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February 17, 2026

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

Attention: Colleen Jones
Assistant Board Secretary

Re: Quarterly Regulatory Report for the Quarter Ended December 31, 2025

Enclosed is Newfoundland and Labrador Hydro's ("Hydro") Quarterly Regulatory Report for the Quarter Ended December 31, 2025.

The Quarterly Regulatory Report is divided into three reports, as follows:

1) Quarterly Summary;
2) Contribution in Aid of Construction; and
3) Customer Damage Claims.

Hydro will provide the financial data in Tab 1 once the audited financial information becomes available.

If you have any questions on the enclosed, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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

Encl.

ecc:

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

Consumer Advocate
Adrienne H.Y. Ding, O'Dea Earle
Justin W. King, O' Dea Earle

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

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

Quarterly Regulatory Report

Quarter Ended December 31, 2025

February 17, 2026

A report to the Board of Commissioners of Public Utilities

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Tab 1

Quarterly Summary

Quarter Ended December 31, 2025

newfoundland labrador hydro

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Abbreviations

Term	Definition
AIF	All-Injury Frequency Rate
bbl	Barrel
Board	Board of Commissioners of Public Utilities
Cat Arm	Cat Arm Hydroelectric Generating Station
CIAC	Contribution in Aid of Construction
Ebbegunbaeg	Ebbegunbaeg Control Structure
EC	Electricity Canada
EMS	Environmental Management System
FEED	Front-End Engineering Design
FTE	Full-time equivalent
Government	Government of Newfoundland and Labrador
GPS	Global Positioning System
Hinds Lake	Hinds Lake Hydroelectric Generating Station
Holyrood TGS	Holyrood Thermal Generating Station
Hydro	Newfoundland and Labrador Hydro
IOC	Iron Ore Company of Canada
LTIF	Lost-Time Injury Frequency
MCM	Million Cubic Metres
Newfoundland Power NP	Newfoundland Power Inc.

Term	Definition
Q4	Fourth Quarter
RSP	Rate Stabilization Plan
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TRIF	Total Recordable Injury Frequency
T-SAIDI	Transmission System Average Interruption Duration Index
T-SAIFI	Transmission System Average Interruption Frequency Index
T-SARI	Transmission System Average Restoration Index
UFLS	Under Frequency Load Shedding
Upper Salmon	Upper Salmon Hydroelectric Generating Station
WCF	Weighted Capability Factor
YTD	Year-to-Date

Definitions

Break-in Work: Break-in work is work that was not identified at the beginning of the calendar year as part of the annual work plan.

Current Quarter: The period beginning October 1, 2025 and ending December 31, 2025.

EMS Target: An EMS target is an initiative undertaken to improve environmental performance.

End Consumer: End Consumer is a reliability measure of all end consumers of electricity in the province supplied by Hydro, excluding Industrial customers. The measure is a combination of Hydro’s service continuity data and Newfoundland Power’s service continuity data for loss-of-supply outages resulting from events on Hydro’s system.

End-Consumer SAIDI: End-Consumer SAIDI measures reliability to all end customers of electricity in the province who are supplied by Hydro. It is a measure of the duration of service interruptions experienced as a result of Hydro system events, but does not reflect service interruptions that are a result of issues on Newfoundland Power’s distribution system.

End-Consumer SAIFI: End-Consumer SAIFI measures reliability to all end customers of electricity in the province who are supplied by Hydro. It is a measure of the frequency of service interruptions experienced as a result of Hydro system events, but does not reflect service interruptions that are a result of issues on Newfoundland Power’s distribution system.

FTE: One FTE is the equivalent of actual paid regular hours—2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.

Lost Time Injury: An injury/illness resulting in Lost Days beyond the date of injury as a direct result of an Occupational Injury/Illness incident.

LTIF: LTIF is based on the total number of lost-time injuries or illnesses which occurred in the calendar year.

Net FTE: Net FTEs are regulated, Hydro-based employees plus time charged to regulated Hydro, less time charged from regulated Hydro to the non-regulated lines of business.

Major Event: EC defines Major Events as “events that exceed reasonable design and/or operational limits of the electrical power system.”

Service Continuity SAIDI and SAIFI: Service Continuity SAIDI and SAIFI measure the duration and frequency of service interruptions to Hydro’s Isolated and Interconnected systems.

SAIDI: SAIDI is the average interruption duration per customer. It is calculated by dividing the number of customer-outage hours by the total number of customers in an area.

SAIFI: SAIFI is a reliability key performance indicator for distribution service, measuring the average cumulative number of sustained interruptions per customer per year. SAIFI is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

TRIF: TRIF is a calculation of the rate at which injuries occur.

T-SAIDI: T-SAIDI is a reliability key performance indicator for bulk transmission assets, measuring the average duration of outages in minutes per delivery point.

T-SAIFI: T-SAIFI is a reliability key performance indicator for bulk transmission assets, measuring the average frequency of outages per delivery point.

T-SARI: T-SARI is a reliability key performance indicator for bulk transmission assets, measuring the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.

UFLS: Under frequency load shedding is the reliability performance indicator that measures the number of events in which shedding of customer load is required to counteract the loss of generation capacity. During a UFLS event, customers are automatically removed from the electrical system. The quantity of customers removed is linearly proportional to the amount of generation lost.

YTD: The period ending December 31 of the applicable year.

1.0 Highlights

Table 1: Highlights YTD

	2025 Actual	2025 Target	2024 Actual
Safety and Environment			
TRIF Rate[1]	0.71	1.25	0.74
LTIF Rate[2]	0.24	0.15	0.25
Achievement of EMS Targets (%)	97	95	95
Reliability			
SAIDI	3.16	2.56	2.33
SAIFI	1.29	1.25	1.65
Production			
Holyrood No. 6 Fuel Oil Average Cost ($/bbl)	109	102	118
Holyrood Efficiency (kWh/bbl)	566	583	558
Electricity Delivery (GWh)			
Energy Sales	7,783	7,600	7,855
Financial ($ Millions)[3]			
Revenue	N/A	649.7	648.6
Operating Expenses	N/A	158.1	145.2
Net Income	N/A	8.3	20.5
RSP ($ Millions)[4]			
RSP Balance	12.6	12.6	30.6
Supply Cost Variance Deferral Account ($ Millions)[5]			
Cumulative Net Balance	350.4	346.4	531.7
FTE Employees[6]			
Regulated	846.6	860.20	821.20

[1] TRIF = $\frac{\text{number of recordable injuries x 200,000}}{\text{number of hours worked}}$

[2] LTIF = $\frac{\text{number of lost-time injuries x 200,000}}{\text{exposure hours}}$

[3] Financial figures exclude non-regulated activities.

[4] The RSP report for the current quarter is provided as Attachment 1.

[5] Computed based on methodology presented in "Supply Cost Accounting Compliance Application," Newfoundland and Labrador Hydro, January 21, 2022.

[6] Figures shown are net FTEs.

2.0 Safety and Health

2.1 Safety at Hydro

Safety remains Hydro’s priority. Hydro’s framework for safety performance includes a balanced focus on culture, people, and process as it continues to ensure its safety management system reflects good utility practice or industry standards. Reviewing workplace incidents to prevent future occurrences is a critical part of overall safety management systems. Leading indicators—such as safety meetings, Occupational Health and Safety Committee meetings, leadership safety interactions, and the safety and health monitoring plan, among other performance indicators—continue to be tracked and discussed to ensure safety and health are a continuous part of Hydro’s work focus.

Hydro’s focus on ensuring the safety of its employees, contractors, and the public continued during the current quarter. The advancement of Hydro’s safety and health priorities include:

- Continue risk-based review of existing practices, processes and programs to ensure a focus on hazard recognition, safe job planning, and injury prevention;
- Continue focus on safety training for supervisors, operational managers, and lead hands to reinforce core responsibilities and duties;
- Continue to advance mental health initiatives and ensure support programs are in place for employees; and
- Support employees in Early and Safe Return to Work with disability case management support and attendance support.

2.2 Safety Performance

An overview of Hydro's safety performance is provided in Table 2.

Table 2: Safety Performance Detail[7,8]

	YTD 2025	2024 Annual
Fatalities	0	0
Lost-Time Injuries	2	2
Medical Treatment Injuries	2	3
First Aid with Restrictions	2	1
TRIF Rate	0.71	0.74
LTIF Rate	0.24	0.25
Severity Rate (Days Lost)	7.81(66)	1.60(13)
High-Potential Incidents	3	3

Hydro experienced one first aid with restriction this quarter, for a total of two first aid with restrictions, two medical treatment injuries and two lost-time injuries at year end. As a result of the total number of recordable injuries for the year, Hydro's year-end TRIF rate is 0.71, and its LTIF rate is 0.24. Hydro's lost-time severity rate is 7.81, based on 66 days of lost time from the two lost-time injuries.

A comparison of Hydro's TRIF and LTIF rates over the past five years to the EC average, along with the 2025 rates, is provided in Chart 1. Hydro's annual lost-time severity rate for the past five years, compared to the EC average and the 2025 rate, is provided in Chart 2.

[7] Injury statistics reflect regulated Hydro employees only.
[8] Updated to reflect reclassifications and adjustments determined after the time of initial reporting.

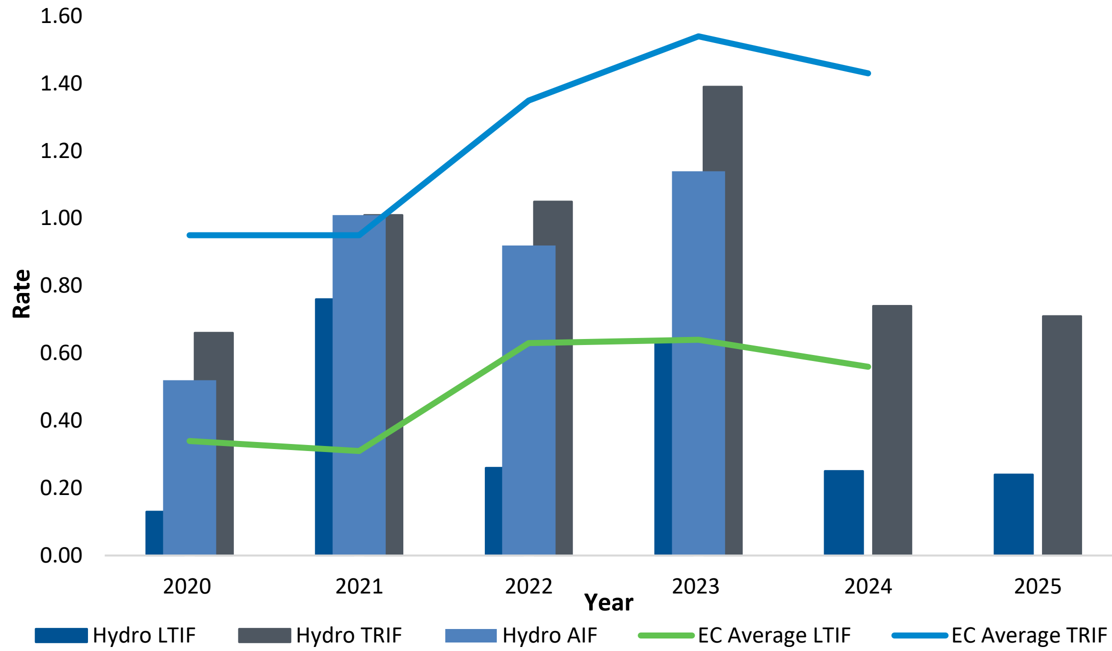

Chart 1: Hydro's TRIF and LTIF Compared to EC Averages[9]

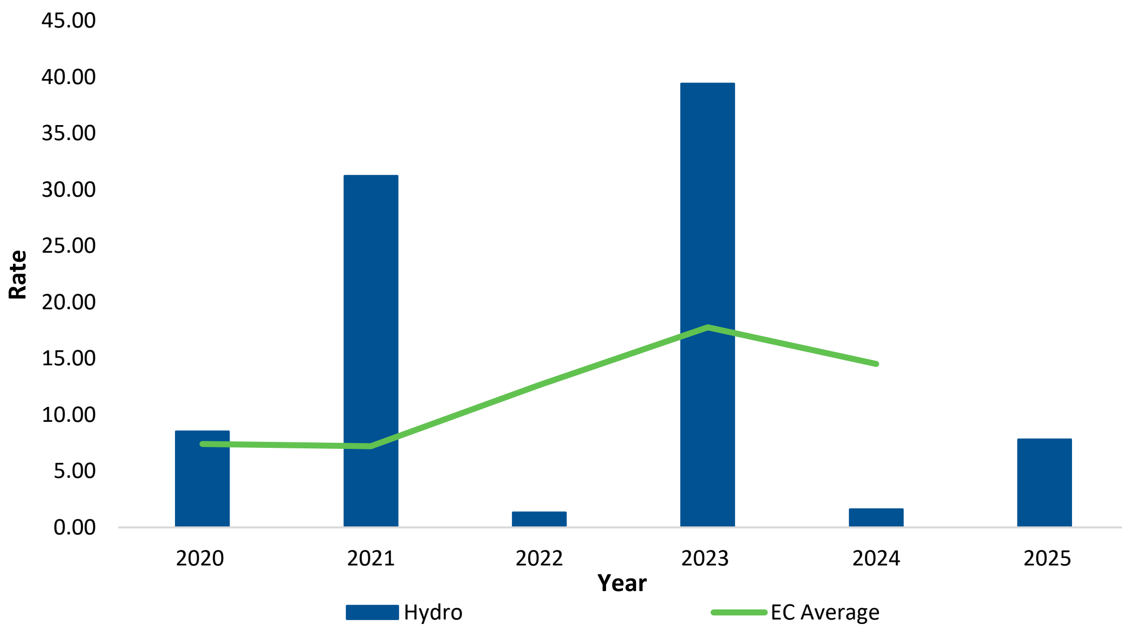

Chart 2: Hydro's Lost-Time Severity Rate Compared to EC Average[10]

[9] Safety and Health performance metrics are compared to EC utility members in Group 2 (300–1,500 employees) until 2022. In 2022 to present, Hydro fell in Group 1 (1,500+ employees). The EC comparator group here is the same baseline that Hydro would use for the total Hydro experience, not just regulated operations.
[10] *Supra,* f.n. 9.

2.3 Line Contacts

There were seven reportable line contact incidents by a third party during the current quarter. There were no injuries as a result of these incidents. Hydro continues to work toward reducing line contact incidents by increasing public and contractor awareness of the hazards associated with contacting power lines through education.

3.0 Reliability

3.1 Outage Information

There were thirteen power outages reported to the Board during the current quarter. Information on each of these outages is provided in Appendix A.

A summary of major events from 2020 to 2025, including the impact the major events would have had on performance indicators, is provided in Appendix B. As electrical systems are neither constructed nor expected to fully withstand extreme weather conditions, such as forest fires and ice storms, the impacts of major events have been removed from the data used in the calculation of each of the electrical system reliability performance indicators in this report.

3.2 Generation Outage Summary

A summary of the status of Hydro's generating units for the current quarter is provided in Appendix C. It classifies which units were available or unavailable and any associated deratings. Further information is provided in Hydro's daily Supply and Demand Status reports filed with the Board.[11]

3.3 Reliability Indicators

For all reliability performance indicators in this report, a year-over-year decrease in reliability indicators indicates an improvement in system performance, and a year-over-year increase in reliability indicators indicates a decline in system performance. Data on reliability indicators, including Service Continuity by Type, Area and Origin, T-SARI, and UFLS, are provided in Appendix D.

[11] Hydro's daily Supply and Demand Status reports can be accessed at http://www.pub.nl.ca/applications/IslandInterconnectedSystem/DemandStatusReports.php.

4.0 Customer Service

4.1 Customer Transactional Surveys

Survey results for the current quarter indicate that approximately 87% of customers were satisfied with the service they received when they reached out to Hydro's Customer Service Department for assistance. As well, 87% of customers felt their concern was resolved with the first call. A summary of these results is provided in Table 3.

Table 3: Customer Service Transactional Survey Data

Measure	Q4 2025	Q4 2024
Overall Satisfaction	87%	91%
First Call Resolution	87%	85%
Number of Surveys Completed	607	1,282[12]

4.2 Customer Statistics

A summary of the number of Hydro customers in each customer class, including net metering, is provided in Table 4.

Hydro did not receive any new net metering applications during the current quarter. Hydro's total number of net metering customers remains at three, with a total net metering capacity of 71.6 kW.

Table 4: Customer Statistics

	2025 Actual	2024 Actual	2025 Budget
Rural Customers[13]	39,586	39,374	39,423
Industrial Customers	6	6	6
Labrador Industrial Transmission Customers[14]	2	2	2
Utility Customers	1	1	1
Average Monthly Reading Days	29.9	29.8	N/A
Net Metering Customers	3	3	N/A

[12] During Q4 2024, Hydro received an increase in volume of customer service calls in relation to billing issues resulting from the Canada Post strike. This increased the pool of customers who were eligible to receive the survey and thus helped contribute to a greater number of respondents compared to previous quarters.
[13] Includes net metering customers.
[14] IOC and Tacora Resources Inc.

5.0 Supply Costs and Energy Sales

5.1 Fuel Prices[15]

Market prices for No. 6 fuel oil reached a high of $97/bbl in mid October and a low of $85/bbl in the end of December. The ending inventory cost for the current quarter was $97/bbl; this compares to the fuel price of $106/bbl that was reflected in Newfoundland Power's wholesale rates during the current quarter.[16]

There were two shipments of No. 6 fuel oil during the fourth quarter as detailed in Table 5. Inventory at the end of the quarter was 329,937 bbls.

Table 5: No. 6 Fuel Oil Shipments

Delivery Date	Quantity (bbl)	Price/bbl Delivered ($)
10-Nov-2025	202,234	96
18-Dec-2025	205,426	88

A comparison of No. 6 fuel oil prices in 2025 as compared to 2023 and 2024, as well as the fuel oil price reflected in the wholesale rate to Newfoundland Power are provided in Chart 3.

[15] Prices for No. 6 fuel oil are provided in Canadian ("CDN") dollars.
[16] The price of $105.90/bbl is reflected in Newfoundland Power's base rates effective October 1, 2019, as per Board Order No. P.U. 30(2019).

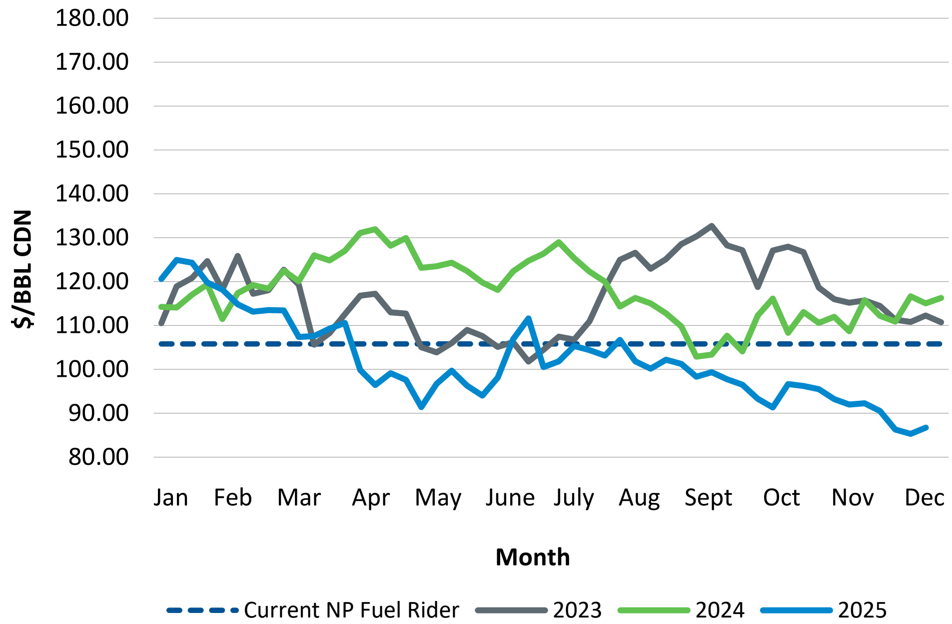

Chart 3: No. 6 Fuel Oil Average Weekly New York Spot Price

1 The monthly forecast price of No. 6 fuel oil for the next twelve months is provided in Table 6.[17]

Table 6: No. 6 Fuel Oil Forecast Prices ($CDN/bbl)

Month	Price
Jan-26	90.20
Feb-26	87.30
Mar-26	85.10
Apr-26	83.80
May-26	86.20
Jun-26	86.70
Jul-26	85.80
Aug-26	84.70
Sep-26	83.20
Oct-26	81.20
Nov-26	82.10
Dec-26	81.10

[17] The price forecast is based on Platts Analytics fuel price outlook, December 2025 World Oil Market Forecast and includes the premium for the No. 6 fuel oil.

A comparison of the Ultra Low Sulphur Diesel No. 1 (used in diesel generation) fuel oil prices in 2025 as compared to 2023 and 2024 is provided in Chart 4.

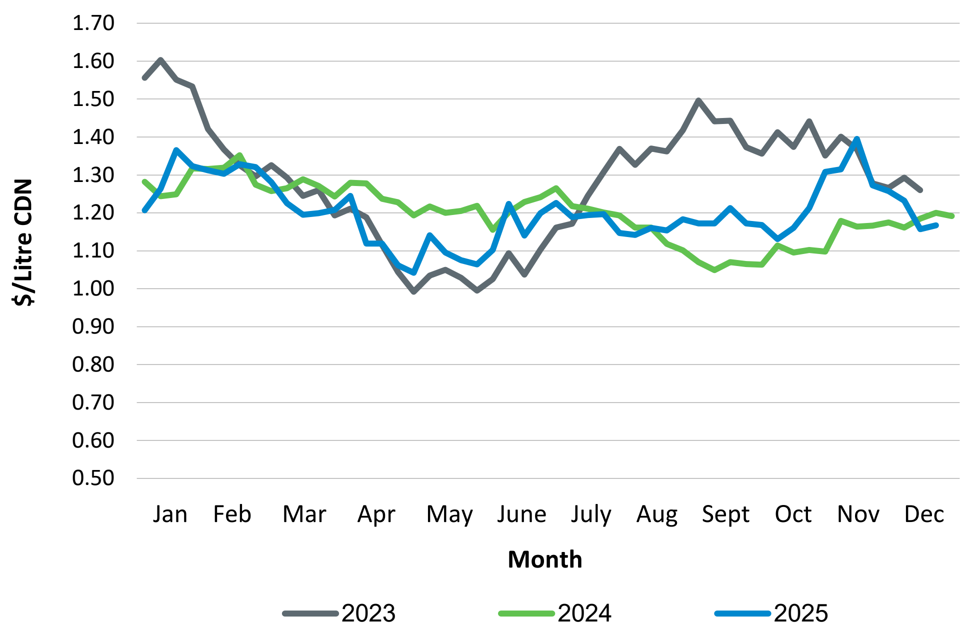

Chart 4: Ultra Low Sulphur No. 1 Diesel Weekly Montreal Rack Price

5.2 Transfers to Supply Cost Deferral Accounts

5.2.1 Supply Cost Variance Deferral Account Overview

The balances accumulated in the Supply Cost Variance Deferral Account as at December 31, 2025, are reported in Attachment 2.

