Doane Grant Thornton

Board of Commissioners of Public Utilities

Newfoundland and Labrador Hydro – 2022/2023 Annual Review

Report date: May 26, 2026

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Executive summary

Purpose

Doane Grant Thornton LLP ("we", "us", "our", or "Doane Grant Thornton") has been engaged by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board" or "P.U.B"). The purpose of our engagement was to present our observations, findings, and recommendations with respect to our 2022-2023 annual financial review of Newfoundland and Labrador Hydro (the "Company", "Hydro").

Scope of work

Our review was carried out in accordance with the following Terms of Reference:

1) Review Hydro's accounting system and code of accounts for any changes since 2021 to ensure that it can provide information sufficient to meet the reporting requirements of the Board.
2) Review Hydro's 2022 and 2023 calculations of return on rate base, return on equity, embedded cost of debt, weighted average cost of capital, capital structure and interest coverage ratio to ensure they are in compliance with Board orders. Doane Grant Thornton has previously been engaged to review the 2023 average rate base in a separate engagement, therefore it is not necessary to include as part of this review.
3) Conduct an analysis of revenue from rates, including GWhs. Compare the 2022 and 2023 actual results to prior years, 2019 Test Year and the 2022 and 2023 Plans, and follow up on significant variances.
4) Conduct an analysis of power purchase expense, including GWhs. Compare the 2022 and 2023 actual results to prior years, 2019 Test Year and the 2022 and 2023 Plans, and follow up on significant variances.
5) Conduct a review of operations and administration expenses, fuels, power purchased, depreciation and interest for 2022 and 2023 in relation to sales of power and energy. Include an analytical review reporting on trends, including comparison with prior years, the 2019 Test Year and the 2022 and 2023 Plans, and follow up on significant variances. The examination of the foregoing will include, but is not limited to, the following:
    a) salaries and benefits
    b) system equipment maintenance
    c) insurance (including director's liability)
    d) transportation
    e) building rental and maintenance
    f) professional services
    g) vegetation management

h) training
i) travel
j) software expenditures
k) miscellaneous
l) capitalized expenses
m) intercompany charges
n) membership fees
o) fuels
p) depreciation
q) Interest
r) office supplies and expenses
s) bad debts.

6) Conduct an analysis of labour costs, including executive compensation, full-time equivalents ("FTEs") and short - term incentives ("STI"). In conducting this review, please present comparisons with prior years, the 2019 Test Year and the 2022 and 2023 Plan, and follow up on significant variances.

7) Review Hydro's 2022 and 2023 non-regulated activity and assess the appropriateness of adjustments in the calculation of regulated earnings.

8) On June 23, 2021, Hydro's corporate structure changed to include all Nalcor Energy ("Nalcor") operations, which resulted in a change in reporting throughout the organization, including the elimination of the Nalcor executive team. This review should include the following:

   a) A review of how costs are allocated between the regulated and non-regulated operations including a review of Hydro's labour costing relating to its billing rates. As part of this analysis, review the process of how labour costs are allocated for senior management that supervise both regulated and non-regulated employees.

   b) Identify any areas in the 2023 organizational structure where regulated and non-regulated employees work together for efficiency purposes.

   c) A review of the policy regarding the sharing mechanism used to allocate exports between regulated and non-regulated operations and the monetization of deferred energy as per the Muskrat Falls Power Purchase Agreement ("MFPPA" or "Muskrat Falls PPA").

   d) Obtain an understanding of the new role of Nalcor Energy Marketing ("NEM" or "Energy Marketing") and its reporting structure, including a review of how the costs incurred by Nalcor Energy Marketing is allocated between regulated and non-regulated operations.

   e) Also, please comment on whether the current intercompany guidelines continue to be appropriate based on the current organizational structure of Hydro.

9) Review the Supply Cost Variance Deferral Account ("SCVDA") and assess the appropriateness of the activity recorded throughout the year, including the following:

a) Review the various components of the SCVDA to assess compliance with Board Orders.
b) Review the policy and procedures in place with regards to the Indemnity Agreement between Nalcor and Hydro to ensure that the regulated operations are treated appropriately as a result of the reduction in deliveries over the Labrador Island Link ("LIL") when Nalcor commenced the delivery of the Nova Scotia Block ("NS Block").
c) Test the details of the activity in the SCVDA for one month for 2022 and 2023.

10) Conduct a review of the charges (credits) to and amortization of the other deferral accounts and assess their compliance with the Board Orders, including the following new deferral accounts that have been implemented in 2022 and 2023:
    a) Holyrood Thermal Generating Station Accelerated Depreciation Deferral Account
    b) Muskrat Falls Power Purchase Agreement Sustaining Capital Deferral Account
    c) Power Purchase Expense Recognition Account
    d) Muskrat Falls Export Revenue Recognition Deferral Account
    e) Business Systems Transformation Program (approved for recovery)
    f) Electrification Cost Deferral Account
    g) Conservation and Demand Management Account, including the incorporation of costs relating to the Labrador Interconnected System, and change from 7 years of amortization to 10 years
11) Charges relating to the MFPPA came into effect November, 2021 and the charges relating to the Transmission Funding Agreement ("TFA") became effective April, 2023. The costs relating to these agreements are billed to Hydro each month based on a forecast and are trued up on a quarterly basis to reflect actual costs. Review and explain the process and controls that Hydro has in place to ensure the actual costs are captured appropriately and are reflective of the agreements.
12) Review Hydro's annual report on Key Performance Indicators ("KPIs") and any other information on initiatives and efforts targeting productivity or efficiency improvements.

The nature and extent of the procedures we will perform in our financial review will vary for each of the items listed above. In general, our procedures will consist of:

- inquiry and analytical procedures with respect to financial information as provided by Hydro;
- examination of, on a test basis where appropriate, documentation supporting amounts included in Hydro's records; and
- assessing Hydro's compliance with Board directives.

The procedures undertaken in the course of our financial review will not constitute an audit of Hydro's financial information and consequently, we will not express an opinion on the financial information as provided by Hydro.

The financial statements of the Company for the years ended December 31, 2022 and 2023 have been audited by Deloitte, who have expressed their opinion on the fairness of the statements in their reports dated March 21, 2023 and March 13, 2024, respectively. In the

course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Restrictions and limitations

Our scope of work is as set out throughout this report. The procedures undertaken in the course of our review do not constitute an audit of the Company's financial information and consequently, we do not express an audit opinion on the financial information provided by the Company. Our opinions on other matters are outlined throughout this report.

We acknowledge that our report will be communicated to the parties to the matter and may become a public document accessible through the Board's website. We have given the Board our consent to use our report for this purpose. Our report is not to be reproduced or used for any purpose other than that outlined above without prior written permission in each specific instance. Doane Grant Thornton LLP recognizes no responsibility to any third party who may rely on this report or other material provided to the Board.

Unless stated otherwise in this report, Doane Grant Thornton LLP has relied on information provided by the Company, the Board's website and third-party sources in preparing this report, whom Doane Grant Thornton LLP believes is reliable. We are not guarantors of the information upon which we have relied in preparing the report and, except as stated, we have not audited or otherwise attempted to verify any of the underlying information or data contained in this report. We have made efforts to ensure a conservative, realistic and transparent approach, however, some of the analysis depends on the input from third parties whose opinions may influence the conclusions. All analysis, information and recommendations contained herein are based on the information available to Doane Grant Thornton LLP as of this report's date.

Summary of findings, observations, and conclusions

The following represents a summary of our key findings and recommendations based on the procedures outlined throughout the report:

Figure 1 – Summary of findings, observations, and conclusions

#	Report section	Findings, observations, and conclusions
1.	**Accounting system and code of accounts**	We have reviewed Hydro's accounting system and code of accounts for 2022 and 2023. We confirm that the accounts added were required to enhance the Company's ability to provide sufficient information to meet the reporting requirements of the Board.

#	Report section	Findings, observations, and conclusions
2.	**Return on rate base and other metrics**	We have completed our procedures in the review of Hydro's 2022 and 2023 calculations of return on rate base, return on equity, embedded cost of debt, weighted average cost of capital, capital structure, and interest coverage ratio to ensure they are in compliance with Board orders. We have not noted any discrepancies in the calculations or compliance.
3.	**Revenue from rates**	We have completed our procedures on Hydro's revenue from rates, including GWh, for 2022 and 2023 actual results to prior years, 2019 Test Year and the 2022 and 2023 Plans, and have not noted any issues in our analysis.
4.	**Power purchased**	We have completed our analysis of Hydro's power purchase expense (including GWhs) and compared the 2022 and 2023 actual results to prior years, 2019 Test Year and the 2022 and 2023 Plans. Our analysis identified notable trends and budget variances, and we made subsequent inquiries with Hydro for further clarification. We found that actual power purchases from "Secondary and other" sources fluctuated significantly from budgets from 2020-2023. Based on correspondence with Hydro, we understand that this is a result of budget assumptions around the commissioning date of the Muskrat Falls project in which budgets assumed assets were commissioned at various levels which were not achieved. We did not identify any issues in our overall analysis.
5.	**Operations and administration expenses**	We have completed our procedures in the review of Hydro's operations and administration expenses. We compared 2022 and 2023 actual results to prior years, the 2019 Test Year and the 2022 and 2023 Plans. Our analysis identified notable trends and budget variances, and we made subsequent inquiries with Hydro for further clarification, including their budgeting approach and methodology. Overall expenses under the scope of our review experienced a significant decrease in 2020 and 2021 but returned to previous levels in 2022. In 2022, actual expenditures were 63% higher than budget. Based on our discussions with Hydro, we understand that this discrepancy is due to the exclusion of fuel-related supply deferrals as they are categorized as "Other expense" in the budget figures. Once

#	Report section	Findings, observations, and conclusions
		adjusted for deferrals, we found that actual fuels expense was consistent with budgets throughout the period under review. When we compared budget to actual costs we noted several categories where Hydro's actual expenses have fallen within their budgets. These categories include but are not limited to office supplies, insurance, and professional services. However, there are several cost categories where actual expenditures have exceeded budget. These categories include but are not limited to software, travel, vegetation management, and transportation. We have received explanations from Hydro on the trends identified and are satisfied with their explanations. Based on our trend analysis we noted that the utility continues to face pressures from increasing costs. We encourage the Board to actively monitor expense budgeting and cost controls in the next general rate application.
6.	**Labour costs**	We have completed our procedures in the review of Hydro's labour costs. Our review included comparing 2022 and 2023 actual results to prior years, the 2019 Test Year and the 2022 and 2023 Plans. Our analysis included trending on total salaries and fringe benefits, executive compensation, salary expense by FTE, and capitalized salaries and overtime. We identified significant year-over-year trends and made subsequent inquiries with Hydro for further clarification. Our key findings include the following: • Total labour costs have remained relatively consistent over the period of our review. • Average net FTE employees by division have deceased from 830 in 2019 to 804 in 2023, and there has not been a significant change in average salary per net FTE. • As a result of the reorganization in 2021, executive positions supporting shared service departments were transferred to Non-regulated Hydro. A pro-rated portion of their labour costs associated with these positions is then charged to regulated Hydro using the established intercompany guidelines.

#	Report section	Findings, observations, and conclusions
		Overall we have not noted any issues in our analysis and are satisfied with Hydro's explanations provided through our inquiry process.
7.	**Non-regulated activity**	We have completed our procedures in the review of Hydro's non-regulated activity which included understanding Hydro's non-regulated activity, analyzing year-over-year trends of the non-regulated statement of earnings, and reviewing the regulatory adjustments for 2022 and 2023. In our analysis of the non-regulated statement of earnings we found that operating costs increased significantly in 2023. Based on our discussions with Hydro, we understand that the increase in operating costs is primarily due to an increase in bad debt expense. Additionally, we found that transmission rental and market fees fluctuated year -over -year. Based on discussions with Hydro, we understand that transmission costs from Hydro-Quebec are recorded as transmission costs, then resold to Energy Marketing as per the PPA. In 2022, there was a short-term amendment to the Hydro and Energy Marketing PPA and a retroactive adjustment to the monthly transmission invoices from Hydro-Quebec that caused a one-time decrease in this cost category. During our review nothing came to our attention to suggest the adjustments in the calculation of regulated earnings were not appropriate.
8.	**Corporate structure**	We have completed our procedures in the review of Hydro's organizational structure, including the NEM reporting structure, and have concluded on the following: • We have reviewed Hydro's current Intercompany Costing Guidelines and have found no exceptions that would deem them inappropriate based on Hydro's current organizational structure. However, given the significance of the recent reorganization, we recognize the need for Hydro to update these guidelines for consideration of the corporate structure changes. We understand that Hydro is currently in the process of reviewing their intercompany costing guidelines. • We have reviewed Hydro's process for cost allocations between the regulated and non-regulated operations, specifically the labour costing process. As part of this process, we conducted walkthroughs with Hydro to understand how labour costs are allocated for senior management that supervise both regulated and non-regulated employees. We

#	Report section	Findings, observations, and conclusions
		found that executive employees charge their time to regulated based on two methods: daily time worked by task, and an overall annual allocation. This is determined based on the nature of the role. • We have reviewed the policy regarding the sharing mechanism used to allocated exports between regulated and non-regulated operations and the monetization of deferred energy as per the Muskrat Falls Power Purchase Agreement. Our review included reviewing NEM's reporting structure, reviewing the Muskrat Falls Power Purchase Agreement, and conducting walkthroughs with Hydro to understand the nature and treatment of exports. During the course of our engagement Hydro walked us through the process for the three types of energy export transactions; legacy recapture, incremental recapture, and residual block energy. Based upon our review of the above, we are satisfied with the information provided surrounding Hydro's corporate structure with regards to cost and export allocations. We also note that the intercompany costing guidelines currently in place are dated given the corporate structure changes and warrant a review (which is currently in progress).
9.	**Supply cost variance deferral account**	We have completed our procedures in the review of the Supply Cost Variance Deferral Account and the Indemnity Agreement. Based on our analysis, we note that the SCVDA activity and components are in compliance with relevant Board Orders and we found no errors in our test of details completed for May 2022 and March 2023. We reviewed and completed a walkthrough on the policies and procedures in place with regards to the Indemnity Agreement between Nalcor and Hydro. Based on our review, nothing has come to our attention to suggest that regulated operations were not treated appropriately as a result of the reduction in deliveries of the LIL due to the early commencement of the NS Block.
10.	**Deferrals**	We have completed our procedures in the review of Hydro's 2022 and 2023 charges (credits) to and amortization of the other deferral accounts and note the following:

#	Report section	Findings, observations, and conclusions
		• We acknowledge that Hydro's regulatory assets/liabilities include significant regulated deferral balances. In 2022 and 2023, the balance of the regulatory assets/liabilities totaled $507 million and $846 million, respectively. We understand that Hydro has plans to address these deferrals. These plans were not specifically part of this review. However, we encourage the Board to continue monitoring deferrals in future filings. • Based upon our analysis, we noted that recovery of Phase II hearing costs, the reliability and resource adequacy balance, Muskrat Falls Power Purchase Agreement sustaining capital, Holyrood thermal generating station accelerated depreciation, electrification cost deferral, and a portion of the business systems transformation program have not yet been approved by the Board. These deferral accounts have been appropriately excluded from rate base. • We also note that power purchase expense recognition deferral represents a timing difference in expense recognition and is appropriately excluded from rate base. Finally, we note that the Muskrat Falls export revenue recognition deferral represents a timing difference in revenue recognition and is appropriately excluded from rate base.
11.	**Muskrat Falls Power Purchase Agreement and Transmission Funding Agreement**	We have completed our procedures in the review of Hydro's process and controls surrounding the MFPPA and TFA charges. As part of our procedures, we reviewed these agreements. We also obtained process narratives and observed walkthroughs of the preparation of monthly invoices and quarterly true up adjustments for both the MFPPA and TFA. We then conducted testing procedures of the monthly invoicing and quarterly true up processes. We did not note any errors in our analysis and conclude that Hydro has adequate processes and controls in place to ensure the actual costs are captured appropriately and are reflective of the agreements.
12.	**Key performance Indicators**	We have reviewed the KPI results and note the following findings:

#	Report section	Findings, observations, and conclusions
		• Hydro did not meet their safety targets (All Injury Frequency or Lead/lag ratio) in 2022 or 2023. • Hydro met their environment and conservation targets, including the achievement of EMS targets and annual energy savings from conservation and demand management programs, in 2022 and 2023. • Hydro met all applicable reliability KPIs in 2022 and 5 of the 9 targets in 2023. Per Hydro, fewer targets were met in 2023 due to significant forced outages in the year and an increase in forced deratings. • Hydro did not meet their operating KPI targets in 2022 or 2023. Per Hydro, while generation remained maximized to the extent possible, multiple spill events in both years ultimately resulted in lost energy and therefore a reduction to the Hydraulic Conversion factor. • We understand that Hydro does not have set targets for their financial KPIs and instead compares these metrics to peer group data in line with Board direction in Order No. P.U. 8 (2007). We note that Hydro is outperforming their peer group in these metrics, however, Hydro does not believe that the selected peer group is an appropriate comparator on all metrics. As such, the Board should consider reviewing the selected peer group as part of the next general rate application. We have reviewed the explanations provided by Hydro for the changes and variations experienced in 2022 and 2023 and find them to be consistent with our observations and findings noted in conducting our annual financial review. There were no internal inconsistencies identified in Hydro's report.

1. Accounting system and code of accounts

Scope

Review Hydro's accounting system and code of accounts for any changes since 2021 to ensure that it can provide information sufficient to meet the reporting requirements of the Board.

Procedures

Our review of the accounting system and code of accounts included the following specific procedures:

- Inquired as to the extent of changes (if any) to the code of accounts since 2021 and assess the impact on the Board's reporting requirements.
- For any additions or deletions from the approved chart of accounts, understood the rationale for the change.

Analysis

Section 58 of the *Public Utilities Act* states that the Board may prescribe the form of all books, accounts, papers, and records to be kept by Hydro and that Hydro shall comply with all such directions of the Board.

The objective of our review of Hydro's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. The system allows for adequate flexibility to allow the Company to meet its own, as well as the Board's, reporting requirements.

Our review noted the creation of 15 additional accounts to the code of accounts in 2022 and 21 additional accounts to the code of accounts in 2023. The new accounts were added in relation to the following categories:

Muskrat Falls

During 2021 Hydro filed an application for approval of new accounts, changes to existing accounts, and an accounting deviation associated with the commissioning of the Muskrat Falls Project. In 2022, new accounts for Muskrat Falls Project were added in relation to the following:

- Four new accounts relating to interest. Two to record the interest from a regulated perspective and remove the interest from an International Financial Reporting Standards ("IFRS") perspective and two to capture the interest paid by Hydro under the MFPPA in regulatory adjustments, as per Order No. P.U.33 (2021).
- Three new accounts relating to settlement of MFPPA monetization. One to capture the estimated amount, one to capture the actual settlement, and one to

capture the timing difference between the estimated amount and the actual settlement, as per Order No. P.U.33 (2021).

- Two new accounts relating to relating to accounting deviation, as per Order No. P.U.33 (2021).
- Two new accounts relating to supply deferral to capture the deferral of the net profits from the export of incremental recapture energy.
- Two new accounts relating to market fee. One to capture purchase price variances in the inventory subledger and the vendor invoices, and one to capture costs associated with export of incremental recapture energy as per Order No. P.U.33 (2021).
- One new account relating to power purchase expense to capture the cost of Muskrat Falls Residual block.

In 2023, new accounts for Muskrat Falls Project were added in relation to the following:

- Two new accounts relating to accounting deviation to capture contract payments versus expense recognition timing differences.

Government grant

In 2023, accounts for Government Grant were added in relation to the following:

- Four new accounts to set up the government grant for rate mitigation related to the Muskrat Falls Project.

Holyrood thermal generating station

In 2023, accounts for Holyrood Thermal Generating Station were added in relation to the following:

- Three new accounts relating to Holyrood accelerated depreciation deferral as per Order No. P.U.33 (2021).

Energy Marketing

In 2023, accounts for Energy Marketing were added in relation to the following:

- Two new accounts relating to point to point transmission revenue.

Internal contribution from Nalcor

In 2023, accounts for internal contribution from Nalcor were added in relation to the following:

- Three new accounts to set up the internal contribution from Nalcor for rate mitigation related to the Muskrat Falls Project.

Electric Vehicle ("EV") Charger

In 2023, seven new accounts relating to the EV charger deferral account were added, as per Order No. P.U. 33 (2023). These accounts included the following:

- Three balance sheet accounts, including:
  - One account for EV charger asset elimination;
  - One account for EV charger deferred contribution elimination; and,
  - One EV charger deferral account.

- Four income statement accounts, including:
  - One account for EV charger deferral depreciation elimination;
  - Two accounts for EV charger deferral CIAC amortization elimination; and,
  - One account for EV charger deferral depreciation elimination.

Per Hydro, Regulated Hydro has one system asset module which is used for both Regulated and IFRS presentations. Under IFRS, the EV chargers and corresponding EV charger contributions qualify as an asset and contributions and are therefore included in the asset module. For regulated presentation, Order No. P.U. 33(2023) notes that Hydro is required to include the EV chargers and contributions in the Electrification Cost Deferral Account. Hydro uses the new elimination accounts to make the appropriate adjustments for regulated presentation.

Other

In addition, in 2022, an account was added for the following:

- A new account created to record inter/intra-company recovery line for employee accommodations.

Conclusion

We have reviewed Hydro's accounting system and code of accounts for 2022 and 2023. We confirm that the accounts added were required to enhance the Company's ability to provide sufficient information to meet the reporting requirements of the Board.

2. Return on rate base and other metrics

Scope

Review Hydro's 2022 and 2023 calculations of return on rate base, return on equity, embedded cost of debt, weighted average cost of capital, capital structure and interest coverage ratio to ensure they are in compliance with Board orders.

Procedures

Our review of return on rate base included the following specific procedures:

- Agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable.
- Agreed component data (dividends, regulated earnings, etc.) to supporting documentation.
- Recalculated return on rate base for 2022 and 2023.
- Recalculated average common equity for 2022 and 2023.
- Recalculated return on common equity for 2022 and 2023.
- Recalculated embedded cost of debt for 2022 and 2023.
- Recalculated the weighted average cost of capital for 2022 and 2023.
- Recalculated the interest coverage ratio for 2022 and 2023.
- Recalculated the capital structure for 2022 and 2023. Compare to Hydro target of 80:20.
- Reviewed the above for compliance with relevant Board Orders.

Analysis

Return on rate base

The Company's calculation of return on average rate base is included on Return 12 of the annual report to the Board. The return on average rate base for 2022 and 2023 as filed was 5.40% and 5.02%, respectively (2021 – 5.46%).

Details with respect to Hydro's calculation of return on average rate base as filed on Return 12 for 2022 and 2023, with 2021 as a comparative, are as follows:

Figure 2 – Rate of return on average rate base

(000s)	2023	2022 Revised[1]	2021
Corporate net income - Return 1	$ 70,280	$ 99,981	$ 91,327
Deduct:			
Unregulated earnings	38,295	63,668	55,528
Regulated net income	31,985	36,313	35,799
Add:			
Compliance adjustments	-	-	-
Cost of service exclusions	7,129	7,620	7,108
Regulated net interest - Return 16	77,801	81,686	83,813
Regulated return	116,915	125,619	126,720
Average rate base at year end - Return 3	2,329,352	2,325,085	2,321,756
Rate of return on average rate base	**5.02%**	**5.40%**	**5.46%**

Note 1: Hydro submitted a request for change or modification to Order No. P.U. 35 (2023) on July 16, 2024. In the request, Hydro proposed a revised 2022 average rate base of $2,325,085,000, reducing the previously approved 2022 average rate base by $9,036,000 for an adjusted working capital allowance of $1,276,000. Hydro restated its working capital allowance for 2022 to exclude power purchases and transmission expenses that were deferred in the Supply Cost Variance Deferral Account to avoid earning a return on these payments in both the calculation of the working capital allowance and through interest accrued in the Supply Cost Variance Deferral Account. In Order No. P.U. 21 (2024) the Board ordered that Order No. P.U. 35 (2023) be amended to reflect a revised 2022 average rate base of $2,325,085,000. We have previously examined the revised 2022 average rate base of $2,325,085,000 detailed in the 2023 Annual Return and verified that the excluded costs are recorded in the Supply Cost Variance Deferral Account with interest accruing on the balance.

The regulated net income component of the return on rate base excludes all of Hydro's non-regulated earnings and expenses. In Order No. P.U. 30(2019), the Board approved an allowed rate of return on rate base of 5.43% with a range of return of 40 basis points (± 20 basis points) for 2019 rate setting. The 2022 return presented above is within the approved range, while the 2023 rate is below the approved range.

Return on equity

The Company's calculation of regulated average equity and rate of return on regulated average equity for 2022 and 2023 is included on Return 13 of the annual report to the Board.

Details with respect to Hydro's calculation of return on regulated average equity as filed in Return 13 is as follows:

Figure 3 – Average equity and return on equity

(000s)	2023	2022	2021
Shareholders equity, beginning of year	$ 605,760	$561,825	$518,920
Shareholders equity, end of year	644,873	605,760	561,825
Average equity	625,317	583,793	540,373
Regulated earnings	31,985	36,313	35,799
Cost of service exclusions	7,129	7,620	7,108
Regulated earnings	39,114	43,933	42,907
Return on equity	**6.26%**	**7.53%**	**7.94%**

The "regulated" shareholder's equity of Hydro excludes the portion of equity attributable to non-regulated operations. Details with respect to Hydro's calculation of regulated shareholder's equity is filed in Return 13.

Cost of debt

The Company's calculation of cost of debt for 2022 and 2023 is included on Return 15 of the 2022 and 2023 annual reports to the Board.

Cost of debt for 2022 and 2023 has been calculated at 4.66% and 4.52%, respectively, compared to 4.75% in 2021.

Hydro utilized its $300.0 million government promissory note program to fulfill its short-term funding requirements in 2022. As at December 31, 2022, there was one promissory note outstanding of $131.0 million with a maturity date of January 3, 2023 bearing an interest rate of 4.27% (2021 - $55.0 million bearing an average interest rate of 0.20%). Additionally, at December 31, 2022, Hydro maintained a $500.0 million CAD or USD equivalent committed revolving term credit facility maturing on July 31, 2023, (2021 - $300.0 million, which was increased to $500.0 million on April 16, 2021, and extended to reflect a new maturity date of July 31, 2022). As at December 31, 2022, there were no amounts drawn on the facility (2021 - $nil).

Hydro also utilized its $300.0 million government promissory note program to fulfill its short-term funding requirements in 2023. As at December 31, 2023, there were two promissory notes outstanding for a total of $230.0 million with a maturity date of January 2, 2024 bearing interest rates ranging from 5.15% to 5.17%. Upon maturity, the promissory notes were reissued. At December 31, 2023 Hydro maintained a $500.0 million CAD or USD equivalent committed revolving term credit facility maturing on July 31, 2024. As at December 31, 2023, there were no amounts drawn on the facility (2022 - $nil).

Borrowings in CAD may take the form of Prime Rate Advances, Bankers' Acceptances ("BAs"), and letters of credit, with interest calculated at the Prime Rate or BA fee. Borrowings in USD

may take the form of Base Rate Advances, Secured Overnight Financing Rate ("SOFR") Advances and letters of credit. The facility also provides coverage for overdrafts on Hydro's bank accounts, with interest calculated at the Prime Rate.

Weighted average cost of capital

The Company's inputs used in the calculation of weighted average cost of capital ("WACC") for 2022 and 2023 are included on Return 13, 14, and 15 of the 2022 and 2023 annual reports to the Board.

Weighted average cost of capital for 2022 and 2023 has been calculated at 5.33% and 5.25%, respectively, compared to 5.37% and 5.43% in 2021 and 2019 TY, respectively.

Details with respect to Hydro's calculation of WACC is as follows:

Figure 4 – Weighted average cost of capital

		2023	2022	2021	2019 TY
Capital structure [1]					
Debt		73.3%	73.4%	74.1%	76.7%
Average debt	A	73.3%	73.7%	74.6%	76.8%
Equity		22.9%	22.6%	21.9%	19.6%
Average equity	B	22.8%	22.3%	21.5%	19.5%
Cost of debt	C	4.52%	4.66%	4.75%	4.91%
Target cost of equity	D	8.50%	8.50%	8.50%	8.50%
Weighted average return on debt	E =A x C	3.32%	3.44%	3.54%	3.77%
Weighted average return on equity	F = B x D	1.94%	1.89%	1.83%	1.66%
Weighted average cost of capital	**G = E + F**	**5.25%**	**5.33%**	**5.37%**	**5.43%**

Note 1: The WACC calculation above excludes the employee future benefits and funded asset retirement obligation components of Hydro's capital structure. WACC is a targeted measure that focuses only on the sources of capital that require a return from investors or lenders. As such, the WACC calculation above appropriately excludes the other components of Hydro's capital structure.

Per Order No. P.U.16(2019), the Board approved the automatic adjustment mechanism for Hydro's target return on equity to reflect any changes to Newfoundland Power's approved target return on equity for rate setting. Per Order No. P.U.3(2022), the Board recommended a rate of return on common equity of 8.50% for rate setting purposes for Newfoundland Power. Therefore, the target cost of equity of 8.50% has been used by Hydro in the calculation of the WACC.

Interest coverage

In 2013, Hydro changed the calculation of its 2013 interest coverage to the Standard & Poor's ("S&P") earnings before interest, taxes, depreciation, and amortization ("EBITDA") interest

coverage methodology. The S&P methodology calculates interest coverage as EBITDA divided by interest. The EBITDA calculation is considered a proxy for cash earnings by S&P.

S&P's definition of interest includes the gross amount of interest, including capitalized interest but excluding interest income. It also includes interest on employee future benefits as well as accretion.

Interest coverage for 2023 and 2022 under the S&P methodology has been calculated at 1.89 times, and 1.82 times, respectively (2021 – 1.99 times).

Capital structure

Details with respect to the capital structure as filed on Return 14 of the 2022 and 2023 annual reports to the Board are as follows:

Figure 5 – Capital structure per Annual Returns

(000s)	2023	%	2022	%	2021	%
Debt	$2,061,000	73.3%	$1,966,000	73.4%	$1,897,000	74.1%
Employee benefits	92,000	3.3%	92,000	3.4%	88,000	3.4%
Asset retirement obligation	15,000	0.5%	14,000	0.5%	14,000	0.5%
Equity	645,000	22.9%	606,000	22.6%	562,000	21.9%
	$2,813,000		**$2,678,000**		**$2,561,000**	

As noted in the above table, the 2022 ratio was approximately 73.4% (2021 – 74.1%) debt (excluding employee benefits and asset retirement obligation) and 22.6% (2021– 21.9%) equity. The 2023 ratio was approximately 73.3% debt (excluding employee benefits and asset retirement obligation) and 22.9% equity.

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratio with 2008 showing a ratio of 81.4:18.6. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0. Currently, the Company's target corporate capital structure is comprised of 75% debt and 25% common equity for regulated operations.

In order to maintain this target ratio, the Company implemented the following dividend policy:

"*Corporation annually on or before March 31 of each year, pay a dividend on its common shares if the percentage of debt to debt plus equity in the capital structure of the corporation on a regulated basis at the end of the immediately preceding fiscal year was less than 75% and that the amount of the dividend in that case will be equal to the amount that would be necessary to bring the percentage of debt to debt plus equity up to 75% at December 31st of the immediately preceding year, as if the dividend in question had been on that date*."

According to Hydro, the corporate regulated capital structure used in the calculation of the regulated dividend is based on an S&P rating agency methodology which differs from the calculation of the capital structure as reported in Return 14. The S&P calculation of debt within

the capital structure includes accrued interest, asset retirement obligations and post-retirement benefit obligations.

Details with respect to the S&P method to calculate capital structure is as follows:

Figure 6 – Capital structure per S&P's methodology

(000s)	2023	2022	2021
Promissory notes	243,500	128,300	40,200
Long-term debt, including current portion	2,023,500	2,039,300	2,048,000
Sinking funds	(205,900)	(201,900)	(191,700)
Total debt before adjustment	**2,061,100**	**1,965,700**	**1,896,500**
Adjustments			
Accrued interest	25,400	25,400	25,300
Asset retirement obligations	26,700	17,200	14,800
Post retirement benefit obligations	78,500	67,600	94,000
Total adjusted debt	**2,191,700**	**2,075,900**	**2,030,600**
Contributed capital	100,000	100,000	100,000
Accumulated other comprehensive income	13,600	24,800	(5,600)
Retained earnings	479,900	447,900	411,600
Shareholder's equity before adjustment	**593,500**	**572,700**	**506,000**
Adjustments			
Post retirement benefit obligations	-	-	-
Total adjusted equity	**593,500**	**572,700**	**506,000**
Total adjusted capital	2,785,200	2,648,600	2,536,600
Debt to total capital before dividends	**78.7%**	**78.4%**	**80.1%**

The debt to total capital ratio was 80.1% at December 31, 2021. The debt to total capital ratio decreased to 78.4% at December 31, 2022, and remained relatively consistent as of December 31, 2023 at 78.7%. In compliance with Hydro's dividend policy, no dividends were paid on common shares in 2021, 2022, or 2023, as the percentage of debt to debt plus equity in the capital structure of the corporation on a regulated basis was greater than 75% at the end of these fiscal years.

Conclusion and recommendation

We have completed our procedures in the review Hydro's 2022 and 2023 calculations of return on rate base, return on equity, embedded cost of debt, weighted average cost of capital, capital structure, and interest coverage ratio to ensure they are in compliance with Board orders. We have not noted any discrepancies in the calculations or compliance.

3. Revenue from rates

Scope

Conduct an analysis of revenue from rates, including GWhs. Compare the 2022 and 2023 actual results to prior years, 2019 Test Year and the 2022 and 2023 Plans, and follow up on significant variances.

Procedures

Our review of revenue from rates on a total basis included the following specific procedures:

- Compiled revenue from rates in both $ and GWh for 2022 and 2023 actual results, 2019 test year, and 2022 and 2023 Budgets.
- Completed a 5-year trend analysis on both budget and actual energy sales at the customer class level.
- Identified significant variances and inquired with Hydro to understand the nature of the variance.

