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June 30, 2021

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: Feasibility of the Addition of a Non-Firm Rate Option to the Network Additions Policy for the Labrador Interconnected System

Please find enclosed Newfoundland and Labrador Hydro's report regarding the feasibility of adding a non-firm rate option to the Network Additions Policy for the Labrador Interconnected System, provided in compliance with Board Order No. P.U. 7(2021).

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Michael S. Ladha
Vice President, General Counsel, Corporate Secretary & Commercial
MSL/sk

Encl.

ecc: **Board of Commissioners of Public Utilities**
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Feasibility of the Addition of a Non-Firm Rate Option to the Network Additions Policy for the Labrador Interconnected System

June 30, 2021

A report to the Board of Commissioners of Public Utilities

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1.0 Introduction

In recent years, Newfoundland and Labrador Hydro ("Hydro") has experienced load growth in Labrador, primarily due to the arrival of data centres/cryptocurrency mining sites to the region. As Hydro's Labrador Interconnected System has minimal excess capacity available to serve new customers, the Labrador Interconnected System will require substantial investment in upgrades to supply firm service to new customer load. To ensure the costs associated with these upgrades are fairly allocated, Hydro undertook the process of developing a new policy for addressing network additions on the Labrador Interconnected System ("Policy") which identifies how new customers will be treated in regards to their impact on the system and how costs will be allocated among customers for reliability, economic, transmission, and load upgrades. The Policy underwent substantial regulatory process and examination by the parties and was approved by the Board of Commissioners of Public Utilities ("Board") on March 17, 2021.[1]

In its report on Hydro's proposed Policy, the Board's consultant, The Brattle Group Inc., recommended that the Policy include a non-firm rate option whereby customers could avail of surplus energy when available but accept interruptions when the system does not have capacity to provide service. This option would require no additional common transmission capacity investment in the Labrador Interconnected System; therefore, no contribution for the provision of additional firm capacity would be required from customers availing of non-firm service. Additionally, there has been a level of customer interest in such an offering. As such, as part of the settlement agreement to the regulatory proceeding examining the Policy, Hydro agreed to conduct a review of the feasibility of adding a non-firm rate option to the Policy and file a report with the Board by mid-2021.

The purpose of this report is to provide the results of Hydro's analysis to determine the technical feasibility of offering a non-firm rate option for customers of the Labrador Interconnected System and to identify other considerations which would require further evaluation should Hydro proceed with implementation of a non-firm rate option. The approach taken to determine the feasibility of creating a non-firm rate option in Labrador was based on a near-term analysis of the current transmission infrastructure (including approved upgrades) and current energy supply available from Churchill Falls for use in Labrador. Depending upon the changes in system costs if material expansion occurs on the

[1] Board Order No. P.U. 7(2021).

Labrador Interconnected System, the pricing of non-firm service would be need to be reviewed to ensure the rate structure is reasonable and promotes efficient usage by participating customers.

2.0 Applicant Load Requests

Since its approval, Hydro has been advancing the work required to implement the Policy and work through the outstanding requests for power in Labrador. As a first step, proponents were asked to submit applications indicating their load and location requirements. Table 1 summarizes the applications received as of June 1, 2021. Hydro is reviewing these applications and completing the assessments necessary to determine next steps and inform customers of potential costs. Hydro believes that a substantial portion of the requests identified in Table 1 may be withdrawn once customers are made aware of the costs associated with fulfilling their requests; however, requests that do materialize into firm customer requirements and changes to the configuration of the Labrador Interconnected System may impact the amount of non-firm load that can be made available on the Labrador Interconnected System.

Table 1: Summary of Applications Received as of June 1, 2021

	Load (MW)	Number of Applications
Labrador West	551	15
Labrador Central	1,141	6
Labrador East	6,227	31
Labrador Interconnected System Total	**7,919**	**52**

3.0 Technical Feasibility of Non-Firm Offering

To determine the amount of energy that could be made available on a non-firm basis, there are two primary considerations—the capacity of the transmission system to deliver the energy to customers and the amount of energy available for supply. Hydro undertook two pieces of analysis to support its assessment of the availability of a potential non-firm offering. The first was a review of the transmission system to quantify how much load could reliably be added to the system during each season of the year. For preliminary planning purposes, the analysis was based on a premise that a maximum of 50 interruptions would provide an acceptable limit for customers and for reliable system operation. The second analysis was to quantify the amount of surplus energy available in the region. If applicants that are interested in non-firm service would not be willing to accept 50 interruptions, Hydro would need to modify the amount of non-firm service that can be made available to reflect what would be acceptable to the applicants.