The 2025 YTD activity in the account decreased the balance by $181.3 million, primarily due to rate mitigation funding of $704.4 million ($441.0 million in February, $150.0 million in August and $113.4 million in December). Payments made under the Muskrat Falls Power Purchase Agreement and Transmission Funding Agreement ($772.7 million) were partially offset by revenue from exports ($58.2 million), fuel savings at the Holyrood TGS ($54.7 million), greenhouse gas credits revenue ($16.1 million), transmission tariff revenue ($18.0 million) and payments received from Newfoundland Power and Island Industrial customers related to the Project Cost Recovery Rider of $75.4 million and $7.6 million, respectively.

As per Order in Council OC2024-062 dated May 7, 2024, Hydro has been directed by the Government to use its own sources of rate mitigation and, accordingly, in February 2025, transferred $441.0 million of funding to its Regulated operations. The $441.0 million includes $90.6 million of rate mitigation funding related to the retirement of the 2023 Supply Cost Variance Deferral Account of $271 million over the 2024 to 2026 period.

Additionally, in December 2025, pursuant to OC2024-062 and OC2024-063, the Government directed Hydro to transfer $113.4 million of rate mitigation funding to its Regulated operations through the use of its own funding.

The total balance in the account as of December 31, 2025, is $350.4 million.[18]

5.2.2 Isolated Systems Cost Variance Deferral Account

Hydro accumulated $6.3 million[19] in the Isolated Systems Cost Variance Deferral Account as of December 31, 2025. The current year's actual unit cost of diesel fuel was approximately 10¢/kWh more than the 2019 Test Year unit cost of fuel, which is the primary driver of the transfer of fuel costs to the account this year.

The current year transfers to the Isolated Systems Cost Variance Deferral Account are provided in Table 7. Pursuant to Board Order No. P.U. 30(2019), Hydro has calculated the transfers relative to the 2019 Test Year.

Table 7: Isolated Systems Cost Variance Deferral Account Transfers ($ Millions)[20]

2025 Actual	2024 Actual	Variance
6.3	6.7	(0.4)

In accordance with the currently approved account definitions, Hydro will file an application for recovery of the Isolated Systems Cost Variance Deferral Account balance on or before March 31, 2026. This

[18] The December 31, 2025 Supply Cost Variance Deferral Account balance of $350.4 million is unaudited.
[19] The December 31, 2025 Isolated System Cost Variance Deferral balance of $6.3 million is unaudited.
[20] Net of deadbands.

application will include the final transfer amounts as well as detailed information as to the drivers of the transfers.

5.3 Statement of Energy Sold

A summary of Hydro's energy sales compared to that of other reporting periods is provided in Table 8.

Table 8: Statement of Energy Sold (GWh)

	2025 Actual	2024 Actual	2025 Annual Target
Island Interconnected			
Newfoundland Power	5,829	5,702	5,857
Island Industrials	507	449	584
Export and Other	254	569	
Rural			
Domestic	253	244	254
General Service	169	154	155
Street Lighting	2	2	2
Subtotal Rural	**424**	**400**	**411**
Subtotal Island Interconnected	**7,014**	**7,120**	**6,852**
Island Isolated			
Domestic	4	4	4
General Service	1	1	2
Street Lighting	-	-	-
Subtotal Island Isolated	**5**	**5**	**6**
Labrador Interconnected			
Domestic	308	293	317
General Service	363	361	356
Non-Firm Energy	32	33	-
Street Lighting	1	1	1
Subtotal Labrador Interconnected	**704**	**688**	**674**
Labrador Isolated			
Domestic	25	24	25
General Service	18	17	18
Street Lighting	-	-	-
Subtotal Labrador Isolated	**43**	**41**	**43**
L'Anse-au-Loup			
Domestic	16	15	16
General Service	9	9	9
Street Lighting	-	-	-
Subtotal L'Anse-au-Loup	**25**	**24**	**25**
Total Energy Sold (Before Rural Accrual)	**7,791**	**7,878**	**7,600**
Rural Accrual	(8)	(23)	N/A
Total Energy Sold	**7,783**	**7,855**	**7,600**
Non-Regulated Customers[21]			
Labrador Industrials	1,839	1,864	1,957

[21] Does not include non-regulated sales for export.

6.0 Asset Management and Investment

6.1 2025 Capital Budget

Hydro's 2025 Capital Budget was approved by the Board in Order No. P.U. 28(2024).[22] In addition to approval for an investment of $136 million in capital projects, Hydro carried forward approximately $30 million from its 2024 capital program, of which approximately $13 million is project carryover and $17 million is multi-year cash flow reallocation. As a result, Hydro's opening capital budget for 2025 was $165 million. Supplemental capital of $63 million has been approved by the Board for 2025, and a total of $8 million has been approved by Hydro for 2025 projects under $750,000. Additionally, an Early Execution Application related to the Avalon Combustion Turbine and Bay d'Espoir Unit 8 projects was approved for $47 million. Hydro's revised Board-approved 2025 Capital Budget as of December 31, 2025, was $284 million. Table 9 shows the breakdown of Hydro's capital budget approvals of $284 million by Board Order.

[22] Originally approved on December 13, 2024.

Table 9: Capital Budget by Board Order as at December 31, 2025 ($000)

2025 Capital Budget	**135,713**
Multi Year Cost Flow Reallocation 2024 to 2025[23]	17,085
Project Carryover 2024 to 2025[23]	12,639
Projects Approved by Board:	
Order No. P.U. 6(2023)[24]	58,023
Order No. P.U. 21(2023)[25]	231
Order No. P.U. 28(2023)[26]	1,822
Order No. P.U. 22(2024)[27]	318
Order No. P.U. 25(2024)[28]	226
Order No. P.U. 9(2025)[29]	344
Order No. P.U. 11(2025)[30]	1,519
Order No. P.U. 17(2025)[31]	47,380
Order No. P.U. 29(2025)[32]	855
Total Projects Approved by Board Order	**110,718**
2025 Projects Under $750,000 approved by Hydro[33,34]	7,633
Total Approved Capital Budget	**283,788**

1 Table 10 outlines the capital projects under $750,000 approved by Hydro within the current quarter.

[23] The carryover budget of $29.7 million, of which approximately $12.6 million is project carryover and $17.1 million is multi-year cash flow reallocation, excludes CIACs. Hydro also carried forward CIACs of ($0.1) million, which would result in an estimated net carryover of $29.6 million to be recovered through customer rates.

[24] The replacement and weld refurbishment of Penstock 1 at the Bay d'Espoir Hydroelectric Generating Station was approved for $65.9 million, of which $58.0 million is budgeted for 2025.

[25] The construction and installation of seven ultra-fast Direct Current Fast Chargers along the Trans-Canada Highway was approved for $2.1 million, of which $0.2 million is budgeted for 2025. Per the Board Order, the costs for these chargers were not to be included in Hydro's rate base or recovered from customers.

[26] The purchase of a spare generator step-up transformer to serve as a capital spare at the Holyrood Thermal Generating Station was approved for $12.3 million, of which $1.8 million is budgeted for 2025.

[27] The completion of fire restoration on the fourth floor of Hydro Place was approved for $1.1 million, of which $0.3 million is budgeted for 2025.

[28] The replacement of Rigolet Unit 2065 and fuel storage upgrades was approved for $3.4 million, of which $0.2 million is budgeted for 2025.

[29] The interconnection and integration of the Puffin Wind Inc. renewable energy project was approved for $1.3 million, of which $0.3 million is budgeted for 2025.

[30] The replacement of Hydro’s Learning Management System and Reporting Tools was approved for $1.7 million, of which $1.5 million is budgeted for 2025.

[31] The Early Execution application for the Avalon Combustion Turbines and Bay d’Espoir Unit 8 was approved for $47.4 million, of which $47.4 million is budgeted for 2025.

[32] The budget of $0.9 million for the Level 2 Condition Assessment on Stage 1 & 2 Cooling Water Sump Structures, as approved by the Board in Order No. P.U. 28(2024) was increased to $1.7 million, all of which is budgeted for 2025.

[33] This includes previously reported 2024 under $750,000 projects that had expenditures in 2025 totalling $0.8 million.

[34] Includes Information Services projects as reported in “Amalgamation Report of Newfoundland and Labrador Hydro and Nalcor Energy – Revision 1,” Newfoundland and Labrador Hydro, April 17, 2025.

Table 10: Capital Expenditures Under $750,000
Approved by Hydro for the Quarter ended December 31, 2025
($000)

Investment Class	Title	Total Budget	Project/ Program	Description
General Plant	Perform Office Renovations – Hydro Place	633.4	Project	The project scope is to supply and install additional workstations and modify existing layouts, required to accommodate an increased employee count. The proposed workstations are necessary to complement the current measures taken to maximize workspaces in the building and provide adequate conditions for employees.
Renewal	Replace Igniter System (2025–2026) – Hardwoods and Stephenville	445.5	Project	The ignition system design is original to the Hardwoods and Stephenville Gas Turbines, which have been in operation since 1975 and 1976, respectively. This system has been previously overhauled due to electrical component failures but is now obsolete, with limited availability of spare parts and without provision of an overhaul service contractor. The project scope is to replace all ignition components and retrofit the associated electrical and ignition controls at the Hardwoods and Stephenville Gas Turbines to maintain their safe and reliable operation.
Service Enhancement	Install Dynamic Line Rating (2025–2026) – TL201	595.5	Project	The project scope is to supply, install and operate a Dynamic Line Rating (“DLR”) system on TL201, a 230kV transmission line between the Western Avalon Terminal Station (“WAV TS”) and the Soldiers Pond Converter Station (“SOP CS”). The proposed installation will serve to enhance the performance of TL201 by implementing real time monitoring, resulting in operational efficiencies by maximizing power transfer capability based on favorable environmental conditions.

In addition, there were CIACs carried forward from the 2024 capital program and supplemental CIACs approved by the Board, totalling $2 million. The 2025 Capital Budget as of December 31, 2025, net of CIACs, was $282 million.

6.2 Capital Expenditures

Capital expenditures for the year ended December 31, 2025, will be provided in Hydro's annual Capital Expenditures and Carryover report, due to be filed with the Board on April 1, 2026.

6.3 2025 Capital Projects and Programs Progress

Hydro's planned capital construction activity typically occurs in the second, third, and fourth quarters. Additionally, throughout the year, certain unplanned capital work, known as "break-in work," may arise, which can impact the completion of planned activities. Actual expenditure relative to the approved budget[35] are shown provided in Chart 5.

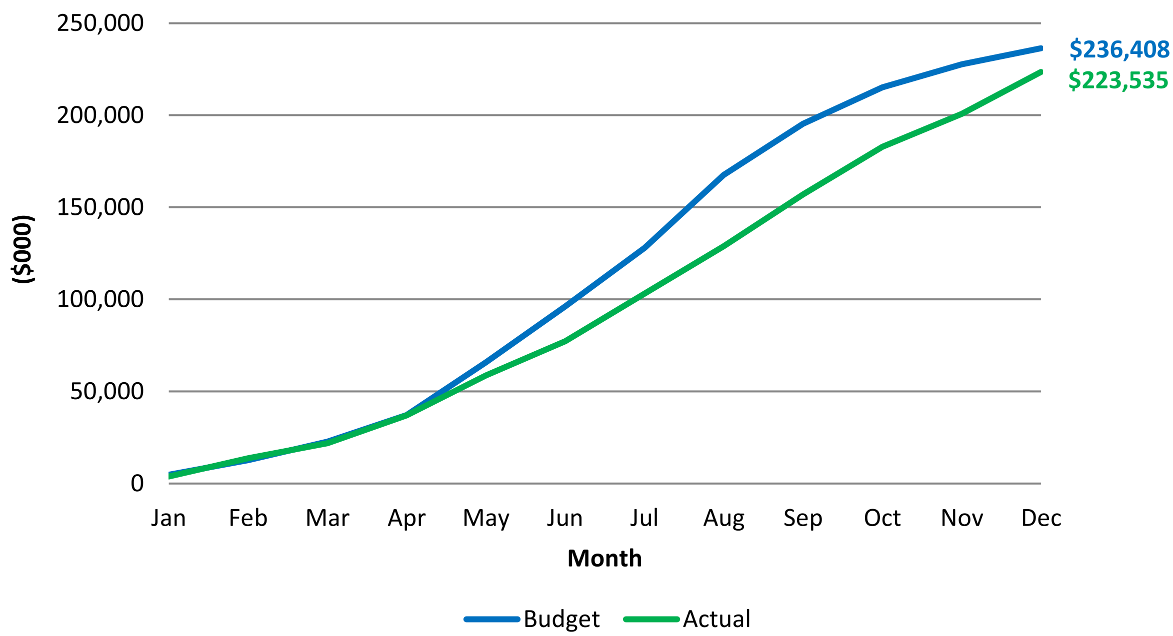

Chart 5: 2025 Capital Program Actual vs Budget, excluding Major Projects currently before the Board[36]

Hydro's 2025 expenditures were 5.4% lower than the budget. The under-expenditure was primarily driven by project activities that have carried over to 2026. These under-expenditures were partially offset by activities completed in 2025 at costs that exceeded the budget amounts. Hydro is completing an analysis of capital expenditures for all 2025 projects and programs to categorize the expenditure

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[35] Excludes approved budget and forecast expenditures related to Hydro's Early Execution Application for Bay d'Espoir Unit 8 and Avalon Combustion Turbine projects. For the latest budget and forecast information, please refer to Major Projects Monthly Updates for February 2026, filed with the Board on February 16, 2026.

[36] Excludes proposed expenditures related to Hydro's 2025 Build Application and Life Extension of Bay d'Espoir Unit 7.

variances from the approved budget and determine key drivers. A summary of that analysis will be included in Hydro's annual Capital Expenditures and Carryover Report, due to be filed with the Board on April 1, 2026.

As required under the provisional Capital Budget Application Guidelines,[37] explanations will be provided for projects and programs with variances exceeding 10% and $100,000 at year-end, as part of Hydro's annual Capital Expenditures and Carryover Report.

A summary of the planned and break-in construction activities completed during the fourth quarter is provided in Table 11.

Table 11: Highlights of Planned and Break-In Work[38] Completed in Current Quarter

Major Asset Category	Minor Asset Category	Planned Work Q4 2025	Break-In Work Q4 2025
General Properties	**Administration**	Various office modifications and procurement of furniture, fixtures, and equipment were completed at Hydro Place.	
General Properties	**Information Systems**	The following software upgrades and minor enhancements were completed: • Modernization of diary applications; • Upgrade of windows operating systems; • Modernization of distribution outage reporting system; • Upgrade of event and device monitoring software for operational technology domain; and • Upgrade of the meter data field collection system and the associated security manager. Cybersecurity infrastructure upgrades were completed.	The work protection code application was upgraded (advanced from 2026 to 2025). Completed installation of software for porting diesel plant metering data into Historian software.
General Properties	**Properties**	Overhead door and dock leveler replacement was completed at the Holyrood TGS. Warehouse outdoor storage rack fencing was installed at Bay d'Espoir Hydroelectric Generating Station ("Bay d'Espoir"). Security access card system improvements were performed at Hydro Place.	Accessibility improvements were completed for the kitchen area on the fourth floor of Hydro Place.

[37] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022.
[38] Break-in work is work that was not identified at the beginning of the calendar year as part of the annual work plan.

Major Asset Category	Minor Asset Category	Planned Work Q4 2025	Break-In Work Q4 2025
General Properties	**Telecontrol**	Two servers were commissioned for the Back-Up Control Centre at the Holyrood TGS. Various mobile devices were replaced. The storage area network was replaced at Hydro Place. Installation of racking and components for core information technology/operational technology was completed at Hydro Place. A remote terminal unit was replaced at Doyles Terminal Station. Closed-circuit television security cameras were replaced at: • Nain Diesel Generating Station; • Whitbourne Office; • Paradise River Hydroelectric Generating Station; • Bottom Brook Terminal Station; • Springdale Terminal Station; • Indian River Terminal Station; • South Brook Terminal Station; and • L'Anse-au-Loup Diesel Generating Station. Meteorological stations were replaced at: • Burnt Dam Spillway Structure; • Ebbegunbaeg ; • Cat Arm Intake Structure; and • Hinds Lake Control Structure. Battery banks were replaced for the telecommunications systems at: • Bay d'Espoir Hill Microwave Site; • Hardwoods Terminal Station; and • Upper Salmon. Battery bank chargers were replaced for the telecommunications systems at: • Stephenville Terminal Station; • Hardwoods Terminal Station; and • Ebbegunbaeg. GPS clocks were replaced at various locations. Minor telecommunications enhancements were performed at various locations.	Spare remote terminal units were procured. Spare closed-circuit television systems were procured.

Major Asset Category	Minor Asset Category	Planned Work Q4 2025	Break-In Work Q4 2025
General Properties	**Tools and Equipment**	Various tools and equipment were purchased.	
General Properties	**Transportation**	One forklift was replaced. Three electric sport utility vehicles were purchased. One material handler was purchased.	Several light and heavy-duty vehicles were refurbished.
Generation	**Combustion Turbines**	Construction of a maintenance platform was completed at the Holyrood Combustion Turbine. The fuel storage tanks were inspected and refurbished at the Stephenville Gas Turbine.	The turbine/generator enclosure was overhauled at Hardwoods Gas Turbine. Vibration monitoring and pressure calibration tools were purchased.
Generation	**Hydraulic Plant**	Penstock 1 was refurbished at Bay d'Espoir. Bay d'Espoir Intake 1 was refurbished. The interior of Surge Tank 1 was refurbished at Bay d'Espoir. Bay d'Espoir Units 1 and 2 annunciator panels were replaced. Bay d'Espoir Unit 1 operating wear pads, linkage bushings, and wicket gate bushings were replaced. Ebbegunbaeg Bays 1, 2, and 3 upstream stop log gains were refurbished. A power canal public safety boom was installed at Upper Salmon. The downstream slope of the Hinds Lake power canal dyke was flattened. A powerhouse slope condition assessment was completed for Cat Arm. An intake structure spare transformer was installed at Upper Salmon. Various tools and equipment were purchased.	A condition assessment of the turbine shut-off spherical valves for Bay d'Espoir Units 1 and 2 was completed. The cladding system was replaced at Bay d'Espoir Surge Tank 2. A dewatering pump motor was refurbished at Bay d'Espoir. A set of stop logs for isolating generating units was procured for Bay d'Espoir Units 1-7.
Generation	**Thermal Plant**	Holyrood TGS Unit 3 boiler condition assessment and various upgrades were completed. Holyrood TGS Unit 3 west boiler feedwater pump and motor were overhauled. Holyrood TGS Unit 2 west boiler feedwater motor critical spare was procured.	Holyrood TGS Unit 3 north extraction pump and motor were refurbished. New suction heaters were purchased and installed for Holyrood TGS Fuel Storage Tank 1.

Major Asset Category	Minor Asset Category	Planned Work Q4 2025	Break-In Work Q4 2025
		Holyrood TGS Stage 2 water sump structure condition assessment was completed. Holyrood TGS Air Compressor 3 was replaced. Various outbuildings roofs, siding and doors were refurbished at the Holyrood TGS. Various tools and equipment were purchased.	Holyrood TGS Unit 3 south extraction pump and motor were refurbished. Holyrood TGS Unit 2 east boiler feed pump volute was overhauled. Holyrood TGS Units 2 and 3 boiler feed pump gland seal water strainers were replaced. Holyrood TGS auxiliary steam desuperheater spray valve was replaced.
Transmission and Rural Operations	**Distribution**	The distribution feeder was upgraded in L'Anse-au-Loup, including the addition of a feeder recloser.	Various customer service extensions were installed. Various distribution upgrades were completed.
Transmission and Rural Operations	**Generation**	Diesel genset replacement for Hopedale Unit 2053 was completed. Plant automation was upgraded in Nain and Hopedale. Switchgear modifications were completed in Nain and Ramea. The diesel genset for Hopedale Unit 2074 was overhauled. The powerhouse roof was replaced in Grey River. Fuel storage tanks were upgraded in Rigolet.	Fuel storage capacity was increased in Ramea. A fence was installed in Ramea for the planned integration of renewable energy. The genset for Makkovik Unit 3033 was replaced. The circuit breaker for L'Anse-au-Loup Unit 2005 was refurbished. The engine for Nain Unit 2085 was refurbished.
Transmission and Rural Operations	**Metering**	The remaining meter replacements were completed for the multi-year Replace Metering System project.	
Transmission and Rural Operations	**Terminal Stations**	Refurbishment was completed for Transformers at the following Terminal Stations: • T2 at Grand Falls Frequency Converter; • T1 at Grandy Brook; • T1 at South Brook; and • T1, T6 and SS1 at Wabush. An on-line oil dehydrator was installed on Transformer T1 at Wabush Terminal Station.	Various failed power transformer protective devices were replaced.

Major Asset Category	Minor Asset Category	Planned Work Q4 2025	Break-In Work Q4 2025
		Circuit breakers B14L15 and T2B14 were replaced at Happy Valley Terminal Station. Reclosing circuit breaker B1L36 was upgraded at Hardwoods Terminal Station. Disconnect switches were replaced at the following Terminal Stations: • Stony Brook (L05L31-1 and L05L35-1/L05G); • South Brook (L22T1-1); • Wabush (B1L24-2 and L24G); and • Western Avalon (B4L64-2/L64G). Protective relays were replaced for: • Transformer T2 at Grand Falls Frequency Converter Terminal Station; • Transformer T3 at Hardwoods Terminal Station; • Transformer T3 at Massey Drive Terminal Station; • Generator G2 and Transformer T2 at Holyrood TGS; • Transmission Line ("TL") 232 at Stony Brook Terminal Station; and • Transformer T5 at Western Avalon Terminal Station. Battery bank chargers were replaced at the following Terminal Stations: • Cow Head; • Farewell Head; • South East Hill; and • Stephenville. Several instrument transformers were replaced at Holyrood and Western Avalon Terminal Stations. Fire protection was installed at Voisey's Bay Nickel Terminal Station.	
Transmission and Rural Operations	**Tools and Equipment**	Various tools and equipment were purchased.	
Transmission and Rural Operations	**Transmission**	Wood pole line inspections were completed for TL218, TL224, TL263, TL227, and TL239.	Eye bolts were replaced for TL254 Structure 91, and TL241 Structure 118.

