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April 8, 2022

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

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

Dear Ms. Blundon:

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. These power system studies are performed by the NLSO and include an annual assessment of the Newfoundland and Labrador bulk 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, and Island Interconnected System. Newfoundland and Labrador Hydro ("Hydro") also performs 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-054: "NL Hydro Report – 2022 Annual Planning Assessment," Newfoundland and Labrador Hydro, April 8, 2022; and
2) TP-R-055: "NLSO Report – 2022 Annual Planning Assessment," Newfoundland and Labrador Hydro, March 30, 2022.

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,

NEWFOUNDLAND AND LABRADOR HYDRO

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

Encl.

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NL Hydro Report - 2022 Annual Planning Assessment

Doc #: TP-R-054

Date: 2022/04/08

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 the Hydro Annual 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 2022 Annual Planning Assessment revealed:

- The pre-contingency and single contingency analysis indicates there are no transmission equipment overloads or voltage violations in the near-term or long-term planning horizons.
- The short circuit analysis reveals 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 the end of 2022. A detailed summary of results for the final operational study will be provided in the 2023 Annual Assessment.
- The results of the analysis presented in Newfoundland Power's loop assessment (Appendix C), indicates an overload in 2027 on the Stony Brook transformer T2 (STB T2) following the loss of STB T1. Therefore, additional transformer capacity or transmission system reinforcements may be required within the 138kV STB/SSD Loop System prior to the year 2027 to address this transformer overload. Hydro will develop alternatives to address this overload condition and determine the least cost solution which will be presented in the 2023 Annual Assessment.

[1] NLSO Annual Transmission Assessment (2022) – TP-R-055

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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 2022 Annual Planning Assessment covers the period extending to 2031/32. Cases are assessed to investigate the capability of the transmission system to meet peak load and to meet firm transmission commitments.[2]

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 2022 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.

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 2031/32. The following system additions are included in the 2031/32 study cases:

- The Muskrat Falls Generating Station (MFAGS) is complete, with four 206 MW generating units in service
- The MFAST2 315 kV, 150 MVAr shunt reactor is removed from 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 Soldiers Pond 175 MVAr synchronous condensers in service for analysis (the third unit is available)
- The ML exports are set at the NS Block (158 MW at Bottom Brook terminal Station 2 – BBKTS2) in both the peak and light load cases
- Happy Valley Terminal Station (HVYTS) is supplied via a new 138 kV transmission line L1303 connecting the Muskrat Falls Terminal Station 2 (MFATS2) to the Muskrat Falls Construction Power Station (MFATS3), where it taps into existing 138 kV transmission line L1302

[2] The firm export limit for the Maritime Link (ML) is set at 158 MW

[3] The NLSO 2022 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

- 138 kV transmission line L1301 from Churchill Falls to Muskrat Falls TS1, as well as Muskrat Falls TS3 have been decommissioned
- The CF T31 power transformer has been relocated to Holyrood to replace failed T7
- SC3 at Wabush Terminal Station is available for service to all customers
- There are two 60 MVAr line reactors installed on the Muskrat Falls end of 315 kV lines L3101 and L3102 (Proposed)
- Holyrood Thermal Generating Station is out of service with Unit 3 operating in synchronous condenser mode
- Holyrood Gas Turbine is available for service as required
- Stephenville gas turbine has been removed from service
- Hardwoods gas turbine is out of service as a generator, but can be operated as a synchronous condenser
- HVYTS has an additional 138/25 kV 50 MVA transformer, T5
- The Happy Valley North Side Diesel Plant is assumed to be out of service
- A new power transformer T4 is installed in Bottom Brook as a backup supply for Stephenville as the gas turbine is no longer in service. 400L is normally in service.
- Valentine Lake Terminal Station is in service, with the following configuration:
    - Phase II: 8 MVAr capacitor bank on 6.9 kV bus VLK T1, and 6 MVAr capacitor bank on 6.9 kV bus VLK T2
- Wabush Terminal Station upgrades include:
    - Addition of a 23 MVAr capacitor bank
    - Transformers T4 and T5 have been replaced with 125 MVA units
- Wabush Substation has been renamed to Jean Lake Terminal Station and upgrades include:
    - Transformers T3, T4, T5 and T6 have been removed from service
    - A new 26.7 MVA transformer T1 has been connected to bus B2, and a new 26.7 MVA transformer T2 (proposed) has been connected to bus B3
    - A bus tie has been added to connect buses B2 and B3, which is normally open

The following load flow plots for the Year Ten (2031/2032) cases are provided in Appendix B:

- 2031/2032 Peak Load Conditions
- 2031 Light Load Conditions

3 SPECIAL CONSIDERATIONS

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

3.1 Operational Studies

Hydro is undertaking a set of operational studies for the interconnection of LCP assets into the NL Transmission System. The objective of the studies is to identify system impacts and operating limits to allow for the development of instructions to be used by the NLSO. These operational studies include assessments of the transient stability. Transient stability considerations will therefore be outside of the scope of annual assessments until the operational studies are complete. These studies are expected to be completed by late 2022.

3.2 Labrador Incremental Load

Throughout 2021, Hydro began investigating incremental customer load requests in Labrador. These incremental requests are beyond the baseline forecast and outside of the scope of the 2022 Annual Assessment. Transmission system expansion requirements to serve incremental customers in Labrador will be assessed in a standalone study to be completed in 2022 in accordance with the Network Addition Policy.

4 LOAD FORECAST

The 2022 Annual Planning Assessment is based upon the following load forecasts prepared by the Market Analysis and Load Forecasting Section, Resource and Transmission Planning Department, Newfoundland and Labrador Hydro:

- IIS Peak Demand Forecast System – prepared in Fall 2021; and
- LIS Long Term Load Forecast – prepared in Fall 2021.

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

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

Forecasted Demand (MW)[4]			
Year[5]	Island Interconnected System (IIS) (Fall 2021)	Labrador Interconnected System (LIS) (Summer 2021)	
		Lab East	Lab West
2021/22	1,686.8	79.4	382.7
2022/23	1,694.7	80.4	383.0
2023/24	1,715.8	81.2	383.2
2024/25	1,720.2	81.7	383.6
2025/26	1,725.6	82.1	383.9
2026/27	1,734.7	82.6	384.2
2027/28	1,743.7	83.3	384.3
2028/29	1,747.6	83.8	384.5
2029/30	1,758.7	84.4	384.6
2030/31	1,770.4	85.0	384.8
2031/32	1,781.4	85.5	384.9

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 (2031/32) 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 (2031/32). A review of the pre-contingency peak cases for long-term horizons indicates that there are no transformer overloads.

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

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

Table 2 – Pre Contingency Transformer Load Levels[1]				
Station	Unit	Rating MVA	2031/32	
			MVA	%
Barachoix	T1	10/13.3/16.7	7.33	43.9%
Bay d'Espoir	T10	15/20/25	9.69	38.8%
	T12	15/20/25	6.82	40.9%
	T11	10/13.3/16.7	10.59	42.4%
Bear Cove	T1	10/13.3/16.7	4.99	29.9%
Berry Hill	T1	15/20/25	1.95	7.8%
Bottom Brook[2]	T1	25/33.3/41.7	25.86	62.0%
	T3	25/33.3/41.7	13.67	32.8%
	T4	40/53.3/66.6	16.54	24.8%
Bottom Waters	T1	10/13.3/16.7	15.33	91.8%
Buchans	T1	40/53.3/66.6	6.20	9.3%
	T2	5/6.6/8.3	2.60	31.3%
Coney Arm	T1	2.5/3.3/4.0	0.00	0.0%
Conne River	T1	2.5/3.3	2.35	71.2%
Cooper Hill	T1	7.5/10	2.66	26.6%
Corner Brook Converter	T1	21/28	8.94	17.9%
	T2	21/28	8.94	17.9%
Cow Head	T1	5/6.7/8.3	1.88	22.6%
Daniel's Harbor	T1	1/1.3	0.54	41.9%
	T2	1	0.54	41.5%
Deer Lake	T1	25/33.3/41.7	9.44	28.4%
	T2	45/60/75	28.51	38.0%
Doyles	T1	25/33.3/41.7	27.62	66.2%
English Harbour West	T1	5/6.7	2.86	42.6%
Farewell Head	T1	10/13.3/16.7	6.19	37.1%
Glenburnie	T1	1.5/3.3	2.09	63.4%
Grand Falls Frequency Converter	T1	30/40/50	22.53	45.1%
	T2	30/40/50	23.11	46.2%
	T3	30/40/50	20.85	41.7%
Grandy Brook	T1	7.5/10/12.5	4.73	37.8%
Hampden	T1	2.5/3.3/4.0	1.59	39.8%
Happy Valley[3]	T1	30/40/50	19.60	39.2%
	T2	15/20/25//28	10.93	39.0%
	T4	15/20/25//28	10.93	39.0%
	T5	30/40/50	19.60	39.2%
Hardwoods	T1	75/100/125	96.41	77.1%
	T2	40/53.3/66.6	49.20	73.8%
	T3	40/53.3/66.6	53.12	79.6%
	T4	75/100/125	95.65	76.5%
Hawke's Bay	T1	5/6	***NOTE 4***	
	T2	2.5/3.3		
Holyrood[5]	T5	15/20/25	19.58	78.3%
	T10	15/20/25	19.06	76.3%
	T6	25/33.3/41.7	9.77	23.4%
	T7	75/100/125	27.67	22.1%
	T8	75/100/125	28.36	22.7%
Howley[6]	T2	7.5/10/12.5	2.96	23.7%
Jackson's Arm	T1	5/6.6/8.3	1.23	14.8%
Main Brook	T1	1.5	0.65	43.1%
Massey Drive	T1	75/100/125	49.94	40.0%

	T2	40/53.3/66.6	33.84	50.7%
	T3	75/100/125	59.98	48.0%
Muskrat Falls TS1	T1	2	0.07	3.7%
Muskrat Falls TS2	T5	75/100/125	30.88	24.7%
	T6	75/100/125	30.94	24.8%
Oxen Pond	T1	75/100/125	158.11	63.2%
	T2	150/200/250	76.25	61.0%
	T3	150/200/250	158.11	63.2%
Parson’s Pond	T1	1/1.3	0.64	48.9%
Peter’s Barren	T1	15/20/25	2.18	8.7%
Plum Point	T1	10/13.3/16.7	3.44	20.6%
Quartzite	T1	15/20/25	17.25	69.0%
	T2	15/20/25	17.14	68.6%
Rocky Harbour	T2	5/6.6/8.3	4.29	51.7%
Roddickton	T2	5/6.6/8.3	2.48	49.6%
South Brook	T1	5/6.6/8.3	6.89	83.0%
Stephenville	T3	40/53.3/66.6	38.61	57.9%
Stony Brook	T1	75/100/125	89.30	71.4%
	T2	75/100/125	88.23	70.6%
St. Anthony Airport[7]	T1	15/20/25	2.97	11.9%
Sunnyside	T1	75/100/125	71.99	57.6%
	T4	75/100/125	72.50	58.0%
	T5	15/20/25	13.31	53.3%
Vanier	T1	15/20/25	13.21	52.8%
	T2	15/20/25	13.41	53.6%
Wabush Terminal[8]	T1	35/47/65	37.48	57.7%
	T2	35/47/65	38.65	59.5%
	T3	35/47/65	38.04	58.5%
	T4	75/100/125	78.28	62.6%
	T5	75/100/125	78.28	62.6%
	T6	35/47/65	36.02	55.4%
	T7	50/66.6/83.3	52.19	62.7%
	T8	50/66.6/83.3	53.26	63.9%
Wabush Substation (AKA Jean Lake)[9]	T1	20/26.7	7.79	29.2%
	T2	20/26.7	17.35	65.0%
Western Avalon	T1	15/20/25	16.41	65.7%
	T2	15/20/25	16.72	66.9%
	T3	25/33.3/41.7	16.30	39.1%
	T4	25/33.3/41.7	16.21	38.9%
	T5	75/100/125	47.50	38.0%
Wiltondale	T1	1.0	0.07	4.8%

Notes:

1. Generator step up transformers and converter transformers are not included as these units have been sized for the full unit capability.
2. A new 230/66 kV, 40/53.3/66.7 MVA power transformer (BBK T4) will be added at Bottom Brook Terminal Station prior to Year 10 (2031).
3. As part of the Muskrat Falls – Happy Valley Interconnection project, a fourth 138/25 kV, 30/40/50 MVA transformer (HVY T5) will be in service by the end of 2022.
4. The Hawke’s Bay system is typically supplied by 15 MVA mobile transformer during the winter season.
5. The 125 MVA transformer (CHFTS1 T31) at the Churchill Falls Terminal Station #1 will be relocated to Holyrood to replace the failed HRD T7 by the Fall of 2022 (prior to next peak season).
6. Rattle Brook assumed to in operation at 4 MW.
7. St. Anthony Diesel Plant is in-service for capacity support.
8. Transformers T4 and T5 will both be replaced with 125 MVA units prior to Year 10.
9. An additional 26.7 MVA transformer (T2) will be installed prior to Year 10 (2031). Transformers T4 and T6 will serve as spare transformers during normal operation.