3.1 Transmission Capacity

A technical analysis of the available transmission capacity in Labrador was conducted to determine the available capacity for connecting non-firm loads and the expected number of interruptions at different load levels. Analysis was completed for each season to identify the number of interruptions a non-firm customer would expect to experience at different load levels. Table 2 identifies the quantity of non-firm load that could be added to each of the regions, by season, while maintaining a maximum planned number of interruptions to fewer than 50 occurrences. Hydro's technical analysis is attached as Appendix A.

Table 2: Maximum Non-Firm Load for Labrador East and Labrador West (MW)

	Winter December to March	Spring April to June	Summer July to September	Fall October to November
Labrador East	28	43	58	38
Labrador West	20	50	50	50

The non-firm capacity available is indicative of the seasonal nature of the load requirements on the Labrador Interconnected System. Higher winter load requirements reduce what can be made available on a non-firm basis during the winter months. If the iron ore mines increased their load requirements during the non-winter months closer to their Power on Order (which they fully utilize during the winter), the amount of non-firm capacity that can currently be made available during the non-winter months would need to be reduced materially.

As indicated earlier, the amount of MW that can be made available will be subject to discussions with the applicants on what will be acceptable to them from an operations perspective.

3.2 Available Generation

Presently, Hydro has two contracts with Churchill Falls to supply power to customers on the Labrador Interconnected System. First, Churchill Falls sells up to 225 MW (TwinCo[2] Block) to Hydro for sale to Labrador West customers, with first priority given to industrial customers in Labrador West. Second,

[2] Twin Falls Power Corporation Limited ("TwinCo").

Churchill Falls sells 300 MW to Hydro for use in the province (Recapture Block) with no limitations on location of use. There is currently more Recapture Energy available than what is currently needed to serve Hydro's existing customers in Labrador. Hydro currently sells the surplus to Nalcor Energy Marketing for export. Table 3 summarizes the average surplus Recapture Energy available by season.

Table 3: Average Surplus Recapture Energy (GWh)

	Winter December to March	Spring April to June	Summer July to September	Fall October to November
Surplus Energy	248	356	524	439

For preliminary planning purposes, available surplus Recapture Energy may be approximated to be 60 MW over peak. The average available surplus recapture capacity over the past three years is provided in Table 4. This capacity could be used to serve non-firm load in Labrador rather than be exported. As indicated, the ability to support incremental load is restricted by transmission system limitations. Under the current load requirements for the Labrador Interconnected System, even if the available transmission capacity were fully utilized at a 100% capacity factor, surplus Recapture Energy would not be exhausted.

Table 4: Average Surplus Recapture Capacity (MW)

	Winter December to March	Spring April to June	Summer July to September	Fall October to November
Surplus Capacity	115	161	237	201

3.3 Total Non-Firm Supply Available

As there is more energy available than transmission capacity, the transmission system remains the constraining factor for adding any new load in Labrador. Based on the available transmission capacity, the quantities of non-firm capacity that could be available in each of Labrador West and Labrador East (subject to customer review) are shown in Table 5.

Table 5: Total Available Non-Firm Capacity (MW)

	Winter December to March	Spring April to June	Summer July to September	Fall October to November
Labrador East	28	43	58	38
Labrador West	20	50	50	50
Total	**48**	**93**	**108**	**88**

4.0 Additional Considerations

There are practical and operational considerations that need to be addressed to offer a non-firm energy product that is fair to customers and that does not impact the reliability of the system. These considerations are noted in the following sections.

4.1 Practical Limitations

In accepting a non-firm energy product, customers must be able to accept that the delivery or receipt of the energy may be interrupted at any time without liability on Hydro or the customer. Non-firm customers must understand that increased usage by other customers on the Labrador Interconnected System with firm service will be prioritized and the amount of non-firm service may decline over time.

As per the technical review provided in Appendix A, the following guidelines are recommended with respect to customer curtailment in the provision of non-firm service:

- Customer curtailment must be automated and controllable by operators in Hydro's Energy Control Centre ("ECC"). The cost of infrastructure to ensure reliable operation and curtailment would be borne by the customer.
- While customer curtailments would be automated to the fullest extent possible, operational procedures and protocols must be established to ensure that manual interruption of all required customers can be safely and effectively performed by ECC operators. On this basis, the total number of interruptible customers must be limited. The exact number of interruptible customers that could be served would be subject to an operational review.
- To ensure reliable system operation, only customers with a load of 1.5 MW or more should be considered for a non-firm energy rate option. To ensure reliable operation from Hydro's ECC, customers would be required to interconnect at transmission system voltages of 46 kV or higher, which would ensure that the required infrastructure and resources are available for reliable monitoring, operational control, and curtailment functionality. To ensure fairness and to enable more than one customer to avail of this service, a maximum non-firm capacity should be established based on the degree of interest in non-firm service.