6.4 Integrated Annual Work Plan

Hydro has an Integrated Annual Work Plan consisting of capital and maintenance work for its generation, transmission, distribution, and other associated assets. Hydro's 2025 Integrated Annual Work Plan completion target is 90%. As of the end of the year, Hydro had completed approximately 95% of the planned activities for 2025. Results for Annual Work Plan activities are provided in Table 12.

Table 12: Annual Work Plan Activity

2025 Actual		
Planned	**Completed**	**%**
6,540	6,194	95

7.0 Financial

7.1 Statement of Income ($000)

Financial data for the year ended December 31, 2025, will follow when audited financial information becomes available.

7.2 Greenhouse Gas Credits

In 2016, the federal government announced plans to implement carbon pricing to help Canada meet its greenhouse gas emission targets, and in October 2018, the provincial government released its approach to carbon pricing. The plan came into effect on January 1, 2019, and provides for Hydro to receive performance credits as the Holyrood TGS uses less fuel and decreases greenhouse gas emissions. Under the *Management of Greenhouse Gas Act*,[39] Hydro may sell these performance credits to other regulated facilities in the province, of which there are 14, excluding the Holyrood TGS. 2025 was the sixth year that Hydro was able to sell its performance credits. The qualifications and other specifics of how the performance credits are earned, how they can be sold, etc., are contained within the Management of Greenhouse Gas Reporting Regulations.[40]

In 2025, Hydro carried forward 541,599 performance credits and earned 515,605 credits as a result of the Holyrood TGS using less fuel and decreasing greenhouse gas emissions in comparison to a baseline forecast for the reporting year 2024. Hydro sold 211,700 performance credits for a total revenue of

[39] *Management of Greenhouse Gas Act*, SNL 2016, c M-1.001.
[40] NLR 14/17.

$15.8 million. Hydro used 3,671 credits for compliance obligations with respect to the Holyrood Combustion Turbine. Hydro is carrying forward 841,833 performance credits to apply to future compliance requirements or to be sold in future years.[41] Table 13 provides a summary of Hydro's greenhouse gas credit activity since 2020.

Table 13: Summary of Greenhouse Gas Credit Activity

Year	Opening Balance	Credits Earned	Credits Used	Credits Sold	Closing Balance
2020	-	169,734	303	55,000	114,431
2021	114,431	292,676	923	125,106	281,078
2022	281,078	462,545	1,708	248,015	493,900
2023	493,900	382,058	364	493,536	382,058
2024	382,058	490,917	882	330,494	541,599
2025	541,599	515,605	3,671	211,700	841,833

The revenues from the sale of the greenhouse gas performance credits are credited to the Supply Cost Variance Deferral Account.[42]

8.0 People and Community

8.1 Diversity and Inclusion

8.1.1 Gender Equity Targets

Hydro has corporate gender equity targets as part of its strategy on diversity and inclusion. In 2025, Hydro continued proactive efforts to attract and retain women in leadership, operations, and engineering positions, while supporting their advancement. Table 14 shows Hydro's progress towards its gender equity targets.

[41] Credits expire seven years after creation.

[42] As per Board Order No. P.U. 33(2021).

Table 14: Gender Equity Statistics

	2025 Year End			2024 Year End			Target
	Total	**Female**	**% Female**	**Total**	**Female**	**% Female**	**% Female**
Executive	10	5	50%	9	4	44%	30%
Management	126	44	35%	113	42	37%	35%
Engineers & Engineers in Training	153	39	25%	147	36	24%	30%
Technicians & Technologists	289	26	9%	292	25	9%	10%
Field Supervisors	93	4	4%	93	5	5%	6%
Skilled Trades & Apprentices	294	14	5%	298	16	5%	10%
Manual Workers	81	21	26%	85	17	20%	20%

8.2 Community Initiatives

During the final quarter of 2025, Hydro worked with current and new organizations to provide volunteer and fundraising support. Hydro also supported the Community Food Sharing Association through the annual Cheer Challenge as well as employee-led events.

8.2.1 Hydro Employees Spread Cheer in Support of Community Food Sharing Association

In December, employees were encouraged to spread cheer to their colleagues by participating in the 5th Annual Cheer Challenge. By submitting a safety commendation or acknowledgement through our internal recognition system, employees shared their appreciation for those who supported them or their teams, went the extra mile or showed their commitment to Hydro's values. For each submission, the Energy from the Heart program provides a donation to the Community Food Sharing Association.

In 2025, a $10,000 donation was made to the Community Food Sharing Association, helping to support people in cities, towns and communities throughout the province.

8.2.2 Celebrating Final Steps with Ronald McDonald House Charities

In October, Hydro was honoured to join the team at Ronald McDonald House as they announced a record-breaking total of $310,970 raised during the Red Shoe Crew Walk. As the presenting partner of the Red Shoe Crew Walk, Hydro employees helped to organize walks throughout the province, volunteered and fundraised in support of the House and programs for families from around the province.

Hydro has been a long-time partner of Ronald McDonald House Charities Newfoundland and Labrador, supporting the House through volunteering, in-kind and financial contributions since it opened in 2012.

8.2.3 Hydro Employees Take on Movember in Support of Men's Health Programs

This year, Hydro took part in Movember for the first time, raising awareness and funds for men's health issues. The inaugural team was small—with a mix of employees from across the province—but dedicated. At the end of the month, the team raised more than $2,800 in support of mental health and suicide prevention, prostate cancer and testicular cancer projects.

Support for Movember was widespread, with a group in Muskrat Falls participating while the team in Holyrood held a fundraising cornhole tournament as well as hosted a men's health webinar.

8.2.4 Supporting Young Adults with Cancer at the Energy Shave for the Brave

In November, Hydro's President and CEO, Jennifer Williams, joined colleagues from ExxonMobil Canada, Equinor Canada, Cenovus, Suncor and the newly-appointed Minister of Energy and Mines, the Honourable Lloyd Parrott, for "the most powerful haircut of their lives" during the 2025 Energy Shave in support of Young Adult Cancer Canada ("YACC"). During the event, Jennifer had eight inches of hair cut off while the male participants had their heads shaved.

YACC supports young adults (teens–30s) who are living with cancer by providing specialized programs connecting participants to peers and providing a bridge out of the isolation that often occurs.

The 2025 Energy Shave raised $317,802 for YACC programs, bringing the total raised at all Energy Shave events to more than $1.1 million since 2021.

8.2.5 Wrapping up the Year with Home Again Furniture Bank

Hydro and its employees continue to support the work of Home Again Furniture Bank to help alleviate furniture insecurity on the eastern Avalon peninsula. In December, 24 Hydro employees volunteered for their gift-wrapping fundraiser—spending time at the Avalon Mall offering gift-wrapping services for donations to Home Again.

Through the Energy from the Heart Community Program, Hydro also supported Home Again's year-end campaign again in 2025, with a matching donation of $10,000, with the goal of encouraging others to make a donation throughout December. The nearly $40,000 raised through the campaign will help ensure more furniture is available for those in need.

Appendix A

Power Outages Reported to the Board of Commissioners of Public Utilities

Power Outages

Table A-1: Power Outages Reported to the Board for the Current Quarter

Date	Area Affected	Cause	Customers Affected	Duration
06-Oct-2025	Labrador West	Lightning	6,008	Up to 1 hour, 30 minutes
07-Oct-2025	L'Anse-au-Loup	Defective Equipment	1,060	Up to 7 hours, 11 minutes
07-Oct-2025	UFLS	Protection Trip	54,807	Up to 15 minutes
12-Oct-2025	Labrador West	Ground Fault	6,204	Up to 2 hours, 01 minute
18-Oct-2025	Labrador West	Mechanical Transformer Fault	6.009	Up to 1 hours, 33 minutes
01-Nov-2025	Mud Lake	Tree Contact	40	Up to 27 hours, 0 minutes
01-Nov-2025	Northern Peninsula	Defective Equipment	5,400	Up to 10 hours, 49 minutes
03-Nov-2025	English Harbour West	Defective Equipment	93	Up to 66 hours, 17 minutes
12-Nov-2025	St. Anthony	Unknown Trip	2,422	Up to 2 hours, 57 minutes
19-Nov-2025	L'Anse-au-Loup	Defective Equipment	1,098	Up to 7 hours, 5 minutes
05-Dec-2025	Fogo	Defective Equipment	1,811	Up to 28 hours, 55 minutes
05-Dec-2025	Rocky Harbour	Unknown Trip	2,071	Up to 4 hours, 0 minutes
21-Dec-2025	South Brook	Tree Contact	1,188	Up to 6 hours, 4 minutes

Appendix B

Major Events Excluded From Performance Index Tables

Major Events

Table B-1: Major Events Excluded From Performance Index Tables[1]

		End-Consumer		Service Continuity		Transmission	
Year	**Event Description**	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**	**T-SAIDI**	**T-SAIFI**
2025	November 1 Northern Peninsula outage	0.19	0.02	1.48	0.14	72.09	0.12
	December 5 winter storm	0.20	0.01	1.53	0.10	51.30	0.09
	December 15 winter storm	0.23	0.01	1.80	0.11	0.00	0.00
	December 25 winter storm	0.29	0.01	2.25	0.09	38.26	0.02
2024	Labrador West outage due to Churchill Falls forest fires	0.24	0.02	1.64	0.16	64.67	0.05
2023	No major events	N/A	N/A	N/A	N/A	N/A	N/A
2022	TL214 outage due to extreme winds	0.26	0.03	0.00	0.00	35.67	0.03
	Great Northern Peninsula outage	0.38	0.03	2.93	0.20	91.92	0.23
	Connaigre Peninsula outage due to freezing rain	0.24	0.01	1.81	0.06	0.00	0.00
2021	No major events	N/A	N/A	N/A	N/A	N/A	N/A
2020	Winter storm affecting Change Islands/Fogo	0.09	0.01	0.71	0.09	0.00	0.00

[1] Data for 2025 reflects major events to the end of the current quarter. Data for 2020–2024 reflects major events experienced through the year.

Appendix C

Generation Unit Outages

October 2025

Location	Asset	Capacity	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Island																																	
Bay d'Espoir	G1	76.5 MW																															
	G2	76.5 MW																															
	G3	76.5 MW																															
	G4	76.5 MW																															
	G5	76.5 MW																															
	G6	76.5 MW																															
	G7	154.4 MW																															
Cat Arm	G1	67 MW																															
	G2	67 MW																															
Granite Canal	Unit	40 MW																															
Hardwoods	GT	50 MW																															
Hawkes Bay	Unit	5 MW																															
Hinds Lake	Unit	75 MW																															
Holyrood	G1	170 MW	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	G2	170 MW	115	115	115	115	115	115	115	115	115	115	115	115	115	115	140	140	140	140	140	140	140	140	163	163	163	163	163	163	163	163	163
	G3	150 MW																															
	GT	123.5 MW																															
	Diesels	10 MW																															
Soldiers Pond Labrador-Island Link	Monopole ("M") Bipole ("B")	700 MW	M 450	M 450	M 450	M 450	M 450	M 450	M 450	M 450	M 450	M 450	M 450	M 450	M 450	M 450																	
Paradise River	Unit	8 MW																															
Stephenville	GT	50 MW																															
St. Anthony	Unit	9.7 MW																					5.7					4.7	4.7	4.7	4.7	4.7	4.7
Upper Salmon	Unit	84 MW																															
Labrador																																	
Happy Valley	GT	25 MW																															
Muskrat Falls	G1	206 MW																															
	G2	206 MW																															
	G3	206 MW																															
	G4	206 MW																															

Available
Available Derated
Unavailable

November 2025

Location	Asset	Capacity	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Island																																
Bay d'Espoir	G1	76.5 MW																														
	G2	76.5 MW																														
	G3	76.5 MW																														
	G4	76.5 MW																														
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Cat Arm	G1	67 MW																														
	G2	67 MW																														
Granite Canal	Unit	40 MW																														
Hardwoods	GT	50 MW																				25	25	25	25	25	25	25	25	25	25	25
Hawkes Bay	Unit	5 MW																														
Hinds Lake	Unit	75 MW																														
Holyrood	G1	170 MW	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100				150	150	150	120
	G2	170 MW	163	163	163	163	163	163	163	163	163	163	163	163																		
	G3	150 MW																														
	GT	123.5 MW																														
	Diesels	10 MW																														
Soldiers Pond Labrador-Island Link	Monopole ("M") Bipole ("B")	700 MW																M 450													M 450	
Paradise River	Unit	8 MW																														
Stephenville	GT	50 MW																														
St. Anthony	Unit	9.7 MW	5.7	5.7	5.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Upper Salmon	Unit	84 MW																														
Labrador																																
Happy Valley	GT	25 MW																														
Muskrat Falls	G1	206 MW																														
	G2	206 MW																														
	G3	206 MW																														
	G4	206 MW																														

Available
Available Derated
Unavailable

December 2025

Location	Asset	Capacity	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Island																																	
Bay d'Espoir	G1	76.5 MW																															
	G2	76.5 MW																															
	G3	76.5 MW																															
	G4	76.5 MW																															
	G5	76.5 MW																															
	G6	76.5 MW																															
	G7	154.4 MW																															
Cat Arm	G1	67 MW																															
	G2	67 MW																															
Granite Canal	Unit	40 MW																															
Hardwoods	GT	50 MW	25	25	25	25	25																										
Hawkes Bay	Unit	5 MW																															
Hinds Lake	Unit	75 MW																															
Holyrood	G1	170 MW	150	50	163	163	163	163	163	163	163	163	163	163	163	163	163	163	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
	G2	170 MW		50							130																						
	G3	150 MW																															
	GT	123.5 MW																															
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Paradise River	Unit	8 MW																															
Stephenville	GT	50 MW																															
St. Anthony	Unit	9.7 MW	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	6.8	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Upper Salmon	Unit	84 MW																															
Labrador																																	
Happy Valley	GT	25 MW																															
Muskrat Falls	G1	206 MW																															
	G2	206 MW																															
	G3	206 MW																															
	G4	206 MW																															

Available	
Available Derated	
Unavailable	

Appendix D

2025 Annual Report on Key Performance Indicators

Contents

List of Attachments

1.0 Introduction

In Order No. P.U. 14(2004), the Board required Hydro to file appropriate historic, current, and forecast comparisons of reliability, operating, financial, and other KPIs. These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In accordance with Board Order No. P.U. 14(2004), Hydro has 14 KPIs, which fall into four categories: reliability, operating, financial, and customer related.

KPI data is reported on a historic basis. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution, or overall corporate activity. For most of the reliability KPIs, with the exception of UFLS, data from EC is provided in this report to compare Hydro's performance with broader industry performance. The KPIs used to measure performance in operations relate to two specific facilities within Hydro's system: Bay d'Espoir Hydroelectric Generating Station and Holyrood TGS. Performance is measured based on the efficiency of the two facilities and is compared on a year-over-year basis.

2.0 Overview of Key Performance Indicator Results

Hydro monitors reliability performance with ten separate metrics. These metrics have been divided into subcategories: generation, transmission, distribution, and other.

Table 1 summarizes Hydro's KPI performance in 2025. The rationale for the 2025 targets is included as Attachment 1 of this report.

Table 1: Hydro's KPI Performance for 2025

Category	KPI	Units	2025 Results	2025 Target
Reliability[1]	WCF	%	71.46	73.30[2]
	DAFOR	%	7.07	N/A[3]
	T-SAIDI	Minutes/Point	374.14	409.56
	T-SAIFI	Number/Point	1.98	2.51
	T-SARI	Minutes/Outage	188.96	N/A
	Service Continuity SAIDI	Hours/Customer	21.09	17.30
	Service Continuity SAIFI	Number/Customer	5.55	5.43
	End-Consumer SAIDI	Hours/Customer	3.16	2.56
	End-Consumer SAIFI	Number/Customer	1.29	1.25
	UFLS	Number of events	3	0
Operating	Hydraulic Conversion Factor	GWh/MCM	0.425	0.433
	Thermal Conversion Factor	kWh/bbl	566	583
Financial	Controllable Unit Cost	$/MWh	N/A[4]	N/A[5]
Other	Customer Satisfaction (Residential)	Max=100%	N/A%	N/A%[6]

3.0 Performance Indicators

The following defines and describes detailed KPI data within four general categories: reliability, operating, financial, and customer-related.

3.1 Reliability Performance Indicators

3.1.1 Reliability Key Performance Indicator: Generation

Weighted Capability Factor

While WCF performance in 2025 was below the annual target in all asset classes, with the exception of the hydraulic assets, Hydro maintained sufficient generation to meet customer requirements at all times in 2025. Hydro plans capital outages and schedules maintenance outages to ensure supply is available as required. This includes the consideration of the availability of generation supplied from Muskrat Falls

[1] Transmission and distribution reliability performance is measured on combined planned and forced outages.
[2] The WCF target is based on planned annual maintenance outages, an allowance for other short-duration maintenance outages, and targeted forced outage durations.
[3] Hydro no longer sets Overall DAFOR targets for combined Thermal and Hydro. Individual targets for each generation class will continue to be established and reported annually.
[4] Financial data will follow when audited financial information becomes available.
[5] Hydro does not set a target for Controllable Unit Cost.
[6] Hydro's most recent residential customer satisfaction survey was completed in 2024. The next residential customer satisfaction survey is scheduled to be completed in 2026.

and delivered via the Labrador-Island Link ("LIL"), which will be used to meet customer needs into the future.

Table 2 Summarizes Hydro's WCF performance in 2025 compared to 2024 performance and the 2025 target. Calculation details for weighted capability, as well as a list of factors that can impact KPI performance, are included as Attachment 2 of this report.

Table 2: WCF Performance

	2025 Annual	2024 Annual	2025 Annual Target[7]
Overall WCF	71.46	76.16	73.30
Thermal WCF	42.31	47.44	56.90
Hydraulic WCF	82.14	89.61	78.00
Gas Turbine WCF	86.85	80.25	90.30

Chart 1 details previous years' performance. Hydro's overall WCF for the period 2020–2024 is 80.34%, which is slightly below the equivalently weighted, most recently available national five-year average of 82.51% for the period 2020–2024.[8,9]

[7] Includes the time that units are unavailable due to maintenance; therefore, capability is affected by planned maintenance and capital work.
[8] EC reliability data is published annually. EC reliability data for generation is not currently available for 2025.
[9] Includes the time that units are unavailable due to maintenance; therefore, capability is affected by planned maintenance and capital work.

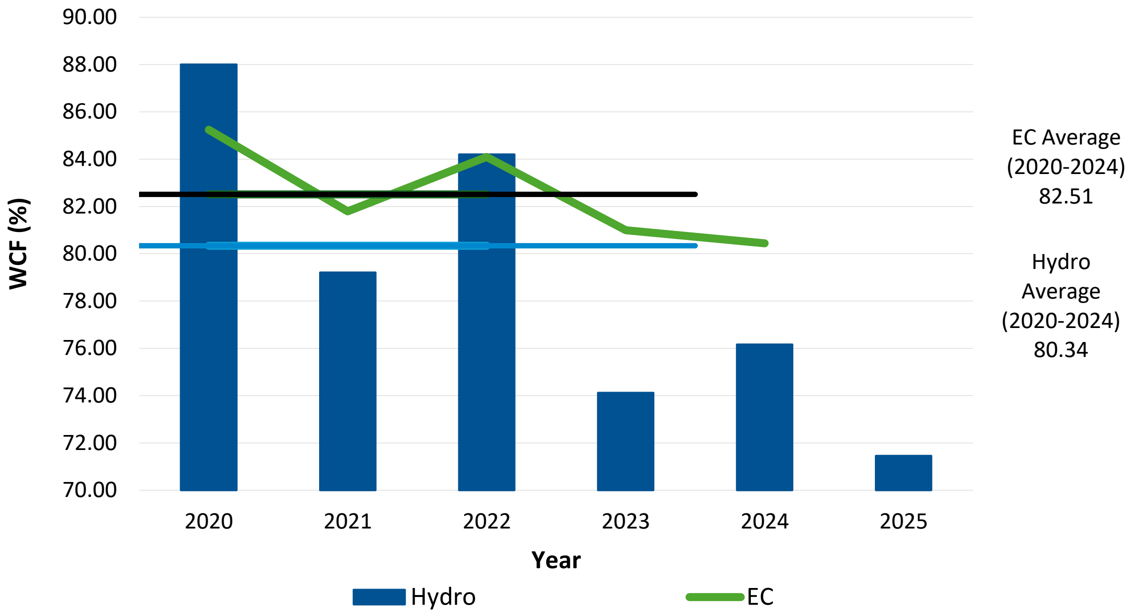

Chart 1: WCF

Weighted Derated Adjusted Forced Outage Rate

Table 3 summarizes Hydro's DAFOR performance in 2025, compared to 2024 performance, and the 2025 target.

Table 3: DAFOR Performance

	2025 Annual	2024 Annual	2025 Annual Target
Overall DAFOR	7.07	11.73	N/A[10]
Thermal DAFOR	26.86	37.29	20.00
Hydraulic DAFOR	0.36	2.07	2.25

Chart 2 details previous years' performance. Hydro's overall weighted DAFOR for the period 2020–2024 is 8.27%, which is better than the equivalently weighted, most recently available EC national five-year average of 12.17% for the period 2020–2024.[11]

[10] Hydro no longer sets overall DAFOR targets for combined Thermal and Hydro. Individual targets for each generation class will continue to be established and reported annually.
[11] EC reliability data for generation is not currently available for 2025.

