found in Table 15.

[15] A normally-open point exists between transmission lines 400L and 404L at NP's Wheeler's Substation ("WHE"). As a result, under normal conditions, loading on BBK-T2 is limited to line charging current on Transmission Line 400L.

Table 15 SVL-BBK 66kV Loop System Transformer Loading Following XFMR Loss P90 + 4.8% Scenario						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 4.8% (No SVL-T3)**		**P90 + 4.8% (No BBK-T2)**	
			MVA	**%**	**MVA**	**%**
Stephenville	T3	66.6	*Out-of-service*		58.5	87.9
Bottom Brook	T2	25	> 58.5[16]	> 234%	*Out-of-service*	

As shown in Table 15, a loss of SVL-T3 during the P90 + 4.8% scenario resulted in a substantial overload to BBK-T2. To mitigate this effect, SVL-GT was dispatched. See Table 16.

Table 16 SVL-BBK 66kV Loop System Transformer Loading Following XFMR Loss P90 + 4.8% Scenario						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 4.8% (No SVL-T3) SVL-GT On**		**P90 + 4.8% (No BBK-T2)**	
			MVA	**%**	**MVA**	**%**
Stephenville	T3	66.6	*Out-of-service*		58.5	87.9
Bottom Brook	T2	25	6.7	26.7	*Out-of-service*	

7.0 Holyrood – Hardwoods 66kV Loop

The Holyrood – Hardwoods Loop ("HRD-HWD") is comprised of 66kV transmission lines that run through the Northeast Avalon area between Hydro's Holyrood Terminal Station ("HRD") and the Hardwoods Terminal Station ("HWD"). The following sections outline load flow results for a pre-contingency scenario, as well as for various N-1 contingency scenarios due to single outages to transmission lines and system transformers along the loop.

[16] Due to the magnitude of the overload condition, CYME was unable to calculate a solution. It is assumed that the SVL-T3 loading would exceed the loading observed during the BBK-T2 contingency scenario.

7.1 Pre-Contingency

Load flow results for 2034 for the current pre-contingency system configuration are shown in Table 17.

Table 17
HRD-HWD 66kV Loop System Transformer Loading for 2034

Station	Unit	Max Rating (MVA)	P90 + 4.8%	
			MVA	%
Holyrood	T5	25	21.2	84.7
	T10	25	20.5	82.2
Hardwoods	T1	125	107.7	86.2
	T2	66.6	54.9	82.5
	T3	66.6	59.5	89.3
	T4	125	106.9	85.5

7.2 Single Line Outages (N-1)

Each 66kV transmission line within the HRD-HWD loop were individually opened in CYME to observe effects during peak. The results are provided in Table 18.

Table 18
HRD-HWD 66kV Loop System
Effect of Transmission Line Contingency Events

Transmission Line	Planning Criteria Violations?
	P90 + 4.8%
4L / 18L / 25L	No
13L	No
15L / 19L / 54L / 69L	No
72L / 73L	No
38L / 51L / 52L	No
49L / 79L	No

7.3 Single Transformer Outages (N-1)

In addition to assessing various transmission line outages, the effect of single system transformer outages within the loop were also analyzed for 2034. In substations with multiple system transformers and bus voltages, the largest transformer per bus was removed. In cases where there were multiple transformers of the same size at a particular substation bus, the transformer with the smallest impedance was removed. The transformers analyzed in this section are HRD-T5 and

HWD-T1. Loading results for the simulated outages during the P90 + 4.8% case are presented in Table 19.

Table 19
N-1 Contingency HRD-HWD 66kV Loop Loading Following XFMR Loss
P90 + 4.8% Scenario

Station	Unit	Max Rating (MVA)	P90 + 4.8% (No HRD-T5)		P90 + 4.8% (No HWD-T1)	
			MVA	%	MVA	%
Holyrood	T5	25	*Out-of-service*		23.3	93.1
	T10	25	25.9	103.4	22.6	90.4
Hardwoods	T1	125	113.0	90.4	*Out-of-service*	
	T2	66.6	57.7	86.6	70.7	106.1
	T3	66.6	62.5	93.8	76.5	114.8
	T4	125	112.2	89.8	137.4	109.9

As shown in Table 19, an overload to HRD-T10 was observed with HRD-T5 out of service for the P90 + 4.8% case. Similarly, overloads to HWD-T2, HWD-T3 and HWD-T4 were observed with HWD-T1 out of service, as also described in Section 3.3.

