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January 6, 2026

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Re: Quarterly Regulatory Report for the Quarter Ended September 30, 2025 – Revision 1

Enclosed is Newfoundland and Labrador Hydro's ("Hydro") revised Quarterly Regulatory Report for the Quarter Ended September 30, 2025, filed with the Board of Commissioners of Public Utilities on November 14, 2025.

Hydro has become aware of typographical errors in Tables 1, 11, 12, and 13 of the Quarterly Summary. The errors have been corrected in the attached revision. For ease of reference, changes have been shaded in grey.

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

Encl.

ecc:

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Bernice Bailey, Browne Fitzgerald Morgan & Avis

Revision History

Revision No.	Revision Date	Location	Reason
1	06-Jan-2026	Tab 1, sec, 1.0, p. 1, Table 1	Correction to the energy sales Q3 2025 Target and 2024 Actual, transcribing error.
1	06-Jan-2026	Tab 1, sec, 6.1, p. 17, Table 11	Correction to the title heading to reflect current quarter.
1	06-Jan-2026	Tab 1, sec, 6.1, p. 18, Table 12	Correction to the title heading to reflect current quarter.
1	06-Jan-2026	Tab 1, sec, 6.2, p. 19, Table 13	Correction to the title heading to reflect current quarter.

Quarterly Regulatory Report

Quarter Ended September 30, 2025

Original Submission: November 14, 2025

Revision 1: January 6, 2026

A report to the Board of Commissioners of Public Utilities

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Tab 1

Quarterly Summary

Quarter Ended September 30, 2025

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Attachment 2: Supply Cost Variance Deferral Account Report (Unaudited)

Abbreviations

Term	Definition
AIF	All-injury Frequency Rate
bbl	Barrel
Board	Board of Commissioners of Public Utilities
CIAC	Contribution in Aid of Construction
EC	Electricity Canada (Formerly known as the Canadian Electricity Association)
EMS	Environmental Management System
FTE	Full-time equivalent
Holyrood TGS	Holyrood Thermal Generating Station
Hydro	Newfoundland and Labrador Hydro
LTIF	Lost-Time Injury Frequency
Newfoundland Power NP	Newfoundland Power Inc.
Q3	Third 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

Term	Definition
UFLS	Under Frequency Load Shedding
YTD	Year-to-Date

Definitions

Current Quarter: The period beginning July 1, 2025 and ending September 30, 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.

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 September 30 of the applicable year.

1 # 1.0 Highlights

Table 1: Highlights YTD

	Q3 2025 Actual	Q3 2025 Target	Q3 2024 Actual	2025 Annual Target
Safety and Environment				
TRIF Rate[1]	0.78	N/A	0.81	1.25
LTIF Rate	0.31	N/A	0.32	<0.15
Achievement of EMS Targets (%)	89	N/A[2]	66	95
Reliability				
SAIDI	2.01	1.97	1.85	2.56
SAIFI	0.78	0.91	1.25	1.25
Production				
Holyrood No. 6 Fuel Oil Average Cost ($/bbl)	114	104	120	102
Holyrood Efficiency (kWh/bbl)	577	583	546	583
Electricity Delivery (GWh)				
Energy Sales	5,688	5,578	5,852	7,600
Financial ($ Millions)[3]				
Revenue	475.6	475.9	474.8	649.6
Operating Expenses	116.1	121.2	111.5	158.1
Net Income	17.7	11.3	24.4	8.3
RSP ($ Millions)[4]				
RSP Balance	19.0	18.4	38.2	12.6
Supply Cost Variance Deferral Account ($ Millions)[5]				
Cumulative Net Balance	404.5	246.6	453.9	346.4
FTE Employees[6]				
Regulated	847.9	N/A	816.5	860.20

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

[2] Hydro does not set a quarterly target, a target of 18 was reported in the "Quarterly Regulatory Report, Quarter Ended June 30, 2025," Newfoundland Labrador Hydro, August 19, 2025, in error.

[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 standards similar to those contained in ISO 45001. 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.

In July 2025, Hydro received notice of charges under the *Occupational Health and Safety* ("OHS") *Act* in connection with the tragic incident that occurred in August 2023, which resulted in the death of an employee. Hydro has fully cooperated with the OHS investigation and provided all requested information. Hydro is currently reviewing the charges and will address them through the appropriate court process. The safety of our employees and contractors remains Hydro's highest priority.

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	YTD 2024	2024 Annual
Fatalities	0	0	0
Lost-Time Injuries	2	2	2
Medical Treatment Injuries	2	2	3
First Aid with Restrictions	1	1	1
TRIF Rate	0.78	0.81	0.74
LTIF Rate	0.31	0.32	0.25
Severity Rate (Days Lost)	10.15(65)	0.48(3)	1.60(13)
High-Potential Incidents	1	3	3

Hydro experienced one lost-time injury and one first aid with restriction this quarter, for a total of one first aid with restrictions, two medical treatment injuries and two lost-time injuries YTD. As a result of the total number of recordable injuries for the year, Hydro's YTD TRIF rate is 0.78, and its LTIF rate is 0.31. Hydro's lost-time severity rate is 10.15, based on 65 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.

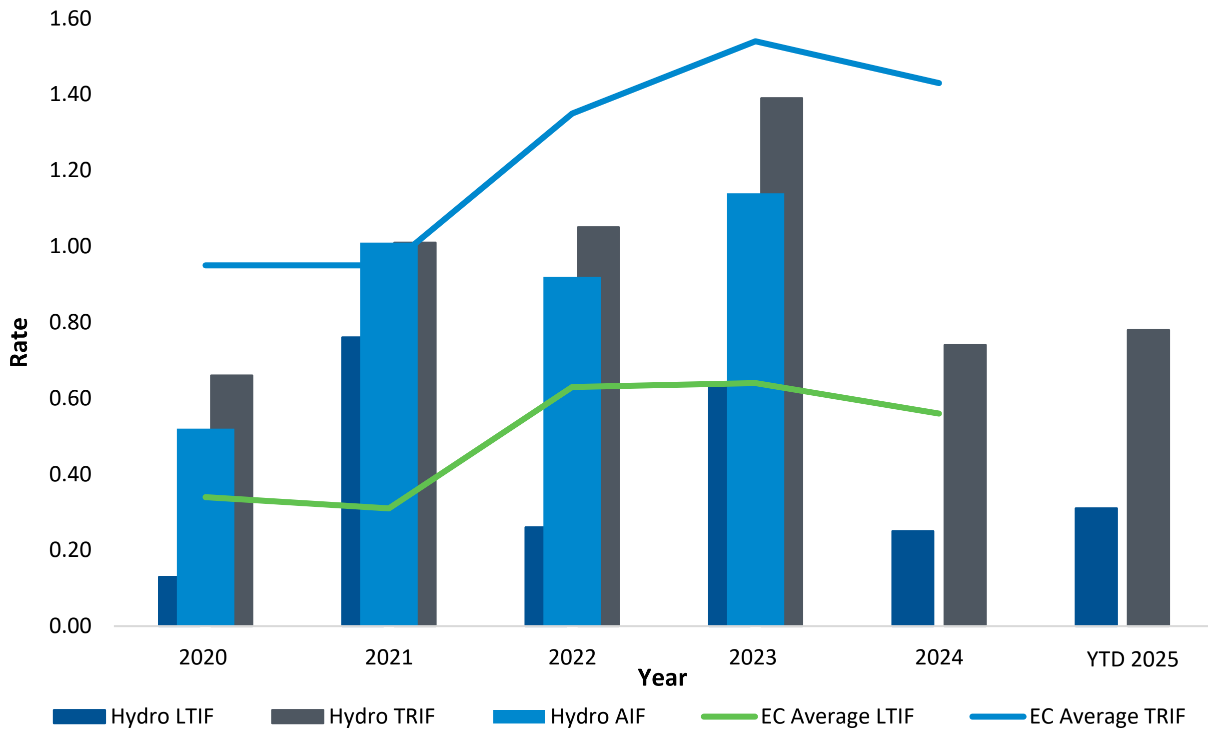

Chart 1: Hydro's TRIF and LTIF Compared to EC Averages[9]

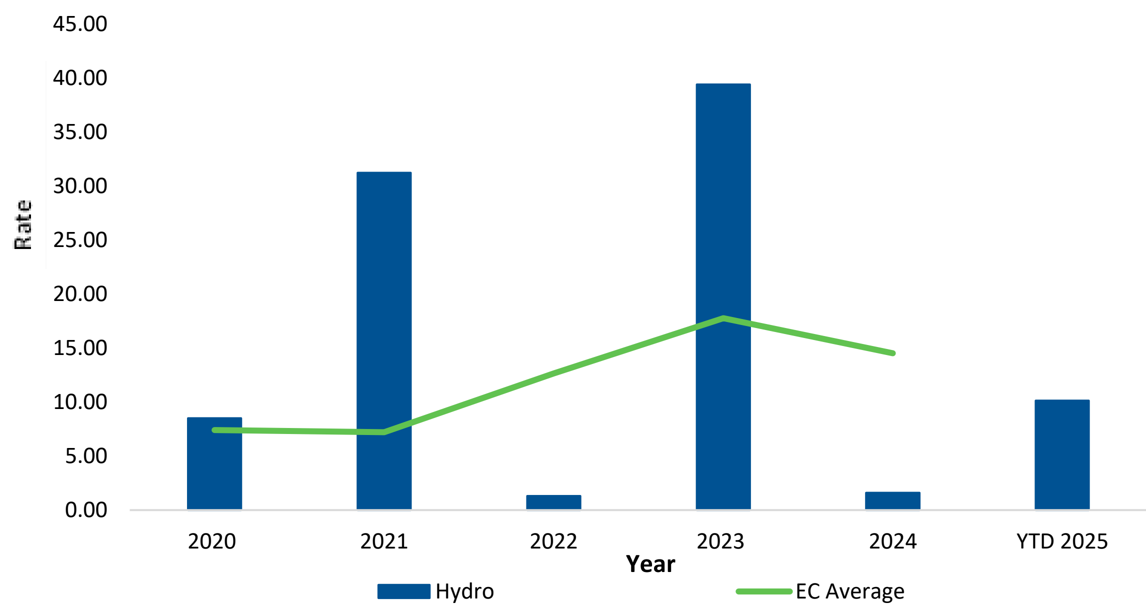

Chart 2: Hydro's Lost-Time Severity Rate Compared to EC Average[10]

[9] Safety and Health performance metrics are compared to EC utility members in Group 2 (300–1,500 employees) until 2022. In 2022 and 2023, 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 no reportable line contact incidents by a third party during the current quarter. 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 six 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.

3.3.1 End-Consumer Performance

The End-Consumer Performance Index data provided in Table 3 are measures of the duration and frequency of service interruptions experienced as a result of Hydro's system events. Hydro uses the

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

averages of its End-Consumer Indices performances for the period 2020–2024 to establish its 2025 annual targets.

Table 3: End-Consumer Performance

	Q3		YTD			2025 Annual Target
	2025	2024	Target	2025	2024	(2020–2024 Average)
SAIDI	1.01	0.84	1.97	2.01	1.85	2.56
SAIFI	0.45	0.76	0.91	0.78	1.25	1.25

Hydro's End-Consumer SAIDI and SAIFI YTD data (2021–2025) is provided in Chart 3 and Chart 4, respectively.