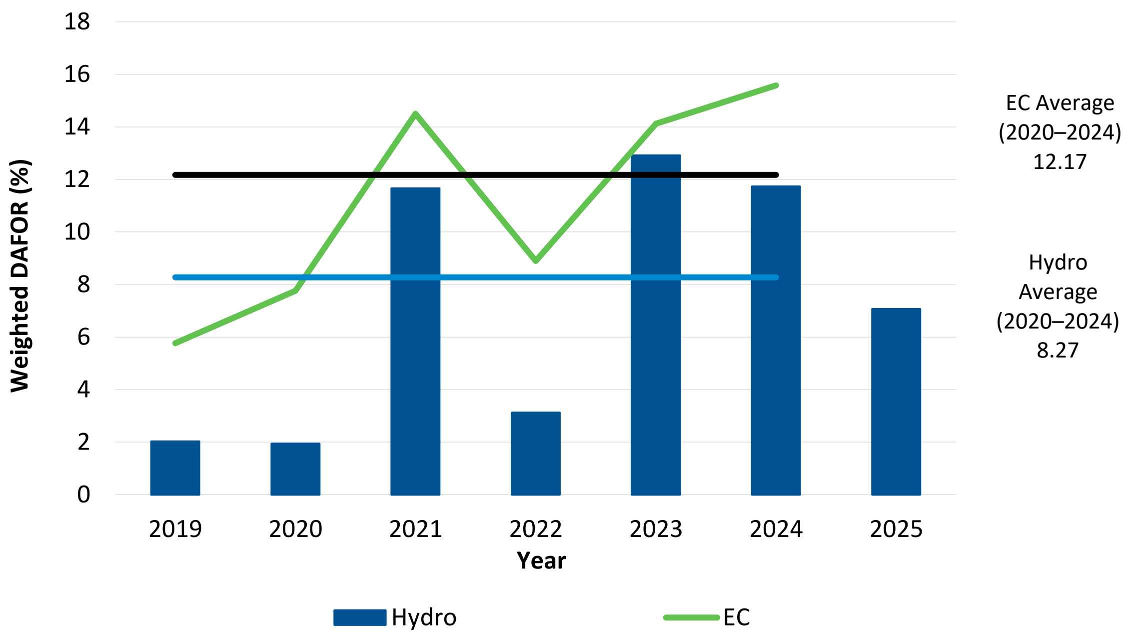

Chart 2: Weighted DAFOR

1 ## Generation Equipment Performance

2 Chart 2 provides the various performance indices for Hydro's generation facilities. Indices for 2025,
3 2024, and for the most recently available EC national five-year average are included for comparison.

Table 4: Generation Performance Indicators

Index		Hydraulic	Thermal	Combustion Turbine
Fail Rate	Hydro 2025	1.73	10.56	189.20
(Forced outages per 8,760	Hydro 2024	2.04	6.32	83.52
operating hours)	EC 2020 to 2024	2.12	8.31	25.08
Incapability Factor	Hydro 2025	17.86	57.69	13.15
(Percent of Time)	Hydro 2024	10.39	52.56	19.75
	EC 2020 to 2024	14.68	26.79	10.40
DAFOR[12]	Hydro 2025	0.36	26.86	N/A
(Percent of Time)	Hydro 2024	2.07	37.29	N/A
	EC 2020 to 2024	6.02	24.48	N/A
DAUFOP[13]	Hydro 2025	N/A	N/A	10.98
(Percent of Time)	Hydro 2024	N/A	N/A	21.91
	EC 2020 to 2024	N/A	N/A	5.23

[12] Hydro does not use DAFOR to measure gas turbine performance. Combustions turbine performance is measured by DAUFOP.
[13] Hydro does not use DAUFOP to measure hydraulic or thermal performance. Hydraulic and thermal performance is measured by DAFOR.

Hydraulic Unit Performance

Hydraulic unit performance for the fail rate improved in 2025 when compared to 2024. This improvement in fail rate performance is the result of fewer generating unit trips occurring in 2025 than in 2024. The outage count in 2025 was 23, whereas in 2024, a total of 27 outages were experienced.[14] This performance is slightly above the most recently available EC national five-year average. DAFOR performance improved when compared to 2024, and is better than the most recently available national five-year average. The improvement in DAFOR performance is largely attributed to the lack of significant outage durations experienced in 2025. Incapability factor performance declined, and this decline is largely attributed to the lengthy planned outages on Bay d'Espoir Units 1 and 2, which were required to complete the replacement of the penstock. Hydro's performance in this measure in 2025 is worse than the most recently available EC national five-year average.

Thermal Unit Performance

Thermal unit fail rate performance declined in 2025 when compared to 2024. This improvement is the result of an increase in the number of forced outages experienced in 2025 when compared to 2024. The number of forced outages in 2025 was fifteen, an increase from nine in 2024. This performance is below the most recently available EC national five-year average. Incapability factor performance declined slightly in 2025 when compared to 2024, while DAFOR performance has improved in 2025 when compared to 2024. Both incapability factor and DAFOR performance are below the most recently available EC national five-year average. The incapability factor and DAFOR performance were negatively impacted by the lengthy duration of planned outages, forced extension of planned outages experienced, forced outages and deratings.

Unit 1 performance was primarily impacted as a result of a forced extension to the planned unit outage in 2024 to overhaul the Unit 1 turbine and replace the L-0 and L-1 blades at the General Electric ("GE") shop in the United States. The outage was extended until the unit was brought online on February 12, 2025. Following return to service, an issue with the main steam controls valves prevented movement beyond 56% opening, which resulted in a forced derating to 105 MW. This derating remained

[14] Further information on outages which occurred that contributed materially to outage rates can be found in Hydro's Quarterly Reports on Asset Performance in Support of Resource Adequacy.

until March 10, 2025, when a planned outage was taken to investigate and correct the issue with the control valves. The unit returned to operation on March 17, 2025, at full capacity.

Holyrood Unit 1 entered the annual planned outage on May 4, 2025 and returned to operation on September 18, 2025. Since returning to service, the unit has experienced issues with the main steam control valves, similar to the issues earlier in 2025, restricting the unit to 100 MW. This derate remained in effect until November 24, 2025, when the unit was taken offline for a planned outage to address the issue with the valves. The unit was returned to service on November 27, 2025, after successful resolution of the issue.

The performance of Unit 2 did not result in material impacts to the overall thermal plant performance in 2025.

The performance of Unit 3 was significantly impacted by a lengthy planned outage to complete the overhaul work. The unit was removed from service on March 30, 2025 and remained unavailable for the remainder of the year. From December 2, 2025, to December 18, 2025, the unit was on a forced extension of the planned outage due to additional work required to restore the stage #7 diaphragm in the intermediate pressure section of the turbine. For the remainder of December, the unit was on a planned outage to complete the turbine overhaul, which was extended due to an external cause; specifically, the failure of the turbine hall overhead crane at Holyrood. The unit has undergone re-assembly and returned to service on February 14, 2026. Commissioning activities remain ongoing, with load testing and safety valve testing planned for February 17, 2026.

Combustion Turbine Unit Performance

The performance of Hydro’s combustion turbines declined in 2025 for the fail rate and improved for the incapability factor and DAUFOP when compared to 2024. The decline in fail rate performance is the result of a decrease in total operating hours in 2025 when compared to 2024. In 2025, the combustion turbine assets experienced a combined approximately 230 operating hours, compared to 315 operating hours in 2024. The improvement in the incapability factor and DAUFOP can be attributed to a significant decrease in forced outage duration in 2025. In 2024, the Stephenville Gas Turbine was in a forced outage state for over 6,400 hours before returning to normal operation in September 2024. In 2025, the combined forced outage duration for the combustion turbine units was approximately 500 hours.

3.1.2 End Consumer Service Continuity Performance

The End Consumer Service Continuity Performance Index was developed to measure the reliability of service to all end consumers of electricity in the province who are supplied by Hydro, other than Hydro's Industrial customers. The measure is a combination of Hydro's service continuity data and Newfoundland Power's service continuity data for outages related to loss of supply due to events on Hydro's transmission system. Therefore, the SAIDI and SAIFI data provided in Table 5 are measures of the duration and frequency of service interruptions experienced as a result of Hydro system events.

Table 5 shows End Consumer Performance data for the fourth quarter of 2025 and 2024, annual 2025, annual 2024, and the 2025 annual target.

Table 5: End Consumer Performance

	Q4 2025	Q4 2024	2025 Annual	2024 Annual	2025 Annual Target (2020–2024 Average)
SAIDI	1.15	0.48	3.16	2.33	2.56
SAIFI	0.51	0.40	1.29	1.65	1.25

Hydro used the average of its End Consumer Service Continuity Indices performances for the period 2020–2024 for its 2025 annual targets.

Chart 3 and Chart 4 compare the fourth quarter performance for the past five years. Chart 5 and Chart 6 compare the annual performance for the past five years.

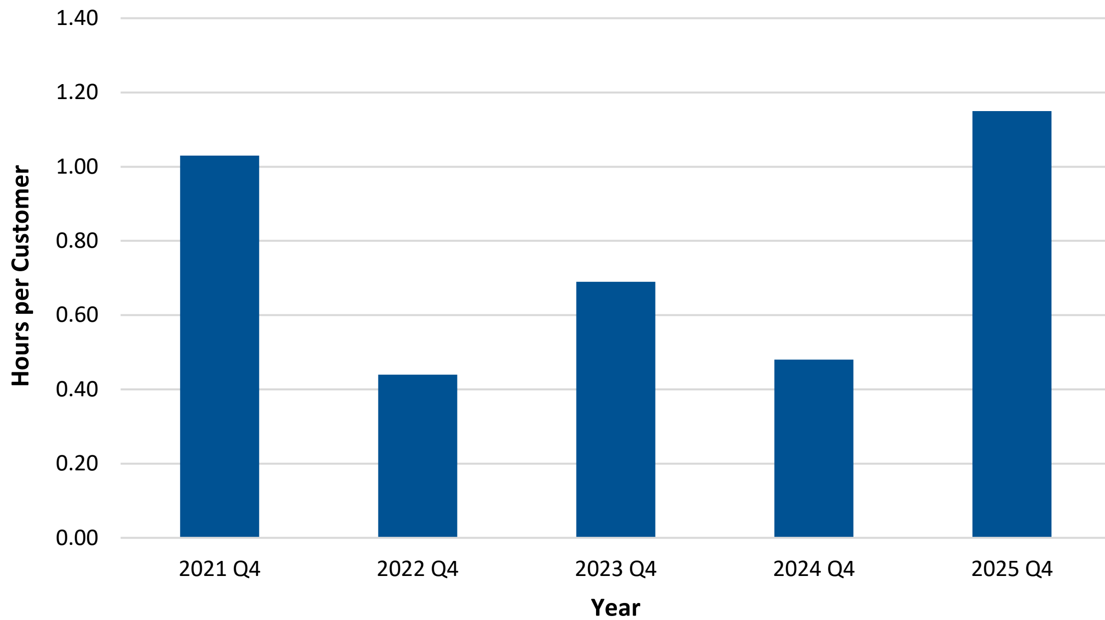

Chart 3: End-Consumer SAIDI Q4 2021–2025

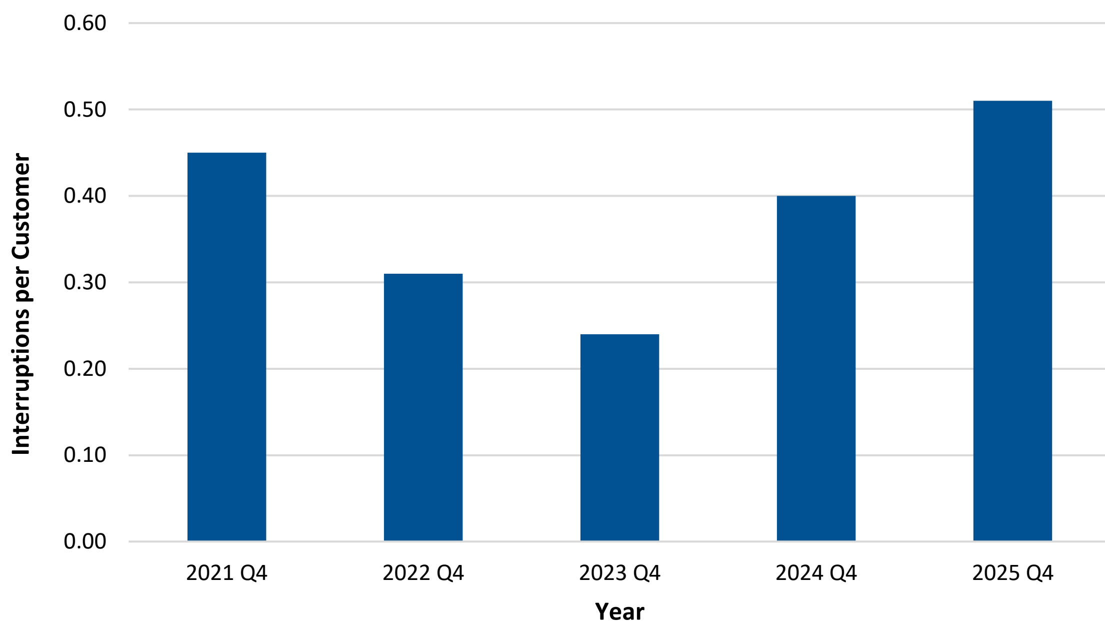

Chart 4: End-Consumer SAIFI Q4 2021–2025

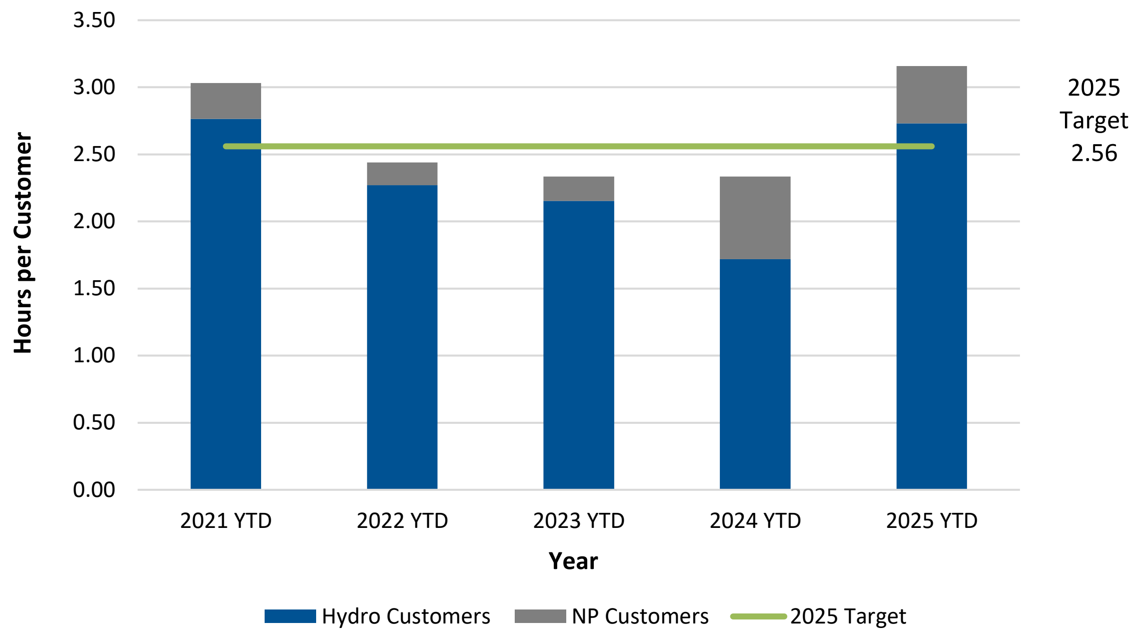

Chart 5: End-Consumer SAIDI Annual 2021–2025

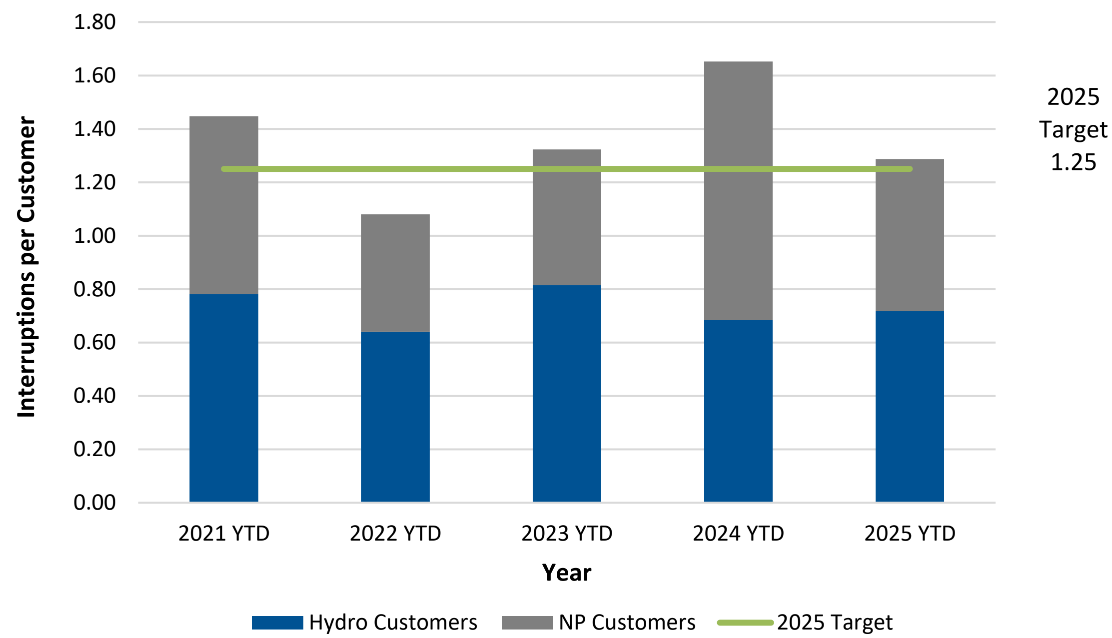

Chart 6: End-Consumer SAIFI Annual 2021–2025

3.1.3 Reliability Key Performance Indicator: Transmission

Transmission—System Average Interruption Duration Index

Table 6 shows the T-SAIDI data for the fourth quarter of 2025 and 2024, annual 2025, annual 2024, and the 2025 annual target.

Table 6: T-SAIDI (Outage Minutes per Delivery Point)

	Q4 2025	Q4 2024	2025 Annual	2024 Annual	2025 Annual Target (2020–2024 Average)
T-SAIDI	104.00	101.00	374.14	422.88	409.56

Hydro uses the average of its T-SAIDI performance for the period 2020–2024 to calculate its 2025 annual T-SAIDI target. Chart 7 shows the annual T-SAIDI performances for the period 2021–2025 and EC 2021–2024 annual T-SAIDI performances.

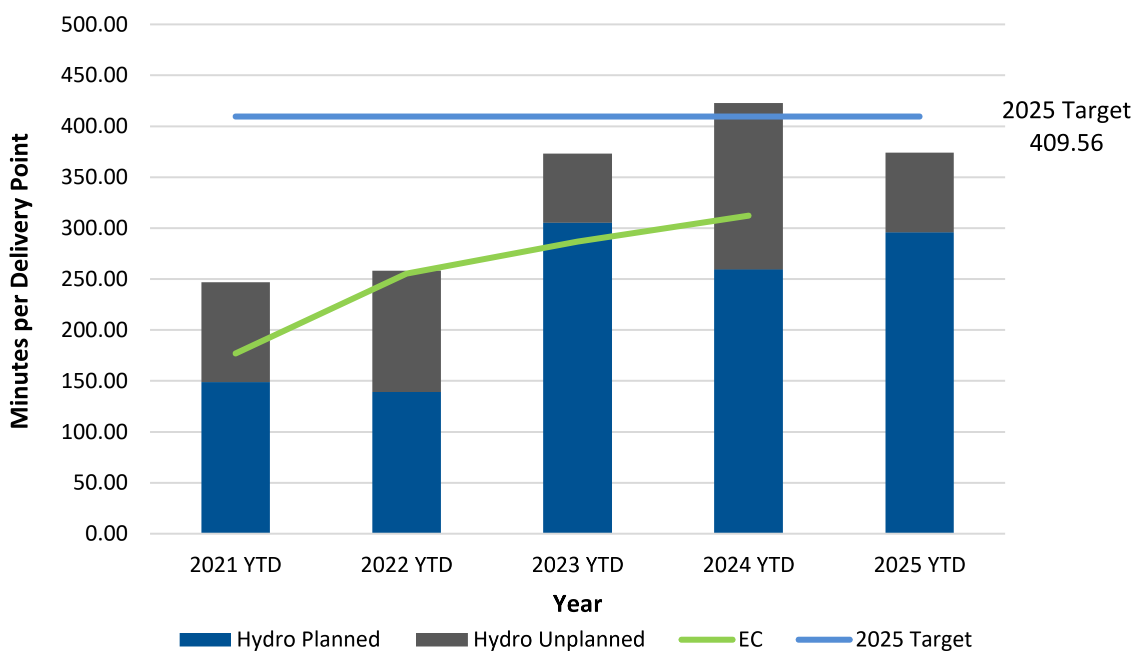

Chart 7: T-SAIDI[15]

[15] EC reliability data for 2025 is not yet available.

Transmission—System Average Interruption Frequency Index

Table 7 shows the T-SAIFI for planned and unplanned outages for the fourth quarter of 2025 and 2024, annual 2025, annual 2024, and the 2025 annual target.

Table 7: T-SAIFI (Outages per Delivery Point)

	Q4 2025	Q4 2024	2025 Annual	2024 Annual	2025 Annual Target (2020–2024 Average)
T-SAIFI	0.70	0.76	1.98	2.52	2.51

Hydro uses the average of its T-SAIFI performance for the period 2020–2024 to calculate its 2025 annual T-SAIFI target. Chart 8 shows the annual T-SAIFI performances for the period 2021–2025 and EC 2021–2024 annual T-SAIFI performances.

