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October 8, 2024

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
Director of Corporate Services and Board Secretary

Re: Quarterly Regulatory Report for the Quarter Ended December 31, 2023

Enclosed is Newfoundland and Labrador Hydro's financial update to its Quarterly Regulatory Report for the fourth quarter of 2023, originally filed with the Board of Commissioners of Public Utilities on February 15, 2024, and revised on March 12, 2024.

For ease of reference, revisions to the most recent filing have been highlighted in yellow. The following items have been updated:

- Tab 1: Quarterly Summary:
  - Highlights;
  - Section 2.2;
  - Section 5.2.1;
  - Section 5.2.2;
  - Section 6.2;
  - Section 6.3;
  - Section 7.1;
  - Appendix D;
    - Section 2.0;
    - Section 3.1.1;
    - Section 3.1.3;
    - Section 3.1.4;
    - Section 3.2.1;
    - Section 3.3;
    - Section 3.3.1;
    - Section 3.3.2;
    - Section 3.3.3;

  - Section 3.3.4;
  - Section 3.3.5;
  - Section 4.0; and
  - Attachment 3, enclosed in full.
- Appendix E, enclosed in full; and
- Attachment 1.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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

Encl.

ecc:

Board of Commissioners of Public Utilities
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Newfoundland Power Inc.
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Island Industrial Customer Group
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Denis J. Fleming, Cox & Palmer
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Quarterly Regulatory Report

Quarter Ended December 31, 2023

Original Submission: February 14, 2024
Revision 1: March 12, 2024
Financial Update: October 8, 2024

A report to the Board of Commissioners of Public Utilities

Index

Tab 1

Quarterly Summary

Quarter Ended December 31, 2023

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Abbreviations

Term	Definition
AIF	All-Injury Frequency
Bay d'Espoir Facility	Bay d'Espoir Hydroelectric Generating Facility
bbl	Barrel
Board	Board of Commissioners of Public Utilities
Cat Arm Station	Cat Arm Hydroelectric Generating Station
CIAC	Contribution in Aid of Construction
DAFOR	Derated Adjusted Forced Outage Rate
DAUFOP	Derated Adjusted Utilization Forced Outage Probability
EC	Electricity Canada (Formerly known as the Canadian Electricity Association)
EMS	Environmental Management System
FTE	Full-time equivalent
Granite Canal Station	Granite Canal Hydroelectric Generating Station
Hinds Lake Station	Hinds Lake Hydroelectric Generating Station
Holyrood TGS	Holyrood Thermal Generating Station
Hydro	Newfoundland and Labrador Hydro
KPI	Key Performance Indicators
LIL	Labrador-Island Link
LTIF	Lost-Time Injury Frequency
Newfoundland Power NP	Newfoundland Power Inc.

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

Definitions

Current Quarter: The period beginning September 30, 2023 and ending December 31, 2023.

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.

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

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

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

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

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

1 # 1.0 Highlights

Table 1: Highlights YTD

	2023 Actual	2023 Target	2022 Actual
Safety and Environment			
Lead/Lag Ratio	315:1	1,000:1	851:1
AIF Rate	1.14	<0.60	0.92
LTIF Rate	0.63	<0.15	0.26
Achievement of EMS Targets (%)	97	95	98
Reliability			
SAIDI	2.33	2.77	2.44
SAIFI	1.32	1.11	1.08
Production			
Holyrood No. 6 Fuel Oil Average Cost ($/bbl)	124	112	125
Holyrood Efficiency (kWh/bbl)	540	583	573
Electricity Delivery (GWh)			
Energy Sales	7,885	7,450	7,857[1]
Financial ($ Millions)[2]			
Revenue	654.7	642.1	650.8
Operating Expenses	142.8	136.1	130.5
Net Income	32.0	31.4	36.3
RSP ($ Millions)[3]			
RSP Balance	47.4	47.6	52.3
Supply Cost Variance Deferral Account ($ Millions)[4]			
Cumulative Net Balance	271.3	439.3	190.4
FTE Employees[5]			
Regulated	804.30	N/A	789.8

[1] Restated to reflect Exports scheduled at Bottom Brook.
[2] Financial figures exclude non-regulated activities.
[3] The RSP report for the current quarter is provided as Attachment 1.
[4] Computed based on methodology presented in "Supply Cost Accounting Compliance Application," Newfoundland and Labrador Hydro, January 21, 2022.
[5] Figures shown are net FTEs.

2.0 Safety and Health

2.1 Safety at Hydro

Hydro experienced a tragic incident on August 10, 2023, resulting in a workplace fatality. Hydro has undertaken an internal investigation and is using its learnings to inform safety and health priorities within the company.

Safety remains Hydro's first 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 that are similar to that contained in ISO 45001. Completing investigations into workplace incidents to prevent future incidents 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 initiatives include:

- A continued focus on hazard awareness and injury prevention through the development of improved hazard recognition, evaluation and control processes, and injury prevention campaign initiatives;
- Improving contractor safety management; and
- Completing Safety and Health Monitoring Plan targeted inspections, audits, and field compliance audits.

2.2 Safety Performance

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

Table 2: Safety Performance Detail[6]

	YTD Q4 2023	YTD Q3 2023	YTD Q4 2022
Fatalities	1	1	0
Lost-Time Injuries	5	1	2
Medical Treatment Injuries	3	4	5
Lead/Lag Ratio	315:1	338:1	851:1
AIF Rate	1.14	1.05	0.92
LTIF Rate	0.63	0.18	0.26
Severity Rate (Days Lost)	39.40(312)	3.33(19)	1.31(10)
High-Potential Incidents	4	3	2

One of the previously reported medical treatment injuries changed to a lost-time injury during this quarter. In addition, Hydro experienced two lost-time injuries during the current quarter, resulting in an YTD AIF rate of 1.14 and an LTIF rate of 0.63. Hydro's lost-time severity rate was 39.40, based on 312 days of lost time from the five lost-time injuries.

A comparison of Hydro's AIF and LTIF rates over the past five years and the 2023 rates is provided in Chart 1. Hydro's annual lost-time severity rate for the past five years compared to 2023 is provided in Chart 2.

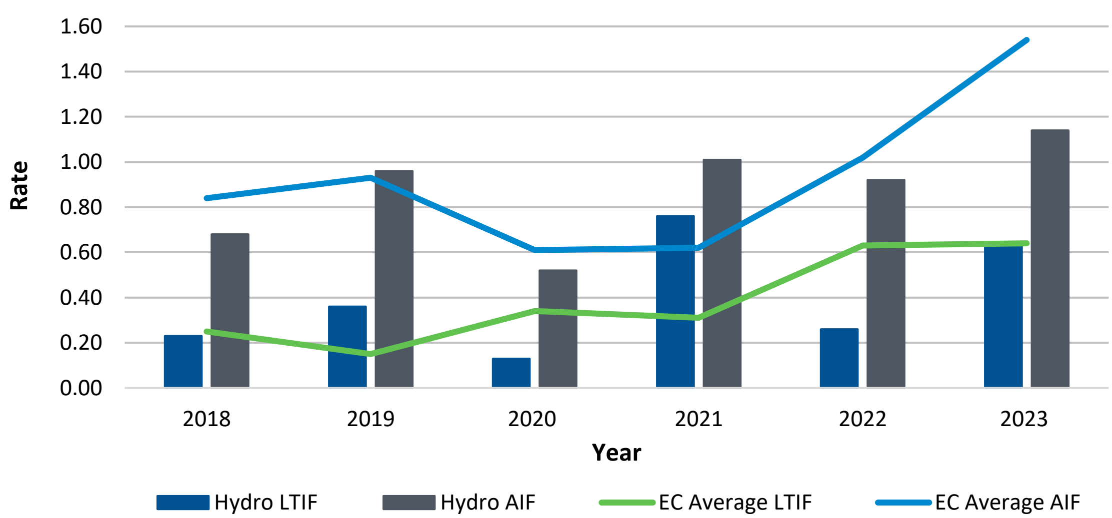


Chart 1: Hydro's AIF and LTIF Compared to EC Averages[7,8]

[6] Injury statistics reflect regulated Hydro employees only.
[7] Safety and Health performance metrics are compared to EC utility members in Group 2 (300–1,500 employees), except in 2022 where we fell in Group 1 (1,500+ employees).
[8] [ ]

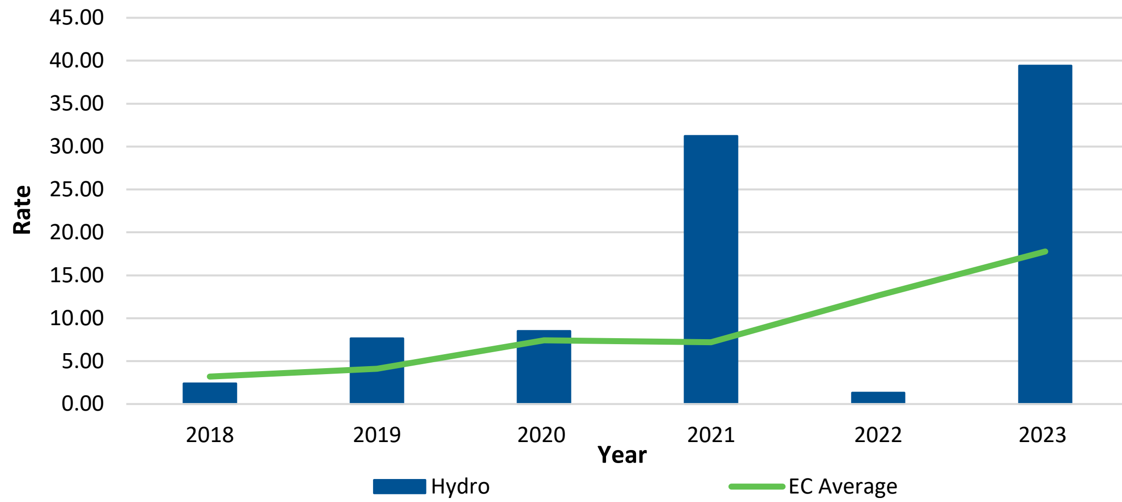


Chart 2: Hydro's Lost-Time Severity Rate Compared to EC Average[9,10]

2.3 Line Contacts

As shown in Table 3, Hydro had three reportable line contact incidents by third parties 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.

Table 3: Line Contact Equipment/Vehicle Incidents

Date	Location	Incident Description
20-Nov-2023	West Pond	Excavator tore service drop from customers mast
30-Nov-2023	Makkovik	Dump truck hooked neutral wire
03-Dec-2023	Trout River	Public vehicle collided with pole

[9] Safety and Health performance metrics are compared to EC utility members in Group 2 (300–1,500 employees), except in 2022 where we fell in Group 1 (1,500+ employees).
[10] [ ]

3.0 Reliability

3.1 Outage Information

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

Outages result from such causes as:

- Adverse environment;
- Adverse weather;
- Defective equipment;
- Foreign interference;
- Human error;
- Loss of supply;
- Lightning;
- Planned outages;
- Tree contact; and
- Unknown/other causes.

As electrical systems are neither constructed nor expected to fully withstand extreme weather conditions such as hurricanes 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. A summary of major events from 2018 to 2023, including the associated impact the major events would have had on performance indicators, is provided in Appendix B.

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

A summary of customer reliability indicators is provided in Table 4. Additional information on these reliability indicators is included in Appendix D.

Table 4: Reliability Indicators

	Current Quarter	
	2023	**2022**
End-Consumer SAIDI	0.69	0.44
End-Consumer SAIFI	0.24	0.31
T-SAIDI	187	34
T-SAIFI	1.02	0.32
Service Continuity SAIDI	4.53	3.11
Service Continuity SAIFI	1.35	0.78
UFLS Events	0	2

4.0 Customer Service

4.1 Customer Transactional Surveys

Survey results for the current quarter indicate that approximately 85% of customers were satisfied with the service they received when they reached out to Hydro's Customer Service department for assistance and 84% of customers felt their concern was resolved with the first call. Participation by customers declined versus the same quarter last year.[12] A summary of these results is provided in Table 5.

Table 5: Customer Service Transactional Survey Data

Measure	Q4 2023	Q4 2022
Overall Satisfaction	85%	85%
First Call Resolution	84%	86%
Number of Surveys Completed	568	688

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

[12] Similar to the previous quarter, the current provider of the telephone survey experienced technical difficulties during the current quarter, contributing to the decline in responses compared to the same quarter last year. Hydro is reviewing options to modify its survey delivery to remedy this issue for the future.

4.2 Customer Statistics

A summary of the number of Hydro customers in each customer class, including net metering, is provided in Table 6.

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

Table 6: Customer Statistics

	2023 Actual	2022 Actual	2023 Budget
Rural Customers[13]	39,221	39,101	39,126
Industrial Customers	5	5	6
Labrador Industrial Transmission Customers[14]	2	2	2
Utility Customers	1	1	1
Average Monthly Reading Days	30.0	30.1	N/A
Net Metering Customers	3	3	N/A

5.0 Supply Costs and Energy Sales

5.1 Fuel Prices[15]

Market prices for No. 6 fuel oil reached a high of $128/bbl in mid-October and a low of $111/bbl in late December. The ending inventory cost for the current quarter was $119/bbl; this compares to the fuel price of $105.90/bbl that was reflected in Newfoundland Power's wholesale rates during the current quarter.[16]

There was one shipment of No. 6 fuel oil during the fourth quarter. Hydro purchased 207,224 bbls at a cost of approximately $111/bbl. Inventory at the end of the quarter was 343,421 bbls.

A comparison of No. 6 fuel oil prices in 2023 as compared to 2021 and 2022 as well as the fuel oil price reflected in the wholesale rate to Newfoundland Power are provided in Chart 3.

[13] Includes net metering customers.
[14] Iron Ore Company of Canada and Tacora Resources Inc.
[15] Prices for No. 6 fuel oil are provided in Canadian ("CDN") dollars.
[16] The price of $105.90/bbl is reflected in Newfoundland Power's base rates effective October 1, 2019, as per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 30(2019), Board of Commissioners of Public Utilities, September 11, 2019.

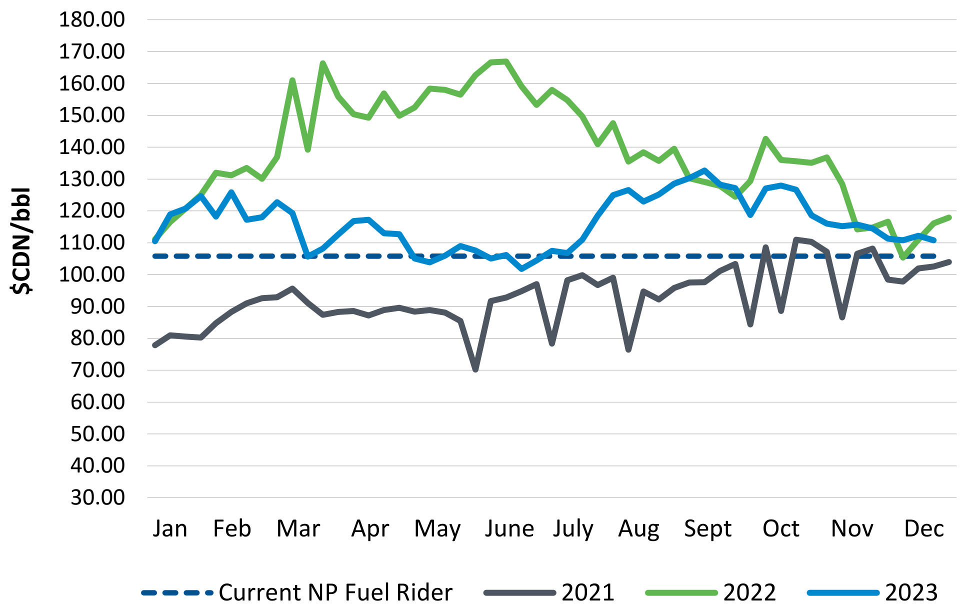


Chart 3: No. 6 Fuel Oil Average Weekly New York Spot Price

1 The monthly forecast price of No. 6 fuel oil is provided in Table 7.[17]

Table 7: No. 6 Fuel Oil Forecast Prices ($CDN/bbl)

Month	Price
January 2024	108.30
February 2024	104.60
March 2024	106.00
April 2024	116.20
May 2024	122.70
June 2024	127.10
July 2024	130.10
August 2024	128.60
September 2024	128.30
October 2024	121.50
November 2024	115.40
December 2024	107.90

2 A comparison of the Ultra Low Sulphur Diesel No. 1 (used in diesel generation) fuel oil prices in 2023 as
3 compared to 2021, and 2022 is provided in Chart 4.

[17] The price forecast is based on Platts Analytics fuel price outlook, November 2023 World Oil Market Forecast and includes the premium for the No. 6 fuel oil.

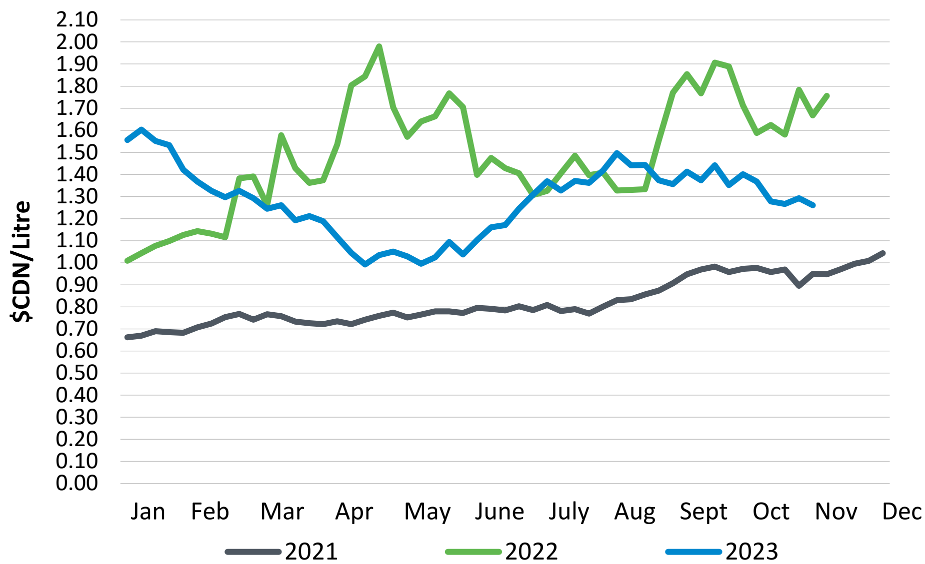


Chart 4: Ultra Low Sulphur No. 1 Diesel Weekly Montreal Rack Price

5.2 Transfers to Supply Cost Deferral Accounts

5.2.1 Supply Cost Variance Deferral Account Overview

The balances accumulated in the Supply Cost Variance Deferral Account as at December 31, 2023 are reported in Attachment 2. During 2023, the activity in the account increased the balance by $80.9 million, primarily as a result of $335.1 million in rate mitigation funding received.

On March 30, 2023, Hydro received correspondence from the Minister of Industry, Energy and Technology regarding the provision of a $190.4 million grant for the purposes of rate mitigation. This grant was credited to the Rate Mitigation Fund component of the Supply Cost Variance Deferral Account in March 2023, settling the December 31, 2022 balance.

In 2022, as part of the provincial government's rate mitigation plan, Hydro, the Government of Newfoundland and Labrador, and the Government of Canada signed term sheets enabling access, upon commissioning of the LIL, to a $1.0 billion investment in the LIL by the Government of Canada in the form of a convertible debenture. On August 15, 2023, the first drawing on the convertible debenture of $144.7 million was received by LIL (2021) Limited Partnership; on August 28, 2023, the funds were transferred to Hydro for the purpose of rate mitigation. This funding was credited to the Rate Mitigation Fund component of the Supply Cost Variance Deferral Account, further reducing the balance.

The 2023 YTD payments made under the Muskrat Falls Power Purchase Agreement ("Muskrat Falls PPA") and Transmission Funding Agreement were $577.5 million. This increase in costs was offset by fuel savings at the Holyrood TGS ($48.9 million), Greenhouse Gas Performance Credits sold in 2023 ($23.1 million), payments received from Newfoundland Power related to the Project Cost Recovery Rider (implemented on July 1, 2022), which is credited to the Utility component of the Supply Cost Variance Deferral Account ($46.8 million), and rate mitigation received ($144.7 million).[18] The total balance in the account as at December 31, 2023 is $271.3 million.[19]

5.2.2 Isolated Systems Cost Variance Deferral Account

Hydro accumulated $12.1 million[20] in the Isolated Systems Cost Variance Deferral Account as at December 31, 2023. The current year's actual unit cost of diesel fuel was approximately 18¢/kWh more than the 2019 Test Year unit cost of fuel, which is the primary driver of the YTD transfer of fuel oil costs to this account this year.

The current year transfers to the Isolated Systems Cost Variance Deferral Account are provided in Table 8. Pursuant to Board Order No. P.U. 30(2019), Hydro has calculated the transfers relative to 2019 Test Year.

Table 8: Isolated Systems Cost Variance Deferral Account Transfers ($ Millions)[21]

2023 Actual	2022 Actual	Variance
12.1	9.0	3.1

In accordance with the currently approved account definitions, Hydro will file its application for recovery of the Isolated Systems Cost Variance Deferral Account on or before March 31, 2024. This application will include the final transfer amounts as well as detailed information as to the drivers of the transfers.

5.3 Statement of Energy Sold

A summary of Hydro's energy sales YTD compared to that of other reporting periods is provided in Table 9.

[18] Of the $335.1 million in rate mitigation received in 2023, $144.7 million offset the 2023 payments made under the Muskrat Falls PPA while $190.4 million settled the December 31, 2022 balance in the account.
[19] [ ]
[20] [ ]
[21] Net of deadbands.

Table 9: Statement of Energy Sold (GWh)

	2023 Actual	2022 Actual[22]	2023 Budget
Island Interconnected			
Newfoundland Power	5,858	5,509	5,708
Island Industrials	334	387	590
Export and Other	529	770	0
Rural			
Domestic	250	240	237
General Service	159	176	167
Street Lighting	3	3	3
Subtotal Rural	**412**	**419**	**407**
Subtotal Island Interconnected	**7,133**	**7,085**	**6,705**
Island Isolated			
Domestic	4	4	4
General Service	1	2	2
Street Lighting	-	-	-
Subtotal Island Isolated	**5**	**6**	**6**
Labrador Interconnected			
Domestic	302	315	319
General Service	402	389	349
Street Lighting	1	2	2
Subtotal Labrador Interconnected	**705**	**706**	**670**
Labrador Isolated			
Domestic	19	19	25
General Service	17	18	19
Street Lighting	-	-	-
Subtotal Labrador Isolated	**36**	**37**	**44**
L'Anse-au-Loup			
Domestic	15	15	16
General Service	9	9	9
Street Lighting	-	-	-
Subtotal L'Anse-au-Loup	**24**	**24**	**25**
Total Energy Sold (Before Rural Accrual)	**7,903**	**7,858**	**7,450**
Rural Accrual	(18)	(1)	N/A
Total Energy Sold	**7,885**	**7,857**	**7,450**
Non-Regulated Customers[23]			
Labrador Industrials	1,798	1,961	2,116

[22] Restated to reflect exports scheduled at Bottom Brook.
[23] Does not include non-regulated sales for export.

6.0 Asset Management and Investment

6.1 2023 Capital Budget

Hydro's 2023 Capital Budget was approved by the Board in Order No. P.U. 2(2023).[24] In addition to approval for an investment of $91 million in capital projects, Hydro carried forward approximately $40 million from its 2022 capital program. As a result, Hydro's opening capital budget for 2023 was $131 million. Additionally, supplemental capital of $16 million has been approved for 2023. Hydro's revised Board-approved 2023 capital budget as at December 31, 2023, was $146 million. Table 10 shows the breakdown of Hydro's Capital Budget approvals of $146 million by Board Order.[25]

In advance of the 2024 Capital Budget Application, the Government of Newfoundland and Labrador amended the *Electrical Power and Control Act, 1994*[26] to increase the threshold for capital expenditures requiring pre-approval from the Board to $750,000. There were no under $750,000 capital projects approved by Hydro in the current quarter.

Table 10: Capital Budget by Board Order as of December 31, 2023 ($000)[27]

2023 Capital Budget[28]	**90,829**
Carryover Projects 2022 to 2023[29]	39,991
Projects Approved by Board:	
Order No. P.U. 27(2021)[30]	586
Order No. P.U. 28(2021)[31]	118
Order No. P.U. 12(2022)[32]	457
Order No. P.U. 14(2022)[33]	138
Order No. P.U. 17(2022)[34]	1,561

[24] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 2(2023), Board of Commissioners of Public Utilities, January 26, 2023.
[25] Total does not add due to rounding.
[26] *Electrical Power and Control Act, 1994*, SNL, 1994, c E-5.1.
[27] Numbers may not add due to rounding.
[28] Approved in *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 2(2023), Board of Commissioners of Public Utilities, January 26, 2023.
[29] The carryover budget of $40.0 million excludes CIACs. Hydro also carried forward CIACs of ($3.1) million, which would result in an estimated net carryover of $36.9 million to be recovered through customer rates.
[30] The construction of an interconnection between Star Lake Terminal Station and Valentine Terminal Station was approved for $15.8 million, of which $0.6 million is budgeted for 2023. The project is fully contributed.
[31] The purchase of a diesel generating unit for the Ramea Diesel Generating Station was approved for $2.4 million, of which $0.1 million is budgeted for 2023.
[32] The roof replacement for the Makkovik Diesel Generating Station was approved for $0.6 million, of which $0.5 million is budgeted for 2023.
[33] The purchase and install of a 545 kW diesel engine at the Mary's Harbour Diesel Generating Station was approved for $0.1 million.
[34] The purchase of one set of last stage blades to serve as capital spares for Units 1 and 2 at the Holyrood TGS was approved for $1.6 million, of which $1.56 million is budgeted for 2023.

Order No. P.U. 18(2022)[35]	3,040
Order No. P.U. 30(2022)[36]	3,386
Order No. P.U. 32(2022)[37]	45
Order No. P.U. 6(2023)[38]	2,105
Order No. P.U. 12(2023)[39]	3,597
Order No. P.U. 21(2023)[40]	63
Order No. P.U. 28(2023)[41]	40
Total Projects Approved by Board Order	**15,135**
2023 New Projects Under $750,000 approved by Hydro	449
Total Approved Capital Budget[42,43]	**146,403**

In addition, there were CIACs carried forward from the 2022 capital program and supplemental CIACs approved by the Board totalling $3 million. The 2023 capital budget as at December 31, 2023, net of CIACs, was $143 million.