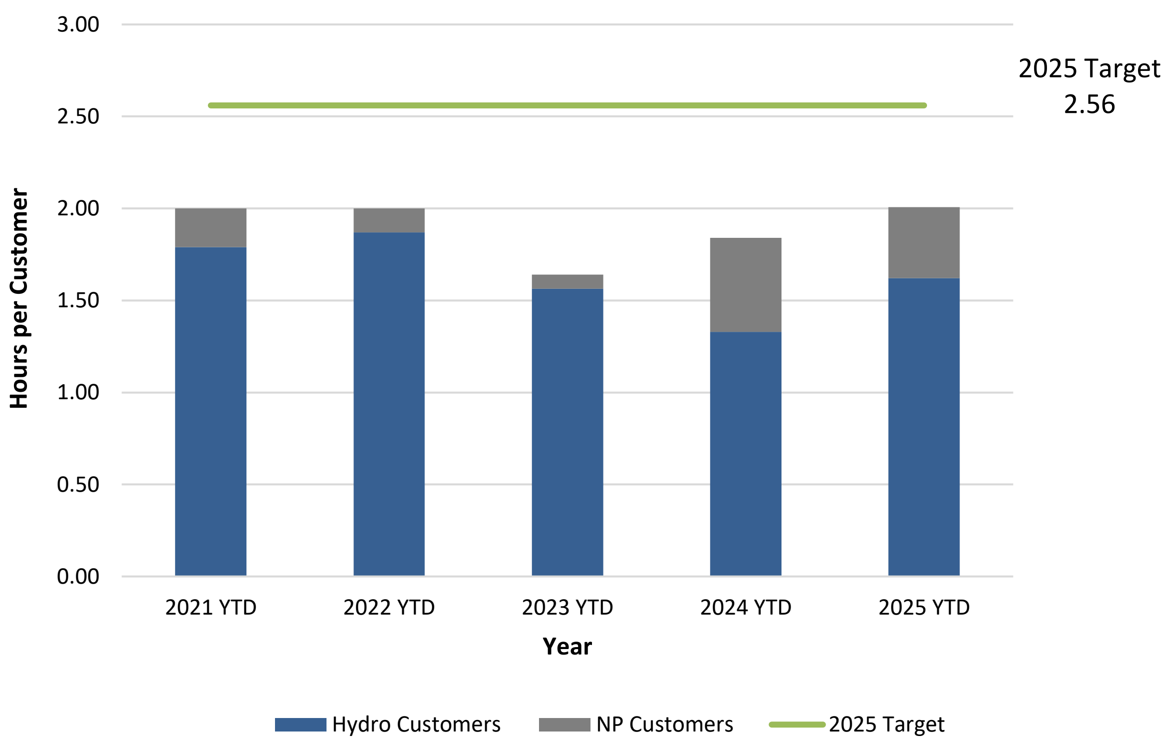

Chart 3: End-Consumer SAIDI

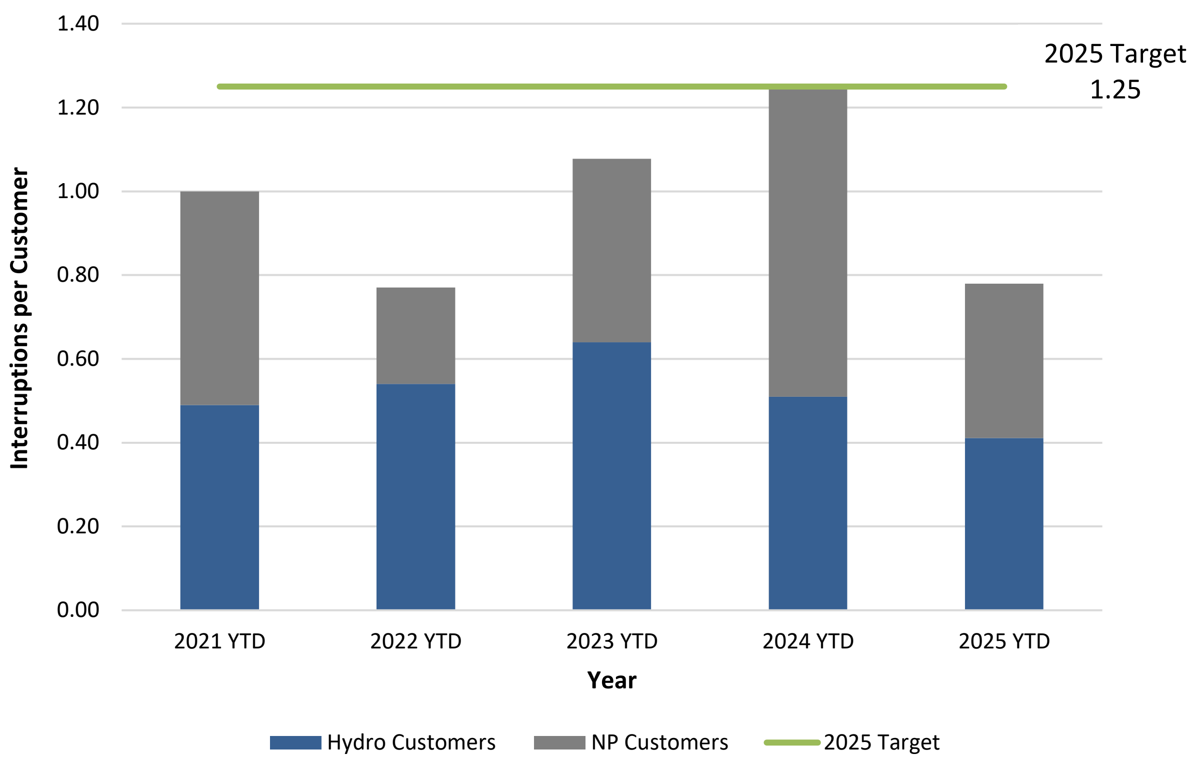

Chart 4: End-Consumer SAIFI

3.3.2 Bulk Power System Delivery Point Interruption Performance

T-SAIDI and T-SAIFI data are provided in Table 4. Hydro uses the averages of each Index for the period 2020–2024 to establish its annual target for 2025. The T-SAIDI and T-SAIFI performance for Hydro, including planned and unplanned outages (2021–2025 YTD), and EC are provided in Chart 5 and Chart 6, respectively.

Table 4: Transmission Delivery Point Performance

	Q3		YTD			2025 Annual Target
	2025	**2024**	**Target**	**2025**	**2024**	**(2020–2024 Average)**
T-SAIDI	207.00	120.19	320.33	270.14	321.57	409.56
T-SAIFI	0.68	0.78	1.74	1.28	1.76	2.51

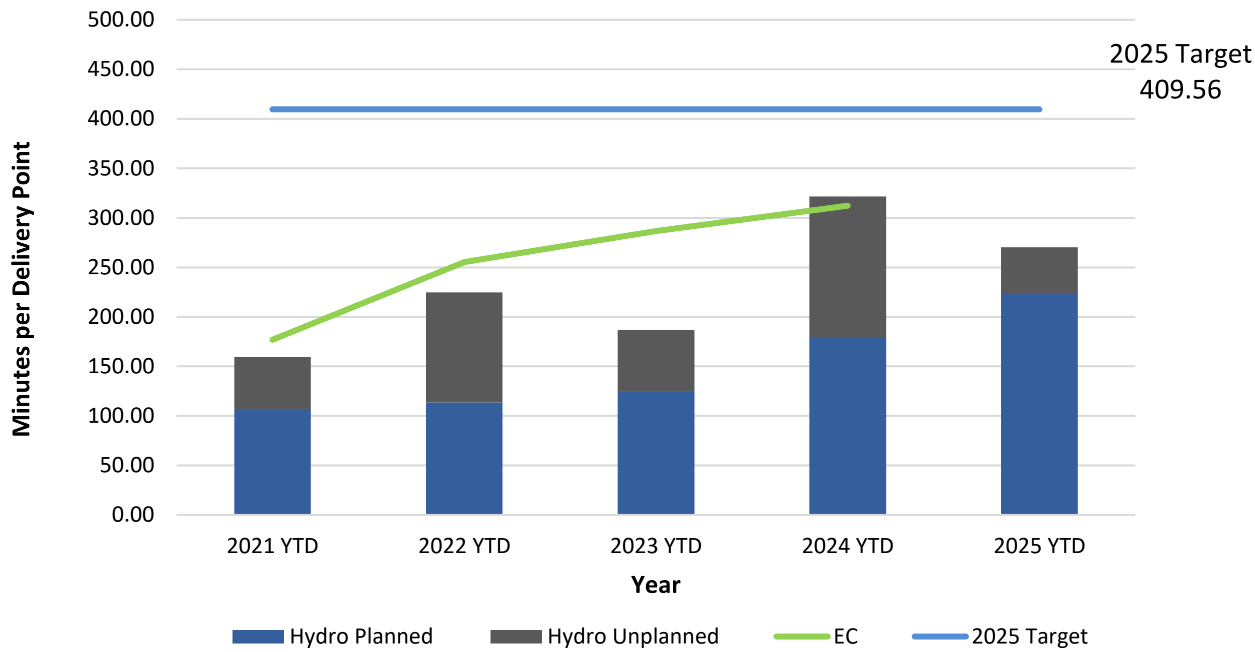

Chart 5: T-SAIDI

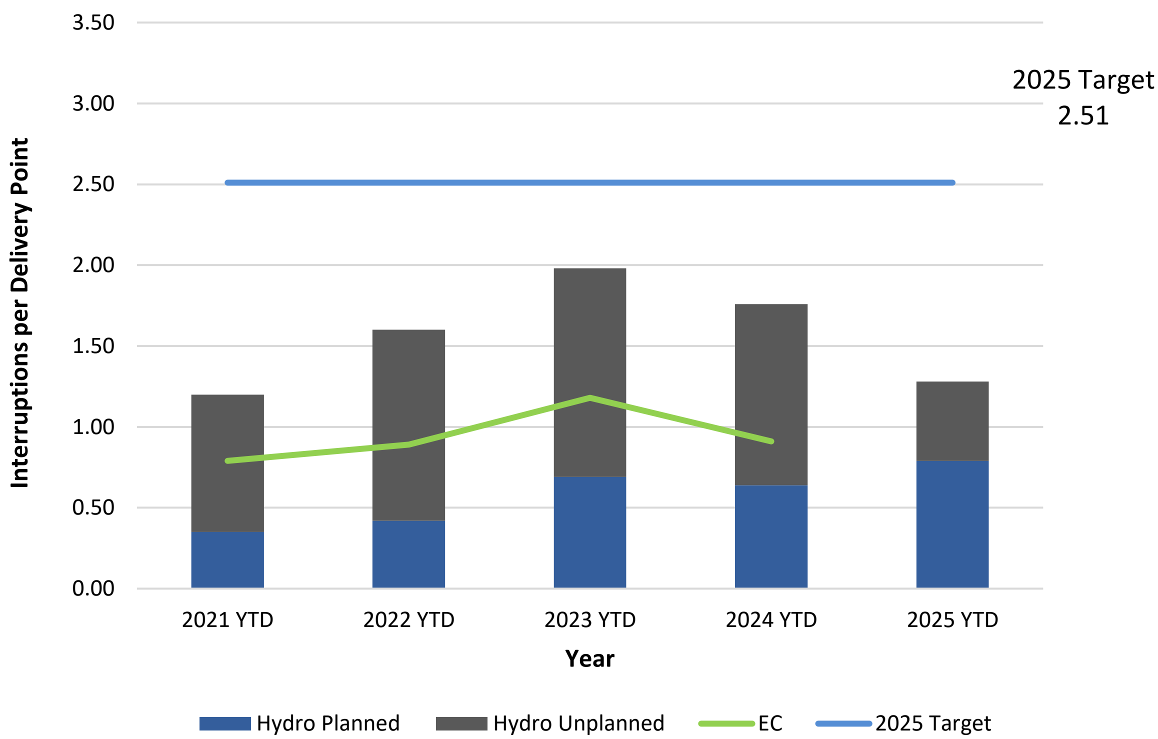

Chart 6: T-SAIFI

3.3.3 Service Continuity Performance

Service Continuity SAIDI and SAIFI performance data are provided in Table 5. Hydro uses the average of each index for the period 2020–2024 to establish its annual targets for 2025 for these indices. Service Continuity SAIDI and SAIFI performance data for Hydro (2021–2025 YTD) and EC are provided in Chart 7, and Chart 8, respectively.

Table 5: Service Continuity SAIDI and SAIFI

	Q3		YTD			2025 Annual Target
	2025	2024	Target	2025	2024	(2020–2024 Average)
SAIDI	5.21	3.40	13.29	12.52	10.27	17.30
SAIFI	1.21	1.46	3.94	3.17	3.93	5.43

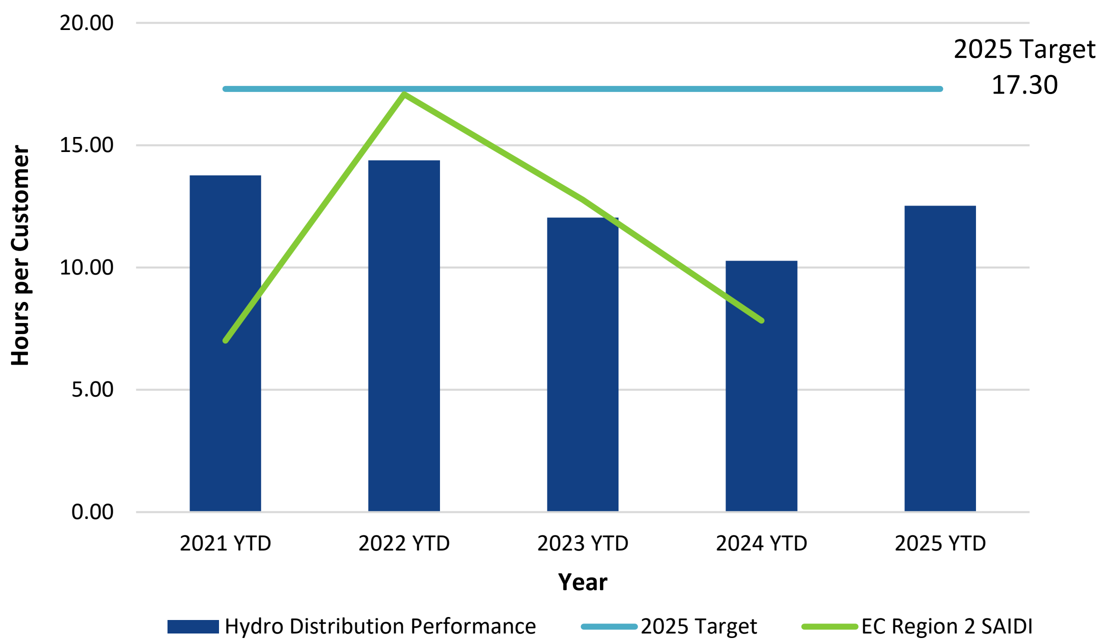

Chart 7: Service Continuity SAIDI

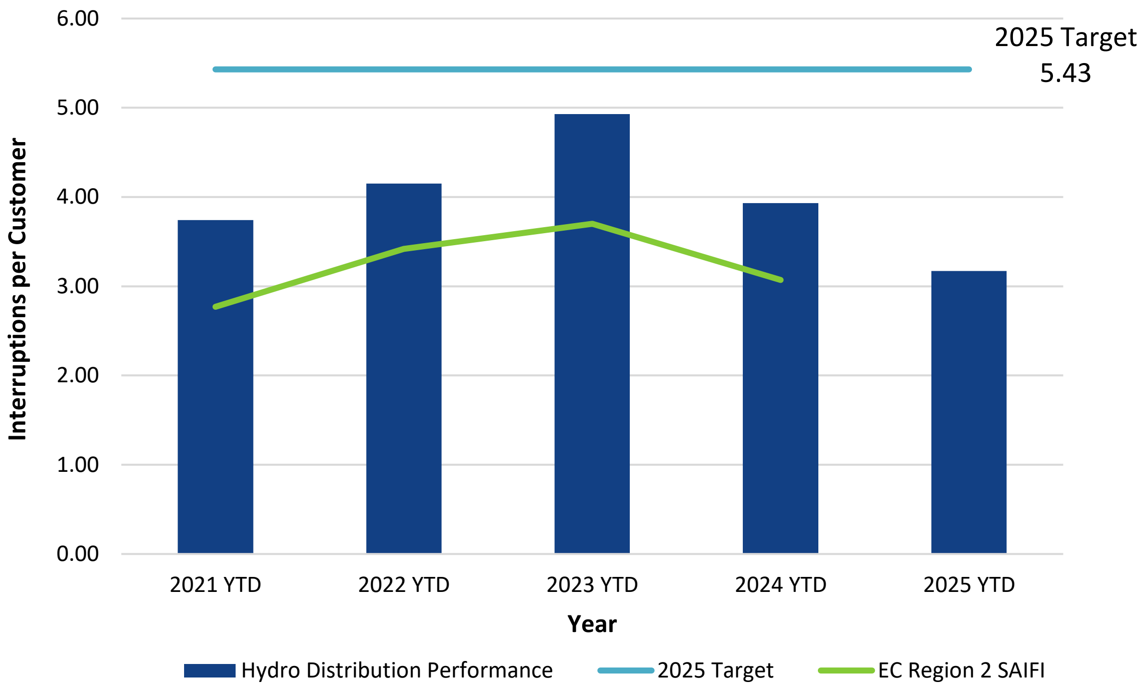

Chart 8: Service Continuity SAIFI

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 6.