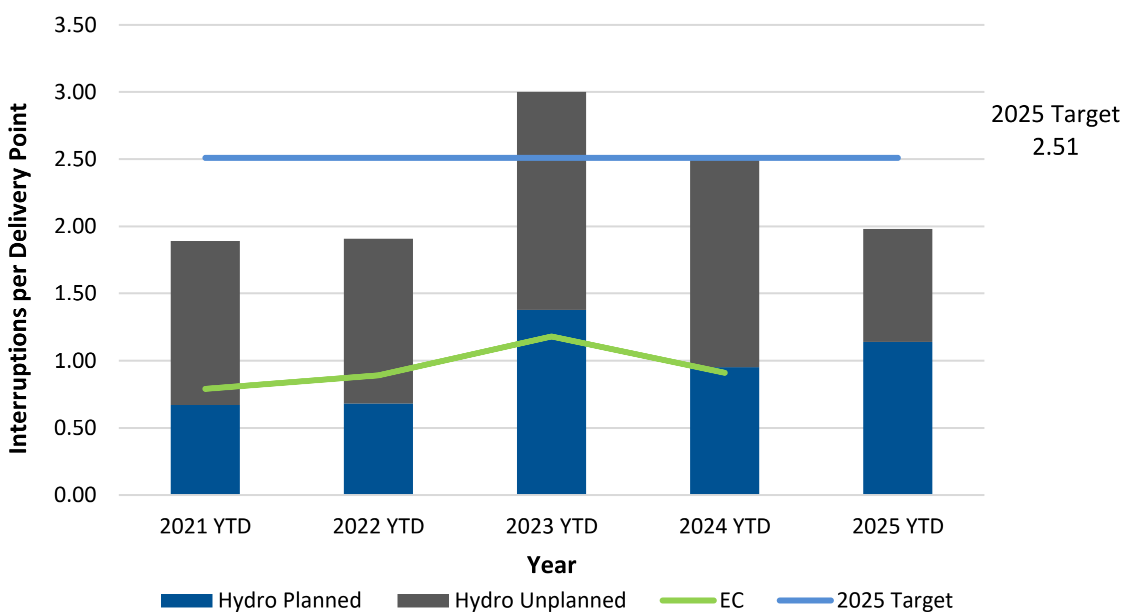

Chart 8: T-SAIFI[16]

[16] EC reliability data for 2025 is not yet available.

Transmission—System Average Restoration Index

Hydro's 2025 annual T-SARI was 189 minutes per interruption compared to 168 minutes per interruption for annual 2024. Hydro does not establish a restoration index target. T-SARI Chart 9 shows the annual T-SARI performance for the period 2021–2025 and the EC 2021–2024 annual T-SARI performances.

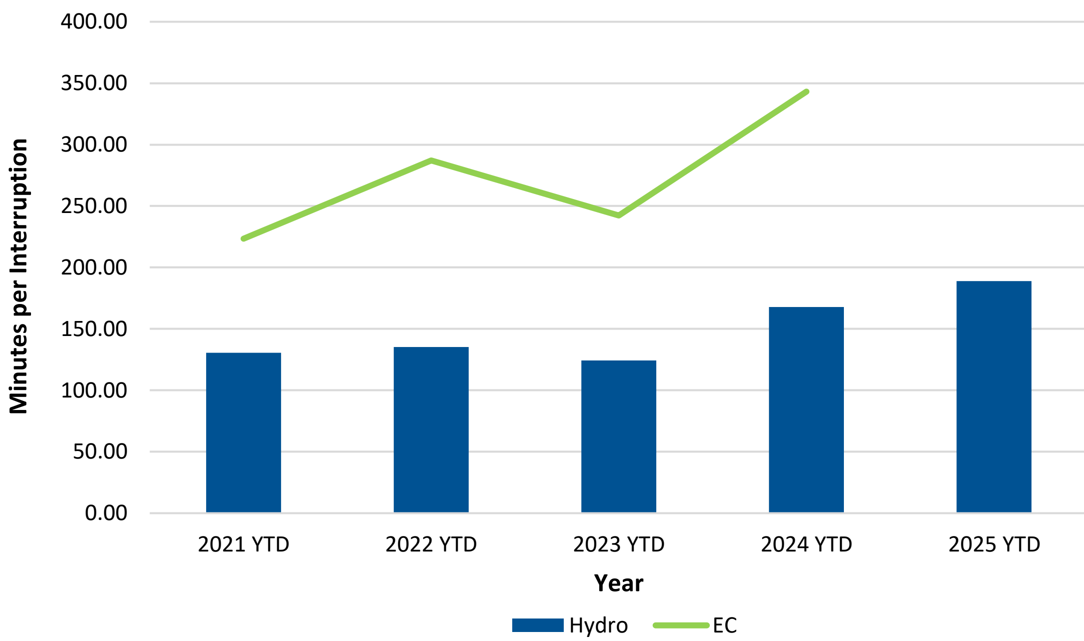

Chart 9: T-SARI[17]

3.1.4 Reliability Key Performance Indicator: Service Continuity Performance

Service Continuity System Average Interruption Duration Index

Table 8 shows the SAIDI performances for the fourth quarter of 2025 and 2024, annual 2025, annual 2024, and the 2025 annual target.

[17] EC reliability data for 2025 is not yet available.

Table 8: Service-Continuity SAIDI (Hours per Customer)[18,19]

	Q4 2025	Q4 2024	2025 Annual	2024 Annual	2025 Annual Target (2020–2024 Average)
SAIDI	8.98	2.99	21.09	13.26	17.30

1 Hydro uses the average of its Service-Continuity SAIDI performances for the period 2020–2024 as its
2 2025 annual target for this index.

3 Chart 10 Service-Continuity SAIDI shows EC 2021–2024 annual SAIDI performances and Hydro's 2021–
4 2025 annual SAIDI performances.

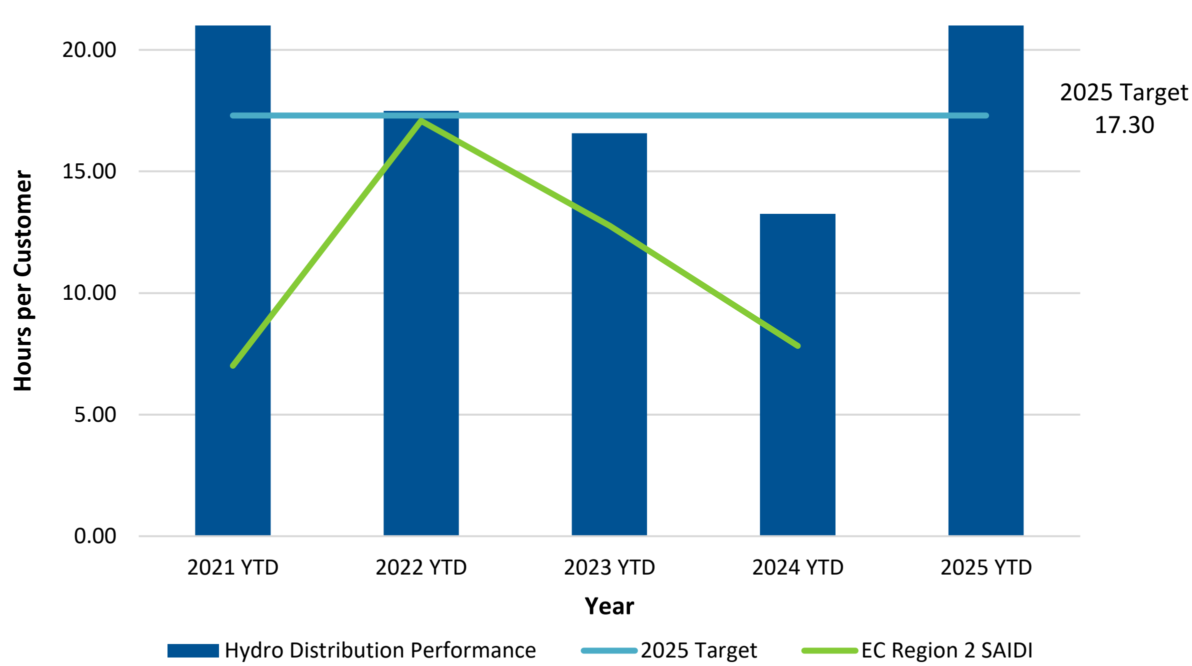

Chart 10: Service-Continuity SAIDI[20]

[18] Database upgrades have been completed, and the reporting methodology is currently under review.
[19] The outage database is live and continuously updated. Quarterly figures reflect data available at the time of each report and may be revised; therefore, cumulative quarterly totals may not align with the current year-to-date value. This detail is relevant for all Service Continuity values reported in this report.
[20] EC reliability data for 2025 is not yet available.

Service Continuity System Average Interruption Frequency Index

Table 9 shows the SAIFI for the fourth quarter of 2025 and 2024, annual 2025, annual 2024, and the 2025 annual target.

Table 9: Service-Continuity SAIFI (Interruptions per Customer)[21]

	Q4 2025	Q4 2024	Annual 2025	Annual 2024	2025 Annual Target (2020–2024 Average)
SAIFI	2.37	1.36	5.55	5.29	5.43

Hydro uses the average of its Service Continuity SAIFI Index Performances for the period 2020–2024 as its 2025 annual target for this index.

Chart 11 shows EC 2021–2024 annual SAIFI performances and Hydro's 2021–2025 annual SAIFI performances.

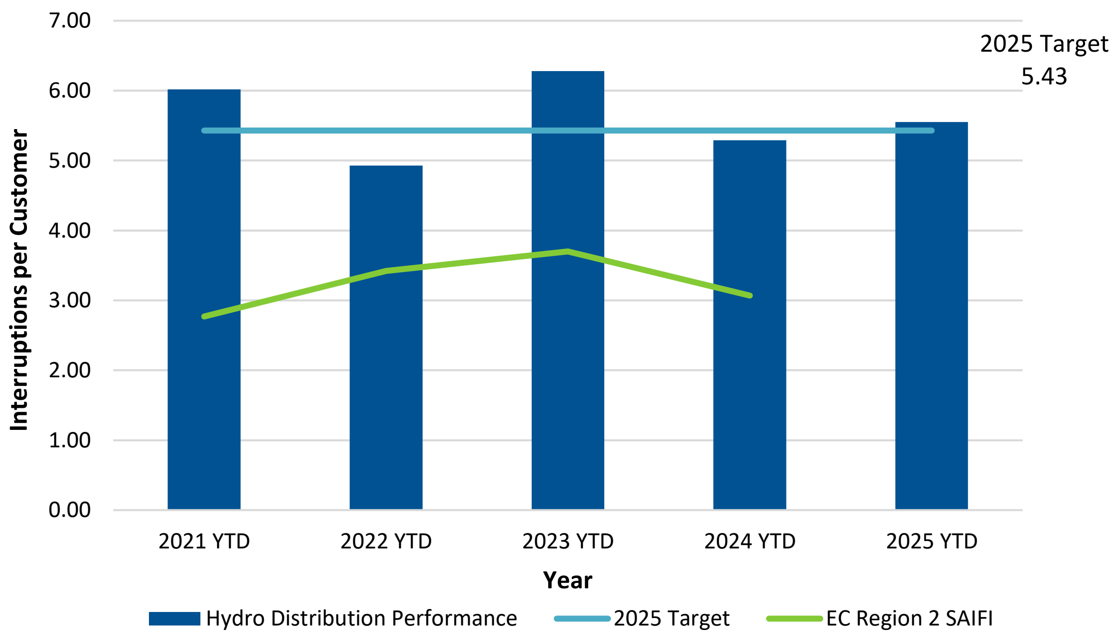

Chart 11: Service-Continuity SAIFI[22]

[21] Database upgrades have been completed and reporting methodology is currently under review.
[22] EC reliability data for 2025 is not yet available.

Additional Information

Service Continuity Performance by Area

Service Continuity SAIDI and SAIFI performance data, broken down by geographical area, are provided in Table 10 and Table 11, respectively.

Table 10: Service-Continuity SAIDI (Hours per Period)[23,24]

	Q4		Annual		2025 Annual
Area	**2025**	**2024**	**2025**	**2024**	**Target**
Labrador Region	5.77	0.84	5.95	7.50	N/A
Island Region	3.21	4.41	15.14	17.17	N/A
All Areas	8.98	2.99	21.09	13.26	17.30

Table 11: Service-Continuity SAIFI (Number per Period)[25,26]

	Q4		Annual		2025 Annual
Area	**2025**	**2024**	**2025**	**2024**	**Target**
Labrador Region	1.08	0.61	2.15	4.25	N/A
Island Region	1.29	1.85	3.40	5.99	N/A
All Areas	2.37	1.36	5.55	5.29	5.43

Service Continuity Performance by Origin

Service Continuity SAIDI and SAIFI values, broken down by origin, are provided in Table 12 and Table 13, respectively.

Table 12: Service-Continuity SAIDI (Hours per Period)[27]

	Q4		Annual		2025 Annual
Origin	**2025**	**2024**	**2025**	**2024**	**Target**
Loss of Supply: Transmission	3.20	1.39	6.81	5.55	N/A
Distribution	5.78	1.60	14.28	7.71	N/A
Totals	**8.98**	**2.99**	**21.09**	**13.26**	17.30

[23] Table updated to reflect current internal reporting.
[24] Historically, values for Labrador and Island Regions were calculated using their respective customer counts. To align with updated internal reporting, 2025 values and beyond will be displayed as a portion of the total.
[25] Table updated to reflect current internal reporting.
[26] Historically, values for Labrador and Island Regions were calculated using their respective customer counts. To align with updated internal reporting, 2025 values and beyond will be displayed as a portion of the total.
[27] Database upgrades have been completed and reporting methodology is currently under review.

Table 13: Service-Continuity SAIFI (Number per Period)[28]

Origin	Q4 2025	Q4 2024	Annual 2025	Annual 2024	2025 Annual Target
Loss of Supply: Transmission	0.86	0.66	1.82	2.16	N/A
Distribution	1.51	0.70	3.73	3.13	N/A
Totals	**2.37**	**1.36**	**5.55**	**5.29**	**5.43**

Service Continuity Performance by Type for the Fourth Quarter of 2025 Only

Table 14 shows the Service-Continuity SAIDI and SAIFI values for the fourth quarter of 2025 broken down by geographical area and interruption type. The area performance indicators are calculated using the area customer count. The all areas performance indicators are for all Hydro customers; therefore, the area performances cannot be summed to provide the all areas performances.

Table 14: Interruptions by Type[29]

Area	Q4 2025 Unplanned SAIDI	Q4 2025 Unplanned SAIFI	Q4 2025 Planned SAIDI	Q4 2025 Planned SAIFI	Q4 2025 Total SAIDI	Q4 2025 Total SAIFI
Labrador	1.67	0.83	1.55	0.25	3.21	1.08
Island	4.37	0.97	1.39	0.32	5.77	1.29
All Areas	**6.04**	**1.80**	**2.94**	**0.57**	**8.98**	**2.37**

[28] Database upgrades have been completed and reporting methodology is currently under review.
[29] Database upgrades have been completed and reporting methodology is currently under review.

Service Continuity Customer Interruptions by Cause

Table 15 shows the Service Continuity interruptions for the fourth quarter of 2025 and the annual 2025 grouped by cause.

Table 15: Interruptions by Cause[30,31]

	Q4 2025		2025 Annual	
Cause	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**
Adverse Environment	0.36	0.09	0.40	0.11
Adverse Weather	1.19	0.20	3.18	0.58
Defective Equipment	0.49	0.10	2.99	0.67
Foreign Interference	0.00	0.00	0.08	0.04
Human Error	0.00	0.00	0.15	0.04
Loss of Supply	3.20	0.86	6.81	1.82
Lightning	0.31	0.15	0.44	0.19
Distribution Planned	0.23	0.08	1.11	0.39
Tree Contacts	1.60	0.22	3.39	0.73
Undetermined/Other	1.59	0.67	2.53	0.97
Total	**8.98**	**2.37**	**21.09**	**5.55**

3.1.5 Reliability Key Performance Indicators: Other

Under Frequency Load Shedding

UFLS is the reliability KPI that measures the number of events in which shedding of customer load is required to counteract loss of generation capacity. During an UFLS event, customers are removed from the electrical system. The quantity of customers removed is linearly proportional to the amount of generation lost.

Table 16 shows the UFLS events for the fourth quarter of 2025 and 2024, Annual for 2025 and 2024, 2025 annual target, and 2020–2024 average by customer breakdown. Table 17 shows the UFLS undersupplied energy for the fourth quarter of 2025 and 2024, Annual for 2025 and 2024, and 2020–2024 average by customer breakdown. As individual UFLS events can affect customer types differently, total events may not be the sum of the customer types.

Chart 12 compares the number of UFLS events for the past five years.

[30] Outage cause codes updated to align with current EC reporting.
[31] Numbers may not add due to rounding.

Table 16: Customer Breakdown of UFLS Events

Customers	Q4 2025	Q4 2024	Annual 2025	Annual 2024	Annual Target 2025	Average 2020-2024
Newfoundland Power	1	1	3	4	N/A	1.8
Industrials	0	1	1	3	N/A	1.8
Hydro Rural	0	0	0	0	N/A	0.0
Total Events	**1**	**1**	**3**	**4**	**0**	**1.8**

Table 17: Customer Breakdown of UFLS Undersupplied Energy (MW-min)

Customers	Q4 2025	Q4 2024	Annual 2025	Annual 2024	Average 2020-2024
Newfoundland Power	1,545	747	5,073	1,842	2,750
Industrials	0	135	300	154	237
Hydro Rural	0	0	0	0	0
Total Undersupplied Energy	**1,545**	**882**	**5,373**	**1,996**	**2,987**

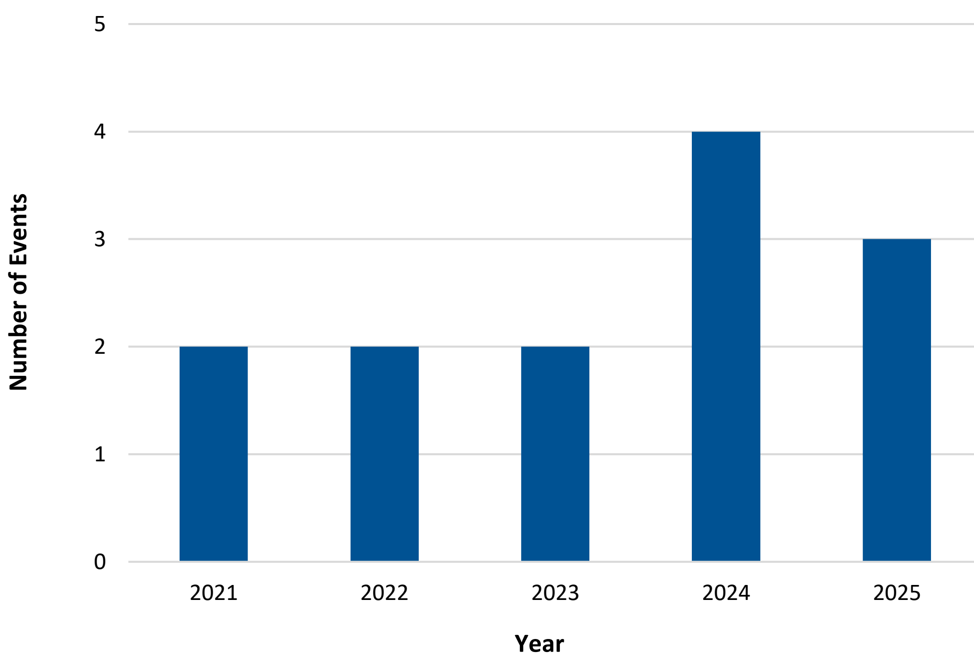

Chart 12: UFLS Events

3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which are associated with generation.

3.2.1 Operating Key Performance Indicator: Generation

Hydraulic Conversion Factor

As shown in Chart 13, in 2025, the hydraulic conversion factor for Bay d'Espoir was 0.4249 GWh/MCM, lower than the 2024 performance of 0.4286 GWh/MCM.

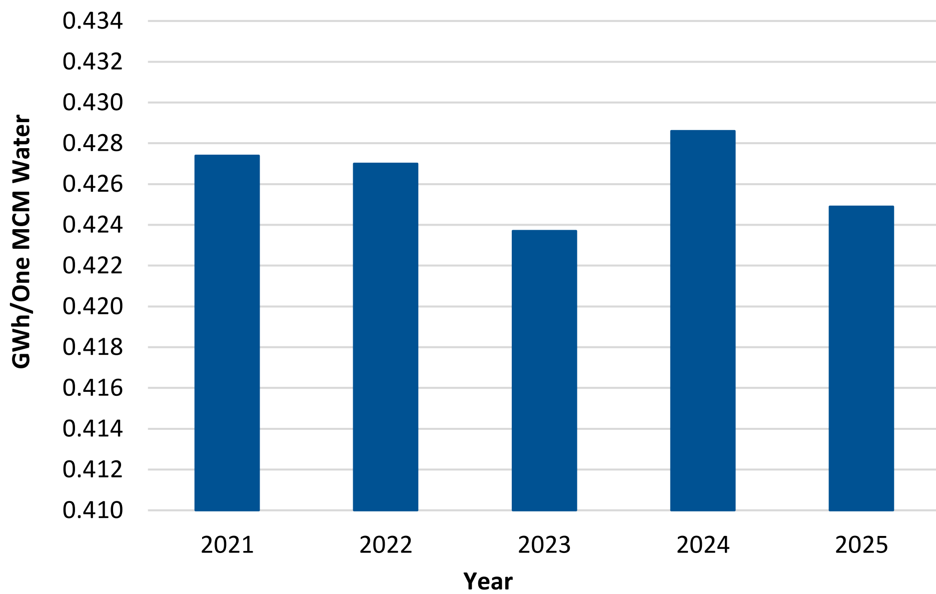

Chart 13: Hydraulic Conversion Factor (Bay d'Espoir)

In 2025, inflows to the Bay d'Espoir System as a whole were approximately 53% of average due to the Island experiencing prolonged drought conditions.

Inflows in the first quarter of 2025 were above average and marked by an early start to spring freshet along the Bay d'Espoir System. There were two significant rainfall events in March 2025. On March 2, 2025, 26 mm of rainfall was recorded at Burnt Dam, while 34 mm was recorded at Long Pond. A total of 45 mm of rainfall was recorded at Burnt Dam on March 7 and 8, while a total of 69 mm was recorded at Long Pond. Average daily temperatures above freezing were experienced on several occasions at multiple locations throughout the month, resulting in significant runoff from snow melt. The rain events combined with runoff from snow melt led to elevated water levels in Burnt Pond and

Granite Reservoir, eventually resulting in the requirement to bypass at the Granite Canal Bypass Structure on two occasions in the month, totalling a loss of 2.2 GWh.

Below-average inflows persisted throughout the second and third quarters, and spill and/or bypass did not occur. There were no significant weather events to note; however, overall conditions were very dry compared to the historical average. Commencing in September 2025, Hydro engaged Energy Marketing to seek imports over the Maritime Link to supplement reservoir storage while the LIL was on a planned bipole outage. Deliveries of energy to the Island Interconnected System from Labrador via the LIL were also being maximized to the extent possible to support Island reservoir storage. Despite efforts to conserve reservoir storage, overall system storage went below the minimum storage limits by the end of the quarter. Holyrood TGS was returned to service, and available units were used to further support reservoir storage.