- In the event that there is more customer demand for a non-firm rate option than Hydro has capacity to serve, a fair and transparent process must be developed to determine how customers will be selected.

4.2 Non-Firm Service Terms and Conditions

Hydro believes the following process would be reasonable to apply to applicants willing to proceed with non-firm service.

The group of applicants interested in proceeding with non-firm service would fund a system impact study for use in finalizing the amount of non-firm capacity that will be made available.

After receiving the results of the system impact study, Hydro would finalize the proposed terms of non-firm service rate with the applicants and apply to the Board for approval of the terms and conditions and the pricing structure. Anticipated provisions of a non-firm service rate would include:

- Non-Firm Offering: The product is non-firm energy, meaning delivery or receipt of the energy may be interrupted at any time without liability on Hydro or the customer. Standby generation would not be used to ensure continuity of service to non-firm customers.
- Interconnection Costs: Customer is required to pay the full cost of interconnection in advance of Hydro starting any work related to connecting the customer.
- Service Size: Minimum customer service size to be 1.5 MW.
- Notice to Curtail and Automatic Curtailment: Customer would be required to curtail load within ten minutes of being advised by Hydro. In the case where the customer does not manually curtail their load within ten minutes then Hydro can automatically curtail the customer’s load. Any equipment, software, and resources required to remotely monitor and enable automatic curtailment at both Hydro’s facilities and the customer’s facilities will be paid for fully by the customer.
- Service at Transmission Voltage: To allow real-time monitoring of the reliability of the Labrador Interconnected System, non-firm energy customers would be required to interconnect at transmission system voltages of 46 kV or higher. Non-firm customers must provide their own transformation, breaker, protection, communications equipment, etc. at their site as per normal firm service customers.

- Security Deposit: The customer would be required to provide reasonable security prior to Hydro connecting service, usually in the form of two months equivalent bills. The security deposit will be returned when the customer has established two consecutive years of good credit history with Hydro.
- Term of Agreement: The term of the Non-Firm Power Service Agreement would be for a minimum of three years. Revision to the terms of the non-firm service would be subject to approval of the Board.

5.0 Rate and Regulatory Considerations

To determine a just and reasonable rate for a non-firm service offering on the Labrador Interconnected System, Hydro has considered generally accepted sound public utility practice and regulatory principles.

5.1 Non-Firm Rates in Canadian Jurisdictions

Based on a review of other jurisdictions in Canada, non-firm rates appear to be of two types: i) the provision of non-firm capacity in excess of the customer's firm load requirements based on the incremental cost of supply and ii) the payment of a credit to customers to reduce their available firm load.

Hydro offers its industrial customers on the Island Interconnected System a non-firm energy rate for a customer-specific MW block which is in excess of their firm load. The energy price which applies when using load in excess of firm load is based upon Hydro's incremental energy costs at the time of delivery, plus an administrative fee and a charge for system losses. Historically, the energy costs have typically been based on the monthly Holyrood Thermal Generating Station fuel cost. In recent years, there has been no demand charge on the island for the use of the non-firm demand made available within the contracts. Customers that avail of non-firm purchases must discontinue use of interruptible demand if requested by Hydro due to system constraints.

Hydro offers up to 5 MW of interruptible load to Labrador Industrial Customers. This enables these customers to use 5 MW above their firm demand without impacting their annual Power on Order. Because there have historically been capacity constraints on the Labrador Interconnected System, these customers pay the approved demand charge for interruptible demand. The price these customers pay for non-firm energy is typically based on the second block energy rate, which is a market-based rate. As these customers primarily use their interruptible demand during the winter season, the second block energy rate or the imbalance energy rate would normally apply. The second block energy rate is set annually based on a forecast market-based rate. The imbalance energy rate applies to energy usage above the forecast provided by the customer and is based on the average market price in the month the energy is used. The Labrador Industrial Customers must also discontinue the use of interruptible load when requested by Hydro.

In New Brunswick, customers can avail of interruptible energy in excess of the demand reserved for the customer if energy is available and can be provided with available resources over and above the utility's other firm commitments. The rate charged for interruptible energy is based on NB Power's incremental cost, plus an adder of 0.9 cents per kWh on peak and 0.3 cents per kWh off peak. In substance, this rate offering is similar to Hydro's non-firm energy rate on the Island Interconnected System.