Table 6: Customer Service Transactional Survey Data

Measure	Q3 2025	Q3 2024
Overall Satisfaction	87%	87%
First Call Resolution	87%	85%
Number of Surveys Completed	956	896

4.2 Customer Statistics

A summary of the number of Hydro customers in each customer class, including net metering, is provided in Table 7.

Hydro has received and approved one new net metering application during the current quarter. The application is for a Residential customer and has a capacity of 19 kW. The customer's system has not been installed, and Hydro's total number of net metering customers remains at three, with a total net metering capacity of 71.6 kW.

Table 7: Customer Statistics

	Q3		Annual	
	2025 Actual	**2024 Actual**	**2025 Budget**	**2024 Actual**
Rural Customers[12]	39,473	39,241	39,423	39,374
Industrial Customers	6	6	6	6
Labrador Industrial Transmission Customers[13]	2	2	2	2
Utility Customers	1	1	1	1
Average Monthly Reading Days	29.8	29.0	N/A	29.8
Net Metering Customers	3	3	N/A	3

5.0 Supply Costs and Energy Sales

5.1 Fuel Prices

Market prices for No. 6 fuel oil reached a high of $107/bbl in early August and a low of $98/bbl in mid-September.[14] The ending inventory cost for the current quarter was $108/bbl; this compares to the fuel price of $106/bbl that was reflected in Newfoundland Power's wholesale rates during the current quarter.[15]

There were no shipments of No. 6 fuel oil during the third quarter. Inventory at the end of the quarter was 450,631 bbls.

[12] Includes net metering customers.
[13] Iron Ore Company of Canada and Tacora Resources Inc.
[14] Prices for No. 6 fuel oil are provided in Canadian ("CDN") dollars.
[15] 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).

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, is provided in Chart 9.

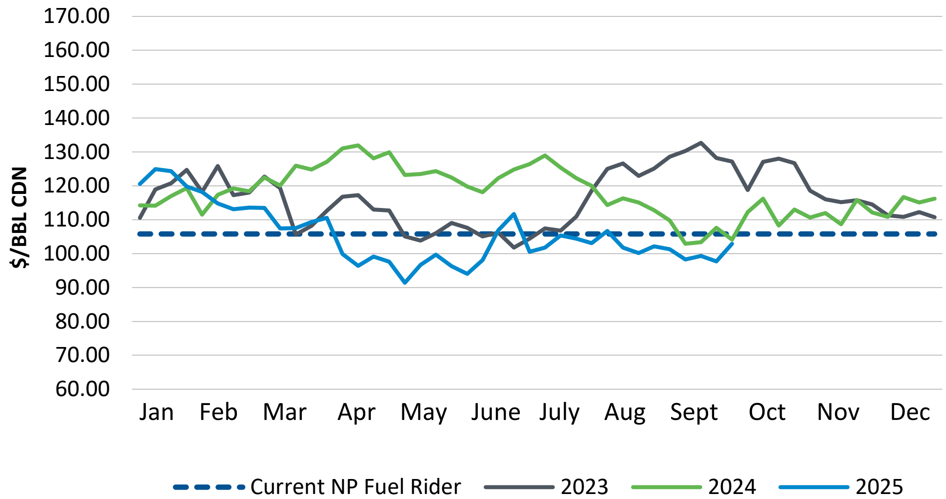

Chart 9: No. 6 Fuel Oil Average Weekly New York Spot Price

The monthly forecast price of No. 6 fuel oil for the next twelve months is provided in Table 8.[16]

Table 8: No. 6 Fuel Oil Forecast Prices ($CDN/bbl)

Month	Price
Oct-25	92.70
Nov-25	89.10
Dec-25	83.20
Jan-26	80.30
Feb-26	79.30
Mar-26	78.60
Apr-26	79.60
May-26	82.60
Jun-26	83.90
Jul-26	83.50
Aug-26	82.00
Sep-26	81.00

[16] The price forecast is based on Platts Analytics fuel price outlook, October 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 10.

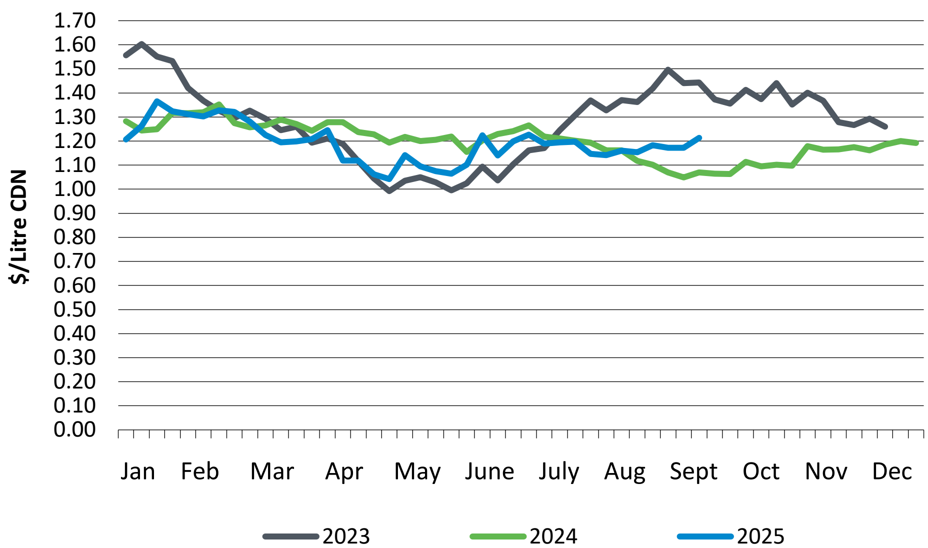

Chart 10: Ultra Low Sulphur No. 1 Diesel Weekly Montreal Rack Price

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 September 30, 2025, are reported in Attachment 2.

The 2025 YTD activity in the account decreased the balance by $127.2 million, primarily due to rate mitigation funding of $591.0 million ($441.0 million in February and $150.0 million in August). Payments made under the Muskrat Falls Power Purchase Agreement and Transmission Funding Agreement ($589.4 million) were partially offset by fuel savings at the Holyrood TGS ($43.5 million), and payments received from Newfoundland Power and Industrial customers related to the Project Cost Recovery Rider of $51.4 million and $5.4 million, respectively.

As per Order in Council OC2024-062, Hydro has been directed by the Government of Newfoundland and Labrador to retire the 2023 Supply Cost Variance Deferral Account balance of $271.3 million over the 2024–2026 period using its own sources of funding. In 2025, Hydro transferred $441.0 million of funding to its regulated operations, which includes $90.6 million of rate mitigation funding related to the retirement of the 2023 Supply Cost Variance Deferral Account.

The total balance in the account as of September 30, 2025, is $404.5 million.[17]

5.2.2 Isolated Systems Cost Variance Deferral Account

Hydro accumulated $4.8 million[18] in the Isolated Systems Cost Variance Deferral Account as of September 30, 2025. The current year's actual unit cost of diesel fuel was approximately 12¢/kWh more than the 2019 Test Year unit cost of fuel, which is the primary driver of the YTD 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 9. Pursuant to Board Order No. P.U. 30(2019), Hydro has calculated the transfers relative to the 2019 Test Year.

Table 9: Isolated Systems Cost Variance Deferral Account Transfers ($ Millions)[19]

Q3		
2025 Actual	2024 Actual	Variance
4.8	5.8	(1.0)

In accordance with the currently approved account definitions, Hydro filed its application for recovery of the Isolated Systems Cost Variance Deferral Account on March 12, 2025, before the March 31, 2025, deadline. This application included 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 YTD compared to that of other reporting periods is provided in Table 10.

[17] The September 30, 2025 Supply Cost Variance Deferral Account balance of $404.5 million is unaudited.
[18] The September 30, 2025 Isolated System Cost Variance Deferral balance of $4.8 million is unaudited.
[19] Net of deadbands.

Table 10: Statement of Energy Sold YTD (GWh)[20]

	YTD 2025 Actual	YTD 2024 Actual	YTD 2025 Target	2025 Annual Target
Island Interconnected				
Newfoundland Power	4,243	4,190	4,291	5,857
Island Industrials	369	325	443	584
Export and Other	210	529	-	-
Rural				
Domestic	195	188	187	254
General Service	131	120	114	155
Street Lighting	2	2	2	2
Subtotal Rural	**328**	**310**	**303**	**411**
Subtotal Island Interconnected	**5,150**	**5,354**	**5,037**	**6,852**
Island Isolated				
Domestic	4	4	3	4
General Service	1	1	1	2
Street Lighting	-	-	-	-
Subtotal Island Isolated	**5**	**5**	**4**	**6**
Labrador Interconnected				
Domestic	236	223	226	317
General Service	279	278	258	356
Non-Firm Energy	25	22	-	-
Street Lighting	1	1	1	1
Subtotal Labrador Interconnected	**541**	**524**	**485**	**674**
Labrador Isolated				
Domestic	19	19	19	25
General Service	13	13	14	18
Street Lighting	-	-	-	-
Subtotal Labrador Isolated	**32**	**32**	**33**	**43**
L'Anse-au-Loup				
Domestic	12	11	12	16
General Service	7	7	7	9
Street Lighting	-	-	-	-
Subtotal L'Anse-au-Loup	**19**	**18**	**19**	**25**
Total Energy Sold (Before Rural Accrual)	**5,747**	**5,933**	**5,578**	**7,600**
Rural Accrual	(59)	(81)	N/A	N/A
Total Energy Sold	**5,688**	**5,852**	**5,578**	**7,600**
Non-Regulated Customers[21]				
Labrador Industrials	1,402	1,361	1,452	1,957

[20] Numbers may not add due to rounding.
[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 $7 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 September 30, 2025, was $283 million. Table 11 shows the breakdown of Hydro's capital budget approvals of $283 million by Board Order.

[22] Originally approved on December 13, 2024.

Table 11: Capital Budget by Board Order as of September 30, 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]	7,269
Total Approved Capital Budget	**283,424**

1 Table 12 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 contributions in aid of construction (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 Works 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 of $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 12: Capital Expenditures Under $750,000
Approved by Hydro for the Quarter Ended September 30, 2025
($000)

Investment Class	**Title**	**Total Budget**	**Project/ Program**	**Description**
Renewal	Overhaul Main Enclosure (2025) - Harwoods	627.1	Project	The enclosure housing the gas turbine and its associated equipment is original to the Hardwoods Gas Turbine facility, and has been operational for 49 years. The metal structure and exterior components of the enclosure has experienced significant degradation over time. Despite interventions, corrosion has continued to advance to the point where the enclosure can no longer effectively prevent water ingress, creating a significant risk of damage to the sensitive turbine and generator components. The project scope involves stripping the failed coating from the enclosure, replacement of metal sheeting based on inspected condition, and reapplication of a protective coating system.
Renewal	Install Carbon Dust Collection System (2025-2026) – Hinds Lake	620.9	Project	The project scope is to design and install an integral carbon dust collection system on the Hinds Lake generator. Despite efforts to mitigate carbon dust accumulation, significant contamination has been observed on the stator windings, rotor poles, and within the brush gear housing, degrading the rotor insulation and compromising the integrity of the generator. This project is critical to maintain safe and reliable operation of the generating unit, and will be completed to align with the extended unit outage in 2026 to complete the stator rewind.[35]

[35] Originally approved under the Rewind Stator (2025–2026) – Hinds Lake project in Board Order No. P.U. 28(2024).

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 September 30, 2025, net of CIACs, was $281 million.

6.2 Capital Expenditures

Table 13 provides an overview of Hydro's capital expenditures for the current quarter.