The Board also requested we analyze revenue from rates on a customer class basis. Our analysis included the following:

- Obtaining an understanding of the trends in revenue from rates in both $CAD and GWh for 2019 Test Year, 2020-2023 budget, and 2019-2023 Actuals for exports and others, as well as the following classes:
  - Newfoundland Power
  - Hydro Rural
  - Industrial customers

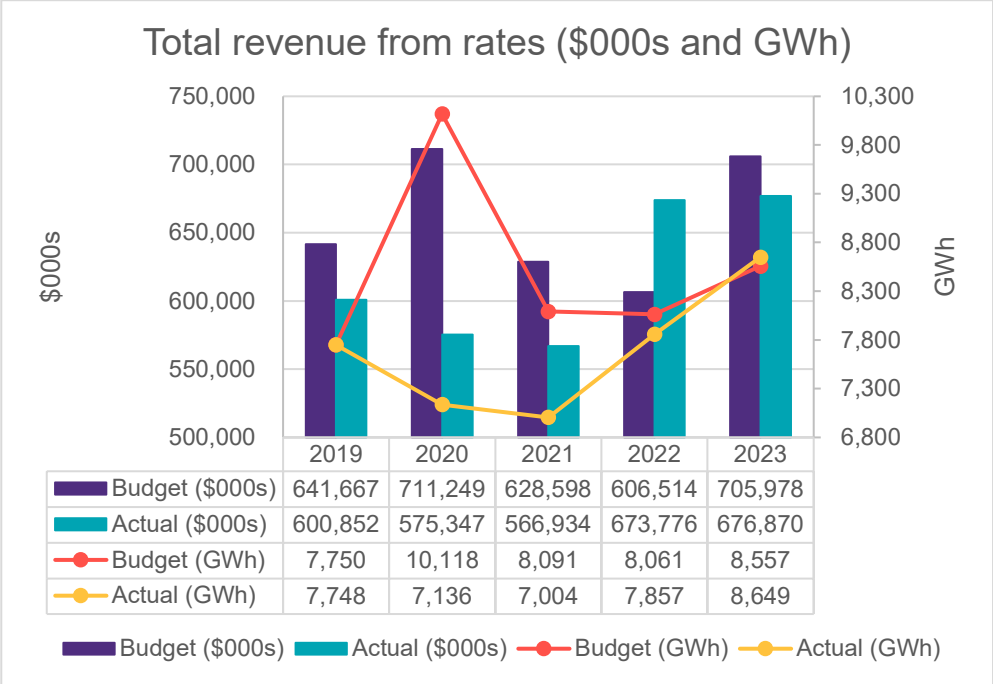
Our observations and findings on the above have been detailed in the following section.

Analysis – total basis

Total revenue from rates

As part of our trend analysis, we observed changes in budget and actual revenue from rates in both $CAD and GWh. The chart below illustrates the total revenue from rates in both $CAD and GWh for 2019 Test Year, 2020-2023 budget, and 2019-2023 Actuals.

Figure 7 – Total revenue from rates



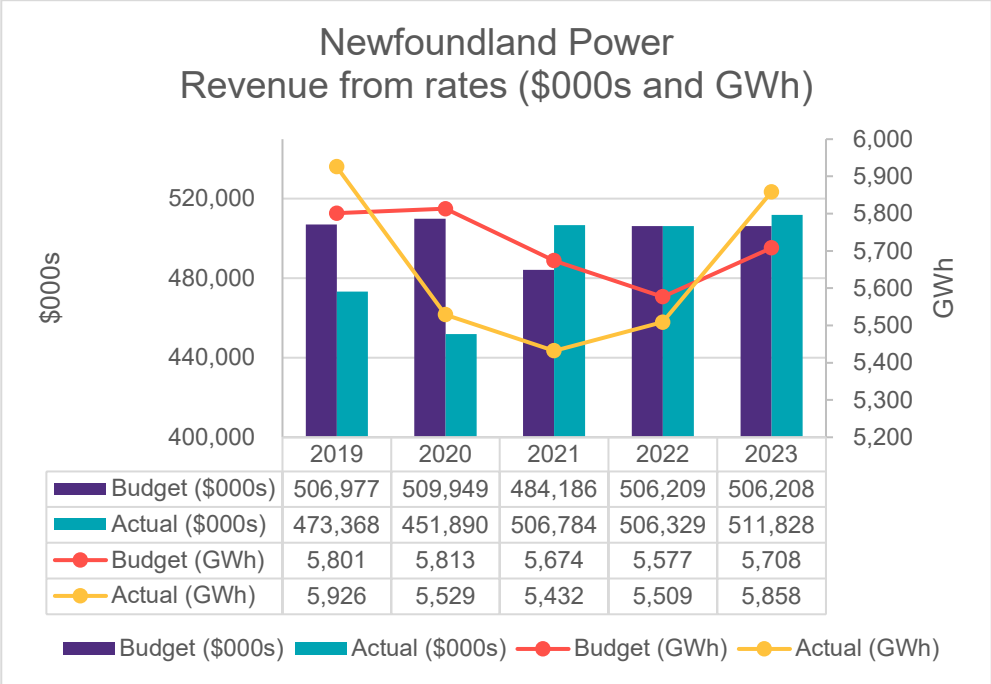
Our analysis of revenue from rates by customer class, including Newfoundland Power, Hydro Rural, Industrial Customers, and Exports and other categories has been outlined in the following sections.

Analysis – by customer class

Newfoundland Power

The following chart details the revenue from rates in both ($000s) and GWh from Newfoundland Power for 2019 Test Year, 2020-2023 budget, and 2019-2023 Actuals.

Figure 8 – Revenue from rates – Newfoundland Power



From 2019-2023, revenue from rates from Newfoundland Power fluctuated from a low of $448,952,000 in 2021 to a high of $511,828,000 in 2023. Sales in GWh have fluctuated from a low of 5,432 GWh in 2021 to 5,926 GWh in 2019. Based on the chart above, we noted the following significant variances:

- **2020 actual energy sales (GWh) and ($CAD) decreased by 7% and 5%, respectively compared to 2019 actual, as well as 2020 actual sales ($CAD) being 11% lower than 2020 budget.** These decreases can mainly be explained by the Covid-19 pandemic. During our review of 2020 Newfoundland Power we noted that while residential customers' energy consumption stayed relatively steady during the first year of the pandemic with only a 13 GWh decrease, commercial customers consumption decreased on average by 104 GWh as a result of the pandemic. The decrease in $CAD sales to Newfoundland Power in 2020 compared to 2019 was partially offset by a higher wholesale electrical rate effective October 1, 2019.

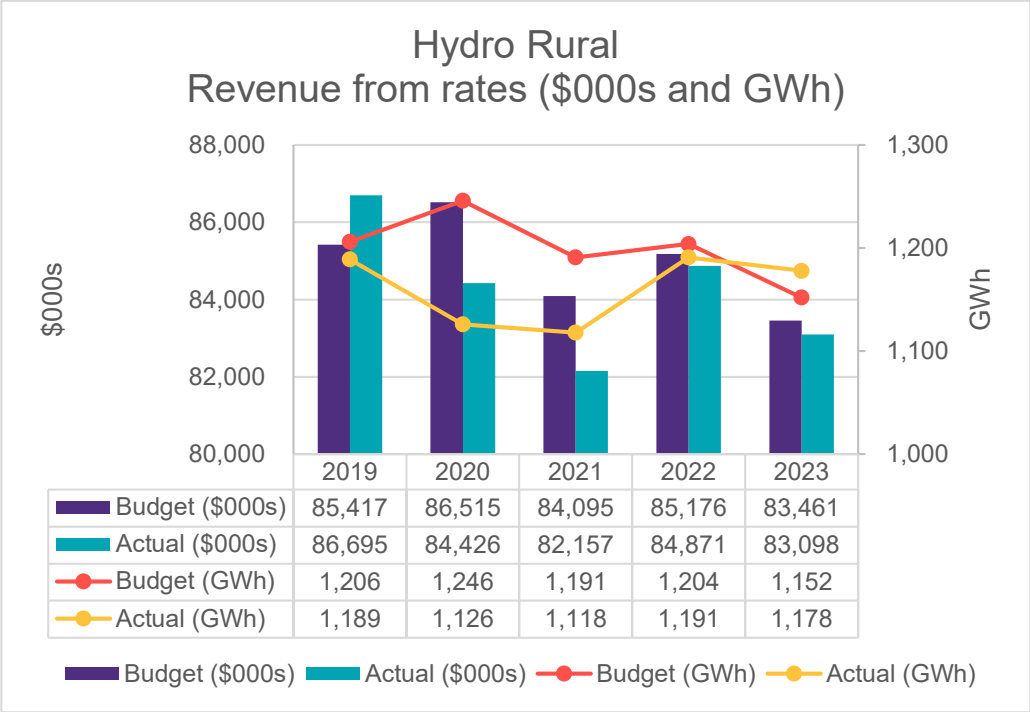
- **2021 actual energy sales ($CAD) was 7% lower than budget.** According to Hydro, there were classification changes for the Newfoundland Power revenue load variance that impacted reported sales for 2021. Specifically, prior to November 1, 2021, the load variance was recorded in the fuel expense line on the Income Statement, not revenue. The revenue load variation for January 1 - October 31, 2021 was $57,832,000, which when included in 2021 actual energy sales, results in total revenue for 2021 of $506,784,000, compared to a budget of $484,186,000.

- **2022 actual energy sales ($CAD) was 9% higher than budget.** According to Hydro, similar to the above explanation for 2021, there was a classification change for its budget 2022 revenue load variance with $40,599,000 included in the budget line of other expense (income) instead of energy sales. When the budget for the load variance is adjusted to energy sales, it results in a budget from energy sales of $506,209,000, compared to an actual of $506,329,000.

Hydro Rural

The following chart details the revenue from rates in both ($000s) and GWh from Hydro Rural customers for 2019 Test Year, 2020-2023 budget, and 2019-2023 Actuals.

Figure 9 – Revenue from rates – Hydro Rural

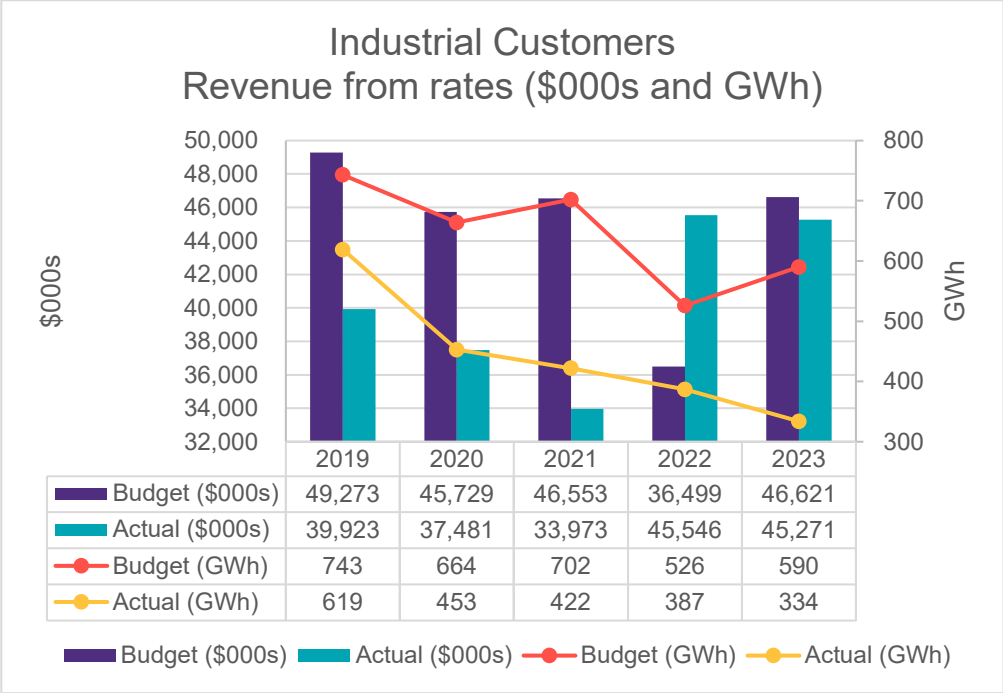


From 2019-2023 revenue from rates from Hydro Rural Customers remained relatively stable from a low of $82,157,000 in 2021, to a high of $86,695,000 in 2019. Revenue in GWh experienced similar trends with a low of 1,118 in 2021, and a high of 1,189 in 2019. There were limited notable discrepancies in annual budget and actual results during the period.

Industrial

The following chart details the revenue from rates in both ($000s) and GWh from Industrial customers for 2019 Test Year, 2020-2023 budget, and 2019-2023 Actuals.

Figure 10 – Revenue from rates – Industrial Customers



Over the period, revenue from rates from industrial customers fluctuated from a low of $33,973,000 in 2021 to a high of $45,546,000 in 2022. Revenue in GWh fluctuated from a low of 334 in 2023 and a high of 619 in 2019. Hydro also noted that in both 2019 and 2020 Industrial Energy Sales and Export Energy sales relating to the Maritime Link and Soldiers Pond were combined on the Statement of Energy Sold. For the purpose of our analysis, we have separated export energy and industrial sales. Based on the chart above, we investigated the following significant variances:

- **2020 actual energy sales (GWh) for industrial customers decreased by 27% compared to 2019.** According to Hydro, this decrease was the result of the reduction in Braya Renewable Fuels ("Braya") operations to a minimum level in April 2020 due economic conditions during the COVID-19 pandemic. In 2019, actual GWh consumption for Braya was 249 GWh and in 2020 it was 86 GWh.

- **2021-2022 budgeted energy sales for industrial customers in $CAD decreased by 22%. A decrease in GWh of 25% was also budgeted for the same period.** According to Hydro, this decrease was mainly due to Braya having reduced operations to a minimum level in April 2020 due to the economic conditions during the COVID-19 pandemic. Braya's 2021 budget was $14,985,300 for 247 GWh, and the 2022 budget was adjusted to $4,969,866 for 80 GWh.

- **2021-2022 actual energy sales $CAD for industrial customers increased by 34%.** According to Hydro, this was mainly due to the difference in Load Variation in the

amount of $15,809,289 recorded in 2022 compared to a Load Variation amount of $2,485,599 recorded in 2021. The Load Variation represents the load variance deferred in the Supply Cost Energy Variance Deferral Account ("SCVDA"). Prior to the SCVDA in 2021, the industrial revenue Load Variance was deferred in the rate stabilization plan and recorded in the fuel line.

- **2023 budgeted energy sales ($CAD) for industrial customers increased 28% compared to 2022 budget.** According to Hydro, this was primarily due to an expected increase in Braya operations in 2023 compared to 2022. In 2023, expected revenue from Braya was $7,352,675 compared to $4,969,866 in 2022. Also embedded within the 2023 budget is a load variation amount of $6,785,306 whereas the 2022 budget for load variation was included under other expense (income) due to a reclassification of the Load Variation deferred in the SCVDA to revenue. Prior to November 2021, the actual industrial customer revenue load variance was recorded in the fuel expense line on the income statement.

Exports and other

Exports and other includes revenue from the following sources:

- Muskrat Falls Power Purchase Agreement Monetization
- Hydraulic Optimization (Ponding/Spill Avoidance)
- Incremental Recapture Exports
- Emergency Energy – NLSO

The table below details the revenue by source in both ($000s) and GWH for 2019, 2019 Test Year, budget 2020-2023, and actual 2019-2023.

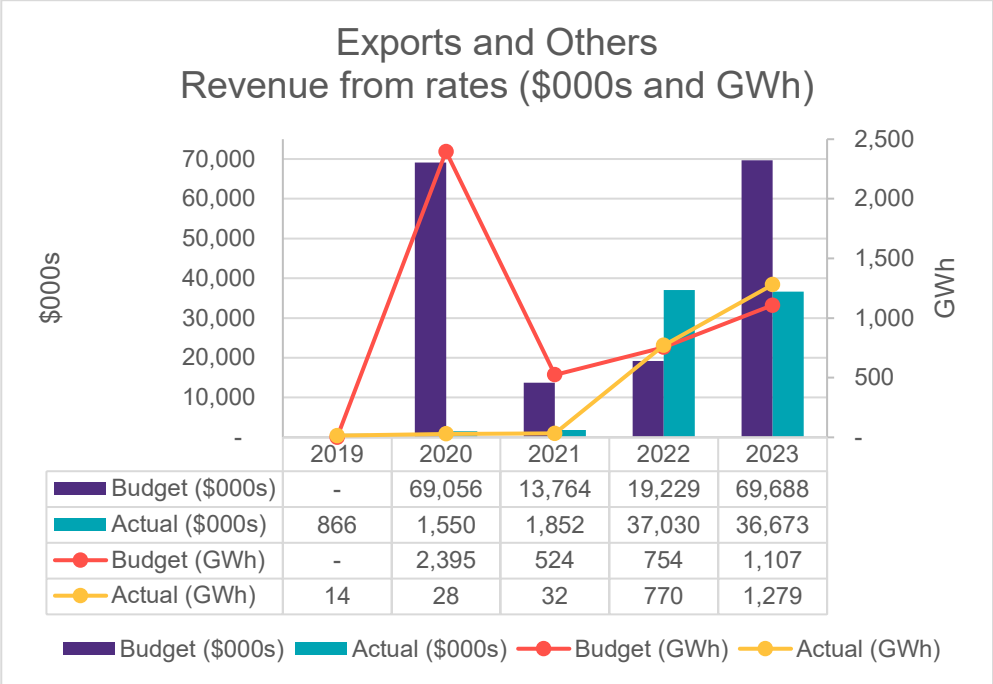
Figure 11 – Revenue from rates – Exports and other by source

	2019	2020	2021	2022	2023
(000s)					
Budget revenue ($)					
MF PPA Monetization	$ -	$69,056	$13,764	$19,229	$35,010
Incremental Recapture Exports [1]	-	-	-	-	34,678
Total budget revenue ($)	**$ -**	**$69,056**	**$13,764**	**$19,229**	**$69,688**
Actual revenue ($)					
MF PPA Monetization	$ -	$ -	$ -	$ -	$25,407
Hydraulic Optimization (Ponding/Spill Avoidance)	866	1,528	1,390	3,224	-
Incremental Recapture Exports [1]	-	-	-	32,299	10,909
Emergency Energy - NLSO	-	22	463	1,507	356
Total actual revenue ($)	**$ 866**	**$ 1,550**	**$ 1,852**	**$37,030**	**$36,673**
(GWh)					
Budget revenue (GWh)					
MF PPA Monetization	-	2,395	524	754	430
Incremental Recapture Exports [1]	-	-	-	-	677
Total budget revenue (GWh)	**-**	**2,395**	**524**	**754**	**1,107**
Actual revenue (GWh)					
MF PPA Monetization	**-**	**-**	**-**	**-**	760
Hydraulic Optimization (Ponding/Spill Avoidance)	14	27	30	29	-
Incremental Recapture Exports [1]	-	-	-	735	518
Emergency Energy - NLSO	-	1	2	6	1
Total actual revenue (GWh)	**14**	**28**	**32**	**770**	**1,279**

Note 1: Incremental Recapture Exports Revenue relates to the sale of incremental recapture to NEM. Incremental Recapture energy is created through Hydro's use of Muskrat Falls energy to serve Labrador customers and it is important to note that this revenue is largely offset by a power purchase of energy from Muskrat Falls. The purpose of these transactions is to optimize the available energy for export.

The table below details revenue in both ($000s) and GWH for 2019, 2019 Test Year, budget 2020-2023, and actual 2019-2023.

Figure 12 – Revenue from rates – Exports and other



	2019	2020	2021	2022	2023
Budget ($000s)	-	69,056	13,764	19,229	69,688
Actual ($000s)	866	1,550	1,852	37,030	36,673
Budget (GWh)	-	2,395	524	754	1,107
Actual (GWh)	14	28	32	770	1,279

Over the period, revenue from exports and others fluctuated significantly from a low of $866,000 in 2019 to a high of $37,030,000 in 2022. Revenue in GWh also fluctuated significantly from 14 GWh in 2019 to 1,279 GWh in 2023. Based on the chart above, we identified the following significant variances:

- **Budgeted revenue in ($) and GWh is $nil and 0 in 2019.** According to Hydro, in 2019, no exports were budgeted because the Muskrat Falls Hydroelectric Generating Station and the Labrador-Island Link were not yet confirmed to be operational at the time the budget was prepared.

- **Actual revenue (GWh) has fluctuated significantly over the past five years.** According to Hydro, the fluctuations are primarily due to the Power Purchase Agreement ("PPA") between Muskrat Falls and Hydro 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, was serviced with energy from the Muskrat Falls Hydroelectric Generating Facility. Entering into this agreement allowed additional Recapture Energy exports to external markets helping to ensure maximum value from the organization's hydrological resources. The amount of energy utilized in Labrador is dependent on availability. The significant increases in actual revenue in ($) and GWh from 2021-2022 are a result of Hydro generating incremental recapture exports starting in 2022, and Muskrat Falls PPA Monetization in 2023. It should be noted that revenues and expenses associated with Muskrat Falls PPA Monetization and Incremental Recapture Export Sales are included in the Supply Cost Variance Deferral

Account. As well, revenue and expenses from Hydraulic Optimization are included in the Hydraulic Resources Optimization Deferral Account.

Conclusion and recommendation

We have completed our procedures on Hydro's revenue from rates, including GWh, for 2022 and 2023 actual results to prior years, 2019 Test Year and the 2022 and 2023 Plans, and have not noted any issues in our analysis.

4. Power purchased

Scope

Conduct an analysis of power purchase expense, including GWhs. Compare the 2022 and 2023 actual results to prior years, 2019 Test Year and the 2022 and 2023 Plans, and follow up on significant variances.

Procedures

Our review of power purchased included the following specific procedures:

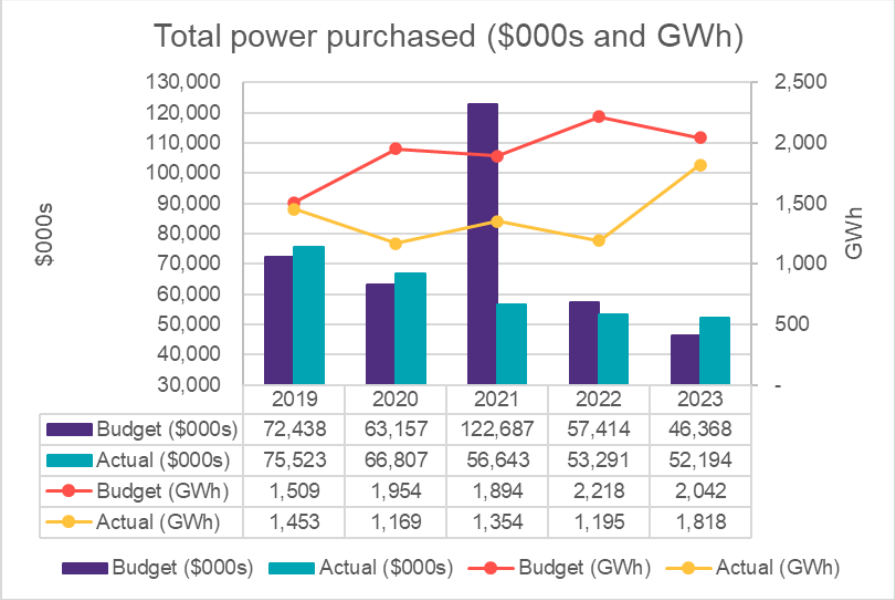
- Compiled power purchased in both $ and GWh for 2019 Test Year, 2020-2023 budget, and 2019-2023 actuals.
- Conducted a trend analysis on both budget and actual power purchase expense in both $ and GWh.
- Identified significant variances and inquired with Hydro to understand the nature of the variance.

Analysis

Total power purchased

The following chart illustrates the total power purchased in both $CAD and GWh for 2019 Test Year, 2020-2023 budget, and 2019-2023 actuals.

Figure 13 – Total power purchased



A breakdown of total power purchased by category is detailed in the figures below.

Figure 14 – Power purchased by account ($)

(000s)	2019TY	2019A	2020B	2020A	2021B	2021A	2022B	2022A	2023B	2023A
Rattle Brook	$ 1,263	$ 1,244	$ 1,247	$ 1,166	$ 1,259	$ 1,283	$ 1,282	$ 1,361	$ 916	$ 1,575
CBPP Co-generation	12,534	10,429	11,452	9,543	10,914	9,488	10,914	8,738	37	7,264
St. Lawrence Wind	7,567	6,810	7,206	7,714	7,228	7,382	7,328	7,257	7,397	7,482
Fermeuse Wind	6,514	7,056	7,422	6,161	7,438	6,715	7,533	6,837	7,724	5,860
New World Dairies	-	405	459	297	458	388	59	426	-	240
Subtotal NUGs	27,878	25,944	27,786	24,881	27,297	25,256	27,116	24,619	16,074	22,421
CBPP Secondary	-	1,605	-	2,119	-	343	-	-	-	-
CBPP Capacity Assistance	-	1,323	-	-	-	-	-	-	-	-
Hydro Request for Newfoundland Power Standby [1]	-	-	-	-	-	-	-	-	-	-
Nalcor Energy [2]	30,270	27,987	30,210	28,034	30,276	28,518	30,278	28,671	30,266	29,773
Labrador Island Link [3]	797	557	744	-	64,471	231	20	-	28	-
Maritime Link Imports	13,493	18,107	4,417	11,773	643	2,295	-	1	-	-
Subtotal Secondary and Other	44,560	49,579	35,371	41,926	95,390	31,387	30,298	28,672	30,294	29,773
Subtotal Power Purchases Island Interconnected System (per figure above)	**$ 72,438**	**$ 75,523**	**$ 63,157**	**$ 66,807**	**$ 122,687**	**$ 56,643**	**$ 57,414**	**$ 53,291**	**$ 46,368**	**$ 52,194**
Total Other Power Purchases [4]	9,224	8,015	9,977	7,882	9,305	8,884	9,197	11,424	8,419	9448
Total Regulated Power Purchase Expense	**$ 81,662**	**$ 83,538**	**$ 73,134**	**$ 74,689**	**$ 131,992**	**$ 65,527**	**$ 66,611**	**$ 64,715**	**$ 54,787**	**$ 61,642**

Note 1: Hydro Request for Newfoundland Power Standby pertains to requests made to Newfoundland Power to run their gas turbine units. There were no payments during these years.

Note 2: Nalcor Energy includes Star Lake and Exploits generation.

Note 3: Labrador Island Link Imports include expenses related to the Lower Churchill assets net of deferrals. These assets supply energy to Hydro for customer use, to fulfill commitments under the Nova Scotia Block, and provide surplus energy for export market sales.

Note 4: Other Power Purchases relate to power purchase costs that are not specifically related to GWh and do not have associated energy. This includes costs for isolated systems, wheeling costs, costs for exports that are deferred in the SCVDA, TFA payments that are deferred in the SCVDA or the Power Purchase Expense Recognition Deferral, ponding purchases which are deferred in the Hydraulic Resources Optimization Deferral, capacity assistance charges, and power purchases for customers in Labrador.

Figure 15 – Power purchased by account (GWh)

(GWh)	2019TY	2019A	2020B	2020A	2021B	2021A	2022B	2022A	2023B	2023A
Rattle Brook	15	14	15	13	15	14	14	15	10	17
CBPP Co-generation	67	55	61	50	58	50	58	46	0	51
St. Lawrence Wind	105	94	100	98	99	101	99	98	99	100
Fermeuse Wind	84	88	97	78	96	85	96	86	96	73
New World Dairies	-	3	3	2	3	3	3	3	-	2
Subtotal NUGs	271	254	274	242	271	254	270	249	206	242
CBPP Secondary	-	41	-	46	-	25	-	41	-	33
CBPP Capacity Assistance	-	15	-	-	-	1	-	-	-	-
Hydro Request for Newfoundland Power	-	-	-	-	-	-	-	-	-	-
Nalcor Energy	757	700	755	701	757	713	757	717	757	745
Labrador Island Link	341	198	879	(11)	857	350	1,191	187	1,079	797
Maritime Link Imports	141	245	46	192	10	12	-	2	-	-
Subtotal Secondary and Other	1,238	1,199	1,680	928	1,624	1,100	1,947	946	1,836	1,575
Total	**1,509**	**1,453**	**1,954**	**1,169**	**1,894**	**1,354**	**2,218**	**1,195**	**2,042**	**1,818**

Please note that contract costs paid by Hydro to the Muskrat Falls project entities reflect full plant cost recovery, while energy reported in GWh in the above table reflects the deliveries needed for Hydro's customers on the Island Interconnected system only. As such, calculating these costs on a per-GWh basis would not yield an accurate comparison.

During the course of our review, we conducted a trend analysis on Hydro's power purchased expense. Our findings on identified significant variances are detailed throughout the remainder of this report section.

Outliers identified in $ and GWh reporting

In completing our analysis, we identified outliers in the $ and GWh reporting data provided by Hydro. Our observations and explanations provided by Hydro are detailed below.

Figure 16 – Power purchases – Outliers in reporting

(000s)	2019TY	2019A	2020B	2020A	2021B	2021A	2022B	2022A	2023B	2023A	Notes
CBPP Secondary ($)	$ -	$ 1,605	$ -	$ 2,119	$ -	$ 343	$ -	$ -	$ -	$ -	1
CBPP Secondary (GWh)	-	41	-	46	-	25	-	41	-	33	1
CBPP Capacity Assistance ($)	$ -	$ 1,323	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	2
CBPP Capacity Assistance (GWh)	-	15	-	-	-	1	-	-	-	-	2
Labrador Island Link ($)	$ 797	$ 557	$ 744	$ -	$ 64,471	$ 231	$ 20	$ -	$ 28	$ -	3
Labrador Island Link (GWh)	341	198	879	(11)	857	350	1,191	187	1,079	797	3

Note 1: Power Purchases from CBPP Secondary were reported in GWh in 2022A and 2023A, however, no corresponding dollar values were reported. Per Hydro, under their secondary energy framework with CBPP, secondary energy is only purchased and paid for if it is demonstrated to be "used and useful,". Specifically, if it offsets Holyrood generation and does not contribute to spill. Where there is spill risk or uncertainty that the energy displaced Holyrood TGS, Hydro does not purchase the energy and no payment is made. In 2022 and 2023, although secondary energy was delivered (41 GWh and 33 GWh respectively), Hydro determined that the energy did not meet the used-and-useful test and therefore was not purchased. As a result, no costs were incurred, and no expense was recorded for CBPP Secondary in those years.

Note 2: Power purchases from CBPP for Capacity Assistance were reported as $nil in all years other than 2019A. Per Hydro, under the Capacity Assistance Agreement with CBPP, Hydro makes fixed monthly payments to secure the availability of capacity, independent of dispatch. The fixed payment includes a defined number of capacity assistance calls and hours of energy delivery each year, with no additional cost. Incremental energy payments are only incurred if usage exceeds those included thresholds.

Note 3: Power purchases from the Labrador Island Link were reported in GWh in 2022A and 2023A, however, no corresponding dollar values were reported. Per Hydro, the corresponding costs associated with LIL relate to the MF PPA and as such were deferred in the SCVDA.

Capacity assistance

Certain power purchase costs, such as capacity assistance charges, are not tied to the delivery of energy and therefore do not have associated GWh. These charges represent payments for capacity availability, rather than consumption. The following capacity assistance costs were reported within "Total Other Power Purchases" in Figure 14.

Figure 17 – Power purchases – Capacity assistance

(000s)	2019TY	2019A	2020B	2020A	2021B	2021A	2022B	2022A	2023B	2023A
Capacity Assistance CBPP	$ 2,993	$ 2,793	$ 2,993	$ 2,900	$ 2,993	$ 3,416	$ 2,993	$ 2,565	$ 1,995	$ 2,898
Capacity Assistance Vale	381	433	213	213	213	160	-	211	-	-
Capacity Assistance Praxair	-	-	-	45	-	109	-	17	-	-
Total	**3,373**	**3,226**	**3,205**	**3,158**	**3,205**	**3,685**	**2,993**	**2,793**	**1,995**	**2,898**

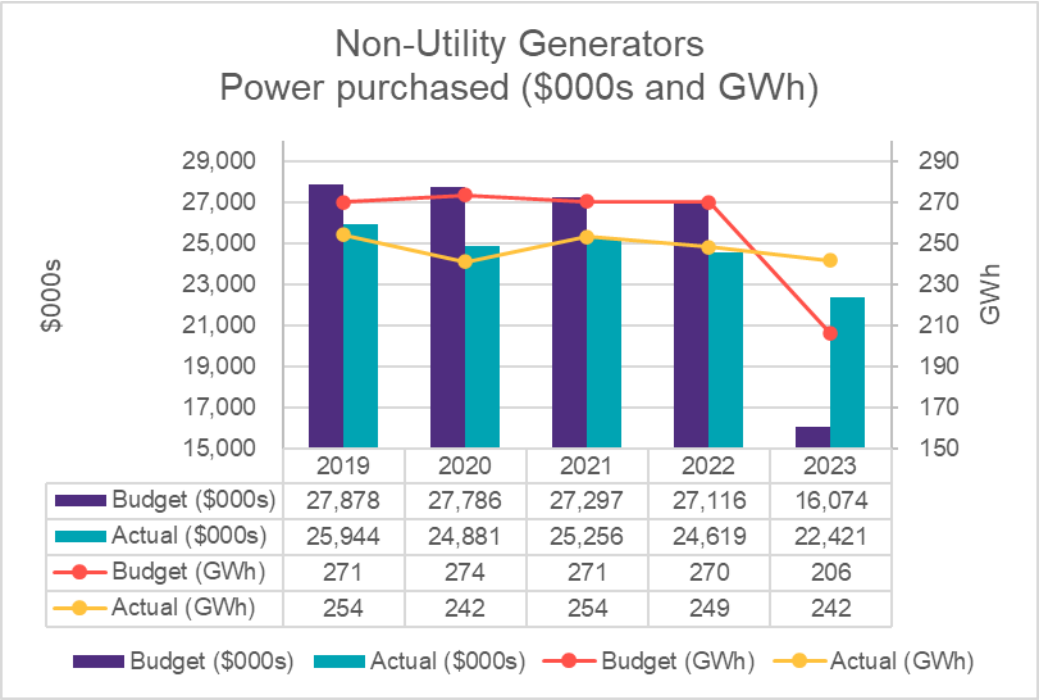
Budgeting methodology

According to Hydro, their budget for the generation necessary for the Island Interconnected System is based upon an annual production plan. This plan forecasts the usage of each of Hydro's available generation sources throughout the year and reflects the effective management and dispatch of generation resources. This plan is then used for budgetary purposes, including the budget for purchased power requirements. Power purchases from non-utility generators and Secondary and Other are budgeted based on commercial and operational requirements and are a key component of the operation of the Island Interconnected System that is balanced with the load requirements and optimization of generation sources.

Non-Utility Generators ("NUGs")

The chart below illustrates the NUGs power purchased in both $CAD and GWh for 2019 Test Year, 2020-2023 budget, and 2019-2023 actuals.