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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
L1303	138	Churchill Falls/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 no violations to the Transmission Planning Criteria following the loss of the following Hydro owned equipment:

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

5.3.2 Summary of Multi Transformer Station Contingency Loading

Table 4 provides the transformer loading for each multi transformer station with the largest transformer out of service.

Table 4– Multi Transformer Contingency Load Levels[1]

Station	Unit	Rating MVA	2031/2032	
			MVA	%
Bay d'Espoir	T10	15/20/25	*Out-of-Service*	
	T12	15/20/25	20.35	81.4%
Bottom Brook[2]	T1	25/33.3/41.7	32.85	78.8%
	T3	25/33.3/41.7	*Out-of-Service*	
Daniel's Harbour	T1	1/1.3	*Out-of-Service*	
	T2	1	1.08	83.4%
Grand Falls Frequency Converter	T1	30/40/50	*Out-of-Service*	
	T2	30/40/50	29.48	59.0%
	T3	30/40/50	35.00	70.0%
Happy Valley[3]	T1	30/40/50	*Out-of-Service*	
	T2	15/20/25//28	16.08	57.4%
	T4	15/20/25//28	16.08	57.4%
	T5	30/40/50	28.85	57.7%
Hawke's Bay	T1	5/6.7	*Note 4*	
	T2	2.5/3.3		
Holyrood[5]	T5	15/20/25	6.98	27.9%
	T10	15/20/25	*Out-of-Service*	
Massey Drive[6]	T1	75/100/125	*Out-of-Service*	
	T2	40/53.3/66.6	46.75	70.1%
	T3	75/100/125	82.86	66.3%
Muskrat Falls TS2	T5	75/100/125	*Out-of-Service*	
	T6	75/100/125	61.82	49.5%
Wabush Terminal[7]	T1	35/47/65	37.48	57.7%
	T2	35/47/65	38.64	59.4%
	T3	35/47/65	38.04	58.5%
	T4	75/100/125	*Out-of-Service*	
	T5	75/100/125	115.13	92.1%
	T6	35/47/65	52.98	81.5%
	T7	50/66.6/83.3	76.75	92.1%
	T8	75/100/125	53.25	63.9%
Wabush Substation (AKA Jean Lake)[8]	T1	20/26.7	*Out-of-Service*	
	T2	20/26.7	25.44	95.4%
Western Avalon[9]	T1	15/20/25	*Out-of-Service*	
	T2	15/20/25	6.31	25.2%

Notes:

1. The loading provided is with the largest transformer in the station removed from service and back up generation on line where applicable.
2. Bottom Brook 138 kV bus tie switch B2B3 closed.
3. As part of the Muskrat Falls – Happy Valley Interconnection project, a fourth 138/25 kV, 30/40/50 MVA transformer (HVY T5) will be in service by 2022.
4. The Hawke's Bay system is typically supplied by 15 MVA mobile transformer during the winter season.
5. The 66kV loop between Holyrood and Hardwoods must be opened to avoid the overload of transformer T5.
6. 66 kV bus tie B2B4-1 closed.
7. Transformers T4 and T5 will both be replaced with 125 MVA units prior to Year 10.
8. 46 kV bus tie B2B3 closed.
9. The overload of T2 (106%) can be mitigated by opening 80L in Blake town.

5.3.3 Summary of Looped System Transformer Contingency Loading

Newfoundland Power executed a 10-year assessment (2022-2031) of looped systems that are supplied by Hydro's power transformers (Appendix C)[6]. This loop assessment evaluated two load forecasts; (1) P90 + 3.25%[7] and (2) P90 +6%[8]. The P90 +6% is a high growth sensitive case, and therefore the base case, P90 + 3.25%, was considered for this Annual Assessment.

As per the results of the analysis presented in Newfoundland Power's loop assessment for the P90 +3.25% forecast, an overload to Stony Brook transformer T2 ("STB-T2") following the loss of STB-T1 is expected beyond 2027. Therefore, additional transformer capacity or transmission system reinforcements may be required within the 138kV STB/SSD Loop System prior to the year 2027 to address this transformer overload. Hydro will develop alternatives to address this overload condition and determine the least cost solution. A detailed scope of the preferred solution will be established prior to the completion of the 2023 Annual Assessment.

5.3.4 Generator and Synchronous Condenser Contingency Analysis

There are no violations to the Transmission Planning Criteria following the loss of any other generator or synchronous condenser.

5.3.5 Shunt Contingency Analysis

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

[6] NP 138kV/66kV Loop Assessments: 2022-2031

[7] Load data was scaled an additional 3.25% to allow for potential demand growth through to 2031 based on correspondence with NLH in early 2022

[8] A second load profile was also considered, which scales the worst-case P90 loads an additional 6% to reflect the potential of unmanaged electric vehicle charging through to 2031.

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[9]. Short circuit analysis was performed and the results indicate that there are no circuit breaker rating violations.

7 STABILITY ANALYSIS

Hydro is currently 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. Once the Lower Churchill Project (LCP) assets are closer to being fully integrated into the NL Transmission System the Operational Studies can be finalized. The operational studies are ongoing and expected to be completed by the end of 2022.

8 CONCLUSIONS

The 2022 Annual Planning Assessment focuses on the long-term planning horizon (10 years).
The conclusions of the 2022 Annual Planning Assessment are specified as follows:

- The pre-contingency and single contingency analysis indicates there are no transmission equipment overloads or voltage violations in the near-term or long-term planning horizons.
- The short circuit analysis reveals 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. These studies will be completed in 2022.
- The results of the analysis presented in Newfoundland Power's loop assessment, indicates an overload in 2027 on STB-T2 following the loss of STB-T1. Therefore, additional transformer capacity or transmission system reinforcements may be required within the 138kV STB/SSD Loop System prior to the year 2027 to address this transformer overload. Hydro will develop alternatives to address this overload condition and determine the least cost solution.

[9] Planned outages are required to gather this missing information and will be collected during scheduled maintenance to avoid additional customer impact.

9 REFERENCE DOCUMENTS

- 2022 NLSO Annual Assessment (TP-R-055)
- Labrador Interconnected System - Expansion Study (TP-R-019)
- NLSO Standard – Transmission Facilities rating Guide (TP-S-001)
- TP-S-003 NLSO Standard – Annual Planning Assessment
- TP-S-007 NLSO Standard – Transmission Planning Criteria
- Newfoundland Power 138kV/66kV Loop Assessment: 2022 - 2031

APPENDIX A

Maps of the Island and Labrador Interconnected Systems post completion of the Lower Churchill Project

Figure 1: Island Interconnected System

Figure 2: Labrador Interconnected System

APPENDIX B

Load Flow Plots Primary Transmission System Year Ten

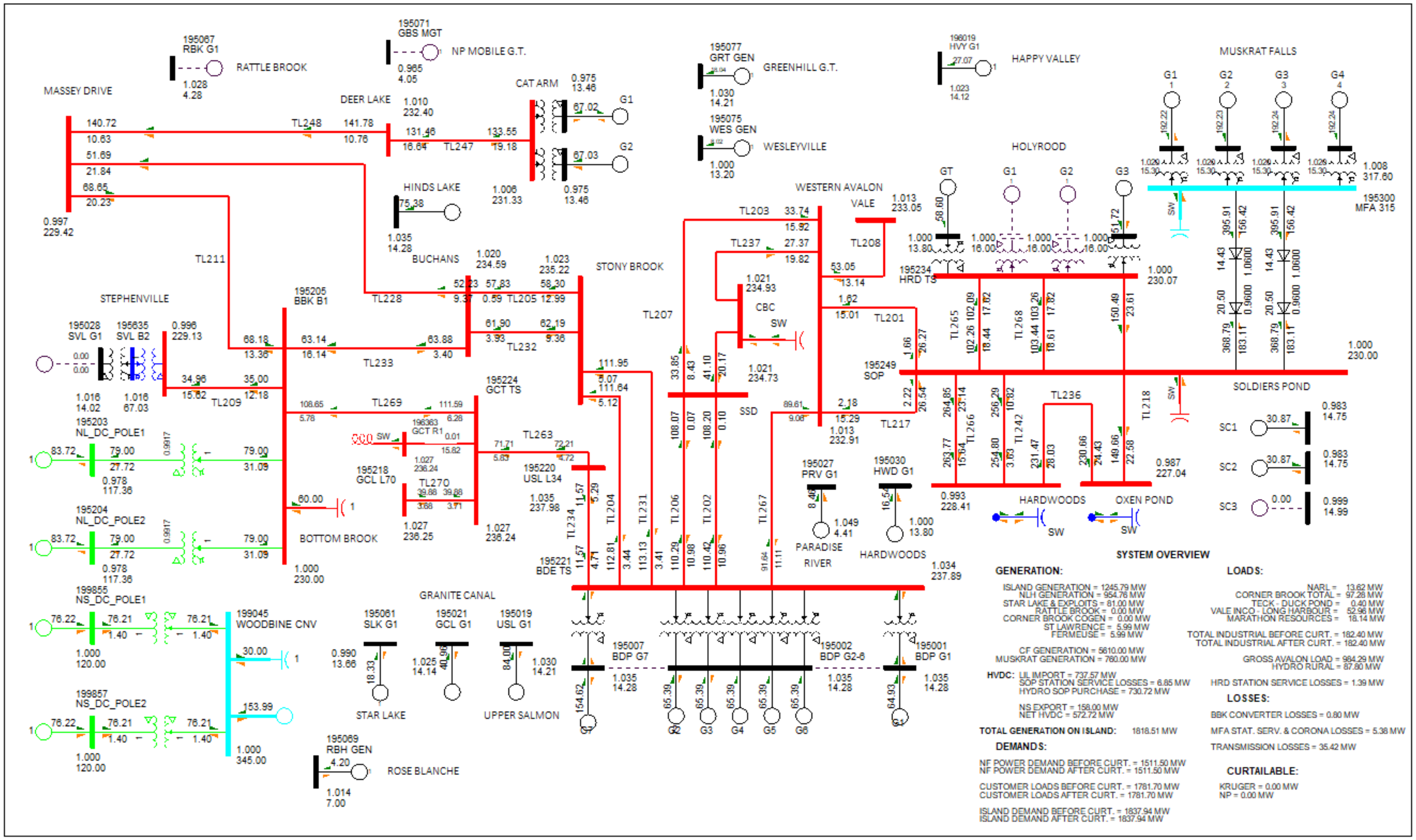

Figure 3 – IIS (2031/32 Peak Conditions – ML Exports (Emera Block – 158 MW))