Table 13: Capital Expenditures Overview for the Quarter Ended September 30, 2025, excluding Major Projects currently before the Board ($000)[36]

	Board-Approved Budget 2025[37]	Q3 Actual 2025	YTD Actual 2025	Forecast Remaining Expenditures 2025[38]
Access	5,007	1,363	3,641	1,615
General Plant	45,974	9,683	20,616	18,397
Mandatory	1,815	632	1,954	66
Renewal	160,924	61,287	119,027	47,416
Service Enhancement	11,377	3,589	7,684	3,955
System Growth[37]	9,947	3,160	4,113	350
Allowance for Unforeseen Expenditures	1,000	-	-	-
Total 2025[39,40,41]	**236,044**	**79,713**	**157,036**	**71,799**

6.3 2025 Capital Projects and Programs Progress

Hydro's approved planned capital projects and programs continue to advance through stages of planning, design, procurement, and construction. Typically, most of Hydro's capital construction activity occurs in the second, third, and fourth quarters of each year. Additionally, throughout the year, certain unplanned capital work, known as "break-in work," may arise and need to be addressed, which could

[36] Numbers may not add due to rounding.
[37] Excludes approved budget and expenditures related to Hydro's Early Execution Capital Work for Bay d'Espoir Unit 8 and Avalon Combustion Turbine project. For the latest budget and forecast information please refer to *Major Projects Monthly Update*, Newfoundland and Labrador Hydro, October 21, 2025.
[38] Forecast is based on assumptions made at a point in time and is subject to change.
[39] Expenditures are before CIACs.
[40] Table 13 does not include modifications to Hydro's infrastructure due to implementation of the Muskrat Falls Project, given that all aspects of incorporation of the Muskrat Falls Project are fully funded by the project (Labrador Hydro Project Exemption Order in Council OC2000-206 and OC2013-342, NLR 120/13). Expenditures related to these modifications were approximately $17,526 in the current quarter.
[41] The net FEED activity for the current quarter of $0.9 million and YTD of $(4.7) million has been excluded from total capital expenditures.

affect the amount of planned work that can be completed. Hydro's actual and forecast expenditures relative to the approved budget[42] are provided in Chart 11.

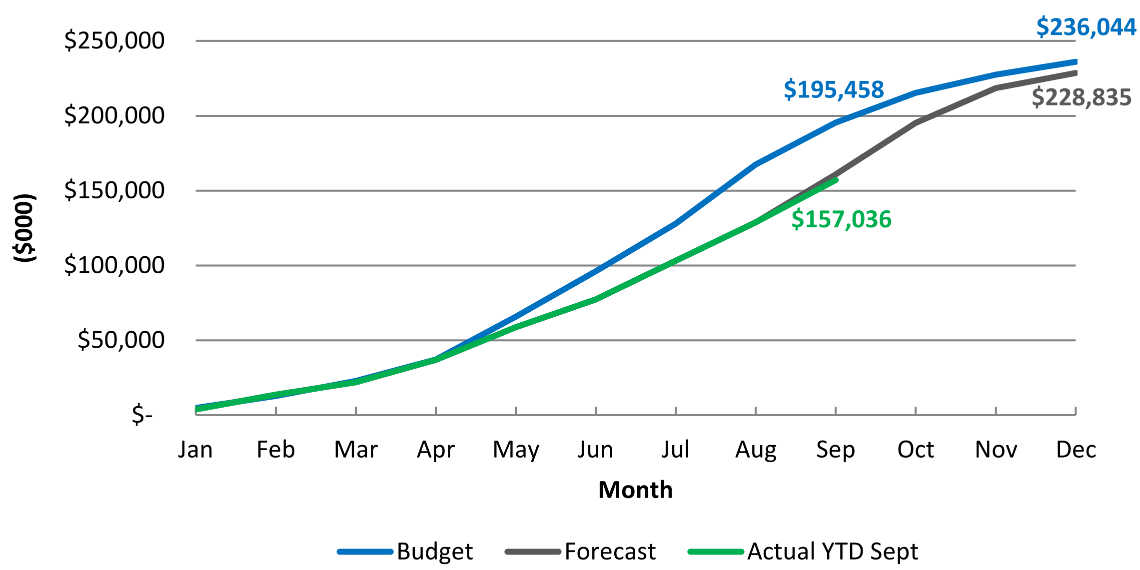

Chart 11: 2025 Capital Program Actual and Forecast vs Budget, excluding Major Projects currently before the Board[43]

To the end of the third quarter, Hydro's expenditures were approximately 20% below budget, primarily due to:

- Lower expenditures than the budget estimate for the Bay d'Espoir Penstock 1 Refurbishment project;[44]
- Re-pacing of scopes of work within programs resulting in forecasted lower expenditures than the budget estimates;
- Schedule changes within some multi-year projects resulting in forecasted carryover of expenditures into future years;
- Pause of some project scopes to re-assess scope, cost and justification; and

[42] Excludes approved budget and forecast expenditures related to Hydro's Early Execution Capital Work for Bay d'Espoir Unit 8 and Avalon Combustion Turbine project. For latest budget and forecast information, please refer to *Major Projects Monthly Update*, Newfoundland and Labrador Hydro, October 21, 2025.
[43] Excludes proposed expenditures related to Hydro's 2025 Build Application and Unit 7 Life Extension project.
[44] Completion of the Penstock 1 Life Extension project is now expected early December 2025.

- Carry over of some project scopes of work into 2026.

Hydro is forecasting to underspend the approved 2025 budget by approximately 3%, primarily due to:

- Schedule changes within some multi-year projects resulting in forecasted carryover of expenditures into future years;
- Re-pacing of scopes of work within programs resulting in forecasted lower expenditures than the budget estimates; and
- Planned scopes of work on some projects and programs being executed at forecasted lower costs than the budget estimates.

This forecast under-expenditure at year-end is partially offset by:

- Greater work volume to address findings of condition assessments than was allowed for in the budget estimates; and
- Planned scopes of work on some projects and programs being executed at forecasted higher costs than the budget estimates.

As required by the provisional Capital Budget Application Guidelines,[45] explanations will be provided for projects and programs with variances exceeding 10% and $100,000 at year-end, as part of Hydro's Capital Expenditures and Carryover Report.

A summary of the planned and break-in construction activities completed during the third quarter is provided in Table 14.

[45] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022.

Table 14: Highlights of Planned and Break-In Work[46] Completed

Asset Category	Planned Work Q3 2025	Break-In Work Q3 2025
Hydraulic Plant	Various turbine bushings and wear pads were replaced for Bay d'Espoir Units 1 and 2, as part of the unit overhauls. The Bay d'Espoir Complex domestic/fire water system condition assessment and upgrades were completed. The Bay d'Espoir Powerhouse 1 office area air conditioning unit was replaced. A diesel genset was replaced at Ebbegunbaeg Control Structure. The superstructure was refurbished at the Salmon River Spillway Structure. The Cat Arm Unit 1 turbine runner was replaced. The Cat Arm Unit 2 and common systems annunciator panels were replaced.	The Bay d'Espoir Unit 4 generator surface air cooler was replaced. The Bay d'Espoir Units 1 and 3 exciter slip rings were refurbished. The turbine inflatable seal was replaced for the unit at Granite Canal. Rescue tripods and self-retracing lanyards were procured.

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

Asset Category	Planned Work Q3 2025	Break-In Work Q3 2025
Thermal Plant	Condition assessment and miscellaneous upgrade work was completed for the Holyrood Units 1 and 2 boilers, and the Unit 3 boiler steam chest was refurbished. The Holyrood Unit 2 east boiler feed pump was overhauled. Upgrades were completed for the Holyrood Units 1, 2 and 3 distributed control systems hardware. The uninterruptible power supply for Holyrood Units 1 and 2 was upgraded. The Holyrood Shawmont Building[47] metal roofing system was replaced. The Holyrood sanitary sewer distribution line was replaced and the lift station was overhauled.	Steam heat tracing was replaced for the Holyrood heavy fuel oil storage Tanks 3 and 4, and the day tank. The Holyrood Unit 2 east boiler feedwater pump motor was overhauled.
Combustion Turbines	The fuel storage tank was inspected and refurbished at the Hardwoods Gas Turbine. The instrumentation for End A was upgraded at the Hardwoods Gas Turbine.	The main lubrication oil supply piping was replaced at the Hardwoods Gas Turbine.
Diesel Generation	The Charlottetown diesel engine for Unit 2088 was overhauled. The aftercooler was replaced at Port Hope Simpson. The intermediate fuel tanks were replaced at Nain. Generating Unit 1 switchgear was upgraded at Ramea.	The diesel engine for St. Brendan’s Unit 578 was overhauled. The generator for L’Anse-au-Loup Unit 2041 was refurbished. The cylinder heads for Mary’s Harbour Unit 2104 were replaced.

[47] The Shawmont Building is used as a storage facility.

Asset Category	Planned Work Q3 2025	Break-In Work Q3 2025
Transmission	Wood pole refurbishment work was completed for Transmission Lines TL 212, TL 214, TL 222 (between Stony Brook and South Brook Terminal Stations), TL 233, TL 241, and TL 259. Wood pole line inspections were completed for Transmission Line TL 250.	The eye bolt was replaced on Structure 427 of Transmission Line TL 207. The Gang Switch L40-11 on Line 40 in Labrador West was replaced.
Terminal Stations	Transformers T4 at Wabush Terminal Station and T16 at Holyrood Terminal Station were replaced. Refurbishment was completed for Transformers: • T1 and T2 at Holyrood Terminal Station; • T1 and T3 at Stephenville Terminal Station; and • T1 at Wiltondale Terminal Station. On-line dissolved gas analysis monitoring devices were installed for: Transformer T8 at Wabush Terminal Station and Transformer T3 at Stephenville Terminal Station. Circuit Breaker B3B4 at Wabush Terminal Station was replaced. The revenue metering tank was replaced at Doyles Terminal Station. Circuit breakers B7T2 at Hardwoods Terminal Station and B1L363 at Indian River Terminal Station were refurbished. Reclosing circuit breaker controllers were upgraded at Cat Arm Terminal Station (L47T1 and L47T2) and Deer Lake Terminal Station (B3L47). Disconnect switches were replaced at: • Massey Drive Terminal Station (B5L11-1 and B5L11-2/L11G);	A portion of a 69 kV wooden structure was replaced at Glenburnie. Buchans Transformer T1 refurbishment work was completed, including tap changer oil replacement, access hatch re-gasketing, and leak repairs. The 138 kV Disconnect Switch B1L56-BP was replaced at Bear Cove.

<table>
<tr><th>Asset Category</th><th>Planned Work Q3 2025</th><th>Break-In Work Q3 2025</th></tr>
<tr><td></td><td>

Oxen Pond Terminal Station (B2B3);
Holyrood Terminal Station (B12L68-1);
Sunnyside Terminal Station (B1L03-1); and
Stony Brook Terminal Station (L05L31-2).

A digital fault recorder was installed at Wabush Terminal Station.
The data alarm system was upgraded at Buchans Terminal Station.
Protective relays were replaced for:

Generator G1 and Transformer T1 at Granite Canal Generating Station;
Transformers T3 and GT1 at Stephenville Terminal Station;
Transformer T2 at Hardwoods Terminal Station
Transformer T4 at Sunnyside Terminal Station;
Transformer T1 at Massey Drive Terminal Station;
Transformer T1 at Grand Falls Frequency Convertor;
Transmission Line TL 232 at Buchans Terminal Station; and
Transmission Line TL 237 at Come by Chance and Western Avalon Terminal Stations.

Station lighting was replaced at Western Avalon Terminal Station.
</td><td></td></tr>
</table>

Asset Category	Planned Work Q3 2025	Break-In Work Q3 2025
Telecontrol	Remote terminal units were replaced at Granite Canal powerhouse and Indian River, Springdale, South Brook and Howley Terminal Stations. Closed-circuit television security cameras were replaced at Whitbourne Office and Nain Diesel Generating Station. The battery banks were replaced for the telecommunications systems at: • Hydro Place; • Plum Point Terminal Station; • Stephenville Terminal Station; • Ebbegunbaeg Control Structure; and • Burnt Dam Spillway Structure. Cut over to the upgraded supervisory control and data acquisition system was completed.	-
Information Systems	The centralized data historian system was upgraded at Hydro Place.	-
Properties	Refurbishment of exterior stairwells and walkways at Hydro Place was completed.	A dehumidifier was installed for the day care facility at Hydro Place.
Metering	Customer meters for medium-demand applications such as small businesses (Meter Forms 12S and 16S) were replaced at several locations.	Residential customer meter bases were replaced, where required for safe replacement of meters.
Transportation	Two heavy-duty vehicle “cherry-pickers” were received.	-

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 third quarter, Hydro had completed approximately 89% of the forecasted planned activities and completed 66% of the planned activities for 2025. Results for Annual Work Plan activities are provided in Table 15.