Figure 18 – NUGs power purchased



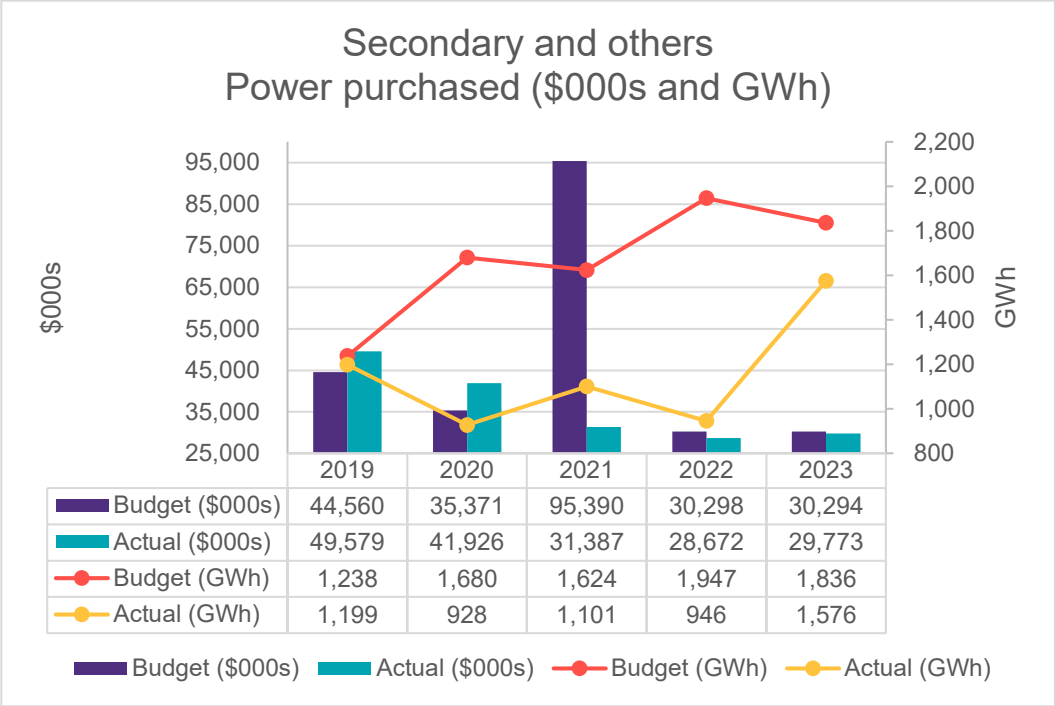
Based on the chart above, we identified the following variance:

- **2023 budgeted NUG power purchased is notably lower than the actual results (in both $ and GWh) which was largely driven by the lower budget for Corner Brook Pulp and Paper ("CBPP") Co-generation. The budget (in both $ and GWh) for CBPP Co-generation was lower in 2023 while the actual results remained relatively consistent with prior years**. Per Hydro, the budget for CBPP Co-generation was lower than actual results in 2023, as the contract was set to expire on January 1, 2023, and it was assumed it wouldn't be subsequently renewed. However, subsequent to the preparation of the budget, Hydro received direction from the Government of Newfoundland and Labrador to extend the Cogeneration Power Purchase Agreement. Additionally, there were no power purchases expected for New World Diaries in 2023. At the time the production plan was compiled for the 2023 budget, the power purchase agreement was set to expire, and it was assumed it wouldn't be renewed; however, it was subsequently renewed after the budget was prepared.

Secondary and others

The chart below illustrates the secondary and others power purchased in both $CAD and GWh for 2019 Test Year, 2020-2023 budget, and 2019-2023 actuals.

Figure 19 – Secondary and others power purchased



	2019	2020	2021	2022	2023
Budget ($000s)	44,560	35,371	95,390	30,298	30,294
Actual ($000s)	49,579	41,926	31,387	28,672	29,773
Budget (GWh)	1,238	1,680	1,624	1,947	1,836
Actual (GWh)	1,199	928	1,101	946	1,576

Based on the chart above, we identified the following variance:

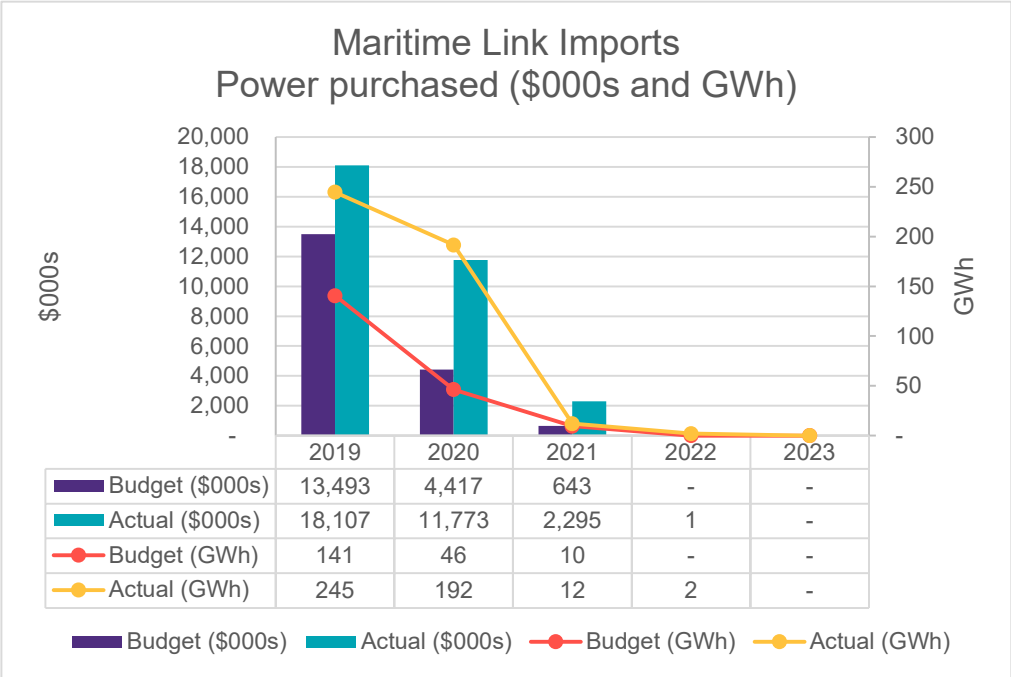
- **Actual purchases (in GWh) were notably lower than the annual budgets in 2020-2023.** Per Hydro, actual purchases (in GWh) of Secondary and Other were lower than the annual budgets from 2020-2023 as a result of budget assumptions around the commissioning date of the Muskrat Falls project. The budgets for 2020-2023 assumed the assets were commissioned at various levels; however, these assumptions did not come through in actuals. Although some deliveries of Muskrat Falls energy to the island occurred in 2021 through 2023, it was not at the level of that assumed in the budget.

Maritime Link Imports

In our review of secondary and other power purchased, we noted fluctuations specifically for Maritime Link Imports which led to further analysis of this category, as detailed below.

The chart below illustrates the Maritime Link Imports in both $CAD and GWh for 2019 Test Year, 2020-2023 budget, and 2019-2023 actuals.

Figure 20 – Maritime Link Imports power purchased



	2019	2020	2021	2022	2023
Budget ($000s)	13,493	4,417	643	-	-
Actual ($000s)	18,107	11,773	2,295	1	-
Budget (GWh)	141	46	10	-	-
Actual (GWh)	245	192	12	2	-

Based on the chart above, we identified the following variance:

- **Power purchases from Maritime Link Imports declined in 2021.** Per Hydro**,** the Muskrat Falls plant was fully commissioned in late November 2021, and the LIL was fully commissioned on April 14, 2023. The LIL was intermittently available in the interim period prior to its full commissioning in April 2023.Power purchases over the Maritime

Link declined in 2021 as a result of transmission constraints and a lack of surplus capacity in neighbouring jurisdictions.

Conclusion and recommendation

We have completed our analysis of Hydro's power purchase expense (including GWhs) and compared the 2022 and 2023 actual results to prior years, 2019 Test Year and the 2022 and 2023 Plans. Our analysis identified notable trends and budget variances, and we made subsequent inquiries with Hydro for further clarification. We found that actual power purchases from "Secondary and other" sources fluctuated significantly from budgets from 2020-2023. Based on correspondence with Hydro, we understand that this is a result of budget assumptions around the commissioning date of the Muskrat Falls project in which budgets assumed assets were commissioned at various levels which were not achieved. We did not identify any issues in our overall analysis.

5. Operations and administration expenses (excluding labour costs)

Scope

Conduct a review of operations and administration expenses, fuels, power purchased, depreciation and interest for 2022 and 2023 in relation to sales of power and energy. Include an analytical review reporting on trends, including comparison with prior years, the 2019 Test Year and the 2022 and 2023 Plans, and follow up on significant variances. The examination of the foregoing will include, but is not limited to, the following:

a) salaries and benefits
b) system equipment maintenance
c) insurance (including director's liability)
d) transportation
e) building rental and maintenance
f) professional services
g) vegetation management
h) training
i) travel
j) software expenditures
k) miscellaneous
l) capitalized expenses
m) intercompany charges
n) membership fees
o) fuels
p) depreciation
q) interest
r) office supplies and expenses
s) bad debts

Procedures

Our review of operations and administration expenses included the following specific procedures:

- Summarized expenses by category above including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets. In compiling our data, we reconciled expense amounts to Hydro's quarterly reports and annual returns and verified cost category totals with Hydro. We note that while the terms of reference noted in the scope above include power purchases and salaries and benefits, our findings on these categories can be found in **Section 4** and **Section 6**, respectively.

- Performed a 5-year trend analysis on the costs considering both year-over-year trends in actual costs as well as annual budgets vs actual annual results. For cost categories with significant variances, we completed the following procedures:

    - Reviewed Hydro's Annual Return 9a to obtain explanations provided by Hydro for notable variances.

    - Requested and reviewed additional detailed explanations from Hydro.

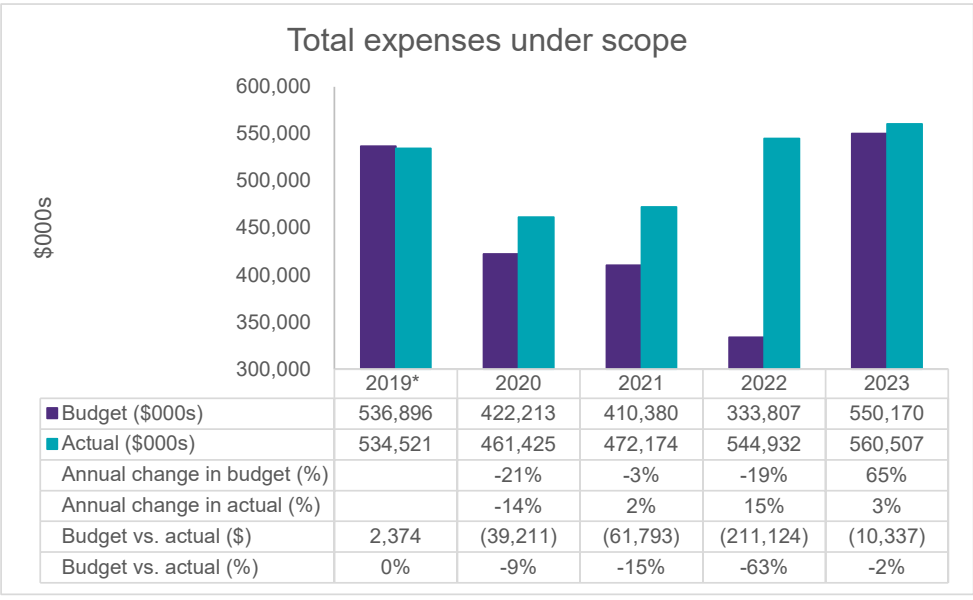
    - Requested and reviewed Hydro's budgeting methodologies and cost mitigation strategies.

    - Assessed the reasonableness of Hydro's explanations provided.

Analysis

The following table outlines the total expenses under the scope of our review for 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 21 – Total expenses under scope



	2019*	2020	2021	2022	2023
Budget ($000s)	536,896	422,213	410,380	333,807	550,170
Actual ($000s)	534,521	461,425	472,174	544,932	560,507
Annual change in budget (%)		-21%	-3%	-19%	65%
Annual change in actual (%)		-14%	2%	15%	3%
Budget vs. actual ($)	2,374	(39,211)	(61,793)	(211,124)	(10,337)
Budget vs. actual (%)	0%	-9%	-15%	-63%	-2%

**2019 budget as depicted in the various charts in this section of our report refers to 2019 Test Year.*

A breakdown of the total costs by key cost category is detailed in the figure below.

Figure 22 – Total costs by category

(000s)	2019TY	2019A	2020B	2020A	2021B	2021A	2022B	2022A	2023B	2023A
O&M costs under scope of review										
Salaries and benefits [1]	111,576	115,744	111,287	112,277	108,944	109,631	107,774	110,935	112,980	114,031
System equipment maintenance	26,796	22,883	23,935	20,491	23,565	21,819	21,055	22,299	22,920	30,060
Insurance including director's liability insurance	3,425	3,507	3,574	3,785	4,639	4,412	5,603	4,703	5,112	4,973
Transportation [2]	3,361	3,087	3,441	3,059	2,936	3,644	3,435	4,215	3,670	4,019
Building rental and maintenance	1,100	979	952	911	951	932	973	972	1,008	1,053
Professional services	7,620	6,062	8,196	5,836	7,595	5,865	6,852	6,389	8,420	7,820
Training	716	567	650	219	650	467	500	521	501	453
Travel	2,759	2,404	2,414	1,500	2,374	1,591	1,972	2,037	2,031	2,836
Software expenditures	1,205	1,360	1,561	1,495	1,756	1,696	1,779	1,889	2,035	2,222
Miscellaneous	5,152	4,466	4,942	4,376	4,930	4,687	4,585	4,514	4,734	4,765
Membership fees	399	383	405	431	409	428	441	492	476	431
Office supplies and expenses	2,121	1,860	1,871	1,857	2,169	1,654	1,973	1,822	1,991	1,794
Bad debts	118	391	118	2,908	118	(703)	177	(511)	(636)	2,137
Capital labour and overtime[1]	(26,072)	(31,156)	(28,649)	(27,835)	(28,635)	(30,631)	(29,702)	(28,497)	(30,886)	(30,812)
Capital fleet [2]	(2,087)	(1,727)	(1,869)	(1,844)	(1,661)	(1,781)	(1,814)	(1,857)	(1,814)	(1,573)
Total O&M costs under scope of review	$ 138,189	$ 130,810	$ 132,828	$ 129,466	$ 130,740	$ 123,711	$ 125,603	$ 129,923	$ 132,542	$ 144,209
Vegetation management [3]	2,962	3,260	3,126	3,345	3,215	3,288	3,172	3,546	3,090	3,064
Non O&M costs under scope of review										
Fuels	219,857	223,928	107,100	159,932	100,094	171,857	30,927	242,958	244,857	245,088
Depreciaton	85,429	87,569	88,314	84,403	84,814	88,548	88,449	85,611	87,597	88,067
Interest	93,421	92,214	93,971	87,624	94,732	88,058	88,828	86,440	85,174	83,143
Total Non O&M costs under scope of review	$ 398,707	$ 403,711	$ 289,385	$ 331,959	$ 279,640	$ 348,463	$ 208,204	$ 415,009	$ 417,628	$ 416,298
Total costs under scope of review	**$ 536,896**	**$ 534,521**	**$ 422,213**	**$ 461,425**	**$ 410,380**	**$ 472,174**	**$ 333,807**	**$ 544,932**	**$ 550,170**	**$ 560,507**

Note 1: Salaries and benefits are inclusive of capitalized salaries and overtime.

Note 2: Transportation is inclusive of capital fleet.

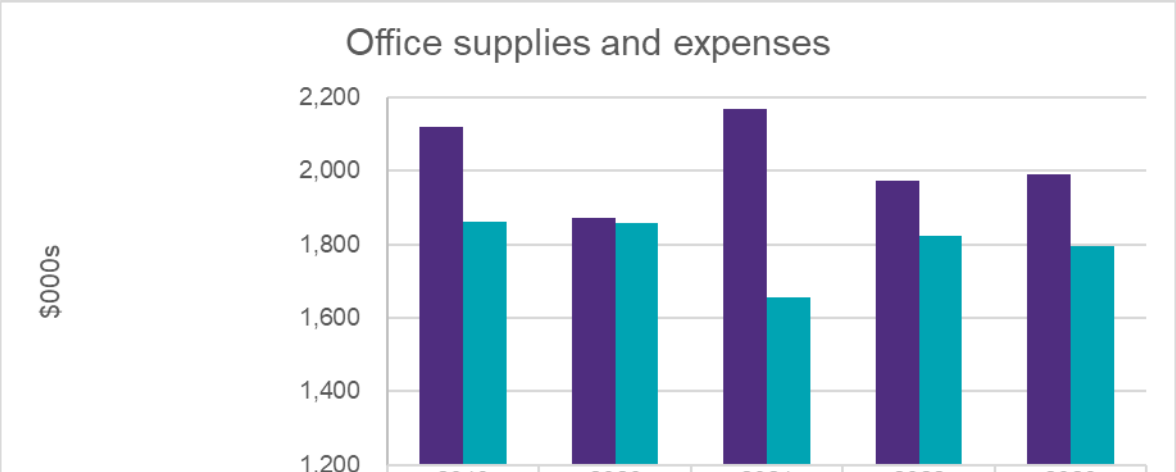
Note 3: Vegetation management consists of expenses across various cost categories including salaries and benefits, overtime, employee expenses, travel, materials, and internal equipment.

During the course of our review, we verified the totals per cost category with Hydro and conducted a trend analysis. Our findings on significant variances by cost category are detailed throughout this section of our report.

Office supplies and expenses

The following chart details the 5-year trends for office supplies and expenses including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 23 – Office supplies and expenses



	2019	2020	2021	2022	2023
Budget ($000s)	2,121	1,871	2,169	1,973	1,991
Actual ($000s)	1,860	1,857	1,654	1,822	1,794
Annual change in budget (%)		-12%	16%	-9%	1%
Annual change in actual (%)		0%	-11%	10%	-2%
Budget vs. actual ($)	261	14	515	151	197
Budget vs. actual (%)	12%	1%	24%	8%	10%

Historically, Hydro applied a zero-based budgeting approach, where each department assessed its operational needs annually and budgeted accordingly. This method was used for all office supply categories from 2019 to 2023, including heat and light, telecommunications, postage, advertising, books and subscriptions, and memberships and dues. While not under the scope of this review, Hydro noted that in the 2025 budget it introduced a revised methodology for several categories—such as cell phone, telephone and fax, postage, advertising, and books and subscriptions—by using a three-year historical average (2022–2024) adjusted by the GDP deflator to better align with actual expenditures. Heat and light, along with memberships and dues, continue to follow the zero-based budgeting model.

Based on the chart above, we identified the following significant variance:

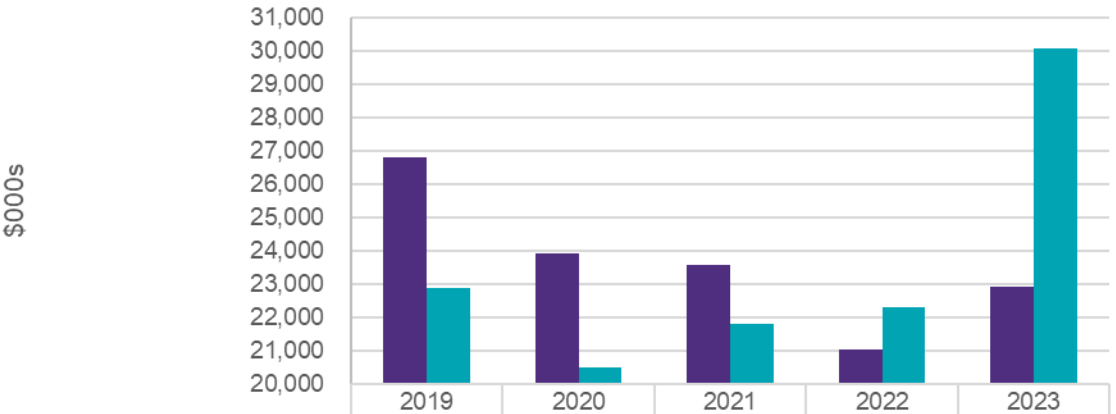
- **2021 actual office supply expenses were 24% lower than budget.** Per Hydro, this is primarily due to reduced electricity usage during the COVID-19 pandemic, as well as lower telecommunications and advertising costs. Although some cost reductions were reflected in subsequent budgets, an increase in heat and light expenses—particularly due to service upgrades at the Holyrood facility—led to higher electricity costs from 2022 onward. Hydro noted that it is committed to budgeting based on operational

requirements and adjusts its approach as needed to reflect evolving cost drivers and organizational needs.

System equipment maintenance

The following chart details the 5-year trends for system equipment and maintenance expenses including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 24 – System equipment maintenance



	2019	2020	2021	2022	2023
Budget ($000s)	26,796	23,935	23,565	21,055	22,920
Actual ($000s)	22,883	20,491	21,819	22,299	30,060
Annual change in budget (%)		-11%	-2%	-11%	9%
Annual change in actual (%)		-10%	6%	2%	35%
Budget vs. actual ($)	3,913	3,444	1,746	(1,244)	(7,140)
Budget vs. actual (%)	15%	14%	7%	-6%	-31%

Hydro uses a zero-based budgeting approach for system equipment and maintenance expenses, where each department forecasts its operational needs for the upcoming year and budgets accordingly.

Based on the chart above, we identified the following significant variances:

- **2023 actual system equipment and maintenance expense was 35% higher than 2022 actuals.** Per Hydro, this increase was primarily driven by the following additional costs:
    - Transmission and Rural Operations ("TRO") – The TL1301 transmission line removal project incurred an increase in contract labour of approximately $4.3 million. This project qualifies as a removal cost project and as such the costs associated with this are deferred as part of Hydro's removal deferral provision with no overall impact on total operating costs as they are deferred instead of

expensed in the current period. Per Hydro, the flow of transactions for removal costs in the income statement is to record the cost in their operating account with an off-set in cost recoveries. As such, the amount presented above is the gross cost of the removal project included in system equipment and maintenance and cost recoveries. Hydro also noted that for IFRS external financial statement purposes, the removal costs are then recorded in "Other Expense" and off-set in "Regulatory Adjustment".

- Holyrood facility - Additional costs of approximately $1.2 million were incurred for boiler stack inspections. Two of the three stacks were inspected during 2023, with the other stack completed in 2024. Also, an additional $1.0 million was incurred related to the boiler maintenance contract and higher maintenance costs of approximately $0.2 million were required for Units 1 and 3. The Indian Pond dredging project also resulted in additional costs of $0.4 million.

- Hydro Generation – Increased contract labour was required to complete the Penstock weld repairs ($0.1 million), the Upper Salmon structure assessment ($0.1 million); and grader transmission failure repair ($0.1 million). Additionally, increased material costs were incurred due to completion of weld repairs on Bay d'Espoir Unit 2 ($0.2 million).

- **2023 actual system equipment and maintenance expense was 31% higher than budget**. Per Hydro, the nature of this discrepancy is due to cost over runs on the same activities as noted in the explanations above. Specifically:

  - TRO – The TL1301 removal project was not included in a line-by-line basis in the 2023 budget. Prior to 2025, the removal costs relating to the 'other expense' and 'regulatory adjustment line' portion of activity were budgeted but the activity within operating costs was not budgeted as it is considered a flow through in operating costs and didn't impact the total operating cost budget. However, Hydro has noted that in the 2025 budget they have commenced budgeting the full transaction to make it more consistent with the activity that occur on an actual basis.

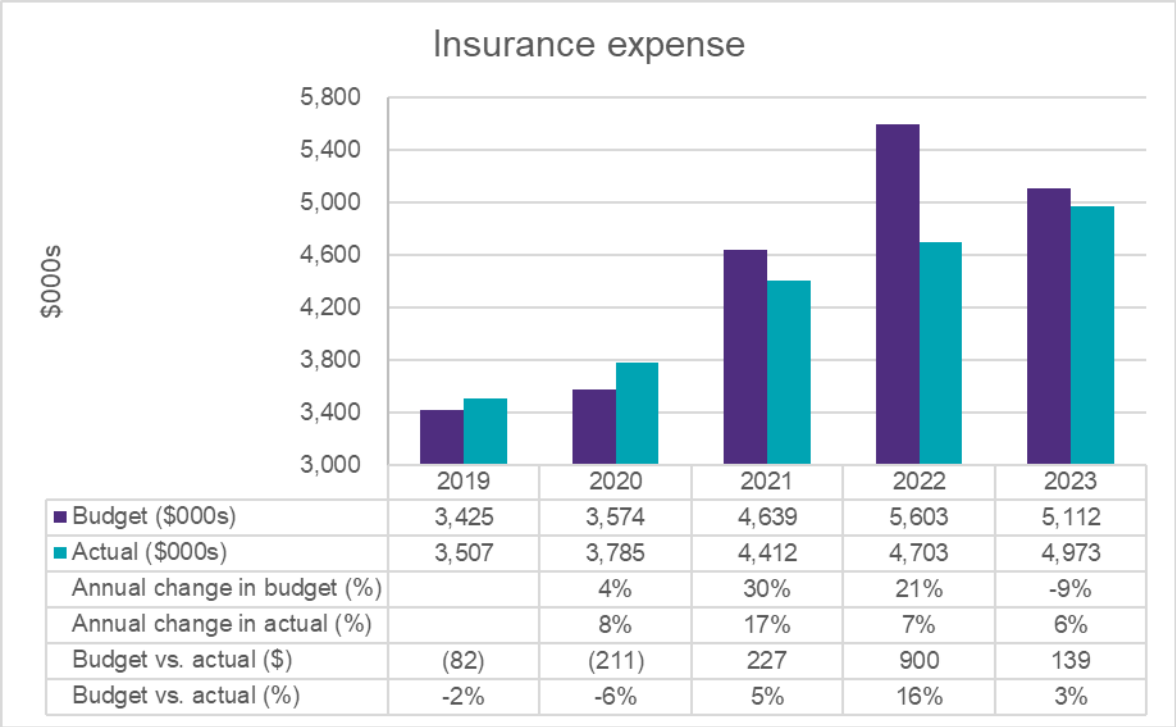
  - Holyrood facility – the costs incurred for boiler stack inspections ($1.2 million), boiler maintenance contract costs ($0.4 million), increased costs for Indian Pond dredging ($0.3million), and additional tanker support requirements ($0.4 million) were incurred that were not included in the 2023 budget.

  - Hydro Generation – Increased contract labour as a result of crown weld repair requirement ($0.2 million) as well as the Upper Salmon Reliability and Resource Adequacy Study completed in 2023 that were not anticipated in the budget ($0.1 million). Additionally, increased materials costs due to weld repairs on Bay d'Espoir Unit 2 ($0.2 million) were not included in the 2023 budget.

Insurance (including director's liability)

The following chart details the 5-year trends for insurance expense (including director's liability) including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 25 – Insurance expense



	2019	2020	2021	2022	2023
Budget ($000s)	3,425	3,574	4,639	5,603	5,112
Actual ($000s)	3,507	3,785	4,412	4,703	4,973
Annual change in budget (%)		4%	30%	21%	-9%
Annual change in actual (%)		8%	17%	7%	6%
Budget vs. actual ($)	(82)	(211)	227	900	139
Budget vs. actual (%)	-2%	-6%	5%	16%	3%

Hydro employs a zero-based budgeting approach for its insurance expenses. Per Hydro, typically, the budget assumes a 3–5% increase, which is adjusted based on market conditions, historical claims, and the addition of new assets. These factors influence the insurable value and premiums. For instance, in 2023, Hydro noted that they incorporated terrorism coverage and an additional $25 million in excess liability coverage due to emerging operational risks and increased litigation costs. These additions are factored into the budget when known during its preparation.

Based on the chart above, we identified the following significant variances:

- **Actual insurance costs have increased over the past five years.** Per Hydro, insurance costs are driven by insurance claims, insurance market conditions, the addition of new assets, increases in replacement value and specific coverages carried. During 2019-2023, the following factors contributed to insurance premiums:
    - Claims—Increased claims including the Charlottetown Diesel Fire and Churchill Falls Transformer Fire.

- Market conditions—The North American insurance market was in a hardening cycle during the 2018–2023 period. During hard markets, insurance premiums rise, coverage is harder to obtain, and insurance limits offered by insurers can be lower. During this time, increases in insurance premiums occurred. Markets started to soften in 2024 and remain soft in 2025. When markets soften, rates go down. During the 2022 insurance renewal, premiums increased by 53% for the same Cyber Liability coverage, Property coverage increased by 12%, Auto coverage increased by 9% and General Liability coverage increased by 7.4% overall.

- Replacement values - Hydro's property insurance prices insurance premiums based on both the insured value of property and the rates offered. Each year, it is typical to see an increase in insured values due to inflationary effects such that even if the rates offered stay stable, the cost of insurance will still rise.

- **2022 budgeted insurance expense was 16% higher than actual results.** Per Hydro, the 2022 budgeted numbers were obtained with input from the insurance broker during a hardening market period and the expectation at the time was that the hardening market was going to continue for the near future. Actuals reflected a changing marketplace where the hardening market had essentially reached its peak and the softening market was starting to take place resulting in lower-than-expected actual insurance rates. The lag between budget timing and insurance renewals can also be noted. Hydro finalizes its budgets each fall, while the insurance renewals take place at the end of June in the following year.

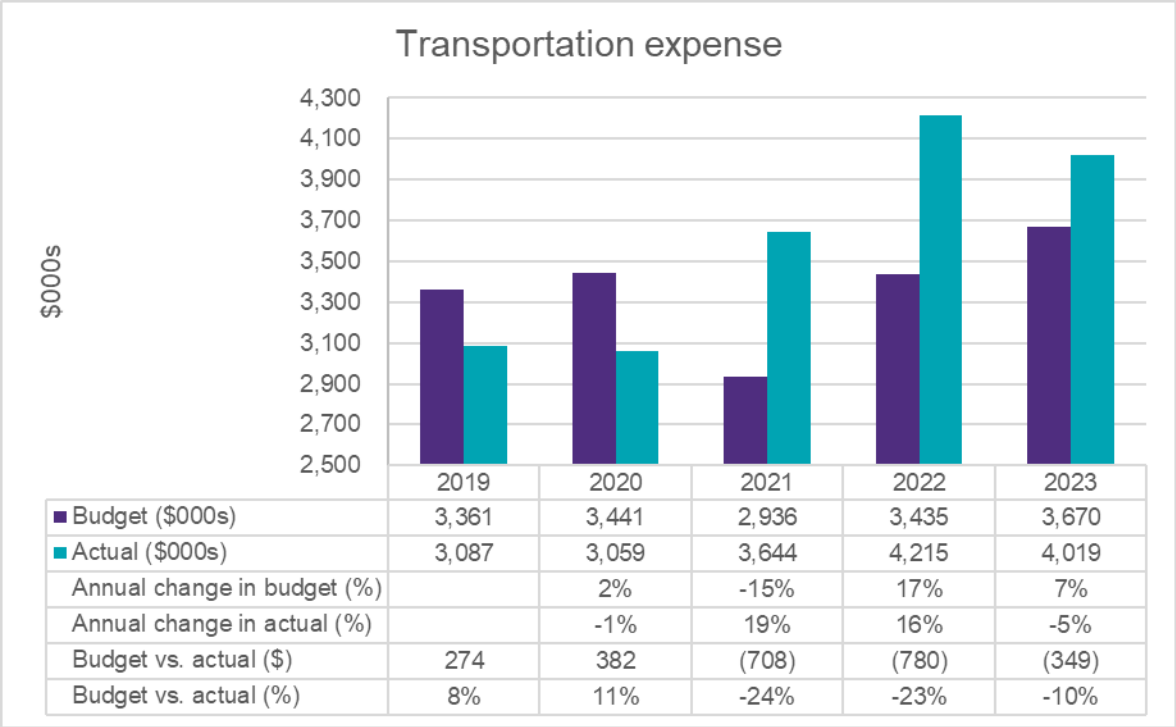
Based on our observations in the above chart, we noted that while 2022 saw a gap between actual and budgeted costs, 2023 results closely aligned with the budget. Per Hydro, there has been no change in their approach to budgeting insurance. In terms of the 2023 budget versus actual expenditures, input from their insurance broker was now showing that the insurance market was entering a softening period as predicted and thus more accurately reflected what was predicted of the changing insurance marketplace.

With regards to cost mitigation strategies, Hydro also noted that it engages in re-marketing efforts each year on specific lines of insurance (i.e., property was re-marketed in 2024). These efforts may result in reductions in rates, changes in insurance companies or changes in the percent of coverage for each insurance company in a syndicate arrangement. Hydro will evaluate the quotes provided by the insurance companies to ensure lowest cost, while also ensuring adequate coverage. In addition to re-marketing activities, Hydro also holds annual renewal meetings with all lines of existing insurance carriers each May. This competitive approach ensures that competitive tensions between Hydro's existing insurance providers (many of their policies are syndicated) are brought to bear each year in an effort to ensure that pricing received is as low as possible. Hydro also assesses its coverage needs each year to ensure that coverages are both sufficient and not excessive.

Transportation

The following chart details the 5-year trends for transportation expense including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets:

Figure 26 – Transportation expense



	2019	2020	2021	2022	2023
Budget ($000s)	3,361	3,441	2,936	3,435	3,670
Actual ($000s)	3,087	3,059	3,644	4,215	4,019
Annual change in budget (%)		2%	-15%	17%	7%
Annual change in actual (%)		-1%	19%	16%	-5%
Budget vs. actual ($)	274	382	(708)	(780)	(349)
Budget vs. actual (%)	8%	11%	-24%	-23%	-10%

Hydro budgets transportation expenses—primarily vehicle and aircraft fuel and service costs—using a zero-based approach. Per Hydro, vehicle fuel costs are estimated based on a three-year historical average of volumes and projected fuel prices using S&P Global Platts indices. Aircraft fuel and service costs are similarly based on historical averages and contractual rates, with anticipated usage factored in. Hydro has noted that in recent years there have been discrepancies in budgeted and actual costs due to fuel price volatility which is amplified by the timing gap between budget preparation and actual expenditures.