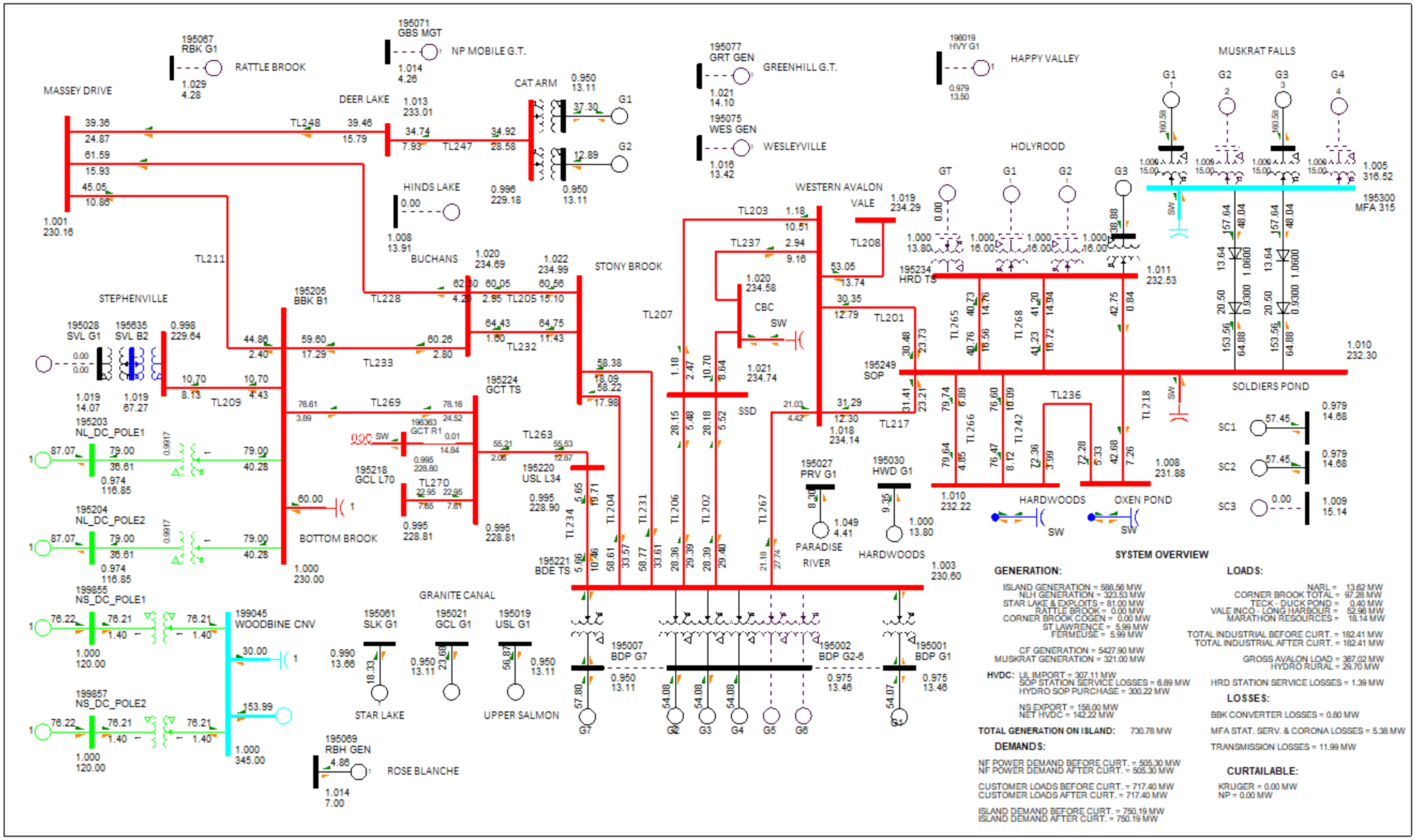

Figure 4 - IIS (2031 Light Conditions – ML Firm Exports (158 MW))

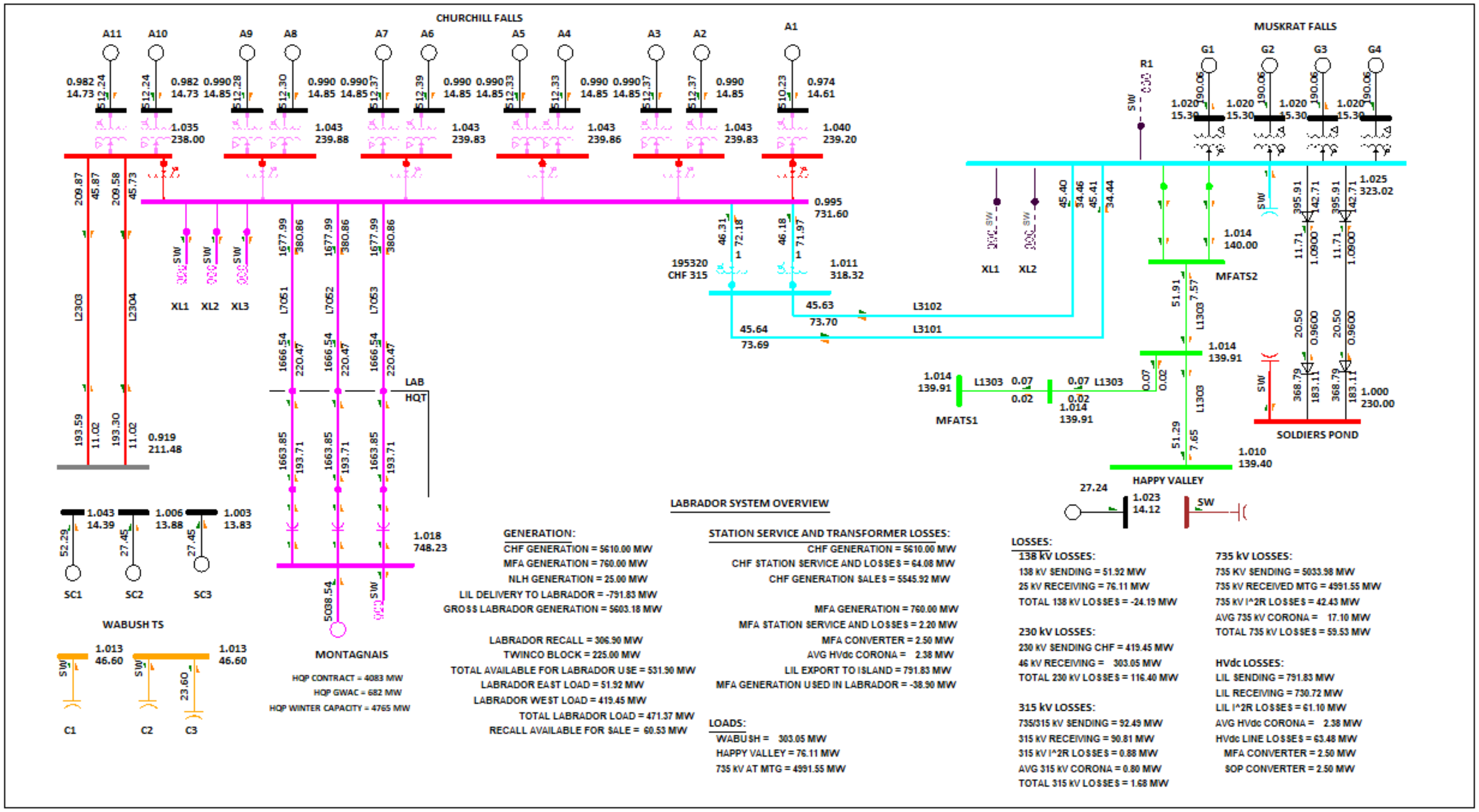

Figure 5 – LIS (2031/32 Peak Conditions)

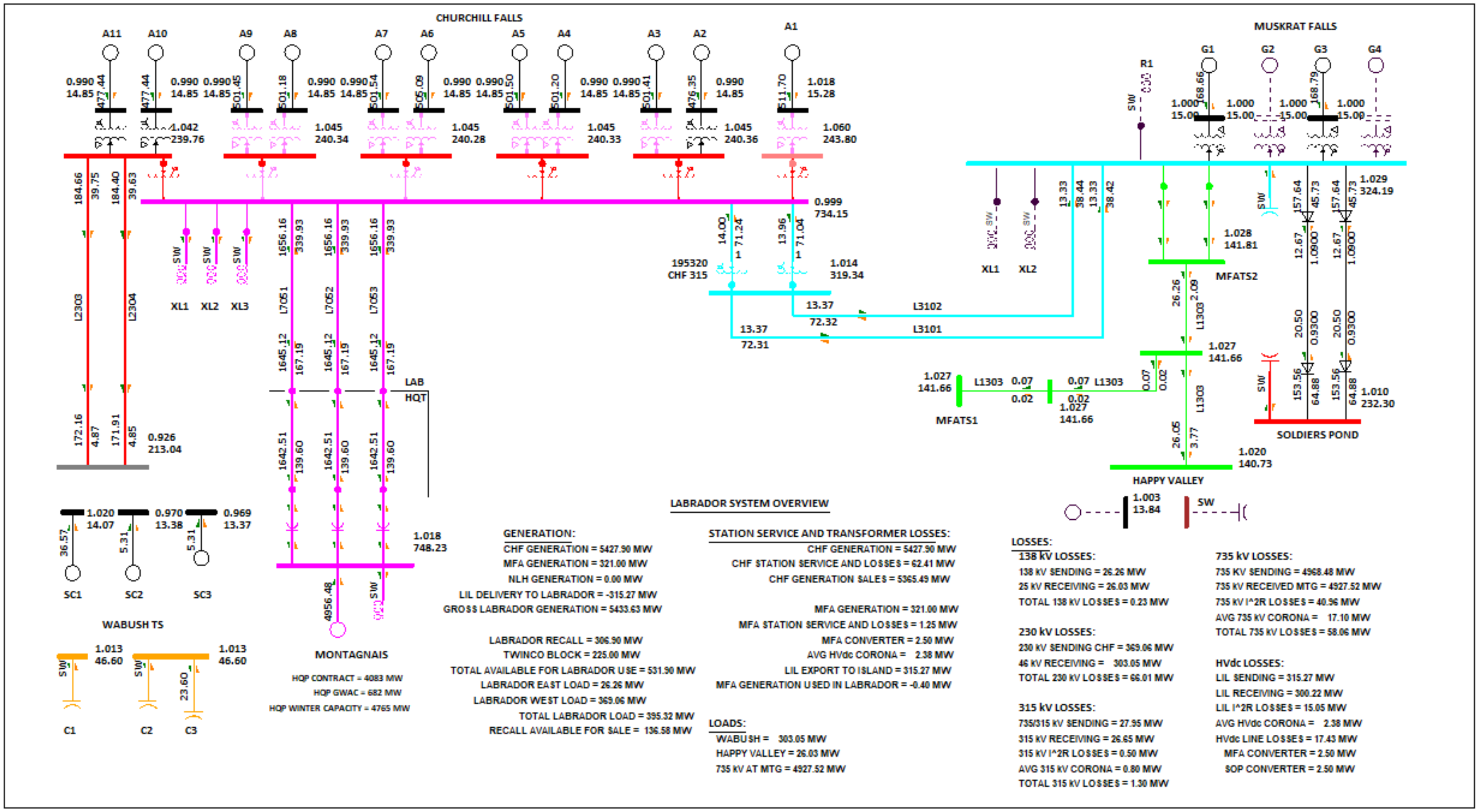

Figure 6 - LIS (2031 Light Conditions)

APPENDIX C

Summary of Newfoundland Power's 138 kV/66 kV 2022 – 2031 Loop Assessments

See Attachment A

Document Summary

Document Owner:	
Document Distribution:	

Revision History

Revision	Prepared by	Reason for change	Effective Date
0	B. Odetayo	Original Issue	2022/04/08

Document Approvers

Position	Signature	Approval Date
Sr. Manager, Transmission and Rural Planning		2022/04/08

Document Control

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

Attachment A

138 kV/66 kW Loop Assessments 2022–2031

Rev 3

138kV/66kV Loop Assessments

2022-2031

Rev. 3

Prepared by: Tony Jones, P. Eng.

April 4, 2022

Revision History

Rev. #	Comments	Date
3	Added clarification regarding new MUN Electric Boiler	April 4, 2022
2	-Added clarification regarding HRD-T7 and CHF-T31. -Added footnotes regarding local generation for each loop. -Added footnote specifying violation year for STB-SSD overload.	March 15, 2022
1	Values for SSD-STB loop updated to reflect contribution from St. Anthony & Hawke's Bay diesels and Rattle Brook hydro plant.	March 3, 2022
0	Initial version.	February 22, 2022

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April 4, 2022

Table of Contents

138kV/66kV Loop Assessments: 2022-2031
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1.0 Introduction

The purpose of this report is to assess five 138kV/66kV transmission loop systems based on forecast data for 2022 – 2031. 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 138kV/66kV loop.

2.0 Overview of Methodology

CYME was used to model load flows assuming worst-case peaks forecasted for 2022 – 2026 based on the latest P90 In-Feed Forecast provided to Newfoundland & Labrador Hydro ("NLH") in November 2021. Load data was scaled an additional 3.25% to allow for potential demand growth through to 2031 based on correspondence with NLH in early 2022. A second load profile was also considered, which scales the worst-case P90 loads an additional 6% to reflect the potential of unmanaged electric vehicle charging through to 2031.

Potential equipment overloading, as well as any observed voltages outside of either NP's or NLH's planning criteria limits[1] based on P90 + 3.25% and P90 + 6% 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. It should be noted that bus voltages under normal operating conditions were based on transformer tap changer settings obtained from NLH in October, 2021.

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/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.