Table 15: Annual Work Plan Activity

YTD Actual			2025 Forecast		
Planned	**Completed**	**%**	**Baseline**	**Scheduled**	**%**
5,011	4,440	89	6,680	6,436	96

7.0 Financial

7.1 Statement of Income ($000)

Statement of Income - Regulated Operations
for the nine months ended September 30, 2025

($000)

Q3				YTD			Annual
2025 Actual	2025 Budget	2024 Actual		2025 Actual	2025 Budget	2024 Actual	2025 Budget
			Revenue				
98,082	97,257	95,626	Energy Sales	469,039	471,409	469,106	643,583
1,598	1,504	1,224	Other Revenue	6,519	4,515	5,700	6,045
99,680	**98,761**	**96,850**		**475,558**	**475,924**	**474,806**	**649,628**
			Expenses				
11,201	11,384	12,467	Fuels	160,008	157,146	163,306	233,775
14,722	14,614	12,515	Power Purchased	48,581	50,145	45,545	67,200
37,922	40,878	34,041	Operating Costs	116,111	121,244	111,471	158,112
-	-	24	Transmission Rental	-	-	24	-
24,252	23,189	22,375	Depreciation and Amortization	69,683	69,377	65,768	93,401
20,688	20,945	20,036	Net Finance Expense	62,189	65,078	62,574	86,714
541	539	544	Other Expense	1,284	1,618	1,744	2,157
109,326	**111,549**	**102,002**		**457,856**	**464,608**	**450,432**	**641,359**
(9,646)	**(12,788)**	**(5,152)**	**Net Income**	**17,702**	**11,316**	**24,374**	**8,269**

Net income for the nine months ending September 30, 2025, was $17.7 million, which is $6.7 million lower than the same period in 2024. The decrease in net income is primarily due to higher operating costs and depreciation expense partially offset by miscellaneous revenue.

8.0 People and Community

8.1 Diversity and Inclusion

8.1.1 Multiculturalism Fair

In July, as a way to recognize and celebrate the diverse cultures in our organization and community, our Inclusion, Diversity, Equity and Accessibility ("IDEA") Ambassadors in Hydro Place hosted Hydro's first Multiculturalism Fair. The day offered many ways to experience aspects of various cultures. Participants played a great round of Multicultural Trivia and had the opportunity to engage in various sessions and activities like henna, Bollywood Jig dancing and Tai Chi. Attendees also had the opportunity to try new and delicious food from vendors like Andaluzia Market, Mamacita Mexican Kitchen and Latin Market, and Grilleopatra. This well attended event was a fantastic way to help celebrate the many cultures that make up our Hydro team and we hope it's an initiative that will continue to grow each year!

8.1.2 National Day for Truth and Reconciliation

Each year Hydro recognizes National Day for Truth and Reconciliation – a day to honour the survivors of residential schools, their families and the children who never returned home. This year Jennifer Williams, Hydro President and CEO, was invited to attend the Gathering at Gull Island. Each year, in September the Innu people of Sheshatshiu organize the Manishan Nui Gathering at Gull Island – a week long community event with hundreds of people staying in traditional Innu tents and other infrastructures. The Gathering is a re-creation of and evocation of the past but also a place to perform current and cultural practices and is a place of learning. Ms. Williams shared her experience at The Gathering with all employees at Hydro and provided further learning opportunities in recognition of National Day for Truth and Reconciliation.

8.2 Community Initiatives

During the third quarter of 2025, Hydro partnered with our community partners in events around the province where our employees were able to volunteer and participate. Hydro also recognized the academic and community achievements of 17 students with the annual Hydro Family Scholarship Program awards.

8.2.1 Employees make their steps count for families in the province at the Red Shoe Crew Walk

In September, Hydro was proud to be the presenting sponsor for the 14th annual Ronald McDonald House Charties Newfoundland and Labrador, Red Shoe Crew Walk for Families. The walk, which takes place in communities throughout the province, raises much needed funds to support the facility and programs for families who stay at the House while their child is in St. John's for medical treatment.

Hydro employees in cities and town throughout the province organized, volunteered with and participated in the walk this year.

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

8.2.2 Hitting the Links in Support of Go Girls Programs

In August, Hydro joined Big Brothers Big Sisters of Eastern Newfoundland for their annual Go Girls Golf Tournament as a corporate sponsor and participating team. The tournament supports the Go Girls! Health Bodies, Healthy Minds mentoring program – a diversity mentoring program designed to address the physical activity, balanced eating and positive self-image needs of girls and those who identify as female and non-binary, ages 10-13.

The participating teams hit the course in Hydro-sponsored golf carts in support of this important program. With Hydro's commitment to diversity and inclusion, we were proud to again be part of this year's tournament and the efforts of Big Brothers Big Sisters in building awareness and support for such an important community initiative.

8.2.3 Supporting Students with Hydro's Family Scholarship Program

In September, Hydro awarded 17 scholarships to children and dependents of Hydro employees who entered post-secondary education this fall. In addition to 13 family scholarships, four memorial scholarships were also awarded honouring Jennifer Snow, Rick Leggo, Steve Power and Bill Walsh. Family scholarship recipients are chosen based on a combination of academics and community work while the memorial scholarships have additional considerations including the highest marks at Eric G. Lambert School (Jennifer Snow), involvement in mentoring and giving back to others (Rick Leggo), a dedication to live-long learning (Steve Power) and enrolment in a trades program (William Walsh).

This year, 40 students applied for a scholarship, this largest number of applicants since the program launched two decades ago. This year's program included students from St. John's, Churchill Falls, Bay d'Espoir, Whitbourne, Holyrood, L'Anse au Loup and St. Lewis.

8.2.4 Stepping Up on 9/11

On September 11, the Muskrat Falls Volunteer Emergency Response Team partnered with the Happy Valley-Goose Bay Volunteer Fire Department to complete the 110-story 9/11 Memorial Stair Climb. Started in 2005 to honour the firefighters and first responders who lost their lives on September 11, 2001, the challenge was introduced in Canada in 2021.

This year, Hydro participants raised more than $1,700 for local organizations including the SPCA, Labrador Friendship Centre, MS Canada, Kids Eat Smart and the Canadian Red Cross wildfire relief.

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
04-Jul-2025	Bottom Brook Terminal Station	Lightning	15,782	Up to 1 hour
05-Jul-2025	Fogo Island	Loss of Supply from Newfoundland Power. Suspected Lightning.	1,882	Up to 3 hours, 14 minutes
9-Jul-2025	South Brook	Defective Equipment	1,266	Up to 5 hours, 30 minutes
12-Jul-2025	Labrador East	Arcing on 138kV Disconnect	5,611	Up to 6 hours, 50 minutes
29-Jul-2025	Bottom Brook TS/Doyles TS	Failed Metering Tank	13,303	Up to 6 hours, 31 minutes
20-Sept-2025	Newfoundland Power	UFLS due to Pole 2 trip	55,327	Up to 44 minutes

Appendix B

Major Events Excluded From Performance Index Tables

Major Events

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

Year	Event Description	End-Consumer SAIDI	End-Consumer SAIFI	Service Continuity SAIDI	Service Continuity SAIFI	Transmission T-SAIDI	Transmission T-SAIFI
2025	No major events	N/A	N/A	N/A	N/A	N/A	N/A
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

July 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																															
	G2	170 MW																															
	G3	150 MW																															
	GT	123.5 MW																															
	Diesels	10 MW																															
Soldiers Pond Labrador-Island Link	Monopole ("M") Bipole ("B")	700 MW																															
Paradise River	Unit	8 MW																															
Stephenville	GT	50 MW								25	25	25																					
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	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

August 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																															
	G2	170 MW																															
	G3	150 MW																															
	GT	123.5 MW																															
	Diesels	10 MW																															
Soldiers Pond Labrador-Island Link	Monopole ("M") Bipole ("B")	700 MW																															
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	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

September 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																														
	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																		140	140	140	140	140	100	100		100	100	100	100	100
	G2	170 MW													115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
	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
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													
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

Supplemental Reliability Information

1.0 Service Continuity Performance

1.1 Service Continuity by Outage Type

Service Continuity SAIDI and SAIFI performance data, by outage type, are provided in Table D-1 and Table D-2, respectively. Hydro uses the average of each index for the period 2020 to 2024 to establish its annual targets for 2025 for these indexes.

Table D-1: Service Continuity SAIDI (Hours per Customer)[1]

	Q3		YTD			Annual Target
	2025	**2024**	**Target**	**2025**	**2024**	**2025**
Planned	0.63	0.99	N/A	0.85	1.49	N/A
Unplanned	4.58	2.41	N/A	11.67	8.78	N/A
Planned and Unplanned	**5.21**	**3.40**	**13.29**	**12.52**	**10.27**	**17.30**

Table D-2: Service Continuity SAIFI (Interruptions per Customer)[2]

	Q3		YTD			Annual Target
	2025	**2024**	**Target**	**2025**	**2024**	**2025**
Planned	0.17	0.49	N/A	0.27	0.77	N/A
Unplanned	1.04	0.97	N/A	2.90	3.16	N/A
Planned and Unplanned	**1.21**	**1.46**	**3.94**	**3.17**	**3.93**	**5.43**

1.2 Service Continuity Performance by Area

Service Continuity SAIDI and SAIFI performance data, broken down by geographical area, are provided in Table D-3 and Table D-4, respectively. The area performance indicators are calculated using the respective area customer count.[3]

[1] Planned outages consist of only planned distribution outages.
[2] Planned outages consist of only planned distribution outages.
[3] Hydro has aligned its geographical areas with its internal reporting; Northern and Central Regions within Transmission and Rural Operations were combined into 'Island Region.'

Table D-3: Service Continuity SAIDI

	Q3		YTD	
Area	**2025**	**2024**	**2025**	**2024**
Labrador Region	4.94	3.37	6.85	6.59
Island Region	5.39	3.41	16.36	12.76
All Areas[4]	5.21	3.40	12.52	10.27

Table D-4: Service Continuity SAIFI

	Q3		YTD	
Area	**2025**	**2024**	**2025**	**2024**
Labrador Region	1.27	1.57	2.65	3.63
Island Region	1.17	1.39	3.53	4.14
All Areas[5]	1.21	1.46	3.17	3.93

1.3 Service Continuity Performance by Origin

Service continuity SAIDI and SAIFI values, broken down by origin, are provided in Table D-5 and Table D-6, respectively.

Table D-5: Service Continuity SAIDI (Hours per Customer)

	Q3		YTD		Average
Origin	**2025**	**2024**	**2025**	**2024**	**2020–2024[6]**
Loss of Supply: Transmission	2.55	1.19	3.78	4.16	N/A
Distribution	2.66	2.21	8.74	6.11	N/A
Overall SAIDI	**5.21**	**3.40**	**12.52**	**10.27**	**17.30**

[4] All areas performance indicators are calculated using all of Hydro Rural customers; therefore, the area performances cannot be summed to provide all areas performances.

[5] *Supra,* f.n. 4.

[6] Hydro no longer averages LOS or Distribution values for internal reporting, as reliability assessments are now performed individually based on specific situations.

Table D-6: Service Continuity SAIFI (Interruptions per Customer)

	Q3		YTD		Average
Origin	**2025**	**2024**	**2025**	**2024**	**2020–2024**[7]
Loss of Supply: Transmission	0.52	0.51	1.21	1.50	N/A
Distribution	0.69	0.95	1.96	2.43	N/A
Overall SAIFI	**1.21**	**1.46**	**3.17**	**3.93**	**5.43**

1.4 Service Continuity Performance by Type

Service Continuity SAIDI and SAIFI values by type, broken down by geographical area, are provided in Table D-7. The area performance indicators are calculated using the area customer count.

Table D-7: Service Continuity by Interruption Type[8]

	Q3 2025 Unplanned		Q3 2025 Planned		Q3 2025 Total	
Area	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**
Labrador Region	4.73	1.17	0.21	0.10	**4.94**	**1.27**
Island Region	4.48	0.95	0.91	0.22	**5.39**	**1.17**
All Areas	**4.58**	**1.04**	**0.63**	**0.17**	**5.21**	**1.21**

1.5 Service Continuity Customer Interruptions by Cause

Service Continuity interruptions, grouped by cause, are provided in Table D-8.

Table D-8: Service Continuity by Cause of Interruption[9,10]

	Q3 2025		YTD	
Cause	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**
Adverse Environment	0.00	0.00	0.04	0.02
Adverse Weather	0.00	0.00	2.39	0.38
Defective Equipment	1.60	0.30	2.50	0.57
Foreign Interference	0.01	0.00	1.01	0.17
Human Error	0.00	0.00	0.15	0.04
Loss of Supply	2.55	0.52	3.78	1.21
Lightning	0.17	0.03	0.17	0.03
Scheduled Outage: Planned	0.63	0.17	0.85	0.27
Tree Contacts	0.02	0.06	0.66	0.13
Undetermined/Other	0.23	0.13	0.97	0.34
Total	**5.21**	**1.21**	**12.52**	**3.17**

[7] Hydro no longer averages LOS or Distribution values for internal reporting, as reliability assessments are now performed individually based on specific situations.
[8] Planned outages consist of only planned distribution outages.
[9] Some causes have been combined to align with Electricity Canada reporting requirements.
[10] Numbers may not add due to rounding.

2.0 Transmission System Average Restoration Index

Hydro's 2025 YTD T-SARI[11] was 211 minutes per interruption compared to 183 minutes per interruption for 2024 YTD. Hydro does not establish a restoration index target.

Chart D-1 shows the annual YTD T-SARI performance from 2021 to 2025 and the EC 2021 to 2024 annual T-SARI performances.