At the beginning of the fourth quarter, inflows remained well below average, and Holyrood TGS continued to support reservoir storage. As system conditions allowed, two units operated above minimum for further support. There were five notable rain events throughout the month of November across Hydro's reservoir system, which resulted in an overall increase in system energy storage. These events brought a total of 256 mm of rainfall to the Bay d'Espoir System. By December, thermal generation was not required to support reservoir storage, and overall system storage was well above the minimum storage limits; however, remained below the 20-year average. Spill and/or bypass did not occur.

Below-average inflows into the Bay d'Espoir System due to the drought conditions persisted throughout the second, third, and into the fourth quarter of 2025. While generation was reduced to conserve reservoir storage, the dry conditions resulted in a decrease in the Bay d'Espoir KPI from the target level of 0.433 GWh/MCM.

The thermal conversion factor for the Holyrood TGS is proportional to the output level of its units, with higher averages and sustained loadings resulting in higher conversion factors. The output level at Holyrood TGS will vary depending on hydraulic production on the Island, quantity of power purchases (including LIL energy), customer energy requirements, system security requirements, and customer demand. The thermal conversion factor is also impacted by the heating content in the No. 6 fuel oil consumed at the plant, measured in BTU/bbl.

As shown in Chart 14, in 2025, Hydro's net thermal conversion factor was 566 kWh/bbl. The conversion factor is lower than the 2019 Test Year approved conversion factor of 583 kWh/bbl. The efficiency at the Holyrood TGS showed a decreased performance with a net heat rate performance of 10,975 BTU/kWh in 2025 compared to 10,756 BTU/kWh in 2024.

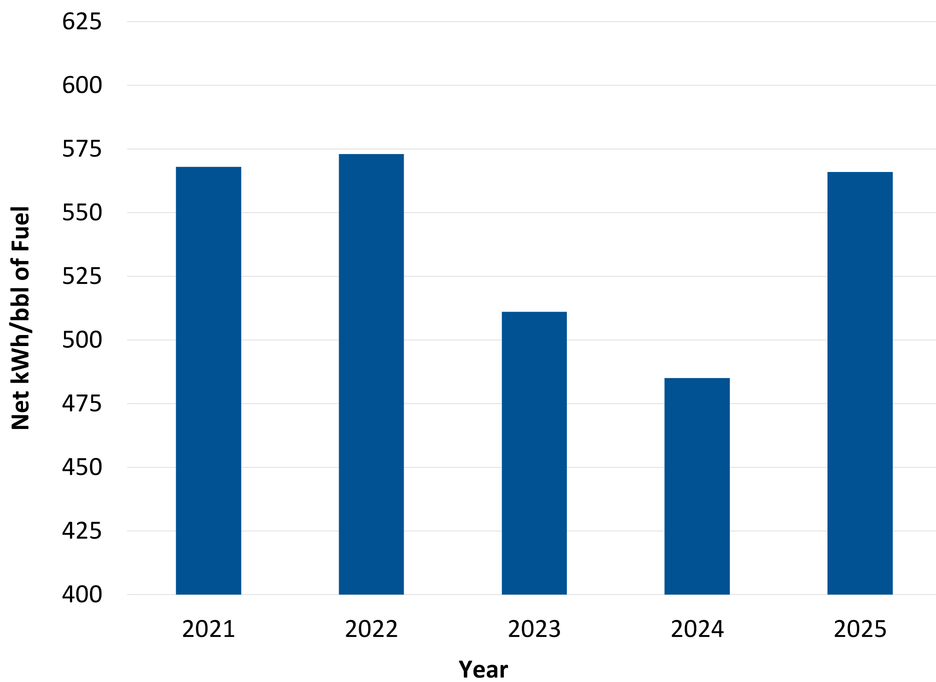

Chart 14: Thermal Conversion Factor (Holyrood TGS)

In 2025, the units were dispatched as required for system reliability support and system peak load considerations, in consideration of unit availability. The average net unit load, while operating, was 71.5 MW, an increase of 20% from 58.0 MW in 2024.

Energy production from the Holyrood TGS for 2025 was 728 GWh, a 9% increase from 2024 production levels of 666 GWh. The increase in energy production from the Holyrood TGS can be attributable to an increase in generation required to support the Island reservoir storage in the fall due to a prolonged drought period that occurred throughout the summer and into early fall that significantly decreased reservoir storage.

3.3 Financial Performance Indicators

Financial data will follow when audited financial results become available.

3.4 Customer-Related Performance Indicators

As shown in Chart 15, the 2024 residential customer satisfaction survey[32] showed that 89% of customers are either very satisfied or somewhat satisfied with Hydro. As this survey is conducted on a biennial basis, the 2024 survey results are the most recent available. The 2026 survey results are not yet available, but will be released once the audited financial statements are filed later this year.

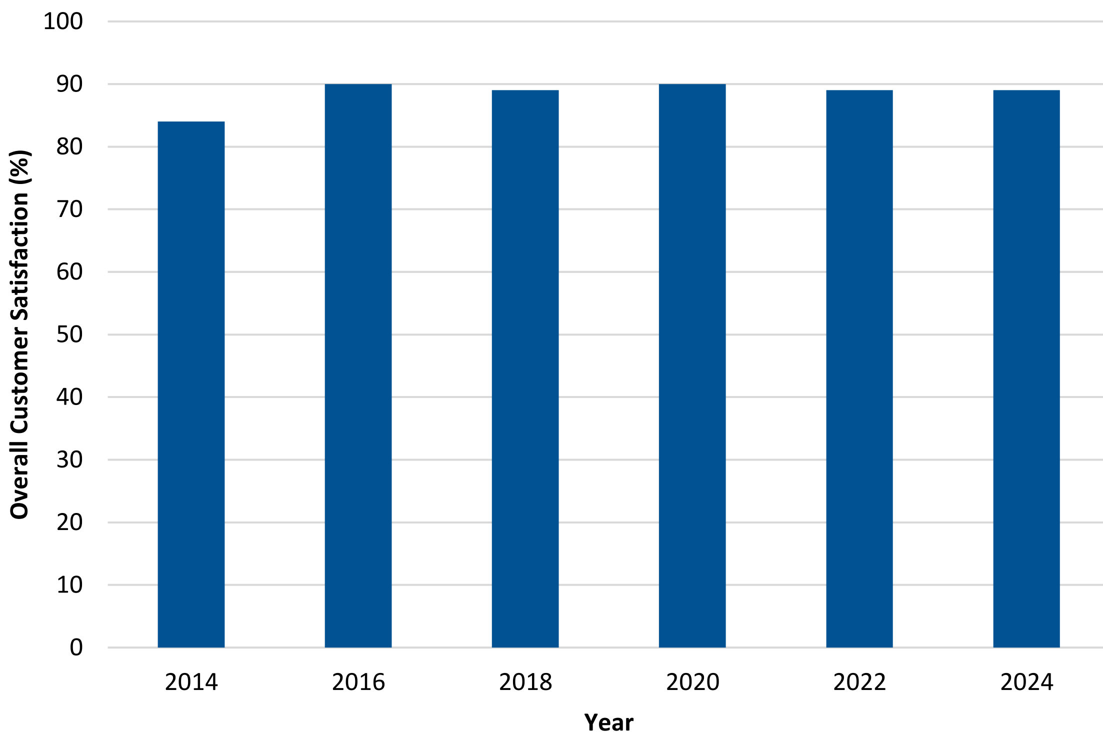

Chart 15: Residential Customer Satisfaction

[32] Residential customer satisfaction is an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI. The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced through regular surveys of Hydro's residential customers.

Attachment 1

Rationale for Hydro’s 2025 Key Performance Indicators Targets

Key Performance Indicators	Comment on Key Performance Indicators 2025 Target
Reliability	Hydro has adopted a target-setting approach wherein the five-year outage performance is used for distribution and transmission targets.
WCF	The target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The targets for outage performance were based on the five-year average performance.
Distribution SAIDI and SAIFI	The targets for outage performance were based on the five-year average performance.
UFLS	The target is set at 0 events.
Operating	
Hydraulic Conversion Factor	Held at the previous target value.
Thermal Conversion Factor	The target was 583 kWh/bbl based on the 2019 Test Year.

Attachment 2

Computation of Weighted Capability Factor and Factors Impacting Performance

newfoundland labrador hydro

WCF is calculated using the following formula:

$$1-\frac{\sum_{all\,units}\left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours}\right)}{\sum_{all\,units} unit\ MCR}$$

Where:

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by EC under nine categories, which are outlined on page 2 of this report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact WCF on a year-to-year basis, since MCR and unit hours are unlikely to change.

Factors that Affect Unit Total Equivalent Outage Time:

1) **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.

2) **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (ten minutes).

3) **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.

4) **Starting Failure**. A condition wherein a unit is unable to start.

5) **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.

6) **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.

7) **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.

8) **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is de-rated to remove a pump from service.

9) **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of EC equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Factors that Affect Unit Total Equivalent Outage Time:

1) **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.

2) **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (ten minutes).

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Note: There are hundreds of EC equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix E

Financial Schedules

(To be provided when audited financial information becomes available)

Attachment 1

Rate Stabilization Plan Report (Unaudited)

Quarter Ended December 31, 2025

Newfoundland and Labrador Hydro
Rate Stabilization Plan Report
December 31, 2025

Summary of Key Facts

The Rate Stabilization Plan ("RSP") of Newfoundland and Labrador Hydro ("Hydro") was established for Hydro's Utility customer, Newfoundland Power Inc. ("Newfoundland Power") and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 Fuel cost at Hydro's Holyrood Thermal Generating Station;
- Customer Load (Utility and Island Industrial); and
- Rural rates.

In Board Order No. P.U. 33(2021), the Board of Commissioners of Public Utilities (“Board”) approved the Supply Cost Variance Deferral Account ("SCVDA") to deal with future supply cost variances on the Island Interconnected System beginning in the month in which Hydro was required to begin payments under the Muskrat Falls Purchase Power Agreement (i.e., November 2021). The approval of the SCVDA discontinued transfers to the RSP, effective as of the implementation of the SCVDA, resulting from variations in future costs associated with the Test Year Cost of Service estimates for the items listed above. However, the Board directed that the RSP balances be maintained for the transparent and timely recovery of historical balances. The rules provide for the disposition of historical balances in accordance with the RSP Rules previously approved by the Board in Board Order No. P.U. 4(2022).

The Hydraulic Variation Account Balance as of October 31, 2021 was fully assigned to customers as of December 31, 2024 as per the Rate Stabilization Plan Rules for Balance Disposition approved by the Board in Board Order No. P.U. 4(2022).

Per Board Order No. P.U. 10(2025), finance charges are calculated on the balances using the approved weighted average cost of capital, which is currently 5.45% per annum effective January 1, 2025.

Rate Stabilization Plan
Summary of Utility Customer
December 31, 2025

	A	B	C	D	E	F	G	H
	Load Variation ($)	Allocation Fuel Variance ($)	Allocation Rural Rate Alteration ($)	Subtotal Monthly Variances ($)	Financing Charges ($)	Adjustment[1,2] ($)	Transfers[3] ($)	Cumulative Net Balance ($)
				(A + B + C)				(to page 4)
Opening Balance								30,588,113
Adjustment								-
Adjusted Opening Balance								**30,588,113**
January	-	-	-	-	135,567	(3,129,390)	-	27,594,290
February	-	-	-	-	122,298	(3,216,944)	-	24,499,644
March	-	-	-	-	108,583	(2,800,744)	6,462,978	28,270,461
April	-	-	-	-	125,295	(2,485,782)	-	25,909,974
May	-	-	-	-	114,834	(2,122,955)	-	23,901,853
June	-	-	-	-	105,933	(1,451,101)	-	22,556,685
July	-	-	-	-	99,972	(1,300,555)	-	21,356,102
August	-	-	-	-	94,651	(1,300,916)	-	20,149,837
September	-	-	-	-	89,304	(1,300,192)	-	18,938,949
October	-	-	-	-	83,938	(1,683,535)	-	17,339,352
November	-	-	-	-	76,848	(2,069,688)	-	15,346,512
December	-	-	-	-	68,016	(2,796,933)	-	12,617,595
YTD	-	-	-	-	1,225,239	(25,658,735)	6,462,978	(17,970,518)
Total	**-**	**-**	**-**	**-**	**1,225,239**	**(25,658,735)**	**6,462,978**	**12,617,595**

[1] Effective August 1, 2024, the RSP Adjustment rate is 0.461 cents per kWh as per Board Order No. P.U. 15(2024).

[2] Effective July 1, 2025, the RSP Adjustment rate is 0.413 cents per kWh as per Board Order No. P.U. 22(2025).

[3] Recovery of the 2024 Isolated Systems Supply Costs Deferral was approved in Board Order No. P.U. 13(2025).

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2025

	A	B	C	D	E	F	G
	Load Variation ($)	**Allocation Fuel Variance ($)**	**Subtotal Monthly Variances ($) (A + B)**	**Financing Charges ($)**	**Adjustment[1] ($)**	**Transfers ($)**	**Cumulative Net Balance ($) (to page 4)**
Opening Balance							399,333
Adjustment							-
Adjusted Opening Balance							**399,333**
January	-	-	-	1,770	(36,356)	-	364,747
February	-	-	-	1,617	(27,586)	-	338,778
March	-	-	-	1,501	(36,558)	-	303,721
April	-	-	-	1,346	(28,527)	-	276,540
May	-	-	-	1,226	(37,655)	-	240,111
June	-	-	-	1,064	(35,751)	-	205,424
July	-	-	-	910	(43,080)	-	163,254
August	-	-	-	724	(44,454)	-	119,524
September	-	-	-	530	(45,466)	-	74,588
October	-	-	-	331	(41,095)	-	33,824
November	-	-	-	150	(33,598)	-	376
December	-	-	-	2	(52,194)	-	(51,816)
YTD	-	-	-	11,171	(462,320)	-	(451,149)
Total	**-**	**-**	**-**	**11,171**	**(462,320)**	**-**	**(51,816)**

[1] Effective January 1, 2025, the RSP Adjustment rate is 0.093 cents per kWh as per Board Order No. P.U. 7(2025).

Rate Stabilization Plan
Overall Summary
December 31, 2025

	A	B	C
	Utility Balance ($)	**Industrial Balance ($)**	**Total To Date ($)**
			(A + B)
	(from page 2)	**(from page 3)**	
Opening Balance	30,588,113	399,333	30,987,446
Adjustments	-	-	-
Adjusted Opening Balance	**30,588,113**	**399,333**	**30,987,446**
January	27,594,290	364,747	27,959,037
February	24,499,644	338,778	24,838,422
March	28,270,461	303,721	28,574,182
April	25,909,974	276,540	26,186,514
May	23,901,853	240,111	24,141,964
June	22,556,685	205,424	22,762,109
July	21,356,102	163,254	21,519,356
August	20,149,837	119,524	20,269,361
September	18,938,949	74,588	19,013,537
October	17,339,352	33,824	17,373,176
November	15,346,512	376	15,346,888
December	12,617,595	(51,816)	12,565,779

Attachment 2

Supply Cost Variance Deferral Account Report (Unaudited)

Quarter Ended December 31, 2025

Newfoundland and Labrador Hydro
Supply Cost Variance Deferral Account
December 31, 2025

Summary of Key Facts
In Board Order No. P.U. 33(2021), the Board of Commissioners of Public Utilities ("Board") approved Hydro's proposal to establish an account to defer payments under the Muskrat Falls Project agreements, rate mitigation funding, project cost recovery from customers and supply cost variances.

In Board Order No. P.U. 4(2022), the Board approved the Supply Cost Deferral Account definition with an effective date of November 1, 2021.

The Cost Variance Threshold of +/- $500,000 on the Other Island Interconnected System Supply Cost Variance component commenced January 1, 2022. This avoided duplication of the Cost Variance Threshold already applied to the Revised Energy Supply Cost Variance Deferral Account as of October 31, 2021.

Financing charges accrued at the 2024 short-term cost of borrowing of 5.03% for the period of January to November 2025. In December, financing costs were trued-up to reflect the actual short-term cost of borrowing for 2025 of 3.35%.

Supply Cost Variance Deferral Account[1]
Summary
December 31, 2025

	Supply Cost Variance Deferral Account Balance ($) (from page 3)	Utility[2] Balance ($) (from page 4)	Industrial Balance ($) (from page 5)	Total to Date ($)
Opening Balance	554,338,269	(22,623,806)	-	**531,714,463**
Adjustment	-	-	-	**-**
Adjusted Opening Balance	**554,338,269**	**(22,623,806)**	**-**	**531,714,463**
January	588,411,644	(24,241,266)	-	**564,170,378**
February	180,289,526	(26,140,997)	-	**154,148,529**
March	264,428,192	(27,778,636)	-	**236,649,556**
April	322,917,903	(29,382,460)	-	**293,535,443**
May	365,616,143	(30,750,936)	-	**334,865,207**
June	418,674,576	(31,599,806)	-	**387,074,770**
July	476,614,986	(32,726,595)	-	**443,888,391**
August	377,412,977	(33,786,603)	-	**343,626,374**
September	434,824,943	(34,861,370)	-	**399,963,573**
October	476,213,525	(36,179,161)	-	**440,034,364**
November	518,308,228	(37,997,838)	-	**480,310,390**
December	390,740,090	(40,366,584)	-	**350,373,506**

[1] Numbers may not add throughout the report due to rounding.

[2] Financing charges accrued at the 2024 short-term cost of borrowing of 5.03% for the period of January to November 2025. In December, the interest expense was trued-up for the year based on the short-term interest rate for 2025 of 3.35%.

Supply Cost Variance Deferral Account
Section A: Summary
December 31, 2025

			Project Cost Recovery Rider						Load Variation				Financing Charges[1]				
	Muskrat Falls Project Cost Variance ($)	Rate Mitigation Fund[2,3] ($)	Utility[4] ($)	Industrial[5] ($)	Holyrood TGS[6] Fuel Cost Variance ($)	Other IIS[7] Supply Cost Variance ($)	Net Revenue From Exports Variance[8,9] ($)	Transmission Tariff Revenue Variance ($)	Utility[10] ($)	Industrial ($)	Greenhouse Gas Credit Revenue Variance[11] ($)	Subtotal Monthly Variances ($)	Utility ($)	Industrial ($)	Other ($)	Transfers ($)	Cumulative Net Balance ($)
	(from page 6)	(from page 15)			(from page 7)	(from page 8)	(from page 9)	(from page 10)	(from page 11)	(from page 12)	(from page 14)						(to page 2)
Opening Balance	1,565,667,129	(575,433,434)	(118,120,018)	(3,949,867)	(169,459,883)	(74,168,156)	(125,975,029)	(44,759,484)	71,094,076	49,633,069	(55,600,303)	518,928,100	(6,870,157)	(83,286)	42,363,612	-	554,338,269
Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Adjusted Opening Balance	**1,565,667,129**	**(575,433,434)**	**(118,120,018)**	**(3,949,867)**	**(169,459,883)**	**(74,168,156)**	**(125,975,029)**	**(44,759,484)**	**71,094,076**	**49,633,069**	**(55,600,303)**	**518,928,100**	**(6,870,157)**	**(83,286)**	**42,363,612**	**-**	**554,338,269**
January	63,252,043	-	(7,630,010)	(541,038)	(22,981,814)	(2,129,352)	(450,605)	(1,498,023)	3,546,897	1,058,632	(77,618)	32,549,112	(324,794)	(10,861)	1,859,918	-	588,411,644
February	63,572,270	(441,000,000)	(7,843,481)	(410,521)	(15,854,148)	(2,835,601)	(346,785)	(1,498,127)	(4,782,917)	1,259,237	-	(409,740,073)	(345,775)	(12,349)	1,976,079	-	180,289,526
March	88,848,280	-	(6,828,712)	(544,039)	4,902,645	(5,435,736)	(409,673)	(1,498,023)	3,730,178	1,062,312	(184,308)	83,642,924	(367,342)	(13,477)	876,561	-	264,428,192
April	63,377,303	-	(6,060,778)	(424,524)	2,244,723	(558,482)	(295,801)	(1,498,023)	(386,216)	1,364,987	(576)	57,762,613	(386,119)	(14,973)	1,128,190	-	322,917,903
May	56,707,440	-	(5,176,142)	(560,378)	(5,970,598)	(1,017,946)	(343,726)	(1,498,023)	(1,301,717)	996,754	(25,351)	41,810,313	(402,784)	(16,141)	1,306,852	-	365,616,143
June	65,911,307	-	(3,538,042)	(532,034)	(3,120,731)	(1,165,181)	(6,019,721)	(1,498,023)	1,020,541	994,450	533	52,053,099	(417,017)	(17,682)	1,440,033	-	418,674,576
July	64,693,800	-	(4,773,950)	(765,258)	102,126	(1,029,689)	(397,818)	(1,498,023)	(234,927)	711,885	(18,965)	56,789,181	(426,745)	(19,145)	1,597,119	-	476,614,986
August	57,916,699	(150,000,000)	(4,775,276)	(789,648)	41,664	(1,228,914)	(348,682)	(1,498,023)	(486,056)	655,365	314	(100,512,557)	(439,872)	(21,249)	1,771,669	-	377,412,977
September	65,078,915	-	(4,772,619)	(807,641)	(2,879,139)	1,017,812	(222,257)	(1,498,023)	(10,617)	536,290	(68,527)	56,374,194	(453,003)	(23,420)	1,514,195	-	434,824,943
October	64,104,672	-	(6,179,756)	(729,993)	3,040,552	(3,724,639)	(104,992)	(1,498,023)	203,400	832,975	(15,751,252)	40,192,944	(466,126)	(25,641)	1,687,405	-	476,213,525
November	55,491,413	-	(7,597,208)	(596,816)	(2,717,830)	(3,013,686)	(182,062)	(1,498,023)	(189,002)	1,088,097	376	40,785,259	(483,119)	(27,648)	1,820,211	-	518,308,228
December	63,714,625	(113,400,000)	(10,266,707)	(927,148)	(11,549,091)	(5,056,867)	(49,077,770)	(1,498,023)	(1,272,706)	339,947	411	(128,993,329)	(504,009)	(29,289)	1,958,489	-	390,740,090
YTD	**772,668,767**	**(704,400,000)**	**(75,442,681)**	**(7,629,038)**	**(54,741,641)**	**(26,178,281)**	**(58,199,892)**	**(17,976,380)**	**(163,142)**	**10,900,931**	**(16,124,963)**	**(177,286,320)**	**(5,016,705)**	**(231,875)**	**18,936,721**	**-**	**(163,598,179)**
Total	**2,338,335,896**	**(1,279,833,434)**	**(193,562,699)**	**(11,578,905)**	**(224,201,524)**	**(100,346,437)**	**(184,174,921)**	**(62,735,864)**	**70,930,934**	**60,534,000**	**(71,725,266)**	**341,641,780**	**(11,886,862)**	**(315,161)**	**61,300,333**	**-**	**390,740,090**

[1] Financing charges accrued at the 2024 short-term cost of borrowing of 5.03% for the period of January to November 2025. In December, the interest expense was trued-up for the year based on the short-term interest rate for 2025 of 3.35%.