3.0 Hardwoods – Oxen Pond 66kV Loop

The Hardwoods – Oxen Pond Loop ("HWD-OPD") is comprised of numerous 66kV transmission lines that run primarily through the St. John's area between the Hardwoods Substation ("HWD") and the Oxen Pond Substation ("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

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

were completed assuming the gas turbine currently installed in HWD is retired and out-of-service and all CYME modeling was completed with Fermeuse Wind disconnected.[2]

Furthermore, the results in Tables 1-6 below exclude an estimated 22MW of additional demand associated with the addition of an electric boiler at Memorial University of Newfoundland ("MUN"), currently scheduled for commissioning in 2024. This load is expected to be interruptible, and was therefore omitted from the contingency analysis presented in the following sections.

3.1 Pre-Contingency

Load flow results for 2031 for the current pre-contingency system configuration are shown in Table 1. [3]

Table 1
HWD-OPD 66kV Loop
System Transformer Loading for 2031

Station	Unit	Max Rating (MVA)	P90 + 3.25%		P90 + 6%	
			MVA	%	MVA	%
Hardwoods	T1	125	90.8	73%	103.1	82%
	T2	66.6	50.9	76%	49.8	75%
	T3	66.6	55.1	83%	53.9	81%
	T4	125	98.9	79%	96.8	77%
Oxen Pond	T1	250	162.1	65%	167.1	67%
	T2	125	78.2	63%	80.6	64%
	T3	250	162.2	65%	167.2	67%

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 were individually disconnected in CYME to observe effects during peak. The results are provided in Table 2.

[2] All local generating plants were modeled as "on" for the Hardwoods-Oxen Pond loop, including Cape Broyle, Horsechops, Mobile, Morris, Petty Harbour, Pierre's Brook, Rocky Pond, Seal Cove, Topsail, and Tors Cove.
[3] The Pre-Contingency results in Table 1 also exclude the 22MW associated with MUN's electric boiler. However, CYME load flows were completed for the pre-contingency case, and no planning violations were observed.

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Table 2 HWD-OPD 66kV Loop Effect of Single Line Outages		
Transmission Line(s)	**Planning Criteria Violations?**	
	P90 + 3.25%	**P90 + 6%**
4L / 25L	No	No
12L / 14L	No	No
13L	No	No
15L / 19L	No	No
16L / 74L	No	No
18L / 72L / 73L	No	No
30L / 32L / 67L	No	No
31L / 70L	No	Yes
34L / 58L	No	No
33L / 35L	No	No
49L / 79L	No	No
54L	No	No
69L	No	No

3.2.1 Loss of 31L / 70L

As per Table 2, a potential NP transmission line overload was observed during the N-1 case where an outage to either 31L or 70L during P90 + 6% peak resulted in an overload to the other transmission line. Preliminary load flows suggest disconnecting the remaining overloaded transmission line forces additional power flow over 30L, 32L, 33L and 35L with each line remaining within winter ampacity limits. The scenario may be further assessed by NP in a future transmission contingency planning study.

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 2031. 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 + 3.25% case are found in Table 3; results for the P90 + 6% case are found in Table 4.

Table 3
HWD-OPD 66kV Loop
System Transformer Loading Following XFMR Loss
P90 + 3.25% Scenario

Station	Unit	Max Rating (MVA)	P90 + 3.25% (No HWD-T1)		P90 + 3.25% (No OPD-T3)	
			MVA	%	MVA	%
Hardwoods	T1	125	*Out-of-service*		104.7	84%
	T2	66.6	64.7	97%	56.8	85
	T3	66.6	70.0	105%	61.4	92
	T4	125	125.7	101%	110.4	99
Oxen Pond	T1	250	175.7	70%	250.3	100%
	T2	125	84.7	68%	120.7	97%
	T3	250	175.8	70%	*Out-of-service*	

Table 4
HWD-OPD 66kV Loop:
System Transformer Loading Following XFMR Loss
P90 + 6% Scenario

Station	Unit	Max Rating (MVA)	P90 + 6% (No HWD-T1)		P90 + 6% (No OPD-T3)	
			MVA	%	MVA	%
Hardwoods	T1	125	*Out-of-service*		109.5	88%
	T2	66.6	67.7	102%	58.3	88%
	T3	66.6	73.2	110%	63.1	95%
	T4	125	131.6	105%	113.4	91%
Oxen Pond	T1	250	179.8	72%	256.8	103%
	T2	125	86.7	69%	123.9	99%
	T3	250	179.9	72%	*Out-of-service*	

As shown in Tables 3 and 4, potential transformer overloads were observed with either HWD-T1 or OPD-T3 out-of-service in both the P90 + 3.25% and P90 + 6% cases. To attempt to mitigate these overloads, a voltage management scheme was implemented and bus voltages were adjusted from their normal setpoints to reduce voltage at the overloaded substation relative to the other in the loop. This was found, in general, to force power flow from an alternate direction, thereby reducing demand on the overloaded transformer(s). See Tables 5 and 6.

Table 5 HWD-OPD 66kV Loop: System Transformer Loading Following XFMR Loss P90 + 3.25% Scenario (MITIGATED via Voltage Management)						
Station	**Unit**	**Max Rating (MVA)**	**P90 Load + 3.25% (No HWD-T1) OPD 66 @ 1.00pu HWD 66 @ 0.9875pu**		**P90 Load + 3.25% (No OPD-T3) OPD 66 @ 0.9875pu HWD 66 @ 1.00pu**	
			MVA	**%**	**MVA**	**%**
Hardwoods	T1	125	*Out-of-service*		113.3	91%
	T2	66.6	60.2	90%	57.8	87%
	T3	66.6	65.1	98%	62.6	94%
	T4	125	119.3	95%	112.4	90%
Oxen Pond	T1	250	181.1	72%	239.9	96%
	T2	125	87.4	70%	115.7	93%
	T3	250	181.2	72%	*Out-of-service*	

Table 6 HWD-OPD 66kV Loop: System Transformer Loading Following XFMR Loss P90 + 6% Scenario (MITIGATED via Voltage Management)						
Station	**Unit**	**Max Rating (MVA)**	**P90 Load + 6% (No HWD-T1) OPD 66 @ 0.975pu HWD 66 @ 0.950pu**		**P90 Load + 6% (No OPD-T3) OPD 66 @ 0.950pu HWD 66 @ 0.975pu**	
			MVA	**%**	**MVA**	**%**
Hardwoods	T1	125	*Out-of-service*		120.7	97%
	T2	66.6	58.2	87%	61.6	92%
	T3	66.6	63.0	95%	66.6	100%
	T4	125	113.2	91%	119.7	96%
Oxen Pond	T1	250	196.8	79%	240.5	96%
	T2	125	94.9	76%	116	93%
	T3	250	196.9	79%	*Out-of-service*	

As shown in Tables 5 and 6, the observed transformer overloads resulting from a loss of HWD-T1 or OPD-T3 may be mitigated by implementing a contingency voltage management scheme at both OPD and HWD. CYME results show than in either case, transmission voltages may be maintained within emergency limits.

It should be noted that in the case of OPD-T1 being out of service during the P90 + 6% load scenario, HWD-T3 is loaded to 100% even after implementing voltage management. As such, if further load beyond the P90 + 6% scenario materializes in the St. John's region in the coming years, the data in Table 6 suggests that transformer capacity additions may be required at HWD.

4.0 Holyrood – Western Avalon 138kV/66kV Loop

The Holyrood – Western Avalon Loop ("HRD-WAV") is comprised of 138kV and 66kV transmission line sections that run through the Avalon Peninsula between the Holyrood Substation ("HRD") and the Western Avalon Substation ("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. It should be noted that this assessment assumes that HRD-T7 is back in service[4]. As this unit is expected to remain out-of-service for the 2022 winter season, a separate report has been developed to address the near-term implications of the unavailability of HRD-T7.[5] It should also be noted that all CYME modeling was completed with the mobile gas turbine currently installed in Blaketown substation disconnected.[6]

4.1 Pre-Contingency

Load flow results for the 2022-2031 pre-contingency system configuration are shown in Table 7. It was found that no transformer overloads nor system voltage criteria violations were observed in the pre-contingency configuration.

[4] HRD-T7 to be replaced by the existing CHF-T31 currently located in Churchill Falls. The results herein are based on impedance data for the existing HRD-T7. Further analysis is recommended to verify the results utilizing impedance data for CHF-T31.
[5] See "HRD-WAV 66kV/138kV Loop Assessment for 2021-2022 Winter Season: Implications due to Unavailability of HRD-T7".
[6] The following NP local generating plants were modeled as "on" for the Holyrood-Western Avalon loop: Victoria, Heart's Content, New Chelsea, and Pittman's Pond. MG2 in BLK was modeled as "off".

Table 7 HRD-WAV 138kV/66kV Loop System Transformer Loading for 2031						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 3.25%**		**P90 + 6%**	
			MVA	**%**	**MVA**	**%**
Blaketown	T3	41.6	26.4	63%	30.1	72%
Bay Roberts	T2	41.6	21.5	52%	22.3	54%
	T3	41.6	21.1	51%	21.9	53%
Western Avalon	T1	25	15.3	61%	15.8	63%
	T2	25	15.6	62%	16.1	64%
	T3	41.7	13.8	33%	15.2	36%
	T4	41.7	13.7	33%	15.2	36%
	T5	125	40.1	32%	44.4	36%
Holyrood	T6	41.7	15.1	36%	14.6	35%
	T7	125	15.0	12%	14.5	12%
	T8	125	43.9	35%	42.4	34%

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 8 below.

Table 8 HRD-WAV 138kV/66kV Loop Effect of Single Line Outages		
TL	**Planning Criteria Violations?**	
	P90 + 3.25%	**P90 + 6%**
39L / 42L / 46L / 47L	No	No
48L	No	No
64L	No	Yes
56L / 57L / 68L	No	No
41L	No	No
80L	No	No
86L	No	No

4.2.1 *Loss of 64L*

Transmission line 64L comprises the 138kV loop section between Blaketown Substation ("BLK") and WAV. CYME analysis shows that an outage to 64L during the P90 + 6% load scenario results in an overload to WAV-T2. The observed transformer overloads were mitigated by opening the 66kV loop by disconnecting 80L in BLK, as shown in Table 9.

Table 9
HRD-WAV 138kV/66kV Loop
P90 + 6% Scenario (Loss of 64L & MITIGATION)

Station	Unit	Max Rating (MVA)	P90 + 6%		P90 + 6% *80L Opened*	
			MVA	%	MVA	%
Western Avalon	T1	25	24.9	99.6%	20.5	82%
	T2	25	25.4	102%	20.9	84%

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 2031. 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 + 3.25% peak are found in Tables 10a and 10b; results for the P90 + 6% case are found in Tables 11a and 11b.

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Table 10a
HRD-WAV 138kV/66kV Loop
System Transformer Loading Following XFMR Loss (HRD-T8, WAV-T2, WAV-T5)
P90 + 3.25% Scenario

Station	Unit	Max Rating (MVA)	P90 + 3.25% (No HRD-T8)		P90 + 3.25% (No WAV-T5)		P90 + 3.25% (No WAV-T2)	
			MVA	%	MVA	%	MVA	%
Blaketown	T3	41.6	28.5	69%	26.4	63%	30.5	73%
Bay Roberts	T2	41.6	21.1	51%	21.3	51%	21.8	52%
	T3	41.6	20.7	50%	20.9	50%	22.4	54%
Western Avalon	T1	25	15.8	63%	16.9	68%	23.0	92%
	T2	25	16.1	64%	17.2	69%	*Out-of-Service*	
	T3	41.7	15.9	38%	29.1	70%	14.8	35%
	T4	41.7	15.8	38%	29.0	70%	14.8	35%
	T5	125	46.3	37%	*Out-of-service*		43.2	35%
Holyrood	T6	41.7	32.6	78%	16.3	39%	15.4	37%
	T7	125	32.4	26%	16.2	13%	15.3	12%
	T8	125	*Out-of-service*		47.4	38%	44.8	36%

Table 10b
HRD-WAV 138kV/66kV Loop
System Transformer Loading Following XFMR Loss (BRB-T2, BLK-T3)
P90 + 3.25% Scenario

Station	Unit	Max Rating (MVA)	P90 + 3.25% (No BRB-T2)		P90 + 3.25% (No BLK-T3)	
			MVA	%	MVA	%
Blaketown	T3	41.6	29.4	71%	*Out-of-service*	
Bay Roberts	T2	41.6	*Out-of-service*		24.4	59%
	T3	41.6	38.9	94%	24.9	60%
Western Avalon	T1	25	16.5	66%	23.8	95%
	T2	25	16.8	67%	24.3	97%
	T3	41.7	13.8	33%	11.3	27%
	T4	41.7	13.7	33%	11.2	27%
	T5	125	40.2	32%	32.8	26%
Holyrood	T6	41.7	15.1	36%	13.9	33%
	T7	125	15.0	12%	13.9	11%
	T8	125	43.8	35%	40.5	32%