Based on the chart above, we identified the following significant variances:

- **2021 budgeted transportation costs were 15% lower than prior years and 24% lower than 2021 actuals.** Per Hydro, the 2021 budget was lower due to anticipated decreases in vehicle fuel and aircraft expense. Specifically, fuel prices were expected to decrease and as well as aircraft hourly rates. However, actual expenses rose significantly in 2021 and 2022 due to higher fuel prices and increased travel for operational requirements in a strategic effort to increase crew efficiency.

- **Actual transportation expense increased by 16% in 2022**. Per Hydro, in 2022 they continued to see increases in actual fuel prices for both vehicles and helicopter fuel compared to 2021.

    - The increase of vehicle fuel was mainly due to an increase in price of $413,000 ($1.52/L for 2021 versus $1.93/L for 2022) and an increase in volume of $72,000 (47,704 L). This increase in fuel consumption was due to more travel for operational requirements largely due to Hydro's strategic effort to travel and bring crews together to execute larger pieces of work efficiently and cost effectively, reducing outage time.

    - The increase in aircraft fuel ($213,000) was also mainly due to price. This was partially offset by a decrease in aircraft usage ($126,000) mainly due to increased usage by non-regulated Hydro which decreased regulated portion of the daily rate expenses (daily standby costs are proportionately allocated based on usage amongst Regulated and Non-Regulated hours flown) as well as a decline of approximately 91 hours due to fewer flights required for trouble shooting and maintenance in Labrador when compared to 2021.

- **2022 actual transportation expenses were 23% higher than budget.** Per Hydro, the increase in 2022 actuals over budget was mainly due to an increase in vehicle fuel due to an increase in price of $558,000 ($1.37/L Budget versus $1.93/L Actual) and an increase in fuel volume of $42,000 (961,985 L Budget versus 992,552 L Actual). The increase in volume is due to operational requirements compared to budget which was based on a three-year historical average volume. There was also an increase in aircraft costs ($194,000) mainly due to increased usage requirements, compared to budget, in Hydro Generation for water management and urgent responses to weather systems and various troubleshooting and transmission line maintenance in the Central region.

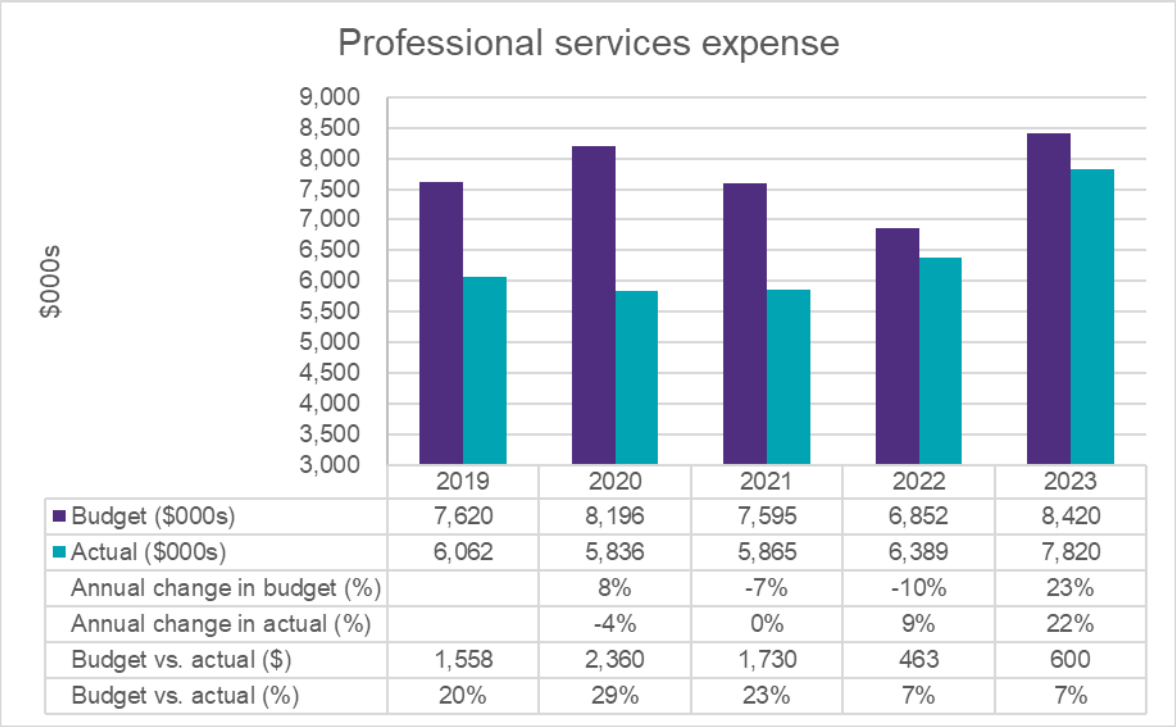
- **Actual transportation expense decreased in 2023.** Per Hydro, transportation decreased in 2023 from 2022 mainly due to a decrease in vehicle fuel due to a decrease in price of $260,000 ($1.69/L in 2023 versus $1.93/L in 2022). The price decrease was partially offset by an increase in fuel volumes of $163,000 (84,148 L). Helicopter expenses also decreased ($77,000) compared to 2022 actuals due to decreased requirements in Hydro Generation for water management and urgent responses to weather systems and various troubleshooting and transmission line maintenance in the Central region.

To mitigate rising costs, Hydro has noted that they employ several strategies: leveraging retailer discounts and purchase card controls, competitively procuring fleet and helicopter services, and implementing monthly helicopter cost reviews. A new Fleet Maintenance Service Provider is also being secured to enhance cost control through better analytics, fraud detection, and billing transparency.

Professional services

The following chart details the 5-year trends for professional services including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 27 – Professional services



	2019	2020	2021	2022	2023
Budget ($000s)	7,620	8,196	7,595	6,852	8,420
Actual ($000s)	6,062	5,836	5,865	6,389	7,820
Annual change in budget (%)		8%	-7%	-10%	23%
Annual change in actual (%)		-4%	0%	9%	22%
Budget vs. actual ($)	1,558	2,360	1,730	463	600
Budget vs. actual (%)	20%	29%	23%	7%	7%

The professional services expenses for Hydro are budgeted using a zero-based approach, where each department assesses its specific needs for the upcoming year and budgets accordingly.

Based on the chart above, we identified the following significant variances:

- **2019 actual professional services costs were 20% lower than 2019 test year.** Per Hydro, this is primarily the result of a decrease in legal and consulting costs due to the following:
    - Lower regulatory professional services primarily due to lower consulting and legal costs associated with the delay in the timing of the next general rate application ("GRA") ($0.6 million).
    - Lower consulting costs resulting from the environmental monitoring for Transmission Line TL267 not being required in 2019 and other reduced requirements for the environmental monitoring and site assessments program ($0.5 million).

- Uncertain future regarding extended operation of Holyrood Thermal Generating Station ("Holyrood TGS") necessitated a delay in several consulting work scopes ($0.4 million).

- **2020 actual professional services were 29% lower than budget.** Per Hydro, the decrease is primarily a result of the decrease in consulting and Board-related costs due to:

  - Reduced program spending costs associated with Customer Demand Management programs due to COVID-19 pandemic protocols ($1.1 million).

  - Uncertain future regarding extended operation of Holyrood TGS necessitated a delay in several work scopes ($0.4 million).

  - Lower Regulatory consulting costs ($0.3 million).

  - Reduced costs for environmental monitoring, site assessments and Environmental Management System audits due to COVID-19 impacts ($0.5 million).

- **2021 actual professional services were 23% lower than budget.** Per Hydro, this decrease is primarily the result of a decrease in consulting and Board-related costs due to the following:

  - Reduced costs for environmental monitoring, site assessments and other environmental costs ($0.7 million).

  - Variance in Regulatory consulting and Board-related costs primarily associated with delay in the next GRA ($0.8 million).

- **2023 actual professional services costs increased by 22% compared to 2022 actuals.** Per Hydro, increases in professional services in 2023 are a result of increases in consulting costs of $1.1 million and higher P.U.B. related costs of $0.3 million related to miscellaneous proceedings.

  - The increase in consulting costs was primarily due to the engagement of contract resources as a result of resource availability of $0.4 million; condition assessment work in Labrador of $0.3 million, and an increase in consulting costs associated with various system planning and regulatory requirements of $0.4 million. Hydro notes that it conducts operations necessary to ensure safe, cost-conscious, reliable electricity and undertakes the necessary studies and activities needed to do so. Hydro also notes that they monitor professional services costs to mitigate costs where possible and uses competitive public procurement processes to minimize costs as well.

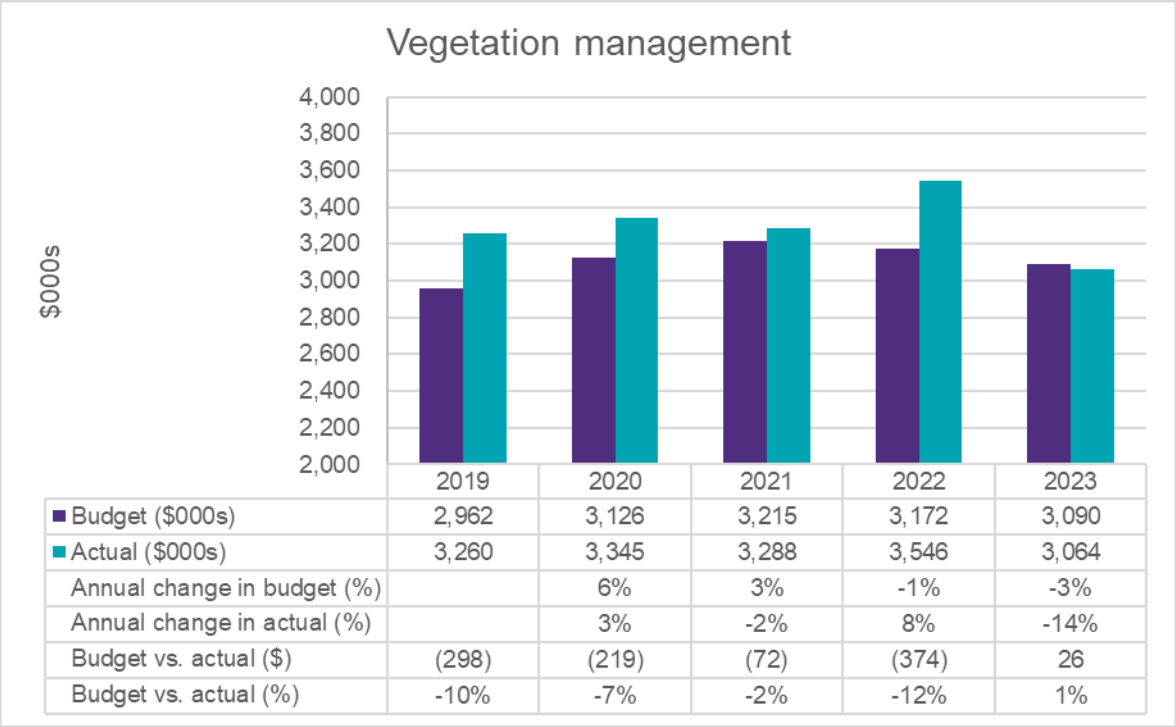
Hydro noted that they continue to plan and budget professional services expenditures at a detailed level based on the best estimate of work requirements and plans at the time the budget

is complied. This approach is aligned with upcoming work activity; however, there can be changes based on the timing of actual work execution. Often, operational decisions are made throughout the year, and priorities may shift, which will create timing variances between budgeted costs versus actual costs incurred.

Vegetation management

The following chart details the 5-year trends for vegetation management including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 28 – Vegetation management



	2019	2020	2021	2022	2023
Budget ($000s)	2,962	3,126	3,215	3,172	3,090
Actual ($000s)	3,260	3,345	3,288	3,546	3,064
Annual change in budget (%)		6%	3%	-1%	-3%
Annual change in actual (%)		3%	-2%	8%	-14%
Budget vs. actual ($)	(298)	(219)	(72)	(374)	26
Budget vs. actual (%)	-10%	-7%	-2%	-12%	1%

Vegetation management expenses are budgeted using a zero-based approach, with costs estimated on a detailed line-item basis aligned with detailed work plans.

Based on the chart above, we identified the following significant variance:

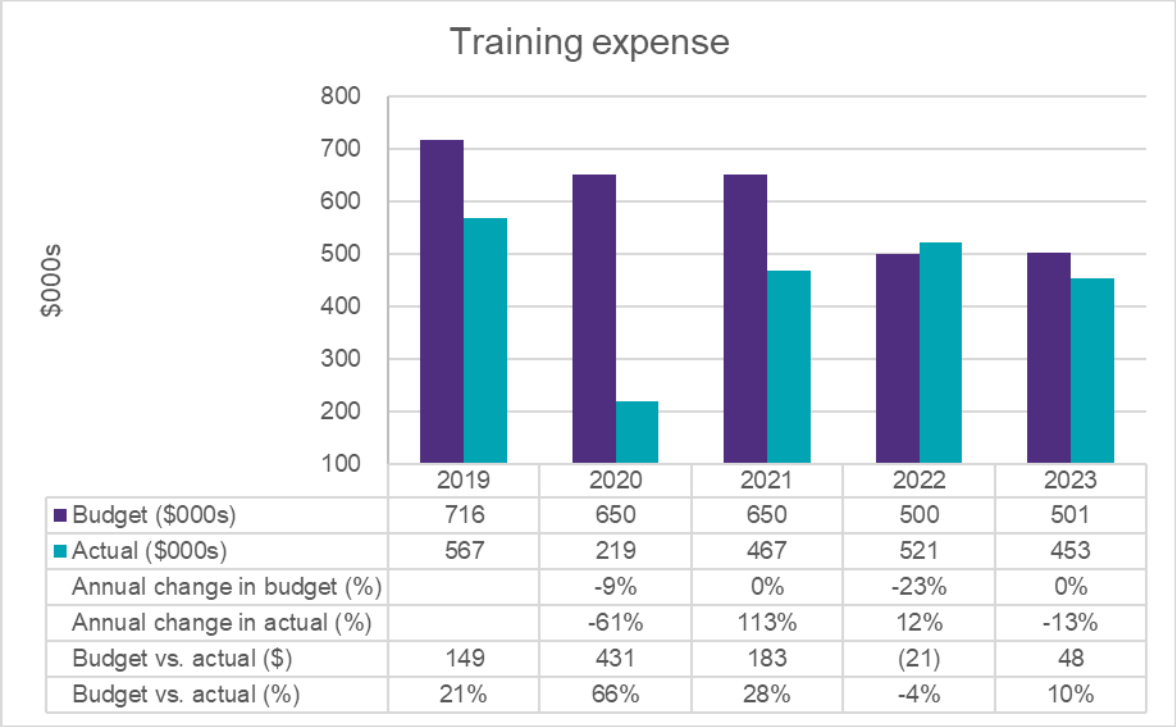
- **2022 actual vegetation management expenses were 12% higher than budget and 2023 actual vegetation management expenses were 14% lower than 2022 actual**. Per Hydro, actuals were higher than budget in 2022 due to an overestimated accrual of $265,000. Hydro noted that this discrepancy was corrected in 2023 when the actual invoice was recorded, resulting in a reversal of the accrual. Consequently, vegetation management expenses decreased in 2023, which per Hydro, reflects the impact of this accounting adjustment. On an overall basis, the average of actual vegetation

management expenses in 2022 and 2023 is relatively consistent with actual vegetation management expense levels in 2019 to 2021.

Training

The following chart details the 5-year trends for training including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 29 – Training expense



	2019	2020	2021	2022	2023
Budget ($000s)	716	650	650	500	501
Actual ($000s)	567	219	467	521	453
Annual change in budget (%)		-9%	0%	-23%	0%
Annual change in actual (%)		-61%	113%	12%	-13%
Budget vs. actual ($)	149	431	183	(21)	48
Budget vs. actual (%)	21%	66%	28%	-4%	10%

Hydro employs a zero-based, centralized budgeting methodology for training expenses. According to Hydro, the Training and Development team collaborates with functional leaders annually to identify training needs, which are then reviewed through an organizational priority lens before finalizing the budget. Since a corporate reorganization in 2021, Hydro has focused on right-sizing its training budget, prioritizing mandatory safety and legislative training, as well as addressing skill gaps due to employee turnover or new asset installations.

Based on the chart above, we identified the following significant variance:

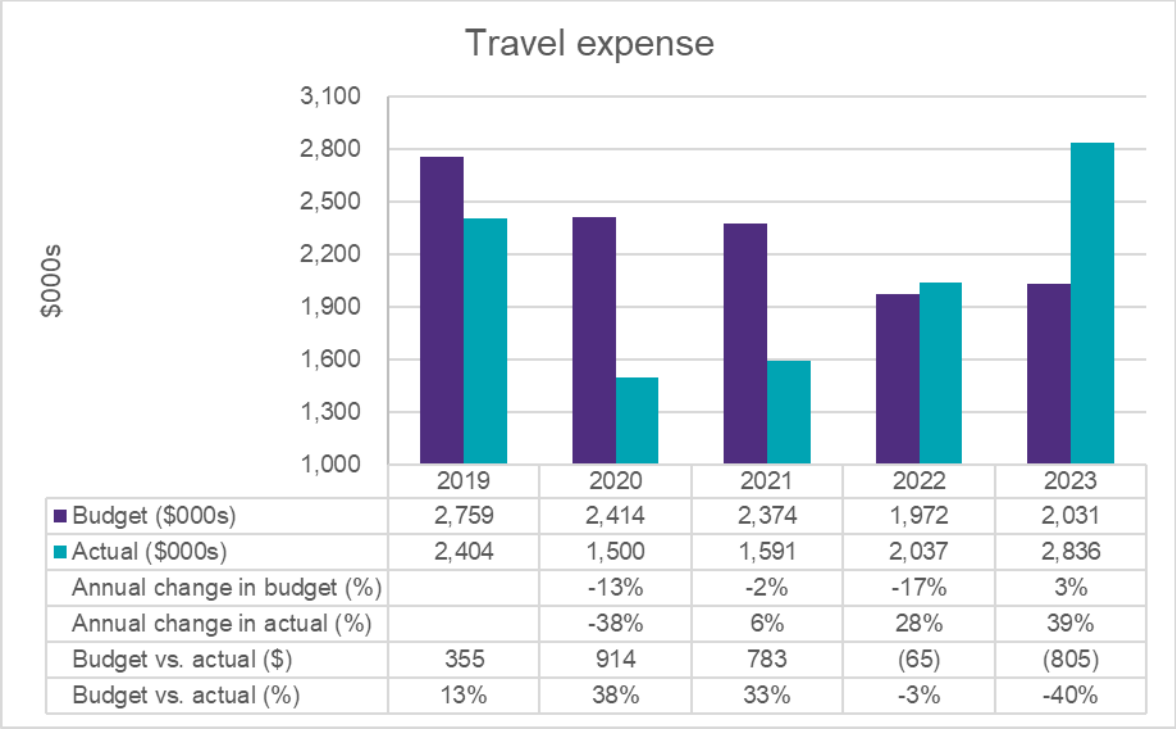
- **Actual training costs were lower than annual budgets in 2019, 2020, and 2021 (21%, 66%, and 28%, respectively).** Per Hydro, this was primarily due to operational demands, such as unplanned outages and emergency responses, which limited staff availability for training. In 2020 and 2021, the significant drop in training expenditures was confirmed to be a result of COVID-19 public health restrictions, including travel limitations and social distancing measures.

By 2022 and 2023, actual training expenses aligned more closely with budgeted amounts. Hydro noted that this improvement reflects their ongoing efforts to refine the budgeting process post-reorganization. Although the budgeting methodology remained unchanged, the establishment of a centralized Training and Development team in late 2023 enhanced oversight and alignment with organizational priorities. Hydro noted that the 2022 and 2023 figures included accruals that were reversed in 2024, revealing adjusted actuals of $413,000 and $349,000, respectively. Hydro noted that these figures underscore their commitment to maintaining cost-effective training that meets both role-specific and organizational needs.

Travel

The following chart details the 5-year trends for travel including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 30 – Travel expense



	2019	2020	2021	2022	2023
Budget ($000s)	2,759	2,414	2,374	1,972	2,031
Actual ($000s)	2,404	1,500	1,591	2,037	2,836
Annual change in budget (%)		-13%	-2%	-17%	3%
Annual change in actual (%)		-38%	6%	28%	39%
Budget vs. actual ($)	355	914	783	(65)	(805)
Budget vs. actual (%)	13%	38%	33%	-3%	-40%

Historically, Hydro used a zero-based budgeting approach for travel expenses, with department managers submitting detailed travel plans based on operational needs. While not within the scope of our review, for the 2025 budget, Hydro noted that they transitioned to a new methodology that calculates travel expenses using a three-year historical average (2022–2024), adjusted by the gross domestic product deflator, to better reflect actual spending patterns.

Based on the chart above, we identified the following significant variances:

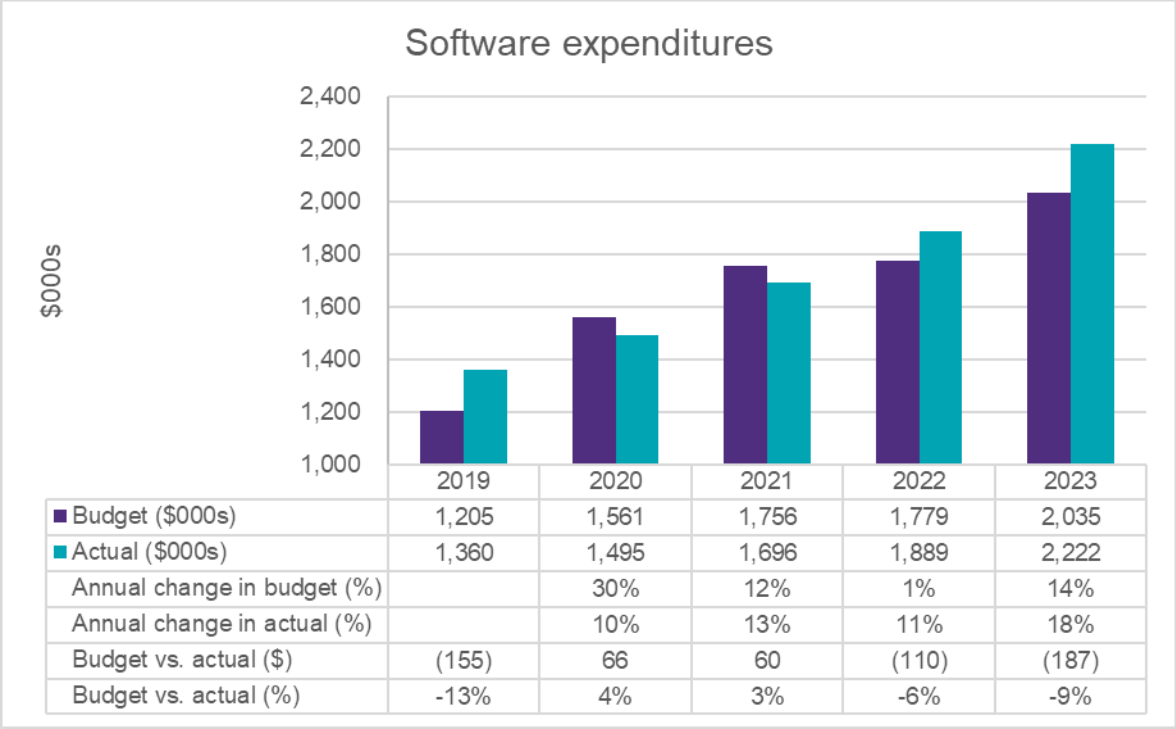
- **2020 and 2021 actual travel expenses were lower than budgets (38% and 33%, respectively).** Per Hydro, the notable drop in travel expenses during 2020 and 2021 was primarily due to COVID-19 related travel restrictions. Once these restrictions were lifted, travel resumed to support the completion of annual work plans.

- **2023 actual travel expense was 40% higher than budget**. Per Hydro, in 2023, this overage was largely due to staffing vacancies in the Transmission and Rural Operations group, which required employees from other communities to travel across Newfoundland and Labrador to maintain operations. Additionally, unplanned travel was necessary to support the inspection and removal of a transmission line in Labrador.

Software expenditures

The following chart details the 5-year trends for software expense including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 31 – Software expenditures



	2019	2020	2021	2022	2023
Budget ($000s)	1,205	1,561	1,756	1,779	2,035
Actual ($000s)	1,360	1,495	1,696	1,889	2,222
Annual change in budget (%)		30%	12%	1%	14%
Annual change in actual (%)		10%	13%	11%	18%
Budget vs. actual ($)	(155)	66	60	(110)	(187)
Budget vs. actual (%)	-13%	4%	3%	-6%	-9%

Hydro uses a zero-based budget approach for its software expense. The software budget is prepared by analyzing business requirements with software information housed in an inventory application that is leveraged to analyze, trend and forecast future cost for each piece of software. The budget proposals are based on historical data and updated to include an anticipated escalation percentage which varies by vendor and software. Software requirements are assessed annually through an architecture review, in consultation with stakeholders. Any

newly identified software requirements are added, and any software planned for decommissioning is removed.

Based on the chart above we identified the following significant variance:

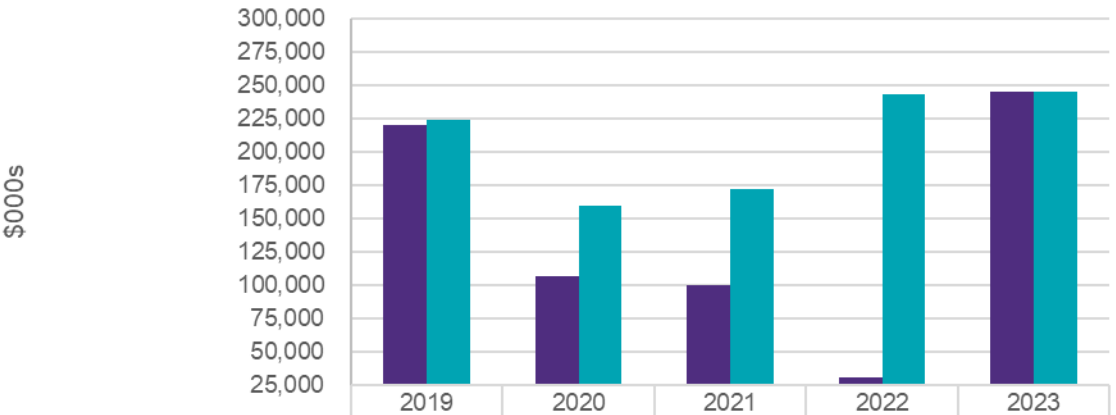
- **Actual software expenditures continuously increased.** Per Hydro, the rise in software expenditures from 2021 through 2023 is largely due to increased cybersecurity requirements, which are essential for protecting critical infrastructure and ensuring asset reliability. Additional cost drivers include new business software needs, software replacements, and vendor price increases—many of which are influenced by inflation. Hydro also noted that a notable industry trend contributing to rising costs is the shift from perpetual software licenses to subscription-based models, which require ongoing annual fees.

To mitigate escalating costs, Hydro has noted that it conducts quarterly reviews of upcoming software renewals to assess necessity and long-term use. When appropriate, the company opts for multi-year renewals to secure cost savings. Per Hydro, all software purchases are made in compliance with the Public Procurement Act, ensuring transparency and fiscal responsibility.

Fuels

The following chart details the 5-year trends for fuels expense including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 32 – Fuels expense



	2019	2020	2021	2022	2023
Budget ($000s)	219,857	107,100	100,094	30,927	244,857
Actual ($000s)	223,928	159,932	171,857	242,958	245,088
Annual change in budget (%)		-51%	-7%	-69%	692%
Annual change in actual (%)		-29%	7%	41%	1%
Budget vs. actual ($)	(4,071)	(52,832)	(71,763)	(212,031)	(231)
Budget vs. actual (%)	-2%	-49%	-72%	-686%	0%

Budgeting methodology

Hydro's fuel budget for the Island Interconnected System is based upon an annual production plan which forecasts the usage of each of Hydro's available generation sources throughout the year, and according to Hydro, reflects the effective management and dispatch of generation resources. This plan is then used for budgetary purposes, including the budget for fuel volume requirements. The fuel forecast for the isolated and rural areas is based on a customer load forecast prepared by Hydro and fuel prices in both cases are based on monthly data provided by Platts.

In addition, the fuel budget also included the budgeted supply deferral amounts, such as the Rate Stabilization Plan ("RSP"), the Energy Supply Deferrals (until their discontinuance on November 1, 2021) and the Supply Cost Variance Deferral account (effective November 1, 2021). The budget for the supply deferrals is derived from the variances between the budgeted supply costs in comparison to the test year supply balances. However, according to Hydro, all of the supply deferral activity in 'Fuel' does not directly relate to fuel, and as a result, it is not a one-to-one comparison. For example, for 2019, 2020, and 2021, the RSP load variation is included in the fuel expense line but relates to revenue load. In 2022 and 2023, the revenue load adjustment flows through revenue instead, following the introduction of the SCDVA.

It should also be noted that with regards to the SCVDA, the details of the deferral were not finalized in each budget year, resulting in the grouping within the Other Expense line item on the income statement. Commencing in 2023, the SCVDA was budgeted in a manner consistent with the actual presentation.

Notable budget vs. actual variances

During our initial analysis of Hydro's fuels expense, we noted that actual fuel costs were higher than budgets in 2020, 2021 and 2022 (49%, 72%, and 686%, respectively). According to Hydro, actual fuel costs differed from budget in these years because the fuel expense shown in the above, and as shown in the chart (and Hydro's Statement of Income – Regulation Operations in their Quarterly Reports) excludes fuel-related supply deferrals which were categorized under "Other Expense" in the budgeted figures. Additionally, up until October 31, 2021, the RSP deferral included revenue load variations for both utility and industrial customers, and the supply deferrals reflected fluctuations in power purchase costs for domestic and off-island sources.

The following tables outline the fuel costs and fuel-related deferrals, along with any notable variance explanations in each year.

Figure 33 – 2020 restated fuel costs

Restated fuel costs (000s)	Actual 2020	Budget 2020	Variance	Notes
No 6 fuel	142,440	150,108	**(7,668)**	*1*
Gas turbine fuel	2,479	1,427	**1,052**	*2*
Diesel	12,603	20,253	**(7,650)**	*3*
Other	349	223	**126**	
Sub total	157,871	172,011	**(14,140)**	
RSP/Supply Deferrals	2,060	(64,911)	**66,971**	
Fuel as per Figure 30	159,932	107,100	**52,831**	
Less portion of deferral not related to fuel	(63,186)	9,232	**(72,418)**	
Add fuel related deferral in Other Expense	-	122,600	**(122,600)**	
Restated fuel costs	**223,118**	**220,469**	**2,649**	

Note 1: The variance in No. 6 fuel was primarily attributed to a decrease in fuel price, partially offset by an increase in fuel consumption. The increase in volume was driven by increased thermal generation due to the commercial in-service of the Labrador-Island Link being later than budgeted.

Note 2: The variance in gas turbine fuel was primarily attributed to an increase in fuel consumption, partially offset by a decrease in fuel price.

Note 3: The variance in diesel fuel was primarily attributed to a decrease in fuel price and fuel consumption. The reduction in volume was driven by lower customer requirements.

Figure 34 – 2021 restated fuel costs

Restated fuel costs (000s)	Actual 2021	Budget 2021	Variance	Notes
No 6 fuel	97,761	66,803	**30,958**	*1*
Gas turbine fuel	9,138	3,807	**5,331**	*2*
Diesel	13,115	12,958	**157**	
Other	495	63	**432**	
Sub total	120,508	83,630	**36,877**	
RSP/SCDVA/Supply Deferral	51,349	16,463	**34,886**	
Fuel as per Figure 30	171,857	100,094	**71,763**	
Less portion of deferral not related to fuel	-51,022	(74,594)	**23,571**	
Add fuel related deferral in Other Expense	-	49,348	**(49,348)**	
Restated fuel costs	**222,879**	**224,035**	**(1,156)**	

Note 1: The variance in No. 6 fuel was primarily attributed to an increase in fuel price and fuel consumption. The increase in volume was driven by increased thermal generation due to the commercial in-service of the LIL being later than budgeted.

Note 2: The variance in gas turbine fuel was primarily attributed to an increase in fuel consumption, partially offset by a decrease in fuel price. The increase in volume was primarily due to unplanned outages of hydraulic and thermal units.

Figure 35 – 2022 restated fuel costs

Restated fuel costs (000s)	Actual 2022	Budget 2022	Variance	Notes
No 6 fuel	162,962	13,566	**149,396**	*1*
Gas turbine fuel	1,507	1,153	**354**	
Diesel	24,102	16,157	**7,945**	*2*
Other	98	52	**46**	
Sub total	188,668	30,927	**157,741**	
SCVDA / Isolated Systems Supply Deferral	54,291	-	**54,291**	
Fuel as per Figure 30	242,958	30,927	**212,031**	
Less portion of deferral not related to fuel	20,084	-	**20,084**	
Add fuel related deferral in Other Expense	-	187,330	**(187,330)**	
Restated fuel costs	**222,875**	**218,257**	**4,618**	

Note 1: The variance in No. 6 fuel was primarily attributed to an increase in fuel consumption and fuel price. The increase in volume was driven by increased thermal generation due to the commercial in-service of the LIL being later than budgeted and the use of the Holyrood TGS for system load and reliability.

Note 2: The variance in diesel fuel was primarily attributed to an increase in fuel price, partially offset by a decrease in fuel consumption. The reduction in volume was due to lower customer requirements.

Notable actual year-over-year variances

During our analysis of Hydro's fuels expense, we noted the following variance and requested further explanation:

- **Actual fuels expense increased by 41% from 2021 to 2022:** This increase was due mainly to an increase in No. 6 fuel as well as smaller fluctuations to gas turbine fuel and diesel which have been elaborated on in Notes 1 to 3 from the table below.

  In addition, according to Hydro, the supply deferrals include deferral of the variances in domestic and off-island power purchases. Therefore, the below table shows the 2021 and 2022 actual results when non-fuel related deferrals are excluded.

Figure 36 – 2021 actual vs. 2022 restated fuel costs

Restated fuel costs (000s)	Actual 2022	Actual 2021	Variance	Notes
No. 6 fuel	162,962	97,761	**65,201**	*1*
Gas turbine fuel	1,507	9,138	**(7,631)**	*2*
Diesel	24,102	13,115	**10,987**	*3*
Other	98	495	**(397)**	
Sub total	188,668	120,508	**68,160**	
SCVDA / RSP / Supply Deferrals	54,291	51,349	**2,941**	
Fuel as per Figure 30	242,958	171,857	**71,102**	
Less portion of deferral not related to fuel	20,084	-51,022	**71,106**	
Restated fuel costs	**222,875**	**222,879**	**(4)**	

Note 1: The variance in No. 6 fuel was primarily attributed to an increase in fuel price and fuel consumption. Holyrood production was slightly higher in 2022 than in 2021 due to additional Holyrood generation in the fourth quarter for system reliability.