In British Columbia, industrial customers[3] can avail of "Freshet Energy" during spring runoff periods where excess energy is available on the system. Customers pay their standard transmission demand rate; however, they can avail of Freshet Energy at a price equal to the greater of the hourly day-ahead market price or $0, plus an adder of $3/MWh.[4]

In Quebec, industrial customers[5] are offered bill credits for interruptions at the request of the utility. Depending on the number and duration of interruptions, customers can receive both fixed (demand) and variable (energy) credits against their published industrial rates.[6] In substance, this program is similar to Hydro's Capacity Assistance Program on the Island Interconnected System.

In Nova Scotia, large industrial customers[7] who agree to be interrupted qualify for a demand charge discount $3.43 per month per kVA for billed interruptible demand against published industrial rates.[8]

[3] Customers served at voltages of 60 kV and greater (BC Hydro Rate 1823).
[4] BC Hydro Rate 1892.
[5] Rate L applies to an annual contract whose contract power is 5,000 kW or more and which is principally for an industrial activity.
[6] "Interruptible Electricity Options for Rate L customers," Hydro Québec, <https://www.hydroquebec.com/business/customer-space/rates/interruptible-electricity-options-large-power-customers.html>.
[7] Customers on the Large Industrial Tariff with a minimum regular billing demand of 2,000 kVA at 90% Power Factor.
[8] "Interruptible Rider to the Large Industrial Tariff, Nova Scotia Power, <https://www.nspower.ca/about-us/electricity/rates-tariffs/interruptible-rider>.

In Hydro's view, the provision of a non-firm rate in Labrador should reflect a similar pricing approach that applies to Hydro's approach to non-firm service for additional load requested by its industrial customers in the province. The provision of a demand-based credit is generally applied to reduce the charge as a result of providing a reduced quality of service to customers that already have firm service. In the case where firm service cannot be provided, Hydro believes it is appropriate to emphasize marginal costs in considering the pricing approach for non-firm service. The provision of non-firm service on the Labrador Interconnected System will result in reduced energy available for exports. The provision of non-firm service is also accompanied by administrative costs to Hydro to ensure non-firm capacity use does not impact the provision of firm service. Hydro's pricing approach for non-firm service is conceptually similar to the approach used in New Brunswick and British Columbia.

5.2 Potential Rate Structure

Based on the foregoing, Hydro believes the following rate design approach would be appropriate for non-firm service on the Labrador Interconnected System.

Table 6: Potential Labrador Interconnected System Non-Firm Rate Structure

Rate	Details
Demand Charge	Demand charge based on transmission costs[9] (non-ratcheted)
Energy Charge	Greater of market-based energy charge[10] or incremental energy supply cost[11] (updated monthly) Plus: an administrative and variable operating and maintenance charge (10.0%)

As the non-firm customers would use the transmission system, Hydro believes it would be appropriate for the customers to pay a transmission demand charge based on the average embedded cost of demand. This is currently \$1.08 per kW on the Labrador Interconnected System. As this service is non-

[9] Hydro is not including a standby generation demand charge as non-firm customers would be subject to interruption; therefore, standby generation would not be used to ensure continuity of service.
[10] This approach is similar to the imbalance rate applicable to Labrador Industrial customers, which is also a market based rate. For July 2021, the imbalance rate is \$31.46 per MWh.
[11] If the incremental supply costs are used in determining the non-firm rate, the incremental supply cost would be adjusted to reflect Labrador Interconnected System losses.

firm, the rate would apply to the maximum monthly demand and would not apply to the maximum annual demand as is the case for firm demand.

The proposed energy rate should be based upon the greater of Hydro's forecast marginal energy cost reflecting the opportunity cost of lost export sales[12] or Hydro's incremental cost of supplying the non-firm energy. This approach ensures that Hydro can cover its cost of serving non-firm customers if Recapture Energy is fully utilized and other more expensive supply sources are required. An administration fee of 10% will recover Hydro's cost of offering this rate and is consistent with current practice on the Island Interconnected System. Hydro will finalize the details of the proposed rate design if its discussions with customers result in Hydro proposing a non-firm rate.

6.0 Conclusion

Hydro believes that a non-firm rate option may be feasible for a limited number of customers in Labrador. However, further discussions are required to finalize what can be made available and attributes that would be practical to implement for both Hydro and the potential customers. Hydro will proceed with engaging customers who have expressed an interest and move forward to determine if the applicants are interested in proceeding with development of a rate option based on the parameters described in this report. Hydro welcomes feedback from the Board and parties on its proposed approach.