Table 11a
HRD-WAV 138kV/66kV Loop
System Transformer Loading Following XFMR Loss (HRD-T8, WAV-T2, WAV-T5)
P90 + 6% Scenario

Station	Unit	Max Rating (MVA)	P90 Load + 6% (No HRD-T8)		P90 Load + 6% (No WAV-T5)		P90 Load + 6% (No WAV-T2)	
			MVA	%	MVA	%	MVA	%
Blaketown	T3	41.6	28.2	68%	29.3	70%	33.9	81%
Bay Roberts	T2	41.6	22.1	83%	22.0	53%	23.1	56%
	T3	41.6	21.7	53%	21.6	52%	22.7	55%
Western Avalon	T1	25	16.5	66%	17.5	70%	23.5	94%
	T2	25	16.8	67%	17.8	71%	*Out-of-Service*	
	T3	41.7	16.4	39%	31.9	76%	16.3	39%
	T4	41.7	16.3	39%	31.7	76%	16.2	39%
	T5	125	47.8	38%	*Out-of-service*		47.6	38%
Holyrood	T6	41.7	34.3	82%	16.4	38%	15.0	36%
	T7	125	34.1	27%	16.3	82%	14.9	12%
	T8	125	*Out-of-service*		47.6	27%	43.5	35%

Table 11b
HRD-WAV 138kV/66kV Loop
System Transformer Loading Following XFMR Loss (BRB-T2, BLK-T3)
P90 + 6% Scenario

Station	Unit	Max Rating (MVA)	P90 Load + 6% (No BRB-T2)		P90 Load + 6% (No BLK-T3)	
			MVA	%	MVA	%
Blaketown	T3	41.6	32.0	77%	*Out-of-service*	
Bay Roberts	T2	41.6	*Out-of-service*		25.1	60%
	T3	41.6	13.1	31%	24.6	59%
Western Avalon	T1	25	17.2	69%	25.5	102%
	T2	25	17.5	70%	26.0	104%
	T3	41.7	14.7	35%	11.6	28%
	T4	41.7	14.6	35%	11.5	28%
	T5	125	42.9	34%	33.7	27%
Holyrood	T6	41.7	15.2	36%	14.5	35%
	T7	125	15.1	12%	14.4	12%
	T8	125	44.2	35%	42.1	34%

As shown in Tables 10a and 10b, no overloads were observed for any of the N-1 contingency scenarios analyzed during the P90 + 3.25% load scenario. However, overloads to WAV-T1 and WAV-T2 were observed with BLK-T3 disconnected during the P90 + 6% load scenario. To mitigate this, 80L was disconnected in BLK. See Table 12.

Table 12
HRD-WAV 138kV/66kV Loop
P90 + 6% Scenario (Loss of BLK-T3 & MITIGATION)

Station	Unit	Max Rating (MVA)	P90 Load + 6%		P90 Load + 6% *80L Opened*	
			MVA	%	MVA	%
Western Avalon	T1	25	25.5	102	18.9	76%
	T2	25	26.0	104	19.3	77%

5.0 Sunnyside – Stony Brook 138kV Loop

The Sunnyside-Stony Brook loop ("SSD-STB") is comprised of a 138kV section that runs through Central Newfoundland between the Sunnyside Substation ("SSD") and the Stony Brook Substation ("STB"). All CYME modeling for this loop was completed with St. Laurence Wind disconnected. [7]

5.1 Pre-Contingency

Load flow results for the 2031 pre-contingency configurations are shown in Table 13. The results indicate no transformer overloads or planning criteria violations.

Table 13
SSD-STB 138kV Loop
System Transformer Loading for 2031

Station	Unit	Max Rating (MVA)	P90 + 3.25%		P90 + 6%	
			MVA	%	MVA	%
Sunnyside	T1	125	70.0	56%	71.5	57%
	T4	125	70.3	56%	71.8	57%
Stony Brook	T1	125	86.4	69%	91.9	74%
	T2	125	87.3	70%	92.9	74%

[7] The following local generating plants were modeled as "on" for the Sunnyside-STB loop: Paradise River, Lockston, Port Union, Lawn, West Brook, Rattling Brook, Sandy Brook, Rattle Brook, Hind's Lake, Hawke's Bay and St. Anthony. The gas turbines in Wesleyville and Greenhill were modeled as "off".

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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, 124L, 144L, 146L, 130L/132L/133L, 136L/137L/147L, and TL210. The results are provided in Table 14.

Table 14
SSD-STB 138kV Loop
Effect of Single Line Outages

Transmission Line(s)	Planning Criteria Violations?	
	P90 + 3.25%	P90 + 6%
100L / 109L	No	No
124L	Yes	Yes
146L	No	No
144L	No	Yes
130L / 132L / 133L	No	No
136L / 137L / 147L	Yes	Yes
TL210	Yes	Yes

5.2.1 Loss of 124L

Transmission line 124L comprises the 138kV loop section between Clarenville Substation (“CLV”) and Gambo Substation (“GAM”). CYME analysis shows that disconnecting 124L on the CLV-side during both the P90 + 3.25% and P90 + 6% load scenarios results in undervoltage conditions of 0.898pu and 0.893pu along 146L, respectively.

To mitigate this effect, the STB 138kV bus was boosted to 1.0375pu, resulting in acceptable post-contingency voltages of 0.918pu and 0.913pu on 146L, for the P90 + 3.25% and P90 + 6% scenarios, respectively. No transformer overloads were observed during these contingency scenarios, and no planning criteria violations were observed when 124L was disconnected on the GAM-side at normal operating voltages.

5.2.2 Loss of 144L

Transmission line 144L comprises the 138kV loop section between Gander Substation (“GAN”) and Cobb’s Pond Substation (“COB”). CYME analysis shows that disconnecting 144L during the P90 + 6% load scenario results in an undervoltage condition of 0.886pu on 146L.

To mitigate this effect, the SSD 138kV bus was boosted to 1.02, resulting in an acceptable post-contingency voltage of 0.930pu on 146L. No transformer overloads were observed during this contingency scenario.

5.2.3 Loss of 137L

Transmission line 137L comprises the 138kV loop section between Rattling Brook Substation ("RBK") and Lewisporte Substation ("LEW"). CYME analysis shows that disconnecting 137L during the P90 + 3.25% load scenario results in an undervoltage condition of 0.884pu along 147L. During the P90 + 6% load scenario, undervoltage conditions of 0.870pu along 147L and 0.886pu along 144L and TL-210 were observed.

To mitigate these effects, the STB 138kV bus was boosted to 1.0375pu. For the P90 + 3.25% scenario, an acceptable post-contingency voltage of 0.907pu was observed along 147L; for the P90 + 6% scenario, acceptable post-contingency voltages of 0.900 on 144L and 0.908pu on TL210 and 144L were observed. No transformer overloads were observed during either contingency scenario.

5.2.4 Loss of TL210

CYME analysis shows that disconnecting TL210 during the P90 + 3.25% load scenario results in undervoltage conditions of 0.881pu along 144L and 147L. During the P90 + 6% load scenario, undervoltage conditions of 0.879pu were observed along 144L and 147L.

To mitigate these effects, the STB 138kV bus was boosted to 1.05pu and the SSD 138kV bus was boosted to 1.02pu. During the P90 + 3.25% load scenario, this resulted in acceptable post-contingency voltages of 0.921pu to 144L and 147L. During the P90 + 6% load scenario, this resulted in acceptable post-contingency voltages of 0.913pu to 144L and 147L. No transformer overloads were observed during this 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 2031. 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-T1 and STB-T1; loading results for the simulated outages for the P90 + 3.25% case are found in Table 15 and results for the P90 + 6% case are found in Table 16.

Table 15 SSD-STB 138kV Loop System Transformer Loading Following XFMR Loss for 2031 P90 + 3.25% Scenario						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 3.25% (No SSD-T1)**		**P90 + 3.25% (No STB-T1)**	
			MVA	**%**	**MVA**	**%**
Sunnyside	T1	125	*Out-of-service*		73.3	59%
	T4	125	136.4	109%	73.6	59%
Stony Brook	T1	125	89.1	71%	*Out of Service*	
	T2	125	90.1	72%	164.6	132%

Table 16 – SSD-STB 138kV Loop System Transformer Loading Following XFMR Loss for 2031 P90 + 6% Scenario						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 6% (No SSD-T1)**		**P90 + 6% (No STB-T1)**	
			MVA	**%**	**MVA**	**%**
Sunnyside	T1	125	*Out of Service*		74.8	60%
	T4	125	139.0	111%	75.1	60%
Stony Brook	T1	125	92.9	74%	*Out of Service*	
	T2	125	93.9	75%	171.8	137%

In attempt to mitigate the transformer overloads presented in Tables 15 and 16, various transmission configurations and transformer tap changer settings were assessed. The overload to SSD-T1 following a loss of SSD-T4 for both the P90 + 3.25% and P90 + 6% scenarios were able to be successfully mitigated by disconnecting 124L and boosting the STB 138kV bus to 1.0375pu. However, mitigating the overload to STB-T2 following a loss of STB-T1 was unsuccessful for both the P90 + 3.25% and P90 + 6% scenarios. In either case, load was able to be minimized by opening 136L and 144L, as well as boosting the SSD 138kV bus to 1.05pu and reducing the STB 138kV bus to 0.975pu - although overloads still persisted in this configuration. See Tables 17 and 18.

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Table 17 SSD-STB 138kV Loop System Transformer Loading Following XFMR Loss for 2031 P90 + 3.25% Scenario (MITIGATED)						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 3.25% (No SSD-T1)** ***124L Opened*** ***STB 138 @ 1.0375pu***		**P90 + 3.25% (No STB-T1)** ***136L Opened*** ***144L Opened*** ***SUN 138 @ 1.05pu*** ***STB 138 @ 0.975pu***	
			MVA	**%**	**MVA**	**%**
Sunnyside	T1	125	*Out-of-service*		91.1	73%
	T4	119	114.0	91%	91.5	73%
Stony Brook	T1	125	105.1	84%	*Out-of-Service*	
	T2	125	106.2	85%	129.7	104%

Table 18 SSD-STB 138kV Loop System Transformer Loading Following XFMR Loss for 2031 P90 + 6% Scenario (MITIGATED)						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 6% (No SSD-T1)** ***124L Opened*** ***STB 138 @ 1.0375pu***		**P90 + 6% (No STB-T1)** ***136L Opened*** ***144L Opened*** ***STB 138 @ 0.975pu*** ***SSD 138 @ 1.05pu***	
			MVA	**%**	**MVA**	**%**
Sunnyside	T1	125	*Out-of-service*		93.3	75%
	T4	125	115.9	93%	93.7	75%
Stony Brook	T1	125	109.3	88%	*Out-of-Service*	
	T2	125	110.5	88%	135.1	108%

The results from Tables 17 and 18 suggest that additional transformer capacity may be required in STB for proper contingency based on future load growth.[8]

[8] For both the P90 + 3.25% and P90 + 6% mitigated cases presented in Tables 17 and 18, the overloads to STB-T2 materialize in 2027. The mitigated P90 load on STB-T2 in 2026 is 124.2MVA; the mitigated P90 + 3.25% load on STB-T2 in 2027 is 125.6MVA; he mitigated P90 + 6% load on STB-T2 in 2027 is 126.5 MVA.

6.0 Stephenville – Bottom Brook 66kV Loop

The Stephenville – Bottom Brook Loop ("SVL-BBK") is comprised of a 66kV section that runs through Western Newfoundland between the Stephenville Substation ("SVL") and the Bottom Brook Substation ("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 following load flows assume the retirement of the Stephenville gas turbine and the subsequent installation of a new transformer in Bottom Brook as per the NLH 2021 Capital Budget Application.[9]

6.1 Pre-Contingency

Load flow results for 2031 for the current pre-contingency system configuration are shown in Table 19. No overloads were observed.

Table 19
SVL-BBK 66kV Loop
System Transformer Loading for 2031

Station	Unit	Max Rating (MVA)	P90 + 3.25%		P90 + 6%	
			MVA	%	MVA	%
Stephenville	T3	66.6	35.1	53%	35.6	53%
Bottom Brook	T4	66.6	16.0	24%	16.8	25%

6.2 Single Line Outages (N-1)

Each 66kV transmission line within the SVL-BBK loop were individually opened in CYME to observe effects during peak. The results are provided in Table 20 below.