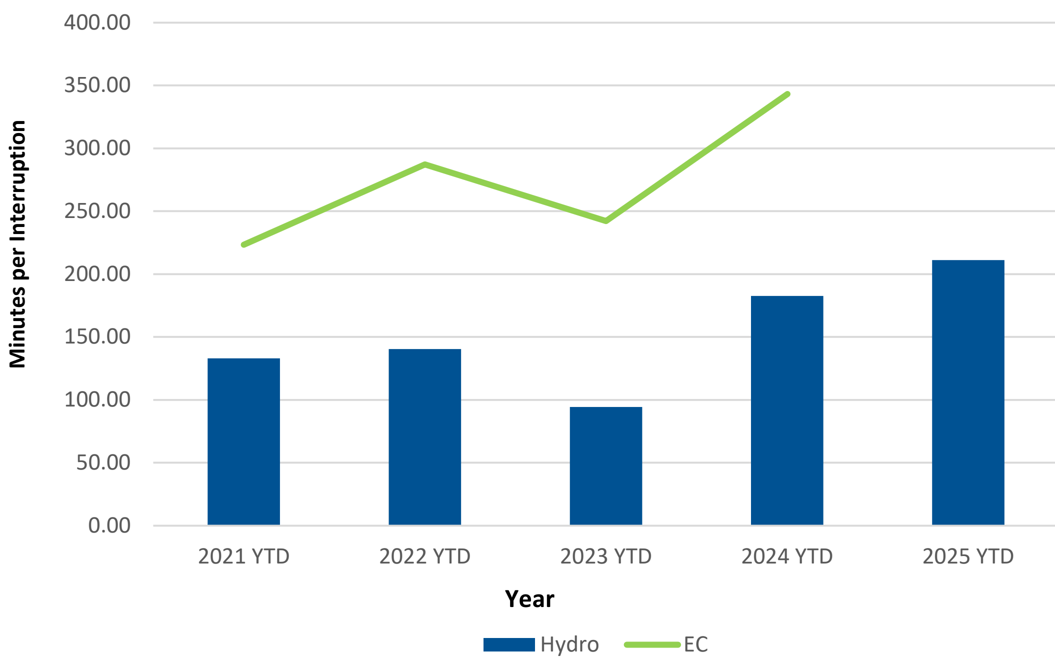

Chart D-1: T-SARI

3.0 Under Frequency Load Shedding

Performance data for UFLS events and UFLS undersupplied energy, by customer breakdown, are provided in Table D-9 and Table D-10, respectively. The 2025 UFLS target is zero events. Hydro does not establish a UFLS event YTD target or UFLS undersupplied energy targets. Performance data for UFLS events is provided in Chart D-2.

[11] T-SARI is calculated based on numbers that have not been rounded; therefore, T-SARI may not equate to T-SAIDI divided by T-SAIFI as presented in this report due to rounding.

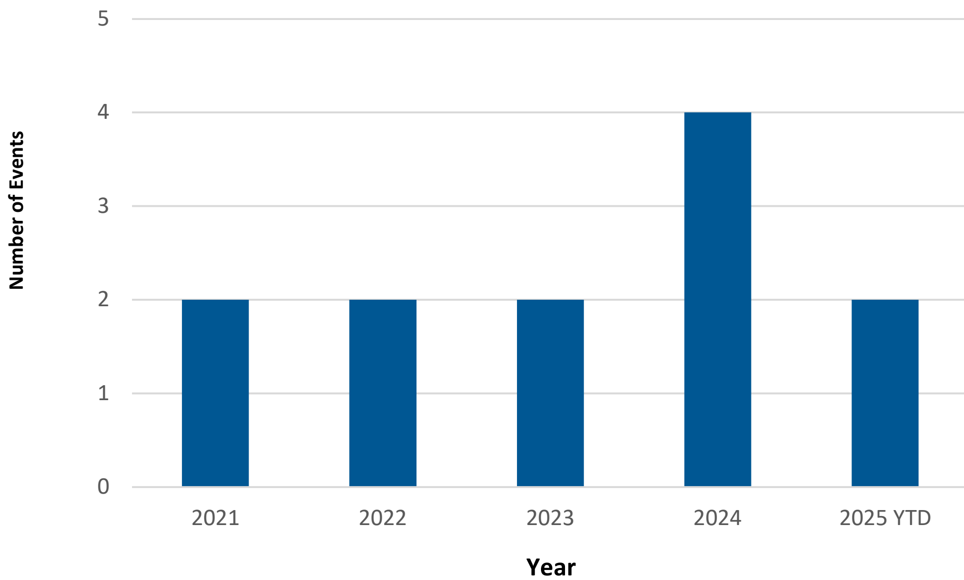

Chart D-2: UFLS Events

Table D-9: Customer Breakdown of UFLS Events

	Q3		YTD		Annual Target	Average
Customer	**2025**	**2024**	**2025**	**2024**	**2025**	**2020–2024**
Newfoundland Power	1	2	2	3	N/A	1.8
Industrials	0	2	1	2	N/A	1.8
Hydro Rural	0	0	0	0	N/A	0
Total Events[12]	**1**	**2**	**2**	**3**	**0**	**1.8**

Table D-10: Customer Breakdown of UFLS Undersupplied Energy (MW-min)

	Q3		YTD		Average
Customer	**2025**	**2024**	**2025**	**2024**	**2020–2024**
Newfoundland Power	1,848	255	3,528	1,095	2,750
Industrials	0	19	300	19	237
Hydro Rural	0	0	0	0	0
Total Undersupplied Energy[13]	**1,848**	**274**	**3,828**	**1,114**	**2,987**

[12] As individual UFLS events can affect customer types differently, totals may not be the sum of the customer types.
[13] *Supra*, f.n. 12.

Appendix E

Financial Schedules

Balance Sheet - Regulated Operations
as at September 30, 2025
($000)[1]

Assets	**September 2025**	**September 2024**
Current Assets		
Cash	1,731	4,682
Accounts Receivable[2]	66,966	67,043
Inventories	110,547	111,086
Current Portion of Sinking Fund Investments	114,475	9,820
Contract Receivable	5,736	2,165
Prepayments	9,254	8,628
Due from Related Parties	143	645
Promissory Note - Non-Regulated[1]	17,072	4,083
	325,924	**208,152**
Property, Plant, and Equipment	2,507,048	2,373,231
Intangible Assets	3,792	4,824
Sinking Fund Investments	104,597	198,336
Right-of-Use Assets	2,397	2,423
Long-Term Receivable	187	165
Regulatory Assets[2]	1,588,513	1,264,192
Total Assets	**4,532,458**	**4,051,323**

Liabilities and Shareholder's Equity		
Current Liabilities		
Short-Term Borrowings	473,000	400,000
Accounts Payable and Accrued Liabilities	92,998	104,688
Accrued Interest	23,656	23,656
Current Portion of Contract Payable	318,951	288,296
Current Portion of Long-Term Debt	235,454	6,650
Current Portion of Deferred Credits[1]	6,384	5,307
Current Portion of Deferred Contributions	1,228	981
Current Portion of Decommissioning Liabilities	1,360	96
Due to Related Parties	18,262	17,409
	1,171,293	**847,083**
Long-Term Debt	1,763,380	2,002,251
Deferred Contributions	69,298	67,185
Decommissioning Liabilities	32,436	27,396
Employee Future Benefits	87,020	80,155
Contract Payable	762,342	385,487
Long-Term Payable	824	824
Lease Liability	2,569	2,540
Regulatory Liabilities	15,706	21,227
Shareholder Contributions	100,000	100,000
Accumulated Other Comprehensive Income	9,490	12,896
Retained Earnings	518,100	504,279
Total Liabilities and Shareholder's Equity	**4,532,458**	**4,051,323**

[1] Comparative figures for Current Portion of Deferred Credits and Promissory Notes in Regulated and Non-Regulated, have been restated due to categorization of a third party contribution related to a non regulated project that was misclassified as regulated. Restated balances are as follows:
Q3 2024 Current Portion of Deferred Credits is restated from $6,106 to $5,307. Change of ($799).
Q3 2024 Promissory Note - Non-Regulated is restated from $4,882 to $4,083. Change of ($799).

[2] Comparative figures for Accounts Receivable and Regulatory Assets have been restated due to timing of a performance obligation where binding agreements were obtained in September 2024 and finalized in October 2024. Restated balance are as follows:
Q3 2024 Accounts Receivable is restated from $86,825 to $67,043. Change of ($19,782).
Q3 2024 Regulatory Assets is restated from $1,244,410 to $1,264,192. Change of $19,782.

Statement of Income - Regulated Operations
for the Nine Months Ended September 30, 2025
($000)

Q3 2025 Actual	Q3 2025 Budget	Q3 2024 Actual		YTD 2025 Actual	YTD 2025 Budget	YTD 2024 Actual	Annual 2025 Budget
			Revenue				
98,082	97,257	95,626	Energy Sales	469,039	471,409	469,106	643,583
1,598	1,504	1,224	Other Revenue	6,519	4,515	5,700	6,045
99,680	**98,761**	**96,850**		**475,558**	**475,924**	**474,806**	**649,628**
			Expenses				
11,201	11,384	12,467	Fuels	160,008	157,146	163,306	233,775
14,722	14,614	12,515	Power Purchased	48,581	50,145	45,545	67,200
37,922	40,878	34,041	Operating Costs	116,111	121,244	111,471	158,112
-	-	24	Transmission Rental	-	-	24	-
24,252	23,189	22,375	Depreciation and Amortization	69,683	69,377	65,768	93,401
20,688	20,945	20,036	Net Finance Expense	62,189	65,078	62,574	86,714
541	539	544	Other Expense	1,284	1,618	1,744	2,157
109,326	**111,549**	**102,002**		**457,856**	**464,608**	**450,432**	**641,359**
(9,646)	**(12,788)**	**(5,152)**	**Net Income**	**17,702**	**11,316**	**24,374**	**8,269**

Statement of Comprehensive Income - Regulated Operations
for the Nine Months Ended September 30, 2025
($000)

Q3				YTD		
2025 Actual	**2025 Budget**	**2024 Actual**		**2025 Actual**	**2025 Budget**	**2024 Actual**
(9,646)	(12,788)	(5,152)	Net Income	17,702	11,316	24,374
			Other Comprehensive Loss			
(164)	-	(249)	Employee Future Benefit Actuarial Loss	(490)	-	(747)
(9,810)	**(12,788)**	**(5,401)**	**Total Comprehensive Income**	**17,212**	**11,316**	**23,627**

Statement of Cash Flows - Regulated Operations
for the Nine Months Ended September 30, 2025
($000)

	YTD	
	2025	**2024**
Operating Activities		
Net Income	17,702	24,374
Adjusted for Items not Involving Cash Flow		
Depreciation and Amortization	69,683	65,768
Accretion of Asset Retirement Obligation and Long-Term Debt	1,919	1,858
Amortization of Deferred Contributions	(1,789)	(1,493)
Employee Future Benefits	2,204	1,703
Other	(14,954)	(12,396)
	74,765	**79,814**
Changes in Non-Cash Working Capital Balances		
Accounts Receivable[2]	57,014	37,767
Inventory	(6,800)	(10,380)
Prepaid Expenses	(5,066)	(3,950)
Regulatory Assets[2]	(141,281)	(414,510)
Regulatory Liabilities	(5,514)	275
Accounts Payable and Accrued Liabilities	(37,815)	(12,225)
Contract Payable	355,458	222,486
Accrued Interest	(1,707)	(1,706)
Contract Receivable	(2,809)	10,385
Due to/from Related Parties	(1,075)	18,006
	285,170	**(74,038)**
Financing Activities		
(Increase) decrease in Long-Term Receivable	(22)	30
(Decrease) increase in Deferred Credits[1]	(1,948)	1,651
Increase in Deferred Capital Contributions	2,965	3,355
(Decrease) increase in Promissory Notes[1]	(133,891)	152,427
	(132,896)	**157,463**
Investing Activities		
Additions to Property, Plant and Equipment	(163,745)	(105,288)
Additions to Intangible Assets	-	(1)
Increase in Sinking Funds	(6,650)	(6,650)
Changes in Non-Cash Working Capital Balances	16,702	3,846
	(153,693)	**(108,093)**
Net (Decrease) Increase in Cash	(1,419)	(24,668)
Cash Position, Beginning of Period	3,150	29,350
Cash Position, End of Period	**1,731**	**4,682**

[1] Comparative figures for Increase in Deferred Credits and Promissory Notes have been restated for transactions misclassified between Regulated and Non-Regulated Hydro.

[2] Comparative figures for Accounts Receivable and Regulatory Assets have been restated due to timing of a performance obligation where binding agreements were obtained in September 2024 and finalized in October 2024. Restated balance are as follows:
Q3 2024 Accounts Receivable is restated from $17,985 to $37,767. Change of $19,782.
Q3 2024 Regulatory Assets is restated from ($394,728) to ($414,510). Change of ($19,782).

Revenue Summary - Regulated Operations
for the Nine Months Ended September 30, 2025
($000)

Q3 2025 Actual	Q3 2025 Budget	Q3 2024 Actual		YTD 2025 Actual	YTD 2025 Budget	YTD 2024 Actual	Annual 2025 Budget
			Industrial				
9,913	10,694	9,032	Industrial	25,625	31,000	24,712	41,226
1,904	1,429	2,712	Industrial Load[1]	8,640	5,004	10,369	7,046
11,817	12,123	11,744	**Total Industrial**	34,265	36,004	35,081	48,272
			Utility				
71,929	68,844	68,749	Newfoundland Power Inc.	372,183	385,126	367,997	521,480
(732)	903	1,228	Utility Load[2]	1,095	(11,528)	6,750	(10,298)
71,197	69,747	69,977	**Total Utility**	373,278	373,598	374,747	511,182
15,068	15,387	13,905	**Rural**	61,496	61,807	59,278	84,129
			Other Revenue				
201	129	147	Sundry	940	388	732	542
411	409	411	Pole Attachments	1,233	1,227	1,233	1,636
596	576	497	Amortization of CIAC[3]	1,789	1,730	1,493	2,307
-	-	(221)	Recovery of Supply Power[4]	1,387	-	1,072	-
390	390	390	Generation Demand Recovery	1,170	1,170	1,170	1,560
1,598	**1,504**	**1,224**	**Total Other Revenue**	**6,519**	**4,515**	**5,700**	**6,045**
99,680	**98,761**	**96,850**	**Total Revenue**	**475,558**	**475,924**	**474,806**	**649,628**

[1] Industrial load represents the revenue load variance recognized through the Supply Cost Variance Deferral Account ("SCVDA").