[12] This currently reflects the New York Market for Labrador sales.

Appendix A

TP-TN-101

Labrador West and Labrador East Customer Curtailment/Interruptible Assessment

Doc #: TP-TN-101
Issue Date: 2021/04/06
Document Type: Technical Note

TP-TN-101

Labrador West and Labrador East Customer Curtailment/Interruptible Assessment

Purpose

The purpose of this technical note is to assess the opportunities available for connecting interruptible/curtailable load at Labrador East and Labrador West. The assessment includes a review of projected loads in Labrador East and Labrador West from 2021 to 2026, with the objective to determine the available capacity for connecting firm and interruptible industrial loads and expected number of interruptions at different load levels.

Overview

LABRADOR EAST

The construction of a 6 km transmission line extension from L1302 to the Muskrat Falls Terminal Station 2 ("L1303"), the expansion of the Muskrat Falls Terminal Station 2, and the upgrades to the Happy Valley Terminal Station will increase the available capacity in Labrador East to 104 MW during the winter, spring and fall months and 88.9 MW during the summer months. The ten-year P90 peak forecast[1] for Labrador East is shown in Table 1.

Table 1: Labrador East Load Forecast (MW)

Year	Baseline Peak
2021	79.70
2022	80.40
2023	81.00
2024	81.60
2025	81.90
2026	82.20
2027	82.90
2028	83.60
2029	84.30
2030	84.90

[1] Labrador Interconnected System Long-Term Load Forecast at January 2021 – transmittal.

LABRADOR WEST

Under existing system conditions with WTS Synchronous Condenser #3 ("SC3") in service, the total peak capacity of Labrador West is 385 MW during the winter, spring, and fall months and 310 MW during the summer months. The expected peak forecasts for Labrador West for the study period were derived from the baseline peak load forecast[2] which includes the loads for Newfoundland and Labrador Hydro ("Hydro") Rural, Iron Ore Company of Canada ("IOC") and Tacora Resources Inc. ("Tacora"). The ten-year P90 load forecast for Labrador West is shown in Table 2.

Table 2: Labrador West Load Forecast (MW)

Year	Baseline Peak
2021	377.3
2022	377.6
2023	377.9
2024	378.3
2025	378.6
2026	378.8
2027	379.0
2028	379.2
2029	379.3
2030	379.5

OPERATIONAL CONSIDERATIONS

The following operational considerations are defined for the purpose of this investigation:

INTERRUPTIONS DUE TO PLANNED AND FORCED OUTAGES

In addition to the planned interruptions due to system loading conditions quantified in this analysis, interruptible customers would also be subject to interruptions due to annual maintenance outages and forced outages. Contractual provisions are therefore recommended to accommodate potential capacity limitations during such events or due to force majeure.

Operational Management of Customer Interruption

The number of interruptions is dependent on the size of the load blocks and the curtailment required.

[2] Labrador Interconnected System Long-Term Load Forecast at January 2021 – transmittal, adjusted to reflect the operation of SC3

The smaller the size of independent load blocks, the greater the flexibility an operator will have to rotate interruptions. That being said, the number of independent load blocks must be limited due to the complexity of operation.

To ensure reliable operation, the following premises have been established with respect to customer interruption:

- Customer interruption must be automated and controllable by operators in Hydro's Energy Control Center ("ECC"). The cost of infrastructure to ensure reliable operation and interruption must be borne by the interruptible customer.

- While customer interruptions would be automated to the fullest extent possible, operational procedures and protocols must be established to ensure that manual interruption of all required customers can be safely and effectively performed by ECC operators in case of emergency. On this basis, the total number of interruptible customers must be limited. The exact number of interruptible customers that could be served would be subject to an operational review.

  As described in the following sections, a seasonal review of each system has been performed and a determination has been made on the acceptable number customer interruptions in each case. For the purposes of this preliminary investigation, if the number of interruptions is found to be in the order if 50 occurrences or more, it is deemed to be unacceptable due to the complexity of protocols and challenges associated with reliable operation.

Industrial Customer Entitlements

Contractual arrangements with IOC and Tacora are such that each of these customers has a entitlement to a Power on Order capacity plus an interruptible capacity of 5 MW each. As a result of capacity allocations, no firm capacity is available in western Labrador. For the purposes of this analysis, capacity available for new interruptible arrangements is calculated on the basis of historic load profiles. The opportunity for such arrangements could be rescinded if industrial customers were to develop projects or modify production profiles that resulted in off-peak load increases within their entitled capacities.