Table 20
SVL-BBK 66kV Loop
Effect of Single Line Outages

Transmission Line	Planning Criteria Violations?	
	P90 + 3.25%	P90 + 3.25%
400L / 404L	No	No
401L / 405L / 406L	No	No

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.

[9] The following NP local generating plants were modeled as "on" for the Stephenville-Bottom Brook loop: Lookout Brook, Rose Blanche, Port-Aux-Basque diesel, mobile diesel (MD3) and mobile gas turbine (MGT).

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 2031. 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 SVL-T3 and BBK-T4; loading results for the simulated outages for the P90 + 3.25% case are found in Table 21; results for the P90 + 6% case are found in Table 22.

Table 21
SVL-BBK 66kV Loop
System Transformer Loading Following XFMR Loss
P90 + 3.25% Scenario

Station	Unit	Max Rating (MVA)	P90 + 3.25% (No SVL-T3)		P90 + 3.25% (No BBK-T4)	
			MVA	%	MVA	%
Stephenville	T3	66.6	*Out-of-service*		50.8	76%
Bottom Brook	T4	66.6	53.7	81%	*Out-of-service*	

Table 22
SVL-BBK 66kV Loop
System Transformer Loading Following XFMR Loss
P90 + 6% Scenario

Station	Unit	Max Rating (MVA)	P90 + 6% (No SVL-T3)		P90 + 6% (No BBK-T4)	
			MVA	%	MVA	%
Stephenville	T3	66.6	*Out-of-service*		52.4	79%
Bottom Brook	T4	66.6	55.6	83%	*Out-of-service*	

7.0 Holyrood – Hardwoods 66kV Loop

The Holyrood – Hardwoods Loop ("HRD-HWD") is comprised of a 66kV section that runs through the St. John's Area between the Holyrood Substation and the Hardwoods Substation. 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 all CYME modeling was completed with Fermeuse Wind disconnected.[10]

[10] The following local generating plants were modeled as "on" for the Hardwoods-Oxen Pond loop: Cape Broyle, Horsechops, Mobile, Morris, Petty Harbour, Pierre's Brook, Rocky Pond, Seal Cove, Topsail, and Tors Cove.

7.1 Pre-Contingency

Load flow results for 2031 for the current pre-contingency system configuration are shown in Table 23.

Table 23
HRD-HWD 66kV Loop System Transformer Loading for 2031

Station	Unit	Max Rating (MVA)	P90 + 3.25%		P90 + 6%	
			MVA	%	MVA	%
Holyrood	T5	25	22.4	90%	23.7	95%
	T10	25	21.7	87%	23.0	92%
Hardwoods	T1	125	91.3	73%	93.3	75%
	T2	66.6	46.6	70%	47.6	71%
	T3	66.6	50.4	76%	51.5	77%
	T4	125	90.6	72%	92.6	74%

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 24.

Table 24
HRD-HWD 66kV Loop System
Effect of Single Line Outages to XFMR Loading and System Voltages

Transmission Line	Planning Criteria Violations?	
	P90 + 3.25	P90 + 6%
4L / 25L	No	No
13L	No	No
15L / 19L / 54L / 69L	No	No
18L / 72L / 73L	No	No
38L / 51L / 52L	No	No
49L / 79L	No	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 2031. 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 + 3.25% case are presented in Table 25; results for the P90 + 6% case are presented in Table 26.

Table 25
N-1 Contingency HRD-HWD 66kV Loop Loading Following XFMR Loss
P90 + 3.25% Scenario

Station	Unit	Max Rating (MVA)	P90 + 3.25% (No HRD-T5)		P90 + 3.25% (No HWD-T1)	
			MVA	%	MVA	%
Holyrood	T5	25	*Out-of-service*		24.9	99.6%
	T10	25	32.0	128%	24.2	97%
Hardwoods	T1	125	94.6	76%	*Out-of-service*	
	T2	66.6	48.2	72%	59.9	90%
	T3	66.6	52.2	78%	64.8	97%
	T4	125	93.9	75%	116.5	93%

Table 26
N-1 Contingency HRD-HWD 66kV Loop Loading Following XFMR Loss
P90 + 6% Scenario

Station	Unit	Max Rating (MVA)	P90 + 6% (No HRD-T5)		P90 + 6% (No HWD-T1)	
			MVA	%	MVA	%
Holyrood	T5	25	*Out-of-service*		25.5	102%
	T10	25	33.2	133%	24.8	99%
Hardwoods	T1	125	96.7	77%	*Out-of-service*	
	T2	66.6	49.3	74%	62.5	94%
	T3	66.6	53.4	80%	67.6	102%
	T4	125	96.0	77%	121.5	97%

As shown in Tables 25 and, an overload to HRD-T10 was observed with HRD-T5 out of service for both the P90 + 3.25% and P90 + 6% cases. With HWD-T1 out of service, an overload to HWD-T3 and HRD-T5 were observed during the P90 + 6% peak scenario.

To mitigate the overload to HRD-T10 following a loss of HRD-T5, 38L was opened in HRD for both the P90 + 3.25% and P90 + 6% scenarios. See Table 27. 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.

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To mitigate the overloads to HRD-T5 and HWD-T3 following a loss of HWD-T1, a voltage management scheme at HRD and HWD was implemented. See Table 28.

Table 27 HRD-HWD 66kV Loop System Transformer Loading Following XFMR Loss P90 + 3.25% Scenario (MITIGATED)				
Station	**Unit**	**Max Rating (MVA)**	**P90 + 3.25% (No HRD-T5) Open 38L**	
			MVA	**%**
Holyrood	T5	25	*Out-of-service*	
	T10	25	0	0%
Hardwoods	T1	125	102.4	82%
	T2	66.6	52.2	78%
	T3	66.6	56.6	85%
	T4	125	101.7	81%

Table 28 HRD-HWD 66kV Loop System Transformer Loading Following XFMR Loss P90 + 6.0% Scenario (MITIGATED)						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 6% (No HRD-T5) Open 38L**		**P90 + 6% (No HWD-T1) HRD @ 1.00pu HWD @ 1.00pu**	
			MVA	**%**	**MVA**	**%**
Holyrood	T5	25	*Out-of-service*		24.3	97%
	T10	25	0	0%	23.6	94%
Hardwoods	T1	125	104.8	84%	*Out-of-service*	
	T2	66.6	53.4	80%	58.2	87%
	T3	66.6	57.9	87%	63.0	95%
	T4	125	104.1	83%	113.2	91%

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 + 3.25% or P90 + 6% load scenarios.
    - Disconnecting either 31L or 70L during the P90 + 6% scenario resulted in an overload to the other line. Disconnecting the remaining line results in additional power flow over adjacent lines to all be within winter ampacity ratings. A future planning study is recommended to further assess transmission contingency loading in the St. John's area.
    - A loss of either HWD-T1 or OPD-T3 during both the P90 + 3.25% and P90 + 6% load scenarios 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 OPD, while maintaining emergency voltage limits in the St. John's area. It should be noted that for the mitigated P90 + 6% case, HWD-T3 was loaded to 100%.
    - Analysis of the HWD-OPD loop assumed Fermeuse Wind was unavailable. Further analysis is recommended to verify the impact of wind availability on potential overloads.
    - Analysis of the HWD-OPD loop excluded an additional 22MW of load associated with MUN's electric boiler to be commissioned in 2024. Details surrounding this potentially interruptible load and its effect on N-1 contingency analysis will be considered in the 2023 Loop Assessment.
- HRD-WAV 66/138kV Loop
    - No overloads or planning criteria violations were observed during the pre-contingency P90 + 3.25% or P90 + 6% load scenarios.
    - An overload on WAV-T2 was observed following the loss of 64L during P90 + 6% scenario. This overload was mitigated in CYME by disconnecting 80L in BLK.
    - No overloads were observed following the loss of the largest transformers during the P90 + 3.25% scenario.

- Overloads to WAV-T1 and WAV-T2 were observed following the loss of BLK-T3 during the P90 + 6% scenario. This overload was mitigated in CYME by opening 80L in BLK.

- SUN-STB 138kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 3.25% or P90 + 6% load scenarios.
  - Potential undervoltages to transmission lines in the Central Newfoundland area were observed when the following lines were individually disconnected from CYME during the P90 + 3.25% and P90 + 6% scenarios: 124L, 137L and TL210. Further undervoltages were observed when 144L was disconnected during the P90 + 6% scenario. All observed undervoltages were able to mitigated in CYME by boosting the STB 138kV bus to a maximum of 1.05pu and the SSD 138kV bus to a maximum of 1.02pu. Further analysis is recommended to address potential voltage issues in the Gander / Cobb's Pond areas.
  - Overloads to SSD-T4 were observed following a loss of SSD-T1 during both the P90 + 3.25% and P90 + 6% scenarios. In both cases, the overload was able to be mitigated in CYME by opening 124L in CLV and boosting the STB 138kV bus to 1.0375pu.
  - Overloads to STB-T2 were observed starting in 2027 following a loss of STB-T1 during both the P90 + 3.25% and P90 + 6% scenarios. STB-T1 loading could be reduced by disconnecting 136L and 144L, boosting the SSD 138kV bus to 1.05pu, and reducing the STB 138kV bus to 0.975pu. **However, overload conditions still persisted for both the P90 + 3.25% and P90 + 6% contingency scenarios, regardless of mitigation attempts.** Therefore, additional transformer capacity may be required in STB to provide adequate supply during future potential contingency scenarios.

- STV-BBK 66kV Loop
  - No overloads or planning criteria violations were observed during the pre- or post-contingency analysis of the P90 + 3.25% or P90 + 6% load scenarios.

- HRD-HWD 66kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 3.25% or P90 + 6% load scenarios.

- No overloads or planning criteria violations were observed with any single transmission line disconnected in CYME during the P90 + 3.25% or P90 + 6% load scenarios.

- Overloads to HRD-T10 were observed following the loss of HRD-T5 during both the P90 + 3.25% and P90 + 6% scenarios. In both cases, the overload could be mitigated by disconnecting 38L in HRD, thereby supplying the HRD 66kV bus from HWD.

- Overloads to HRD-T5 and HWD-T3 were observed following the loss of HWD-T1 during the P90 + 6% scenario. The overload was mitigated by implementing a voltage management scheme at HWD and HRD.

NLSO Report - 2022 Annual Planning Assessment

Doc #: TP-R-055

Date: 2022/03/30

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 Maritime Link ("ML"), the Labrador Transmission Assets ("LTA"), the Labrador Interconnected System ("LIS") and Island Interconnected System ("IIS").[1]

Conclusions of the 2022 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.
- Transmission Planning Criteria are strictly applied to the Primary Transmission System ("PTS")[2]. 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
  - There are no steady state transmission equipment overloads or voltage violations due to any transformer, transmission line, generator, synchronous condenser, or shunt element contingency
- 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 the end of 2022. A detailed summary of results for the final operational study will be provided in the 2023 Annual Assessment.

[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] 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.

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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 2022 Annual Planning Assessment covers the period extending to 2031. Cases are assessed to investigate the capability of the transmission system to meet peak load and to meet firm transmission commitments.[3]

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 TP-S-007 NLSO Standard – Transmission Planning Criteria.

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

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 2031. The following system additions are included in the 2031/32 study cases:

- The Muskrat Falls Generating Station (“MFAGS”) is complete, with four 206 MW generating units in service
- The MFAST2 315 kV, 150 MVAr shunt reactor is removed from 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 IIS
- There are two Soldiers Pond 175 MVAr synchronous condensers in service for analysis (the third unit is available)
- The ML exports are set at the NS Block (158 MW at Bottom Brook terminal Station 2 – “BBKTS2”) in both the peak and light load cases
- Happy Valley Terminal Station (“HVYTS”) is supplied via a new 138 kV transmission line L1303 connecting the Muskrat Falls Terminal Station 2 (“MFATS2”) and taps into existing 138 kV transmission line L1302.
- 138 kV transmission line L1301 from Churchill Falls to Muskrat Falls Terminal Station 1 (“MFATS1”), as well as Muskrat Falls Terminal Station 3 (“MFATS3”) have been decommissioned
- The Churchill Falls T31 power transformer has been relocated to Holyrood to replace failed T7
- SC3 at Wabush Terminal Station is available for service to all customers

[3] The firm export limit for the Maritime Link (ML) is specified at 158 MW.

[4] Newfoundland and Labrador Hydro (Hydro) performs an annual assessment of the NL interconnected system, which includes all system elements 46 kV and above that are under its operational control and not included in the NLSO assessment.