6.2 Capital Expenditures

Capital expenditures for the year ended December 31, 2023 were provided in Hydro's annual Capital Expenditures and Carryover report, which was filed with the Board on April 1, 2024.

[35] The rotor rim shrinking and stator recentering at the Upper Salmon Station was approved for $4.0 million, of which $3.0 million is budgeted for 2023.

[36] Four projects at the Holyrood TGS were approved—the refurbishment of the Day Tank was approved for $0.8 million, of which $0.7 million is budgeted for 2023; the refurbishment of Tank 1 was approved for $2.0 million, of which $0.9 million is approved for 2023; the replacement of the Tank Farm Underground Firewater Distribution System was approved for $1.4 million, of which $1.3 million is approved for 2023; and the upgrade of the Unit 2 Turbine Control System was approved for $0.7 million, of which $0.5 million is approved for 2023.

[37] The acquisition and repair of the Lower Churchill Project genset for use in L'Anse-au-Loup, relocation of Unit 2082 from L'Anse-au-Loup to Charlottetown, and the winterization of Unit 2101 at Charlottetown was approved for $1.3 million, of which $45,000 is budgeted for 2023.

[38] The replacement and weld refurbishment of Penstock 1 at Bay d'Espoir Facility was approved for $50.6 million, of which $2.1 million is budgeted for 2023.

[39] The replacement of last stage blades on Units 1 and 2 at the Holyrood TGS, including the purchase of a second set of last stage blades and an *in-situ* inspection of the Unit 2 last stage blades, was approved for $6.4 million, of which $3.6 million is budgeted for 2023.

[40] 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 $62,500 is budgeted for 2023.

[41] The purchase of a spare generator step-up transformer set of last stage blades to serve as a capital spare at the Holyrood TGS was approved for $7.5 million, of which $40,000 is budgeted for 2023.

[42] In *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 15(2022), Board of Commissioners of Public Utilities, May 6, 2022, the Board approved an Upstream Capacity Charge contribution of ($0.3) million to be received subsequent to 2023.

[43] In Board Order No. P.U. 31(2023), the contribution by Braya Renewable Fuels (Newfoundland) GP Inc. was approved for costs associated with the replacement of transformers and bushings which is estimated to be $28,000 in 2023 and $0.4 million in 2024.

6.3 2023 Capital Projects Progress

Hydro's approved planned capital projects and programs continue to advance through stages of planning, design, procurement, and construction. It is typical for most of Hydro's capital construction activity to take place in the second, third, and fourth quarters each year. Additionally, throughout the year, certain unplanned capital work arises that must be addressed ("break-in work"), which may have an impact on the amount of planned work that can be performed. Hydro's actual expenditures relative to the approved budget are provided in Chart 5.

Hydro's actual capital expenditures for 2023 were 1.7% higher than the approved budget. Hydro is completing an analysis of capital expenditures for 2023 projects and programs to determine the contributions to the overall variance from the approved budget. A summary of that analysis was provided in Hydro's Capital Expenditures and Carryover Report which was filed on April 1, 2024.[44]

As required by the provisional Capital Budget Application Guidelines,[45] explanations were provided for projects with variances exceeding 10% and $100,000 at year-end, as part of Hydro's Capital Expenditures and Carryover Report which was filed on April 1, 2024.

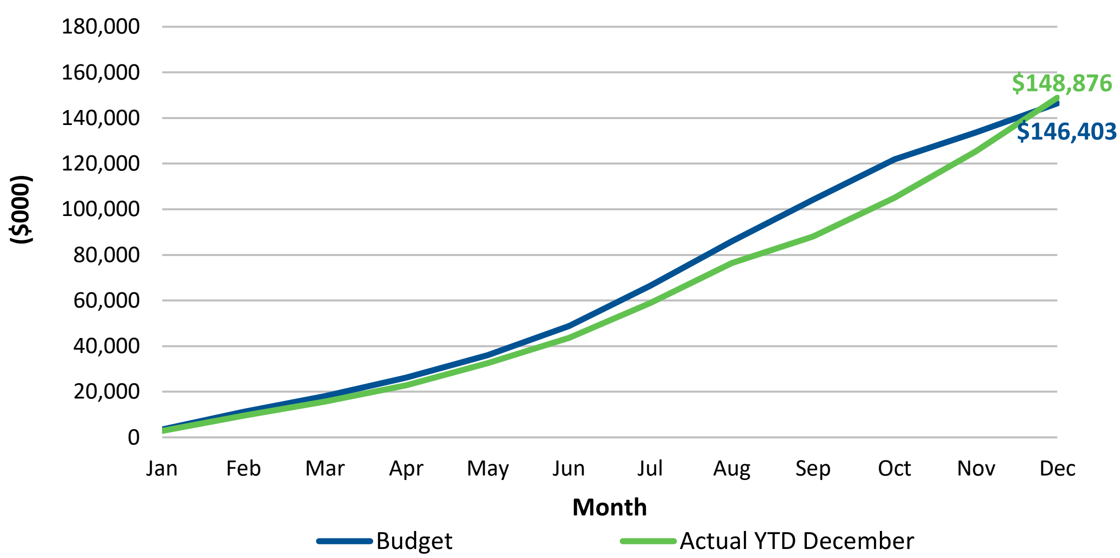


Chart 5: 2023 Capital Program Actual vs Budget

[44] Pursuant to *Public Utilities Act*, RSNL 1990, c P-47, s. 41(4), "A public utility shall submit a report on its actual expenditures on improvements or additions to its property in the prior calendar year, together with an explanation as to expenditures in excess of those approved under subsection (1) not later than April 1 in each year."

[45] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022. http://pub.nl.ca/PU/guidelines/Capital%20Budget%20Application%20Guidelines%20(Provisional)%20-%202021-12-20.PDF.

1 A high-level summary of the planned and break-in construction activities completed during the current
2 quarter is provided in Table 11.

Table 11: Highlights of Planned and Break-In Work Completed

Asset Category	Planned Work Q4 2023	Break-In Work Q4 2023
Gas Turbine Generation	Infrared scanning ports were installed in electrical panels at the Happy Valley Gas Turbine.	A failed diesel genset muffler was replaced at the Holyrood Gas Turbine.
Hydraulic Generation	The unit recentering and unit overhaul were completed at the Upper Salmon Station. The cooling water rotary strainer was replaced at the Upper Salmon Station. Generator bearing cover seals were installed on Units 1 and 2 at the Bay d'Espoir Facility. A spare cooling water pump was procured for the Hinds Lake Station. The Bay 1 gate, hoisting system, and associated equipment were refurbished at the Ebbegunbaeg Control Structure. The Bay 2 gate, hoisting system, and associated equipment were refurbished at the Burnt Dam Spillway. Monorail beams and associated mounts and the emergency lift system were replaced at the Salmon River Spillway. Various public safety improvements around dams and waterways were completed at Long Pond, Meelpaeg, Burnt Dam, Granite Canal, and Roddickton.	The generator rotor poles were removed and cleaned at the Upper Salmon Station. A generator bearing cooler was replaced at the Granite Canal Station. The riprap was refurbished at the North Salmon Dam. Access road drainage culverts were replaced at the Roddickton Station.
Thermal Generation	The Unit 2 boiler condition assessment and miscellaneous upgrades were completed.	The Unit 1 high pressure drain pump and the Unit 3 south vacuum pump were replaced.

Asset Category	Planned Work Q4 2023	Break-In Work Q4 2023
	The tank farm underground fire water distribution system was replaced. The fuel day tank was inspected and refurbished. The BioGreen sewage system was upgraded. The workshop roof was refurbished.	The Compressor 2 second stage air end was overhauled. The fuel storage Tank 3 steam piping heat tracing was refurbished. Ventilation systems were installed for two chemical storage areas.
Transportation	Electric vehicle fast charging stations were installed at Hydro's Bay d'Espoir and Wabush offices. Snowmobiles and light duty mobile equipment trailers were procured.	
Administrative	Diesel genset automatic transfer switches and associated hardware were replaced at Hydro Place. Various office equipment was procured.	
Information Systems	Software and hardware upgrades were completed for the Backup Control Centre at Holyrood. Various cyber security upgrades were completed. Various software upgrades and service enhancements were completed.	A new server was installed for interconnected electrical system resource and production modeling.
Telecontrol	Remote terminal units were replaced at Hydro Place, Paradise River Powerhouse, Paradise River Intake Structure, Upper Salmon Powerhouse, Ebbegunbaeg Control Structure, Voisey's Bay, and Rattle Brook. The 48 V battery chargers for communications equipment were replaced at the North Salmon Dam, the Granite Canal Powerhouse, and the Granite Canal Intake Control Structure.	-

Asset Category	Planned Work Q4 2023	Break-In Work Q4 2023
	Private Branch Exchange phone systems were replaced at Cat Arm Station, Granite Canal Station, Happy Valley, Port Saunders, Springdale, St. Anthony, Stephenville, and Ramea. Network communications equipment was replaced at various locations. Mobile devices were procured.	
Transmission	Wood pole line refurbishment was completed for TL209, TL228, TL259, and TL260.	Various failed transmission line components were replaced.
Distribution	Distribution feeders were upgraded at Bottom Waters. Recloser Remote Control was installed at Jackson's Arm.	
Metering	Mobile devices for meter reading were procured and tested.	
Terminal Stations	Various upgrades were completed at the Star Lake Terminal Station for the integration of Valentine Gold, including: the expansion of the gantry structure; bus work and grounding; tie-in of Transmission Line TL280; installation of a new circuit breaker; and, installation of new revenue metering. Various upgrades were completed at the Wabush Substation including: installation of Transformer T1; removal of Transformers T3 and T5; installation of protective relays for Transformer T1; installation of an annunciator panel; and, installation of 125 VDC and 48 VDC battery banks and chargers. A capacitor bank was installed at the Wabush Terminal Station.	The failed Transformer T6 was replaced at the Bay d'Espoir Facility. A failed line-to-ground insulator was replaced at the Western Avalon Terminal Station.

Asset Category	Planned Work Q4 2023	Break-In Work Q4 2023
	Online Dissolved Gas Analysis monitoring systems were installed for two transformers at the Happy Valley Terminal Station. A spare transformer was procured for Walsh River and Labrador City Landfill. Circuit breakers were replaced at the Buchans and Wabush Terminal Stations. Circuit breakers were refurbished at the Deer Lake, Howley and Roddickton Terminal Stations. A reclosing circuit breaker was upgraded at the Holyrood Terminal Station. A disconnect switch was replaced at the Wabush Terminal Station. Instrument transformers were replaced at the Massey Drive and Western Avalon Terminal Stations. A battery charger was replaced at the South Brook Terminal Station. Lighting upgrades were completed at the Buchans and Massey Drive Terminal Stations.	
Rural Generation	A genset was replaced at the St. Brendan’s Diesel Generating Station. Engines were overhauled at the Rigolet, Port Hope Simpson, Mary's Harbour, Norman Bay, and Cartwright Diesel Generating Stations. A variable frequency drive was installed at Charlottetown Diesel Generating Station.	A failed generator was refurbished at the L’Anse-au-Loup Diesel Generating Station. A failed radiator fan motor was replaced at the Charlottetown Diesel Generating Station. An engine was overhauled at the Hopedale Diesel Generating Station.

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 2023 Integrated Annual Work Plan completion target is 90%. As of the end of the current quarter, Hydro had completed approximately 92.6% of forecasted planned activities for the year. Results for Annual Work Plan activities are provided in Table 12.

Table 12: Annual Work Plan Activity

Planned	2023 Actual Completed	%
6,738	6,241	92.6

7.0 Financial

7.1 Statement of Income

Statement of Income – Regulated Operations for the 12 Months Ended December 31, 2023[46]

Fourth Quarter 2023 Actual	Fourth Quarter 2023 Budget	Fourth Quarter 2022 Actual		YTD 2023 Actual	YTD 2023 Budget	YTD 2022 Actual	Annual 2023 Budget
			Revenue				
171,177	170,439	170,516	Energy Sales	640,197	636,290	637,319	636,290
1,607	1,500	2,510	Other Revenue	14,545	5,795	13,451	5,795
172,784	**171,939**	**173,026**		**654,742**	**642,085**	**650,770**	**642,085**
			Expenses				
31,493	32,993	32,909	Operating Costs	142,759	136,146	130,494	136,146
76,675	79,688	79,425	Fuels	245,088	244,857	242,958	244,857
15,572	13,505	16,962	Power Purchased	61,643	54,786	64,715	54,786
23,422	22,747	19,499	Amortization	88,067	87,597	85,611	87,597
388	539	2,808	Other Expense	2,057	2,157	4,239	2,157
19,516	20,776	19,815	Interest	83,143	85,174	86,440	85,174
167,066	**170,248**	**171,418**		**622,757**	**610,717**	**614,457**	**610,717**
5,718	**1,691**	**1,608**	**Net Income**	**31,985**	**31,368**	**36,313**	**31,368**

[46] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

Net income for the year ended December 31, 2023 was $32.0 million compared to $36.3 million for the same period in 2022. The decrease in net income is primarily due to higher operating costs partially offset by higher demand revenue and interest income.

7.2 Greenhouse Gas Credits

In 2016, the federal government announced plans to implement carbon pricing to help Canada meet its greenhouse gas emission targets and, in October 2018, the provincial government released its approach to carbon pricing. The plan came into effect on January 1, 2019 and allows Hydro to receive performance credits as the Holyrood TGS uses less fuel and decreases greenhouse gas emissions. Under the *Management of Greenhouse Gas Act*,[47] Hydro may sell these performance credits to other regulated facilities in the province, of which there are 14, excluding the Holyrood TGS. 2023 was the fourth year that Hydro was able to sell its performance credits. The qualifications and other specifics of how the performance credits are earned, how they can be sold, etc. are contained within the *Management of Greenhouse Gas Reporting Regulations*.[48]

In 2023, Hydro carried forward 493,900 performance credits and earned 382,058 credits as a result of the Holyrood TGS using less fuel and decreasing greenhouse gas emissions in comparison to a baseline forecast for reporting year 2022. Hydro sold 493,536 performance credits in 2023 for a total revenue of $22.51 million. As of December 31, 2023, Hydro used 364 credits for compliance obligations with respect to the Holyrood Gas Turbine. Hydro is carrying forward 382,058 performance credits to apply to future compliance requirements or to be sold in future years. Credits expire seven years after creation. Table 13 provides a summary of Hydro's greenhouse gas credit activity since 2020.

Table 13: Summary of Greenhouse Gas Credit Activity

Year	Opening Balance	Credits Earned	Credits Used	Credits Sold	Closing Balance
2020	-	169,734	303	55,000	114,431
2021	114,431	292,676	923	125,106	281,078
2022	281,078	462,545	1,708	248,015	493,900
2023	493,900	382,058	364	493,536	382,058

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

The revenues from the sale of the greenhouse gas performance credits are credited to the Supply Cost Variance Deferral Account.[49]

8.0 People and Community

8.1 Diversity and Inclusion

8.1.1 Equity, Diversity, and Inclusion Date Recognition

Hydro celebrated various dates throughout the year which promote educating and supporting diverse groups. During this quarter, Hydro recognized and shared information for the Purple Ribbon Campaign and International Day for Persons with Disabilities. As part of these dates, Hydro hosts an annual Diversity and Inclusion Day to focus in on a particular topic. This year, Hydro focused on working together for an inclusive workplace. We started the day with a presentation from our Vice President, People and Corporate Affairs who overviewed the proposed next phase of Hydro's multi-year equity, diversity, and inclusion strategy. This overview and introduction was followed by a guest speaker from the Women in Resource Development Corporation ("WRDC") who re-emphasized the roles individuals have to play in creating an inclusive work environment. The day was concluded by an informative session from the Learning Disabilities Association of Newfoundland and Labrador who shared insights on learning disabilities, how to be inclusive, and the perspectives of someone navigating the workplace with a learning disability.

8.1.2 Accessibility Plan

In response to the *Accessibility Act*,[50] which aims to improve accessibility by identifying, preventing, and removing barriers that prevent persons with disabilities from participating in society, Hydro created and published an Accessibility Plan ("Plan").

The Plan was created through best practice reviews, consultation with external partners who work with and for persons with disabilities, and through the creation of an Accessibility Committee which includes Empower NL who was a reliable and helpful advisor throughout the process. The Plan extends from

[49] As per *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 33(2021), Board of Commissioners of Public Utilities, December 8, 2021.
[50] *Accessibility Act*, SNL 2021, c A-1.001.

2024 to 2026, and covers many areas of our business, including employment, customer service, communications, information technology, and our physical/built environment.

The full Plan can be viewed on Hydro's website.[51]

8.1.1 Gender Equity Targets

Hydro has corporate gender equity targets as part of its strategy on diversity and inclusion. In 2023, Hydro continued proactive efforts to attract and retain women in leadership, operations, and engineering positions, while supporting their advancement. Table 14 shows Hydro's progress towards its gender equity targets.

Table 14: Gender Equity Statistics[52]

	2023			2022			Target
	Total	**Female**	**% Female**	**Total**	**Female**	**% Female**	**% Female**
Executive	**9**	4	44	**9**	3	33	30
Management	**113**	41	36	**115**	38	33	35
Engineers and Engineers in Training	**139**	33	24	**133**	33	25	30
Technicians and Technologists	**285**	24	8	**289**	26	9	10
Field Supervisors	**85**	4	5	**84**	4	5	6
Skilled Trades and Apprentices	**289**	14	5	**290**	17	6	10
Manual Workers	**83**	17	20	**80**	15	19	20

8.2 Community Initiatives

During the final quarter of 2023, Hydro worked with community partners on several key initiatives, launched new programming to enhance employee giving opportunities, and was honoured to be recognized for continued efforts to positively impact the lives of those in our province.

[51] https://nlhydro.com/wp-content/uploads/2023/12/Hydro-Accessibility-Plan-2024-2026.pdf.
[52] Gender equity targets reflective of total company.

8.2.1 Local Students Learn About Careers in STEM During Tour of Bay d'Espoir Hydroelectric Generating Facility

In October 2023, employees at our Bay d'Espoir Facility welcomed students from nearby Se't A'newey Kina'matino'kuom (St. Anne's School) in Conne River as part of Hydro's continued partnership with the WRDC.

Throughout the week, WRDC and Hydro employees visited schools in the region, engaging youth in their STEMforGIRLS program and highlighting the exciting opportunities for STEM-related careers at Hydro. Amber Hickman, Apprentice Electrician, served as an in-class role model for the students in St. Anne's School and Bay d'Espoir Academy, sharing her own journey and experiences with them. Hydro Plant Operators Shannon Costello, Kaitlyn Hickey, and Brooke Watson proudly showed the students around the facility, explaining how electricity is generated and helping them understand the exciting career opportunities available to them in the electricity industry.

8.2.2 Hydro Named Outstanding Corporate Philanthropist

On November 15, 2023, recognized as National Philanthropy Day across Canada, the Association of Fundraising Professionals honours organizations and individuals who give back to their communities at their annual Spirit of Philanthropy Awards. This year, in recognition of our continued support of the Ronald McDonald House, Hydro was honoured to be named the 2023 Outstanding Corporate Philanthropist.

The Outstanding Corporate Philanthropist Award honours a business or corporation that demonstrates an outstanding commitment to philanthropy and community involvement through financial support, volunteerism, encouragement, awareness of a cause, and motivation of others to take leadership roles. President and CEO, Jennifer Williams, was proud to recognize the achievements of all nominees and recipients as she accepted the award on Hydro's behalf at a ceremony in St. John's.

8.2.3 Creating New Opportunities for Employee Giving at Hydro

In support of Hydro's community values and strategic priorities, on November 28, 2023, Hydro introduced Hydro Helps, a new payroll giving program that makes it easy for employees to donate to the causes and charities they care about most.

Through Hydro Helps, employees can donate to registered charities of their choice through bi-weekly payroll deductions. The program is being offered in partnership with United Way of Newfoundland and Labrador, helping to maximize impact for charities and non-profits, create administrative efficiencies, and provide flexibility for employees who want participate.

8.2.4 Employees Spread Cheer in Support of Local Food Banks

During the month of December, Hydro employees were encouraged to help spread the cheer—at work and in our communities—by joining the 3rd annual Cheer Challenge. Using Hydro's internal recognition system, a donation was recorded toward the Community Food Sharing Association for each peer recognition or commendation submitted. On December 20, 2023, Hydro donated $10,000, helping families around the province access food at more than 50 food banks supported by the Community Food Sharing Association. As well, both the individual employee and staff department that submitted the most recognitions each received $250 to give to the charitable cause of their choice.

9.0 Ramea

In Board Order No. P.U. 31(2007), the Board directed Hydro to provide quarterly updates on the Ramea Wind-Hydrogen-Diesel project as part of its quarterly report to the Board.[53]

On March 22, 2023, Hydro filed an application proposing to decommission the hydrogen components of the Wind-Hydrogen-Diesel System, as they are not used or useful and their removal will not adversely

[53] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 31(2007), Board of Commissioners of Public Utilities, November 30, 2007, p. 3/35–38.

affect the reliability of the service Hydro provides.[54] Hydro advised that the wind farm assets that form part of the Wind-Hydrogen-Diesel System would remain in place while Hydro continues to pursue partnership opportunities with independent power producers. A further application will be made once there is a finalized plan regarding these assets. Hydro's application to decommission the hydrogen components was approved in Board Order No. P.U. 10(2023).[55]

9.1 Capital Costs

There will be no future capital expenditures incurred for the Ramea Wind-Hydrogen-Diesel Generation project. The decommissioning of the hydrogen components will be a non-regulated expense.

9.2 Operating Costs

The wind turbines were not operational during the current quarter; therefore, no costs were incurred.

9.3 Reliability and Safety Issues

The wind turbines were not operational during the current quarter; as such, there are no safety issues to report.

[54] "Abandonment of Hydrogen System – Ramea Wind-Hydrogen-Diesel Generation Project," Newfoundland and Labrador Hydro, March 22, 2023. http://pub.nl.ca/applications/NLH2023RameaWindHydrogen/app/From%20NLH%20-%20Application%20for%20the%20Abandonment%20of%20the%20Hydrogen%20System%20Portion%20of%20the%20Ramea%20Wind-Hydrogen-Diesel%20Generation%20Project%20-%202023-03-22.PDF.

[55] *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 10(2023), Board of Commissioners of Public Utilities, April 18, 2023.

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
17-Oct-2023	St. Anthony	System Conditions	1,159	9 hours, 20 minutes
28-Nov-2023	Rocky Harbour	Defective Equipment	1,245	6 hours, 10 minutes
22-Dec-2023	King's Point	Adverse Weather	661	29 hours, 10 minutes

Appendix B

Major Events Excluded From Performance Index Tables

Major Events

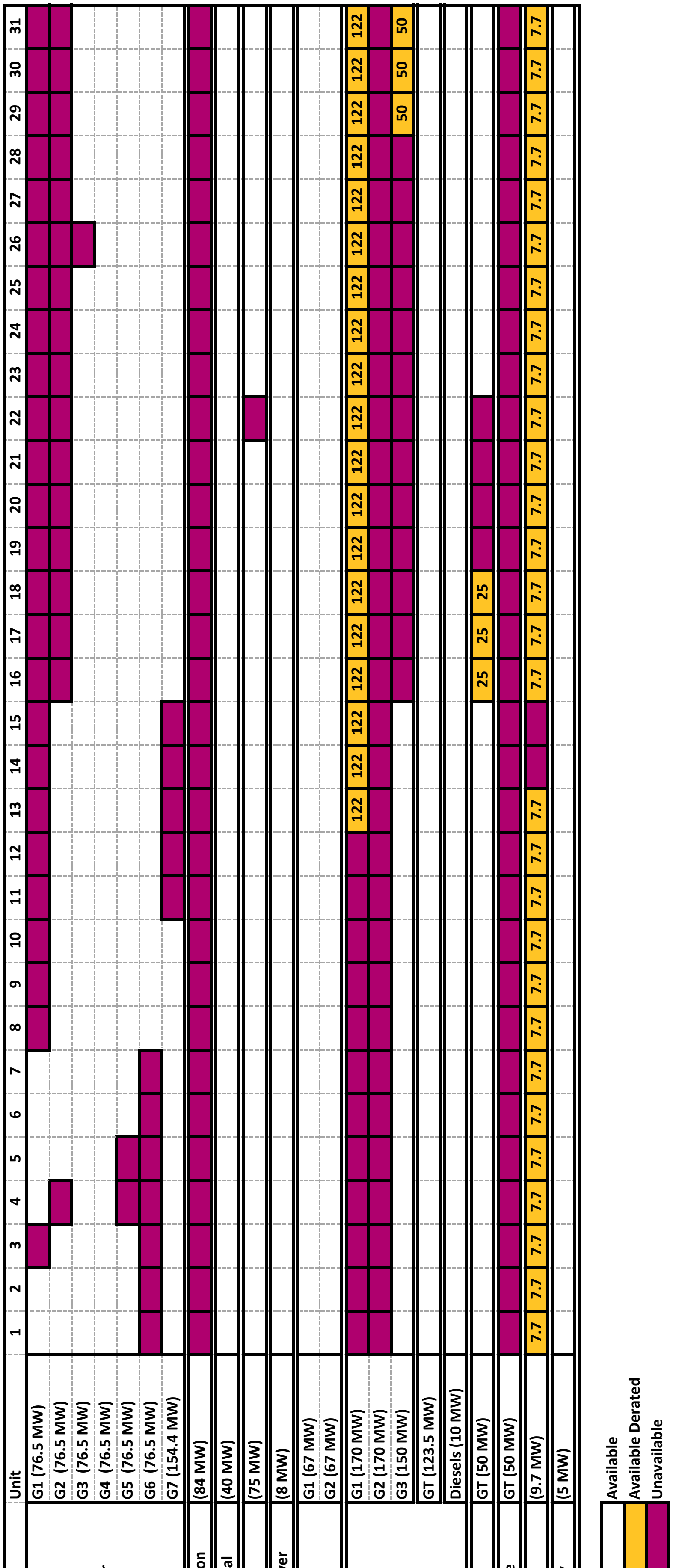
Table B-1: Major Events Excluded From Performance Index Tables[1]

Year	Event Description	End Consumer SAIDI	End Consumer SAIFI	Service Continuity SAIDI	Service Continuity SAIFI	Transmission T-SAIDI	Transmission T-SAIFI
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
2019	No major events	N/A	N/A	N/A	N/A	N/A	N/A
2018	Windstorm affecting TL214 on the southwest coast of the Newfoundland	0.17	0.00	0.00	0.00	11.89	0.00
	Landslide affecting the Glenburnie System on the Great Northern Peninsula	0.06	0.00	3.55	0.22	25.50	0.11

[1] Data for 2023 reflects major events to the end of the current quarter. Data for 2018–2022 reflects major events experienced through the year.