Firm Capacity Availability

The establishment of the Muskrat Falls–Happy Valley Interconnection will result in an increase in available firm capacity in eastern Labrador. The allocation of this firm capacity will be determined by Hydro as part of the ongoing analysis being performed in support of the implementation of the Network Addition Policy. It is recommended that firm capacity be allocated in advance of interruptible capacity.

ANALYSIS

LABRADOR EAST

Labrador East Load Profile:

The projected hourly load profiles for years 2021 to 2026 were extrapolated from historical (i.e., 2018, 2019 and 2020) load profiles. The expected annual load profile for 2026 (assuming no new incremental firm customers) is shown in Figure 1. As shown in Figure 1, there is a reduction in the thermal rating of L1303 and consequently the available capacity in Labrador East in the summer months.

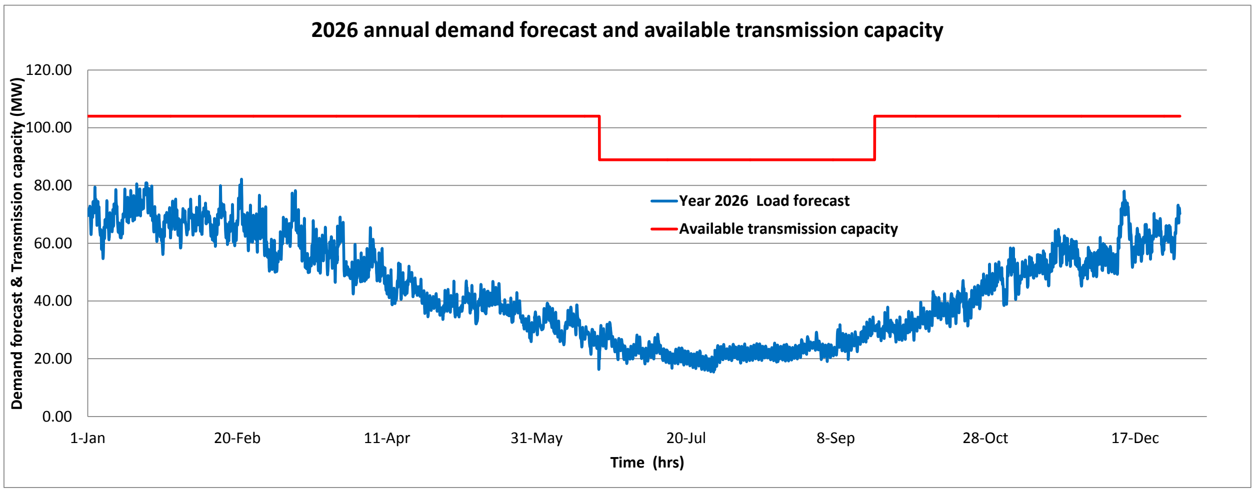

Figure 1: Labrador East Projected Load Profile for 2026 and Available Transmission Capacity

Annual Interruptible Load Analysis[3]

The expected probability and number of interruptions for ranges of load increments in 2026 is shown in Table 3.

[3] Expected curtailments are based on expected load and capacity of the transmission infrastructure and do include annual maintenance and forced outages.

Table 3: Probability and Number of Expected Load Interruptions for Ranges of Load Addition at Labrador East

Additional Load (MW)	Probability of Load Interruption (%)	Number of Interruption
18-23	0.02	1
23-28	0.97	32
28-33	4.93	163
33-38	13.01	430
38-43	21.82	721
43-48	28.89	955
48-53	37.66	1,245
53-58	45.42	1,502
58-63	55.98	1,851
63-68	80.11	2,649
68-73	94.05	3,110
73-78	99.27	3,283
78-83	99.95	3,305
83-88	100.00	3,307

As shown in Table 3, there is a minimum risk of interruption with the connection of up to 23 MW of load. The risk of interruption increases slightly with the connection of an additional 5 MW, however the overall risk of interruption remains below 1%. Therefore, additional 5 MW (i.e., a total of 28 MW) of load can also be accommodated; however, it might be subjected to partial or complete interruption in supply during the winter months.

Seasonal Interruptible Load Analysis

Electricity demand varies through the year; consequently the size of interruptible load that can be accommodated varies as well. Table 4 to Table 7 shows the number of interruptions expected for winter, spring, summer, and fall 2026.[4]

Expected Interruptions during Winter Months

As shown in Table 4, a maximum of 23 MW of firm load can be connected during the winter months. An addition 5 MW (i.e., a total of 28 MW) of load can be connected; however, the additional load will be subjected to manageable interruptions. The addition of loads greater than 28 MW will result in large number of interruptions and unacceptable operational complexity.