Note 2: The variance in gas turbine fuel was primarily attributed to a decrease in fuel consumption, partially offset by an increase in fuel price. Gas Turbine generation was

significantly lower than in 2021, mainly due to lower fourth quarter 2022 requirements due to higher availability and generation from Holyrood.

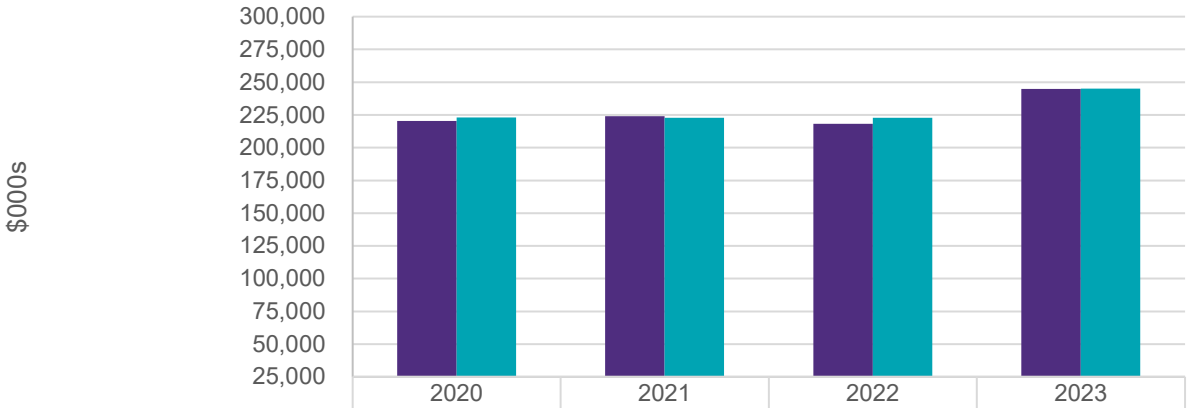
Note 3: The variance in diesel fuel was primarily attributed to an increase in fuel price and fuel consumption. Diesel production in 2022 was higher than 2021 due to colder weather in Labrador.

Overall, when comparing actual fuels expenses after the removal of non-fuels related expenses, the year-over-year trend is consistent.

Restated fuels expense

Given the impact of the grouping of non-fuel costs within the fuels expense line item, as discovered through inquiry with Hydro as outlined above, we have performed a trend analysis using the restated fuel figures, as outlined below:

Figure 37 – Restated fuel analysis



	2020	2021	2022	2023
Budget ($000s)	220,469	224,035	218,257	244,857
Actual ($000s)	223,118	222,879	222,875	245,088
Annual change in budget (%)	0%	2%	-3%	12%
Annual change in actual (%)	0%	0%	0%	10%
Budget vs. actual ($)	(2,649)	1,156	(4,618)	(231)
Budget vs. actual (%)	-1%	1%	-2%	0%

When comparing annual trends after the exclusion of non-fuel related expenses as discussed above for 2020, 2021, and 2022, both budget vs. actual and annual year-over-year changes are more consistent.

Mitigation of fuel cost escalation

Given the significance of fuel costs, it is important that utilities have a clearly defined plan for mitigating cost escalation. According to Hydro, they manage fuel costs through the following strategies:

- **Dispatch of generation resources:** Efficiently dispatching generation resources across the Island and Labrador Interconnected System allows Hydro to meet the electricity needs of provincial consumers.
    - Hydroelectric generation is prioritized, depending on water levels, including both on-island facilities and Muskrat Falls in Labrador, which supplies power to the Island via the LIL.
    - The Holyrood TGS and diesel standby units provide additional capacity on the Island as needed. The Holyrood TGS is primarily used to ensure system reliability during the winter season and when these units must be online, Hydro leverages energy from the LIL to maintain Holyrood TGS at minimum output levels, thereby reducing fuel consumption.
- **Non-utility generation –** Hydro also purchases electricity from non-utility generators, which include small and medium-sized hydroelectric facilities, fossil-fueled co-generation, and wind power.
- **Power sales agreements:** Agreements with large customers are strategically managed to reduce reliance on non-renewable resources.
- **Renewable energy projects:** To further minimize diesel use on isolated systems, Hydro actively collaborates with Indigenous groups and other stakeholders, especially in communities primarily served by diesel generation, to support the development of cost-effective renewable energy projects. Typically, these projects are developed and operated by third parties, with Hydro purchasing the output at a cost lower than that of generating equivalent energy from its diesel facilities. Examples of these projects include the following:
    - The Mary's Harbour Mini Hydro Facility, which combines hydro, solar, and lithium-ion battery storage to reduce the community's diesel fuel use. In 2024, the facility generated approximately 965 MWh, displacing diesel fuel generation;
    - In 2024, Hydro worked with its Indigenous partners to energize an Indigenous-owned solar project in the isolated diesel community of Port Hope Simpson. This latest addition resulted in renewable energy being used to displace diesel-generated electricity in Hydro's 20 isolated diesel systems; and,
    - Hydro also undertakes energy-efficient programming in its isolated communities that provide outreach, education, residential and commercial direct installation of

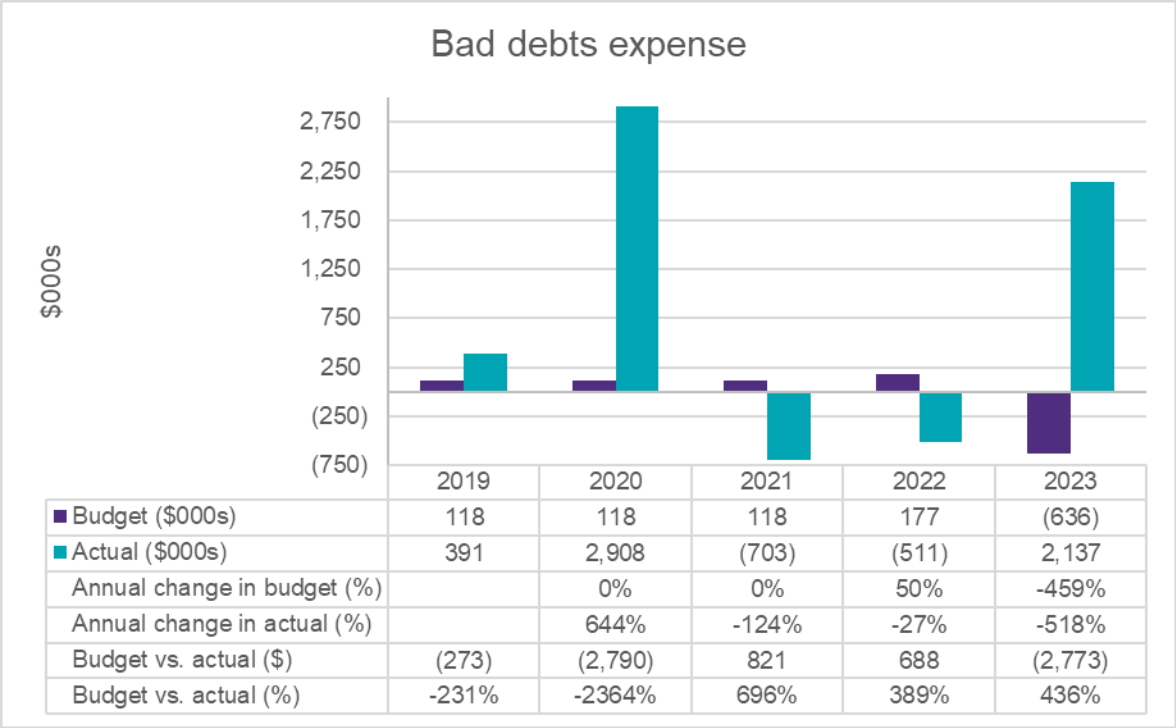
energy efficiency technology, along with other energy efficiency and demand management opportunities.

- **Competitive procurement processes**: Although fuel prices are generally impacted by macroeconomic variables such as exchange rates and global oil prices, Hydro also minimizes its fuel costs by using competitive procurement processes, in compliance with the Public Procurement Act, for its fuel supply services.

Bad debts

The following chart details the 5-year trends for bad debts expense including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 38 – Bad debts



	2019	2020	2021	2022	2023
Budget ($000s)	118	118	118	177	(636)
Actual ($000s)	391	2,908	(703)	(511)	2,137
Annual change in budget (%)		0%	0%	50%	-459%
Annual change in actual (%)		644%	-124%	-27%	-518%
Budget vs. actual ($)	(273)	(2,790)	821	688	(2,773)
Budget vs. actual (%)	-231%	-2364%	696%	389%	436%

Hydro employs a zero-based budgeting approach for bad debts expenses, relying on historical trends to estimate the amount of uncollectible accounts under normal operating conditions. Per Hydro, this estimate remains relatively consistent year over year unless there are known or anticipated changes that could significantly impact customer payment behavior. In such cases, adjustments are made to reflect the expected deviation from typical collectability patterns.

Based on the chart above, we identified the following significant variance:

- **2020 and 2023 bad debts expense was higher than other years.** Per Hydro, in both 2020 and 2023, the Company experienced elevated bad debts expenses due to issues

with a single General Service customer. In 2020, the customer had an outstanding balance of $4 million, of which $3.1 million was eventually recovered. However, in 2023, an additional $1.8 million was written off and not recovered.

To enhance consistency in collections and reduce future bad debts risk, Hydro noted that it has implemented several measures, including:

- Standardized Collections Procedures – Hydro follows a structured, tiered collections process that includes regular billing reminders, escalation timelines, and clear communication protocols. This ensures all customers are treated fairly and consistently, and that overdue accounts are addressed in a timely manner.

- Customer Outreach and Support – Proactive customer engagement has been strengthened through early intervention strategies. Hydro contacts customers before arrears grow significantly and offers payment arrangements or flexible options where appropriate, which improves recovery rates and reduces the likelihood of accounts becoming uncollectible.

- Monitoring and Reporting – accounts receivable aging and disconnection rates are monitored regularly. Any significant trends or variances are analysed to guide operational adjustments.

Conclusion and recommendations

We have completed our procedures in the review of Hydro's operations and administration expenses. We compared 2022 and 2023 actual results to prior years, the 2019 Test Year and the 2022 and 2023 Plans. Our analysis identified notable trends and budget variances, and we made subsequent inquiries with Hydro for further clarification, including their budgeting approach and methodology.

Overall expenses under the scope of our review experienced a significant decrease in 2020 and 2021 but returned to previous levels in 2022. In 2022, actual expenditures were 63% higher than budget. Based on our discussions with Hydro, we understand that this discrepancy is due to the exclusion of fuel-related supply deferrals as they are categorized as "Other expense" in the budget figures. Once adjusted for deferrals, we found that actual fuels expense was consistent with budgets throughout the period under review.

When we compared budget to actual costs we noted several categories where Hydro's actual expenses have fallen within their budgets. These categories include but are not limited to office supplies, insurance, and professional services. However, there are several cost categories where actual expenditures have exceeded budget. These categories include but are not limited to software, travel, vegetation management, and transportation. We have received explanations from Hydro on the trends identified and are satisfied with their explanations.

Based on our trend analysis we noted that the utility continues to face pressures from increasing costs. We encourage the Board to actively monitor expense budgeting and cost controls in the next general rate application.

6. Labour costs

Scope

Conduct an analysis of labour costs, including executive compensation, FTEs and short-term incentives. In conducting this review, present comparisons with prior years, the 2019 Test Year and the 2022 and 2023 Plan, and follow up on significant variances.

Procedures

Our review of labour costs included the following specific procedures:

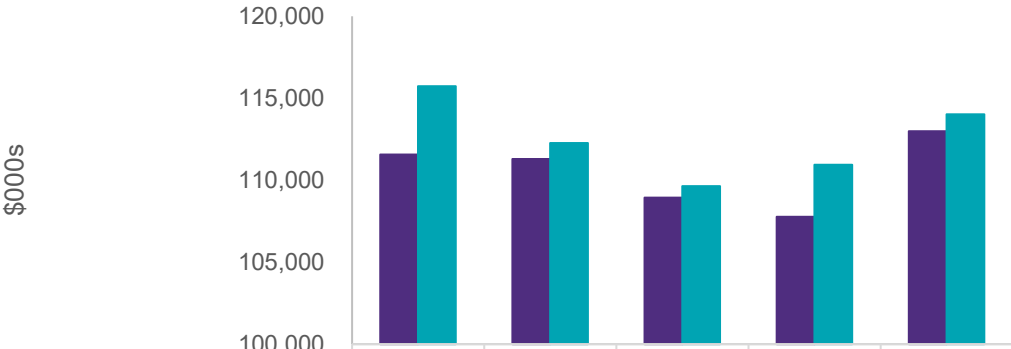
- Obtained schedules of salaries and benefits by category (gross).
- Identified significant variances from prior year for further investigation.
- Identified significant variances from the 2019 test year and 2022/2023 plan for further investigation.
- Assessed the reasonableness and consistency of Hydro variance explanations.
- Summarized executive compensation and analysed variances.
- Obtained schedules of staff complement and filled positions (FTE's). Analysed salary expense by FTE.
- Obtained a summary of STI expenses. Identified significant variances for further investigation.

Analysis

Analysis of gross payroll costs

The following table outlines the total salaries and fringe benefits under the scope of our review for 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 39 – Salaries and fringe benefits



	2019*	2020	2021	2022	2023
Budget ($000s)	111,576	111,287	108,944	107,774	112,980
Actual ($000s)	115,744	112,277	109,631	110,935	114,031
Annual change in budget (%)		0%	-2%	-1%	5%
Annual change in actual (%)		-3%	-2%	1%	3%
Budget vs. actual ($)	(4,169)	(989)	(686)	(3,160)	(1,051)
Budget vs. actual (%)	-4%	-1%	-1%	-3%	-1%

**2019 budget as depicted in the various charts in this section of our report refers to 2019 Test Year.*

A breakdown of the total salaries and benefits costs by key category is detailed in the figure below.

Figure 40 – Total salaries and fringe benefits

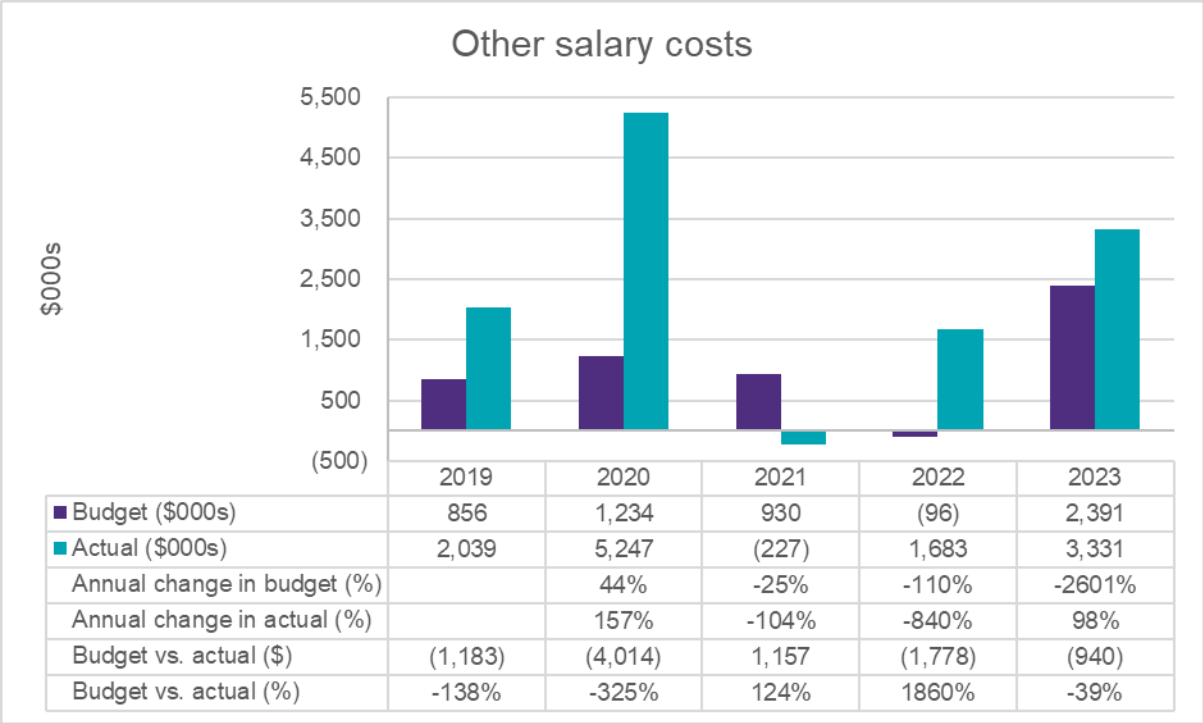
(000s)	2019TY	2019A	2020B	2020A	2021B	2021A	2022B	2022A	2023B	2023A
Salaries	$ 77,366	$ 76,303	$ 76,397	$ 73,409	$ 74,337	$ 73,970	$ 73,904	$ 73,945	$ 76,074	$ 75,064
Other salary costs	856	2,039	1,234	5,247	930	(227)	(96)	1,683	2,391	3,331
Net labour recharge	(842)	(1,932)	(1,099)	(1,525)	(792)	(1,710)	315	(137)	237	302
Subtotal	77,380	76,410	76,532	77,131	74,475	72,033	74,123	75,491	78,702	78,697
Allowances	1,903	2,269	2,270	2,034	2,262	2,171	2,167	2,245	2,337	2,669
Directors fees	65	69	85	59	85	55	60	83	70	81
Overtime	9,888	12,491	10,208	11,413	10,245	13,470	9,672	11,783	10,848	13,560
Employee future bene	6,705	9,023	7,087	7,140	7,277	6,994	7,170	6,546	6,475	3,236
Fringe benefits	12,597	12,426	12,041	11,763	11,727	12,069	11,784	11,928	11,683	12,395
Group insurance	2,875	2,893	2,901	2,573	2,702	2,657	2,638	2,680	2,679	3,215
Labrador travel benefi	164	163	165	164	171	183	160	179	186	178
Subtotal	34,196	39,335	34,756	35,145	34,469	37,598	33,651	35,444	34,278	35,334
Total salaries and benefits	$ 111,576	$ 115,744	$ 111,287	$ 112,277	$ 108,944	$ 109,631	$ 107,774	$ 110,935	$ 112,980	$ 114,031
Capital salaries	(21,086)	(24,428)	(23,689)	(22,553)	(23,726)	(24,228)	(24,804)	(23,314)	(25,016)	(24,702)
Capital overtime	(4,986)	(6,728)	(4,960)	(5,282)	(4,909)	(6,403)	(4,898)	(5,183)	(5,870)	(6,110)
Salaries and benefits included in operating expenses	**$ 85,504**	**$ 84,588**	**$ 82,638**	**$ 84,442**	**$ 80,309**	**$ 79,000**	**$ 78,072**	**$ 82,438**	**$ 82,094**	**$ 83,219**

During the course of our review, we verified the totals per category with Hydro and conducted a trend analysis. Our findings on significant variances by category are detailed throughout this section of our report.

Other salary costs

The following chart details the 5-year trends for other salary costs including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 41 – Other salary costs



	2019	2020	2021	2022	2023
Budget ($000s)	856	1,234	930	(96)	2,391
Actual ($000s)	2,039	5,247	(227)	1,683	3,331
Annual change in budget (%)		44%	-25%	-110%	-2601%
Annual change in actual (%)		157%	-104%	-840%	98%
Budget vs. actual ($)	(1,183)	(4,014)	1,157	(1,778)	(940)
Budget vs. actual (%)	-138%	-325%	124%	1860%	-39%

Hydro uses a zero-based budgeting approach for its other salary costs, aligning the budget with operational needs and workforce composition. Per Hydro, historically, this category included items like maternity leave payments, retention and short-term incentives, and differential payments for frontline supervisors. However, starting in 2022, retention and short-term incentive payments were no longer budgeted. Hydro noted the category also occasionally serves as a holding account for anticipated salary increases that have not yet been finalized, which contributes to discrepancies between budgeted and actual figures. Hydro has also noted that beginning with the 2025 budget, Hydro completed a review of this expense category and the budget in 2025 continued to be zero based.

Based on the chart above we identified the following significant variances:

- **Both budgeted and actual other salary costs fluctuate significantly year over year and actual results are not aligned with budgets.** As noted above, this cost category is

budgeted using a zero-based approach considering operational requirements and workforce composition. Discrepancies in budgeted and actual results are driven by the salary increases held in this account for any union and non-union related increases budgeted for the year but which have either not yet been negotiated or communicated broadly within the organization. These amounts when later incurred flow through the salaries account, thus resulting in variances between budget and actuals from year-to-year. Activity in this category also changed in 2022 when Hydro ceased retention incentives and short-term incentive payments.

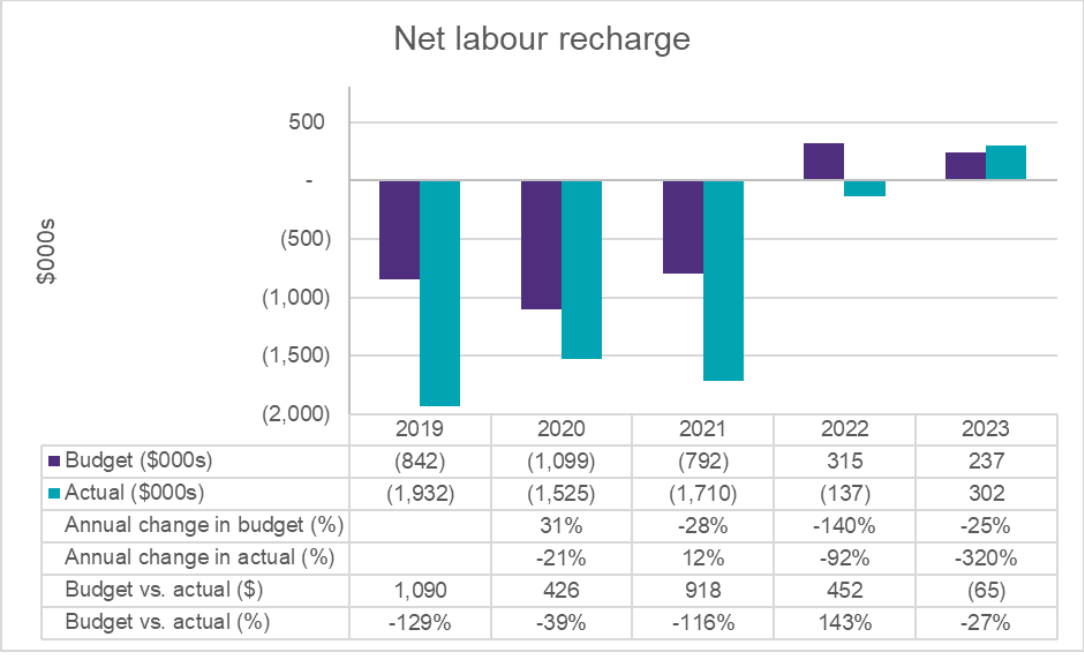
- **Actual other salary costs were in a credit position in 2021**. Per Hydro, the credit position in 2021 was due to variations in estimates for anticipated salary increased from collective bargaining, reversal of general economic increase estimates, variations in termination & vacation costs, and the elimination of performance contract payments.

- **Other salary costs were budgeted to be a credit in 2022.** Per Hydro, the credit position in 2022 was due to an adjustment of $0.3 million made to offset benefits expenses on the benefits line. This adjustment was made late in the budget process and was recorded here for administrative ease. The budget in 2022 was lower than prior years as budget 2022 did not include short-term incentive payments of $0.8 million, which when combined with the adjustment noted above, resulted in a credit balance.

Labour recharges

The following chart details the 5-year trends for labour recharges including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 42 – Labour recharges



	2019	2020	2021	2022	2023
Budget ($000s)	(842)	(1,099)	(792)	315	237
Actual ($000s)	(1,932)	(1,525)	(1,710)	(137)	302
Annual change in budget (%)		31%	-28%	-140%	-25%
Annual change in actual (%)		-21%	12%	-92%	-320%
Budget vs. actual ($)	1,090	426	918	452	(65)
Budget vs. actual (%)	-129%	-39%	-116%	143%	-27%

The budgeting approach for labour recharge is based on a detailed budget approach using a relational data file. The relational data file is populated using updated labour rates and the total hours charged from the previous year. Departments are then required to review the labour recharge data in and out of their applicable business units and adjust for their expected activity for the year. This can require collaboration between business unit managers to ensure there is alignment on the recharge from one department to another based on the expected support from each department. Labour recharge continued to be based on a detailed budget approach in 2025.

Based on the chart above we identified the following significant variances:

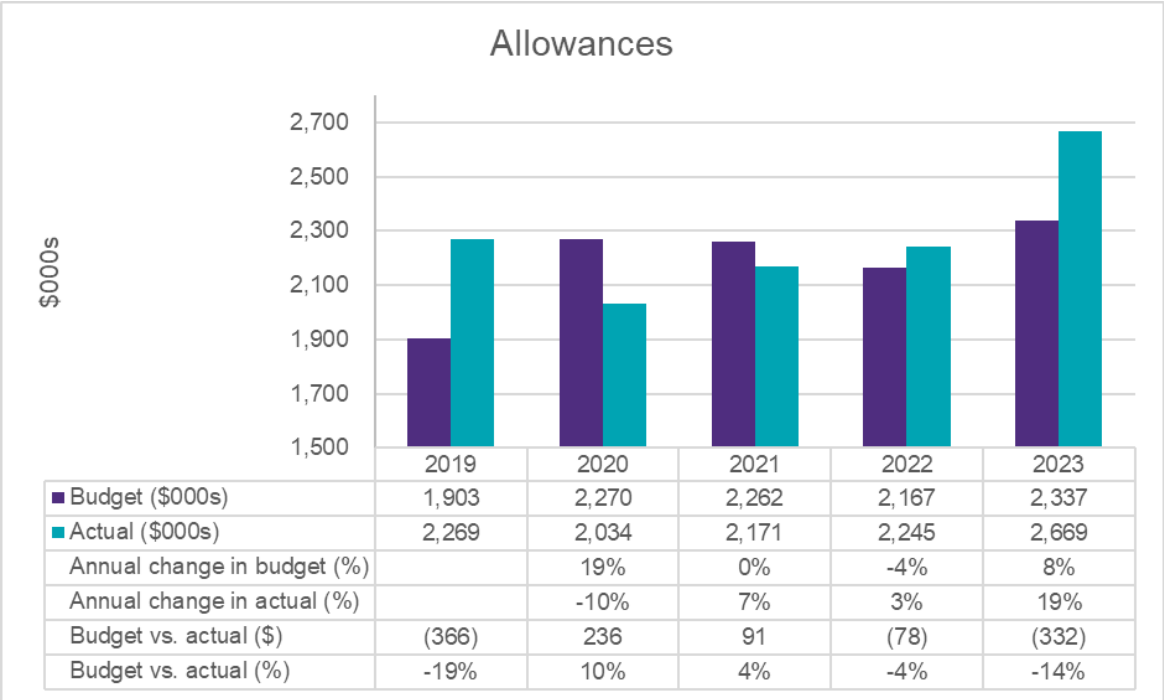
- **Both budgeted and actual labour recharge fluctuate significantly year over year and actual results are not aligned with budgets.** Per Hydro, labour recharge is budgeted based on a detailed budget approach. Department managers must assess their requirements each year for where they anticipate charging time to or from other departments. Operational requirements and, therefore, workplans can change throughout the year which leads to variations in labour being charged between departments and different entities. Variations between budget and actual charges can also be driven by unexpected vacancies when there is a shortage in labour force that requires support from another department.

- **Labour recharge budget changed from a $0.8 million recovery in 2021 to a $0.3 million expense in 2022 resulting in a net variance of approximately $1.1 million**. Per Hydro, this was primarily due to the addition of procurement costs to an admin fee and the transfer of a few executives out of Regulated Hydro as a result of organizational restructuring at that time. The addition of a procurement admin fee resulted in a decreased labour recharge out as charges were allocated by an admin fee instead. In addition, there was an increase to labour recharge in as executive positions were moved out of a Regulated Hydro business unit in the 2022 budget. As a result, their associated costs were included as a labour recharge in Regulated Hydro rather than being included in Regulated Hydro's salary and benefits.

Allowances

The following chart details the 5-year trends for allowances including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 43 – Allowances



	2019	2020	2021	2022	2023
Budget ($000s)	1,903	2,270	2,262	2,167	2,337
Actual ($000s)	2,269	2,034	2,171	2,245	2,669
Annual change in budget (%)		19%	0%	-4%	8%
Annual change in actual (%)		-10%	7%	3%	19%
Budget vs. actual ($)	(366)	236	91	(78)	(332)
Budget vs. actual (%)	-19%	10%	4%	-4%	-14%

Hydro traditionally used a zero-based budgeting approach for allowances, basing projections on workplans and FTE requirements. However, Hydro noted for the 2025 budget, the methodology shifted to using a three-year historical average of expenditures from 2022 to 2024, adjusted by a labour inflator to better reflect actual experience.

Based on the chart above we identified the following significant variances:

- **2019 actual allowance expense was approximately 19% higher than budget**. Per Hydro, the increase is primarily due to increased shift differential ($0.1 million), increased substitute pay ($0.1 million) and increased temporary vacation payout ($0.1 million).

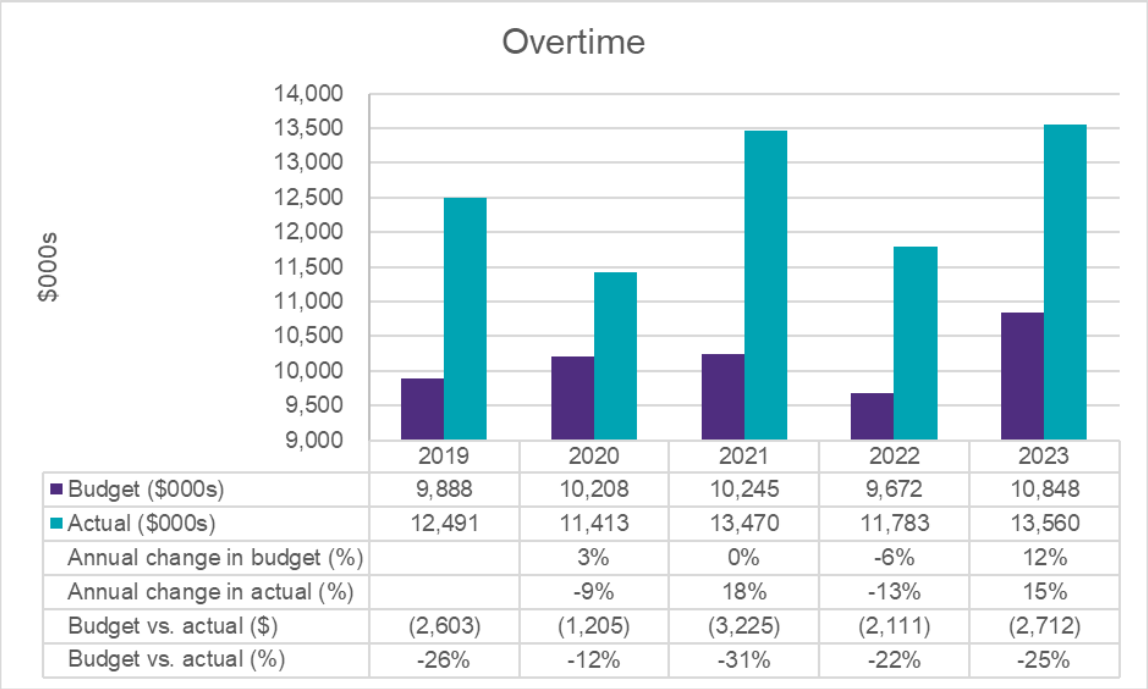
- **2023 actual allowance expense was approximately 14% higher than budget**. Per Hydro, this increase is related to retroactive Labrador allowance adjustments paid to employees in 2023 of approximately $0.3 million.

Hydro has noted that the trending increase in actual allowance expenses since 2020 is largely due to the increased burden reflective of the size and composition of the Company's workforce. Specifically, modest growth in temporary FTEs resulting in increased temporary employee vacation pay. Hydro noted that it remains focused on aligning workforce requirements with operational needs while maintaining competitiveness in attracting and retaining talent within the utility sector.

Overtime

The following chart details the 5-year trends for overtime including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 44 – Overtime



	2019	2020	2021	2022	2023
Budget ($000s)	9,888	10,208	10,245	9,672	10,848
Actual ($000s)	12,491	11,413	13,470	11,783	13,560
Annual change in budget (%)		3%	0%	-6%	12%
Annual change in actual (%)		-9%	18%	-13%	15%
Budget vs. actual ($)	(2,603)	(1,205)	(3,225)	(2,111)	(2,712)
Budget vs. actual (%)	-26%	-12%	-31%	-22%	-25%

Hydro historically used a zero-based budgeting approach for overtime, informed by the minimal amount of overtime required to perform the work plan outlined for each year in an effort to minimize overtime costs throughout the organization. However, there was a shift in budget methodology for overtime in the 2025 budget. Hydro no longer uses a zero-based budget approach but rather bases its budget on a three-year historical average of expenditures incurred in 2022, 2023, and 2024, multiplied by a labour inflator to account for any possible salary increases for the budget year in an effort to be more reflective of actual experience.

Based on the chart above we identified the following significant variances:

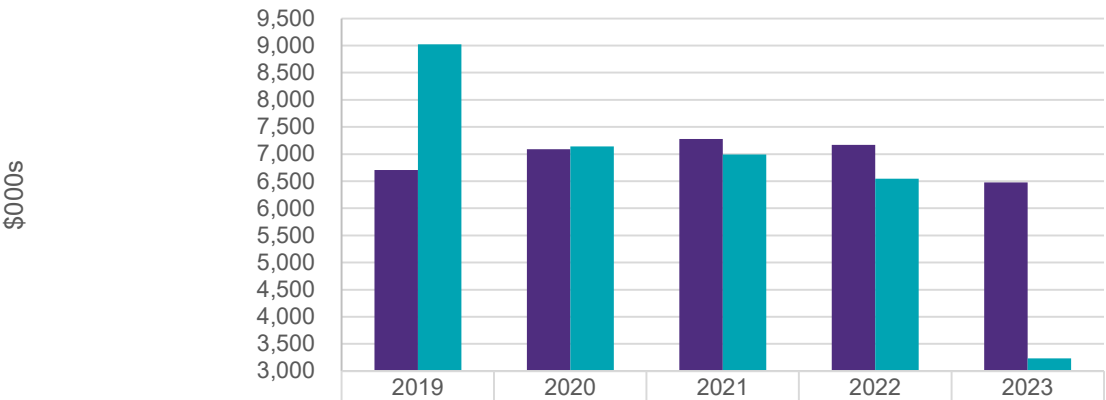
- **Actual overtime expense has consistently been greater than budget in 2019-2023.** Per Hydro, the budget approach used during this period was reflective of efforts to minimize overtime costs throughout the organization. The variance in overtime from year-to-year is reflective of the fact that while some overtime is planned and scheduled based on operational requirements and maintenance schedules, there is an element of overtime costs that are driven by unexpected outages, severe weather events and emergency response activities.