Appendix C

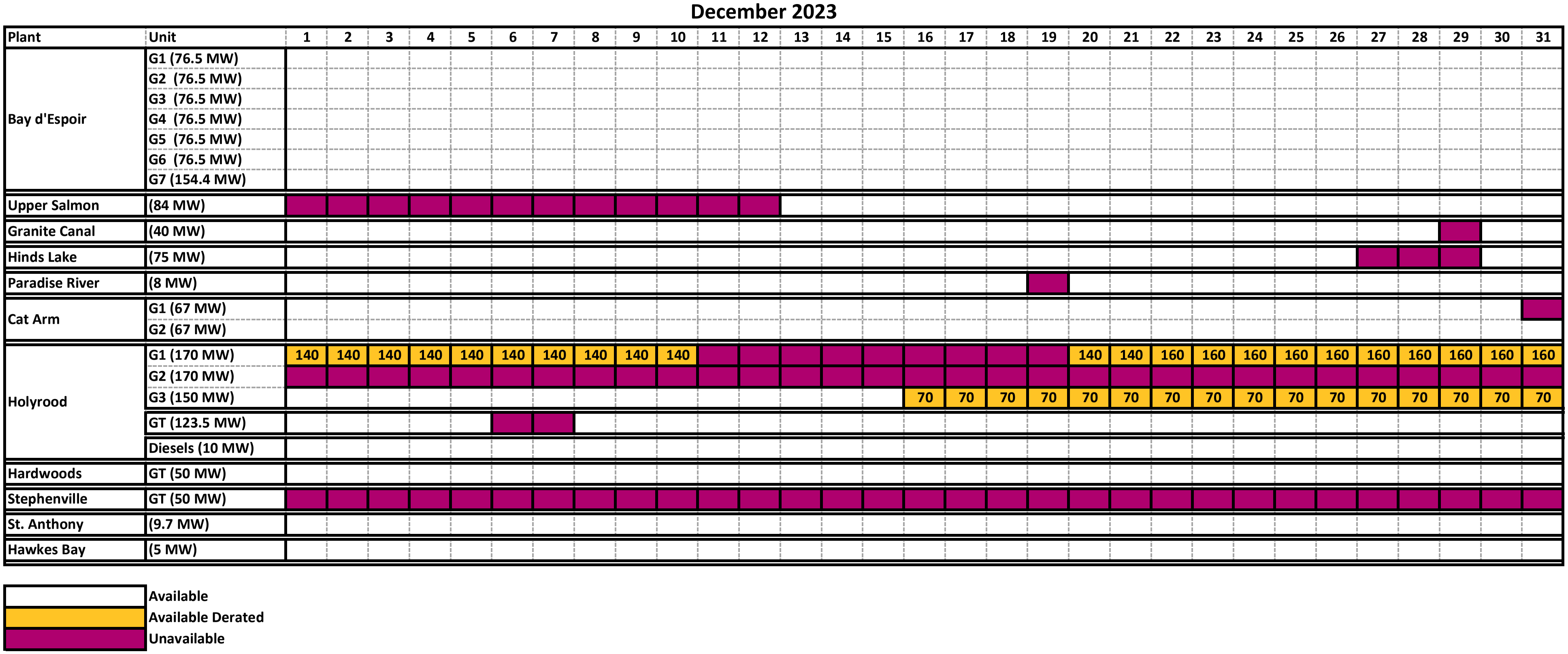
Generation Unit Outages


October 2023
Plant
Unit
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
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)
Upper Salmon
(84 MW)
Granite Canal
(40 MW)
Hinds Lake
(75 MW)
Paradise River
(8 MW)
Cat Arm
G1 (67 MW)
G2 (67 MW)
Holyrood
G1 (170 MW)
122 122 122 122 122 122 122 122 122 122 122 122 122 122 122 122 122 122 122
G2 (170 MW)
G3 (150 MW)
50 50 50
GT (123.5 MW)
Diesels (10 MW)
Hardwoods
GT (50 MW)
25 25 25
Stephenville
GT (50 MW)
St. Anthony
(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
Hawkes Bay
(5 MW)
Available
Available Derated
Unavailable

November 2023

Plant	Unit	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
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)																														
Upper Salmon	(84 MW)																														
Granite Canal	(40 MW)																														
Hinds Lake	(75 MW)																														
Paradise River	(8 MW)																														
Cat Arm	G1 (67 MW)																														
	G2 (67 MW)																														
Holyrood	G1 (170 MW)	122	122	122	122	122	122						130	130	125	125	125	125	140	140	140	140	140	140	140	140	140	140	140	140	140
	G2 (170 MW)																														
	G3 (150 MW)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	70	70	122	130	
	GT (123.5 MW)																														
	Diesels (10 MW)																														
Hardwoods	GT (50 MW)																														
Stephenville	GT (50 MW)																														
St. Anthony	(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			
Hawkes Bay	(5 MW)																														

	Available
	Available Derated
	Unavailable


December 2023
Plant
Unit
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
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)
Upper Salmon
(84 MW)
Granite Canal
(40 MW)
Hinds Lake
(75 MW)
Paradise River
(8 MW)
Cat Arm
G1 (67 MW)
G2 (67 MW)
Holyrood
G1 (170 MW)
140 140 140 140 140 140 140 140 140 140
140 140 160 160 160 160 160 160 160 160 160 160
G2 (170 MW)
G3 (150 MW)
70 70 70 70 70 70 70 70 70 70 70 70 70 70 70 70
GT (123.5 MW)
Diesels (10 MW)
Hardwoods
GT (50 MW)
Stephenville
GT (50 MW)
St. Anthony
(9.7 MW)
Hawkes Bay
(5 MW)
Available
Available Derated
Unavailable

Appendix D

2023 Annual Report on Key Performance Indicators

Contents

List of Attachments

1.0 Introduction

In Order No. P.U. 14(2004), the Board required Hydro to file appropriate historic, current, and forecast comparisons of reliability, operating, financial, and other KPIs. These were ordered to be filed with Hydro's annual financial report, commencing in 2004.[1]

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

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

2.0 Overview of Key Performance Indicator Results

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

Table 1 summarizes Hydro's KPI performance in 2023. The rationale for the 2023 targets is included as Attachment 1 of this report.

[1] *Public Utilities Act*, RSNL 1990, c P-47, Board Order No. P.U. 14(2004), Board of Commissioners of Public Utilities, May 4, 2004.

Table 1: Hydro's KPI Performance for 2023

Category	KPI	Units	2023 Target	2023 Results
Reliability[2]	WCF	%	80.1[3]	74.12
	DAFOR	%	7.00	12.92
	T-SAIDI	Minutes/Point	486.58	373.10
	T-SAIFI	Number/Point	3.37	3.00
	T-SARI	Minutes/Outage	N/A	124.37[4]
	Distribution SAIDI	Hours/Customer	18.47	16.57
	Distribution SAIFI	Number/Customer	5.48	6.28
	End-Consumer SAIDI	Hours/Customer	2.77	2.33
	End-Consumer SAIFI	Number/Customer	1.11	1.32
	UFLS	Number of events	6	0
Operating	Hydraulic Conversion Factor	GWh/MCM[5]	0.434	0.424
	Thermal Conversion Factor	kWh/bbl	583	511
Financial	Controllable Unit Cost	$/MWh	N/A[6]	15.44[7]
Other	Customer Satisfaction (Residential)	Max=100%	N/A[8]	N/A

3.0 Performance Indicators

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

3.1 Reliability Performance Indicators

3.1.1 Reliability Key Performance Indicator: Generation

Weighted Capability Factor

Table 2 summarizes Hydro's WCF performance in 2023 compared to 2022 performance and the 2023 target. Calculation details for weighted capability, as well as a list of factors that can impact KPI performance, are included as Attachment 2 of this report.

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[2] Transmission and distribution reliability performance is measured on combined planned and forced outages.
[3] The WCF target is based on planned annual maintenance outages, an allowance for other short duration maintenance outages, and targeted forced outage durations.
[4] T-SARI does not equate exactly to T-SAIDI/T-SAIFI due to rounding.
[5] Million cubic metres ("MCM").
[6] Hydro does not set a target for Controllable Unit Cost.
[7] [ ]
[8] Hydro's most recent residential customer satisfaction survey was completed in 2022. The next residential customer satisfaction survey is scheduled to be completed in 2024.

While WCF performance in 2023 was below the annual target in all asset classes, Hydro maintained sufficient generation to meet customer requirements at all times in 2023. Hydro plans capital outages and schedules maintenance outages to ensure supply is available as required. This includes the consideration of the availability of generation supplied from Muskrat Falls and delivered via the LIL, which will be used to meet customer needs into the future.

Table 2: WCF Performance

	2023 Annual	2022 Annual	2023 Annual Target[9]
Overall WCF	74.12	84.20	80.1
Thermal WCF	45.56	68.41	56.9
Hydraulic WCF	85.04	89.22	89.0
Gas Turbine WCF	87.45	94.51	90.3

Chart 1 details previous years' performance. Hydro's overall WCF for the period 2018–2022 is 82.55%, which is slightly better than the equivalently weighted, most recently available national five-year average of 81.57% for the period 2017–2021.[10]

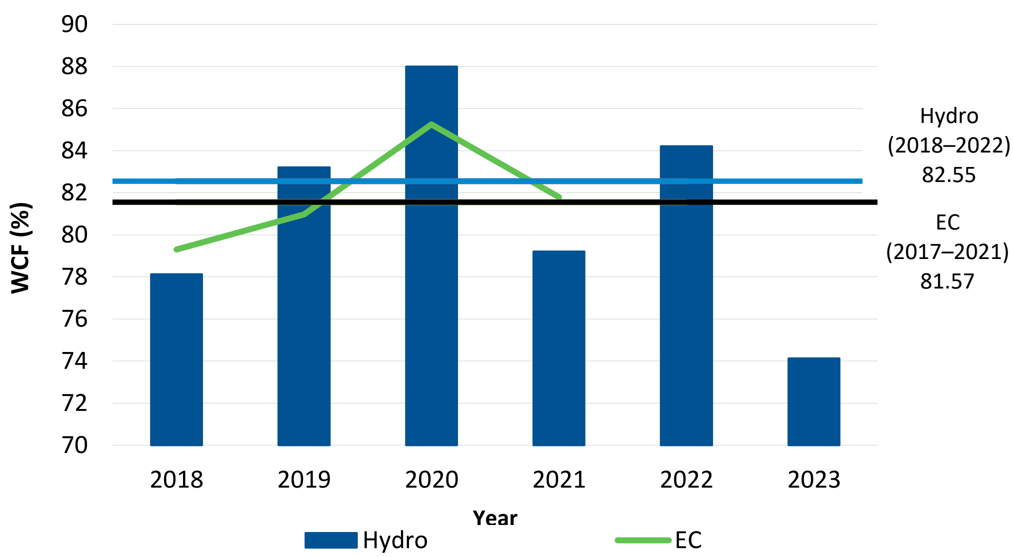

Chart 1: WCF

[9] Includes the time that units are unavailable due to maintenance; therefore, capability is affected by planned maintenance and capital work.
[10] EC reliability data is published annually. EC reliability data for generation is not currently available for 2022 or 2023.

Thermal Weighted Capability Factor

Thermal unit WCF was 45.56% in 2023, compared to 68.41% in 2022, and the 2023 target of 56.9%. Holyrood Unit 1 had a capability factor of 42.77%, Unit 2 had a capability factor of 33.81%, and Unit 3 had a capability factor of 61.64%.

Hydraulic Weighted Capability Factor

Hydro's 2023 hydraulic unit WCF performance was 85.04%, compared to 89.22% in 2022, and the 2023 target of 89.0%.

Gas Turbine Weighted Capability Factor

Gas turbine WCF was 87.45% in 2023, compared to 94.51% in 2022, and the 2023 gas turbine WCF target of 90.3%.

Weighted Derated Adjusted Forced Outage Rate

Table 3 summarizes Hydro's DAFOR performance in 2023, compared to 2022 performance, and the 2023 target.

Table 3: DAFOR Performance

	2023 Annual	2022 Annual	2023 Annual Target
Overall DAFOR	12.92	3.12	7.00
Thermal DAFOR	32.08	7.14	20.00
Hydraulic DAFOR	6.64	2.01	2.25

Chart 2 details previous years' performance. Hydro's overall weighted DAFOR for the period 2018–2022 is 5.32%, which is better than the equivalently weighted, most recently available national five-year average of 7.91% for the period 2017–2021.[11]

[11] EC reliability data for generation is not currently available for 2022 or 2023.

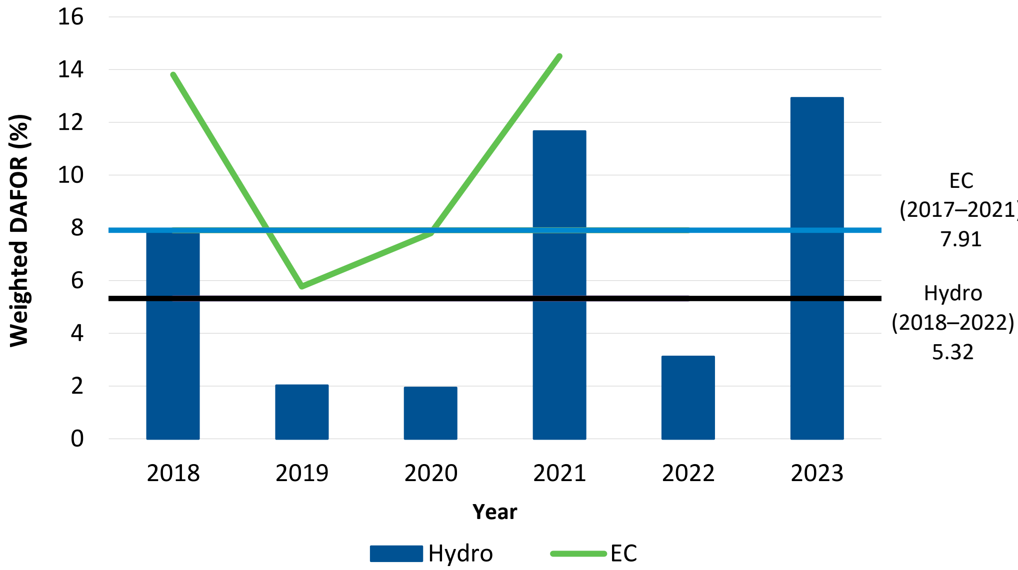

Chart 2: Weighted DAFOR

Generation Equipment Performance

Table 4 provides the various performance indices for Hydro's generation facilities. Indices for 2023, 2022, and for the most recently available EC national five-year average are included for comparison.

Table 4: Generation Performance Indicators

Index		Hydraulic	Thermal	Gas Turbine
Fail Rate	Hydro 2023	1.05	11.06	64.06
(Forced outages per 8,760	Hydro 2022	2.06	3.94	50.37
operating hours)	EC 2017 to 2021	2.02	10.93	113.00
Incapability Factor	Hydro 2023	14.96	54.41	12.55
(Percent of Time)	Hydro 2022	10.78	31.59	5.49
	EC 2017 to 2021	13.32	31.13	12.55
DAFOR[12]	Hydro 2023	6.64	32.02	N/A
(Percent of Time)	Hydro 2022	2.01	7.09	N/A
	EC 2017 to 2021	5.82	18.50	N/A
UFOP[13]	Hydro 2023	N/A	N/A	15.85
(Percent of Time)	Hydro 2022	N/A	N/A	4.4
	EC 2017 to 2021	N/A	N/A	12.76
DAUFOP[14]	Hydro 2023	N/A	N/A	17.44
(Percent of Time)	Hydro 2022	N/A	N/A	4.69
	EC 2017 to 2021	N/A	N/A	15.30

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

Hydraulic Unit Performance

Hydraulic unit performance for fail rate improved in 2023 when compared to 2022, this improvement in fail rate performance is the result of less generating unit trips occurring in 2023 than in 2022. The outage count in 2022 was 20, whereas in 2023 a total of 16 outages were experienced. This performance is also better than the most recently available national five-year average. Conversely, incapability factor and DAFOR performance declined when compared to 2022. The decline in both DAFOR and incapability factor performance is largely attributed to two significant outages experienced in 2023, one each on the Upper Salmon Station unit and on Bay d'Espoir Unit.[15] The Upper Salmon Station unit experienced a forced outage beginning March 10, 2023 which continued until planned life extension activities was completed; the unit returned to service on December 12, 2023. On July 25, 2023, Transformer T6 in Bay d'Espoir experienced a bushing failure, resulting in a forced outage to Unit 6 which lasted until October 7, 2023 when both the transformer and unit were returned to service. Hydro's performance in these two measures in 2023 fell slightly below the most recently available national five-year averages.

Thermal Unit Performance

Thermal unit performance declined in 2023 in all areas when compared to 2022. The decline in fail rate performance is the result of an increase in forced outages in 2023 when compared to 2022. The number of forced outages in 2023 was 14, a significant increase from 7 in 2022. The incapability factor and DAFOR performance were negatively impacted by both the increase in forced outages noted, but also by an increase in forced deratings. In 2023, all three units in Holyrood experienced issues which materially impacted the overall thermal performance.

Unit 1 performance was primarily impacted by a series of forced outages and derates between February 1, 2023 and March 12, 2023, which were the result of electrical issues.[16] Unit 2 experienced a forced extension to the planned outage to overhaul the turbine and replace the L-0 blades, after inspection identified unexpected cracking of the L-1 blades. The forced extension began in September 2023 and re-assembly work is presently ongoing, with anticipated return to service of March 2024.[17] The

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[15] "Quarterly Report on Performance of Generating Units for the Twelve Months Ended December 31, 2023," Newfoundland and Labrador Hydro, January 31, 2024, p. 7.
[16] "Quarterly Report on Performance of Generating Units for the Twelve Months Ended September 30, 2023," Newfoundland and Labrador Hydro, October 30, 2023, p. 9.
[17] *Supra*, f.n. 15 at p. 11.

performance of Unit 3 was primarily impacted by two deratings. From October 24, 2023 until November 25, 2023 the unit was derated to 50 MW due to a failed forced draft fan motor. Then on December 16, 2023 a small boiler tube leak was identified that resulted in a derating to 70 MW for the remainder of December. This leak has since been repaired and the unit returned to full capability on January 17, 2024.[18]

Performance in fail rate, DAFOR, and incapability factor for 2023 are below the most recently available national five-year average.

Gas Turbine Unit Performance

The performance of Hydro's gas turbines declined in 2023 in all areas when compared to 2022. The decline in fail rate performance is the result of an increase in forced outages in 2023 when compared to 2022. In 2023, the gas turbine assets experienced a combined eight forced outages, while only four forced outages occurred in 2022. The decline in incapability factor, UFOP, and DAUFOP can be attributed to a significant increase in forced outage duration in 2023. This increase is the result of a forced outage to the Stephenville Gas Turbine lasting over 4,000 hours in 2023. The Stephenville Gas Turbine was removed from service on July 14, 2023 following the failure of the alternator cooling fan. Inspections were completed and the rotor was removed and shipped to a facility in the United States for testing, inspection, and repair. The necessary work has been completed and the rotor has not been shipped back to site—expected to arrive in mid-February. The unit is expected to be returned to service in March 2024.

Performance in fail rate for 2023 is significantly better than the most recently available national five-year average, while incapability factor performance is equivalent to the average. The UFOP and DAUFOP performance for 2023 is slightly worse than the most recently available national five-year average.

3.1.2 End Consumer Service Continuity Performance

The End Consumer Service Continuity Performance Index was developed to measure reliability of service to all end consumers of electricity in the province who are supplied by Hydro other than Hydro's Industrial customers. The measure is a combination of Hydro's service continuity data and Newfoundland Power's service continuity data for outages related to loss of supply due to events on

[18] Supra, f.n. 15 at p. 12.

Hydro's transmission system. Therefore, the SAIDI and SAIFI data provided in Table 5 are measures of the duration and frequency of service interruptions experienced as a result of Hydro system events. Table 5 shows End Consumer Service Continuity Performance data for the fourth quarter of 2023 and 2022, annual 2023, annual 2022, and the 2023 annual target.

Table 5: End Consumer Performance

	Q4 2023	Q4 2022	2023 Annual	2022 Annual	2023 Annual Target (2018–2022 Average)
SAIDI	0.69	0.44	2.33	2.44	2.77
SAIFI	0.24	0.31	1.32	1.08	1.11

Hydro used the average of its End Consumer Service Continuity Indices performances for the period 2018–2022 for its 2023 annual targets.