[4] Expected interruptions are based on expected load and capacity of the transmission infrastructure and do not include annual maintenance and forced outages.

Table 4: Expected Number of Interruptions per Additional Load Connection to Labrador East in Winter

Additional Load (MW)	Number of Expected Interruptions in Winter 2026
18-23	1
23-28	31
28-33	148

Expected Interruptions during Spring Months:

As shown in Table 5, a maximum of 33 MW of firm load can be connected in spring months. Additional 10 MW (i.e., a total of 43 MW) interruptible loads can be connected without significantly increasing the complexity of scheduling load interruptions. Conversely, connecting a cumulative load greater 43 MW will result in large number of interruptions and increase operational complexity.

Table 5: Expected Number of Interruptions per Additional Load Connection to Labrador East in Spring

Additional Load (MW)	Number of Interruption in Spring 2016
< 33	0
33-38	2
38-43	19
43-48	58

Expected Interruptions during Summer Months:

A maximum of 53 MW of firm load can be connected in summer months with no expected number of interruptions as shown in Table 6. An additional 5 MW (i.e. a total of 58 MW) interruptible load can be connected without significantly increasing the complexities of scheduling interruptions. The addition of a cumulative load greater 58 MW is expected to result in large number of interruptions and unacceptable operational complexities.

Table 6: Expected Number of Interruptions per Additional Load Connection to Labrador East in Summer

Additional Load (MW)	Number of Interruption in Summer 2026
< 53	0
53-58	12
58-63	129

Expected Interruptions during Fall Months:

A maximum of 28 MW firm lo ads can be connected in fall months. An additional 10 MW (i.e., a total of 38 MW) manageable interruptible load can be connected.

Table 7: Expected Number of Interruptions per Additional Load Connection to Labrador East in Fall

Additional Load (MW)	Number of Interruption in Fall 2026
18-23	0
23-28	1
28-33	15
33-38	27
38-43	72

LABRADOR WEST

Labrador West Load Profile:

The projected hourly load profiles for years 2021–2026 were extrapolated from historical (i.e., 2018, 2019, and 2020) load profiles. The expected annual load profile for 2026 is shown in Figure 2. The available transmission capacity in the winter, spring, and fall months is 385 MW. The transmission capacity reduces to 310 MW in summer months due to thermal rating of 230 kV transmission lines L23 and L24. As stated above, IOC and Tacora each have an interruptible entitlement of 5 MW. A total of 10 MW must therefore be deducted from available interruptible capacity.

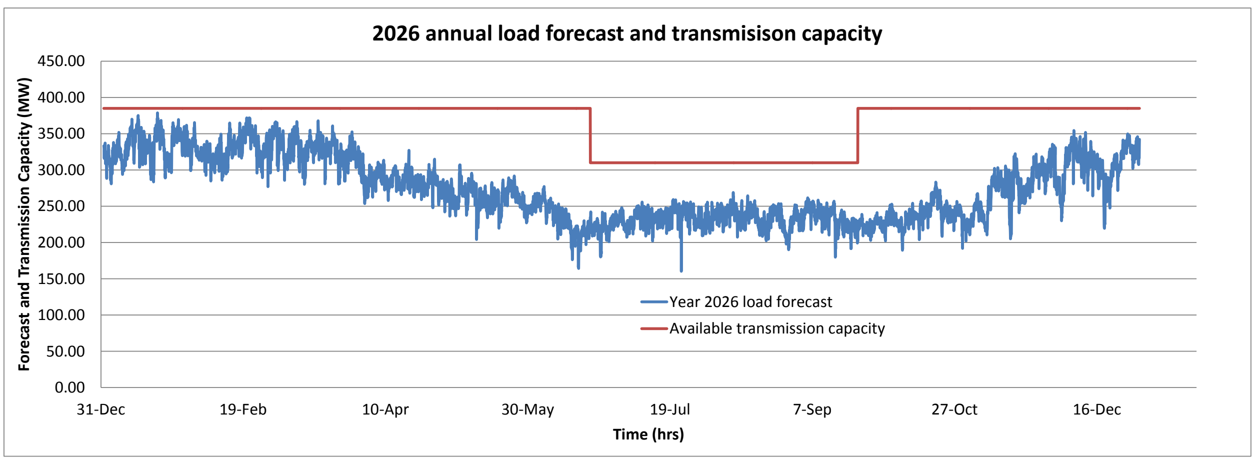

Figure 2: Labrador West projected Load Profile for 2026 and Available Transmission Capacity

Annual Interruptible Load Analysis[5]

The expected probability and number of interruptions for different levels of load additions in year 2026 is shown in Table 8. As indicated, the 10 MW total interruptible entitlement of IOC and Tacora can be accommodated with a low risk of interruptions. An additional 10 MW of interruptible load could also be served with a reasonable number of interruptions.