- **Actual overtime expense increased by 18% in 2021, and increased by 15% in 2023.** Per Hydro, the variances are reflective of unplanned overtime. The variance from actuals in 2021 is due to lower activities caused by the COVID-19 pandemic protocols in 2020. The variance in actuals from 2022 to 2023 is primarily related to overtime incurred as a result of operational issues with the Labrador-Island Link and Holyrood and Stephenville generators ($0.4 million), increase in Transmission and Rural Operations trouble calls ($0.3 million) and coverage for vacancies (related to Long-Term Disability, retirements or recruitment challenges) experienced in Hydro Production department ($0.2 million).

Employee future benefits

The following chart details the 5-year trends for employee future benefits including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 45 – Employee future benefits



	2019	2020	2021	2022	2023
Budget ($000s)	6,705	7,087	7,277	7,170	6,475
Actual ($000s)	9,023	7,140	6,994	6,546	3,236
Annual change in budget (%)		6%	3%	-1%	-10%
Annual change in actual (%)		-21%	-2%	-6%	-51%
Budget vs. actual ($)	(2,319)	(53)	283	624	3,239
Budget vs. actual (%)	-35%	-1%	4%	9%	50%

Hydro budgets employee future benefits based on the most recent actuarial report provided by its actuary, Telus Health.

Based on the chart above we identified the following significant variances:

- **2019 actual employee future benefits were approximately 35% higher than budget.** Per Hydro, the past service costs adjustment relating to life insurance premium assumption updates was the primary reason for the increase in employee future benefits

("EFB") expense in 2019 actuals compared to 2019 budget which was over $2.2 million of the $2.3 million variance.

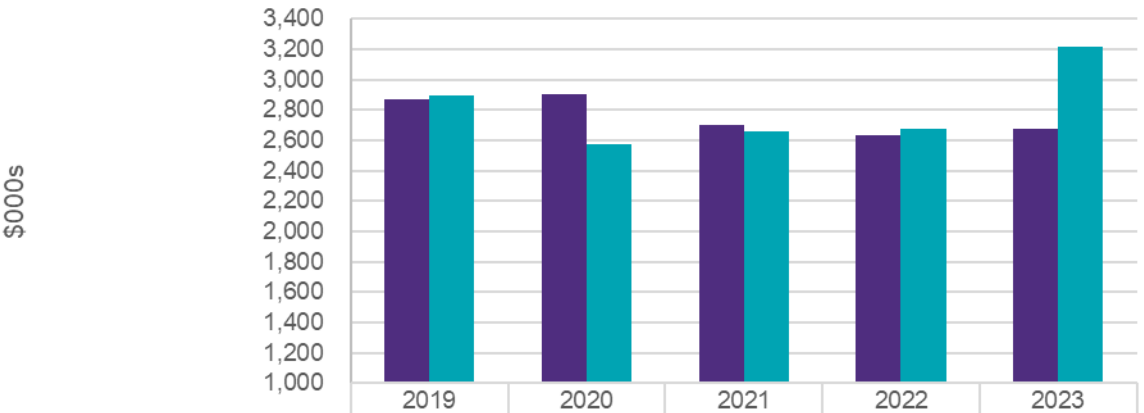
- **2023 actual employee future benefits decreased by approximately 50% compared to 2022 actual.** Per Hydro, the reduction in 2023 actuals is largely driven by the increase to the discount rate that is used in the calculation of the annual other post-employment benefits expense. The discount rate is driven by market related interest rates. During 2022, there was an increase in interest rates by central banks in reaction to high and persistent inflation. As a result, the discount rate increased from 3.35% at December 31, 2021 to 5.2% at December 31, 2022. For EFB, discount rates have a lag effect because they impact the next year's expense rather than the current period. This resulted in a decrease to the employee future benefits expenses in 2023, which were based upon the discount rate at December 31, 2022. Whereas the discount rate used in the 2023 budget and 2022 were based upon the discount rate at December 31, 2021.

Hydro has noted that budgets are based on the best available information at the time, and given these variances are due to changes in discount rates, Hydro has not made any changes to its approach for budgeting this expense.

Group insurance

The following chart details the 5-year trends for group insurance including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 46 – Group insurance



	2019	2020	2021	2022	2023
Budget ($000s)	2,875	2,901	2,702	2,638	2,679
Actual ($000s)	2,893	2,573	2,657	2,680	3,215
Annual change in budget (%)		1%	-7%	-2%	2%
Annual change in actual (%)		-11%	3%	1%	20%
Budget vs. actual ($)	(18)	328	45	(42)	(536)
Budget vs. actual (%)	-1%	11%	2%	-2%	-20%

Hydro budgets group insurance expense based on a combination of factors: (i) rates set by the insurance provider; (ii) experiential information from the twelve-month prior year actual employee dataset (April to March); and (iii) workforce size and composition. As budget preparation and benefits experiential documentation is prepared at different frequencies and times of year, there is a lag effect on budget adjustments reflective of market trends and plan experience. For example, budget 2023 reflected data for the period April 2021–March 2022 and plan experience and market trends post this timeframe would not be reflected in the budget set for that year.

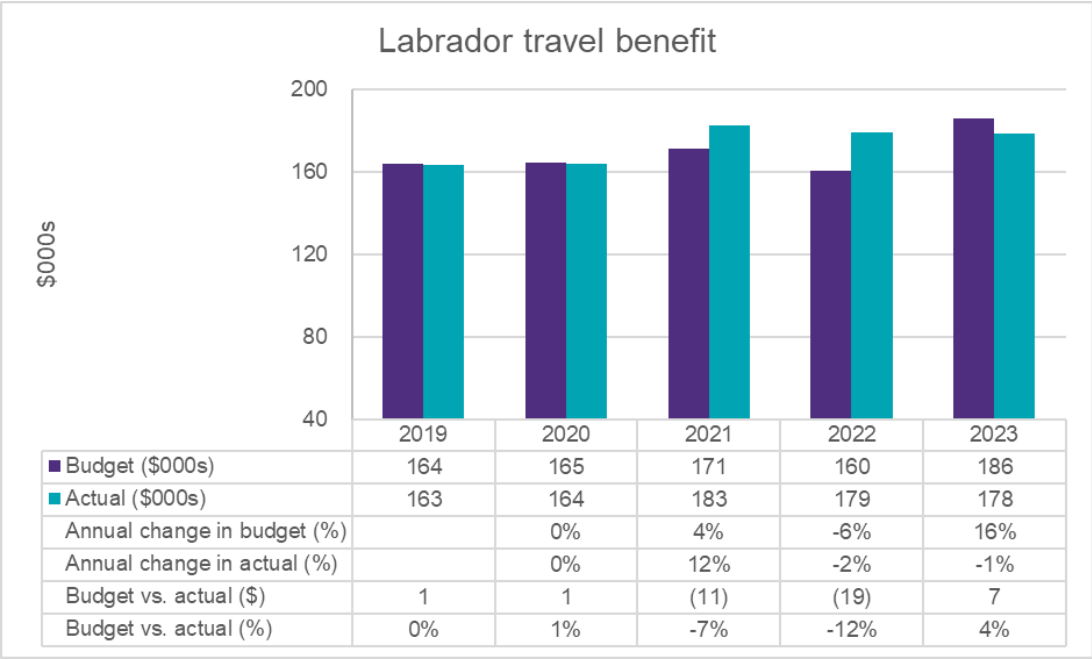
Based on the chart above we identified the following significant variance:

- **2023 actual group insurance was approximately 20% higher than both 2023 budget and 2022 actual.** Per Hydro, budget 2023 was based on data for the period April 2021–March 2022. This budget, finalized in 2022, did not contemplate changes Hydro implemented in the latter part of 2023 to reflect necessary increases in insurance premiums to account for plan experience (i.e., increased benefits usage) and to ensure plan viability. The dataset used to inform the 2023 budget did not reflect market trends occurring post COVID-19 pandemic and was based on a lower employee count reflective of the pandemic period (i.e., 117 fewer employees for health coverage and 183 fewer employees for dental coverage).

Labrador travel benefit

The following chart details the 5-year trends for Labrador travel benefit including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 47 – Labrador travel benefits



	2019	2020	2021	2022	2023
Budget ($000s)	164	165	171	160	186
Actual ($000s)	163	164	183	179	178
Annual change in budget (%)		0%	4%	-6%	16%
Annual change in actual (%)		0%	12%	-2%	-1%
Budget vs. actual ($)	1	1	(11)	(19)	7
Budget vs. actual (%)	0%	1%	-7%	-12%	4%

Hydro noted that it previously used a zero-based budgeting approach for the Labrador Travel Benefit, driven by operational requirements and the estimated number of individuals entitled to the Labrador Travel Benefit at the appropriate rate to derive the expected expenditure for the budget year. However, per Hydro, for the 2025 budget, the methodology shifted to a more data-driven model that uses a three-year historical average of expenditures from 2022 to 2024, adjusted by the GDP deflator to better reflect actual experience.

Based on the chart above we identified the following significant variance:

- **Labrador travel benefit was budgeted to increase by approximately 16% in 2023, however, actual results remained consistent with 2022.** Per Hydro, in 2022, the Labrador Travel Benefit actuals were higher than expected as was the case in 2021. The 2023 Budget amount was adjusted to consider the actual experience in 2021 and 2022.

Compensation matrix

The below matrix illustrates a scale for salary increases and bonuses based on performance ranging from 0 - 6.5% for non-union employees. The compensation matrix allows for pay adjustments above the revised job rate based on an employee's "rating of performance". Ratings of performance include Unacceptable, Improvement Required, Meets Expectations, Exceeds Expectations, and Exceptional.

Figure 48 – Merit compensation matrix (non-union employees)

	Salary Adjustment - Below 100% Job Rate	
Rating of Performance	**2023**	**2022**
Exceptional	6.5% (to the scale maximum)	6.5% (to the scale maximum)
Exceeds Expectations	5.5% (to the scale maximum)	5.5% (to the scale maximum)
Meets Expectations	Up to 4% (to the scale maximum)	Up to 4% (to the scale maximum)

There were no changes in the salary adjustments in 2022 or 2023, however, in October 2023 approval was received to apply a two percent cost of living increase to non-union employees, retroactive to January 1, 2023.

As noted by the Company, all salary adjustment figures are calculated as a percentage of current base salary. All salary adjustments are subject to the maximum scale. Employees can proceed beyond 100% of scale through to 110% if they receive two consecutive years of exceeds and/or exceptional performance ratings. Under these circumstances, once an increase has been applied the employee must then get an additional two years of exceeds and/or exceptional performance ratings before they are entitled to another increase. Employees that are hired in the fourth quarter are not eligible for any increase. Employees with a hire date prior to the fourth quarter will have their merit increase prorated based on their start date.

However, all general scale adjustments were placed on hold as a result of the Order in Council OC2021-127. This order directs the Board of Directors of Nalcor Energy to take such steps as are required to eliminate all performance-based pay policies and incentive programs starting in 2021, and that no action be taken whatsoever with respect to increases in compensation or remuneration for persons not represented by a bargaining agent certified or recognized under an Act of the province, including executive, officers, managers, other staff and employees, and independent contractors. This order remained in effect for both 2022 and 2023. We understand that in 2024, Hydro commissioned Southlea Group LP to complete a Total Compensation Program Review.

Net Full-Time Equivalents

The following table details the average number of net FTE employees by division for 2019 to 2023. Hydro's explanations for changes in 2022 and 2023 noted in net FTE positions are also detailed below.

Figure 49 – Average net FTE employees by division

	2019 [1]	2020 [1]	2021	2022	2023	Note
Executive Leadership	8	9	9	7	7	[2]
Hydro Finance	64	63	59	61	60	
Engineering	129	134	137	132	141	[3]
Transmission Operations	304	284	279	283	281	[4]
Production Operations	207	190	193	190	192	[5]
Corporate Services & Regulatory Affairs	117	111	115	118	124	[6]
	830	**791**	**792**	**790**	**804**	

Note 1: Please note that the 2019 and 2020 FTEs were restated following the release of our 2021 Annual Financial Review of the Company. We have updated the above figures to reflect the Company's restated FTEs.

Note 2: Executive Leadership - Per Hydro, changes in 2022 were due to the transfer of VPs to Hydro Non-Regulated Executive Business Units, partially offset by increased labour recharge in.

Note 3: Engineering – Per Hydro, changes in 2022 were due to higher vacancy due to recruitment challenges. Hydro further noted changes in 2023 were due to filling of vacant positions and conversion of contractors to FTEs.

Note 4: Transmission Operations – Per Hydro, changes in 2022 were due to filling of vacant positions. Hydro further noted changes in 2023 were due to increased vacancy and elimination of the Director role.

Note 5: Production Operations – Per Hydro, changes in 2022 were due to higher vacancy and elimination of the General Manager position. Hydro further noted changes in 2023 were due to increased labour recharge in.

Note 6: Corporate Services & Regulatory Affairs – Per Hydro, changes in 2022 were due to an increase of one FTE and less labour recharge to other areas compared to 2021. Hydro further noted changes in 2023 were due to the addition of four FTEs, filling of vacant positions and increased labour recharge in.

Average salary costs per net FTE for 2019 to 2023 are included in the following table:

Figure 50 – Average salary costs per net FTE

(000s)	2019	2020	2021	2022	2023
Salary costs, including temporary salaries - Figure 38	$76,303	$73,409	$73,970	$73,945	$75,064
Net labour recharge	(1,932)	(1,525)	(1,710)	(137)	302
Total salary costs	74,371	71,884	72,260	73,808	75,366
Net FTE[1] *(in units)*	830	791	792	790	804
Average salary per net FTE	$89,604	$90,877	$91,227	$93,459	$93,703
% increase (decrease)		1.4%	0.4%	2.4%	0.3%

Note 1: FTEs are Hydro based employees, less vacancy, plus time charged to Hydro, less time charged to Hydro from other non-regulated lines of business, excluding FTEs associated with Admin Fees charged by non-regulated lines of business.

The above analysis indicates that the Company experienced a 2.4% increase in average salary per net FTE for 2022, and a 0.3% increase in average salary per net FTE for 2023.

Executive salaries

On November 2, 2021, Hydro announced a reorganization of its executive structure to reduce costs and focus on better serving its customers. Thus, a number of the regulated and non-regulated functions were combined with a focus on business function, rather than line of business under the prior structure. The restructure transferred executive positions supporting shared services departments to Non-Regulated Hydro, meaning executive salaries are first charged to Non-Regulated Hydro, and are then transferred to Regulated Hydro using the established intercompany guidelines. Charges into Regulated Hydro are calculated based on actual hours at the incumbent hourly rate multiplied by the bill rate (1.68) to reflect the all-in cost of the executive.

According to Hydro, Executive Salaries Charged to Regulated Hydro during 2022 and 2023 were as follows:

Figure 51 – Executive Salaries Charged to Regulated Hydro

	2023	2022
President & CEO[1]	$ 394,000	$ -
VP Churchill and Muskrat Falls[2]	7,000	81,000
VP Chief Legal Officer and Corporate Secretary[2]	92,000	163,000
VP People and Corporate Affairs[2]	251,000	180,000
VP Chief Financial Officer[2]	127,000	144,000
Grand Total	$ 871,000	$ 568,000

Note 1: Executive position moved from Regulated to Non-Regulated Hydro in 2023.

Note 2: Executive position moved from Regulated to Non-Regulated Hydro in November 2021.

According to Hydro, Executive Salaries Charged out of Regulated Hydro during 2022 and 2023 were as follows:

Figure 52 – Executive Salaries Charged out of Regulated Hydro

	2023	2022
President & CEO[1]	$ -	$ 182,000
VP Regulatory Affairs & Stakeholder Relations	59,000	33,000
VP Hydro Operations[2]	7,000	15,000
Grand Total	$ 66,000	$ 230,000

Note 1: Executive position moved from Regulated to Non-Regulated Hydro in 2023; however, was budgeted for 2022.

Note 2: Executive position holds accountability for non-regulated operations including Exploits and Star Lake.

The tables below outline the executive salaries by position, including the annual salary, salary earned, performance contract, gross salary, and benefits for 2022 and 2023.

1 ***Figure 53 – Executive salaries by position - 2022***

Position	Annual salary	Salary earned	Salary continuance	Retiring allowance	Retroactive earnings	Vacation pay	Gross salary	Benefits	Total
VP, Power Development	$ 340,000	$ -	$ 340,000	$ -	$ -	$ -	$ 340,000	$ 48,675	$ 388,675
VP, Hydro Engineering & NLSO	238,680	231,286	-	-	5,016	-	236,302	36,329	272,631
VP, People & Corporate Affairs	233,376	225,377	-	-	8,059	-	233,436	35,905	269,341
VP, Hydro Operations	233,376	226,146	-	-	4,904	-	231,050	35,663	266,713
VP, Churchill & Muskrat Falls	291,000	287,292	-	-	4,248	-	291,540	43,277	334,817
VP, Regulatory & Stakeholder Relations	249,600	129,969	-	-	1,846	12,480	144,295	21,910	166,205
VP, Regulatory & Stakeholder Relations	214,200	98,215	-	-	2,462	-	100,677	13,966	114,643
VP, Chief Financial Officer	284,294	275,487	-	-	5,974	-	281,461	42,041	323,502
VP, Chief Legal Officer & Corp Secretary	247,166	239,510	-	-	5,194	-	244,704	37,397	282,101
VP, Transmission & Distribution. & NLSO	215,000	-	40,244	-	-	-	40,244	7,360	47,604
VP, Finance, CF & MF	230,000	-	230,000	-	-	-	230,000	33,842	263,842
VP, Transmission & Town Services	243,984	236,426	-	-	4,248	-	240,674	36,896	277,570
President and CEO	395,000	397,431	-	-	-	-	397,431	55,827	453,258
Total	**$ 3,415,676**	**$ 2,347,139**	**$ 610,244**	**$ -**	**$ 41,951**	**$ 12,480**	**$ 3,011,814**	**$ 449,091**	**$ 3,460,905**

1 ***Figure 54 – Executive salaries by position - 2023***

Position	Annual salary[1]	Salary earned	Salary continuance	Retiring allowance	Retroactive earnings	Vacation pay	Gross salary	Benefits	Total
VP, Power Development	$ 340,000	$ -	$ 340,000	$ -	$ -	$ -	$ 340,000	$ 48,675	$ 388,675
VP, Hydro Engineering & NLSO	238,680	231,286	-	-	5,016	-	236,302	36,329	272,631
VP, People & Corporate Affairs	233,376	225,377	-	-	8,059	-	233,436	35,905	269,341
VP, Hydro Operations	233,376	226,146	-	-	4,904	-	231,050	35,663	266,713
VP, Churchill & Muskrat Falls	291,000	287,292	-	-	4,248	-	291,540	43,277	334,817
VP, Regulatory & Stakeholder Relations	249,600	129,969	-	-	1,846	12,480	144,295	21,910	166,205
VP, Regulatory & Stakeholder Relations	214,200	98,215	-	-	2,462	-	100,677	13,966	114,643
VP, Chief Financial Officer	284,294	275,487	-	-	5,974	-	281,461	42,041	323,502
VP, Chief Legal Officer & Corp Secretary	247,166	239,510	-	-	5,194	-	244,704	37,397	282,101
VP, Transmission & Distribution. & NLSO	215,000	-	40,244	-	-	-	40,244	7,360	47,604
VP, Finance, CF & MF	230,000	-	230,000	-	-	-	230,000	33,842	263,842
VP, Transmission & Town Services	243,984	236,426	-	-	4,248	-	240,674	36,896	277,570
President and CEO	395,000	397,431	-	-	-	-	397,431	55,827	453,258
Total	**$3,415,676**	**$2,347,139**	**$ 610,244**	**$ -**	**$ 41,951**	**$ 12,480**	**$3,011,814**	**$ 449,091**	**$3,460,905**

2 ## Capitalized salaries

3 Capitalized salaries include the salaries and benefits of the Company's employees whose time
4 is charged directly to capital projects. The gross payroll costs for 2019-2023 actuals, 2019 test
5 year, and 2020-2023 budgets were allocated to operations and capital as follows:

6 ***Figure 55 – Gross payroll costs allocated to operations and capital***

(000s)	2019TY	2019A	2020B	2020A	2021B	2021A	2022B	2022A	2023B	2023A
Payroll charged to operating	$ 85,504	$ 84,588	$ 82,638	$ 84,442	$ 80,309	$ 79,000	$ 78,072	$ 82,438	$ 82,094	$ 83,219
Payroll charged to capital	26,072	31,156	28,649	27,835	28,635	30,631	29,702	28,497	30,886	30,812
Total	**$111,576**	**$115,744**	**$111,287**	**$112,277**	**$108,944**	**$109,631**	**$107,774**	**$110,935**	**$112,980**	**$114,031**

7

8 Payroll charged to capital consists of both capital salaries and overtime as detailed below:

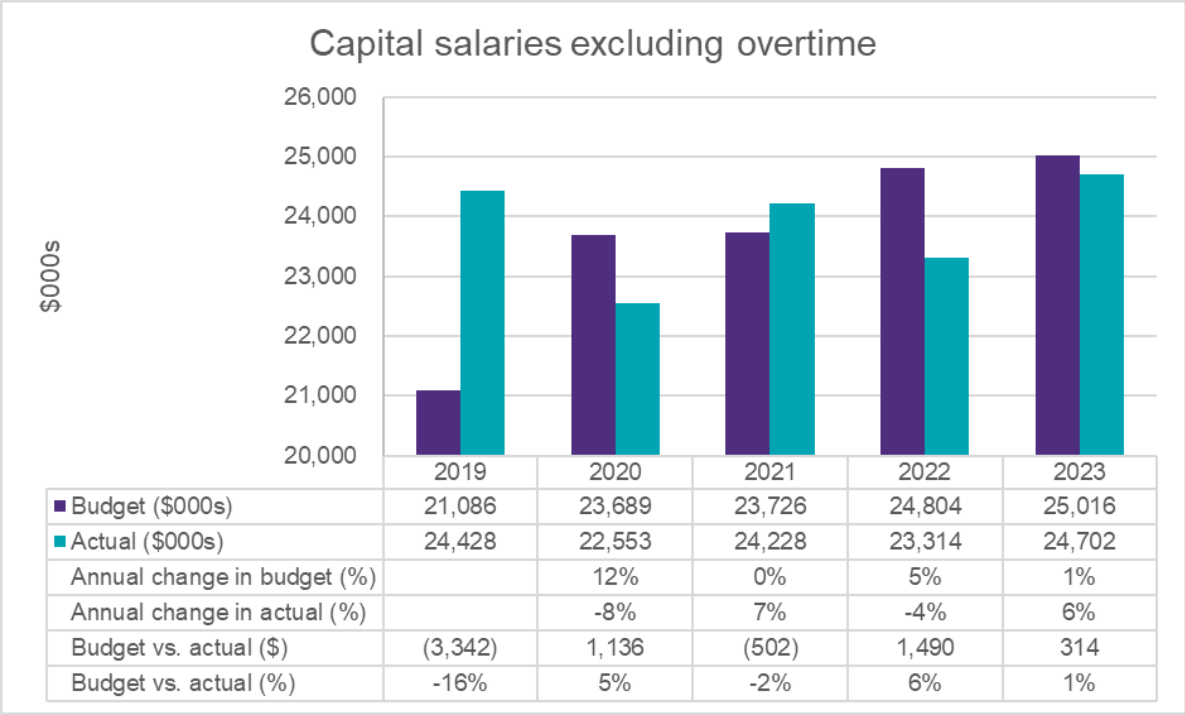
Figure 56 – Capital salaries and overtime

(000s)	2019TY	2019A	2020B	2020A	2021B	2021A	2022B	2022A	2023B	2023A
Capitalized salaries	$ 21,086	$ 24,428	$ 23,689	$ 22,553	$ 23,726	$ 24,228	$ 24,804	$ 23,314	$ 25,016	$ 24,702
Capitalized overtime	4,986	6,728	4,960	5,282	4,909	6,403	4,898	5,183	5,870	6,110
Payroll charged to capital	**$ 26,072**	**$ 31,156**	**$ 28,649**	**$ 27,835**	**$ 28,635**	**$ 30,631**	**$ 29,702**	**$ 28,497**	**$ 30,886**	**$ 30,812**

Capital salaries

The following chart details the 5-year trends for capitalized salaries including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 57 – Capitalized salaries



	2019	2020	2021	2022	2023
Budget ($000s)	21,086	23,689	23,726	24,804	25,016
Actual ($000s)	24,428	22,553	24,228	23,314	24,702
Annual change in budget (%)		12%	0%	5%	1%
Annual change in actual (%)		-8%	7%	-4%	6%
Budget vs. actual ($)	(3,342)	1,136	(502)	1,490	314
Budget vs. actual (%)	-16%	5%	-2%	6%	1%

Hydro uses a zero-based budgeting approach for capital salaries. Per Hydro, each department reviews its annual capital plan and estimates the number of hours each position will dedicate to capital projects. These hours are then multiplied by the applicable bill rate to calculate the total capitalized labour.

Based on the chart above we identified the following significant variance:

- **2019 actual capitalized salaries exceeded budget by 16%.** Per Hydro, the 2019 capital salaries budget was prepared in 2016–2017 to facilitate Hydro's 2017 General Rate Application. This would have resulted in some variation in their expected 2019 capital expenditure projects and the expenditure mix on the jobs between internal capital

labour, contract labour, materials, etc. In particular, the majority of the capital salary variances were driven by the following:

- Engineering services ($2.2 million) – Additional capital recharge primarily relates to additional front-end engineering costs relating to multiple capital jobs, replacement of protective relays in central Newfoundland, upgraded circuit breakers at numerous terminal stations, support in-service failures, and support of turbine refurbishment for Bay d'Espoir ("BDE") Unit 7.

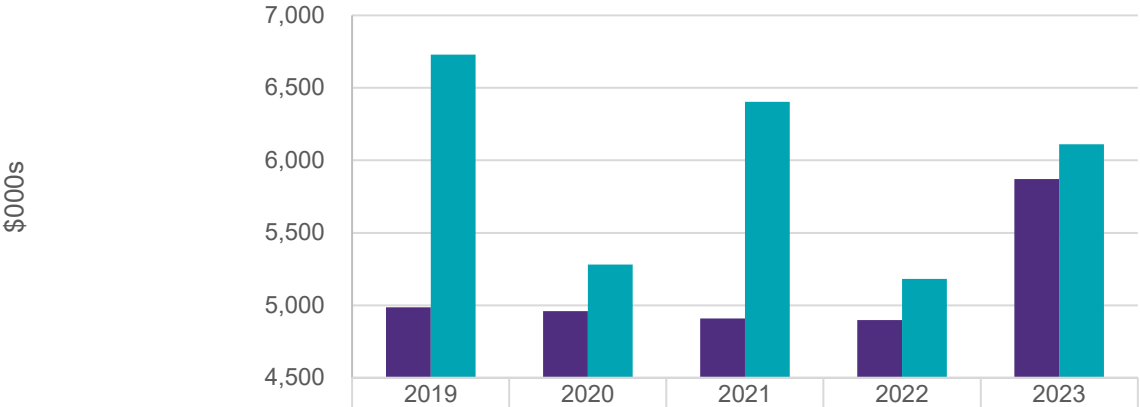
- Hydro production ($1.1 million) – Additional capital recharge relating to turbine refurbishment for BDE Unit 7, refurbishment of powerhouse service station BDE, replacement of pumphouse and equipment in BDE and Hind's Lake Unit 1 overhaul.

- Thermal ($0.4 million) – Additional capital recharge relating to in-service failures, firewater pump refurbishment, upgraded powerhouse crane and other miscellaneous upgrades identified during the 2018 and 2019 maintenance outages.

Capital overtime

The following chart details the 5-year trends for capitalized overtime including 2019-2023 actuals, 2019 test year, and 2020-2023 budgets.

Figure 58 – Capital overtime



	2019	2020	2021	2022	2023
Budget ($000s)	4,986	4,960	4,909	4,898	5,870
Actual ($000s)	6,728	5,282	6,403	5,183	6,110
Annual change in budget (%)		-1%	-1%	0%	20%
Annual change in actual (%)		-21%	21%	-19%	18%
Budget vs. actual ($)	(1,742)	(322)	(1,494)	(285)	(240)
Budget vs. actual (%)	-35%	-6%	-30%	-6%	-4%

Capital overtime is budgeted using the same zero-based approach as regular capitalized salaries. Per Hydro, each department estimates the overtime hours required for capital projects in the upcoming year, and these hours are then multiplied by the applicable bill rate to determine the total capitalized overtime. Hydro noted there were no changes to the budgeting methodology for capital overtime in 2022 and 2023.

Based on the chart above we identified the following significant variances:

- **2019 actual capital overtime was 35% higher than budget**. Per Hydro, the increases in capital overtime for 2019 actuals in comparison to 2019 Test Year is a result of the same factors impacting capital salaries. This would be the early completion of the 2019 capital salaries budget in 2016–2017 to facilitate the 2017 General Rate Application. The majority of the variances are a reflection of the following capital initiatives:
    - Hydro production ($0.6 million) – Additional capital overtime primarily relating to turbine refurbishment for BDE Unit 7 and Hind's Lake Unit 1 overhaul.
    - Thermal ($0.3 million) – Additional capital overtime primarily relating to in-service failures and other miscellaneous upgrades identified during the 2018 and 2019 maintenance outages.
    - Transmission and rural operations ($0.5 million) – Additional capital overtime for Newfoundland and Labrador System Operator group to support Lower Churchill transition to operations and Energy Control Center upgrades, support for transmission in-service failures and other unexpected capital jobs.
    - Gas Turbines ($0.1 million) – Additional capital overtime related to Holyrood Combustion Turbine fuel tanks support.
- **2021 capital overtime was 30% higher than budget.** Per Hydro, the increases in capital overtime for 2021 Actuals in comparison to 2021 Budget is a result of variation in expected capital effort in certain areas versus actual work completed. Variances are driven by the following:
    - Hydro Production ($0.5 million)– Additional capital effort required for hydraulic in-service failures in comparison to estimated amount in capital budget and additional effort required for refurbishment of BDE Unit 5 Generator Stator due to the stator bar removal and stator cleaning. There was also a localized COVID-19 outbreak that led to a pause in work, creating additional effort due to loss of productivity.
    - Thermal ($0.7 million) – Additional capital overtime to support in-service failures due to a higher amount of effort required than expected, partly driven by uncertainty of future operations. Additional drivers include other miscellaneous upgrades as a result of additional boiler refurbishment work and impacts of ongoing COVID-19 protocols.

- Transmission and rural operations ($0.4 million) – Additional capital overtime relating to distribution upgrades due to higher number of service extensions than expected and replacement of diesel generator set in isolated location of Labrador due to unanticipated technical issues requiring additional effort to resolve.

Conclusion and recommendation

We have completed our procedures in the review of Hydro's labour costs. Our review included comparing 2022 and 2023 actual results to prior years, the 2019 Test Year and the 2022 and 2023 Plans. Our analysis included trending on total salaries and fringe benefits, executive compensation, salary expense by FTE, and capitalized salaries and overtime. We identified significant year-over-year trends and made subsequent inquiries with Hydro for further clarification. Our key findings include the following:

- **Total labour costs have remained relatively consistent over the period of our review.**
- **Average net FTE employees by division have deceased from 830 in 2019 to 804 in 2023, and there has not been a significant change in average salary per net FTE.**
- **As a result of the reorganization in 2021, executive positions supporting shared service departments were transferred to Non-regulated Hydro. A pro-rated portion of their labour costs associated with these positions is then charged to regulated Hydro using the established intercompany guidelines.**

Overall, we have not noted any issues in our analysis and are satisfied with Hydro's explanations provided through our inquiry process.

7. Non-regulated activity

Scope

Review Hydro's 2022 and 2023 non-regulated activity and assess the appropriateness of adjustments in the calculation of regulated earnings.

Procedures

To review Hydro's 2022 and 2023 non-regulated activity, we completed following:

- Summarized and reviewed a description of Hydro's various non-regulated activities;
- Reviewed the existence of Hydro's non-regulated statement of earnings and retained earnings for compliance with Board Orders; and,
- Assessed the reasonableness of regulatory adjustments in the calculation of regulated earnings.