- Holyrood Thermal Generating Station is out of service with Unit 3 only operating as a synchronous condenser
- Holyrood Gas Turbine is available for service as required
- There are two 60 MVAr line reactors installed on the Muskrat Falls end of 315 kV lines L3101 and L3102 (Proposed)
- Stephenville gas turbine has been removed from service
- Hardwoods gas turbine is out of service as a generator, but can be operated as a synchronous condenser
- HVYTS has an additional 138/25 kV 50 MVA transformer, T5
- The Happy Valley North Side Diesel Plant is assumed to be out of service
- A new power transformer T4 is installed in Bottom Brook as a backup supply for Stephenville as the gas turbine is no longer in service. 400L is normally in service.
- Valentine Lake Terminal Station is in service, with the following configuration:
    - Phase II: 8 MVAr capacitor bank on 6.9 kv bus VLK T1, and 6 MVAr capacitor bank on 6.9 kV bus VLK T2
- Wabush Terminal Station upgrades include:
    - Addition of a 23 MVAr capacitor bank
    - Transformers T4 and T5 have been replaced with 125 MVA units
- Wabush Substation has been renamed to Jean Lake Terminal Station and upgrades include:
    - Transformers T3, T4, T5 and T6 have been removed from service
    - A new 26.7 MVA transformer T1 has been connected to bus B2, and a new 26.7 MVA transformer T2 has been connected to bus B3 (Proposed)
    - A bus tie has been added to connect buses B2 and B3, which is normally open

The following load flow plots for the Year Ten cases are provided in Appendix B:

- 2031/2032 Peak Load Conditions
- 2031 Light Load Conditions

3 SPECIAL CONSIDERATIONS

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

3.1 Operational Studies

Newfoundland and Labrador Hydro ("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 studies are expected to be completed by late 2022, with a summary of results provided in the 2023 Annual Assessment.

3.2 Labrador Incremental Load

Throughout 2022, Hydro will be undertaking a process to investigate 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 will be assessed in a standalone study to be completed in 2022 in accordance with Hydro's Network Addition Policy.

4 LOAD FORECAST

The 2022 Annual Planning Assessment is based upon the following load forecasts prepared by the Market Analysis and Load Forecasting Section, Resource and Transmission Planning Department, NL Hydro:

- IIS Peak Demand Forecast System – prepared in Fall 2021; and
- LIS Long Term Load Forecast – prepared in Fall 2021.

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

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

Forecasted Demand (MW)[5]			
Year[6]	Island Interconnected System (IIS) (Fall 2021)	Labrador Interconnected System (LIS) (Summer 2021)	
		Lab East	Lab West
2021/22	1,686.8	79.4	382.7
2022/23	1,694.7	80.4	383.0
2023/24	1,715.8	81.2	383.2
2024/25	1,720.2	81.7	383.6
2025/26	1,725.6	82.1	383.9
2026/27	1,734.7	82.6	384.2
2027/28	1,743.7	83.3	384.3
2028/29	1,747.6	83.8	384.5
2029/30	1,758.7	84.4	384.6
2030/31	1,770.4	85.0	384.8
2031/32	1,781.4	85.5	384.9

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.

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

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

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 (2031/32) 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[7]).

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

[7] SC3 is owned by IOC.

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. No violations to the local network criteria were identified.

5.3 Primary Transmission System

Analysis was performed to assess steady state contingencies for the PTS. The PTS includes all transmission elements[8] 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 BDE Unit #7 (154.4 MW), which can also operate as a synchronous condenser.

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

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 instruction TOP-P-068 - Granite Canal Tap Shunt Reactor. 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:

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

- 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.

Operating limits in this corridor are defined in accordance with NLSO Operating instruction TOP-P-076 - NL Transmission System Operating Limits. Transient stability limits for this transmission corridor are currently being assessed as part of the operational studies mentioned in Section 3.1.

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 Gas Turbines at Holyrood and Hardwoods Terminal Station.

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

Operating limits on the Avalon Peninsula are defined in accordance with NLSO Operating instruction TOP-P-076 - NL Transmission System Operating Limits. Transient stability limits for the 230kV lines are currently being assessed as part of the operational studies mentioned in Section 3.1.

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 are defined in accordance with NLSO Operating instruction TOP-P-076 - NL Transmission System 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 instruction TOP-P-022 - TL248 Planned and Forced Outages.

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

Table 2 - Transformer Peak Loads[9]

Transformer	2031/2032	
	MVA	%
CHFTS2 T1	77.11	9.18
CHFTS2 T2	76.89	9.15

Table 3 provides the transformer loading with the largest transformer out of service.

Table 3 – Transformer Peak Loads – Loss of Largest Transformer[9]

Transformer	2031/2032	
	MVA	%
CHFTS2 T1	143.1	17.04
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 Operating Instruction TP-OI-003.

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 contingency event involving the loss of a single 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)
- Available frequency response from the Maritime Link[10]
- Muskrat Falls Generation Dispatch
- Status of the Labrador 315 kV System
- Accepted[11] amount Under Frequency Load Shedding (UFLS) following a LIL Bipole Trip

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[9] The following are two scenarios in which higher flow on the 315kV 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 315kV lines would not be overloaded.

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

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

The LIL limits are provided in the procedure TOP-P-069 ("Guideline for Maximum Loading").

It is noted that Transmission Planning Criteria are not defined for an extended LIL bipole outage. In 2019, Hydro undertook studies[12,13] as part of its Reliability and Resource Adequacy initiative to assess system performance in the event of an extended LIL bipole or pole[14] outage. The results of the analysis included a recommendation for the adoption of Emergency Transmission Planning Criteria with the following considerations:

> *The appropriateness of the Emergency Transmission Planning Criteria as a long term solution is dependent on whether incremental generation is installed and on where the generation is located. The criteria and the resulting impacts shall therefore be re-evaluated as Hydro's Reliability and Resource Adequacy study continues. In the interim, they will provide a basis for Transmission Planning and will serve to further inform the discussion as Hydro looks to ensure long term reliability for its customers.*

Hydro's analysis in support of the Reliability and Resource Adequacy initiative and operating studies will continue in 2022. LIL operational limits and system performance when the LIL is out of service is therefore excluded from the scope of this assessment. The Emergency Transmission Planning Criteria is currently under development.

[12] Newfoundland and Labrador Hydro Avalon Capacity Study - Solutions to Serve Island Demand during a LIL Bipole Outage, TGS, Technical Note: TN1529.01.02, May 23, 2019.

[13] TP-TN-068 Application of Emergency Transmission Planning Criteria for a LIL Bipole Outage, Hydro, July 30, 2019.

[14] If the LIL remains in monopole for an extended period and supply is required to meet demand on the IIS, LIL transfer limits could be increased and customer impact may be deemed acceptable if the remaining pole were to 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 a firm export comment of 158 MW[15] to Nova Scotia that must not be interrupted.

The import and export limits on the Maritime Link are itemized below:

- Import Limits: imports over the ML are limited to prevent the IIS frequency from dropping below 58.0 Hz in the event of a bipole trip of the ML. The ML import limits are a function of Island load and are provided in the procedure TOP-P-069.
- Export Limits: exports over the ML are limited to prevent the IIS frequency from rising above 62.0 Hz in the event of a bipole trip. The ML export limits are a function of Island load and the status of the Holyrood plant and are provided in the procedure TOP-P-069.

The ML will be capable of operating within its full import and export capacity range once LIL Power Demand Overrides ("PDOs")[16] are proven reliable and LIL import limits are high enough to accommodate the sudden runbacks or run-ups. The PDOs are expected to be fully tested and commissioned by the spring of 2022.

[15] At Bottom Brook Terminal Station

[16] HVdc PDOs are used to help regulate system frequency on the Island Interconnected System ("IIS") 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

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[17]. 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. Once the LCP assets are closer to being fully integrated into the NL Transmission System, the operational studies can be finalized. The operational studies are in progress and are expected to be completed by the end of 2022 with a summary of results provided in the 2023 Annual Assessment.

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

8 CONCLUSIONS

The 2022 Annual Planning Assessment focuses on the planning horizon to 2031/32. Conclusions of the 2022 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
    - There are no steady state transmission equipment overloads or voltage violations due to any transmission line, transformer, generator, synchronous condenser, or shunt element contingency
- 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 the end of 2022. A detailed summary of results for the final operational study will be provided in the 2023 Annual Assessment.

9 REFERENCE DOCUMENTS

1. Operational Study - Stage 4C: Labrador Transfer Analysis (TP-R-034)
2. Labrador Interconnected System - Expansion Study (TP-R-019)
3. Application of Emergency Transmission Planning Criteria for a Labrador Island Link Bipole Outage (TP-TN-069)
4. NLSO Operating instruction TOP-P-022 - TL248 Planned and Forced Outages
5. NLSO operating instruction TOP-P-068 - Granite Canal Tap Shunt Reactor
6. NLSO Operating instruction TOP-P-076 - NL Transmission System Operating Limits
7. TP-S-001 NLSO Standard – Facilities Rating Guide
8. TP-S-003 NLSO Standard – Annual Planning Assessment
9. TP-S-007 NLSO Standard – Transmission Planning Criteria
10. TOP-P-069 Guideline for Maximum loading
11. TP-TN-068 Application of Emergency Transmission Planning Criteria for a LIL Bipole Outage
12. Newfoundland and Labrador Hydro Avalon Capacity Study - Solutions to Serve Island Demand during a LIL Bipole Outage
13. NLSO operating instruction TP-OI-003 - 315 kV Transfer Limits
14. NLSO Procedure TP-P-076 – NL Transmission System Operating Limits and Operating Plans for Mitigation.

APPENDIX A

Island and Labrador Interconnected Systems (Maps)

Figure 1: Island Interconnected System

Figure 2: Labrador Interconnected System

APPENDIX B

Load Flow Plots Primary of the Transmission System for Year Ten (2031) – Peak and Light Load Cases

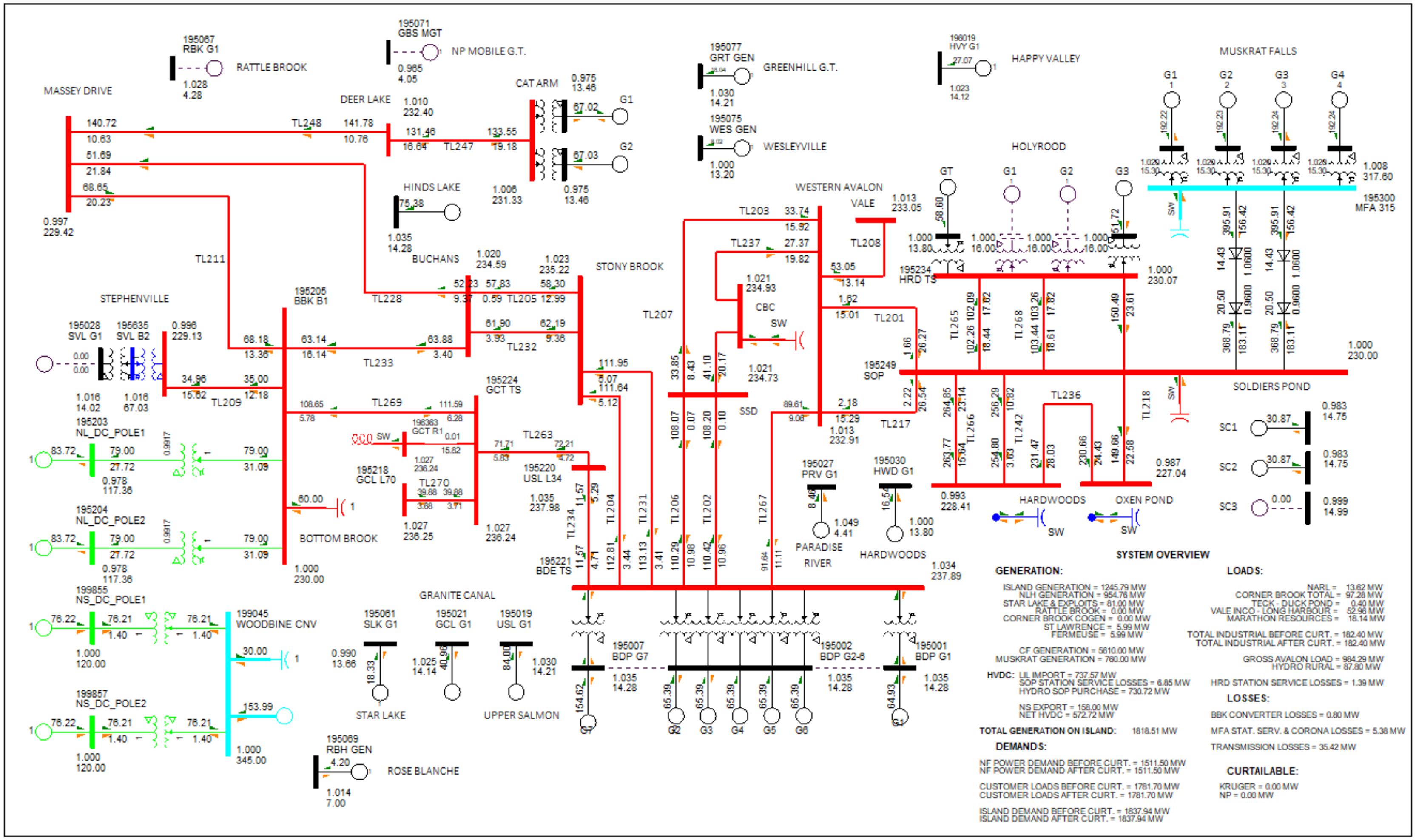

Figure 3 – IIS (2031/2032 Peak Load Conditions)