To mitigate the overload to HRD-T10 following a loss of HRD-T5, 38L was opened in HRD for the P90 + 4.8% scenario. See Table 20. It should be noted that opening 38L while HRD-T5 is out of service results in the 66kV bus at HRD to be supplied from HWD, and therefore, NP's Seal Cove ("SCV") and Kelligrews ("KEL") substations would be supplied radially from HWD.

To mitigate the overload to the remaining HWD transformers following a loss of HWD-T1, the voltage management scheme was implemented in conjunction with a 25MW load curtailment at MUN, along with dispatching all local NP generation to their full ratings. In terms of specific voltages, HWD 66kV was reduced to 0.98pu and HRD 66kV was reduced to 1.00pu. See Table 20.

Table 20 HRD-HWD 66kV Loop System Transformer Loading Following XFMR Loss P90 + 4.8% Scenario (MITIGATED)						
Station	**Unit**	**Max Rating (MVA)**	**(No HRD-T5) Open 38L**		**(No HWD-T1) 25MW MUN Curtail, HWD 66kV@ 0.98pu, HRD 66kV @ 1.00pu, Maximum NP Generation Dispatched**	
			MVA	**%**	**MVA**	**%**
Holyrood	T5	25	*Out-of-service*		23.9	95.7
	T10	25	0	0	23.3	93.0
Hardwoods	T1	125	118.9	95.1	*Out of Service*	
	T2	66.6	60.6	91.1	61.5	92.3
	T3	66.6	65.7	98.6	65.8	98.8
	T4	125	118.0	94.4	118.3	94.6

8.0 Summary

A summary of CYME load flow results for each loop outlined in this report are as follows:

- HWD-OPD 66kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 4.8% load scenario.
  - Disconnecting 30L during the P90 + 4.8% scenario resulted in an overload to 14L. Disconnecting 14L results in additional power flow over adjacent lines to all be within winter ampacity ratings.
  - Disconnecting 31L or 70L during the P90 + 4.8% scenario resulted in an overload to the other transmission line. Disconnecting 14L results in additional power flow over adjacent lines to all be within winter ampacity ratings, for either contingency.
  - A loss of either HWD-T1 or OPD-T1 during the P90 + 4.8% load scenario resulted in various transformer overloads in HWD and OPD at normal operating voltages. All observed overloads could be mitigated in CYME by implementing: a voltage management scheme at HWD and HRD; a 25MW load curtailment at MUN, and dispatching all local NP generation.

- HRD-WAV 66/138kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 4.8% load scenario.
  - An overload to transmission 39L was observed following the loss of 64L during the P90 + 4.8% scenario. This overload was mitigated in CYME by dispatching MG2 at 4.8MW in BLK.
  - An overload to BRB-T3 was observed following the loss of BRB-T2 during the P90 + 4.8% scenario. This overload was mitigated in CYME by opening 48L in BRB.
- SSD-STB 138kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 4.8% load scenario.[17]
  - Various undervoltage conditions to transmission lines in the Central Newfoundland area were observed when 124L, 137L, 144L or TL-210 were disconnected during the P90 + 4.8% scenario. All observed undervoltages were able to be mitigated in CYME by dispatching WES-GT at 8MW.
  - Various undervoltage conditions to transmission lines in the Burin Peninsula area were observed when either TL-212 or TL-219 were disconnected during the P90 + 4.8% scenario. All observed undervoltages were able to be mitigated in CYME by dispatching GRH-GT at 20MW.
  - An overload to SSD-T1 was observed following a loss of SSD-T4 during the P90 + 4.8% scenario. The overload was able to be mitigated in CYME by dispatching WES-GT at 8MW along with 25MW of thermal generation at GRH. It should be noted that this is beyond the existing capacity of GRH-GT, which has been de-rated from its original nameplate capacities. Newfoundland Power and Hydro are currently assessing options to address this contingency. In addition, 124L was opened at CLV to limit power flow from SSD toward Central Newfoundland, thereby further offloading SSD-T1.
  - An overload to STB-T1 was observed following a loss of STB-T2 during the P90 + 4.8% scenario. The overload was able to be mitigated by dispatching 16MW of thermal generation at WES. It should be noted that this is beyond the existing capacity of WES-GT, which has been de-rated from its original nameplate capacity.