Analysis

Description of non-regulated activities

We obtained a description of the key non-regulated activities along with the relevant Business Units ("BU"s) from Hydro. This has been summarized in the following table:

Figure 59 – Non-regulated activities

Non-regulated activity	Description and impact	Relevant business units(s)
Churchill Falls	Services provided to Churchill Falls by Hydro are governed by the CF(L)Co – Hydro Services Agreement dated January 1, 2010. Revenues and expenses from these services are excluded from regulated income determination.	**BU 1955**
Lower Churchill Development Corporation ("LCDC")	No activity has occurred since 2007 but all revenues and expenses from this activity are excluded from regulated income determination.	**BU 1953**
Supply of power to Industrial customers on the Labrador Interconnected System	The rate to recover transmission related costs is regulated by the Board but the rate to recover generation-related costs is not regulated. All revenues and expenses associated with the generation portion are excluded from the determination of regulated net income.	**BU 1952**

Non-regulated activity	Description and impact	Relevant business units(s)
Export sales	Power and energy requirements for the Labrador Interconnected System are met primarily through an agreement with Churchill Falls, allowing Hydro to purchase up to 300 MW and 2,362 GWh annually and any surplus is sold to NEM. To optimize profitability, Muskrat Falls energy may be purchased to make recall energy purchased from Churchill Falls available for export which is captured in BU 1950. BU 1948 captures the power purchase costs and revenue from the sales such that the net impact of these transactions is $nil. During our review, Hydro provided us with an illustrative example of the activity flowing through BU 1948 and the impact of the exported recapture power in the SCDVA. It is our understanding that BU 1948 is credited with revenue based on industrial customer energy requirements at the rate charged by Muskrat Falls, and then charged with a power purchased expense determined by the same calculation. This results in $nil balance in BU 1948. Meanwhile, Regulated Hydro is credited with revenue based on regulated customer energy requirements at the rate NLH can earn on export. Also credited to Regulated Hydro is the incremental difference between industrial customer energy requirements at the Muskrat Falls rate and the NLH Export rate. Regulated Hydro is then charged with power purchased costs calculated based on regulated customer energy requirements at the Muskrat Falls rate. This ultimately results in profits from the difference in rates being reflected in regulated Hydro, specifically within the SCVDA.	**BU 1948** & **BU1950**
Natuashish	Hydro has been operating and maintaining the plant in Natuashish on behalf of the Federal Government on a cost recovery basis. Although the Natuashish assets are owned by Mushuau Innu First Nation, Hydro is responsible for operating and maintaining the assets. All costs relating to the operation and maintenance of the Natuashish assets are charged at bill rates plus overheads to ensure full cost recovery but are not profit driven to earn a return. All revenues and expenses associated with this activity are excluded from the determination of regulated income.	**BU 1405**
Star Lake	Hydro is operating the Star Lake plant as an agent for the Province. The assets are owned by the Province but Hydro is responsible for the operation and maintenance of the assets, costs for which are then recovered from the Province. Hydro also purchases all power generated from these assets which flows through regulated operations. All costs relating to Star Lake are tracked across BUs and actual operating and capital expenditures	**BU 1970**

Non-regulated activity	Description and impact	Relevant business units(s)
	relating to the operation and maintenance of the assets are netted against the power purchased through a contra account. This amount carries forward as a net Accounts Receivable or Accounts Payable balance between Hydro and the Province. Therefore, all revenues and expenses associated with this activity are excluded from the determination of regulated income.	
Exploits	Consistent with Star Lake, Hydro is operating the Exploits generating facilities as an agent for the Province as well. The assets are owned by the Province but Hydro is responsible for the operation and maintenance of the assets, costs for which are then recovered from the Province. Hydro also purchases all power generated from these assets which flows through regulated operations. All costs relating to the Exploits generating facilities are tracked across BUs and actual operating and capital expenditures relating to the operation and maintenance of the assets are netted against the power purchased through a contra account. This amount carries forward as a net Accounts Receivable or Accounts Payable balance between Hydro and the Province. As Hydro acts as an agent for the province, Hydro's revenues and expenses associated with these business units are excluded from the determination of regulated income. Power purchased from Exploits is captured in regulated Hydro.	**BUs 2125, 2127, 2129, 2124**
Ramea project	In accordance with Order No. P.U.31 (2007), all expenses associated with the construction, implementation, operation or abandonment of the wind-hydrogen diesel generation project at Ramea are excluded from the determination of regulated income. Many of the hydrogen assets relating to this project have been written off while wind assets have recently been sold to Frontier Power Systems per Order No. P.U.30 (2024). Therefore, no activity is expected going forward for this project. Please note that there is also a regulated diesel generation operation in Ramea which serves customers in the area as well as wind energy power purchases also used to serve regulated customers. However, the non-regulated operations relate only to the wind-hydrogen diesel generation project per Order No. P.U.31 (2007) which is no longer operational.	**BU 1406**
Conservation demand management	All expenses associated with the energy conservation initiatives in Labrador per Order No. P.U.7 (2008) are excluded from the determination of regulated income. However, Order No. P.U.33 (2022) approved Hydro's proposed revisions to the CDM Cost Deferral Account to allow deferral of conservation and demand management costs incurred for customers on the Labrador Interconnected system. As stated in Hydro's May 28, 2024 Application for July 1, 2024 Utility Rate Adjustments, the	**BU 1949**

Non-regulated activity	Description and impact	Relevant business units(s)
	approved recovery of Labrador Interconnected program costs effective January 1, 2023, will be dealt with through Hydro's future General Rate Applications.	
Cost recovery business units	Cost recovery business units capture costs incurred by Hydro personnel on behalf of other lines of business. These costs are billed on a monthly basis and are excluded from the determination of Hydro regulated income.	**BUs 2100**, **2101, 2103**, **2106**, **1968, 2105**, **2136**
Electric vehicle charging stations	In 2020, Hydro began construction on the province's first electric vehicle fast-charging network consisting of 14 fast charging stations across the Province, funded by Hydro, the Provincial Government, and the Federal Government through Natural Resources Canada. All revenue and expenses associated with these electric vehicle charging stations are excluded from the determination of regulated income.	**BU 1975**
Executive leadership	In June, 2021, Hydro moved the operations of Nalcor Energy under Hydro operations. As part of this organizational change, the Executive leadership team moved to a non-regulated business unit. All revenues and expenses associated with this activity are excluded from the determination of regulated income. Any employee providing services related to this activity will charge their time in accordance with Hydro's Intercompany Transaction Costing Guidelines which have been covered in Section 8 of this report.	**BU 1995**
Finance shared service	Certain finance services are shared among the lines of business and are charged and allocated using an Administration fee in accordance with Hydro's Intercompany Transaction Costing Guidelines which have been covered in Section 8 of this report. Specifically, this administration fee would fall under the common services costs within these guidelines.	**BU 2102** & **BU 2107**
Other specific non-regulated costs	The following are not charged to customers: • Contributions and donations to charities • Advertising expenses • Companion travel costs • Bad debt expenses for uncommon reasons • Power purchases of hydraulic power from Corner Brook Pulp and Paper (export power)	**BU 1955** & **BU 1947**
Dividends	Net cash generated from certain non-regulated activities can be paid to Nalcor as a dividend at the discretion and recommendation of the Chief Financial Officer and must be approved by the Board of Directors. Any remaining cash that is not paid out as dividends is kept within Hydro's legal entity.	**BU 1955**

Non-regulated statement of earnings and retained earnings

In Order No. P.U. 7 (2002-2003), the Board ordered Hydro to file separate financial statements for regulated and non-regulated activities, including reconciliation to annual consolidated financial statements. Included below are the details of the Company's Non-Regulated Statement of Earnings and Retained Earnings for the years ended December 31, 2021 to 2023.

Figure 60 – Non-regulated statement of earnings and retained earnings

				Year-over-year variances			
(000)'s	2021	2022	2023	2022-2021 ($)	2022-2021 (%)	2023-2022 ($)	2023-2022 (%)
Revenue							
Energy sales	$ 51,231	$ 60,002	$ 56,969	$ 8,771	17%	$ (3,033)	-5%
Other revenue (loss)	20,632	15,644	18,855	(4,988)	-24%	3,211	21%
Total revenue	71,863	75,646	75,824	3,783	5%	178	0%
Operations and administration							
Operating costs	1,134	1,115	4,132	(19)	-2%	3,017	271%
Transmission rental and market fees	20,632	15,924	18,855	(4,708)	-23%	2,931	18%
Fuels	21	47	36	26	124%	(11)	-23%
Power purchased	46,882	51,674	51,132	4,792	10%	(542)	-1%
Interest	94	97	-	3	3%	(97)	-100%
Total operating and administration	68,763	68,857	74,155	94	0%	5,298	8%
Net operating income	**3,100**	**6,789**	**1,669**	**3,689**	**119%**	**(5,120)**	**-75%**
Other Revenue							
Equity in CF(L) Co.	41,224	43,486	30,231	2,262	5%	(13,255)	-30%
Preferred dividends	11,204	13,393	6,395	2,189	20%	(6,998)	-52%
Total other revenue	52,428	56,879	36,626	4,451	8%	(20,253)	-36%
Net income	**55,528**	**63,668**	**38,295**	**8,140**	**15%**	**(25,373)**	**-40%**
Retained earnings, beginning of year	$ 563,077	$ 603,496	$ 645,843	$ 40,419	7%	$ 42,347	7%
Net income	55,528	63,668	38,295	8,140	15%	(25,373)	-40%
Dividends	(15,109)	(21,321)	(5,478)	(6,212)	41%	15,843	-74%
Retained earnings, end of year	**603,496**	**645,843**	**678,660**	**42,347**	**7%**	**32,817**	**5%**

Throughout our analysis of the above year-over-year trends, we identified the following variances:

- **Energy sales increase by 17% from 2021-2022.** Per Hydro, there was an increase in energy sales revenue received from Labrador Industrial customers of $5.6 million. This was due to a price and volume increase in both firm energy and imbalance energy. Firm energy rates increased mainly from higher market block rates, which were driven by increased natural gas prices and imbalance energy rates increased as these are based on external market quotes that also increased. Volume increase was driven by increased load requirements from the Unregulated Industrial customers. As well, in 2022, Muskrat Falls and Hydro entered into new arrangements under which a portion of 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 Station. This resulted in an additional $3.8 million in revenue.

- **Other revenue decreased by 24% in 2022, then increased by 21% in 2023.** Per Hydro, other revenue included transmission revenue, which Hydro received from selling the transmission purchased from Hydro-Québec to Energy Marketing to be used for exporting excess recapture energy as per the Power Purchase Agreement in place between Hydro and Energy Marketing. Monthly invoices recorded from Hydro-Québec were approximately $1.72 million per month for 2021 totaling $20.6 million, and $1.57 million per month for 2022 and 2023 totaling $18.8 million. However, during 2022, there were two additional items that occurred, reducing the transmission revenue.

    - During the period from February 12, 2022, to March 31, 2022, there was a short-term amendment to the PPA, in which Hydro would receive the benefit of excess recapture energy exported by Energy Marketing to external markets. This was coupled with other agreements to allow Hydro to purchase Muskrat Falls Residual Block energy to service Labrador customers and maximize the amount of Recapture energy available to export. As an incentive for Hydro to pursue these agreements and amendments, the benefit of the excess recapture exports went to Regulated Hydro to be used for the benefit of ratepayers and offset the costs of Muskrat Falls. As the benefit of the recapture exports went to Hydro, the cost of the transmission rights to export the Recapture to external markets stayed with Hydro as well, so Hydro did not sell the transmission to Energy Marketing during this amendment period, decreasing other revenue received by $2.6 million. This decrease in other revenue is consistent with the decrease in transmission rental and marketing fees in the table, as the transmission costs charged to Non-Regulated Hydro by Hydro-Québec were charged to Regulated Hydro instead to follow the benefit of the recapture export sales revenue.

    - Also in 2022, there was a retroactive adjustment to the monthly transmission invoices from Hydro-Québec for 2021 in the amount of $0.6 million as a result of a reduction in their point-to-point transmission rates.

- **Operating costs increased by 271% in 2023.** Per Hydro, the increase in operating costs by $3 million is primarily related to an increase in bad debt expense of $2 million, other salary of $0.6 million relating to the 2023 portion of the collective agreement adjustment and the vacation accrual, and the timing of recovery of the energy conservation projects.

- **Transmission rental and market fees decreased by 23% in 2022 but then increased by 18% in 2023.** Per Hydro, transmission costs from Hydro-Québec are recorded in Hydro as transmission costs, then resold to Energy Marketing as per the PPA, generating transmission revenue; therefore, the two items partially offset each other. As detailed in the explanations provided for the decrease in other revenue in 2022, the short-term amendment to Hydro and Energy Marketing's PPA and the retroactive adjustment to the monthly transmission invoices from Hydro-Quebec for 2021 contributed to the decrease in this cost category.

- **Fuels increased by 124% in 2022.** Per Hydro, fuel costs were related to diesel used at Battle Harbour for their generators. These costs were incurred as part of Hydro's

Community Investment Program, where Hydro assisted Battle Harbour Historic Trust with the electrical services. In their request, they noted that 2022 was their busiest season to date, with a 37% increase in visitation from their previous best year. Their increase in fuel was a result of the increase in visitation, along with an increase in fuel prices. These donations are included in Non-Regulated Hydro and, as a result, do not impact Regulated Hydro's revenue requirement calculations.

- **Power purchased increase by 10% in 2022.** Per Hydro, in 2022, Hydro began to purchase Muskrat Falls Residual Block energy to service Labrador regulated rural customers and non-regulated industrial customers. This allowed for more recapture energy to be available and sold to Energy Marketing for export to external markets. Regulated Hydro power purchase costs to service Rural and Industrial customers are held at the recapture price, and Regulated Hydro receives the benefits of these arrangements to go to ratepayers via the Supply Cost Variance Deferral Account. To ensure the increased costs of using Muskrat Falls energy to service Labrador Rural and Industrial customers are held at Recapture pricing, the difference between the cost of higher-priced Muskrat Falls energy and Recapture energy is recorded in Non-Regulated Hydro in power purchase costs. This increase in power purchase costs is more than offset by Energy Sales revenue, as the value of incremental Recapture energy sales by Hydro to Energy Marketing exceeds the increased power purchase cost in Non-Regulated Hydro. This ensures that Non-Regulated Hydro is held whole, costs used to service Regulated Labrador customers are held to recapture costs, and Regulated Island customers receive the net benefit of incremental Recapture sales to Energy Marketing.

- **Interest expense was $nil in 2023.** Per Hydro, interest expense recorded pertained to interest on overdue invoices. Due to recurring past due invoices, there has been a greater emphasis on up-front collection on certain projects and parties, which reduced the interest incurred in 2023.

- **The Equity in CF(L) Co. and preferred dividends have fluctuated over the past 3 years.** Hydro provided the following explanations:

    - Equity in CF(L) Co.—The nature of this revenue relates to Hydro's investment (65.8%) in Churchill Falls and is dependent on Churchill Falls earnings for the year. The decrease in Churchill Falls earnings in 2023 was primarily due to a decrease in revenue due to no excess energy sales in 2023 because of low hydrology levels. In 2022, there was excess energy revenue of $38.7 million; whereas, in 2021, it was $nil. In 2021, Churchill Falls received a settlement payment from Hydro-Québec totaling $24.3 million, and they also had excess energy of $3.4 million.

    - Preferred Dividends—The preferred dividend is based on a calculation of taxable income at a rate of 15% per the terms of the shares. It is also dependent on the income earned each year in Churchill Falls. As mentioned above, income was primarily lower in 2023 due to no excess energy revenue in comparison to 2022, which had $38.7 million in excess energy revenue. The primary drivers in 2021

were a settlement payment from Hydro-Québec totaling $24.3 million and excess energy of $3.4 million.

Regulatory adjustments

Given there are separate financial statements for both regulatory and non-regulatory operations, Hydro has reconciled the non-consolidated financial statement balances to the regulated income statement through the application of regulatory adjustments.

This regulatory income statement reconciliation is detailed below for 2022:

Figure 61 – 2022 regulatory income statement reconciliation

(000)'s	Non-regulated (A) [1]	Regulated (B) [1]	Total non-regulated & regulated (C = A + B)	Regulatory adjustments (D) *Note 1*	Non-consolidated income statement (E=C+D) [2]
Revenue					
Energy sales	$ 60,002	$ 637,319	$ 697,321	$ 11,364	$ 708,685
Other revenue (loss)	15,644	13,451	29,095	17,493	46,588
Total revenue	75,646	650,770	726,416	28,858	755,274
Operations and administration					
Operating costs	1,115	130,494	131,609	4,481	136,090
Transmission rental and market fees	15,924	-	15,924	2,908	18,832
Fuels	47	242,958	243,005	(54,797)	188,208
Power purchased	51,674	64,715	116,389	407,937	524,325
Interest	-	85,611	85,611	(5,268)	80,343
Other expense and (income)	0	4,239	4,239	18,162	22,401
Interest	97	86,440	86,537	7,427	93,964
Total operating and administration	68,857	614,457	683,314	380,851	1,064,164
Net operating income	**6,789**	**36,313**	**43,102**	**(351,993)**	**(308,891)**
Other Revenue					
Equity in CF(L) Co.	43,486	-	43,486	-	43,486
Preferred dividends	13,393	-	13,393	-	13,393
Total other revenue	56,879	-	56,879	-	56,879
Net income	**63,668**	**36,313**	**99,982**	**(351,993)**	**(252,011)**

1 *Per Hydro's Quarterly Regulatory Report for the Quarter Ended December 31, 2022.*
2 *Per Hydro's Annual Audited Non-Consolidated Financial Statements for the Year Ended December 31, 2022.*

The regulatory income statement reconciliation is detailed below for 2023:

Figure 62 – 2023 regulatory income statement reconciliation

(000)'s	Non-regulated (A) [1]	Regulated (B) [1]	Total non-regulated & regulated (C = A + B)	Regulatory adjustments (D) *Note 1*	Non-consolidated income statement (E=C+D) [2]
Revenue					
Energy sales	$ 56,969	$ 640,197	$ 697,166	$ 100,170	$ 797,336
Other revenue (loss)	18,855	14,545	33,399	373,669	407,069
Total revenue	75,824	654,742	730,566	473,839	1,204,405
Operations and administration					
Operating costs	4,132	142,759	146,891	5,225	152,116
Transmission rental and market fees	18,855	-	18,855	-	18,855
Fuels	36	245,088	245,124	(57,851)	187,273
Power purchased	51,132	61,643	112,775	864,805	977,580
Interest	-	88,067	88,067	(15,191)	72,875
Other expense and (income)	(0)	2,057	2,057	7,858	9,916
Interest	-	83,143	83,143	11,378	94,521
Total operating and administration	74,155	622,757	696,912	816,224	1,513,136
Net operating income	**1,669**	**31,985**	**33,654**	**(342,385)**	**(308,731)**
Other Revenue					
Equity in CF(L) Co.	30,231	-	30,231	6,395	36,626
Preferred dividends	6,395	-	6,395	(6,395)	-
Total other revenue	36,626	-	36,626	-	36,626
Net income	**38,295**	**31,985**	**70,280**	**(342,385)**	**(272,105)**

1 Per Hydro's Quarterly Regulatory Report for the Quarter Ended December 31, 2023.
2 Per Hydro's Annual Audited Non-Consolidated Financial Statements for the Year Ended December 31, 2023.

In Hydro's Quarterly reports to the Board, the income statement regulatory adjustments are within various accounts. Under IFRS, the regulatory adjustments are included in one regulatory adjustment line. These adjustments represent deferred charges activity. The table below provides a breakdown of the regulatory adjustments for 2022 and 2023. Deferred charges are discussed further in **Section 10** of this report, and specific details on the Supply Cost Variance Deferral Account are detailed in **Section 9**.

Figure 63 – 2023 regulatory adjustment reconciliation

In millions	2023	2022
Deferral activity per figures 73 and 74	339	349
Contributions in Aid of Construction Amortization [1]	1	1
Employee future benefits actuarial loss [2]	2	-
Rounding	-	2
Total regulatory adjustments per above	**$ 342**	**$ 352**

Note 1: Per Order No. P.U. 1 (2017), Hydro recognized amortization of deferred contributions in aid of construction ("CIAC") from entities which are non-customer-related parties in profit or loss. During 2023, Hydro recorded $1.2 million (2022 - $1.2 million) in non-customer CIAC amortization as a regulatory adjustment. In the absence of rate regulation, IFRS requires these non-customer CIACs to be recorded as contributed capital with no corresponding amortization. As a result, during 2023 Hydro also recorded a decrease of $1.2 million (2022 - $1.2 million) to contributed capital to recognize the amount that was reclassified to profit or loss.

Note 2: Per Order No. P.U. 36 (2015), Hydro has recognized the amortization of employee future benefit actuarial gains and losses in net income. During 2023 Hydro recorded $2.0 million (2022 - $nil) employee future benefits losses as a regulatory adjustment. In the absence of rate regulation, IFRS would require Hydro to include employee future benefits actuarial gains and losses in other comprehensive income. As a result, during 2023 Hydro also recorded a decrease of $2.0 million (2022 - $nil) to other comprehensive income to recognize the amount that was reclassified to profit or loss.

As broken down in the tables above, Hydro made approximately $352,000 and $342,000 in regulatory adjustments in 2022 and 2023, respectively. These are IFRS presentation adjustments which reflect deferral activity within the year. These adjustments have been analyzed further in Section 10 of this report.

Conclusion and recommendation

We have completed our procedures in the review of Hydro's non-regulated activity which included understanding Hydro's non-regulated activity, analyzing year-over-year trends of the non-regulated statement of earnings, and reviewing the regulatory adjustments for 2022 and 2023. In our analysis of the non-regulated statement of earnings we found that operating costs increased significantly in 2023. Based on our discussions with Hydro, we understand that the increase in operating costs is primarily due to an increase in bad debt expense. Additionally, we found that transmission rental and market fees fluctuated year -over -year. Based on discussions with Hydro, we understand that transmission costs from Hydro-Quebec are recorded as transmission costs, then resold to Energy Marketing as per the PPA. In 2022, there was a short-term amendment to the Hydro and Energy Marketing PPA and a retroactive adjustment to the monthly transmission invoices from Hydro-Quebec that caused a one-time decrease in this cost category. During our review nothing came to our attention to suggest the adjustments in the calculation of regulated earnings were not appropriate.

8. Corporate structure

Scope

On June 23, 2021, Hydro's corporate structure changed to include all Nalcor Energy operations, which resulted in a change in reporting throughout the organization, including the elimination of the Nalcor executive team. This review should include the following:

a) A review of how costs are allocated between the regulated and non-regulated operations including a review of Hydro's labour costing relating to its billing rates. As part of this analysis, review the process of how labour costs are allocated for senior management that supervise both regulated and non-regulated employees.

b) Identify any areas in the 2023 organizational structure where regulated and non-regulated employees work together for efficiency purposes.

c) A review of the policy regarding the sharing mechanism used to allocate exports between regulated and non-regulated operations and the monetization of deferred energy as per the Muskrat Falls Power Purchase Agreement.

d) Obtain an understanding of the new role of Nalcor Energy Marketing and its reporting structure, including a review of how the costs incurred by Nalcor Energy Marketing is allocated between regulated and non-regulated operations.

e) Also, please comment on whether the current intercompany guidelines continue to be appropriate based on the current organizational structure of Hydro.

Procedures

- Reviewed Hydro's organizational structure. As part of this process, we completed the following:
    - Reviewed departments for which regulated and non-regulated operations have merged as a result of the Government of Newfoundland and Labrador's announcement on June 23, 2021, moving Nalcor Energy's operations under Hydro;
    - Reviewed Hydro's current Intercompany Transaction Costing Guidelines and assessed for appropriateness; and,
    - Reviewed Hydro's labour cost allocation to understand how costs are allocated between regulated and non-regulated operations. Specifically, as part of this process we conducted a walkthrough with Hydro staff to understand how labour is charged for employees that perform services for both regulated and non-regulated business units.

- Reviewed the Nalcor Energy Marketing reporting structure. As part of this process, we completed the following:
    - Reviewed the policy regarding the sharing mechanism used to allocate exports between regulated and non-regulated operations and the monetization of deferred energy as per the Muskrat Falls Power Purchase Agreement;
    - Obtained an understanding of the role of Nalcor Energy Marketing and its reporting structure, including a review of how the costs incurred by Nalcor Energy Marketing is allocated between regulated and non-regulated operations; and,
    - Conducted a walkthrough with Hydro staff to understand the flow of this reporting structure.

Analysis

Organizational structure

Regulated and non-regulated employees

On November 2, 2021, the Government of Newfoundland and Labrador announced that Nalcor Energy's operations would be moved under Hydro. As a result, Hydro announced a reorganization of its executive structure to reduce costs and focus on better serving customers. This reorganization resulted in a number of regulated and non-regulated functions combining with further structural refinements of some shared services groups taking place throughout 2022 and 2023 to increase organizational efficiency. According to Hydro, the following regulated and non-regulated departments have merged to support the whole organization:

1 ***Figure 64 – Reorganization***

Area	Reorganization	Reorganization date
Corporate Communications	The corporate communications reorganization included: • Regulated and non-regulated Public Affairs teams were reorganized reporting to the Director, Public Affairs and Customer Service; and, • The amalgamation of the regulated and non-regulated communications teams within the Strategic Communications, Culture and Brand department, reporting to Manager, Strategic Communications, Culture and Brand.	January 2022
Finance	The regulated and non-regulated Finance teams were combined and reorganized. This reorganization included: • The amalgamation of the regulated and non-regulated Capital teams reporting to the Manager, Capital Accounting and Reporting; • Internal Audit teams reporting to the Director, Internal Audit; Financial services (General Ledger); • Financial reporting teams reporting to the Controller, Hydro; and, • Treasury groups reporting to the Director, Strategic Finance, Treasury & Insurance.	June 2022

Area	Reorganization	Reorganization date
Safety, Health & Environment	The regulated and non-regulated Safety, Health and Environment teams were reorganized reporting to the Director, Safety, Health & Environment.	July 2022
People & Culture	The regulated and non-regulated Human Resources teams were reorganized reporting to the Vice President, People and Corporate Affairs.	May 2023

Intercompany costing guidelines

Hydro filed the Intercompany Transaction Costing Guidelines as part of their 2017 GRA (the "2017 Intercompany Costing Guidelines" or "Intercompany Costing Guidelines") which outlines the guidelines for charging costs across the lines of business within Nalcor. The following sections of this report summarize these guidelines. However, it is important to note that Hydro is currently in the process of updating these Intercompany Costing Guidelines as outlined in the Report on Amalgamation Activities for Hydro and Nalcor Energy – Revision, as submitted by Hydro to the Board on April 17, 2025. Hydro is currently reviewing its Intercompany Guidelines in consideration of the corporate structure changes as a result of amalgamation and in advance of the next GRA. In 2025, Hydro has engaged a third party to review its guidelines with respect to the appropriateness of allocators for intercompany charges and administrative fees, appropriateness of guidelines in light of organizational changes due to amalgamation, appropriateness of new administration fees/allocators proposed by Hydro, and consistency with industry practice.[1] Throughout this section of the report we do refer to Nalcor as a legacy entity to remain consistent with the current Intercompany Costing Guidelines and management responses.

Common service costs

According to Hydro, common service costs are costs for functions that provide common services to various lines of business and are allocated through an Administration Fee. A description of the various common service departments, their allocation basis, and the relevant entity in which the costs are based, has been summarized below. Below is as outlined in the

[1] From NLH - Report on Amalgamation Activities for Hydro and Nalcor Energy - Revision 1 - 2025-04-17.PDF

2017 Intercompany Costing Guidelines with updates made to reflect additional departments designated as common service departments, per discussions with Hydro.

Figure 65– Intercompany Costing Guidelines

Common service department	Description of services	Allocation Basis	Entity
Human resources	Provides general HR services (payroll, pension admin, etc.) to all lines of business	FTE	Nalcor
Safety and health	Provides occupational health services including coordinating corporate efforts for employee safety/wellness.	FTE	Nalcor
Environmental services	Coordinates corporate environmental stewardship	FTE	Nalcor
Information systems	Provides support in software applications, planning and integration/business solutions as well as maintenance of the company-wide computer infrastructure & tech support.	Average user basis ** Costs that are incurred solely for a particular line of business, rather than shared among the lines of business are charged to that line of business and are excluded from the determination of shared costs.*	Nalcor
Office space	Rental charge for floor space occupied by each line of business.	Square footage of space occupied	Hydro
Telephone	Telephone infrastructure and Local Area Network ("LAN") costs	Number of users	Hydro
Accounts payable	Process payables.	Number of invoices processed	Hydro
General ledger	Make adjustments to the general ledger	Number of journal entries posted	Hydro
Procurement	Tendering, purchasing, and contract administration.	Number of purchase orders	Hydro
Network Service	Provide telephone network, local area network and long distance network services.	Average user basis	Hydro

Corporate costs

Corporate costs are the costs of services provided by corporate service departments to other lines of business within Nalcor. Corporate costs incurred within various lines of business are charged to the appropriate line of business as summarized below:

Figure 66 - Allocation of corporate costs

Cost	Description	Allocation basis
Employee labour costs	Time worked by employees of Nalcor, tracked through timesheets that are completed weekly.	Hours worked (charged at cost/bill rate based on the labour cost + fringe benefits + other direct costs).
Overtime	Overtime worked by employees.	Charged as incurred in accordance with the overtime policy.
Fixed charge	Additional charge applied to each hour of regular labour to cover employee related costs such as telephone, subscriptions, membership fees, conferences, training, and other expenses.	Based on hours worked.
Materials cost	Materials issued from inventory.	Charged at cost based on materials used.
Vehicle and other equipment costs	Vehicles used across lines of business.	Charges the rental rate based on type of vehicle and usage time.
Computers	Computer purchases.	Charged directly to the line of business based on the number of computers purchased.

While the above are costs provided by corporate service departments to other lines of business within Nalcor exclusively, the following departments share corporate services across entities:

Figure 67 – Shared services departments

Department	Services
Leadership team	Executive management oversight & management (excluded Hydro prior to the reorganization in 2021 as they had a separate leadership team).
Legal	General counsel - provision of legal and corporate secretary services.
Internal audit	Auditing services as determined in an annual audit plan.

Department	Services
Engineering services	Design, construction, project management, engineering studies/specifications, tender preparation, and review of maintenance problems.
Environmental services	Auditing for compliance with government regulations and policies, obtaining permits and approvals, and advising on environmental matters.
Financial planning	Facilitates the production, review, and distribution of annual long-term financial plans and provides financial planning and analyses.
Risk and insurance	Placement, policies, and claims administration and risk control as well as financing of the corporate insurance program.
Finance	Accounting and treasury services.
Supply chain management	Coordination of procurement process activities.

Cost recovery Business Units

According to Hydro, for business units that incur costs on a cost recovery basis, all costs associated with the activity are charged in accordance with the applicable cost recovery arrangements.

Labour cost allocation

When an employee spends time on specific tasks and work activities for another entity or line of business, time is to be charged at cost. Cost, or the bill rate, is defined as labour costs, fringe benefits (including time off) and other direct costs. The operating bill rates are reviewed annually and updated as required. Labour hours that are recharged through this process are used in the calculation of net FTEs.

Walkthrough

As part of our review, we participated in a walkthrough of Hydro's labour costing relating to its billing rates between regulated and non-regulated operations. During the walkthrough, Hydro reviewed the process of how labour costs are allocated for senior management that supervise both regulated and non-regulated employees.

Employees track time worked for other lines of business using a weekly time sheet. All work hours must be coded in 30-minute increments to work orders in order to adequately track hours to the appropriate business unit. Roles for which individual tasks can be easily traced to regulated verses non-regulated business units code their time by task which is then used to derive the labour recharge amount.

Alternatively, for roles which function on an employee whole basis and are therefore not tracked on a task by task basis, time is charged out on a percentage basis. For example, if the role is

based in the regulated division, time will be charged out based on a percentage representative of non-regulated operations to account for the time utilized by the non-regulated division. According to Hydro, all timesheets receive second-level review and approval to verify the data entered.

Specifically, the walkthrough covered the time allocation process for the following positions:

- **Customer Service:** We looked at an executive in a customer service based role. Labour costs for this role were charged based on daily time worked. The non-regulated tasks are very specific for this role, and as such charged time based on daily time recorded is required for this role.

- **Human Resources:** Another executive timesheet we observed was for an employee who worked in a Human Resources position. Labour costs for this role are defaulted to a non-regulated BU. However, based on the nature of this role, a percentage of the total time worked annually is charged out to the regulated division. In this particular role, the individual is working on employee related matters that deal with employees across the entire organization. For this specific individual, they used a 41% allocation split as their standard percentage to charge out their time. Discretion is used when recording time and the allocation is adjusted weekly depending on the nature of tasks completed by the employee. Based on our discussions with Hydro, we understand that this method of time recording is used by some employees throughout Hydro based on the nature of their roles.

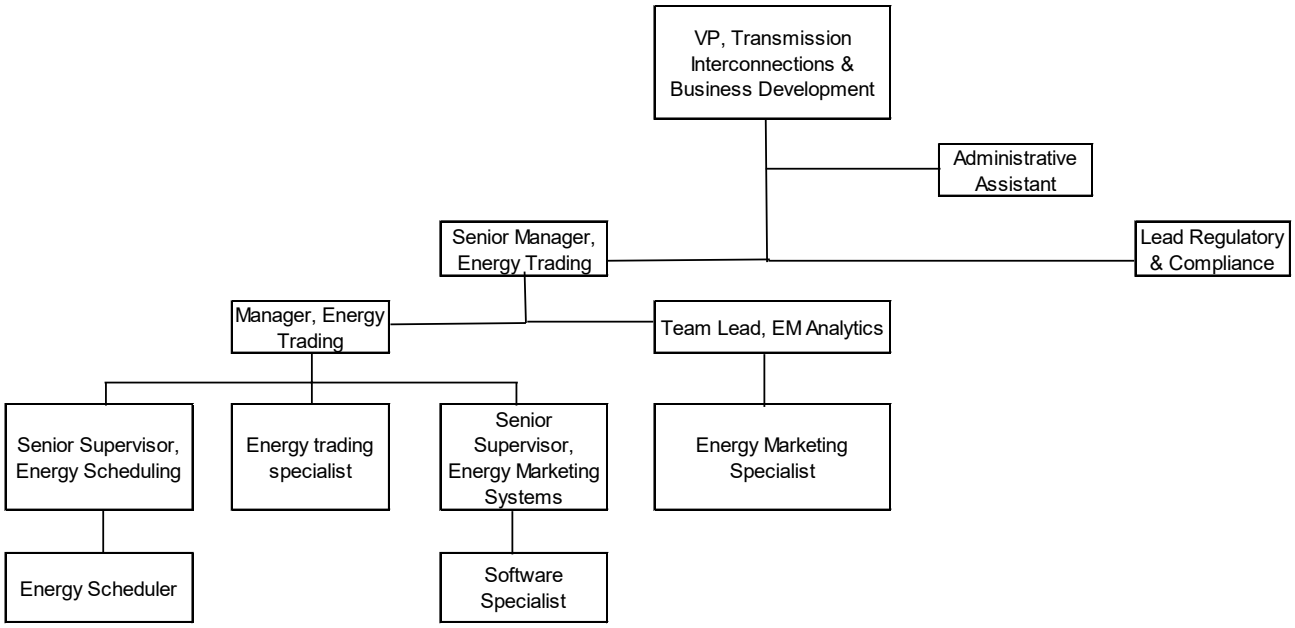
Nalcor Energy Marketing and Exports

NEM Reporting Structure

NEM is a wholly owned subsidiary of Nalcor Energy that was established to manage Nalcor Energy's involvement in extra-provincial electricity markets. NEM is therefore responsible for selling the province's surplus power to external markets.

An organizational chart that summarizes NEM’s reporting structure, updated as of January 15, 2024, is as follows:

Figure 68 - NEM reporting structure updated as of January 15, 2024



Energy exports

NEM purchases energy from Muskrat Falls and Hydro regulated and exports this energy to the electricity market, the price for which is based on market sales proceeds less certain costs incurred. The result is that the revenue recognized by regulated and non-regulated operations is net of costs incurred by NEM.