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

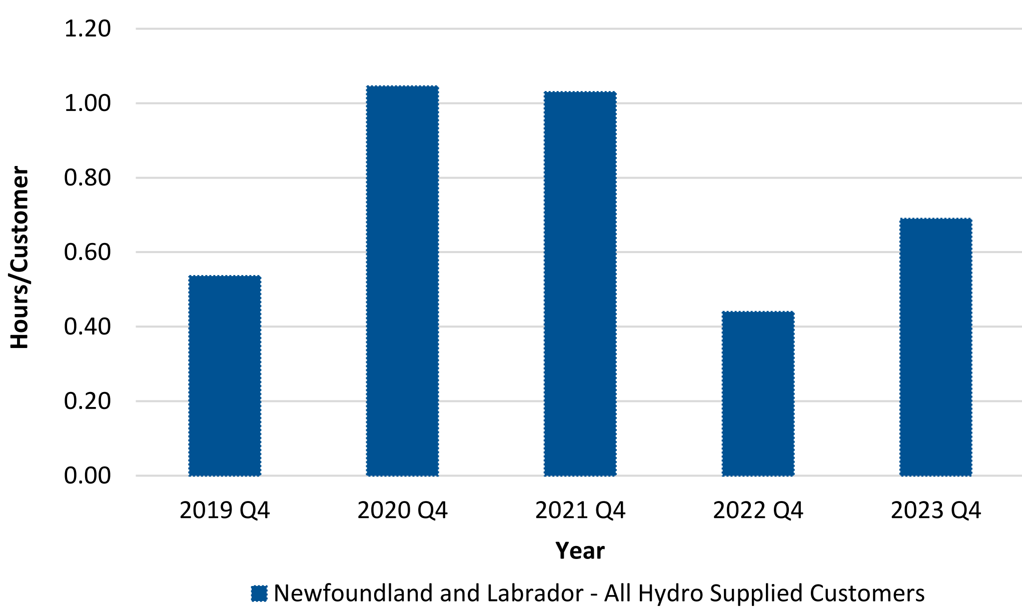

Chart 3: End-Consumer SAIDI Q4 2019–2023

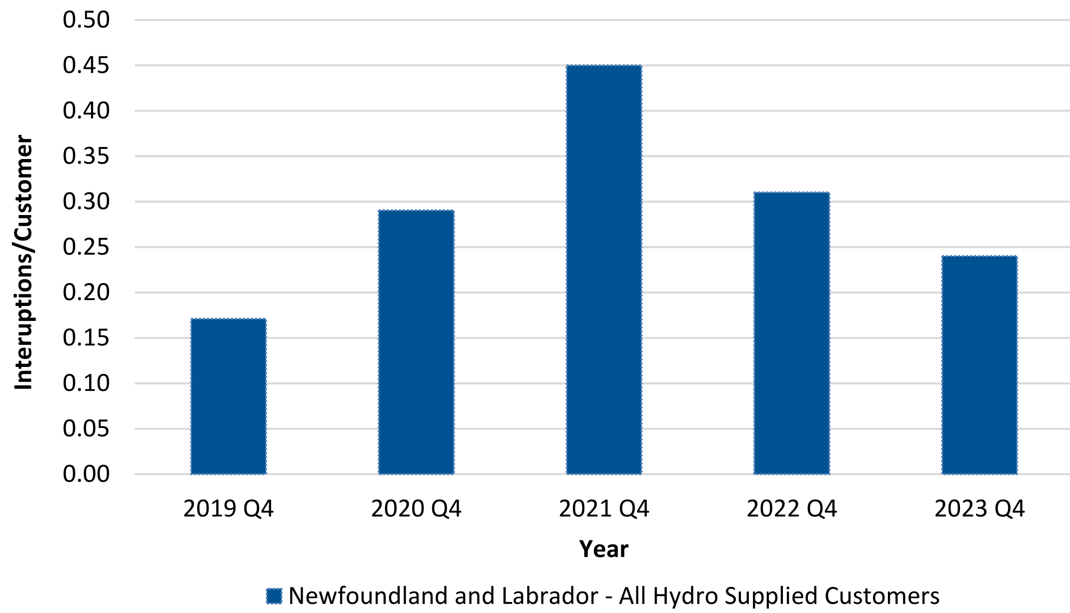

Chart 4: End-Consumer SAIFI Q4 2019–2023

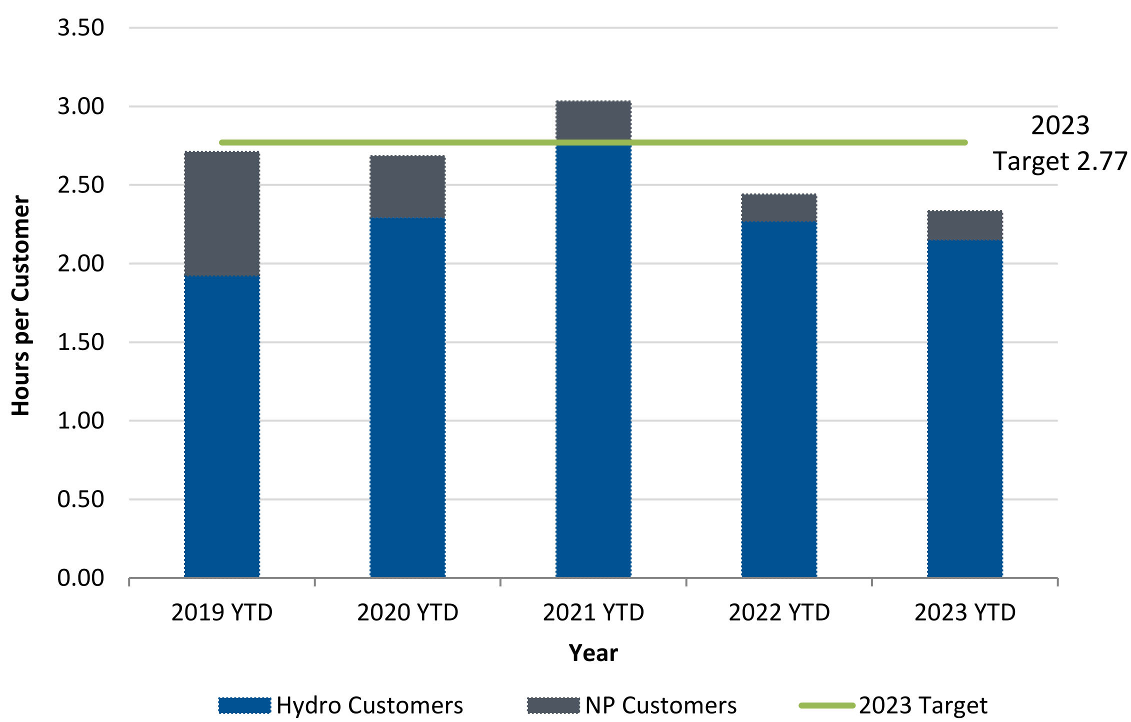

Chart 5: End-Consumer SAIDI Annual 2019–2023

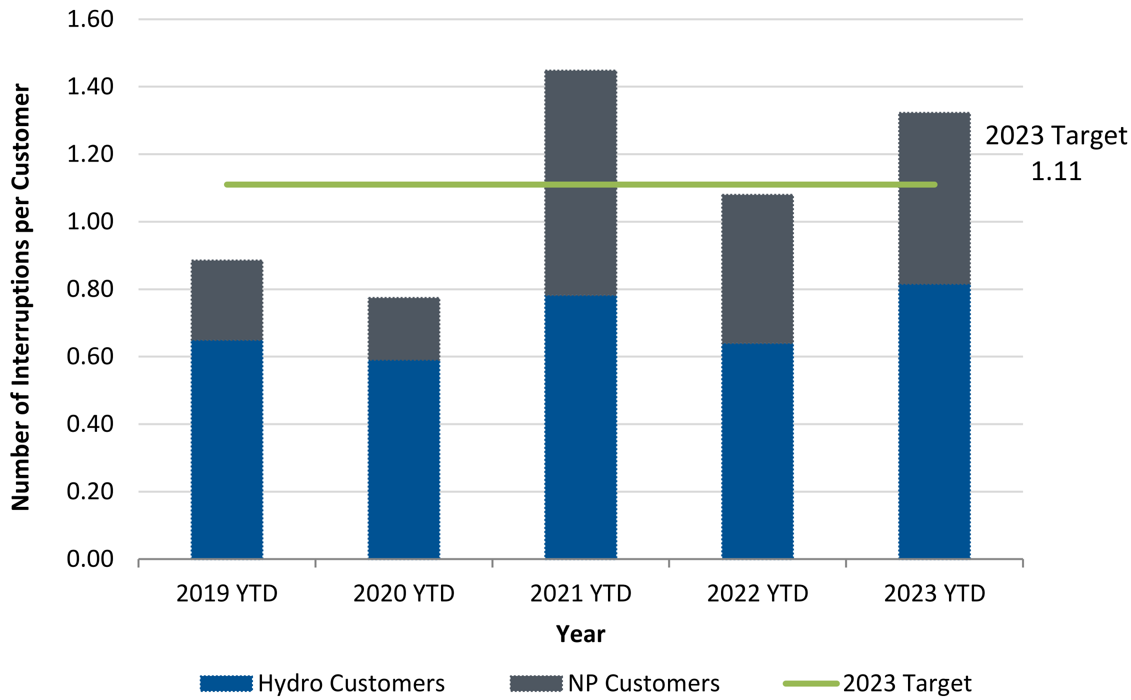

Chart 6: End-Consumer SAIFI Annual 2019–2023

3.1.3 Reliability Key Performance Indicator: Transmission

Transmission—System Average Interruption Duration Index

Table 6 shows the T-SAIDI data for the fourth quarter of 2023 and 2022, annual 2023, annual 2022, and the 2023 annual target.

Table 6: T-SAIDI (Outage Minutes per Delivery Point)[19]

	Q4 2023	Q4 2022	2023 Annual	2022 Annual	2023 Annual Target
T-SAIDI	187	34	373	258	487

[19] Unplanned and planned breakdown is not available at this time due to ongoing database upgrades. This data will be provided when available.

Hydro uses the average of its T-SAIDI performance for the period 2018–2022 to calculate its 2023 annual T-SAIDI target. Chart 7 shows the annual T-SAIDI performances for the period 2019–2023 and EC 2019–2022 annual T-SAIDI performances. EC only publishes annual indicators.

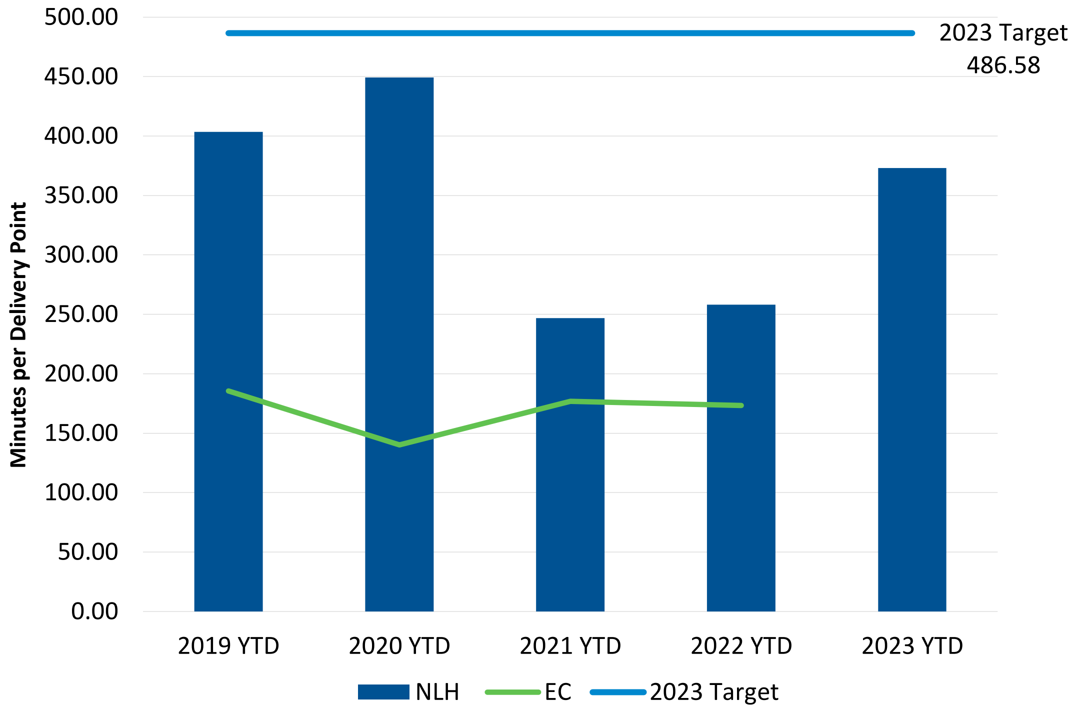

Chart 7: T-SAIDI[20]

Transmission—System Average Interruption Frequency Index

Table 7 shows the T-SAIFI for planned and unplanned outages for the fourth quarter of 2023 and 2022, annual 2023, annual 2022, and the 2023 annual target.

Table 7: T-SAIFI (Outages per Delivery Point)[21]

	Q4 2023	Q4 2022	2023 Annual	2022 Annual	2023 Annual Target
T-SAIFI	1.02	0.32	3.00	1.92	3.37

[20] EC reliability data for transmission is not currently available for [ ] 2023.
[21] Unplanned and planned breakdown is not available at this time due to ongoing database upgrades. This data will be provided when available.

Hydro uses the average of its T-SAIFI performance for the period 2018–2022 to calculate its 2023 annual T-SAIFI target. Chart 8 shows the annual T-SAIFI performances for the period 2019–2023 and EC 2019–2022 annual T-SAIFI performances.

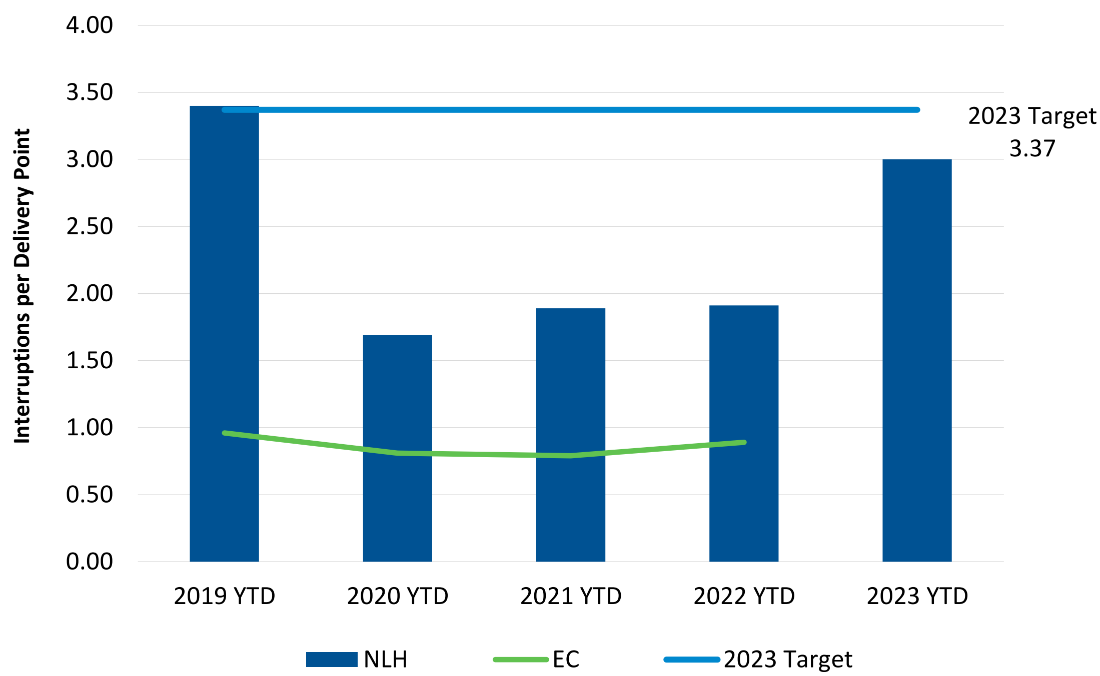

Chart 8: T-SAIFI

Transmission—System Average Restoration Index

Hydro's 2023 annual T-SARI was 124 minutes per interruption compared to 135 minutes per interruption for annual 2022. Hydro does not establish a restoration index target. Chart 9 shows the annual T-SARI performance for the period 2019–2023 and the EC 2019–2022 annual T-SARI performances.

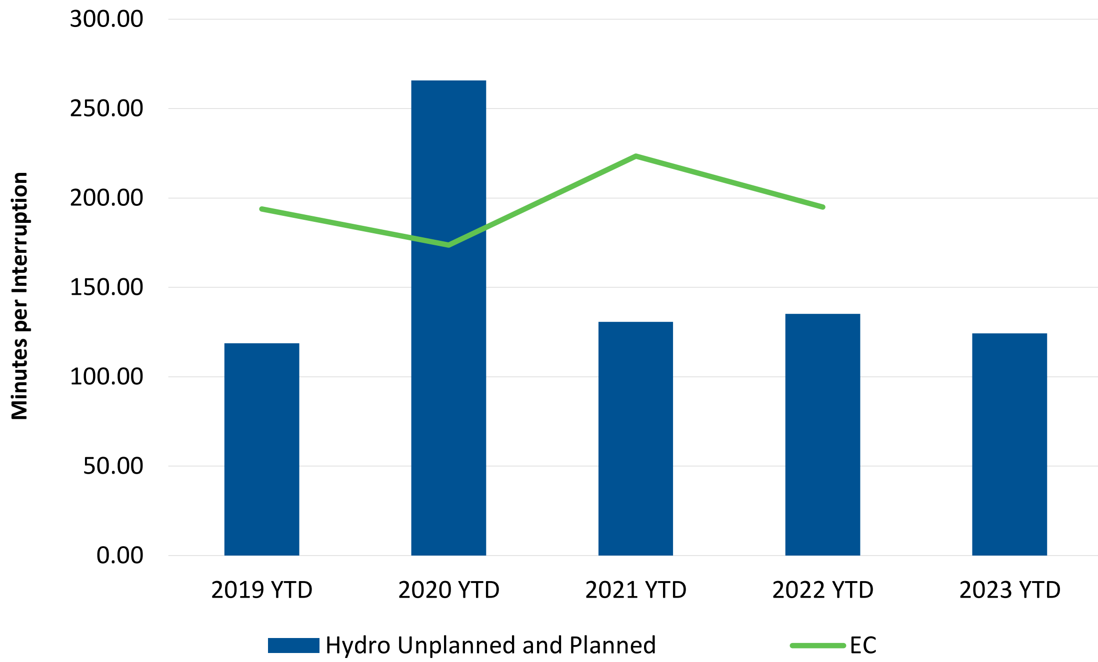

Chart 9: T-SARI[22]

3.1.4 Reliability Key Performance Indicator: Service Continuity Performance

Service Continuity System Average Interruption Duration Index

Table 8 shows the SAIDI performances for the fourth quarter of 2023 and 2022, annual 2023, annual 2022, and the 2023 annual target.

Table 8: Service-Continuity SAIDI (Hours per Customer)[23]

	Q4 2023	Q4 2022	2023 Annual	2022 Annual	2023 Annual Target
SAIDI	4.57	3.11	16.57	17.49	18.47

Hydro uses the average of its Service-Continuity SAIDI performances for the period 2018–2022 as its 2023 annual target for this index.

[22] EC reliability data for transmission is not currently available for [ ] 2023.
[23] Unplanned and planned breakdown is not available at this time due to ongoing database upgrades. This data will be provided when available.

Chart 10 shows EC 2019–2023 annual SAIDI performances and Hydro's 2019–2023 annual SAIDI performances.

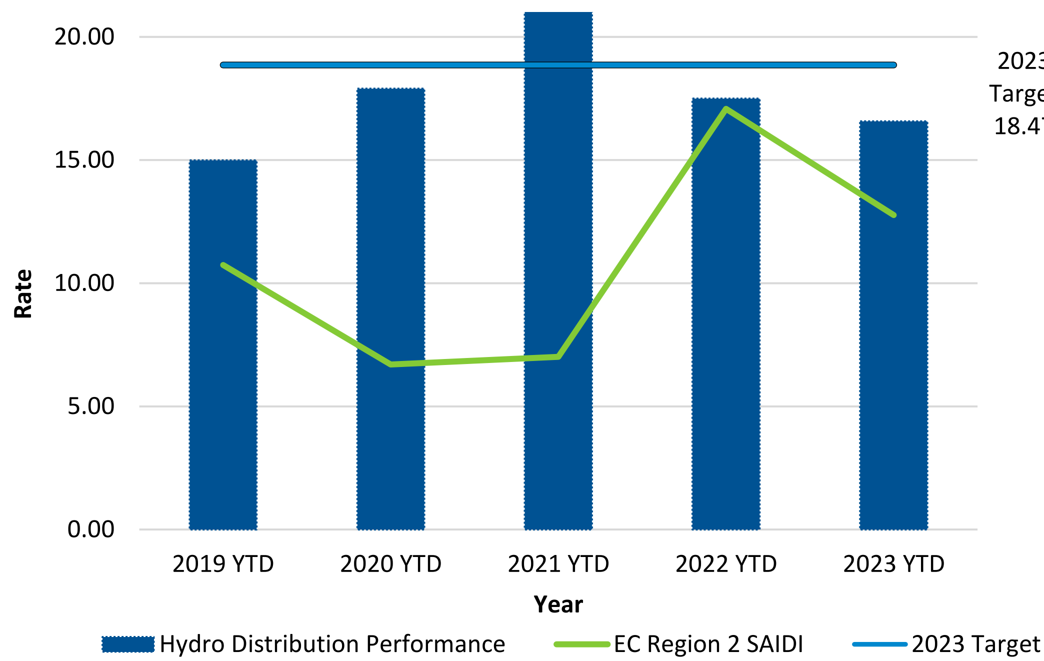

Chart 10: Service-Continuity SAIDI[24]

Service Continuity System Average Interruption Frequency Index

Table 9 shows the SAIFI for the fourth quarter of 2023 and 2022, annual 2023, annual 2022, and the 2023 annual target.

Table 9: Service-Continuity SAIFI (Interruptions per Customer)[25]

	Q4 2023	Q4 2022	Annual 2023	Annual 2022	2023 Annual Target
SAIFI	1.35	0.78	6.28	4.93	5.48

[24] [ ]
[25] Unplanned and planned breakdown is not available at this time due to ongoing database upgrades. This data will be provided when available.

Hydro uses the average of its Service Continuity SAIFI Index Performances for the period 2018–2022 as its 2023 annual target for this index.

Chart 11 shows EC 2019–2023 annual SAIFI performances and Hydro's 2019–2023 annual SAIFI performances.

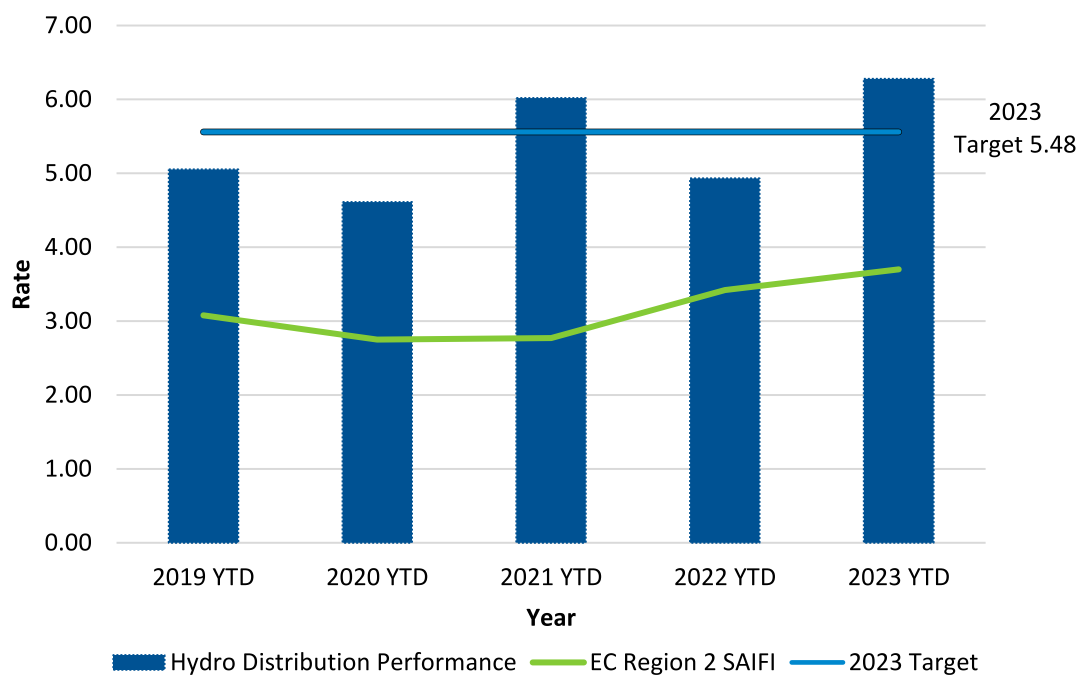

Chart 11: Service-Continuity SAIFI[26]

Additional Information

Service Continuity Performance by Area

Table 10 and Table 11 show the Service-Continuity SAIDI and SAIFI performances, respectively, for the fourth quarter of 2023 and 2022 broken down by geographical area. The tables also show the 12 months-to-date SAIDI and SAIFI performances and the SAIDI and SAIFI average performances for the period 2018–2022. The area performance indicators are calculated using the respective area customer count. The all areas performance indicators are calculated using all of Hydro customers. Therefore, the area performances cannot be summed to provide the all areas performances.

[26] [ ]

Table 10: Service-Continuity SAIDI (Hours per Period)

Area	Q4 2023	Q4 2022	12 Months-to-Date 2023	12 Months-to-Date 2022	Five-Year Average
Central					
Interconnected	5.98	3.30	13.71	19.74	19.70
Isolated	1.32	0.19	3.15	9.04	3.95
Northern					
Interconnected	8.40	1.23	15.87	8.55	11.66
Isolated	1.63	3.11	5.60	11.74	9.86
Labrador					
Interconnected	0.84	5.00	24.52	24.56	26.52
Isolated	1.24	1.19	8.13	15.00	11.43
Totals	**4.57**	**3.11**	**16.57**	**17.49**	**18.47**

Table 11: Service-Continuity SAIFI (Number per Period)

Area	Q4 2023	Q4 2022	12 Months-to-Date 2023	12 Months-to-Date 2022	Five-Year Average
Central					
Interconnected	1.10	0.98	3.19	5.19	5.16
Isolated	1.45	0.25	3.65	2.33	3.38
Northern					
Interconnected	2.39	0.51	6.87	4.55	4.73
Isolated	1.81	0.40	7.02	2.31	4.60
Labrador					
Interconnected	0.42	0.71	8.94	5.33	6.80
Isolated	2.78	1.76	8.90	6.23	5.47
Totals	**1.35**	**0.78**	**6.28**	**4.93**	**5.48**

Service Continuity Performance by Origin

Table 12 and Table 13 show the Service-Continuity SAIDI and SAIFI values, respectively, for the fourth quarter of 2023 and 2022 broken down by origin. They also show the 12 months-to-date and the SAIDI and SAIFI average performances for the period 2018–2022.

Table 12: Service-Continuity SAIDI (Hours per Period)[27,28]

Area	Q4 2023	Q4 2022	12 Months-to-Date 2023	12 Months-to-Date 2022	Five-Year Average
Loss of Supply: Transmission	2.46	1.25	6.08	9.21	10.71
Distribution	2.11	1.86	10.49	8.28	7.76
Totals	**4.57**	**3.11**	**16.57**	**17.49**	**18.47**

Table 13: Service-Continuity SAIFI (Number per Period)[29,30]

Area	Q4 2023	Q4 2022	12 Months-to-Date 2023	12 Months-to-Date 2022	Five-Year Average
Loss of Supply: Transmission	0.68	0.25	3.62	2.21	3.07
Distribution	0.67	0.53	2.66	2.72	2.41
Totals	**1.35**	**0.78**	**6.28**	**4.93**	**5.48**

Service Continuity Performance by Type for the Fourth Quarter of 2023 Only

Table 14 shows the Service-Continuity SAIDI and SAIFI values for the fourth quarter of 2023 broken down by geographical area and interruption type. The area performance indicators are calculated using the area customer count. The all areas performance indicators are for all Hydro customers; therefore, the area performances cannot be summed to provide the all areas performances.

[27] Numbers may not add due to rounding.
[28] Hydro is no longer tracking segmented loss of supply statistics for the Newfoundland Power, Isolated, and L'anse-au-Loup Systems.
[29] Numbers may not add due to rounding.
[30] Hydro is no longer tracking segmented loss of supply statistics for the Newfoundland Power, Isolated, and L'anse-au-Loup Systems.

Table 14: Interruptions by Type[31,32]

Area	Scheduled		Unscheduled		Total	
	Distribution SAIFI	Distribution SAIDI	Distribution SAIFI	Distribution SAIDI	Distribution SAIFI	Distribution SAIDI
Central						
Interconnected	0.23	0.85	0.87	5.13	**1.10**	**5.98**
Isolated	0.00	0.00	1.45	1.32	**1.45**	**1.32**
Labrador						
Interconnected	0.30	0.62	0.12	0.21	**0.42**	**0.84**
Isolated	0.28	0.38	2.50	0.86	**2.78**	**1.24**
Northern						
Interconnected	0.37	1.22	2.02	7.18	**2.39**	**8.40**
Isolated	0.00	0.00	1.81	1.63	**1.81**	**1.63**
All Areas	**0.27**	**0.80**	**1.08**	**3.77**	**1.35**	**4.57**

1 ## *Service Continuity Customer Interruptions by Cause*

2 Table 15 shows the Service Continuity interruptions for the fourth quarter of 2023 and annual 2023
3 grouped by cause.

Table 15: Interruptions by Cause[33]

Cause	Q4 2023		2023 Annual	
	Number of Customer Interruptions	Distribution SAIDI	Number of Customer Interruptions	Distribution SAIDI
Adverse Environment	4	0.00	10	0.00
Adverse Weather	2,504	0.28	3,869	0.43
Defective Equipment	2,869	0.24	10,893	0.84
Environment: Corrosion	138	0.01	1,035	0.04
Environment: Salt Spray	13	0.00	842	0.08
Foreign Interference	0	0.00	2	0.00
Foreign Interference: Object	0	0.00	1,893	0.12
Foreign Interference: Vehicle	789	0.05	3,197	0.19
Human Error	0	0.00	1,093	0.05
Loss of Supply	26,519	2.46	140,795	6.08
Lightning	0	0.00	5,675	0.42
Scheduled Outage: Planned	10,670	0.80	38,809	6.05
Tree Contacts	1,741	0.13	7,116	0.78
Undetermined/Other	7,253	0.61	28,660	1.49
Total	**41,830**	**4.57**	**243,889**	**16.58**

[31] Scheduled numbers only include distribution planned outages.
[32] Totals may not add due to rounding.
[33] Distribution SAIDI totals do not add due to rounding.

3.1.5 Reliability Key Performance Indicators: Other

Under Frequency Load Shedding

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

Table 16 shows the UFLS events for the fourth quarter of 2023 and 2022, 12 months-to-date for 2023 and 2022, 2023 annual target, and 2018–2022 average by customer breakdown. Table 17 shows the UFLS undersupplied energy for the fourth quarter of 2023 and 2022, 12 months-to-date for 2023 and 2022, and 2018–2022 average by customer breakdown. As individual UFLS events can affect customer types differently, total events may not be the sum of the customer types.