[2] As per Order in Council OC2024-062 dated May 7, 2024, Newfoundland and Labrador Hydro ("Hydro") has been directed by the Government of Newfoundland and Labrador ("Government") to use its own sources of rate mitigation and accordingly, in February 2025, transferred $441.0 million of funding to its Regulated operations. The $441.0 million includes $90.6 million of rate mitigation funding related to the retirement of the 2023 Supply Cost Variance Deferral Account of $271 million over the 2024 to 2026 period. Additionally, in December 2025, pursuant to OC2024-062 and OC2024-063, Government directed Hydro to transfer $113.4 million of rate mitigation funding to its Regulated operations through the use of its own funding.

[3] In 2022, as part of the Government's rate mitigation plan, Hydro, the Government and the Government of Canada signed term sheets enabling access, upon commissioning of the Labrador-Island Link ("LIL"), to a $1.0 billion investment by the Government of Canada in the LIL in the form of a convertible debenture. In August 2025, funding was received by LIL (2021) Limited Partnership, and transferred to Hydro for the purpose of rate mitigation, reducing the balance in the Supply Cost Variance Deferral Account.

[4] As per Order No. P.U. 22(2025), the Board of Commissioners of Public Utilities ("Board") approved a Project Cost Recovery Rider of 1.516 cents per kWh effective July 1, 2025.

[5] As per Order No. P.U. 7(2025), the Board approved a Project Cost Recovery Rider of 1.384 cents per kWh effective January 1, 2025 and, in Order No. P.U. 28(2025), the Board approved a Project Cost Recovery Rider of 1.652 cents per kWh effective July 1, 2025.

[6] Holyrood Thermal Generating Station ("Holyrood TGS").

[7] Island Interconnected System ("IIS").

[8] As per Board Order No. P.U. 21(2025), the Board approved the transfer of the $5,711,673 credit balance, as of December 31, 2023, in the Hydraulic Resources Optimization Deferral Account to the Net Revenue from Exports component within the Supply Cost Variance Deferral Account.

[9] In December, the account included an estimate of net export sales that occurred during 2025 but the actual settlement value will not be finalized until the first quarter of 2026.

[10] As per Board Order No. P.U. 1(2025), the Board approved a wholesale rate, effective as of January 1, 2025, to be charged to Utility of 9.698 cents per kWh for winter months of December to March and 3.354 cents per kWh for the non-winter months of April to November.

[11] In October 2025, Hydro sold 211,700 Greenhouse Gas Performance Credits within the Province for $15.8 million.

Supply Cost Variance Deferral Account
Section B: Utility Customer Balance
December 31, 2025

	Allocation Rural Rate Alteration[1] ($)	Financing Charges[2] ($)	Transfers ($)	Cumulative Net Balance ($)
	(from page 13)			**(to page 2)**
Opening Balance	(21,135,737)	(1,488,069)	-	(22,623,806)
Adjustments	-	-	-	-
Adjusted Opening Balance	**(21,135,737)**	**(1,488,069)**	**-**	**(22,623,806)**
January	(1,555,251)	(62,209)	-	(24,241,266)
February	(1,833,075)	(66,656)	-	(26,140,997)
March	(1,565,759)	(71,880)	-	(27,778,636)
April	(1,527,441)	(76,383)	-	(29,382,460)
May	(1,287,683)	(80,793)	-	(30,750,936)
June	(764,314)	(84,556)	-	(31,599,806)
July	(1,039,899)	(86,890)	-	(32,726,595)
August	(970,020)	(89,988)	-	(33,786,603)
September	(981,864)	(92,903)	-	(34,861,370)
October	(1,221,933)	(95,858)	-	(36,179,161)
November	(1,719,195)	(99,482)	-	(37,997,838)
December	(2,264,263)	(104,483)	-	(40,366,584)
YTD	**(16,730,697)**	**(1,012,081)**	**-**	**(17,742,778)**
Total	**(37,866,434)**	**(2,500,150)**	**-**	**(40,366,584)**

[1] The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion that the rural deficit was allocated in the approved 2019 Cost of Service Study, which is 96.1% and 3.9%, respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

The only transactions posted to the Utility's Customer Balance are Newfoundland Power's allocation of Rural Rate Alteration and associated interest until further approval is obtained from the Board.

[2] For the period January to November 2025, the interest rate applied to the deferral account balance was 5.03% based on the prior year-end rate. In December 2025, the interest expense was trued-up for the year based on the short-term interest rate for 2025 of 3.35%.

Supply Cost Variance Deferral Account
Section B: Industrial Customers Balance[1]
December 31, 2025

	Financing Charges ($)	Transfers ($)	Cumulative Net Balance ($) (to page 2)
Opening Balance	-	-	-
January	-	-	-
February	-	-	-
March	-	-	-
April	-	-	-
May	-	-	-
June	-	-	-
July	-	-	-
August	-	-	-
September	-	-	-
October	-	-	-
November	-	-	-
December	-	-	-
YTD	-	-	-
Total	-	-	-

[1] No transactions will be applied to this balance until further approval is obtained from the Board.

Supply Cost Variance Deferral Account
Muskrat Falls Project Cost Variances
December 31, 2025

	Muskrat Falls PPA[1] Charges Actual ($) (A)	Muskrat Falls PPA Charges Test Year ($) ($A_T$)	TFA[2] Charges Actual ($) (B)	TFA Charges Test Year ($) ($B_T$)	Total Variation ($) $(A - A_T) + (B - B_T)$ (to page 3)
January	23,834,984	-	39,417,059	-	**63,252,043**
February	24,145,673	-	39,426,598	-	**63,572,270**
March	53,625,184	-	35,223,096	-	**88,848,280**
April	24,099,424	-	39,277,880	-	**63,377,303**
May	21,546,193	-	35,161,247	-	**56,707,440**
June	24,793,250	-	41,118,057	-	**65,911,307**
July	24,090,665	-	40,603,134	-	**64,693,800**
August	22,302,051	-	35,614,648	-	**57,916,699**
September	23,597,702	-	41,481,213	-	**65,078,915**
October	23,585,381	-	40,519,291	-	**64,104,672**
November	22,265,955	-	33,225,458	-	**55,491,413**
December	23,943,902	-	39,770,723	-	**63,714,625**
Total	**311,830,363**	**-**	**460,838,405**	**-**	**772,668,767**

[1] Power Purchase Agreement ("PPA").
[2] Transmission Funding Agreement ("TFA").

Supply Cost Variance Deferral Account
Holyrood TGS Fuel Cost Variance
December 31, 2025

	Actual Quantity No. 6 Fuel (bbl.)	Actual Quantity No. 6 Fuel for Non-Firm Sales[1] (bbl.)	Net Quantity No. 6 Fuel (bbl.)	Actual Average No. 6 Fuel Cost ($Can./bbl)	Actual ($)	Test Year Quantity No. 6 Fuel (bbl.)	Test Year No. 6 Fuel Cost ($Can./bbl)	Test Year ($)	Total Variation ($)
					C			C_T	$(C - C_T)$ (to page 3)
January	185,467	1,815	183,651	117.70	21,616,065	421,132	105.90	44,597,879	**(22,981,814)**
February	194,566	1,029	193,537	116.76	22,596,766	363,087	105.90	38,450,913	**(15,854,148)**
March[2]	209,605	774	208,831	114.08	23,822,951	178,662	105.90	18,920,306	**4,902,645**
April	124,637	539	124,098	107.59	13,352,469	104,889	105.90	11,107,745	**2,244,723**
May	7,310	-	7,310	107.61	786,669	63,808	105.90	6,757,267	**(5,970,598)**
June[3]	(169)	-	(169)	107.61	(18,178)	29,297	105.90	3,102,552	**(3,120,731)**
July	949	-	949	107.61	102,126	-	105.90	-	**102,126**
August	387	-	387	107.61	41,664	-	105.90	-	**41,664**
September	35,633	1,619	34,014	107.61	3,660,186	61,750	105.90	6,539,325	**(2,879,139)**
October	154,186	349	153,837	107.61	16,555,086	127,616	105.90	13,514,534	**3,040,552**
November	202,489	194	202,295	102.72	20,780,003	221,887	105.90	23,497,833	**(2,717,830)**
December	171,678	3,578	168,100	96.89	16,286,936	262,852	105.90	27,836,027	**(11,549,091)**
Total	**1,286,739**	**9,898**	**1,276,841**	**109.32**	**139,582,742**	**1,834,980**	**105.90**	**194,324,382**	**(54,741,641)**

[1] Includes non-firm sales to Island Industrial Customers and supply of emergency energy to Nova Scotia.

[2] Immaterial adjustment of 4 from 770 reported in March 2025.

[3] Immaterial adjustment for June 2025 for No. 6 barrels that had no impact on ending balance.

Supply Cost Variance Deferral Account
Other IIS Supply Cost Variance Summary
December 31, 2025

	Thermal Variation[1] ($)	Off-Island Power Purchase Variation[1] ($)	On-Island Power Purchase Variation[1] ($)	CBPP Firm Energy Variation[1] ($)	Current Month Variation ($)	Year-to-Date Variation ($)	Cost Variance Threshold[2] ($)	Other IIS Supply Cost Variance ($)
	(D)	(E)	(F)	(G)	(D + E + F + G)			
January	(1,073,331)	(472,575)	(1,083,446)	-	(2,629,352)	(2,629,352)	(500,000)	(2,129,352)
February	391,739	(2,589,278)	(638,062)	-	(2,835,601)	(5,464,953)	(500,000)	(4,964,953)
March	(744,755)	(5,908,637)	1,217,656	-	(5,435,736)	(10,900,689)	(500,000)	(10,400,689)
April	25,061	(145,082)	(438,461)	-	(558,482)	(11,459,171)	(500,000)	(10,959,171)
May	(121,516)	174	(896,604)	-	(1,017,946)	(12,477,117)	(500,000)	(11,977,117)
June	(565,106)	-	(600,075)	-	(1,165,181)	(13,642,298)	(500,000)	(13,142,298)
July	(119,354)	-	(910,335)	-	(1,029,689)	(14,671,987)	(500,000)	(14,171,987)
August	(97,796)	24,667	(1,155,785)	-	(1,228,914)	(15,900,901)	(500,000)	(15,400,901)
September	1,325	3,090,984	(2,074,497)	-	1,017,812	(14,883,089)	(500,000)	(14,383,089)
October	159,845	(1,067,045)	(2,817,439)	-	(3,724,639)	(18,607,728)	(500,000)	(18,107,728)
November	41,293	(1,655,565)	(1,399,414)	-	(3,013,686)	(21,621,414)	(500,000)	(21,121,414)
December	(1,193,194)	(2,148,169)	(1,715,504)	-	(5,056,867)	(26,678,281)	(500,000)	(26,178,281)
Total	**(3,295,789)**	**(10,870,526)**	**(12,511,966)**	**-**	**(26,678,281)**			

[1] The calculation of the variation by source is provided in Appendix A. Given no variation of Corner Brook Pulp and Paper Ltd. ("CBPP") Firm Energy variation, no calculation has been provided.

[2] In the Supply Cost Accounting Compliance Application filed on January 21, 2022, it was proposed the cost variance threshold would commence on January 1, 2022 and the cost variance of +/- $500,000 would apply to the Revised Energy Supply Cost Variance Deferral Account balance as of October 31, 2021.

Supply Cost Variance Deferral Account
Net Revenue from Exports Variance
December 31, 2025

	Test Year ($) ($H_T$)	Transfer[1]	Net Revenue from Exports Excluding Non-Firm Sales Revenue	Non-Firm Sales Revenue[2]	Actual[3] ($) (H)	Total Variation ($) ($H_T$ - H) (to page 3)
January	-	-	158,749	291,856	450,605	**(450,605)**
February	-	-	105,809	240,976	346,785	**(346,785)**
March	-	-	143,118	266,555	409,673	**(409,673)**
April	-	-	91,080	204,721	295,801	**(295,801)**
May	-	-	152,803	190,923	343,726	**(343,726)**
June	-	5,711,673	5,786,921	232,800	6,019,721	**(6,019,721)**
July	-	-	69,528	328,290	397,818	**(397,818)**
August	-	-	10,534	338,148	348,682	**(348,682)**
September	-	-	38,622	183,635	222,257	**(222,257)**
October	-	-	9,619	95,373	104,992	**(104,992)**
November	-	-	30,414	151,648	182,062	**(182,062)**
December	-	-	48,912,211	165,559	49,077,770	**(49,077,770)**
			-			
Total	**-**	**5,711,673**	**55,509,407**	**2,690,485**	**58,199,892**	**(58,199,892)**

[1] As per Board Order No. P.U. 21(2025), the Board approved the transfer of the $5,711,673 credit balance, as of December 31, 2023, in the Hydraulic Resources Optimization Account to the Net Revenue from Exports component within the Supply Cost Variance Deferral Account.

In March, the actual settlement value for net export sales for 2024 was finalized. The settlement did not change the revenue that was accrued in December 2024; therefore, no true-up was required.

[2] Hydro's application to implement a non-firm rate for the Labrador Interconnected System and for Island Industrial customers to be calculated based on export market prices was approved in Board Order No. P.U. 34(2023). The Board Order also approved a revision to the Supply Cost Variance Deferral Account so that revenues from non-firm sales on the Island Interconnected System, supplied by hydraulic generation and revenues from Rate No. 5.1L –Non-Firm Energy, will be credited to the Net Revenue from Exports Variance component.

[3] Muskrat Falls and Hydro entered into a PPA ("Agreement") for the purchase and sale of residual block energy. Under this agreement, Labrador Rural and Industrial customer load, previously serviced with Recapture Energy from Churchill Falls, is now serviced with energy from the Muskrat Falls Hydroelectric Generating Facility. Entering into this agreement has allowed additional Recapture Energy exports to external markets, helping to ensure maximum value from the organization's hydrological resources.

Supply Cost Variance Deferral Account
Tariff Revenue
December 31, 2025

	Test Year ($)	Actual ($)	Total Variation ($)
	(I_T)	(I)	(I_T - I)
			(to page 3)
January	-	1,498,023	**(1,498,023)**
February	-	1,498,127	**(1,498,127)**
March	-	1,498,023	**(1,498,023)**
April	-	1,498,023	**(1,498,023)**
May	-	1,498,023	**(1,498,023)**
June	-	1,498,023	**(1,498,023)**
July	-	1,498,023	**(1,498,023)**
August	-	1,498,023	**(1,498,023)**
September	-	1,498,023	**(1,498,023)**
October	-	1,498,023	**(1,498,023)**
November	-	1,498,023	**(1,498,023)**
December	-	1,498,023	**(1,498,023)**
Total	**-**	**17,976,379**	**(17,976,380)**

Supply Cost Variance Deferral Account
Load Variation - Utility
December 31, 2025

	Test Year Cost of Service Firm Sales (kWh)	Actual Firm Sales (kWh)	Sales Variance (kWh)	Firm Energy Rate ($/kWh)[1]	Load Variation ($)
	(J_T)	(J_A)	(J_T - J_A)	(K_R)	(J_T - J_A) x K_R (to page 3)
January	715,400,000	678,826,511	36,573,489	0.09698	3,546,897
February	648,500,000	697,818,596	(49,318,596)	0.09698	(4,782,917)
March	646,000,000	607,536,622	38,463,378	0.09698	3,730,178
April	527,700,000	539,215,098	(11,515,098)	0.03354	(386,216)
May	421,700,000	460,510,889	(38,810,889)	0.03354	(1,301,717)
June	345,200,000	314,772,424	30,427,576	0.03354	1,020,541
July	307,900,000	314,904,375	(7,004,375)	0.03354	(234,927)
August	300,500,000	314,991,836	(14,491,836)	0.03354	(486,056)
September	314,500,000	314,816,559	(316,559)	0.03354	(10,617)
October	413,700,000	407,635,611	6,064,389	0.03354	203,400
November	495,500,000	501,135,123	(5,635,123)	0.03354	(189,002)
December	664,100,000	677,223,384	(13,123,384)	0.09698	(1,272,706)
Total	**5,800,700,000**	**5,829,387,028**	**(28,687,028)**		**(163,142)**

[1] As per Order No. P.U. 1(2025), the Board approved a wholesale rate, effective as of January 1, 2025, to be charged to Utility of 9.698 cents per kWh for winter months of December to March and 3.354 cents per kWh for the non-winter months of April to November.

Supply Cost Variance Deferral Account
Load Variation - Industrial
December 31, 2025

	Test Year Cost of Service Firm Sales (kWh)	Actual Firm Sales (kWh)	Sales Variance (kWh)	Firm Energy Rate ($/kWh)	Load Variation ($)
	(J_T)	(J_A)	(J_T - J_A)	(K_R)	(J_T - J_A) x K_R (to page 3)
January	63,000,000	39,092,325	23,907,675	0.04428	1,058,632
February	58,100,000	29,661,946	28,438,054	0.04428	1,259,237
March	63,300,000	39,309,203	23,990,797	0.04428	1,062,312
April	61,500,000	30,673,735	30,826,265	0.04428	1,364,987
May	63,000,000	40,489,736	22,510,264	0.04428	996,754
June	60,900,000	38,441,785	22,458,215	0.04428	994,450
July	62,400,000	46,323,095	16,076,905	0.04428	711,885
August	62,600,000	47,799,534	14,800,466	0.04428	655,365
September	61,000,000	48,888,654	12,111,346	0.04428	536,290
October	63,000,000	44,188,455	18,811,545	0.04428	832,975
November	60,700,000	36,126,895	24,573,105	0.04428	1,088,097
December	63,800,000	56,122,776	7,677,224	0.04428	339,947
Total	**743,300,000**	**497,118,139**	**246,181,861**		**10,900,931**

Supply Cost Variance Deferral Account
Rural Rate Alteration
December 31, 2025

	Price ($)	Volume ($)	Total[1] ($)	Utility Allocation[1] ($)	Labrador Interconnected Allocation[1] ($)	Balance ($)
				(to page 4)		
January	(1,499,995)	(118,372)	(1,618,367)	(1,555,251)	(63,116)	-
February	(1,354,882)	(552,584)	(1,907,466)	(1,833,075)	(74,391)	-
March	(1,369,558)	(259,744)	(1,629,302)	(1,565,759)	(63,543)	-
April	(1,175,980)	(413,449)	(1,589,429)	(1,527,441)	(61,988)	-
May	(1,111,657)	(228,284)	(1,339,941)	(1,287,683)	(52,258)	-
June	(996,888)	201,556	(795,332)	(764,314)	(31,018)	-
July	(1,351,374)	269,273	(1,082,101)	(1,039,899)	(42,202)	-
August	(1,308,528)	299,142	(1,009,386)	(970,020)	(39,366)	-
September	(1,250,984)	229,273	(1,021,711)	(981,864)	(39,847)	-
October	(1,452,722)	181,200	(1,271,522)	(1,221,933)	(49,589)	-
November	(1,688,122)	(100,843)	(1,788,965)	(1,719,195)	(69,770)	-
December	(2,029,988)	(326,165)	(2,356,153)	(2,264,263)	(91,890)	-
Total	**(16,590,678)**	**(818,997)**	**(17,409,675)**	**(16,730,697)**	**(678,978)**	**-**

[1] The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion that the Rural Deficit was allocated in the approved 2019 Cost of Service Study, which is 96.1% and 3.9%, respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Supply Cost Variance Deferral Account
Greenhouse Gas Credits
December 31, 2025

	Test Year ($) ($T_T$)	Actual ($) (T)	Total Variation ($) ($T_T$ - T) (to page 3)
January	-	77,618	**(77,618)**
February	-	-	**-**
March	-	184,308	**(184,308)**
April	-	576	**(576)**
May	-	25,351	**(25,351)**
June	-	(533)	**533**
July	-	18,965	**(18,965)**
August	-	(314)	**314**
September	-	68,527	**(68,527)**
October	-	15,751,252	**(15,751,252)**
November	-	(376)	**376**
December	-	(411)	**411**
Total	**-**	**16,124,962**	**(16,124,963)**

Supply Cost Variance Deferral Account
Rate Mitigation Fund
December 31, 2025

	Test Year ($)	Actual ($)	Total Variation ($) (to page 3)
January	-	-	-
February[1]	-	441,000,000	**(441,000,000)**
March	-	-	-
April	-	-	-
May	-	-	-
June	-	-	-
July	-	-	-
August[2]	-	150,000,000	**(150,000,000)**
September	-	-	-
October	-	-	-
November	-	-	-
December[1]	-	113,400,000	**(113,400,000)**
	-	**704,400,000**	**(704,400,000)**

[1] As per Order in Council OC2024-062 dated May 7, 2024, Hydro has been directed by the Government to use its own sources of rate mitigation and accordingly, in February 2025, transferred $441.0 million of funding to its Regulated operations. The $441.0 million includes $90.6 million of rate mitigation funding related to the retirement of the 2023 Supply Cost Variance Deferral Account of $271 million over the 2024 to 2026 period. Additionally, in December 2025, pursuant to OC2024-062 and OC2024-063, Government directed Hydro to transfer $113.4 million of rate mitigation funding to its Regulated operations through the use of its own funding.

[2] In 2022, as part of the Government's rate mitigation plan, Hydro, the Government and the Government of Canada signed term sheets enabling access, upon commissioning of the Labrador-Island Link ("LIL"), to a $1.0 billion investment by the Government of Canada in the LIL in the form of a convertible debenture. In August 2025, funding was received by LIL (2021) Limited Partnership, and transferred to Hydro for the purpose of rate mitigation, reducing the balance in the Supply Cost Variance Deferral Account.

2025 Short-Term Interest Calculation[1]

	($000's)
Promissory Note Interest	7,926
CORRA[2] Interest	5,167
Operating Line Interest	0
Standby and Upfront Fee	709
Brokerage Fee	292
Debt Guarantee Fee – Recoverable Portion Only	375
Total Short-Term Borrowing Costs	**14,469**
Weighted Average Short-Term Debt Balance[3]	**431,293**
Short-Term Cost of Borrowing 2025	**3.35%**

[1] Financing charges accrued at the 2024 short-term cost of borrowing of 5.03% for the period of January to November 2025. In December, the interest expense was trued-up for the year based on the short-term interest rate for 2025 of 3.35%.