[2] Utility load represents the revenue load variance recognized through the SCVDA.

[3] Contribution in aid of Construction ("CIAC").

[4] Recovery of Supply Power includes sales of emergency energy to Nova Scotia Power and in 2024 it also included the recovery of costs incurred by Newfoundland and Labrador Hydro as a result of advanced delivery of the Nova Scotia Block to Emera.

Supplementary Schedule - Regulated Operations
for the Nine Months Ended September 30, 2025
($000)

Q3 2025 Actual	Q3 2025 Budget	Q3 2024 Actual		YTD 2025 Actual	YTD 2025 Budget	YTD 2024 Actual	Annual 2025 Budget
			Interest				
			Interest Income				
4,040	3,948	3,868	Interest on Sinking Fund	11,904	11,792	11,360	15,696
429	163	992	Other Interest Income	2,057	488	2,925	650
4,469	**4,111**	**4,860**	**Total Interest Income**	**13,961**	**12,280**	**14,285**	**16,346**
			Interest Expense				
24,431	24,431	24,431	Interest on Long-Term Debt	73,294	73,294	73,294	97,725
3,973	2,547	5,450	Interest on Short-Term Debt	10,698	9,983	15,375	13,547
2,252	2,253	2,235	Debt Guarantee Fee	6,756	6,760	6,705	9,014
676	639	624	Accretion	1,919	1,901	1,857	2,536
(286)	(273)	(546)	RSP[1] Interest	(1,007)	(968)	(1,745)	(1,191)
(4,854)	(3,567)	(6,543)	SCVDA[2] Interest	(13,497)	(11,806)	(16,861)	(15,557)
19	12	13	Other	48	35	52	47
26,211	**26,042**	**25,664**	**Total Interest Expense**	**78,211**	**79,199**	**78,677**	**106,121**
(1,054)	(986)	(768)	Interest Capitalized during Construction	(2,061)	(1,841)	(1,818)	(3,061)
25,157	25,056	24,896		76,150	77,358	76,859	103,060
20,688	**20,945**	**20,036**	**Net Interest Expense**	**62,189**	**65,078**	**62,574**	**86,714**

[1] Rate Stabilization Plan ("RSP").
[2] Supply Cost Variance Deferral Account (SCVDA).

Balance Sheet - Non-Regulated Activities
as at September 30, 2025
($000)[1]

Assets	**September 2025**	**September 2024**
Current Assets		
Cash	654,018	718,777
Accounts Receivable	34,578	24,489
Inventories	2,193	2,548
Current Portion of Sinking Fund Investments	4,280	4,201
Prepayments	3,844	3,988
Deferred Asset	20,977	17,033
Related Party Loan Receivable	555,342	705,342
Due from Related Party	26,872	43,083
	1,302,104	**1,519,461**
Property, Plant, and Equipment	1,889,588	1,891,968
Intangible Assets	20,923	26,629
Sinking Fund	30,191	31,121
Investment in Joint Arrangement	806,325	763,275
Investment in Subsidiaries	5,105,474	4,764,170
Total Assets	**9,154,605**	**8,996,624**

Liabilities and Shareholder's Equity		
Current Liabilities		
Accounts Payable and Accrued Liabilities	68,041	56,321
Current Portion of Decommissioning Liabilities	3	177
Current Portion of Deferred Credits [2]	99,961	97,253
Derivative Liabilities	19,164	13,533
Other Current Liabilities	14,741	34,434
Due to Related Party	4,983	6,018
Promissory Note[2]	17,072	4,103
	223,965	**211,839**
Deferred Credits	1,480,884	1,534,466
Employee Future Benefits	21,798	20,211
Other Long-Term Liabilities	38,123	36,211
Share Capital	122,504	122,504
Shareholder Contributions	4,658,210	4,658,210
Accumulated Other Comprehensive Income	(34,970)	(39,240)
Retained Earnings	2,644,091	2,452,423
Total Liabilities and Shareholder's Equity	**9,154,605**	**8,996,624**

[1] Nalcor Energy and Newfoundland and Labrador Hydro were legislatively amalgamated effective January 1, 2025. As a result, comparative figures were updated to reflect the results of the combined entity. This means that beginning in Q1 2025, the 2024 comparative figures were updated to reflect the post-amalgamation corporate structure.

[2] Comparative figures for Current Portion of Deferred Credits and Promissory Note in Regulated and Non-Regulated, have been restated due to categorization of a third party contribution related to a non regulated project that was misclassified as regulated.

Statement of Income - Non-Regulated Activities
for the Nine Months Ended September 30, 2025
($000)[1]

Q3 2025 Actual	Q3 2025 Budget	Q3 2024 Actual		YTD 2025 Actual	YTD 2025 Budget	YTD 2024 Actual	Annual 2025 Budget
			Revenue				
14,799	13,080	12,482	Energy Sales	48,692	49,491	45,767	64,948
10,250	9,640	9,135	Other Revenue	29,705	25,327	23,703	33,297
25,049	**22,720**	**21,617**		**78,397**	**74,818**	**69,470**	**98,245**
			Expenses				
13,677	12,825	12,274	Power Purchased	50,504	54,382	63,043	68,208
16,458	10,546	13,524	Operating Costs	42,625	29,350	36,977	38,449
5,157	4,760	4,714	Transmission Rental	17,216	14,280	14,142	19,040
9,596	9,694	9,462	Depreciation and Amortization	29,112	29,081	28,583	38,774
(4,286)	(3,169)	(7,723)	Interest	(12,060)	(11,640)	(22,171)	(15,504)
142,665	150,039	143,194	Other Expense[2]	589,371	683,595	239,329	683,634
183,267	**184,695**	**175,445**		**716,768**	**799,048**	**359,903**	**832,601**
(158,218)	**(161,975)**	**(153,828)**	Net Operating Loss	**(638,371)**	**(724,230)**	**(290,433)**	**(734,356)**
			Other Revenue				
263	(2,117)	(470)	Equity in CF(L)Co	26,256	18,616	30,154	31,345
3,924	1,333	3,134	Preferred Dividends	8,785	3,999	7,276	5,333
155,581	235,224	102,821	Equity in Subsidiaries	647,700	659,545	564,193	821,550
159,768	**234,440**	**105,485**		**682,741**	**682,160**	**601,623**	**858,228**
1,550	**72,465**	**(48,343)**	**Net Income (Loss)**	**44,370**	**(42,070)**	**311,190**	**123,872**

[1] Nalcor Energy and Newfoundland and Labrador Hydro were legislatively amalgamated effective January 1, 2025. As a result, comparative figures were updated to reflect the results of the combined entity. This means that beginning in Q1 2025, the 2024 comparative figures were updated to reflect the post-amalgamation corporate structure.

[2] The balance in Other Expense is related to the fair value valuation of the Energy Marketing - Hydro Power Purchase agreement derivative liability and associated gains and losses as a result of changes in forecasted energy prices as well as rate mitigation transfers under the Province's rate mitigation plan.

Statement of Retained Earnings - Non-Regulated Activities
for the Nine Months Ended September 30, 2025
($000)[1]

Q3 2025 Actual	Q3 2024 Actual		YTD 2025 Actual	YTD 2024 Actual
2,642,541	2,500,766	Balance, Beginning of Period	2,599,721	2,141,233
1,550	(48,343)	Net Income	44,370	311,190
2,644,091	**2,452,423**	Balance, End of Period	**2,644,091**	**2,452,423**

[1] Nalcor Energy and Newfoundland and Labrador Hydro were legislatively amalgamated effective January 1, 2025. As a result, comparative figures were updated to reflect the results of the combined entity. This means that beginning in Q1 2025, the 2024 comparative figures were updated to reflect the post-amalgamation corporate structure.

Statement of Comprehensive Income - Non-Regulated Activities
for the Nine Months Ended September 30, 2025
($000)[1]

Q3 2025 Actual	Q3 2025 Budget	Q3 2024 Actual		YTD 2025 Actual	YTD 2025 Budget	YTD 2024 Actual	Annual 2025 Budget
1,550	72,465	(48,343)	Net Income (Loss)	44,370	(42,070)	311,190	123,872
			Other Comprehensive Income (Loss)				
926		1,218	Share of other comprehensive income of joint arrangement	1,792		1,493	
868	-	643	Share of other comprehensive income of subsidiaries	2,622	-	1,680	-
3,344	**72,465**	**(46,482)**	**Total Comprehensive Income (Loss)**	**48,784**	**(42,070)**	**314,363**	**123,872**

[1] Nalcor Energy and Newfoundland and Labrador Hydro were legislatively amalgamated effective January 1, 2025. As a result, comparative figures were updated to reflect the results of the combined entity. This means that beginning in Q1 2025, the 2024 comparative figures were updated to reflect the post-amalgamation corporate structure.

Statement of Cash Flows - Non-Regulated Activities
for the Nine Months Ended September 30, 2025
($000)[1]

	YTD 2025	YTD 2024
Operating Activities		
Net Income	44,370	311,190
Adjusted for Items not Involving Cash Flow		
Depreciation and Amortization	29,112	28,583
Share of profit of Joint Arrangement	(26,256)	(30,154)
Share of profit of Subsidiaries	(647,700)	(564,193)
Amortization of Deferred Credits	(64,658)	(73,671)
Maritime Link Operating Costs	13,284	(219)
Net Changes in PPA[2] Fair Value	(1,813)	(3,500)
Employee Future Benefits	1,463	1,532
Accretion of long-term payables	1,682	1,531
Sinking fund earnings	(958)	(990)
Other	4	(213)
	(651,470)	**(330,104)**
Changes in Non-Cash Working Capital Balances		
Accounts Receivable	2,337	(4,081)
Accounts Payable and Accrued Liabilities	3,093	13,410
Due to/from Related Parties	16,199	(35,039)
Prepaid Expenses	(88)	41
Inventories	-	(1)
Other Liabilities	(3,247)	25,763
	(633,176)	**(330,011)**
Financing Activities		
Proceeds from related party promissory note	150,000	150,000
Increase in promissory notes[3]	16,891	17,590
Change in deferred credits[3]	22,691	26,386
	189,582	**193,976**
Investing Activities		
Additions to property, plant and equipment	(24,091)	(14,192)
Dividends from Subsidiaries	234,923	223,338
Distributions from Subsidiaries	115,120	229,034
Changes in Non-Cash Working Capital Balances	(9)	839
	325,943	**439,019**
Net (Decrease) Increase in Cash	(117,651)	302,984
Cash Position, Beginning of Period	771,669	415,793
Cash Position, End of Period	**654,018**	**718,777**

[1] Nalcor Energy and Newfoundland and Labrador Hydro were legislatively amalgamated effective January 1, 2025. As a result, comparative figures were updated to reflect the results of the combined entity. This means that beginning in Q1 2025, the 2024 comparative figures were updated to reflect the post-amalgamation corporate structure.

[2] Power Purchase Agreement ("PPA") between Newfoundland and Labrador Hydro and Nalcor Energy Marketing.

[3] Comparative figures for Current Portion of Deferred Credits and Promissory Note in Regulated and Non-Regulated, have been restated due to categorization of a third party contribution related to a non regulated project that was misclassified as regulated.

Attachment 1

Rate Stabilization Plan Report (Unaudited)

Quarter Ended September 30, 2025

Newfoundland and Labrador Hydro
Rate Stabilization Plan Report
September 30, 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 RSP Rules for Balance Disposition approved 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
September 30, 2025

	A	B	C	D	E	F	G	H
	Load Variation ($)	Allocation Fuel Variance ($)	Allocation Rural Rate Alteration ($)	Subtotal Monthly Variances ($) (A + B + C)	Financing Charges ($)	Adjustment[1,2] ($)	Transfers[3] ($)	Cumulative Net Balance ($) (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								
November								
December								
YTD	-	-	-	-	996,437	(19,108,579)	6,462,978	(11,649,164)
Total	**-**	**-**	**-**	**-**	**996,437**	**(19,108,579)**	**6,462,978**	**18,938,949**

[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
September 30, 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							
November							
December							
YTD	-	-	-	10,688	(335,433)	-	(324,745)
Total	**-**	**-**	**-**	**10,688**	**(335,433)**	**-**	**74,588**

[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
September 30, 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			
November			
December			

Attachment 2

Supply Cost Variance Deferral Account Report (Unaudited)

Quarter Ended September 30, 2025

Newfoundland and Labrador Hydro
Supply Cost Variance Deferral Account
September 30, 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 of Commissioners of Public Utilities ("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 will be trued-up to reflect the actual short-term cost of borrowing for 2025.