[5] Expected curtailment is based on expected load and capacity of the transmission infrastructure and does not include annual maintenance and forced outages.

Table 8: Probability and Number of Expected Load Interruption for Ranges of Load Addition at Labrador West

Additional Load (MW)	Probability of Curtailment	Number of Interruption
0-10	0.02	1
10-20	0.78	26
20-30	2.91	96
30-40	6.70	222
40-50	12.35	408
50-60	21.51	711
60-70	34.57	1,143
70-80	46.22	1,528
80-90	56.60	1,872
90-100	64.76	2,142
100-110	71.55	2,366
110-120	76.68	2,536
120-130	80.82	2,673
130-140	85.49	2,827
140-150	90.17	2,982
150-160	94.65	3,130
160-170	98.20	3,247
170-180	99.43	3,288
180-190	99.74	3,298
190-200	99.92	3,304
200- 210	99.95	3,305
210 - 220	100.00	3,307
220 - 230	100.00	3,307
230 - 240	100.00	3,307

Labrador West Seasonal Interruptible Load Analysis[6]

The expected number of interruptions for winter, spring, summer, and fall is shown in Table 9 to Table 12.

Expected Interruptions during Winter Months

As shown in Table 9, the IOC and Tacora 10 MW interruptible entitlement and an additional 10 MW of interruptible load can be accommodated. The addition of loads greater than 20 MW will result in too large a number of interruptions to be operationally viable.

[6] Expected interruptions are based on expected load and capacity of the transmission infrastructure and do include annual maintenance and forced outages.

Table 9: Expected Number of Interruptions per Additional Load Connection to Labrador West in Winter

Additional Load (MW)	Number of Interruption in Winter 2026
0-10	1
10-20	19
20-30	79
30-40	191
40-50	329

Expected Interruptions during Spring Months:

As shown in Table 10, the IOC and Tacora 10 MW interruptible entitlement and an additional 40 MW of interruptible load can reasonably be accommodated in the spring. This includes the interruptible entitlements for IOC and Tacora.

Table 10: Expected Number of Interruptions per Additional Load Connection to Labrador West in Spring

Additional Load (MW)	Number of Interruption in Spring 2026
<30	0
30-40	6
40-50	20
50-60	45

Expected Interruptions during Summer Months:

As shown in Table 11, the IOC and Tacora 10 MW interruptible entitlement and an additional 40 MW of interruptible load can reasonably be accommodated in the summer.

Table 11: Expected Number of Interruptions per Additional Load Connection to Labrador West in Summer

Additional Load (MW)	Number of Interruption in Summer 2026
< 40	0
40-50	2
50-60	75
60-70	270

Expected Interruptions during Fall Months:

As shown in Table 12, the IOC and Tacora 10 MW interruptible entitlement and an additional 40 MW of interruptible load can reasonably be accommodated in the summer.

Table 12: Expected Number of Interruptions per Additional Load Connection to Labrador West in Fall

Additional Load (MW)	Number of Interruption in Fall 2026
< 30	0
30-40	3
40-50	16
50-60	43
60-70	88

CONCLUSION

The amount of interruptible loads that can be connected to Labrador East and Labrador West is summarized in Table 13.

Table 13: Interruptible Load Limits in Labrador West and Labrador East

	Annual	Winter	Spring	Summer	Fall
Labrador East	28	28	43	58	38
Labrador West[7]	20	20	50	50	50

This analysis excludes capacity limitations from planned and unplanned maintenance because they are common to all scenarios, hence, contractually provisions are recommended to accommodate such events.

As stated above, the opportunity to provide interruptible service is subject to review to ensure safe and reliable operation. Opportunities for the addition of interruptible load must be made in consideration of industrial customer entitlements in western Labrador and potential firm load allocations in eastern Labrador.

[7] Labrador West totals include a combined 10 MW interruptible capacity allocation entitled to IOC and Tacora.

Document Summary

Document Owner:	B. Odetayo
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Revision History

Revision	Prepared by	Reason for change	Effective Date
0	B. Odetayo	Initial Release	2021/05/14
1	B. Odetayo	Addition of 10 MW total interruptible entitlement of IOC and Tacora	2021/05/20

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