The annual UFLS target has historically been set at six events. Hydro does not establish a UFLS event target or UFLS undersupplied energy targets.

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

Table 16: Customer Breakdown of UFLS Events

	Q4		12 Months-to-Date		2023 Annual	2018–2022
Customers	**2023**	**2022**	**2023**	**2022**	**Target**	**Average**
Newfoundland Power	0	2	2	2	N/A	2.0
Industrials	0	3	3	3	N/A	1.6
Hydro Rural	0	0	0	0	N/A	0.0
Total Events	**0**	**2**	**2**	**2**	**6**	**2.0**

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

	Q4		12 Months-to-Date		2018–2022
Customers	**2023**	**2022**	**2023**	**2022**	**Average**
Newfoundland Power	0	9,090	553	9,090	3,512
Industrials	0	695	96	695	277
Hydro Rural	0	0	0	0	0
Total Undersupplied Energy	**0**	**9,785**	**649**	**9,785**	**3,789**

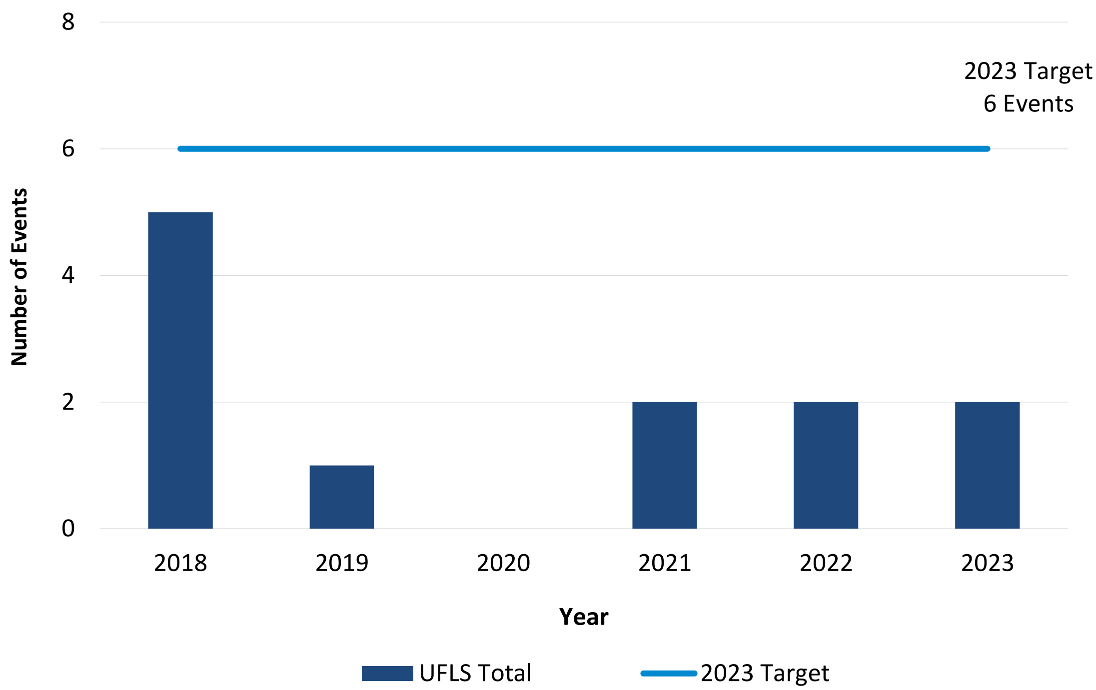

Chart 12: UFLS Events

3.2 Operating Performance Indicators

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

3.2.1 Operating Key Performance Indicator: Generation

Hydraulic Conversion Factor

In 2023, the hydraulic conversion factor for Bay d'Espoir was 0.4237 GWh/MCM, lower than the 2022 performance of 0.4270 GWh/MCM.

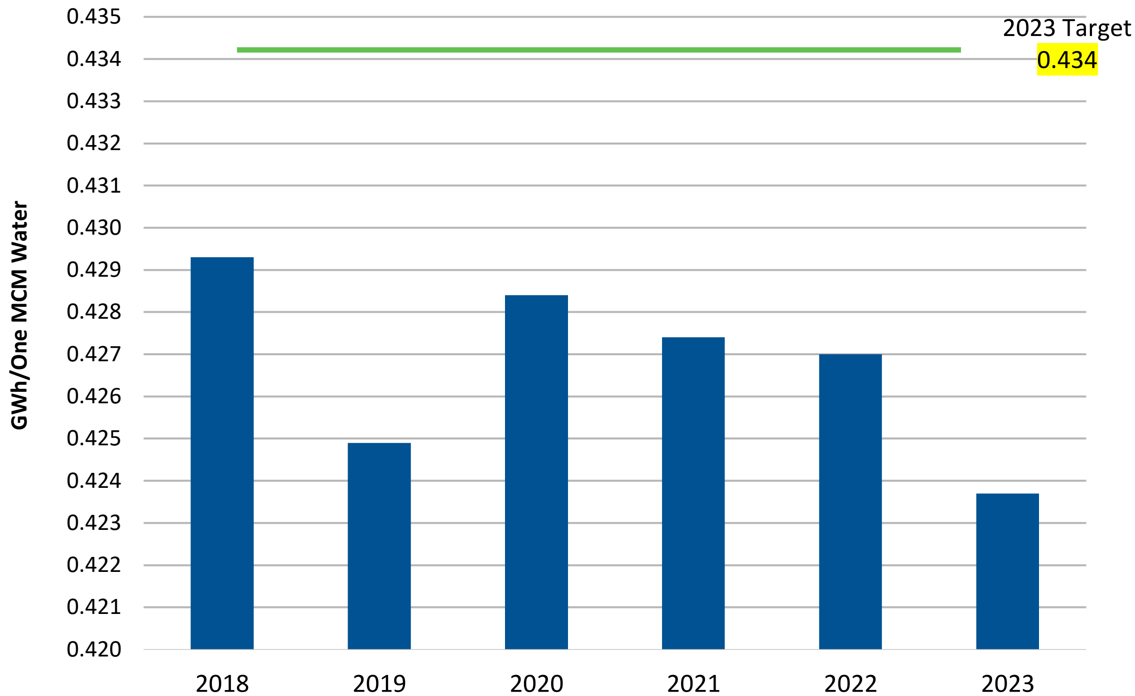

Chart 13: Hydraulic Conversion Factor (Bay d'Espoir)

In 2023, inflows to the Bay d'Espoir System as a whole were approximately 33% above average. Throughout January 2023, a series of mild temperatures in combination with precipitation events and subsequent snowmelt triggered multiple high inflow events in the Bay d'Espoir System, significantly increasing the total system energy in storage. Spill and bypass releases were required at times throughout January at Burn Dam Spillway, the Granite Canal Bypass structure, and bypass releases at the North Salmon Dam Spillway to keep reservoirs below their respective maximum operating levels. Generation prioritization continued through February 2023 along the Bay d'Espoir System with all plants maximized to the extent possible while reservoir levels remained high and inflows above average. There were some generation reductions required at the Granite Canal Station and the Upper Salmon Station to manage the risks associated with frazil ice during extreme cold conditions. In addition, beginning on March 13, 2023, bypass of the Upper Salmon Station was required due to the unit being taken offline because of issues identified during a planned rotor/rim inspection. Bypass continued at varying levels throughout the remainder of the year to support Long Pond Reservoir storage while the unit remained offline.[34]

Inflows due to spring runoff in April and May 2023 were low due to cooler temperatures and a prolonged snow melt, as well as a below average snow pack in many areas in the Bay d'Espoir System which resulted in below average inflows. However, weather conditions were much wetter across the Island in June 2023, with several moderate precipitation events occurring throughout the month and two significant rainfall events occurring. With the exception of continued bypass of the North Salmon Dam structure, spill and/or bypass did not occur.

System inflows for most of the third quarter were above average with the exception of August 2023, where inflows were close to average. With the exception of continued bypass of the North Salmon Dam structure, spill and/or bypass did not occur.

System inflows remained above average during the fourth quarter, once again due to multiple rain events. Inflows to the reservoirs of the Bay d'Espoir System were 191% of average during the month of October 2023, slightly above average for the month of November 2023, and 201% of average in December 2023. A significant weather event took place across central and western Newfoundland from December 19 to 22, 2023 that brought very high amounts of rain to the region. Approximately 240 mm of rain was recorded at Burnt Dam in the Bay d'Espoir System during this period. Because of this event, the Bay d'Espoir System monthly inflows for December 2023 were the third highest on the historical record for the month. To manage the high inflows, spill occurred at Burnt Dam Spillway, the Granite Canal Bypass, and the Granite Lake Overflow Spillway. The high inflows and water levels associated with the rain event led to record spill volumes for December 2023 at multiple locations across the system. Releases from Burnt Dam Spillway, Granite Lake Overflow Spillway, and Upper Salmon Bypass were the highest on record for December. Releases at the Granite Canal Bypass structure were the fourth highest on record for the month.

Above average inflows into the Bay d'Espoir System due to multiple significant rainfall events and exasperated by snowmelt lead to the exceedance of reservoir storage in the Bay d'Espoir System on multiple occasions during January 2023 and again in December 2023. While generation remained

[34] The unit returned to service on December 12, 2023; however, bypass continued in December to maintain the Meelpaeg Reservoir level below the maximum operating level during a historically high inflow event that occurred in December 2023.

maximized to the extent possible, the multiple spill events resulted in lost energy across the reservoirs in the Bay d'Espoir System, resulting in a decrease in the Bay d'Espoir KPI from the target level of 0.434 GWh/MCM.

Thermal Conversion Factor

The thermal conversion factor for the Holyrood TGS is proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. The output level at Holyrood TGS will vary depending on hydraulic production on the Island, quantity of power purchases (including LIL energy), customer energy requirements, system security requirements, and customer demand. The thermal conversion factor is also impacted by the heating content in the No. 6 fuel oil consumed at the plant, measured in BTU[35]/bbl.

In 2023, Hydro's net thermal conversion factor was 511 kWh/bbl. The conversion factor is lower than the 2019 Test Year approved conversion factor of 583 kWh/bbl. The efficiency at the Holyrood TGS showed a decrease in performance with a net heat rate performance of 10,731 BTU/kWh in 2023 compared to 11,016 BTU/kWh in 2022.

In 2023, the units were dispatched as required for system reliability support and system peak load considerations, in consideration of unit availability. The average net unit load, while operating, was 59.2 MW, a decrease of 14.1% from 68.9 MW in 2022.

Energy production from the Holyrood TGS for 2023 was 610 GWh, an 18% decrease from 2022 production levels of 745 GWh. The decrease in energy production from the Holyrood TGS can be attributable to an increase in deliveries received via the LIL between 2022 and 2023.

[35] British thermal unit ("BTU").

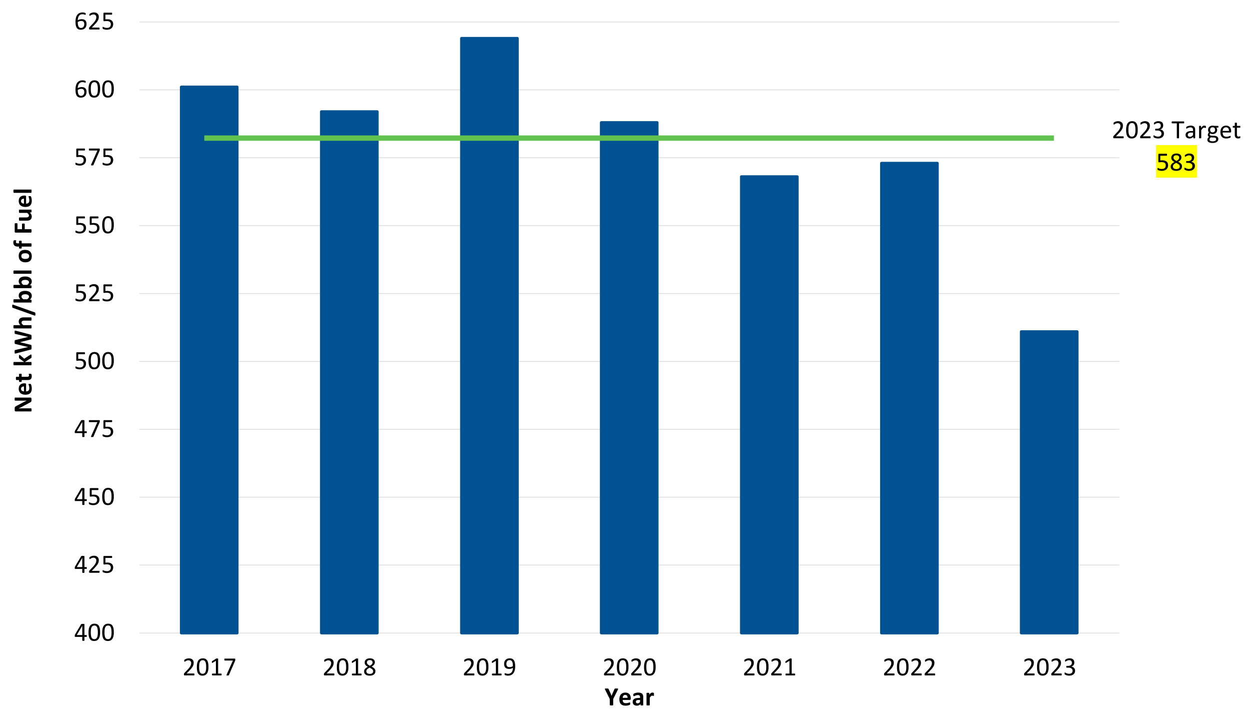

Chart 14: Thermal Conversion Factor (Holyrood TGS)

3.3 Financial Performance Indicators

The financial KPIs that Hydro reports to the Board on an annual basis are:

- Controllable Unit Cost;
- Generation Controllable Cost;
- Generation Output Controllable Cost;
- Transmission Controllable Cost; and
- Distribution Controllable Cost.[36]

In Order No. P.U. 8(2007), the Board ordered that Hydro file a report no later than October 31, 2007, outlining an appropriate peer group with which Hydro's financial performance at the generation and

[36] This KPI has not been available for benchmarking from 2007 onwards. Hydro continues to report it for the purposes of year-over-year comparison.

transmission levels could be compared.[37] In compliance with this Order, Hydro filed a report titled "Peer Group Benchmarking,"[38] which summarized Hydro's findings regarding the development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. The list of peers used for KPI benchmarking for financial performance indicators is included as Attachment 3. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission ("FERC") database, and is available for up to 2022. All financial data for the United States-based peer group is in US dollars and all financial data for Hydro is in Canadian dollars.

Note that Hydro has provided operations, maintenance, and administration ("OM&A") figures based on actual 2023 OM&A costs, which are allocated based on the 2019 Test Year Cost of Service Study. Table 18provides five-year historical trends of KPI data along with comparative 2019 Test Year values.

Table 18: Test Year and Five-Year Historical OM&A Costs ($)

OM&A (COS) KPIs	2019 TY	2019	2020	2021	2022	2023
Controllable Unit Cost (per MWh)	13.96	14.04	14.37	13.78	14.10	15.44
Generation Controllable Cost (per MW)	31,006	30,173	30,292	28,602	29,607	32,390
Generation Output Controllable Cost (per GWh)	9,510	9,117	9,640	9,574	9,506	11,177
Transmission Controllable Cost (per km)	4,460	4,172	4,194	4,086	4,229	4,627
Distribution Controllable Cost (per circuit km)	3,122	3,073	3,079	3,628	3,750	4,101
Distribution Controllable Cost (per MWh retail sales)	9.12	9.27	9.64	9.13	8.83	9.70

3.3.1 Controllable Unit Cost

Hydro's OM&A costs increased from $130.5 million in 2022 to $142.8 million in 2023. The main drivers of this variance include increases in the categories of system equipment maintenance, customer costs, and professional services as outlined in Return 9 and 9A of Hydro's 2023 Annual Return. There were 9,245 GWh of energy deliveries in 2023, which was consistent with 2022 (9,254 GWh). This resulted in

[37] In 2007, Hydro had initially used peer benchmarking data from the CEA Committee on Performance Excellence ("COPE"), as published in the "Peer Group Performance Measures for Newfoundland Power" report. Since then the CEA has advised that neither the composite information from these measures nor any other cost-related CEA composite indicators are available for benchmarking purposes. As a result, Newfoundland Power reports based on a peer group of companies operating in the United States. This group of companies is not an appropriate group for Hydro to use as a peer group of companies due to Hydro's relatively small distribution component; however, in order to maintain consistency for year-over-year comparisons, Hydro uses this group of companies for its financial benchmarking.
[38] "Peer Group Benchmarking," Newfoundland and Labrador Hydro, October 31, 2007.

an increase in Controllable Unit Cost[39] from $14.10 per MWh delivered in 2022 to of $15.44 per MWh delivered in 2023.

Hydro uses normalized energy delivered in the computation of its Corporate Controllable Unit Cost. This is not directly comparable to the peer group data from the FERC database, which is based on net energy generated. To provide for direct comparison with the peer group, Hydro has also calculated Controllable Unit Cost based on net energy generated. Chart 15 illustrates Hydro's Corporate Controllable Unit Cost for 2018–2023 and that of the peer group for 2018–2022. As indicated in Chart 15, Hydro's 2023 corporate OM&A per unit of net generation was $27.94 per MWh. This is higher than the computed Controllable Unit Cost of $15.44 per MWh delivered as normalized deliveries also reflect Hydro's energy purchases and are therefore higher than net generation.

As shown in Chart 15, Hydro's Controllable Unit Cost based on net energy generated remained fairly stable from 2018 to 2022 and was consistently below the peer group average for the same period. While this cost has increased for 2023, it is still below historical peer group averages.

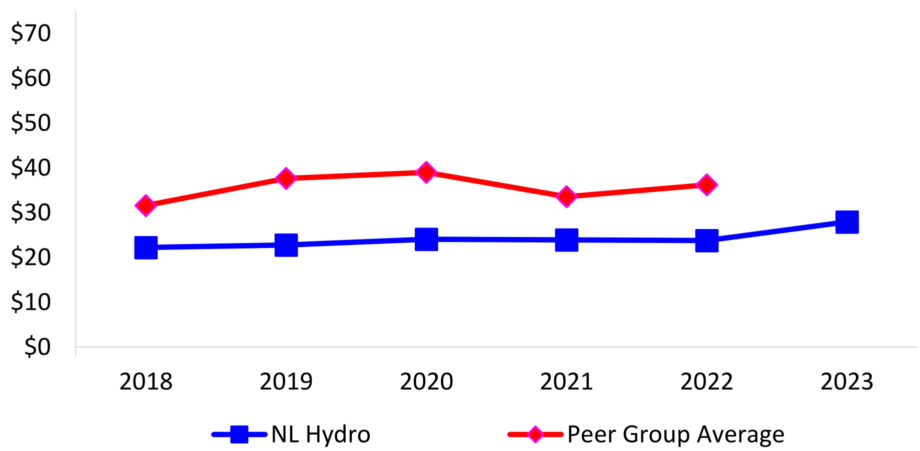

Chart 15: Controllable Unit Cost ($ per Net MWh Generated)

[39] Controllable Unit Cost is a high-level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MWh. Total corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs, and loss on disposal of capital assets. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.

3.3.2 Generation Controllable Cost

Generation Controllable Cost[40] was $32,390 per MW for 2023 compared to $29,607 per MW in 2022, an increase of $2,783 per MW. This escalation is attributable to an increase in OM&A costs in 2023 relative to 2022. Chart 16 demonstrates that Hydro's Generation Controllable Cost has fluctuated in a manner similar to the peer group during the 2018 to 2021 timeframe, with 2022 seeing a spike for the peer group average.

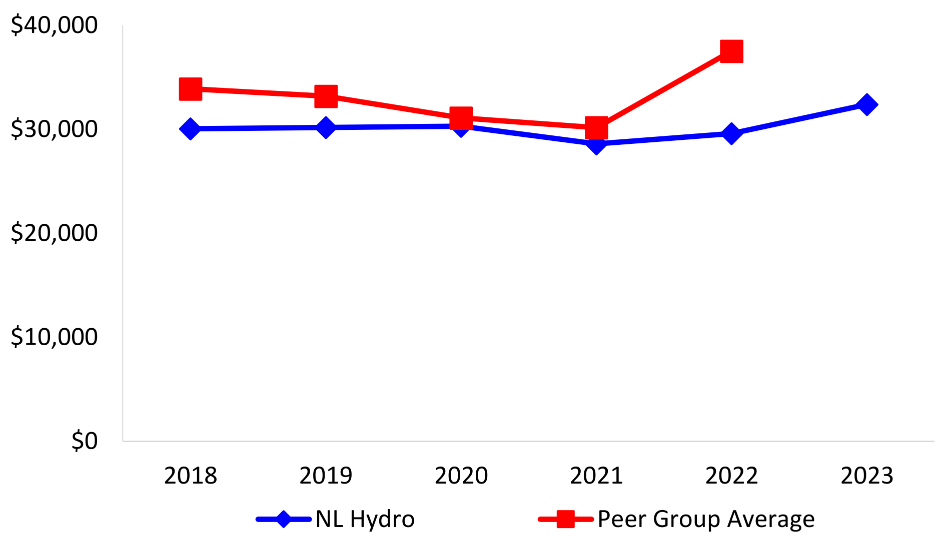

Chart 16: Generation Controllable Cost ($ per MW Installed Capacity)

3.3.3 Generation Output Controllable Cost

In 2023, Hydro's Generation Output Controllable Cost[41] was $11,117 per GWh, which compares to $9,506 in 2022, an increase of $1,671 per GWh. As demonstrated in Chart 17, from 2018 to 2022, Hydro's Generation Output Controllable Cost remained fairly stable, while the peer group average has

[40] Generation Controllable Cost is a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity, measured in MW.
[41] Generation Output Controllable Cost is a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.

seen a slight, gradual increase in the last few years. Hydro notes that its current year cost is lower that historical peer group averages from 2020 to 2022.

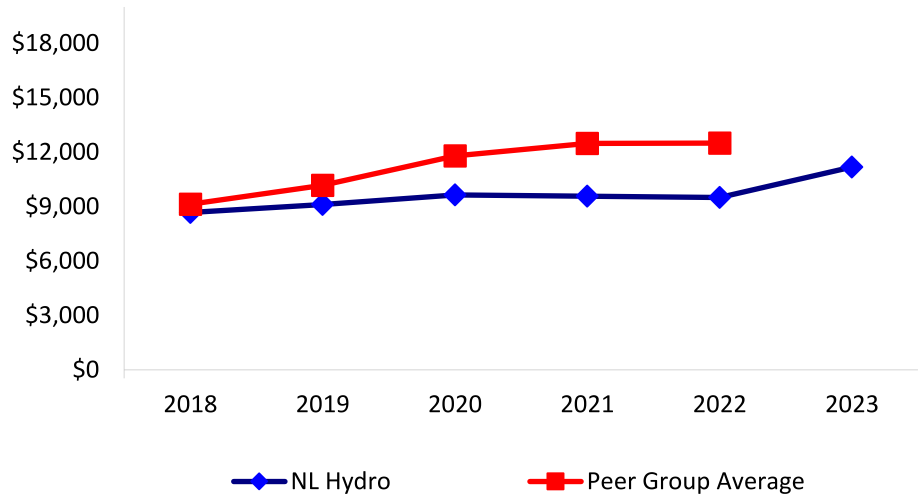

Chart 17: Generation Output Controllable Cost ($ per Net GWh Generated)

3.3.4 Transmission Controllable Cost

In 2023, Hydro's Transmission Controllable Cost[42] of $4,627 per kilometre of transmission was above the $4,229 per kilometre reported in 2022 by $398 per kilometre.

For this particular metric, a comparison of direct cost per unit kilometre between the peer group and Hydro is not meaningful due to differences in accounting treatment and corporate cost allocations. However, tracking trends over several years may be helpful in ensuring consistency with the industry in general. As shown in Chart 18, Hydro's Transmission Controllable Cost has remained fairly stable over the past several years, while the peer group average has trended higher during the same period.

[42] Transmission Controllable Cost is a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV and above).

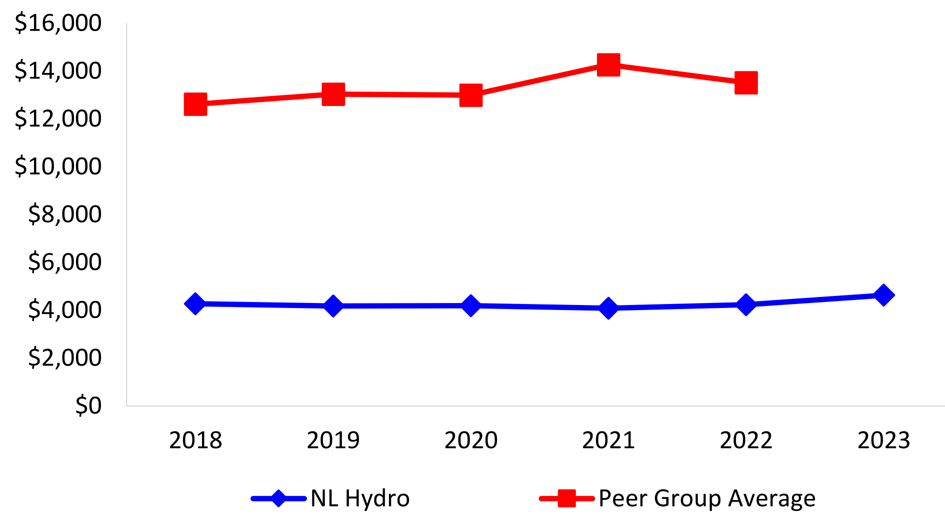

Chart 18: Transmission Controllable Cost ($ per Kilometre 230 kV equivalent)

3.3.5 Distribution Controllable Cost

The Distribution Controllable Cost[43] KPI had previously been reported as dollars per kilometre of distribution using the EC COPE data. As previously noted, the EC COPE data is no longer available for the benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated kilometres of distribution data are unavailable. In the absence of the EC COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales; therefore, Hydro uses this same data set. However, given Hydro's relatively small quantity of retail sales and the rural and remote locations of its retail customers, Hydro's distribution cost per MWh is higher than that of Newfoundland Power and the peer group average.