[17] This assumes the construction of a new 138kV transmission line 148L between LEW and BOY in 2027 to mitigate existing 66kV voltage violations at BOY, SUM, and TWG.

Newfoundland Power is currently working with Hydro to asses alternatives to mitigate this contingency.

- In addition, TL-245 was opened at HOW, and HND, RBK and SBK were dispatched to their full ratings.

- STV-BBK 66kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency analysis of the P90 + 4.8% load scenario.
  - An overload to BBK-T2 was observed following the loss of either SVL-T3 or TL-209. This could be mitigated by dispatching SVL-GT. Hydro is currently performing a condition assessment of this unit to determine if its service life can be extended.

- HRD-HWD 66kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 4.8% load scenario.
  - No overloads or planning criteria violations were observed with any single transmission line disconnected in CYME during the P90 + 4.8% load scenario.
  - An overload to HRD-T10 was observed following the loss of HRD-T5 during the P90 + 4.8% scenario. The overload could be mitigated by disconnecting 38L in HRD, thereby supplying the HRD 66kV bus from HWD.
  - A loss of HWD-T1 during the P90 + 4.8% load scenario resulted in various transformer overloads in HWD at normal operating voltages. All observed overloads could be mitigated in CYME by implementing: a voltage management scheme at HWD and HRD; a 25MW load curtailment at MUN; and dispatching all local NP generation.

Appendix A – Relevant Local Generation Assumptions for N-0 Pre-Contingency Cases

Loop System Generator Loading for 2034/35 [MW]				
Generator	**Loop**	**Owner**	**Modeled Power for N-0 Cases**	**Full Capacity Rating**
St. Lawrence	SSD-STB	Elemental Energy	6.0	27.0
Fermeuse	HWD-OPD & HRD-HRD	Elemental Energy	6.0	27.0
Paradise River	SSD-STB	Hydro	8.0	8.0
Hind's Lake	SSD-STB	Hydro	67.0	75.0
Heart’s Content	HRD-WAV	NP	1.7	2.7
New Chelsea	HRD-WAV	NP	2.7	4.3
Pittman’s Pond	HRD-WAV	NP	0.4	0.6
Victoria	HRD-WAV	NP	0.3	0.6
MG2	HRD-WAV	NP	0.0	5.0
Fall Pond	SSD-STB	NP	0.1	0.3
Greenhill	SSD-STB	NP	0.0	20.0
Lawn	SSD-STB	NP	0.3	0.6
West Brook	SSD-STB	NP	0.2	0.7
Lockston	SSD-STB	NP	1.6	3.0
Port Union	SSD-STB	NP	0.3	0.6
Rattling Brook	SSD-STB	NP	7.8	14.8
Sandy Brook	SSD-STB	NP	3.3	6.3
Wesleyville	SSD-STB	NP	0.0	8.0
Cape Broyle	HWD-OPD & HWD-HRD	NP	4.4	6.3
Horsechops	HWD-OPD & HWD-HRD	NP	5.9	8.1
Mobile	HWD-OPD & HWD-HRD	NP	6.6	10.5
Morris	HWD-OPD & HWD-HRD	NP	0.8	1.1
Petty Harbour	HWD-OPD & HWD-HRD	NP	3.4	5.4
Pierre's Brook	HWD-OPD & HWD-HRD	NP	3.1	4.1
Rocky Pond	HWD-OPD & HWD-HRD	NP	2.3	3.3
Seal Cove	HWD-OPD & HWD-HRD	NP	1.9	3.6
Topsail	HWD-OPD & HWD-HRD	NP	1.4	2.6
Tors Cove	HWD-OPD & HWD-HRD	NP	3.8	6.6
Lookout Brook	SVL-BBK	NP	2.8	5.8