[2] Canadian Overnight Repo Rate Average ("CORRA").

[3] The weighted average of the short-term debt balance is calculated using the 365-day average of the credit facility debt and the promissory note debt balances.

Appendix A

Other Island Interconnected System

Supply Cost Variance Summary

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2025

Holyrood Combustion Turbine	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($)[1,2] (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	660,391	666,592	(6,201)	1,258,888	**(1,265,089)**
February	646,818	2,860	643,958	767,288	**(123,330)**
March	62,280	1,393	60,887	661,531	**(600,644)**
April	552,337	94,335	458,002	392,558	**65,444**
May	72,879	-	72,879	123,373	**(50,494)**
June	(8,983)	-	(8,983)	431,643	**(440,626)**
July	11,046	-	11,046	33,744	**(22,698)**
August	14,376	-	14,376	33,744	**(19,368)**
September	9,528	1,127	8,401	33,744	**(25,343)**
October	85,365	416	84,949	209,033	**(124,084)**
November	166,174	-	166,174	185,808	**(19,634)**
December	363,521	486,660	(123,139)	851,255	**(974,394)**
Subtotal	**2,635,732**	**1,253,383**	**1,382,349**	**4,982,609**	**(3,600,260)**

[1] All non-firm sales are credited under Holyrood Combustion Turbines since the non-firm sales were not distinguished between Holyrood, Hardwoods or Stephenville.
[2] Includes Non-firm sales to Island Industrial Customers and supply of emergency energy to Nova Scotia.

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2025

Hardwoods Gas Turbine	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($) (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	155,981	-	155,981	122,478	**33,503**
February	393,137	-	393,137	123,884	**269,253**
March	17,430	-	17,430	117,271	**(99,841)**
April	47,641	-	47,641	83,554	**(35,913)**
May	-	-	-	57,170	**(57,170)**
June	-	-	-	46,909	**(46,909)**
July	-	-	-	71,469	**(71,469)**
August	(45,794)	-	(45,794)	14,587	**(60,381)**
September	152,839	-	152,839	90,430	**62,409**
October	224,798	-	224,798	20,417	**204,381**
November	35,694	-	35,694	59,755	**(24,061)**
December	18,351	-	18,351	179,920	**(161,569)**
Subtotal	**1,000,078**	**-**	**1,000,078**	**987,844**	**12,233**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2025

Stephenville Gas Turbine	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($) (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	231,542	-	231,542	68,116	**163,426**
February	261,823	-	261,823	46,923	**214,900**
March	592	-	592	40,867	**(40,275)**
April	11,811	-	11,811	56,006	**(44,195)**
May	8,576	-	8,576	25,733	**(17,157)**
June	988	-	988	86,278	**(85,290)**
July	5,766	-	5,766	31,788	**(26,022)**
August	1,908	-	1,908	15,138	**(13,230)**
September	4,959	-	4,959	34,816	**(29,857)**
October	84,503	-	84,503	15,138	**69,365**
November	70,861	-	70,861	25,733	**45,128**
December	12,444	-	12,444	84,827	**(72,383)**
Subtotal	**695,772**	**-**	**695,772**	**531,363**	**164,410**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2025

St. Anthony Diesel Generating Station	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($) (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	(449)	-	(449)	3,147	**(3,596)**
February	25,161	-	25,161	3,089	**22,072**
March	1,126	-	1,126	3,299	**(2,173)**
April	42,365	-	42,365	3,547	**38,818**
May	8,669	-	8,669	3,662	**5,007**
June	13,127	-	13,127	3,604	**9,523**
July	6,290	-	6,290	3,642	**2,648**
August	648	-	648	3,642	**(2,994)**
September	(252)	-	(252)	3,814	**(4,066)**
October	16,164	-	16,164	3,986	**12,178**
November	42,239	-	42,239	4,272	**37,967**
December	15,124	-	15,124	-	**15,124**
Subtotal	**170,213**	**-**	**170,213**	**39,704**	**130,508**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2025

Hawkes Bay Diesel Generating Station	Actual Cost ($) (A)	Fuel for Non-Firm Sales ($) (B)	Net Cost ($) (C = A - B)	Test Year Cost ($) (D)	Thermal Variation ($) (C - D)
January	-	-	-	1,575	**(1,575)**
February	10,391	-	10,391	1,547	**8,844**
March	(170)	-	(170)	1,652	**(1,822)**
April	2,683	-	2,683	1,776	**907**
May	131	-	131	1,833	**(1,702)**
June	-	-	-	1,804	**(1,804)**
July	10	-	10	1,823	**(1,813)**
August	-	-	-	1,823	**(1,823)**
September	91	-	91	1,909	**(1,818)**
October	-	-	-	1,995	**(1,995)**
November	4,031	-	4,031	2,138	**1,893**
December	28	-	28	-	**28**
Subtotal	**17,196**	**-**	**17,196**	**19,875**	**(2,680)**
Total Thermal Generation Cost Variance					**(3,295,789)**

Supply Cost Variance Deferral Account
Off-Island Power Purchase
December 31, 2025

Maritime Link	Actual Cost ($) (A)	Test Year Cost ($) (B)	Off-Island Power Purchase Variation ($) (A - B)
January	(10,877)	325,148	(336,025)
February	14,215	2,548,040	(2,533,825)
March	10,790	5,799,459	(5,788,669)
April	-	-	-
May	174	-	174
June	-	-	-
July	-	-	-
August	-	-	-
September	3,034,037	-	3,034,037
October	120,991	1,245,520	(1,124,529)
November	-	1,522,118	(1,522,118)
December	-	2,052,451	(2,052,451)
Subtotal	**3,169,330**	**13,492,735**	**(10,323,406)**

Supply Cost Variance Deferral Account
Off-Island Power Purchase
December 31, 2025

Labrador-Island Link	Actual Cost ($) (A)	Test Year Cost ($) (B)	Off-Island Power Purchase Variation ($) (A - B)
January	15,336	151,886	(136,550)
February	6,646	62,099	(55,453)
March	403	120,370	(119,968)
April	1,237	146,318	(145,082)
May	-	-	-
June	-	-	-
July	-	-	-
August	24,667	-	24,667
September	56,947	-	56,947
October	89,183	31,699	57,484
November	39,063	172,510	(133,447)
December	16,606	112,324	(95,718)
Subtotal	**250,088**	**797,206**	**(547,120)**
Total Off-Island Power Purchase Variance			**(10,870,526)**

Supply Cost Variance Deferral Account
On-Island Purchases Variation
December 31, 2025

Nalcor Exploits	Actual Production (kWh)	Cost of Service Production (kWh)	Monthly Production Variance (kWh)	Cost of Service Cost (¢/kWh)	Power Purchase Variation ($)
	(A)	(B)	(C) = (A - B)	(D)	(E) = (C x D)
January	59,217,756	54,196,680	5,021,076	0.0400	200,843
February	46,218,660	48,703,200	(2,484,540)	0.0400	(99,382)
March	54,114,927	53,794,920	320,007	0.0400	12,800
April	50,225,357	55,911,600	(5,686,243)	0.0400	(227,450)
May	52,218,379	58,649,520	(6,431,141)	0.0400	(257,246)
June	44,612,682	48,618,000	(4,005,318)	0.0400	(160,213)
July	45,645,414	53,988,360	(8,342,946)	0.0400	(333,718)
August	42,148,092	54,851,400	(12,703,308)	0.0400	(508,132)
September	26,008,145	48,124,800	(22,116,655)	0.0400	(884,666)
October	13,937,623	38,442,480	(24,504,857)	0.0400	(980,194)
November	30,824,617	45,032,400	(14,207,783)	0.0400	(568,311)
December	38,366,027	54,684,000	(16,317,973)	0.0400	(652,719)
Subtotal	**503,537,679**	**614,997,360**	**(111,459,681)**		**(4,458,388)**

Supply Cost Variance Deferral Account
On-Island Purchases Variation
December 31, 2025

Star Lake	**Actual Production (kWh)**	**Cost of Service Production (kWh)**	**Monthly Production Variance (kWh)**	**Cost of Service Cost (¢/kWh)**	**Power Purchase Variation ($)**
	(A)	**(B)**	**(C) = (A - B)**	**(D)**	**(E) = (C x D)**
January	12,161,901	12,391,320	(229,419)	0.0400	(9,177)
February	10,992,813	11,245,920	(253,107)	0.0400	(10,124)
March	12,292,045	12,395,040	(102,995)	0.0400	(4,120)
April	11,724,016	12,308,400	(584,384)	0.0400	(23,375)
May	11,305,270	12,636,840	(1,331,570)	0.0400	(53,263)
June	12,054,552	11,970,000	84,552	0.0400	3,382
July	9,322,721	12,990,240	(3,667,519)	0.0400	(146,701)
August	12,639,686	12,915,840	(276,154)	0.0400	(11,046)
September	3,264,023	6,512,400	(3,248,377)	0.0400	(129,935)
October	-	12,997,680	(12,997,680)	0.0400	(519,907)
November	10,722,565	11,541,600	(819,035)	0.0400	(32,761)
December	12,743,757	11,844,480	899,277	0.0400	35,971
Subtotal	**119,223,349**	**141,749,760**	**(22,526,411)**		**(901,056)**

Supply Cost Variance Deferral Account
On-Island Purchases Variation
December 31, 2025

Rattle Brook	**Actual Production (kWh)**	**Cost of Service Production (kWh)**	**Monthly Production Variance (kWh)**	**Cost of Service Cost (¢/kWh)**	**Power Purchase Variation ($)**
	(A)	**(B)**	**(C) = (A - B)**	**(D)**	**(E) = (C x D)**
January	1,262,941	680,000	582,941	0.0851	49,615
February	124,201	470,000	(345,799)	0.0851	(29,432)
March	1,587,264	630,000	957,264	0.0851	81,475
April	1,533,421	1,600,000	(66,579)	0.0851	(5,667)
May	2,555,586	2,590,000	(34,414)	0.0851	(2,929)
June	1,270,295	1,630,000	(359,705)	0.0851	(30,615)
July	19,242	810,000	(790,758)	0.0851	(67,303)
August	-	800,000	(800,000)	0.0851	(68,090)
September	-	1,170,000	(1,170,000)	0.0851	(99,581)
October	656,779	1,570,000	(913,221)	0.0851	(77,726)
November	2,039,846	1,770,000	269,846	0.0851	22,967
December	997,383	1,120,000	(122,617)	0.0851	(10,436)
Subtotal	**12,046,958**	**14,840,000**	**(2,793,042)**		**(237,722)**

Supply Cost Variance Deferral Account
On-Island Purchases Variation
December 31, 2025

CBPP Co-Generation	**Actual Production (kWh)**	**Cost of Service Production (kWh)**	**Monthly Production Variance (kWh)**	**Cost of Service Cost (¢/kWh)**	**Power Purchase Variation ($)**
	(A)	**(B)**	**(C) = (A - B)**	**(D)**	**(E) = (C x D)**
January	-	6,320,000	(6,320,000)	0.1884	(1,190,688)
February	2,574,169	4,980,000	(2,405,831)	0.1884	(453,259)
March	12,356,570	5,840,000	6,516,570	0.1884	1,227,722
April	4,812,259	5,550,000	(737,741)	0.1884	(138,990)
May	2,858,596	5,740,000	(2,881,404)	0.1884	(542,857)
June	2,667,344	6,070,000	(3,402,656)	0.1884	(641,060)
July	2,780,203	5,580,000	(2,799,797)	0.1884	(527,482)
August	2,295,621	4,230,000	(1,934,379)	0.1884	(364,437)
September	2,485,938	6,240,000	(3,754,062)	0.1884	(707,265)
October	-	5,440,000	(5,440,000)	0.1884	(1,024,896)
November	-	4,290,000	(4,290,000)	0.1884	(808,236)
December	-	6,250,000	(6,250,000)	0.1884	(1,177,500)
Subtotal	**32,830,700**	**66,530,000**	**(33,699,300)**		**(6,348,948)**

Supply Cost Variance Deferral Account
On-Island Purchases Variation
December 31, 2025

St. Lawrence Wind	Actual Production (kWh)	Cost of Service Production (kWh)	Monthly Production Variance (kWh)	Cost of Service Cost (¢/kWh)	Power Purchase Variation ($)
	(A)	(B)	(C) = (A - B)	(D)	(E) = (C x D)
January	10,110,827	11,200,000	(1,089,173)	0.0722	(78,638)
February	11,009,199	11,200,000	(190,801)	0.0722	(13,776)
March	9,340,563	10,570,000	(1,229,437)	0.0722	(88,765)
April	8,701,792	9,420,000	(718,208)	0.0722	(51,855)
May	7,888,054	7,860,000	28,054	0.0722	2,025
June	6,110,313	6,070,000	40,313	0.0722	2,911
July	5,294,253	5,760,000	(465,747)	0.0722	(33,627)
August	4,597,999	5,970,000	(1,372,001)	0.0722	(99,058)
September	5,245,577	7,750,000	(2,504,423)	0.0722	(180,819)
October	6,006,238	8,480,000	(2,473,762)	0.0722	(178,606)
November	8,616,902	9,740,000	(1,123,098)	0.0722	(81,088)
December	10,694,727	10,780,000	(85,273)	0.0722	(6,157)
Subtotal	**93,616,444**	**104,800,000**	**(11,183,556)**		**(807,453)**

Supply Cost Variance Deferral Account
On-Island Purchases Variation
December 31, 2025

Fermeuse Wind	Actual Production (kWh)	Cost of Service Production (kWh)	Monthly Production Variance (kWh)	Cost of Service Cost (¢/kWh)	Power Purchase Variation ($)
	(A)	(B)	(C) = (A - B)	(D)	(E) = (C x D)
January	8,302,097	9,020,000	(717,903)	0.0772	(55,401)
February	8,604,174	9,020,000	(415,826)	0.0772	(32,089)
March	8,361,555	8,510,000	(148,445)	0.0772	(11,456)
April	7,705,019	7,590,000	115,019	0.0772	8,876
May	5,781,415	6,330,000	(548,585)	0.0772	(42,334)
June	7,812,382	4,890,000	2,922,382	0.0772	225,520
July	7,212,186	4,640,000	2,572,186	0.0772	198,496
August	3,449,086	4,810,000	(1,360,914)	0.0772	(105,022)
September	5,303,997	6,240,000	(936,003)	0.0772	(72,231)
October	6,362,075	6,830,000	(467,925)	0.0772	(36,110)
November	8,721,368	7,840,000	881,368	0.0772	68,015
December	9,925,409	8,690,000	1,235,409	0.0772	95,337
Subtotal	**87,540,763**	**84,410,000**	**3,130,763**		**241,601**
Total On-Island Purchases Variance					**(12,511,966)**

Tab 2

Contribution in Aid of Construction

Quarter Ended December 31, 2025

newfoundland labrador hydro

Table 1 summarizes the CIAC[1] activity for the current quarter. It also provides an overview of the following:

- The type of service for which a CIAC has been calculated, either domestic or general service;
- The number of CIACs quoted during the quarter, as well as the number of CIAC quotes that remain outstanding as of the end of the quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter; and
- Information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates that it wishes to proceed with the construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered to expire after six months have elapsed and the customer has not indicated its intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor expired.

Table 1: CIAC Report for the Current Quarterly Reporting Period

Type of Service	CIACs Quoted	CIACs Outstanding from Last Quarter	Total CIACs Quoted	CIACs Accepted	CIACs Expired	CIACs Outstanding
Domestic						
Within Plan Boundary	2	3	5	1	0	4
Outside Plan Boundary	3	2	5	1	2	2
Subtotal	**5**	**5**	**10**	**2**	**2**	**6**
General Service	4	0	4	2	0	2
Total	**9**	**5**	**14**	**4**	**2**	**8**

[1] Includes residential, non-residential, and general service CIAC activities for northern, central, and Labrador regions.

The number of CIACs quoted during the current quarter by region is summarized in Table 2, which also identifies the following:

- The service location for the CIAC;
- The CIAC number related to the quote;
- The amount of the CIAC required to be paid by the customer;
- The estimated construction costs to provide the requested service; and
- Whether the CIAC has been accepted by the customer.

Table 2: CIAC Activity Report for the Current Quarterly Reporting Period

Date Quoted	Service Location	CIAC Number	CIAC Amount ($)	Estimated Construction Costs ($)	Accepted
Domestic: Within Residential Planning Boundaries					
10-Nov-2025	Coachman's Cove	2085782	2,818	7,748	
18-Nov-2025	Rocky Harbour	2097174	1,030	5,960	Yes
Domestic: Outside Residential Planning Boundaries					
04-Nov-2025	Labrador City	2087474	13,859	1,450	Yes
05-Nov-2025	St. Anthony	2069624	3,122	1,450	
24-Nov-2025	South Brook; Green Bay	2076809	1,534	2,984	
General Service					
10-Nov-2025	Kings Point	2087789	4,524	9,454	Yes
13-Nov-2025	Happy Valley-Goose Bay	2074048	14,430	23,020	Yes
27-Nov-2025	Westport	2088975	15,646	25,506	
17-Dec-2025	Happy Valley-Goose Bay	2083920	3,800	8,730	

Tab 3

Customer Damage Claims

Quarter Ended December 31, 2025

The Customer Damage Claims report contains a summary of all damage claims activity on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report provides an overview of the following:

- The number of claims received during the quarter, coupled with claims outstanding from the last quarter;
- The number of claims for which Hydro has accepted responsibility and the amount paid to claimants versus the amount originally claimed;
- The number of claims rejected and the dollar value associated with those claims; and
- Those claims that remain outstanding at the end of the quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims:

- **System Operations:** Claims arising from system operations (e.g., normal reclosing or switching).
- **Power Interruptions:** Claims arising from the interruption of power supply (e.g., all scheduled or unscheduled interruptions).
- **Improper Workmanship:** Claims arising from the failure of electrical equipment caused by improper workmanship or methods (e.g., improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, and inadequate clearance or improper operation of equipment).
- **Weather Related:** Claims arising from weather conditions (e.g., wind, rain, ice, lightning or corrosion caused by weather).
- **Equipment Failure:** Claims arising from failure of electrical equipment not caused by improper workmanship (e.g., broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire).
- **Third Party:** Claims arising from equipment failure caused by acts of third parties (e.g., motor vehicle accidents and vandalism).
- **Miscellaneous:** All claims that are not related to electrical service.
- **Waiting Investigation:** Cause to be determined.

Table 1: Customer Property Damage Claims Report by Region for the Current Quarter

				Claims Accepted			Claims Rejected		Claims Outstanding	
Region	**# Received**	**# Outstanding Since Last Quarter**	**Total**	**#**	**Amount Claimed ($)**	**Amount Paid ($)**	**#**	**Amount ($)**	**#**	**Amount ($)**
Central	5	9	**14**	0	0	0	4	7,196	10	19,500
Northern	5	7	**12**	1	7,587	1,043	2	1,354	9	12,037
Labrador	4	2	**6**	0	0	0	4	8,738	2	1,351
Total	**14**	**18**	**32**	**1**	**7,587**	**1,043**	**10**	**17,288**	**21**	**32,888**

Table 2: Customer Property Damage Claims Report by Region for the Same Quarter, Previous Year

				Claims Accepted			Claims Rejected		Claims Outstanding	
Region	**# Received**	**# Outstanding Since Last Quarter**	**Total**	**#**	**Amount Claimed ($)**	**Amount Paid ($)**	**#**	**Amount ($)**	**#**	**Amount ($)**
Central	7	4	**11**	0	0	0	4	6,868	7	9,445
Northern	2	6	**8**	0	0	0	2	2,094	6	568,208[1]
Labrador	1	1	**2**	0	0	0	0	0	2	3,269
Total	**10**	**11**	**21**	**0**	**0**	**0**	**6**	**8,962**	**15**	**580,922**

[1] The majority of this balance pertains to one damage claim from a General Service customer for $551,549. The customer had claimed for repairs to equipment and for lost business opportunities, employment, and equipment damage. This claim has now been resolved as reported in Q1 2025.

Table 3: Customer Property Damage Claims Report by Cause for the Current Quarter

Cause	# Received	# Outstanding Since Last Quarter	Total	Claims Accepted #	Claims Accepted Amount Claimed ($)	Claims Accepted Amount Paid ($)	Claims Rejected #	Claims Rejected Amount ($)	Claims Outstanding #	Claims Outstanding Amount ($)
System Operations	2	1	**3**	0	0	0	2	2,198	1	0
Power Interruptions	3	4	**7**	0	0	0	4	6,344	3	774
Improper Workmanship	0	4	**4**	1	7,587	1,043	0	0	3	7,250
Weather Related	3	2	**5**	0	0	0	3	2,996	2	9,251
Equipment Failure	2	5	**7**	0	0	0	0	0	7	6,412
Third Party	0	0	**0**	0	0	0	0	0	0	0
Miscellaneous	1	1	**2**	0	0	0	1	5,750	1	1,351
Awaiting Investigation[2]	3	1	**4**	0	0	0	0	0	4	7,850
Total	**14**	**18**	**32**	**1**	**7,587**	**1,043**	**10**	**17,288**	**21**	**32,888**

Table 4: Customer Property Damage Claims Report by Cause for the Same Quarter, Previous Year

Cause	# Received	# Outstanding Since Last Quarter	Total	Claims Accepted #	Claims Accepted Amount Claimed ($)	Claims Accepted Amount Paid ($)	Claims Rejected #	Claims Rejected Amount ($)	Claims Outstanding #	Claims Outstanding Amount ($)
System Operations	0	0	**0**	0	0	0	0	0	0	0
Power Interruptions	1	0	**1**	0	0	0	1	1,500	0	0
Improper Workmanship	1	2	**3**	0	0	0	0	0	3	565,593[3]
Weather Related	2	2	**4**	0	0	0	0	0	4	5,845
Equipment Failure	1	2	**3**	0	0	0	3	4,539	1	3,815
Third Party	2	1	**3**	0	0	0	2	2,923	1	2,800
Miscellaneous	0	1	**1**	0	0	0	0	0	1	100
Awaiting Investigation[2]	3	3	**6**	0	0	0	0	0	5	2,769
Total	**10**	**11**	**21**	**0**	**0**	**0**	**6**	**8,962**	**15**	**580,922**

[2] Claims classified as "Awaiting Investigation" are recategorized once investigations are complete. Accordingly, the total of accepted, rejected and outstanding claims for each cause in the current quarter may be greater than the number of claims received and carried into the quarter for that cause.
[3] This claim has now been resolved as reported in Q1 2025.