Hydro's distribution costs of $9.70 per MWh of retail sales in 2023 are higher than in 2022, but are closer to historical trends, and also remain lower in comparison to the peer group, as demonstrated in Chart 19. Saying that, for the reasons noted above, this number is much higher than the same statistic for Newfoundland Power. Distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and compared to Newfoundland Power's distribution

[43] Distribution Controllable Cost is a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres.

1 assets. Hydro's higher costs per MWh are due to the rural and geographically-dispersed nature of its
2 distribution systems.

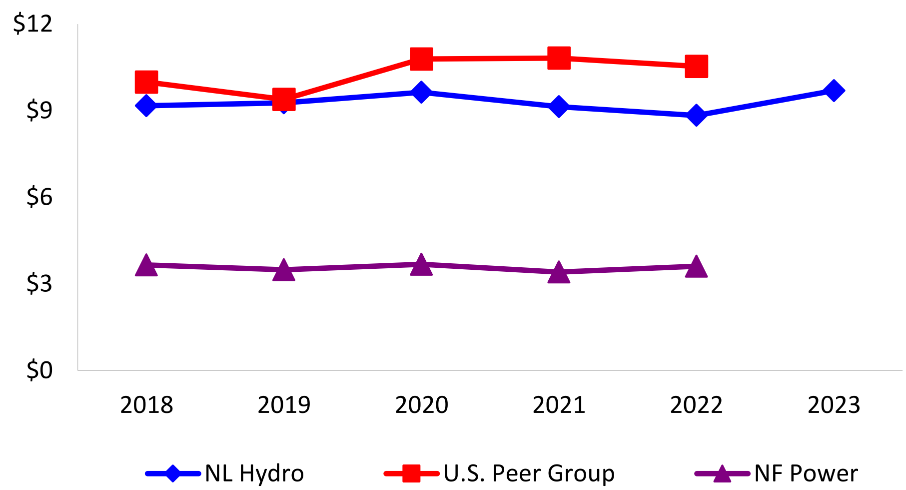

Chart 19: Distribution OM&A per MWh

3 The distribution cost per kilometre of circuit length will continue to be reported for year-over-year trend
4 analysis, as shown in Chart 20. At $4,101 per circuit kilometre in 2023, Hydro's Distribution Controllable
5 Cost increased by $351 per kilometre from $3,750 per kilometre in 2022.

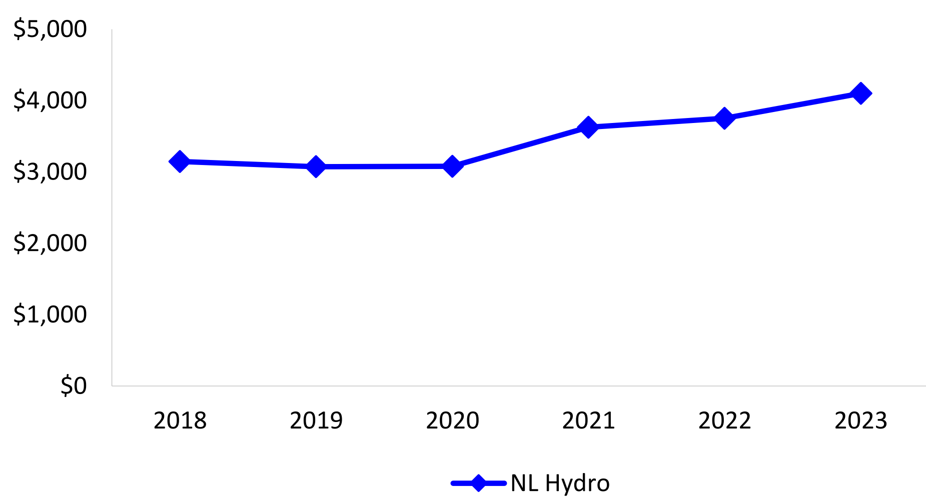

Chart 20: Hydro's Distribution Controllable Cost ($ per Distribution Circuit Kilometres)

3.4 Customer–Related Performance Indicators

The 2022 residential customer satisfaction survey[44] showed that 89% of customers are either very satisfied or somewhat satisfied with Hydro. As this survey is completed on a biennial basis, the 2022 survey results are the most recent results available.

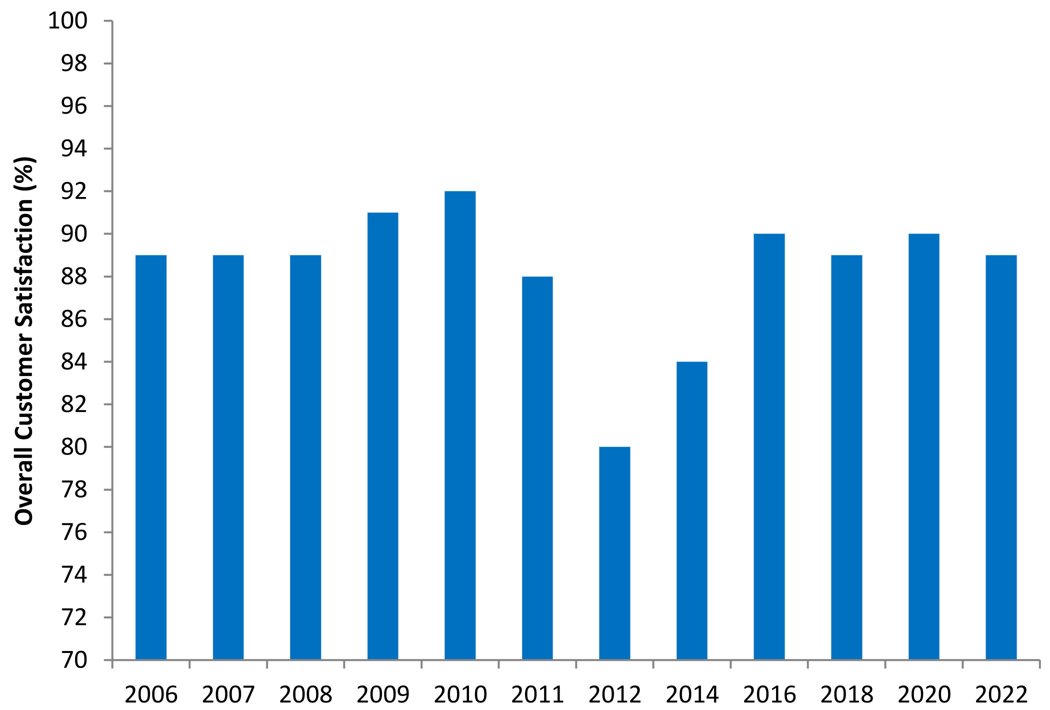

Chart 15: Residential Customer Satisfaction

4.0 Conclusion

In 2023, Hydro's reliability scores for end-consumer SAIDI and SAIFI were below and above target, respectively. Hydro's five-year average generation reliability scores for its weighted capability factor and weighted DAFOR are slightly better than the most recent five year averages for EC. Operating KPIs related to conversion rates for Bay d'Espoir and Holyrood TGS are below target, due to increased spill and decreased unit efficiency, respectively. Hydro's financial KPIs, including Controllable Unit Costs are higher when compared to 2022 report, driven by an increase in OM&A costs from 2023. As allocations

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

are based on the 2019 Test Year, financial KPIs for costs associated with Generation, Transmission and Distribution are not representative of the allocation of 2023 actual costs. Hydro will perform another residential customer satisfaction survey in 2024, the results of which will be included in its 2024 Annual Report on Key Performance Indicators.

Attachment 1

Rationale for Hydro's 2023 Key Performance Indicators Targets

Key Performance Indicators	Comment on Key Performance Indicators 2023 Target
Reliability	Hydro has adopted a target setting approach wherein the five-year outage performance is used for distribution and transmission targets.
WCF	The 2023 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2023 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2023 targets for outage performance were based on the five-year average performance.
Distribution SAIDI and SAIFI	The 2023 targets for outage performance were based on the five-year average performance.
UFLS	The 2023 target is based upon previous history of performance.
Operating	
Hydraulic Conversion Factor	Held at the previous target value.
Thermal Conversion Factor	2023 target was 583 kWh/bbl based on the 2019 Test Year.

Attachment 2

Computation of Weighted Capability Factor and Factors Impacting Performance

WCF is calculated using the following formula:

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

Where:

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

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

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

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

Factors that Affect Unit Total Equivalent Outage Time:

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

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

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

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

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

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

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

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

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

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

Attachment 3

List of U.S.-Based Peers for Financial Key Performance Indicators Benchmarking

List of U.S.-Based Peers for Financial Key Performance Indicators Benchmarking

Generation and Corporate Peer Group:

- Alcoa Power Generating Inc.
- Allete, Inc.
- Aquila, Inc.
- Avista Corporation
- Cleco Power LLC
- Entergy Mississippi, Inc.
- Indiana-Kentucky Electric Corporation
- Kentucky Power Company
- Ohio Valley Electric Corporation
- Portland General Electric Company
- Public Service Company of New Hampshire
- Puget Sound Energy, Inc.
- Sierra Pacific Power Company
- Southern Electric Generating Company
- Southern Indiana Gas and Electric Company
- The Empire District Electric Company

Transmission Peer Group:

- Allete, Inc.
- Aquila, Inc.
- Avista Corporation
- Delmarva Power & Light Company
- Entergy Mississippi, Inc.
- Kentucky Utilities Company
- MDU Resources Group, Inc.
- Mississippi Power Company
- New York State Electric & Gas Corporation
- Northern Indiana Public Service Company
- Northern States Power Company (Wisconsin)
- Oklahoma Gas and Electric Company
- Public Service Company of Colorado
- Public Service Company of Oklahoma
- Sierra Pacific Power Company
- Southwestern Electric Power Company
- Tucson Electric Power Company
- Westar Energy, Inc.

Appendix E

Financial Schedules

[ ]

Balance Sheet – Regulated Operations
as at December 31, 2023
($000)[1]

Assets	**December 2023**	**December 2022**
Current Assets		
Cash and Cash Equivalents	29,350	16,267
Accounts Receivable	104,810	97,047
Current Portion of Sinking Funds	7,355	9,095
Inventory	100,706	98,992
Contract Receivable[2]	12,550	-
Due from Related Parties	1,242	2,592
Prepaid Expenses	4,678	5,707
Related Party Note Receivable	-	29,665
Promissory Note - Non-Regulated	-	2,711
	260,691	**262,076**
Property, Plant, and Equipment	2,327,780	2,245,447
Intangible Assets	6,144	5,865
Sinking Funds	198,510	192,835
Right-of-Use Assets	2,423	2,452
Regulatory Assets	849,682	504,348
Long-Term Receivable	195	257
Total Assets	**3,645,425**	**3,213,280**
Liabilities and Shareholder's Equity		
Current Liabilities		
Accounts Payable and Accrued Liabilities	113,067	99,019
Accrued Interest	25,362	25,363
Current Portion of Long-Term Debt	6,650	6,650
Deferred Credits	3,656	3,011
Current Portion of Deferred Contributions	981	993
Current Portion of Asset Retirement Obligations	96	1,401
Due to Related Parties	-	17,914
Current Portion of Contract Payable	273,731	165,466
Promissory Notes	230,000	131,000
Promissory Note - Non-Regulated	13,490	-
	667,033	**450,817**
Deferred Contributions	65,255	63,713
Long-Term Payable	823	824
Long-Term Debt	2,016,890	2,032,670
Lease Liability	2,611	2,604
Regulatory Liabilities	16,615	6,579
Asset Retirement Obligations	26,632	15,799
Employee Future Benefits	78,452	67,581
Contract Payable	177,566	-
Contributed Capital	100,000	100,000
Retained Earnings	479,905	447,920
Accumulated Other Comprehensive Income	13,643	24,773
Total Liabilities and Shareholder's Equity	**3,645,425**	**3,213,280**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

[2] Payments under the Labrador-Island Link Transmission Funding Agreement ("TFA") commenced in April 2023. The contract receivable balance represents the timing difference between the expense recognition of the value of the service delivered to Newfoundland and Labrador Hydro ("Hydro") and the contractual payments made under the TFA.

Statement of Income – Regulated Operations
for the Twelve Months Ended December 31, 2023
($000)[1]

Fourth Quarter				YTD			Annual
2023 Actual	**2023 Budget**	**2022 Actual**		**2023 Actual**	**2023 Budget**	**2022 Actual**	**2023 Budget**
			Revenue				
171,177	170,439	170,516	Energy Sales	640,197	636,290	637,319	636,290
1,607	1,500	2,510	Other Revenue	14,545	5,795	13,451	5,795
172,784	**171,939**	**173,026**		**654,742**	**642,085**	**650,770**	**642,085**
			Expenses				
31,493	32,993	32,909	Operating Costs	142,759	136,146	130,494	136,146
76,675	79,688	79,425	Fuels	245,088	244,857	242,958	244,857
15,572	13,505	16,962	Power Purchased	61,643	54,786	64,715	54,786
23,422	22,747	19,499	Amortization	88,067	87,597	85,611	87,597
388	539	2,808	Other Expense	2,057	2,157	4,239	2,157
19,516	20,776	19,815	Interest	83,143	85,174	86,440	85,174
167,066	**170,248**	**171,418**		**622,757**	**610,717**	**614,457**	**610,717**
5,718	**1,691**	**1,608**	**Net Income**	**31,985**	**31,368**	**36,313**	**31,368**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

Statement of Comprehensive Income – Regulated Operations
for the Twelve Months Ended December 31, 2023
($000)[1]

Fourth Quarter 2023 Actual	Fourth Quarter 2023 Budget	Fourth Quarter 2022 Actual		YTD 2023 Actual	YTD 2023 Budget	YTD 2022 Actual
5,718	1,691	1,608	Net Income	31,985	31,368	36,313
			Other Comprehensive Loss			
(508)	-	-	Employee Future Benefit Actuarial Loss	(2,033)	-	-
5,210	**1,691**	**1,608**	**Total Comprehensive Income**	**29,952**	**31,368**	**36,313**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

Statement of Cash Flows – Regulated Operations
for the Twelve Months Ended December 31, 2023
($000)[1]

	YTD 2023	YTD 2022
Operating Activities		
Net Income	31,985	36,313
Adjusted for Items not Involving Cash Flow		
Amortization of Property, Plant and Equipment	88,067	85,559
Accretion of Asset Retirement Obligation and Long-Term Debt	2,130	1,525
Amortization of Deferred Contributions	(2,166)	(2,230)
Employee Future Benefits	10,871	(26,417)
Loss on Disposal of Property, Plant and Equipment	-	777
Other	(24,788)	16,883
	106,099	**112,410**
Changes in Non-Cash Working Capital Balances		
Accounts Receivable	(7,763)	10,393
Inventory	(1,714)	(14,838)
Prepaid Expenses	1,029	457
Regulatory Assets	(345,334)	(339,893)
Regulatory Liabilities	193	3,356
Accounts Payable and Accrued Liabilities	(4,478)	30,643
Contract Payable	285,831	147,893
Accrued Interest	(1)	24
Contract Receivable	(12,550)	-
Due to/from Related Parties	(16,564)	15,239
	4,748	**(34,316)**
Financing Activities		
Decrease (increase) in Long-Term Receivable	62	(24)
Decrease in Deferred Credits	645	479
Increase in Deferred Capital Contribution	3,696	10,864
Decrease in Promissory Notes	115,201	88,101
Issuance of Long-Term Debt	-	-
Long-Term Debt Retired	-	-
	119,604	**99,420**
Investing Activities		
Additions to Property, Plant and Equipment	(149,277)	(102,865)
Removal Costs	(4,728)	(486)
Proceeds on Disposal	1,167	13
Additions to Intangible Assets	27	(925)
Increase in Sinking Funds	(6,650)	(6,650)
Decrease in Related Party Note Receivable	29,665	23,555
Changes in Non-Cash Working Capital Balances	18,527	(3,265)
	(111,269)	**(90,623)**
Net Increase (decrease) in Cash	13,083	(25,519)
Cash Position, Beginning of Period	16,267	41,786
Cash Position, End of Period	**29,350**	**16,267**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

Revenue Summary – Regulated Operations
for the Twelve Months Ended December 31, 2023
($000)[1]

Fourth Quarter				YTD			Annual
2023 Actual	**2023 Budget**	**2022 Actual**		**2023 Actual**	**2023 Budget**	**2022 Actual**	**2023 Budget**
			Industrial				
7,359	9,994	6,993	Industrial[2]	27,150	39,836	29,737	39,836
4,061	1,753	4,457	Industrial Load[3]	18,121	6,785	15,809	6,785
11,420	**11,747**	**11,450**	**Total Industrial**	**45,271**	**46,621**	**45,546**	**46,621**
			Utility				
139,135	133,725	121,054	Newfoundland Power Inc.	522,282	489,442	453,311	489,442
(1,269)	2,616	15,327	Utility Load[4]	(10,454)	16,766	53,018	16,766
137,866	**136,341**	**136,381**	**Total Utility**	**511,828**	**506,208**	**506,329**	**506,208**
21,891	22,351	22,112	**Rural**	83,098	83,461	84,871	83,461
-	-	573	**Export Energy[2]**	-	-	573	-
			Other Revenue				
190	130	(358)	Sundry	715	518	681	518
411	403	432	Pole Attachments	1,632	1,610	1,649	1,610
524	575	561	Amortization of CIAC[5]	2,166	2,098	2,230	2,098
117	-	1,502	Recovery of Supply Power[6]	8,573	-	7,400	-
365	392	373	Generation Demand Recovery	1,459	1,569	1,491	1,569
1,607	**1,500**	**2,510**	**Total Other Revenue**	**14,545**	**5,795**	**13,451**	**5,795**
172,784	**171,939**	**173,026**	**Total Revenue**	**654,742**	**642,085**	**650,770**	**642,085**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

[2] Industrial Revenue for 2022 included export energy in error.

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

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

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

[6] Recovery of Supply Power includes sales of emergency energy to Nova Scotia Power and recovery of costs incurred by Hydro as a result of advanced delivery of the Nova Scotia Block to Emera.

Supplementary Schedule – Regulated Operations
for the Twelve Months Ended December 31, 2023
($000)[1]

Fourth Quarter 2023 Actual	Fourth Quarter 2023 Budget	Fourth Quarter 2022 Actual		YTD 2023 Actual	YTD 2023 Budget	YTD 2022 Actual	Annual 2023 Budget
			Interest				
			Interest Income				
3,709	3,575	3,501	Interest on Sinking Fund	14,449	14,034	13,626	14,034
1,204	884	897	Other Interest Income	4,230	3,105	2,009	3,105
4,913	**4,459**	**4,398**	**Total Interest Income**	**18,679**	**17,139**	**15,635**	**17,139**
			Interest Expense				
24,431	24,431	24,455	Interest on Long-Term Debt	97,725	97,725	97,749	97,725
2,645	4,176	1,408	Interest on Short-Term Debt[3]	6,241	11,741	2,274	11,741
2,198	2,241	2,176	Debt Guarantee Fee	8,794	8,963	8,703	8,963
533	378	464	Accretion	2,131	1,500	1,525	1,500
(709)	(698)	(688)	RSP[2] Interest[3]	(2,990)	(2,937)	(2,803)	(2,937)
(4,129)	(4,641)	(3,482)	SCVDA Interest[3]	(8,387)	(12,950)	(4,625)	(12,950)
109	13	99	Other[3]	162	50	134	50
25,078	**25,900**	**24,432**	**Total Interest Expense**	**103,676**	**104,092**	**102,957**	**104,092**
(649)	(665)	(219)	Interest Capitalized during Construction	(1,854)	(1,779)	(882)	(1,779)
24,429	25,235	24,213		101,822	102,313	102,075	102,313
19,516	**20,776**	**19,815**	**Net Interest Expense**	**83,143**	**85,174**	**86,440**	**85,174**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

[2] Rate Stabilization Plan ("RSP").

[3] Comparative figures have been reclassified to conform to the current year's presentation.

Balance Sheet – Non-Regulated Activities
as at December 31, 2023
($000)[1]

Assets	**December 2023**	**December 2022**
Current Assets		
Accounts Receivable	6,786	8,166
Prepaid Expenses	672	639
Deferred Assets	68,131	85,689
Promissory Note Receivable	13,490	-
Due from Related Party	3,450	3,874
	92,529	**98,368**
Investment in CF(L)Co[2]	731,628	702,474
Total Assets	**824,157**	**800,842**
Liabilities and Shareholder's Equity		
Current Liabilities		
Accounts Payable and Accrued Liabilities	3,352	3,173
Due to Related Party	27,097	15,878
Promissory Note	-	2,711
Derivative Liabilities	68,131	85,689
	98,580	**107,451**
Employee Future Benefits	3,919	3,150
Share Capital	22,504	22,504
Lower Churchill Development Corporation	15,400	15,400
Retained Earnings	678,660	645,843
Accumulated Other Comprehensive Income	5,094	6,494
Total Liabilities and Shareholder's Equity	**824,157**	**800,842**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.
[2] Churchill Falls (Labrador) Corporation ("CF(L)Co").

Statement of Income – Non-Regulated Activities
for the Twelve Months Ended December 31, 2023
($000)[1]

Fourth Quarter 2023 Actual	Fourth Quarter 2023 Budget	Fourth Quarter 2022 Actual		YTD 2023 Actual	YTD 2023 Budget	YTD 2022 Actual	Annual 2023 Budget
			Revenue				
15,159	15,344	15,903	Energy Sales	56,969	58,322	60,002	58,322
4,713	5,252	4,719	Other Revenue	18,855	21,010	15,644	21,010
19,872	**20,596**	**20,622**		**75,824**	**79,332**	**75,646**	**79,332**
			Expenses				
708	195	224	Operating Costs	4,132	814	1,115	814
36	-	47	Fuels	36	-	47	-
4,713	5,252	4,719	Transmission Rental	18,855	21,010	15,924	21,010
13,533	12,753	13,550	Power Purchased	51,132	50,851	51,674	50,851
-	-	97	Interest	-	-	97	-
(1,710)	-	(7,457)	Other Expense[2]	-	-	-	-
17,280	**18,200**	**11,180**		**74,155**	**72,675**	**68,857**	**72,675**
2,592	**2,396**	**9,442**	Net Operating Income	**1,669**	**6,657**	**6,789**	**6,657**
			Other Revenue				
11,446	7,122	4,580	Equity in CF(L)Co	30,231	41,283	43,486	41,283
1,230	4,905	7,579	Preferred Dividends	6,395	11,399	13,393	11,399
12,676	**12,027**	**12,159**		**36,626**	**52,682**	**56,879**	**52,682**
15,268	**14,423**	**21,601**	**Net Income**	**38,295**	**59,339**	**63,668**	**59,339**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

[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.

Statement of Retained Earnings – Non-Regulated Activities
for the Twelve Months Ended December 31, 2023
($000)[1]

Fourth Quarter			YTD	
2023 Actual	2022 Actual		2023 Actual	2022 Actual
664,866	633,917	Balance, Beginning of Period	645,843	603,496
15,268	21,601	Net Income	38,295	63,668
(1,474)	(9,675)	Dividends	(5,478)	(21,321)
678,660	**645,843**	Balance, End of Period	**678,660**	**645,843**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

Statement of Comprehensive Income – Non-Regulated Activities
for the Twelve Months Ended December 31, 2023
($000)[1]

Fourth Quarter				YTD		
2023 Actual	**2023 Budget**	**2022 Actual**		**2023 Actual**	**2023 Budget**	**2022 Actual**
15,268	14,423	21,601	Net Income	38,295	59,339	63,668
			Other Comprehensive Gain			
(323)	-	2,029	Actuarial gain on employee benefits liability	(323)	-	2,029
(842)	-	7,376	Share of CF(L)Co other Comprehensive Loss and Other	(1,077)	-	4,665
14,103	**14,423**	**31,006**	**Total Comprehensive Income**	**36,895**	**59,339**	**70,362**

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.

Statement of Cash Flows – Non-Regulated Activities
for the Twelve Months Ended December 31, 2023
($000)[1]

	YTD 2023	YTD 2022
Operating Activities		
Net Income	38,295	63,668
Adjusted for Items not Involving Cash Flow		
Employee Future Benefits	769	(1,268)
Equity in CF(L)Co	(30,231)	(43,486)
Net Changes in PPA[2] Fair Value	-	2,029
Other	(323)	-
	8,510	**20,943**
Changes in Non-Cash Working Capital Balances		
Accounts Receivable	1,380	1,197
Accounts Payable and Accrued Liabilities	(304)	(262)
Due to/from Related Parties	11,643	11,364
Prepaid Expenses	(33)	(47)
	21,196	**33,195**
Financing Activities		
Decrease in Promissory Notes	(16,201)	(12,101)
Dividends	(5,478)	(21,321)
	(21,679)	**(33,422)**
Investing Activities		
Changes in Non-Cash Working Capital Balances	483	227
	483	**227**
Net Change in Cash	-	-
Cash Position, Beginning of Period	-	-
Cash Position, End of Period	-	-

[1] Small differences from balances in prior periods not specifically noted are immaterial and in most cases are the result of rounding differences.
[2] Power Purchase Agreement between Hydro and Nalcor Energy Marketing.

Attachment 1

Rate Stabilization Plan Report

Quarter Ended December 31, 2023

Newfoundland and Labrador Hydro
Rate Stabilization Plan Report
December 31, 2023

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).

Finance charges are calculated on the balances using the test year weighted average cost of capital, which is currently 5.43% per annum.