Supply Cost Variance Deferral Account[1]
Summary
September 30, 2025

	Supply Cost Variance Deferral Account Balance ($) (from page 3)	Utility Balance ($) (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	589,159,074	(24,271,770)	-	**564,887,304**
February	181,833,391	(26,204,311)	-	**155,629,080**
March	266,221,473	(27,877,456)	-	**238,344,017**
April	325,075,069	(29,519,140)	-	**295,555,929**
May	368,217,548	(30,927,793)	-	**337,289,755**
June	421,779,613	(31,818,850)	-	**389,960,763**
July	480,297,258	(32,989,144)	-	**447,308,114**
August	381,752,972	(34,094,354)	-	**347,658,618**
September	439,691,600	(35,215,938)	-	**404,475,662**
October				
November				
December				

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

Supply Cost Variance Deferral Account
Section A: Summary
September 30, 2025

	Muskrat Falls Project Cost Variance ($)	Rate Mitigation Fund[2,3] ($)	Project Cost Recovery Rider		Holyrood TGS[6] Fuel Cost Variance ($)	Other IIS[7] Supply Cost Variance ($)	Net Revenue From Exports Variance[8] ($)	Transmission Tariff Revenue Variance ($)	Load Variation		Greenhouse Gas Credit Revenue Variance ($)	Subtotal Monthly Variances ($)	Financing Charges[1]			Transfers ($)	Cumulative Net Balance ($)
			Utility[4] ($)	Industrial[5] ($)					Utility[9] ($)	Industrial ($)			Utility ($)	Industrial ($)	Other ($)		
	(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	(484,059)	(16,187)	2,771,939	-	589,159,074
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)	(515,327)	(18,404)	2,948,121	-	181,833,391
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	(547,470)	(20,086)	1,312,714	-	266,221,473
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	(575,454)	(22,316)	1,688,753	-	325,075,069
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	(600,291)	(24,055)	1,956,512	-	368,217,548
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	(621,503)	(26,352)	2,156,821	-	421,779,613
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	(636,002)	(28,532)	2,392,998	-	480,297,258
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)	(655,566)	(31,668)	2,655,505	-	381,752,972
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	(675,135)	(34,904)	2,274,473	-	439,691,600
October																	
November																	
December																	
YTD	**589,358,057**	**(591,000,000)**	**(51,399,010)**	**(5,375,081)**	**(43,515,272)**	**(14,383,089)**	**(8,835,068)**	**(13,482,311)**	**1,095,166**	**8,639,912**	**(374,498)**	**(129,271,194)**	**(5,310,807)**	**(222,504)**	**20,157,836**	**-**	**(114,646,669)**
Total	**2,155,025,186**	**(1,166,433,434)**	**(169,519,028)**	**(9,324,948)**	**(212,975,155)**	**(88,551,245)**	**(134,810,097)**	**(58,241,795)**	**72,189,242**	**58,272,981**	**(55,974,801)**	**389,656,906**	**(12,180,964)**	**(305,790)**	**62,521,448**	**-**	**439,691,600**

[1] Financing charges accrued at the 2024 short-term cost of borrowing of 5.03%. In December, finance costs will be trued up to reflect the actual short-term cost of borrowing for 2025.
[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, 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.
[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 Account to the Net Revenue from Exports component within the Supply Cost Variance Deferral Account.
[9] 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.

Supply Cost Variance Deferral Account
Section B: Utility Customer Balance
September 30, 2025

	Allocation Rural Rate Alteration[1] ($)	Financing Charges ($)	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)	(92,713)	-	(24,271,770)
February	(1,833,075)	(99,466)	-	(26,204,311)
March	(1,565,759)	(107,386)	-	(27,877,456)
April	(1,527,441)	(114,243)	-	(29,519,140)
May	(1,287,683)	(120,970)	-	(30,927,793)
June	(764,314)	(126,743)	-	(31,818,850)
July	(1,039,899)	(130,395)	-	(32,989,144)
August	(970,020)	(135,190)	-	(34,094,354)
September	(981,864)	(139,720)	-	(35,215,938)
October				
November				
December				
YTD	**(11,525,306)**	**(1,066,826)**	**-**	**(12,592,132)**
Total	**(32,661,043)**	**(2,554,895)**	**-**	**(35,215,938)**

[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.

Supply Cost Variance Deferral Account
Section B: Industrial Customers Balance[1]
September 30, 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
September 30, 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					
November					
December					
Total	**242,035,125**	**-**	**347,322,933**	**-**	**589,358,057**

[1] Power Purchase Agreement ("PPA").

[2] Transmission Funding Agreement ("TFA").

Supply Cost Variance Deferral Account
Holyrood TGS Fuel Cost Variance
September 30, 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									
November									
December									
Total	**758,386**	**5,777**	**752,609**	**114.22**	**85,960,717**	**1,222,625**	**105.90**	**129,475,988**	**(43,515,272)**

[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
September 30, 2025

	Thermal Variation[1] ($)	Off-Island Power Purchase Variation[1] ($)	On-Island Power Purchase Variation[1] ($)	CBPP Firm Energy Variation[1] ($)	Current Month Variation ($)	YTD Variation ($)	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								
November								
December								
Total	**(2,303,733)**	**(5,999,747)**	**(6,579,609)**	**-**	**(14,883,089)**			

[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
September 30, 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						
November						
December						
Total	**-**	**5,711,673**	**6,557,163**	**2,277,905**	**8,835,068**	**(8,835,068)**

[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 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
September 30, 2025

	Test Year ($) ($I_T$)	Actual ($) (I)	Total Variation ($) ($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			
November			
December			
Total	**-**	**13,482,310**	**(13,482,311)**

Supply Cost Variance Deferral Account
Load Variation - Utility
September 30, 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					
November					
December					
Total	**4,227,400,000**	**4,243,392,910**	**(15,992,910)**		**1,095,166**

[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
September 30, 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)	$(J_T - J_A) \times K_R$ (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					
November					
December					
Total	**555,800,000**	**360,680,013**	**195,119,987**		**8,639,912**

Supply Cost Variance Deferral Account
Rural Rate Alteration
September 30, 2025

	Price ($)	Volume ($)	Total[1] ($)	Utility Allocation[1] ($) (to page 4)	Labrador Interconnected Allocation[1] ($)	Balance ($)
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						
November						
December						
Total	**(11,419,846)**	**(573,189)**	**(11,993,035)**	**(11,525,306)**	**(467,729)**	**-**

[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 Credit Revenue Variance
September 30, 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			
November			
December			
Total	**-**	**374,498**	**(374,498)**

Supply Cost Variance Deferral Account
Rate Mitigation Fund
September 30, 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			
	-	**591,000,000**	**(591,000,000)**

[1] 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, 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.

[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	13,822
BA[2] Interest	1,910
CORRA[3] Interest	4,517
Operating Line of Credit Interest	-
Standby and Upfront Fee	573
Brokerage Fee	299
Debt Guarantee Fee – Recoverable Portion Only	288
Total Short-Term Borrowing Costs	**21,409**
Weighted Average Short-Term Debt Balance[4]	**425,842**
Short-Term Cost of Borrowing 2024	**5.03%**

[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, financing costs will be trued up to reflect the actual short-term cost of borrowing for 2025.

[2] Banker's Acceptance ("BA").

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

[4] 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
September 30, 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					
November					
December					
Subtotal	**2,020,671**	**766,307**	**1,254,364**	**3,736,513**	**(2,482,148)**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
September 30, 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					
November					
December					
Subtotal	**721,234**	**-**	**721,234**	**727,752**	**(6,518)**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
September 30, 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					
November					
December					
Subtotal	**527,964**	**-**	**527,964**	**405,665**	**122,300**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
September 30, 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					
November					
December					
Subtotal	**96,686**	**-**	**96,686**	**31,446**	**65,239**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
September 30, 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					
November					
December					
Subtotal	**13,137**	**-**	**13,137**	**15,742**	**(2,606)**
Total Thermal Generation Cost Variance					**(2,303,733)**

Supply Cost Variance Deferral Account
Off-Island Power Purchase Variance
September 30, 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			
November			
December			
Subtotal	**3,048,339**	**8,672,647**	**(5,624,308)**

Supply Cost Variance Deferral Account
Off-Island Power Purchase Variance
September 30, 2025

Labrador-Island Link	**Actual Cost ($)**	**Test Year Cost ($)**	**Off-Island Power Purchase Variation ($)**
	(A)	**(B)**	**(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			
November			
December			
Subtotal	**105,236**	**480,674**	**(375,439)**
Total Off-Island Power Purchase Variance			**(5,999,747)**

Supply Cost Variance Deferral Account
On-Island Purchases Variance
September 30, 2025

Nalcor Exploits	Actual Production (kWh) (A)	Cost of Service Production (kWh) (B)	Monthly Production Variance (kWh) (C) = (A - B)	Cost of Service Cost (¢/kWh) (D)	Power Purchase Variation ($) (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					
November					
December					
Subtotal	**420,409,412**	**476,838,480**	**(56,429,068)**		**(2,257,164)**

Supply Cost Variance Deferral Account
On-Island Purchases Variance
September 30, 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					
November					
December					
Subtotal	**95,757,027**	**105,366,000**	**(9,608,973)**		**(384,359)**

Supply Cost Variance Deferral Account
On-Island Purchases Variance
September 30, 2025

Rattle Brook	Actual Production (kWh) (A)	Cost of Service Production (kWh) (B)	Monthly Production Variance (kWh) (C) = (A - B)	Cost of Service Cost (¢/kWh) (D)	Power Purchase Variation ($) (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					
November					
December					
Subtotal	**8,352,950**	**10,380,000**	**(2,027,050)**		**(172,527)**

Supply Cost Variance Deferral Account
On-Island Purchases Variance
September 30, 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					
November					
December					
Subtotal	**32,830,700**	**50,550,000**	**(17,719,300)**		**(3,338,316)**

Supply Cost Variance Deferral Account
On-Island Purchases Variance
September 30, 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					
November					
December					
Subtotal	**68,298,577**	**75,800,000**	**(7,501,423)**		**(541,602)**

Supply Cost Variance Deferral Account
On-Island Purchases Variance
September 30, 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					
November					
December					
Subtotal	**62,531,911**	**61,050,000**	**1,481,911**		**114,359**
Total On-Island Purchases Variance					**(6,579,609)**

Tab 2

Contribution in Aid of Construction

Quarter Ended September 30, 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 Quarter

Type of Service	CIACs Quoted	CIACs Outstanding from Last Quarter	Total CIACs Quoted	CIACs Accepted	CIACs Expired	CIACs Outstanding
Domestic						
Within Plan Boundary	3	0	3	0	0	3
Outside Plan Boundary	0	4	4	1	1	2
Subtotal	**3**	**4**	**7**	**1**	**1**	**5**
General Service	2	2	4	2	2	0
Total	**5**	**6**	**11**	**3**	**3**	**5**

[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 Quarter

Date Quoted	Service Location	CIAC Number	CIAC Amount ($)	Estimated Construction Costs ($)	Accepted
Domestic: Within Residential Planning Boundaries					
03-Jul-2025	Pilleys's Island	2071955	11,020	15,950	
11-Aug-2025	Rocky Harbour	2081120	13,340	18,270	
24-Sep-2025	Little Seldom	2083606	5,040	9,970	
Domestic: Outside Residential Planning Boundaries					
n/a	n/a	n/a	n/a	n/a	
General Service					
08-Aug-2025	English Harbour West	1622772	1,786,976	3,250,700	
26-Aug-2025	King's Point	2084511	42,398	47,328	Yes

Tab 3

Customer Damage Claims

Quarter Ended September 30, 2025

newfoundland labrador hydro

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[1]

				Claims Accepted			Claims Rejected		Claims Outstanding	
Region	**# Received**	**# Outstanding Since Last Quarter**	**Total**	**#**	**Amount Claimed ($)**	**Amount Paid ($)**	**#**	**Amount ($)**	**#**	**Amount ($)**
Central	4	10	**14**	2	2,006	816	3	7,097	9	14,559
Northern	1	7	**8**	1	11,716	3,835	0	0	7	18,648
Labrador	2	1	**3**	0	0	0	1	1,569	2	8,250
Total	**7**	**18**	**25**	**3**	**13,722**	**4,650**	**4**	**8,666**	**18**	**41,457**

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	2	2	**4**	0	0	0	0	0	4	3,751
Northern	4	8	**12**	2	1,942	1,668	4	910	6	566,487[2]
Labrador	3	0	**3**	0	0	0	2	3,785	1	2,800
Total	**9**	**10**	**19**	**2**	**1,942**	**1,668**	**6**	**4,695**	**11**	**573,038**

[1] Numbers may not add due to rounding.

[2] 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	1	1	**2**	0	0	0	1	800	1	1,900
Power Interruptions	4	1	**5**	0	0	0	2	2,086	4	6,504
Improper Workmanship	0	4	**4**	0	0	0	0	0	4	17,744
Weather Related	0	2	**2**	0	0	0	0	0	2	2,734
Equipment Failure	1	8	**9**	3	13,722	4,650	1	5,780	5	4,675
Third Party	0	0	**0**	0	0	0	0	0	0	0
Miscellaneous	1	0	**1**	0	0	0	0	0	1	5,750
Awaiting Investigation[3]	0	2	**2**	0	0	0	0	0	1	2,150
Total	**7**	**18**	**25**	**3**	**13,722**	**4,650**	**4**	**8,666**	**18**	**41,457**

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

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	0	0	**0**	0	0	0	0	0	0	0
Improper Workmanship	1	3	**4**	1	1,502	1,502	1	0	2	561,543[5]
Weather Related	0	2	**2**	0	0	0	0	0	2	1,756
Equipment Failure	3	4	**7**	1	441	167	4	1,360	2	2,094
Third Party	2	0	**2**	0	0	0	1	3,335	1	2,800
Miscellaneous	1	0	**1**	0	0	0	0	0	1	100
Awaiting Investigation[3]	2	1	**3**	0	0	0	0	0	3	4,745
Total	**9**	**10**	**19**	**2**	**1,942**	**1,668**	**6**	**4,695**	**11**	**573,038**

[3] 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.
[4] Numbers may not add due to rounding.
[5] This claim has now been resolved as reported in Q1 2025.