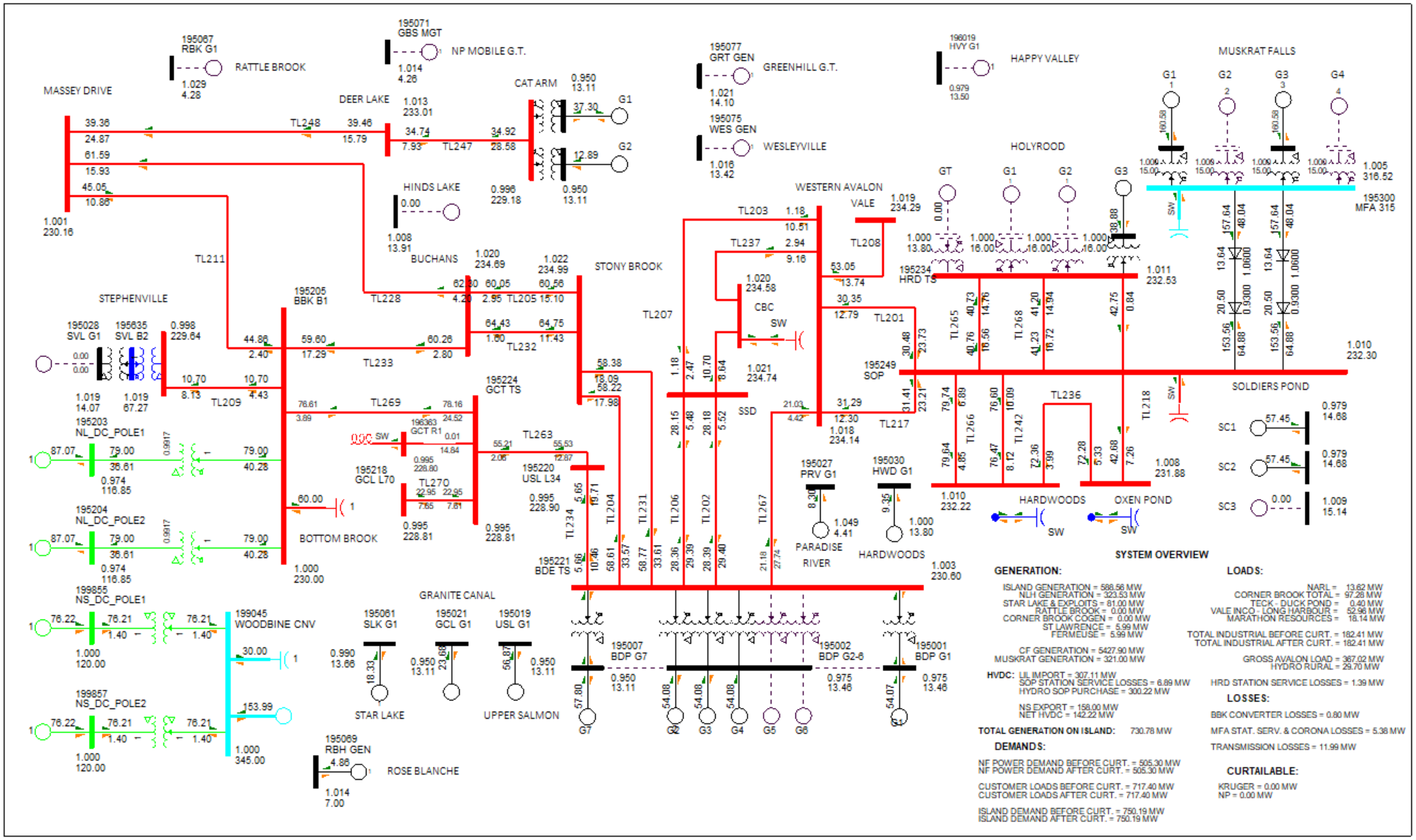

Figure 4 - IIS (2031 Light Load Conditions)

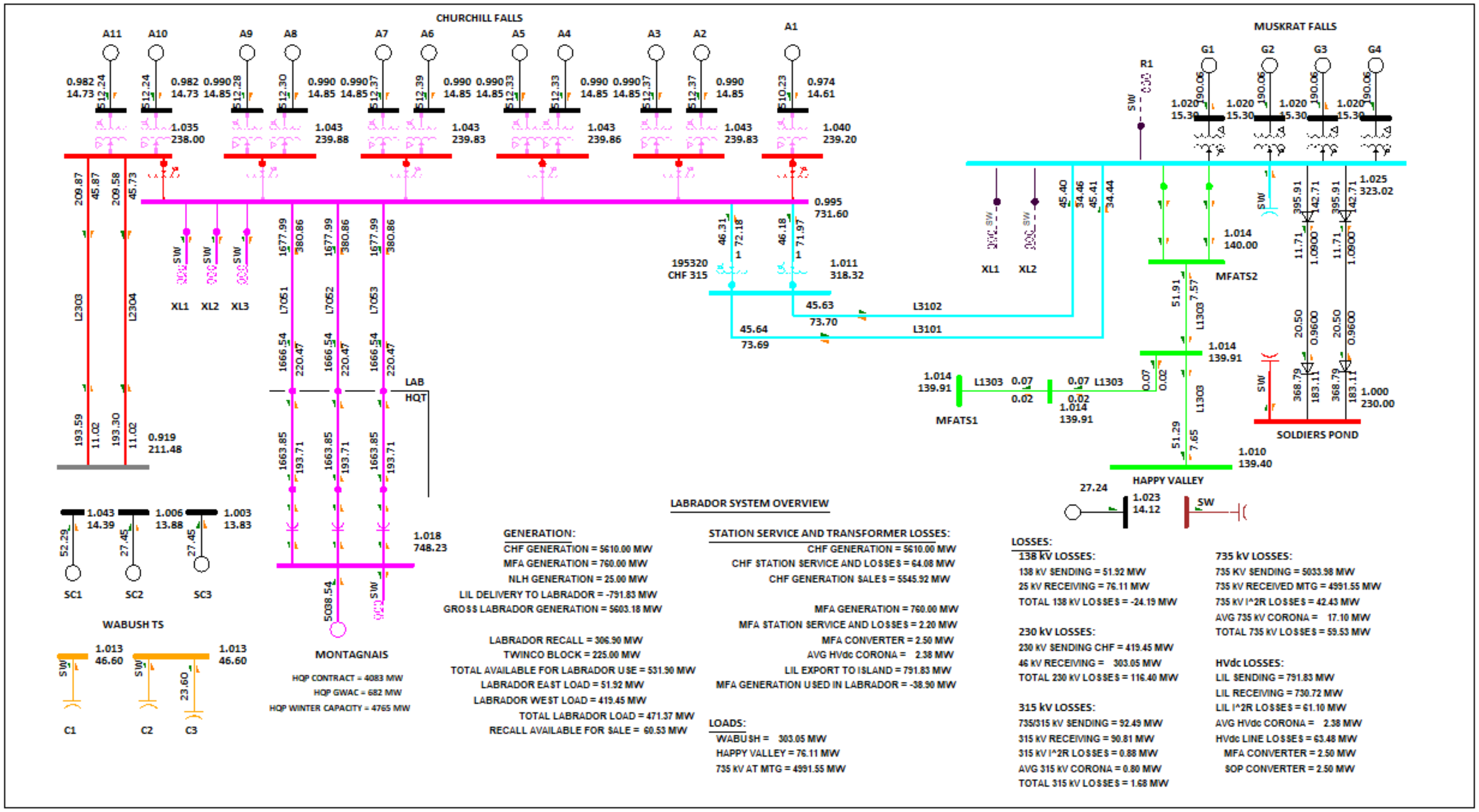

Figure 5 – LIS (2031/2032 Peak Load Conditions)

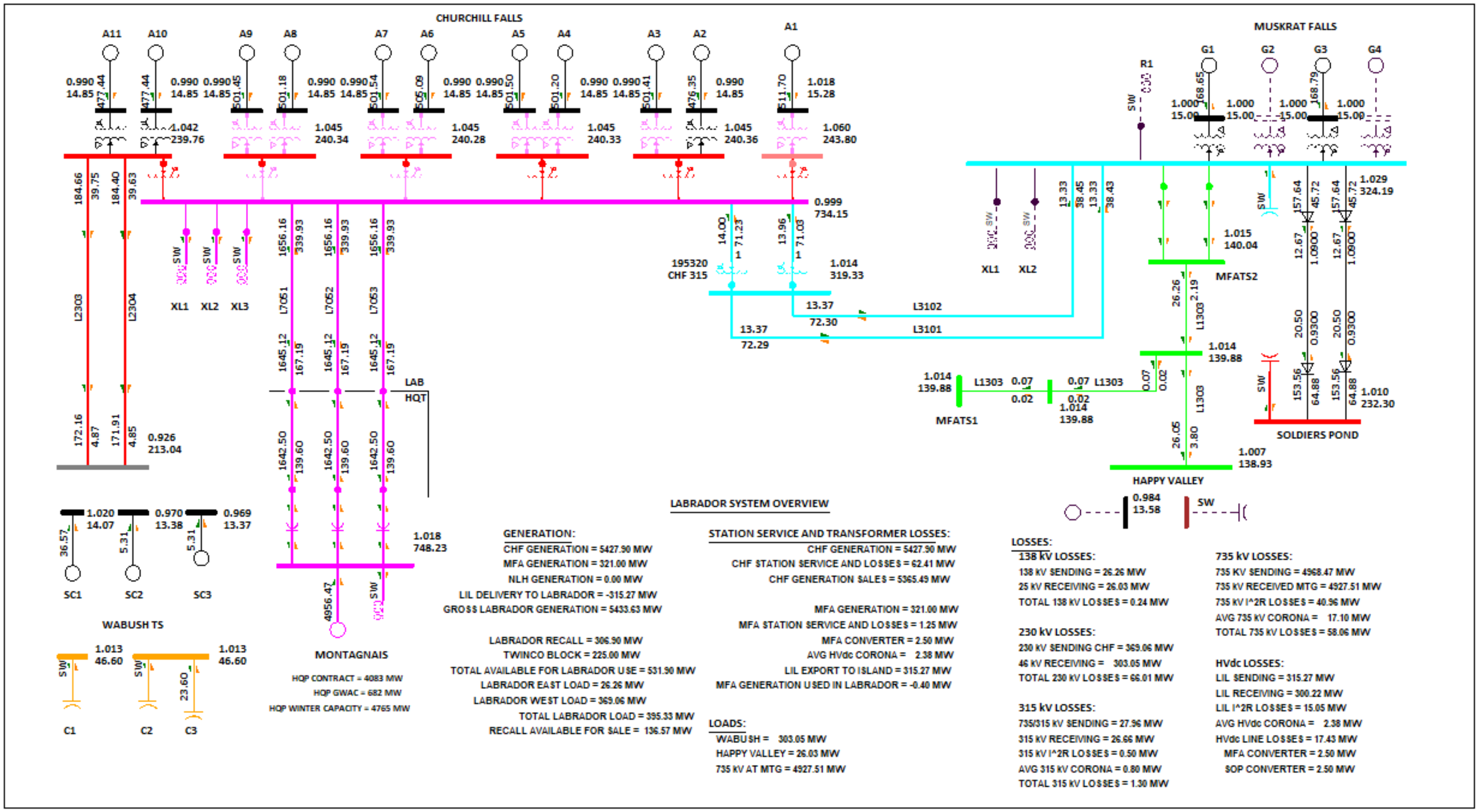

Figure 6 - LIS (2031 Light Load Conditions)

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0	B. Odetayo	Original Issue	2022/03/30

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