[ ]

Rate Stabilization Plan
Net Hydraulic Production Variation
December 31, 2023

	A	B1	B2	B3	B	C	D	E	F	G	H
	Cost of Service Net Hydraulic Production (kWh)	Actual Net Hydraulic Production (kWh)	Net Ponded Energy (kWh)	Spill Exports (kWh)	Net Hydraulic Production for Variance Calculation (kWh)	Monthly Net Hydraulic Production Variance (kWh)	Cost of Service No. 6 Fuel Cost ($CDN/bbl)	Net Hydraulic Production Variation ($)	Financing Charges ($)	Transfers	Cumulative Variation and Financing Charges ($)
					(B1 + B2 - B3)	(A - B)		(C / O[1] X D)			(E + F) (to page 5)
Opening Balance											29,776,723
Adjustment											-
Adjusted Opening Balance											**29,776,723**
January	-	-	-	-	-	-	105.90	-	131,498	-	29,908,221
February	-	-	-	-	-	-	105.90	-	132,079	-	30,040,300
March	-	-	-	-	-	-	105.90	-	132,662	-	30,172,962
April	-	-	-	-	-	-	105.90	-	133,248	-	30,306,210
May	-	-	-	-	-	-	105.90	-	133,837	-	30,440,047
June	-	-	-	-	-	-	105.90	-	134,428	-	30,574,475
July	-	-	-	-	-	-	105.90	-	135,021	-	30,709,496
August	-	-	-	-	-	-	105.90	-	135,618	-	30,845,114
September	-	-	-	-	-	-	105.90	-	136,216	-	30,981,330
October						-	105.90		136,818		31,118,148
November						-	105.90		137,422		31,255,570
December						-	105.90		138,029		31,393,599
Year-to-Date	-	-	-	-	-	-		-	**1,616,876**	-	**31,393,599**
Hydraulic Allocation								(14,888,362)	(1,616,876)		(16,505,238)
Hydraulic Variation at Year End[2]								**(14,888,362)**	-	-	**14,888,361**

[1] O is the Holyrood Operating Efficiency of 583 kWh/barrel, as per Board Order No. P.U. 16(2019).

[2] At year end 25% of the hydraulic variation balance as of October 31, 2021, excluding financing charges and 100% of the annual financing charges, are allocated to customers as follows:

	Approved kWh	% of kWh to total	Allocation	Reallocate Rural	Net (to pages 3 & 4)
Utility	5,399,356,095	86.2%	(14,223,678)	(1,118,913)	(15,342,591)
Industrial	424,107,383	6.8%	(1,117,238)	-	(1,117,238)
Rural	441,980,531	7.0%	(1,164,322)	1,164,322	-
Total	**6,265,444,009**	**100.0%**	**(16,505,238)**	**45,409**	**(16,459,829)**
Labrador Interconnected (write-off to income)				(45,409)	(45,409)
				-	(16,505,238)

Rate Stabilization Plan
Summary of Utility Customer
December 31, 2023

	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 ($)**	**Adjustment[1] ($)**	**Transfers[2] ($)**	**Cumulative Net Balance ($)**
								(to page 5)
Opening Balance								16,963,988
Adjustment								-
Adjusted Opening Balance								**16,963,988**
January	-	-	-	-	74,915	147,973	-	17,186,876
February	-	-	-	-	75,900	157,693	-	17,420,469
March	-	-	-	-	76,931	153,873	8,685,251	26,336,524
April	-	-	-	-	116,306	124,968	-	26,577,798
May	-	-	-	-	117,371	103,505	-	26,798,674
June	-	-	-	-	118,347	85,010	-	27,002,031
July	-	-	-	-	119,245	(1,522,761)	-	25,598,515
August	-	-	-	-	113,047	(1,492,099)	-	24,219,463
September	-	-	-	-	106,957	(1,533,460)	-	22,792,960
October	-	-	-	-	100,657	(1,922,532)	-	20,971,085
November	-	-	-	-	92,611	(2,749,777)	-	18,313,919
December	-	-	-	-	80,877	(3,165,935)	-	15,228,861
Year-to-Date	-	-	-	-	1,193,164	(11,613,542)	8,685,251	(1,735,127)
Hydraulic Allocation **(from page 2)**								15,342,591
Total	**-**	**-**	**-**	**-**	**1,193,164**	**(11,613,542)**	**8,685,251**	**30,571,452**

[1] Effective July 1, 2023, the RSP Adjustment rate is 0.496 cents per kWh as per Board Order No. P.U. 15(2023).
[2] Recovery of the 2022 Isolated Systems Supply Costs Deferral was approved in Board Order No. P.U. 7(2023).

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2023

	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 5)
Opening Balance							5,549,727
Adjustment							-
Adjusted Opening Balance							**5,549,727**
January	-	-	-	24,508	(474,453)	-	5,099,782
February	-	-	-	22,521	(497,882)	-	4,624,421
March	-	-	-	20,422	(502,649)	-	4,142,194
April	-	-	-	18,293	(486,870)	-	3,673,617
May	-	-	-	16,223	(246,805)	-	3,443,035
June	-	-	-	15,205	(109,360)	-	3,348,880
July	-	-	-	14,789	(272,025)	-	3,091,644
August	-	-	-	13,653	(452,761)	-	2,652,536
September	-	-	-	11,714	(476,668)	-	2,187,582
October			-	9,661	(427,224)		1,770,019
November			-	7,817	(502,768)		1,275,068
December			-	5,631	(484,714)		795,985
Year-to-Date	-	-	-	180,437	(4,934,179)	-	(4,753,742)
Hydraulic Allocation **(from page 2)**							1,117,238
Total	**-**	**-**	**-**	**180,437**	**(4,934,179)**	**-**	**1,913,223**

[1] Effective January 1, 2023, the RSP Adjustment rate is 1.4770 cents per kWh as per Board Order No. P.U. 3(2023).

Rate Stabilization Plan
Overall Summary
December 31, 2023

	A	B	C	D
	Hydraulic Balance ($)	**Utility Balance ($)**	**Industrial Balance ($)**	**Total To Date ($)**
				(A + B + C)
	(from page 2)	**(from page 3)**	**(from page 4)**	
Opening Balance	29,776,723	16,963,988	5,549,727	52,290,438
Adjustments	-	-	-	-
Adjusted Opening Balance	**29,776,723**	**16,963,988**	**5,549,727**	**52,290,438**
January	29,908,221	17,186,876	5,099,782	52,194,879
February	30,040,300	17,420,469	4,624,421	52,085,190
March	30,172,962	26,336,524	4,142,194	60,651,680
April	30,306,210	26,577,798	3,673,617	60,557,625
May	30,440,047	26,798,674	3,443,035	60,681,756
June	30,574,475	27,002,031	3,348,880	60,925,386
July	30,709,496	25,598,515	3,091,644	59,399,655
August	30,845,114	24,219,463	2,652,536	57,717,113
September	30,981,330	22,792,960	2,187,582	55,961,872
October	31,118,148	20,971,085	1,770,019	53,859,252
November	31,255,570	18,313,919	1,275,068	50,844,557
December	14,888,361	30,571,452	1,913,223	47,373,036

Attachment 2

Supply Cost Variance Deferral Account Report

Quarter Ended December 31, 2023

Newfoundland and Labrador Hydro
Supply Cost Variance Deferral Account
December 31, 2023

Summary of Key Facts

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

In Board Order No. P.U. 4(2022), the Board approved the Supply Cost Variance 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.

For the period January to November 2023, the interest rate applied to the deferral account balance was 4.32%, based on the prior year-end rate. In December 2023, the interest expense was trued-up for the year, based on the short-term interest rate for 2023 of 5.72%.

Supply Cost Variance Deferral Account
Summary
December 31, 2023

	Supply Cost Variance Deferral Account Balance[1,2,3,4] ($) (from page 3)	Utility Balance[4] ($) (from page 4)	Industrial Balance ($) (from page 5)	Total to Date ($)
Opening Balance	196,185,156	(5,784,457)	-	**190,400,699**
Adjustment	-	-	-	-
Adjusted Opening Balance	**196,185,156**	**(5,784,457)**	**-**	190,400,699
January	207,837,816	(6,394,437)	-	**201,443,379**
February	192,873,065	(7,482,907)	-	**185,390,158**
March	20,728,990	(8,241,621)	-	**12,487,369**
April	56,116,635	(8,651,043)	-	**47,465,592**
May	105,902,499	(8,987,627)	-	**96,914,872**
June	157,304,255	(9,325,035)	-	**147,979,220**
July	216,822,839	(9,598,603)	-	**207,224,236**
August	126,239,693	(10,012,717)	-	**116,226,976**
September	155,772,745	(10,312,317)	-	**145,460,428**
October	212,448,322	(10,668,497)	-	**201,779,825**
November	249,522,707	(11,617,366)	-	**237,905,341**
December	283,716,067	(12,444,308)	-	**271,271,759**

[1] In March 2023, the Government of Newfoundland and Labrador ("Government") provided $190.4 million for the purpose of mitigating projected future customer rate increases that would be required to recover net supply costs incurred.

[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. On August 15, 2023, the first drawing on the convertible debenture of $144.7 million was received by LIL (2021) Limited Partnership, and on August 28, 2023, the funds were transferred to Hydro for the purpose of rate mitigation, reducing the balance in the Supply Cost Variance Deferral Account.

[3] Balances in this report reflect the true-up of initial estimates made throughout the year relating to the elimination of incremental costs for fuel and/or imports over the Maritime Link as a result of delivery of the Nova Scotia Block. All balances reported as at December 31, 2023 reflect final actual incremental cost eliminations. Please refer to footnote 7 on p. 3.

[4] For the period January to November 2023, the interest rate applied to the deferral account balance was 4.32%, based on the prior year-end rate. In December 2023, the interest expense was trued-up for the year, based on the short-term interest rate for 2023 of 5.72%.

Supply Cost Variance Deferral Account
Section A: Summary
December 31, 2023

	Muskrat Falls Project Cost Variance[2] ($)	Rate Mitigation Fund[3,4] ($)	Project Cost Recovery Rider: Utility[5] ($)	Project Cost Recovery Rider: Industrial ($)	Holyrood TGS[6] Fuel Cost Variance[7] ($)	Other IIS[8] Supply Cost Variance[7] ($)	Net Revenue From Exports Variance ($)	Transmission Tariff Revenue Variance[9] ($)	Load Variation: Utility ($)	Load Variation: Industrial ($)	Greenhouse Gas Credit Revenue Variance[10] ($)	Subtotal Monthly Variances ($)	Financing Charges[1]: Utility ($)	Financing Charges[1]: Other ($)	Transfers ($)	Cumulative Net Balance ($)
	(from page 6)	(from page 15)			(from page 7)	(from page 8)	(from page 9)	(from page 10)	(from page 11)	(from page 12)	(from page 14)					(to page 2)
Opening Balance	277,547,131	-	(18,942,087)	-	(65,302,273)	(28,114,785)	(33,075,710)	(10,113,160)	63,550,645	18,294,888	(12,412,517)	191,432,132	(133,641)	4,886,665	-	196,185,156
Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Adjusted Opening Balance	**277,547,131**	**-**	**(18,942,087)**	**-**	**(65,302,273)**	**(28,114,785)**	**(33,075,710)**	**(10,113,160)**	**63,550,645**	**18,294,888**	**(12,412,517)**	**191,432,132**	**(133,641)**	**4,886,665**	**-**	**196,185,156**
January	19,795,154	-	(5,134,003)	-	(16,202,730)	(812,794)	(499,872)	(862,075)	13,086,281	1,367,244	3,962	10,741,167	(88,007)	999,500	-	207,837,816
February	19,400,443	-	(5,471,265)	-	(17,752,133)	(4,643,889)	(385,775)	(1,179,438)	(6,743,241)	1,080,034	(235,119)	(15,930,383)	(111,860)	1,077,492	-	192,873,065
March	20,390,107	(190,404,321)	(5,338,713)	-	11,674,220	(5,025,833)	(343,485)	(1,107,140)	(4,180,062)	1,295,997	(950)	(173,040,180)	(137,280)	1,033,385	-	20,728,990
April	40,844,451	-	(4,335,837)	-	2,992,153	(951,082)	(146,610)	(1,534,710)	(2,840,629)	1,263,600	-	35,291,336	(162,084)	258,393	-	56,116,635
May	59,641,132	-	(3,591,165)	-	(1,095,680)	(725,657)	(110,345)	(1,498,412)	(5,144,457)	2,049,725	-	49,525,141	(182,228)	442,951	-	105,902,499
June	60,819,151	-	(2,949,492)	-	(3,102,773)	(71,781)	(41,093)	(1,498,023)	(4,434,173)	2,368,795	(180,887)	50,909,724	(198,913)	690,945	-	157,304,255
July	61,225,265	-	(2,449,926)	-	(138,368)	(392,215)	(68,528)	(1,498,023)	161,981	1,947,549	-	58,787,735	(212,617)	943,466	-	216,822,839
August	56,198,307	(144,700,000)	(2,400,596)	-	(654)	(474,663)	(71,846)	(1,498,023)	(59,310)	1,414,565	1,697	(91,590,523)	(223,999)	1,231,376	-	126,239,693
September	60,909,116	-	(2,467,140)	-	(6,540,541)	(1,107,382)	(81,876)	(1,498,023)	969,035	1,272,044	(22,508,701)	28,946,532	(235,153)	821,673		155,772,745
October	60,823,046	-	(3,093,106)	-	(4,254,770)	(2,164,312)	(109,625)	(1,498,023)	4,739,753	1,508,835	46	55,951,844	(246,615)	970,348		212,448,322
November	59,216,366	-	(4,424,036)	-	(5,332,555)	(1,727,587)	(464,203)	(1,498,023)	(10,697,456)	1,180,513	(165,687)	36,087,332	(260,986)	1,248,039		249,522,707
December[11]	58,227,348	-	(5,093,581)	-	(9,136,964)	(2,356,175)	(13,171,948)	(1,498,023)	4,687,782	1,371,907	3,710	33,034,056	(281,541)	1,440,845		283,716,067
Year-to-Date	**577,489,886**	**(335,104,321)**	**(46,748,860)**	**-**	**(48,890,795)**	**(20,453,370)**	**(15,495,206)**	**(16,667,936)**	**(10,454,496)**	**18,120,808**	**(23,081,929)**	**78,713,781**	**(2,341,283)**	**11,158,413**	**-**	**87,530,911**
Total	**855,037,017**	**(335,104,321)**	**(65,690,947)**	**-**	**(114,193,068)**	**(48,568,155)**	**(48,570,916)**	**(26,781,096)**	**53,096,149**	**36,415,696**	**(35,494,446)**	**270,145,913**	**(2,474,924)**	**16,045,078**	**-**	**283,716,067**

[1] For the period January to November 2023, the interest rate applied to the Supply Cost Variance Deferral Account balance was 4.32%, based on the prior year-end rate. In December 2023, the interest expense was trued-up for the year, based on the short-term interest rate for 2023 of 5.72%. Please refer to p. 16 for a detailed calculation of the short-term interest rate and further information.
[2] The LIL was commissioned on April 14, 2023, and Hydro began making payments under the Transmission Funding Agreement ("TFA").
[3] In March 2023, the Government provided $190.4 million for the purpose of mitigating projected future customer rate increases that would be required to recover net supply costs incurred.
[4] 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 LIL, to a $1.0 billion investment by the Government of Canada in the LIL in the form of a convertible debenture. On August 15, 2023, the first drawing on the convertible debenture of $144.7 million was received by LIL (2021) Limited Partnership and on August 28, 2023, the funds were transferred to Hydro for the purpose of rate mitigation, reducing the balance in the Supply Cost Variance Deferral Account.
[5] As per Order No. P.U. 19(2022), the Board approved a Project Cost Recovery Rider of 0.798 cents per kWh that became effective as of July 1, 2022. There is no change to the Project Cost Recovery Rider effective July 1, 2023, as per Board Order No. P.U. 15(2023).
[6] Holyrood Thermal Generating Station ("Holyrood TGS").
[7] In 2021, Nalcor Energy ("Nalcor") commenced delivery of the Nova Scotia Block that, combined with limited LIL capacity, meant Hydro could not be delivered as much energy from the Muskrat Falls Hydroelectric Generating Facility as it would otherwise. Nalcor committed to indemnify Hydro for any damages suffered as a result of this reduction in deliveries, including compensating Hydro for incremental costs of fuel and/or imports over the Maritime Link. The 2023 balances reflect adjustments to the calculation to eliminate incremental costs incurred by Hydro as a result of reduced deliveries. The balances in this report reflect the true-up of initial estimates of incremental costs made throughout the year. All balances reported as at December 31, 2023 reflect final actual incremental cost eliminations.
[8] Island Interconnected System ("IIS").
[9] Effective June 1, 2023, Hydro assigned its long-term transmission rights, including associated payment obligations, to Nalcor Energy Marketing ("Energy Marketing") for a period of ten years. Energy Marketing has been paying all costs associated with these rights under an interim agreement for the month of May 2023, since Hydro's long-term rights commenced on May 1, 2023, following commissioning of the LIL in April 2023.
[10] In September 2023, Hydro sold 493,536 Greenhouse Gas Performance Credits within the province for $22.5 million through a request for bids.
[11] In December 2023, the account included a true-up of the actual settlement of 2022 net export sales under the Muskrat Falls Power Purchase Agreement ("Muskrat Falls PPA") as compared to the estimate included in December 2022. Also included in December 2023, is an estimate of net export sales that occurred during 2023; the actual settlement value will not be finalized until the first quarter of 2024.

Supply Cost Variance Deferral Account
Section B: Utility Customer Balance
December 31, 2023

	Allocation Rural Rate Alteration[1] ($)	Financing Charges[2] ($)	Transfers ($)	Cumulative Net Balance ($)
	(from page 13)			(to page 2)
Opening Balance	(5,625,788)	(158,669)	-	(5,784,457)
Adjustments	-	-	-	-
Adjusted Opening Balance	**(5,625,788)**	**(158,669)**	**-**	**(5,784,457)**
January	(583,105)	(26,875)	-	(6,394,437)
February	(1,058,761)	(29,709)	-	(7,482,907)
March	(723,948)	(34,766)	-	(8,241,621)
April	(371,131)	(38,291)	-	(8,651,043)
May	(296,391)	(40,193)	-	(8,987,627)
June	(295,651)	(41,757)	-	(9,325,035)
July	(230,243)	(43,325)	-	(9,598,603)
August	(369,518)	(44,596)	-	(10,012,717)
September	(253,080)	(46,520)	-	(10,312,317)
October	(308,268)	(47,912)		(10,668,497)
November	(899,302)	(49,567)		(11,617,366)
December	(772,967)	(53,975)		(12,444,308)
Year-to-Date	**(6,162,365)**	**(497,486)**	**-**	**(6,659,851)**
Total	**(11,788,153)**	**(656,155)**	**-**	**(12,444,308)**

[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).

Monthly balances reflect immaterial adjustments.

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

[2] For the period January to November 2023, the interest rate applied to the deferral account balance was 4.32%, based on the prior year-end rate. In December 2023, the interest expense was trued-up for the year, based on the short-term interest rate for 2023 of 5.72%. Please refer to p. 16 for a detailed calculation of the short-term interest rate and further information.

Supply Cost Variance Deferral Account
Section B: Industrial Customers Balance[1]
December 31, 2023

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

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

Supply Cost Deferral Account
Muskrat Falls Project Cost Variances
December 31, 2023

	Muskrat Falls PPA Charges Actual ($) (A)	Muskrat Falls PPA Charges Test Year ($) ($A_T$)	TFA Charges Actual[1] ($) (B)	TFA Charges Test Year ($) ($B_T$)	Total Variation ($) $(A - A_T) + (B - B_T)$ (to page 3)
January	19,795,154	-	-	-	**19,795,154**
February	19,400,443	-	-	-	**19,400,443**
March	20,390,107	-	-	-	**20,390,107**
April	20,016,506	-	20,827,945	-	**40,844,451**
May	19,144,430	-	40,496,702	-	**59,641,132**
June	21,561,722	-	39,257,429	-	**60,819,151**
July	21,043,075	-	40,182,190	-	**61,225,265**
August	19,303,954	-	36,894,352	-	**56,198,307**
September	20,768,263	-	40,140,853	-	**60,909,116**
October	20,661,951	-	40,161,095	-	**60,823,046**
November	20,636,072	-	38,580,294	-	**59,216,366**
December	19,303,782	-	38,923,567	-	**58,227,348**
Total	**242,025,458**	**-**	**335,464,427**	**-**	**577,489,886**

[1] The LIL was commissioned on April 14, 2023. The April 2023 charges reflect the first payment of $20.8 million under the TFA for the partial period of April 15–30, 2023. The variances beginning in May 2023 reflect full months.

Supply Cost Deferral Account
Holyrood TGS Fuel Cost Variance
December 31, 2023

	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 ($Can/bbl)	Actual[2] ($)	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	214,813	1,882	212,931	132.67	28,395,149	421,132	105.90	44,597,879	**(16,202,730)**
February	188,565	21,322	167,243	123.76	20,698,780	363,087	105.90	38,450,913	**(17,752,133)**
March	253,675	7,004	246,671	124.03	30,594,526	178,662	105.90	18,920,306	**11,674,220**
April	116,278	111	116,166	121.38	14,099,898	104,889	105.90	11,107,745	**2,992,153**
May	47,617	141	47,476	118.91	5,661,587	63,808	105.90	6,757,267	**(1,095,680)**
June	-	307	(307)	118.91	(220)	29,297	105.90	3,102,552	**(3,102,773)**
July	(1,160)	4	(1,164)	118.91	(138,368)	-	105.90	-	**(138,368)**
August	-	5	(5)	118.91	(654)	-	105.90	-	**(654)**
September	-	10	(10)	118.91	(1,216)	61,750	105.90	6,539,325	**(6,540,541)**
October	74,921	48	74,873	123.67	9,259,764	127,616	105.90	13,514,534	**(4,254,770)**
November	147,285	643	146,642	123.88	18,165,278	221,887	105.90	23,497,833	**(5,332,555)**
December	159,836	2,175	157,661	118.66	18,699,063	262,852	105.90	27,836,027	**(9,136,964)**
Total	**1,201,829**	**33,653**	**1,168,176**	**124.50**	**145,433,588**	**1,834,980**	**105.90**	**194,324,382**	**(48,890,795)**

[1] Includes non-firm sales to Island Industrial Customers, supply of emergency energy to Nova Scotia and the reimbursement of fuel costs by Nalcor under the Indemnity Agreement.

[2] In 2021, Nalcor commenced delivery of the Nova Scotia Block that, combined with limited LIL capacity, meant Hydro could not be delivered as much energy from the Muskrat Falls Hydroelectric Generating Facility as it would otherwise. Nalcor committed to indemnify Hydro for any damages suffered as a result of this reduction in deliveries, including compensating Hydro for incremental costs of fuel and/or imports over the Maritime Link. The 2023 balances reflect adjustments to the calculation to eliminate incremental costs incurred by Hydro as a result of reduced deliveries. The balances in this report reflect the true-up of initial estimates of incremental costs made throughout the year. All balances reported as at December 31, 2023 reflect final actual incremental cost eliminations.

Supply Cost Deferral Account
Other IIS Supply Cost Variance Summary
December 31, 2023

	Thermal Variation[1,2] ($)	Off-Island Power Purchase Variation[1] ($)	On-Island Power Purchase Variation[1] ($)	CBPP[3] Firm Energy Variation[1] ($)	Current Month Variation ($)	Year-to-Date Variation ($)	Cost Variance Threshold[4] ($)	Other IIS Supply Cost Variance ($)
	(D)	(E)	(F)	(G)	(D + E + F + G)			
January	(377,495)	(477,034)	(458,265)	-	(1,312,794)	(1,312,794)	(500,000)	(812,794)
February	(1,491,966)	(2,610,139)	(541,784)	-	(4,643,889)	(5,956,683)	(500,000)	(5,456,683)
March	1,077,734	(5,919,829)	(183,738)	-	(5,025,833)	(10,982,516)	(500,000)	(10,482,516)
April	(506,222)	(146,318)	(298,542)	-	(951,082)	(11,933,598)	(500,000)	(11,433,598)
May	(96,199)	-	(629,458)	-	(725,657)	(12,659,255)	(500,000)	(12,159,255)
June	32,885	-	(104,666)	-	(71,781)	(12,731,036)	(500,000)	(12,231,036)
July	205,744	-	(597,959)	-	(392,215)	(13,123,251)	(500,000)	(12,623,251)
August	(52,292)	-	(422,371)	-	(474,663)	(13,597,914)	(500,000)	(13,097,914)
September	42,765	-	(1,150,147)	-	(1,107,382)	(14,705,296)	(500,000)	(14,205,296)
October	(162,315)	(1,277,219)	(724,778)	-	(2,164,312)	(16,869,608)	(500,000)	(16,369,608)
November	(211,367)	(1,694,628)	178,408	-	(1,727,587)	(18,597,195)	(500,000)	(18,097,195)
December	(649,103)	(2,164,775)	457,703	-	(2,356,175)	(20,953,370)	(500,000)	(20,453,370)
Total	**(2,187,831)**	**(14,289,942)**	**(4,475,597)**	**-**	**(20,953,370)**			

[1] The calculation of the variation by source is provided in Appendix A.

[2] In 2021, Nalcor commenced delivery of the Nova Scotia Block that, combined with limited LIL capacity, meant Hydro could not be delivered as much energy from the Muskrat Falls Hydroelectric Generating Facility as it would otherwise. Nalcor committed to indemnify Hydro for any damages suffered as a result of this reduction in deliveries, including compensating Hydro for incremental costs of fuel and/or imports over the Maritime Link. The 2023 balances reflect adjustments to the calculation to eliminate incremental costs incurred by Hydro as a result of reduced deliveries. The balances in this report reflect the true-up of initial estimates of incremental costs made throughout the year. All balances reported as at December 31, 2023 reflect final actual incremental cost eliminations.

[3] Corner Brook Pulp and Paper Ltd. ("CBPP").

[4] 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 Deferral Account
Net Revenue from Exports Variance
December 31, 2023

	Test Year ($) ($H_T$)	Actual[1] ($) (H)	Total Variation ($) ($H_T$ - H) (to page 3)	Non-Firm Sales Revenue[2]
January	-	499,872	**(499,872)**	-
February	-	385,775	**(385,775)**	-
March	-	343,485	**(343,485)**	-
April	-	146,610	**(146,610)**	-
May	-	110,345	**(110,345)**	-
June	-	41,093	**(41,093)**	-
July	-	68,528	**(68,528)**	-
August	-	71,846	**(71,846)**	-
September	-	81,876	**(81,876)**	-
October	-	109,625	**(109,625)**	-
November	-	464,203	**(464,203)**	-
December[3]	-	13,171,948	**(13,171,948)**	-
Total	**-**	**15,495,206**	**(15,495,206)**	**-**

[1] 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.

[2] Non-firm sales supplied from hydraulic sources for 2023 were not separately identified. Any non-firm sales were charged to customers at the cost of fuel and credited to the appropriate fuel account. Tracking of sales from hydraulic sources will begin in 2023 pending approval of market rates for non-firm sales.

[3] In December 2023, the account included a true-up of the actual settlement of 2022 net export sales under the Muskrat Falls PPA as compared to the estimate included in December 2022. Also included in December 2023, is an estimate of net export sales that occurred during 2023; the actual settlement value will not be finalized until the first quarter of 2024.

Supply Cost Deferral Account
Tariff Revenue
December 31, 2023

	Test Year ($) ($I_T$)	Actual[1] ($) (I)	Total Variation ($) ($I_T$ - I) (to page 3)
January	-	862,075	**(862,075)**
February	-	1,179,438	**(1,179,438)**
March	-	1,107,140	**(1,107,140)**
April	-	1,534,710	**(1,534,710)**
May	-	1,498,412	**(1,498,412)**
June	-	1,498,023	**(1,498,023)**
July	-	1,498,023	**(1,498,023)**
August	-	1,498,023	**(1,498,023)**
September	-	1,498,023	**(1,498,023)**
October	-	1,498,023	**(1,498,023)**
November	-	1,498,023	**(1,498,023)**
December	-	1,498,023	**(1,498,023)**
Total	**-**	**16,667,936**	**(16,667,936)**

[1] Effective June 1, 2023, Hydro assigned its long-term transmission rights, including associated payment obligations, for a period of ten years to Energy Marketing. Energy Marketing has been paying all costs associated with these rights under an interim agreement for the month of May, since Hydro's long-term rights commenced on May 1, 2023 following commissioning of the LIL in April 2023.

Supply Cost Deferral Account
Load Variation - Utility
December 31, 2023

	Test Year Cost of Service Firm Sales (kWh) (J_T)	Actual Firm Sales (kWh) (J_A)	Sales Variance (kWh) $(J_T - J_A)$	Firm Energy Rate ($/kWh) (K_R)	Load Variation ($) $(J_T - J_A) \times K_R$ (to page 3)
January	715,400,000	643,358,819	72,041,181	0.18165	13,086,281
February	648,500,000	685,622,163	(37,122,163)	0.18165	(6,743,241)
March	646,000,000	669,011,627	(23,011,627)	0.18165	(4,180,062)
April	527,700,000	543,337,922	(15,637,922)	0.18165	(2,840,629)
May	421,700,000	450,020,710	(28,320,710)	0.18165	(5,144,457)
June	345,200,000	369,610,532	(24,410,532)	0.18165	(4,434,173)
July	307,900,000	307,008,278	891,722	0.18165	161,981
August	300,500,000	300,826,507	(326,507)	0.18165	(59,310)
September	314,500,000	309,165,372	5,334,628	0.18165	969,035
October	413,700,000	387,607,220	26,092,780	0.18165	4,739,753
November	495,500,000	554,390,481	(58,890,481)	0.18165	(10,697,456)
December	664,100,000	638,293,327	25,806,673	0.18165	4,687,782
Total	**5,800,700,000**	**5,858,252,958**	**(57,552,958)**		**(10,454,496)**

Supply Cost Deferral Account
Load Variation - Industrial
December 31, 2023

	Test Year Cost of Service Firm Sales (kWh) (J_T)	Actual Firm Sales (kWh) (J_A)	Sales Variance (kWh) $(J_T - J_A)$	Firm Energy Rate ($/kWh) (K_R)	Load Variation ($) $(J_T - J_A) \times K_R$ (to page 3)
January	63,000,000	32,122,755	30,877,245	0.04428	1,367,244
February	58,100,000	33,708,987	24,391,013	0.04428	1,080,034
March	63,300,000	34,031,770	29,268,230	0.04428	1,295,997
April	61,500,000	32,963,409	28,536,591	0.04428	1,263,600
May	63,000,000	16,709,915	46,290,085	0.04428	2,049,725
June	60,900,000	7,404,175	53,495,825	0.04428	2,368,795
July	62,400,000	18,417,418	43,982,582	0.04428	1,947,549
August	62,600,000	30,654,094	31,945,906	0.04428	1,414,565
September	61,000,000	32,272,722	28,727,278	0.04428	1,272,044
October	63,000,000	28,925,125	34,074,875	0.04428	1,508,835
November	60,700,000	34,039,811	26,660,189	0.04428	1,180,513
December	63,800,000	32,817,465	30,982,535	0.04428	1,371,907
Total	**743,300,000**	**334,067,646**	**409,232,354**		**18,120,808**

Supply Cost Deferral Account
Rural Rate Alteration
December 31, 2023

	Price ($)	Volume ($)	Total[1] ($)	Utility Allocation[1] ($)	Labrador Interconnected Allocation[1] ($)	Balance ($)
				(to page 4)		
January	(494,263)	(112,506)	(606,769)	(583,105)	(23,664)	-
February	(446,702)	(655,026)	(1,101,728)	(1,058,761)	(42,967)	-
March	(450,521)	(302,807)	(753,328)	(723,948)	(29,380)	-
April	(388,658)	2,465	(386,193)	(371,131)	(15,062)	-
May	(366,835)	58,416	(308,419)	(296,391)	(12,028)	-
June	(338,914)	31,265	(307,649)	(295,651)	(11,998)	-
July	(639,588)	400,001	(239,587)	(230,243)	(9,344)	-
August	(618,105)	233,591	(384,514)	(369,518)	(14,996)	-
September	(589,765)	326,414	(263,351)	(253,080)	(10,271)	-
October	(688,119)	367,341	(320,778)	(308,268)	(12,510)	-
November	(781,449)	(154,349)	(935,798)	(899,302)	(36,496)	-
December	(952,332)	147,996	(804,336)	(772,967)	(31,369)	-
Total	**(6,755,251)**	**342,801**	**(6,412,450)**	**(6,162,365)**	**(250,085)**	**-**

[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 Deferral Account
Greenhouse Gas Credits
December 31, 2023

	Test Year ($)	Actual ($)	Total Variation ($)
	(T_T)	(T)	(T_T - T)
			(to page 3)
January	-	(3,962)	**3,962**
February	-	235,119	**(235,119)**
March	-	950	**(950)**
April	-	-	**-**
May	-	-	**-**
June	-	180,887	**(180,887)**
July	-	-	**-**
August	-	(1,697)	**1,697**
September[1]	-	22,508,701	**(22,508,701)**
October	-	(46)	**46**
November	-	165,687	**(165,687)**
December	-	(3,710)	**3,710**
Total	**-**	**23,081,930**	**(23,081,929)**

[1] In September 2023, Hydro sold 493,536 Greenhouse Gas Performance Credits within the province for $22.5 million through a request for bids.

Supply Cost Deferral Account
Rate Mitigation
December 31, 2023

	Test Year ($)	Actual ($)	Total Variation ($) (to page 3)
January	-	-	**-**
February	-	-	**-**
March[1]	-	190,404,321	**(190,404,321)**
April	-	-	**-**
May	-	-	**-**
June	-	-	**-**
July	-	-	**-**
August[2]	-	144,700,000	**(144,700,000)**
September	-	-	**-**
October	-	-	**-**
November	-	-	-
December	-	-	-
	-	**335,104,321**	**(335,104,321)**

[1] In March 2023, the Government provided $190.4 million for the purpose of mitigating projected future customer rate increases that would be required to recover net supply costs incurred to the end of 2022.

[2] In 2022, as part of the Government of Newfoundland and Labrador's rate mitigation plan, Hydro, the Government, and the Government of Canada signed term sheets enabling access, upon commissioning of the LIL, to a $1.0 billion investment by the Government of Canada in the LIL, in the form of a convertible debenture. On August 15, 2023 the first drawing on the convertible debenture of $144.7 million was received by LIL (2021) Limited Partnership, and on August 28, 2023, the funds were transferred to Hydro for the purpose of rate mitigation, reducing the balance in the Supply Cost Variance Deferral Account.

2023 Short-Term Interest Calculation[1]

	($000)
Promissory Note Interest	5,429
Operating Line Interest	-
Standby and Upfront Fee	699
Brokerage Fee	112
Debt Guarantee Fee – Recoverable Portion Only	164
Total Short-Term Borrowing Costs	**6,404**
Weighted Average Short-Term Debt Balance[2]	**111,934**
Short-Term Cost of Borrowing 2023	**5.72%**

[1] Financing charges accrued at the 2023 short-term cost of borrowing of 4.32% for the period of January to November, 2023. In December, financing costs was trued up to reflect the actual short-term cost of borrowing for 2023.

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

Appendix A

Other Island Interconnected System

Supply Cost Variance Summary

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2023

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	780,546	342,859	437,687	1,258,888	**(821,201)**
February	2,341,228	3,663,268	(1,322,040)	767,288	**(2,089,328)**
March	1,940,020	122,711	1,817,309	661,531	**1,155,778**
April	20,482	-	20,482	392,558	**(372,076)**
May	93,327	12,196	81,131	123,373	**(42,242)**
June	546,526	76,085	470,441	431,643	**38,798**
July	240,937	-	240,937	33,744	**207,193**
August	1,023	-	1,023	33,744	**(32,721)**
September	203,522	-	203,522	33,744	**169,778**
October	(2,166)	-	(2,166)	209,033	**(211,199)**
November	14,642	61,734	(47,092)	185,808	**(232,900)**
December	632,899	321,541	311,358	851,255	**(539,897)**
Subtotal	**6,812,985**	**4,600,394**	**2,212,592**	**4,982,609**	**(2,770,017)**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2023

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	271,279	-	271,279	122,478	**148,801**
February	394,415	-	394,415	123,884	**270,531**
March	13,633	-	13,633	117,271	**(103,638)**
April	5,616	-	5,616	83,554	**(77,938)**
May	19,239	-	19,239	57,170	**(37,931)**
June	38,814	-	38,814	46,909	**(8,095)**
July	92,992	-	92,992	71,469	**21,523**
August	15,877	-	15,877	14,587	**1,290**
September	1,457	-	1,457	90,430	**(88,973)**
October	18,600	-	18,600	20,417	**(1,817)**
November	93,066	-	93,066	59,755	**33,311**
December	27,559	-	27,559	179,920	**(152,361)**
Subtotal	**992,546**	**-**	**992,546**	**987,844**	**4,703**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2023

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	266,113	-	266,113	68,116	**197,997**
February	353,434	-	353,434	46,923	**306,511**
March	21,254	-	21,254	40,867	**(19,613)**
April	605	-	605	56,006	**(55,401)**
May	15,956	-	15,956	25,733	**(9,777)**
June	94,417	-	94,417	86,278	**8,139**
July	13,001	-	13,001	31,788	**(18,787)**
August	(105)	-	(105)	15,138	**(15,243)**
September	191	-	191	34,816	**(34,625)**
October	(319)	-	(319)	15,138	**(15,457)**
November	2,136	-	2,136	25,733	**(23,597)**
December	(846)	-	(846)	84,827	**(85,673)**
Subtotal	**765,837**	**-**	**765,837**	**531,363**	**234,474**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2023

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	52,240	-	52,240	3,147	**49,093**
February	13,881	-	13,881	3,089	**10,792**
March	35,159	-	35,159	3,299	**31,860**
April	1,009	-	1,009	3,547	**(2,538)**
May	(453)	-	(453)	3,662	**(4,115)**
June	(1,025)	-	(1,025)	3,604	**(4,629)**
July	1,041	-	1,041	3,642	**(2,601)**
August	(185)	-	(185)	3,642	**(3,827)**
September	1,904	-	1,904	3,814	**(1,910)**
October	72,128	-	72,128	3,986	**68,142**
November	18,240	-	18,240	4,272	**13,968**
December	86,763	-	86,763	-	**86,763**
Subtotal	**280,702**	**-**	**280,702**	**39,704**	**240,998**

Other Island Interconnected System Supply Cost Variance
Thermal Generation Cost Variance
December 31, 2023

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	49,390	-	49,390	1,575	**47,815**
February	11,075	-	11,075	1,547	**9,528**
March	14,999	-	14,999	1,652	**13,347**
April	3,507	-	3,507	1,776	**1,731**
May	(301)	-	(301)	1,833	**(2,134)**
June	476	-	476	1,804	**(1,328)**
July	239	-	239	1,823	**(1,584)**
August	32	-	32	1,823	**(1,791)**
September	404	-	404	1,909	**(1,505)**
October	11	-	11	1,995	**(1,984)**
November	(11)	-	(11)	2,138	**(2,149)**
December	42,065	-	42,065	-	**42,065**
Subtotal	**121,886**	**-**	**121,886**	**19,875**	**102,011**
Total					**(2,187,831)**

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

Supply Cost Variance Deferral Account
Off-Island Power Purchase
December 31, 2023

Maritime Link	**Actual Cost ($) (A)**	**Test Year Cost ($) (B)**	**Off-Island Power Purchase Variation ($) (A - B)**
January	-	325,148	(325,148)
February	-	2,548,040	(2,548,040)
March	-	5,799,459	(5,799,459)
April	-	-	-
May	-	-	-
June	-	-	-
July	-	-	-
August	-	-	-
September	-	-	-
October	-	1,245,520	(1,245,520)
November	-	1,522,118	(1,522,118)
December	-	2,052,451	(2,052,451)
Subtotal	**-**	**13,492,735**	**(13,492,736)**

Supply Cost Variance Deferral Account
Off-Island Power Purchase
December 31, 2023

Labrador-Island Link	Actual Cost ($) (A)	Test Year Cost ($) (B)	Off-Island Power Purchase Variation ($) (A - B)
January	-	151,886	(151,886)
February	-	62,099	(62,099)
March	-	120,370	(120,370)
April	-	146,318	(146,318)
May	-	-	-
June	-	-	-
July	-	-	-
August	-	-	-
September	-	-	-
October	-	31,699	(31,699)
November	-	172,510	(172,510)
December	-	112,324	(112,324)
Subtotal	**-**	**797,206**	**(797,206)**
Total			**(14,289,942)**

Supply Cost Deferral Account
On-Island Purchases Variation
December 31, 2023

Nalcor Exploits	Actual Production (kWh)	Cost of Service Production (kWh)	Monthly Production Variance (kWh)	Cost of Service Cost (¢/kWh)	Power Purchase Variation ($)
	(A)	(B)	(C) = (A - B)	(D)	(E) = (C x D)
January	58,066,871	54,196,680	3,870,191	0.0400	154,808
February	48,178,264	48,703,200	(524,936)	0.0400	(20,997)
March	52,473,234	53,794,920	(1,321,686)	0.0400	(52,867)
April	58,185,357	55,911,600	2,273,757	0.0400	90,950
May	52,403,537	58,649,520	(6,245,983)	0.0400	(249,839)
June	56,043,130	48,618,000	7,425,130	0.0400	297,005
July	53,686,519	53,988,360	(301,841)	0.0400	(12,074)
August	53,094,541	54,851,400	(1,756,859)	0.0400	(70,274)
September	41,454,837	48,124,800	(6,669,963)	0.0400	(266,799)
October	53,224,221	38,442,480	14,781,741	0.0400	591,270
November	46,529,898	45,032,400	1,497,498	0.0400	59,900
December	58,744,514	54,684,000	4,060,514	0.0400	162,421
Subtotal	**632,084,923**	**614,997,360**	**17,087,563**		**683,504**

Supply Cost Deferral Account
On-Island Purchases Variation
December 31, 2023

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	12,532,676	12,391,320	141,356	0.0400	5,654
February	10,914,516	11,245,920	(331,404)	0.0400	(13,256)
March	12,990,760	12,395,040	595,720	0.0400	23,829
April	11,541,679	12,308,400	(766,721)	0.0400	(30,669)
May	12,116,699	12,636,840	(520,141)	0.0400	(20,806)
June	12,297,970	11,970,000	327,970	0.0400	13,119
July	12,738,922	12,990,240	(251,318)	0.0400	(10,053)
August	12,851,013	12,915,840	(64,827)	0.0400	(2,593)
September	9,324,536	6,512,400	2,812,136	0.0400	112,485
October	0	12,997,680	(12,997,680)	0.0400	(519,907)
November	0	11,541,600	(11,541,600)	0.0400	(461,664)
December	5,444,704	11,844,480	(6,399,776)	0.0400	(255,991)
Subtotal	**112,753,475**	**141,749,760**	**(28,996,285)**		**(1,159,852)**

Supply Cost Deferral Account
On-Island Purchases Variation
December 31, 2023

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	1,089,549	680,000	409,549	0.0851	34,858
February	445,844	470,000	(24,156)	0.0851	(2,056)
March	236,106	630,000	(393,894)	0.0851	(33,525)
April	1,456,139	1,600,000	(143,861)	0.0851	(12,244)
May	2,573,832	2,590,000	(16,168)	0.0851	(1,376)
June	2,381,006	1,630,000	751,006	0.0851	63,920
July	1,186,661	810,000	376,661	0.0851	32,058
August	1,481,703	800,000	681,703	0.0851	58,021
September	1,390,909	1,170,000	220,909	0.0851	18,802
October	1,483,769	1,570,000	(86,231)	0.0851	(7,339)
November	1,527,431	1,770,000	(242,569)	0.0851	(20,646)
December	1,483,931	1,120,000	363,931	0.0851	30,975
Subtotal	**16,736,880**	**14,840,000**	**1,896,880**		**161,448**

Supply Cost Deferral Account
On-Island Purchases Variation
December 31, 2023

CBPP Co-Generation	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	4,379,398	6,320,000	(1,940,602)	0.1884	(365,609)
February	3,742,962	4,980,000	(1,237,038)	0.1884	(233,058)
March	4,599,478	5,840,000	(1,240,522)	0.1884	(233,714)
April	3,835,008	5,550,000	(1,714,992)	0.1884	(323,104)
May	2,251,800	5,740,000	(3,488,200)	0.1884	(657,177)
June	3,350,879	6,070,000	(2,719,121)	0.1884	(512,282)
July	3,045,430	5,580,000	(2,534,570)	0.1884	(477,513)
August	3,055,265	4,230,000	(1,174,735)	0.1884	(221,320)
September	2,092,372	6,240,000	(4,147,628)	0.1884	(781,413)
October	1,872,528	5,440,000	(3,567,472)	0.1884	(672,112)
November	8,713,153	4,290,000	4,423,153	0.1884	833,322
December	10,301,369	6,250,000	4,051,369	0.1884	763,278
Subtotal	**51,239,642**	**66,530,000**	**(15,290,358)**		**(2,880,702)**

Supply Cost Deferral Account
On-Island Purchases Variation
December 31, 2023

St. Lawrence Wind	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	8,856,540	11,200,000	(2,343,460)	0.0722	(169,198)
February	8,422,046	11,200,000	(2,777,954)	0.0722	(200,568)
March	10,984,097	10,570,000	414,097	0.0722	29,898
April	10,840,404	9,420,000	1,420,404	0.0722	102,553
May	10,535,036	7,860,000	2,675,036	0.0722	193,138
June	7,962,303	6,070,000	1,892,303	0.0722	136,624
July	4,743,762	5,760,000	(1,016,238)	0.0722	(73,372)
August	4,870,724	5,970,000	(1,099,276)	0.0722	(79,368)
September	6,548,368	7,750,000	(1,201,632)	0.0722	(86,758)
October	8,352,818	8,480,000	(127,182)	0.0722	(9,183)
November	7,911,532	9,740,000	(1,828,468)	0.0722	(132,015)
December	9,736,803	10,780,000	(1,043,197)	0.0722	(75,319)
Subtotal	**99,764,433**	**104,800,000**	**(5,035,567)**		**(363,568)**

Supply Cost Deferral Account
On-Island Purchases Variation
December 31, 2023

Fermeuse Wind	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	7,480,823	9,020,000	(1,539,177)	0.0772	(118,778)
February	8,088,954	9,020,000	(931,046)	0.0772	(71,849)
March	9,580,893	8,510,000	1,070,893	0.0772	82,641
April	5,956,874	7,590,000	(1,633,126)	0.0772	(126,028)
May	7,711,394	6,330,000	1,381,394	0.0772	106,602
June	3,554,617	4,890,000	(1,335,383)	0.0772	(103,052)
July	3,901,304	4,640,000	(738,696)	0.0772	(57,005)
August	3,425,558	4,810,000	(1,384,442)	0.0772	(106,837)
September	4,342,063	6,240,000	(1,897,937)	0.0772	(146,464)
October	5,436,877	6,830,000	(1,393,123)		(107,507)
November	6,537,825	7,840,000	(1,302,175)		(100,489)
December	6,517,384	8,690,000	(2,172,616)		(167,661)
Subtotal	**72,534,566**	**84,410,000**	**(11,875,434)**		**(916,427)**
Total					**(4,475,597)**

Indemnity Agreement
Fuel Costs Reimbursed by Nalcor[1]
December 31, 2023

	Actual Production No. 6 Fuel (kWh)	Actual Cost No. 6 Fuel[2] ($)	Actual Production Gas Turbine Fuel (kWh)	Actual Cost Gas Turbine Fuel[2] ($)	Actual Costs Reimbursed[2] ($)
January	1,096,000	103,753	755,000	256,255	360,008
February	12,387,000	2,629,636	8,875,000	3,511,085	6,140,721
March	3,964,000	843,301	224,000	122,690	965,991
April	26,000	5,413	-	-	5,413
May	80,000	-	31,000	12,196	12,196
June	-	-	16,000	6,275	6,275
July	-	-	-	-	-
August	-	-	-	-	-
September	-	-	-	-	-
October	27,000	5,728	-	-	5,728
November	374,000	79,467	135,000	61,734	141,201
December	1,268,000	258,089	788,000	321,457	579,546
	19,222,000	**3,925,387**	**10,824,000**	**4,291,691**	**8,217,078**

[1] In 2021, Nalcor commenced delivery of the Nova Scotia Block that, combined with limited LIL capacity, meant Hydro could not be delivered as much energy from the Muskrat Falls Hydroelectric Generating Facility as it would otherwise. Nalcor committed to indemnify Hydro for any damages suffered as a result of this reduction in deliveries, including compensating Hydro for incremental costs of fuel and/or imports over the Maritime Link. The 2023 balances reflect adjustments to the calculation to eliminate incremental costs incurred by Hydro as a result of reduced deliveries. The balances in this report reflect the true-up of initial estimates of incremental costs made throughout the year. All balances reported as at December 31, 2023 reflect final actual incremental cost eliminations.

[2] These costs have been eliminated as referenced on Holyrood TGS Fuel Cost Variance (p. 7) and Thermal Generation Cost Variance (Appendix A).

Tab 2

Contribution in Aid of Construction

Quarter Ended December 31, 2023

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	1	4	0	0	4
Outside Plan Boundary	7	4	11	3	3	5
Subtotal	**10**	**5**	**15**	**3**	**3**	**9**
General Service	3	4	7	0	3	4
Total	**13**	**9**	**22**	**3**	**6**	**13**

[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					
01-Nov-2023	Monkstown	1879101	24,960	29,125	
13-Dec-2023	South Brook; Green Bay	1891872	1,773	5,938	
18-Dec-2023	Bear Cove	1878827	2,352	6,517	
Domestic: Outside Residential Planning Boundaries					
10-Oct-2023	St. Anthony	1875949	2,347	3,572	
12-Oct-2023	Labrador City	1872725	13,859	1,225	
17-Oct-2023	L’Anse-au-Loup	1871165	4,655	5,880	Yes
31-Oct-2023	Wabush	1873845	519,336	580,586	
03-Nov-2023	St. Anthony	1878205	2,235	1,225	Yes
17-Nov-2023	Labrador City	1873912	13,442	3,185	
13-Dec-2023	Westport	1892400	3,536	3,488	
General Service					
17-Oct-2023	Conne River	1879107	46,920	53,275	
25-Oct-2023	Roddickton	1874273	52,184	56,349	
09-Nov-2023	L’Anse-au-Loup	1862774	7,840	12,005	

Tab 3

Customer Damage Claims

Quarter Ended December 31, 2023

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	5	**9**	0	0	0	0	0	9	9,365
Northern	2	12	**14**	2	1,948	1,198	0	0	12	19,874
Labrador	1	4	**5**	0	0	0	2	1,380	3	8,531
Total	**7**	**21**	**28**	**2**	**1,948**	**1,198**	**2**	**1,380**	**24**	**37,771**

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

				Claims Accepted			Claims Rejected		Claims Outstanding	
Region	**# Received**	**# Outstanding Since Last Quarter**	**Total**	**#**	**Amount Claimed ($)**	**Amount Paid ($)**	**#**	**Amount ($)**	**#**	**Amount ($)**
Central	5	8	**13**	5	7,661	4,973	2	1,150	6	3,055
Northern	3	5	**8**	0	0	0	2	1,860	6	25,565
Labrador	2	8	**10**	3	3,772	2,586	3	4,750	4	2,864
Total	**10**	**21**	**31**	**8**	**11,434**	**7,559**	**7**	**7,760**	**16**	**31,484**

[1] Numbers may not add due to rounding.
[2] Numbers may not add due to rounding.

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

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	1	**1**	0	0	0	1	1,000	1	3,105
Power Interruptions	1	0	**1**	0	0	0	0	0	1	2,800
Improper Workmanship	2	4	**6**	0	0	0	1	380	5	3,389
Weather Related	1	3	**4**	1	1,000	250	0	0	4	7,317
Equipment Failure	2	7	**9**	1	948	948	0	0	9	18,519
Third Party	0	0	**0**	0	0	0	0	0	0	0
Miscellaneous	0	0	**0**	0	0	0	0	0	0	0
Awaiting Investigation	1	6	**7**	0	0	0	0	0	4	2,640
Total	**7**	**21**	**28**	**2**	**1,948**	**1,198**	**2**	**1,380**	**24**	**37,771**

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	1	0	**1**	0	0	0	1	1,900	0	0
Power Interruptions	1	2	**3**	0	0	0	3	2,850	0	0
Improper Workmanship	1	9	**10**	4	7,458	6,272	0	0	6	14,850
Weather Related	0	8	**8**	4	3,975	1,287	2	1,150	2	4,987
Equipment Failure	1	1	**2**	0	0	0	0	0	2	1,336
Third Party	0	1	**1**	0	0	0	1	1,860	0	0
Miscellaneous	0	0	**0**	0	0	0	0	0	0	0
Awaiting Investigation	6	0	**6**	0	0	0	0	0	6	10,311
Total	**10**	**21**	**31**	**8**	**11,433**	**7,559**	**7**	**7,760**	**16**	**31,484**

[3] Numbers may not add due to rounding.
[4] Numbers may not add due to rounding.