NEM purchases three types of energy exports, as follows:

1) Legacy recapture;
2) Incremental recapture (both non-regulated and regulated); and,
3) Residual block energy.

A summary of theses transactions and how these costs are allocated between regulated and non-regulated has been detailed in the following table:

1 ***Figure 69 - Energy export transactions***

NEM Exports			
Type of energy	**Description**	**Relevant agreements**	**Allocation between regulated and non-regulated**
Legacy recapture	Hydro purchases recall power and energy from Churchill Falls up to a maximum of 300 MW and 2,362 GWh annually. Power and energy surplus required to meet the needs of the Labrador Interconnected System is sold by Hydro to NEM.	Hydro-NEM PPA, dated October 1, 2015	All revenue and expenses associated with this activity are captured in non-regulated BUs and are excluded from the determination of regulated income. Any employee providing services related to this activity will charge their time in accordance with Hydro's Intercompany Transaction Costing Guidelines.
Incremental recapture (non-regulated Labrador customers)	To optimize the profitability of energy exports, Muskrat Falls energy may be purchased to service non-regulated Labrador industrial customers in order to make recall energy purchased from Churchill Falls available for export.	Hydro-NEM Amendment of PPA, dated February 13, 2022	All revenue and expenses associated with this activity are captured in non-regulated BUs and are excluded from the determination of regulated income. Any employee providing services related to this activity will charge their time in accordance with Hydro's Intercompany Transaction Costing Guidelines.
Incremental recapture (regulated Labrador customers)	Hydro purchases energy from Muskrat Falls for regulated customers in Labrador to optimize the amount of recapture energy available for exports.	Hydro-NEM Amendment of PPA, dated February 13, 2022	This optimization of energy usage in Labrador results in a benefit to Island Interconnected Customers through net revenues credited to the "Net Revenue from Exports Variance" component of Hydro's SCVDA without impacting costs for Labrador customers. These energy exports are recorded in the regulated operations of Hydro and Hydro Regulated records the margin on the energy it sells to NEM in the SCVDA as a component of net exports.

NEM Exports			
Type of energy	**Description**	**Relevant agreements**	**Allocation between regulated and non-regulated**
Residual block energy	Hydro is entitled to a fixed amount of Muskrat Falls block energy per year in addition to any undelivered amounts from prior periods. Throughout the year, Muskrat Falls exports available residual block energy and on an annual basis, Hydro has the option to deem the exports previously recorded by Muskrat Falls as Hydro exports which is referred to as monetization.	Terms of Service Agreement between NEM & Muskrat Falls Corporation, dated July 15, 2022	The estimated value of the monetization is recorded by Hydro in the year in which the exports were made in the SCVDA for the benefit of customers. The amounts are settled in the first quarter of the following year in accordance with the terms outlined in the PPA. Any differences between the estimate and the settlement monetization value are adjusted for in the SCVDA at the time of settlement. These energy exports are recorded in the regulated operations of Hydro.

Walkthrough – export allocations

We completed a walkthrough with relevant Hydro staff members for each type of export. Specifically, our walkthrough included:

1) **Recapture energy**
   We observed how costs pertaining to recapture are allocated between regulated and non-regulated operations. It is our understanding that Hydro charges NEM for the exports it sells to them. Using metering data, this is allocated to regulated and non-regulated operations based on the portion of total energy pertaining to Labrador industrial verses Labrador regulated customers. Hydro regulated's portion of the charge is then broken out further based on the legacy and incremental recapture rates.

   Throughout the walkthrough we observed supporting calculations along with the related invoices and to ultimately understand the impact that the incremental energy purchases has on the "Net revenue from exports" variance component of the SCVDA.

2) **Residual block**
   We reviewed how costs are allocated per the service agreement which includes a calculation of the monthly average sales price for NEM as well as O&M cost reimbursement for costs incurred on behalf of Muskrat Falls.

We also reviewed how the amounts on the invoices are determined which includes power purchased at a monthly average sales price net of O&M costs incurred by NEM on behalf of Muskrat Falls.

In addition, we observed the annual true-up process within the "Net revenue from exports" component of the SCVDA during which the actual settlement of net export sales under the Muskrat Falls PPA are compared to the estimate included in the prior year.

Conclusion and recommendation

We have completed our procedures in the review of Hydro's organizational structure, including the NEM reporting structure, and have concluded on the following:

- **We have reviewed Hydro's current Intercompany Costing Guidelines and have found no exceptions that would deem them inappropriate based on Hydro's current organizational structure. However, given the significance of the recent reorganization, we recognize the need for Hydro to update these guidelines for consideration of the corporate structure changes. We understand that Hydro is currently in the process of reviewing their intercompany costing guidelines.**

- **We have reviewed Hydro's process for cost allocations between the regulated and non-regulated operations, specifically the labour costing process. As part of this process, we conducted walkthroughs with Hydro to understand how labour costs are allocated for senior management that supervise both regulated and non-regulated employees. We found that executive employees charge their time to regulated based on two methods: daily time worked by task, and an overall annual allocation. This is determined based on the nature of the role.**

We have reviewed the policy regarding the sharing mechanism used to allocate exports between regulated and non-regulated operations and the monetization of deferred energy as per the Muskrat Falls Power Purchase Agreement. Our review included reviewing NEM's reporting structure, reviewing the Muskrat Falls Power Purchase Agreement, and conducting walkthroughs with Hydro to understand the nature and treatment of exports. During the course of our engagement Hydro walked us through the process for the three types of energy export transactions; legacy recapture, incremental recapture, and residual block energy.

Based upon our review, we are satisfied with the information provided surrounding Hydro's cost and export allocations. We also note that the intercompany costing guidelines currently in place are dated given the corporate structure changes and warrant a review (which is currently in progress).

9. Supply Cost Variance Deferral Account

Scope

Review the Supply Cost Variance Deferral Account and assess the appropriateness of the activity recorded throughout the year, including the following:

a) Review the various components of the SCVDA to assess compliance with Board Orders.

b) Review the policy and procedures in place with regards to the Indemnity Agreement between Nalcor and Hydro to ensure that the regulated operations are treated appropriately as a result of the reduction in deliveries over the Labrador Island Link when Nalcor commenced the delivery of the Nova Scotia Block.

c) Test the details of the activity in the SCVDA for one month for 2022 and 2023.

Procedures

Our review of the SCVDA include the following specific procedures:

- Agreed all carry-forward data to supporting documentation.
- Reviewed the Supply Cost Variance Deferral Account Reports for the quarters ended December 31, 2022 and December 31, 2023.
- Reviewed the components of the SCVDA and assessed compliance with Board Orders.
- Reviewed the Early Nova Scotia Block Indemnification Agreement.
- Reviewed documentation provided by Hydro and completed walkthroughs with Hydro's Resource and Production Planning ("RPP") team on the policies and procedures in place with regards to the Early Nova Scotia Block Indemnification Agreement between Nalcor and Hydro.
- Selected samples and tested the details of the activity of the SCVDA for May 2022 and March 2023.

Analysis

Components of the SCVDA

The Supply Cost Variance Deferral Account came into effect on November 1, 2021. The SCVDA had an accumulated debit balance, or due from customers balance of approximately $190.4 million at December 31, 2022 and $271.3 million at December 31, 2023 (2021 - $18.3 million). This balance is a receivable for Hydro and is a liability for rate payers. The breakdown

of the Section A and Section B components included in the account, as defined in Order Nos. P.U. 4(2022), in 2022 and 2023 is as follows:

Figure 70 – Summary of activity in the SCVDA

	2023	2022
Section A		
SCVDA balance	$ 283,716,067	$ 196,185,156
Section B		
Utility customer	(12,444,308)	(5,784,457)
Industrial customer	-	-
Total due from customers (due to)	**$ 271,271,759**	**$ 190,400,699**

The table below provides a breakdown of the activity in the Section A and Section B of the SCVDA for 2022 and 2023. Positive values denotes amounts owing from customers to Hydro, while negative values denote amounts owing from Hydro to customers.

Figure 71 – Breakdown of SCVDA

Section A: Summary						
Component	**2022 Opening**	**Adjustment[1]**	**2022 Activity**	**2022 Closing**	**2023 Activity**	**2023 Closing**
Muskrat Falls Project Cost Variance	$ 39,876,511	$ -	$ 237,670,620	$ 277,547,131	$ 577,489,886	$ 855,037,017
Rate Mitigation Fund	-	-	-	-	(335,104,321)	(335,104,321)
Project Cost Recovery - Utility	-	-	(18,942,087)	(18,942,087)	(46,748,860)	(65,690,947)
Project Cost Recovery - Industrial	-	-	-	-	-	-
Holyrood Thermal Generating Station Fuel Cost Variance	(26,879,560)	(1,391,304)	(37,031,409)	(65,302,273)	(48,890,795)	(114,193,068)
Other Island Interconnected System	(3,220,124)	129,804	(25,024,465)	(28,114,785)	(20,453,370)	(48,568,155)
Net Revenue from Exports Variance	-	-	(33,075,710)	(33,075,710)	(15,495,206)	(48,570,916)
Transmission Tariff Revenue Variance	(700,298)	-	(9,412,862)	(10,113,160)	(16,667,936)	(26,781,096)
Load Variation - Utility	10,532,226	-	53,018,419	63,550,645	(10,454,496)	53,096,149
Load Variation - Industrial	2,485,599	-	15,809,289	18,294,888	18,120,808	36,415,696
Greenhouse Gas Credit Revenues Variance	(3,096,317)	-	(9,316,200)	(12,412,517)	(23,081,929)	(35,494,446)
Financing costs - Utility[2]	-	-	(133,641)	(133,641)	(2,341,283)	(2,474,924)
Financing costs - Other[2]	(8,356)	(1,679)	4,896,700	4,886,665	11,158,413	16,045,078
Section A total	**$ 18,989,681**	**$ (1,263,179)**	**$ 178,458,654**	**$ 196,185,156**	**$ 87,530,911**	**$ 283,716,067**
Section B: Summary						
Utility Customer	**2022 Opening**	**Adjustment[3]**	**2022 Activity**	**2022 Closing**	**2023 Activity**	**2023 Closing**
Allocation Rural Rate Alternation	$ (729,046)	$ (123,374)	$ (4,773,368)	$ (5,625,788)	$ (6,162,365)	$ (11,788,153)
Financing Costs[2]	(350)	-	(158,319)	$ (158,669)	(497,486)	(656,155)
Utility customer total	**$ (729,396)**	**$ (123,374)**	**$ (4,931,687)**	**$ (5,784,457)**	**$ (6,659,851)**	**$ (12,444,308)**
Industrial Customer[4]	-	-	-	-	-	-
Section B total	**$ (729,396)**	**$ (123,374)**	**$ (4,931,687)**	**$ (5,784,457)**	**$ (6,659,851)**	**$ (12,444,308)**
Total (Section A + B)	**18,260,285**	**(1,386,553)**	**173,526,967**	**190,400,699**	**80,871,060**	**271,271,759**

Note 1: In August 2021, Nalcor commenced early delivery of the Nova Scotia Block that, combined with limited LIL capacity, meant Hydro could not deliver as much energy from the Muskrat Falls Hydroelectric Generating Facility as it would have 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 opening adjustment of the 2022 balances reflect adjustments to the calculation to eliminate incremental costs incurred by Hydro as a result of reduced deliveries.

Note 2: For the period January to November 2022, the interest rate applied to the deferral account was 1.84% based on the prior year-end rate. In December 2022, the interest expense was trued-up for the year based on the short-term interest rate for 2022 of 4.32%. For the period January to November 2023, the interest rate applied to the SCVDA 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%.

Note 3: There was a correction to the volume calculation for November and December 2021 Rural Rate Alteration that is reflected as an adjustment to the opening balance for 2022.

Note 4: There were no transactions applied to the Industrial Customer balance in 2022 or 2023. Hydro is required to obtain approval from the Board in compliance with Order No. P.U.4 (2022).

Muskrat Falls Project Cost Variance

Per Order No. P.U.4 (2022), the balance applied to the Muskrat Falls Project Cost Variance represents the difference between actual purchased power and test year purchase power under the Muskrat Falls Power Purchase Agreement and Transmission Funding Agreement.

Rate Mitigation Fund

Per Order No. P.U.4 (2022), the Rate Mitigation Fund component pertains to any funding to provide rate mitigation to offset the cost of the Muskrat Falls Project. There was no activity in the Rate Mitigation Fund in 2022 (2021 - $Nil). However, in March 2023, the Government of Newfoundland and Labrador provided $190.4 million for the purpose of mitigating projected future customer rate increases that would be required to recover net supply costs.

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 $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 SCVDA. As a result, the balance for the Rate Mitigation Fund at December 31, 2023 was ($335,104,321) owed to customers.

Project Cost Recovery – Utility and Industrial customers

Per Order No. P.U.4 (2022), the Project Cost Recovery component consists of charges applied to customers to recover Muskrat Falls Project Costs and are tracked by customer class. In Order No. P.U.19 (2022), the Board approved a Project Cost Recovery Rider of 0.798 cents per kWh for the utility, which became effective July 1, 2022, with payments to be credited to the Project Cost Recovery – Utility component of the SCVDA. In Order No. P.U.15 (2023), the Board approved that there was to be no change to the Project Cost Recovery Rider for the utility effective July 1, 2023. There was no activity in the Project Cost Recovery – Industrial component of the SCVDA in 2022 or 2023.

Holyrood Thermal Generating Station Fuel Cost Variance

Per Order No. P.U.4 (2022), this component is based on the difference between actual and test year Holyrood TGS fuel costs incurred monthly to supply firm energy to the customers on the Island Interconnected System.

Other Island Interconnected System

Per Order No. P.U.4 (2022), Other Island Interconnected System component includes cost variances, such as differences between actual and test year, in thermal generation costs, on-island power purchases, Corner Brook Pulp and Paper firm energy power purchases and off-island power purchases, in excess of the Cost Variance Threshold. The Cost Variance Threshold is applied on a calendar year, equals ±$500,000.

Net Revenue from Exports Variance

In Order No. P.U.4 (2022), Net Revenue from Exports Variance reflects the revenues from Hydro exports less the costs incurred to export energy. As per the MFPPA between Hydro and Muskrat Falls, 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. The account is credited in December of each year with an estimate of net export sales that occurred during the year, however, the actual settlement value is not finalized until the following period. The account is adjusted by a true-up in the following period for any differences between estimated and actual value. Order No. P.U. 4 (2022) also notes that revenue from non-firm sales on the Island Interconnected System supplied by hydraulic generation will also be credited to the Net Revenue from Exports Variance component. In 2022 and 2023, non-firm sales from hydraulic sources were not separately identified and were charged to customers at the cost of fuel and credited to the appropriate fuel account.

In Order No. P.U. 34 (2023), Hydro's application to implement a non-firm rate for the Labrador Interconnected System and the Non-Thermal Generation Sources Non-Firm rate for the Island Industrial customers to be calculated based on the export market prices was approved. The Board Order also approved a revision to the SCVDA so that revenues from Rate No. 5.1L – Non-Firm Energy will also be credited to the Net Revenue from Exports Variance component.

Transmission Tariff Revenue Variance

Per Order No. P.U.4 (2022), Transmission Tariff Revenue Variance reflects the transmission revenues paid by third parties to enable exports. It is computed on a monthly basis as the difference between actual and test year transmission tariff revenues paid by third parties.

The LIL was commissioned in April 2023. Starting on May 1, 2023, Energy Marketing has been paying all costs associated with the long-term rights under an interim agreement. Effective June 1, 2023, Hydro assigned its long-term transmission rights, including associated payment obligations, to Energy Marketing for a period of ten years.

Load Variation

Per Order No. P.U.4 (2022), Load Variation component represents firm load variation based on the revenue variation for firm energy sales compared to the test year Cost of Service Study firm sales and is calculated separately for Newfoundland Power firm sales and Island Industrial firm sales.

Greenhouse Gas Credit Revenues Variance

Per Order No. P.U.4 (2022), the Greenhouse Gas Credit Revenues Variance is the difference between actual and test year Greenhouse Gas Credit Revenues. Significant transactions during the period of our review include:

- In July 2022, Hydro sold 230,000 Greenhouse Gas Performance Credits within the province through request for bids ($7.9 million).
- Hydro also sold 406,412 Renewable Energy Certificates associated with the St. Lawrence Wind and Fermeuse Wind projects and the Granite Canal Hydroelectric generating station to external markets through Energy Marketing ($0.6 million).
- In September 2023, Hydro sold 493,536 Greenhouse Gas Performance Credits within the province for $22.5 million through a request for bids.

Rural Rate Alteration

Per Order No. P.U.4 (2022), the Rural Rate Alteration represents the changes in Hydro's rural revenues resulting from changes in Rural Rates between test years and the change in Rural revenues on the Island Interconnected System because of changes in Rural load between test years. 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.

Early NS Block Indemnification Agreement

On July 31, 2012, Nalcor and Emera Inc. entered into the Energy and Capacity Agreement ("ECA"), which obligated Nalcor to deliver energy to the NS Block, pending specific conditions,

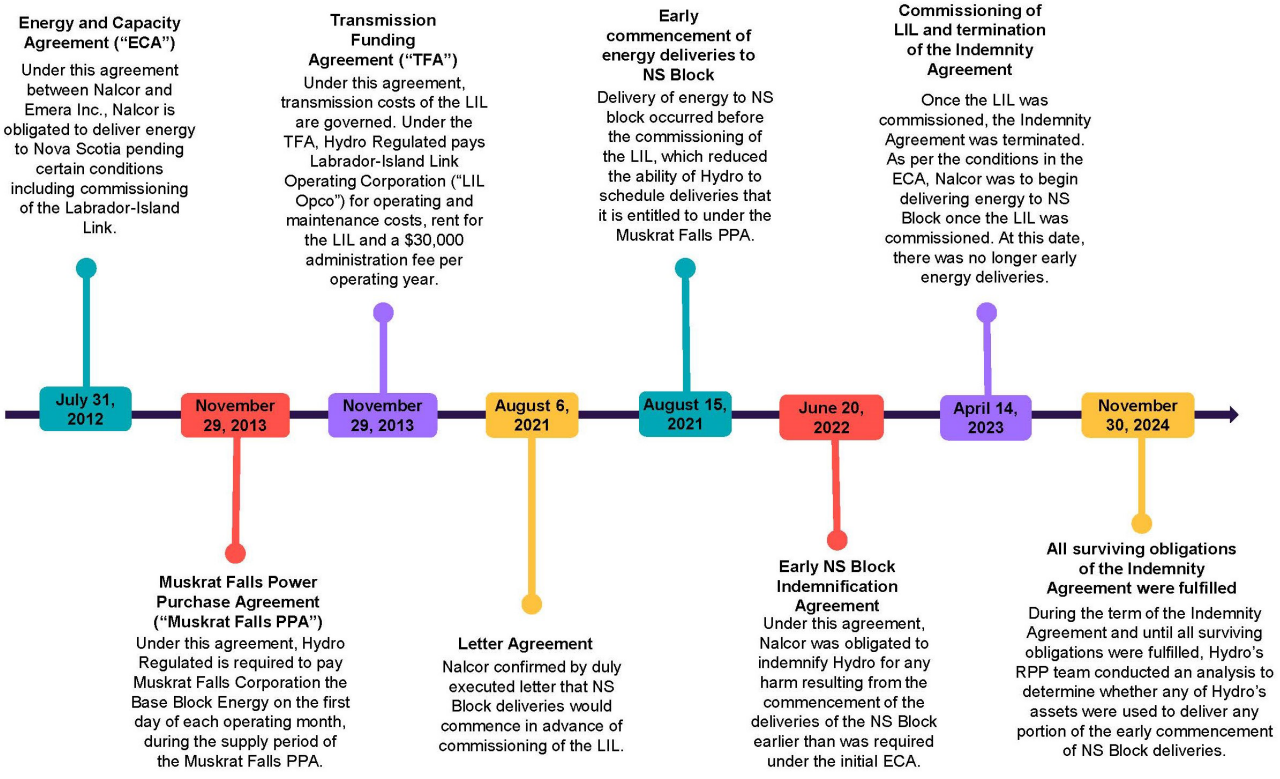
including the commissioning of the Labrador-Island Link. On August 6, 2021, Nalcor confirmed that the NS Block deliveries would commence in advance of the commissioning of the LIL.

Early delivery to the NS Block commenced on August 15, 2021, which reduced the ability of Hydro to schedule deliveries of Commissioning Period Block and Base Block energy, which are blocks of energy that Hydro is entitled to under the Muskrat Falls PPA. The early commencement of deliveries to NS Block, combined with the limited Labrador-Island Link capacity, meant Hydro could not deliver as much energy from the Muskrat Falls Hydroelectric Generating Facility as it would have otherwise.

To indemnify Hydro for any harm which resulted from the early commencement of the deliveries of the NS Block, Nalcor, Hydro and Muskrat Falls Corporation entered into the Early NS Block Indemnification Agreement ("Indemnity Agreement") on June 20, 2022, applied retroactively to August 15, 2021. Under the Indemnity Agreement, Nalcor committed to indemnify Hydro for any damages suffered as a result of the reduction in deliveries, including compensating Hydro for incremental costs of fuel and/or other imports over the Maritime Link. The agreement was terminated upon commissioning of the LIL on April 14, 2023, and all surviving obligations were fulfilled on November 30, 2024.

The following figure illustrates the timeline of events and agreements pertaining to the Indemnity Agreement:

Figure 72 – Timeline of events



Components of the Indemnity Agreement

The indemnity agreement addresses both cost indemnity and deferred energy indemnity, as outlined below.

Cost Indemnity

Under the Indemnity Agreement, Nalcor was to reimburse Hydro for all costs to which it and its customers may have been exposed to as a result of the early commencement of delivery of the NS Block. Costs that Nalcor was obligated to reimburse Hydro include Incremental Thermal Energy and Incremental Imports.

- Incremental Thermal Energy – Nalcor was obligated to reimburse Hydro for Incremental Thermal Energy using gas turbine and Holyrood Thermal Generating Station production costed at the applicable Monthly Non-firm Mill Rate before Administration in the month in which the production was incurred. In the event that Holyrood gas turbine was required to be online, but would not have been if not for the early commencement of deliveries to NS Block, an additional charge of $39,000 was to be paid by Nalcor to Hydro each time the unit was started.

- Incremental Imports – Nalcor was obligated to reimburse Hydro for all costs incurred in the purchase and delivery of importing 21,910 MWh of energy over the Maritime Link to offset declining storage after NS Block deliveries commenced and before commissioning of the Muskrat Falls Plant (“Incremental Commissioning Period Imports”). Hydro was required to secure imports following the commissioning of the Muskrat Falls Plant and before the termination of the Indemnity Agreement. Nalcor was also required to reimburse Hydro for all costs related to the purchase and delivery of imports that would not have been necessary if the energy and capacity available to Hydro had not been reduced by the NS Block deliveries ("Incremental Supply Period Imports").

Deferred Energy Indemnity

Under the Indemnity Agreement, Muskrat Falls Corporation was to indemnify Hydro for all impacts on deferred energy to which it and its customers may have been exposed to as a result of the early commencement of delivery of the NS Block. Adjustments to the balance of deferred energy to which Hydro was entitled include Unavailable Commissioning Period Deferred Energy, Base Block Equivalency, and Deferred Energy Impact Indemnification.

- Unavailable Commissioning Period Deferred Energy – During the supply period, the Muskrat Falls PPA ensures that the entire Base Block to which Hydro is entitled to will be delivered to Hydro, or sold in external markets on its behalf. During the commissioning period, Hydro is entitled to “request Muskrat Falls Corporation to defer the energy portion to become Hydro Deferred Energy” thereby obligating Muskrat Falls Corporation to deliver the incremental Deferred Energy to Hydro, or sell it in external markets on its behalf, at some future time. An analysis completed by Hydro’s Resource and Production Planning group indicated that approximately 25,715 MWh of energy could have been, but due to the early commencement of delivery to NS Block was not,

available to be deferred by Hydro during the commissioning period ("Unavailable Commissioning Period Deferred Energy").

- Base Block Equivalency – Incremental Thermal Energy generated following commissioning of the Muskrat Falls Plant ("Incremental Supply Period Thermal Energy"), and Incremental Supply Period Imports, for which Hydro was reimbursed by Nalcor, are used for NL Native Load at no additional cost to Hydro. Therefore, this energy is effectively equivalent to Base Block energy which, if actually deferred from Muskrat Falls Corporation, would not have been available to be deferred and would result in an equivalent reduction to the balance of Deferred Energy.

- Deferred Energy Impact Indemnification - Upon the effective date, Muskrat Falls Corporation is to increase the balance of the Deferred Energy by the Unavailable Commissioning Period Block Energy less any Incremental Supply Period Imports or Incremental Supply Period Thermal Energy for which Nalcor has previously reimbursed Hydro. Following the effective date, Muskrat Falls Corporation is to decrease the balance of Deferred Energy by any amounts of Incremental Supply Period Imports or Incremental Supply Period Thermal Energy upon reimbursement by Nalcor to Hydro for such amounts of energy.

Indemnity Agreement Invoicing

Under the Indemnity Agreement, Hydro was to prepare and send Nalcor an invoice for any previous calendar month setting out the payments to be made by Nalcor for the month. Nalcor was to pay the invoice prior to accounts payable close for the month in which the invoice was delivered. If Hydro did not deliver an invoice in one month, Nalcor was still obligated to reimburse Hydro for costs incurred in a future invoice.

Hydro's Resource and Production Planning Team analysis

During the term of the Indemnity Agreement and until all surviving obligations were fulfilled, Hydro's RPP team conducted an analysis to determine whether any of Hydro's assets were used to deliver any portion of the NS Block relating to early commencement of NS Block deliveries, in order to ensure Hydro was not disadvantaged. The RPP team conducted two assessments, an initial high-level assessment and a detailed, in-depth analysis.

The RPP team conducted an initial high-level assessment of monthly activities to identify hours with Holyrood Thermal Generating Station off minimum and/or gas turbine generation while there were exports on the Maritime Link resulting from the early commencement of NS Block deliveries.

Following the initial high-level assessment, the RPP team conducted an in-depth analysis. The analysis consisted of assessing the actual daily dispatch for every hour of every day for each month. The RPP team was then able to review the following:

- All generating assets on the Island Interconnected System and the generation for each hour;
- Imports via the LIL;

- Exports via the Maritime Link;
- Imports via the Maritime Link;
- Spinning reserves;
- Regulating reserves;
- Actual load;
- Whether testing occurred on specific assets;
- Planned and/or unplanned outages;
- Emergency energy deliveries;
- Inadvertent payback;
- Operation situations (i.e. frazil ice issues);
- Enacting Capacity Assistance Agreements (Corner Brook Pulp and Paper Limited Capacity Assistance);
- Maritime Link frequency support limitations; and
- LIL operational mode.

The above review was then validated by the Energy Marketing – Marketing Analytics Team. Once the assessment was complete, the RPP team calculated the MWh of gas turbine use and/or Holyrood TGS fuel used and the cost of this activity was calculated using the monthly Non-firm rate for the month in which production occurred.

The costs that Hydro incurs for importing or producing incremental energy in-lieu of obtaining it from Muskrat Falls are initially recorded in Hydro's fuel costs and for the purposes of calculating the fuel component of the SCVDA, the costs associated with the use of Holyrood TGS No. 6 or gas turbine fuel are removed from the fuel costs and included in the SCVDA.

Walkthrough

As part of our review, we completed a walkthrough of the process with Hydro's RPP team. Our walkthrough was for the month ended November 30, 2023 and included the following:

- Demonstration of the initial high-level analysis including observing the initial raw data obtained that shows the hourly activity of every generating asset during the month of review. We then observed how the RPP team refines that data to identify amounts pertaining to Holyrood off minimum and gas turbine generation. The RPP team then reviews whether there is any LIL flow or exports corresponding to the Holyrood off minimum and gas turbine generation activity. The team reviews system diary logs to investigate the nature of the activity and further refines the data to filter out any activity not pertaining to LIL (such as load tests).

- The team then walked us through their process for their more detailed analysis. This includes taking the data refined in the first analysis and obtaining more detailed supporting evidence to determine whether flagged activity warrants indemnification. The team walked us through some of the activity they investigated that warranted indemnification as well as activity that was not applicable. For example, some of the investigated activity was required due to emergency energy requirements which is handled through a separate agreement and would not fall under the indemnification.

- Finally, we then observed how the final monthly amount was summarized, provided to Energy Marketing for the Market Analytics team to review, and ultimately reflected in the fuels costs reimbursed in the SCVDA.

Testing

As part of our review, transactions in the SCVDA were tested for 2022 and 2023. For May 2022 and March 2023, we selected samples for balances in various components of the SCVDA and supporting calculations, invoices, and general ledger adjustments were requested. We found no exceptions in our testing.

Conclusion and recommendation

We have completed our procedures in the review of the Supply Cost Variance Deferral Account and the Indemnity Agreement. Based on our analysis, we note that the SCVDA activity and components are in compliance with relevant Board Orders and we found no errors in our test of details completed for May 2022 and March 2023. We reviewed and completed a walkthrough on the policies and procedures in place with regards to the Indemnity Agreement between Nalcor and Hydro. Based on our review, nothing has come to our attention to suggest that regulated operations were not treated appropriately as a result of the reduction in deliveries of the LIL due to the early commencement of the NS Block.

10. Deferrals

Scope

Conduct a review of the charges (credits) to and amortization of the other deferral accounts and assess their compliance with Board Orders, including the following new deferral accounts that have been implemented in 2022 and 2023:

a) Holyrood Thermal Generating Station Accelerated Depreciation Deferral Account

b) Muskrat Falls Power Purchase Agreement Sustaining Capital Deferral Account

c) Power Purchase Expense Recognition Account

d) Muskrat Falls Export Revenue Recognition Deferral Account

e) Business Systems Transformation Program (approved for recovery)

f) Electrification Cost Deferral Account

g) Conservation and Demand Management Account, including the incorporation of costs relating to the Labrador Interconnected System, and change from 7 years of amortization to 10 years.

Procedures

Our review of deferrals included the following specific procedures:

- Obtained a listing of changes to deferred charges and vouched the additions to Hydro's audited financial statements.
- Agreed all carry-forward data and ending deferred charges to supporting documentation, including audited financial statements and internal accounting records where applicable.
- Reviewed amortization for reasonableness considering the nature of the deferred charge being amortized.
- Assessed compliance with Board orders.

Analysis

The following table shows the transactions in the deferred charges account for 2022, including the prior year.

Figure 73 – 2022 Deferred charges

(000s)	Balance Jan 01/22 (A)	Adjustments (B)	Addition (disposal) (C)	Amortization (D)	Total activity (E = C+D)	Balance Dec 31/22 (F = A + B + E)	21A - 22A (G = A - F)
Regulatory assets/liabilities included in rate base							
Foreign Exchange Losses	$ 43,139	$ -	$ -	$ (2,157)	$ (2,157)	$ 40,982	$ 2,157
Deferred Energy Conservation	8,300	-	1,081	(1,855)	(774)	7,527	774
Deferred Foreign Exchange on Fuel	(16)	-	418	-	418	401	(418)
Asset Disposal	292	-	-	(19)	(19)	273	19
Energy Supply Deferral	12,323	(12,394)	9,027	-	9,027	8,955	3,367
Deferred Power Purchase Savings	(177)	-	-	36	36	(140)	(36)
Business Systems Transformation Program [2]	-	1,626	5,061	-	5,061	6,686	(6,686)
2018 Revenue Deficiency	(1)	-	-	-	-	(1)	-
2019 Revenue Deficiency	77	-	-	-	-	77	-
Hydraulic Resource Optimization	(2,548)	-	(3,164)	-	(3,164)	(5,712)	3,164
Frequency Converter	(473)	-	(229)	-	(229)	(702)	229
Total deferred charges included in rate base	**$ 60,916**	**$ (10,769)**	**$ 12,193**	**$ (3,994)**	**$ 8,199**	**$ 58,346**	**$ 2,570**
Rate Stabilization Plan	56,497	12,193	(16,366)	-	(16,366)	52,324	4,173
Supply Cost Variance deferral	18,260	-	172,140	-	172,140	190,401	(172,140)
Regulatory assets/liabilities that earn interest	**74,757**	**12,193**	**155,775**	**-**	**155,775**	**242,725**	**(167,968)**
Removal Provision	(17,010)	-	(4,963)	-	(4,963)	(21,973)	4,963
Insurance Proceeds	(6,945)	-	2,587	178	2,765	(4,180)	(2,765)
Retirement Asset Pool	19,185	-	16,118	-	16,118	35,302	(16,118)
Regulatory assets/liabilities net in property, plant and equipment	**(4,770)**	**-**	**13,741**	**178**	**13,920**	**9,150**	**(13,920)**
Phase Two Hearing Costs	1,364	-	-	-	-	1,364	-
Muskrat Falls Power Purchase Agreement Sustaining Capital	-	-	536	-	536	536	(536)
Muskrat Falls Export Revenue Recognition Deferral [1]	-	-	25,757	-	25,757	25,757	(25,757)
Power Purchase Expense Recognition [1]	17,573	-	148,155	-	148,155	165,728	(148,155)
Reliability and Resource Adequacy	2,057	-	286	-	286	2,343	(286)
Business Systems Transformation Program [2]	4,600	-	(3,573)	-	(3,573)	1,027	3,573
Regulatory assets/liabilities excluded from rate base [1,2]	**25,594**	**-**	**171,161**	**-**	**171,161**	**196,755**	**(171,161)**
Total regulatory assets and liabilities	**$ 156,498**	**$ 1,424**	**$ 352,870**	**$ (3,816)**	**$ 349,054**	**$ 506,976**	**$ (350,478)**

Note 1: Power Purchase Expense Recognition and Muskrat Falls Export Revenue Recognition represent timing differences in revenue and expense recognition and are excluded from rate base.

Note 2: Business Systems Transformational Program Deferral in the amount of $4.60 million as at January 1, 2022 was not approved to be included in rate base. Subsequently, in Order No. P.U. 27(2022), actual costs totalling $6.68 million, which includes the $4.60 million, were approved to be included in rate base at December 31, 2022.

The following table shows the transactions in the deferred charges account for 2023, including prior year.

Figure 74 – 2023 Deferred charges

(000s)	Balance Jan 01/23 (A)	Adjustments (B)	Addition (disposal) (C)	Amortization (D)	Total activity (E = C+D)	Balance Dec 31/23 (F = A + B + E)	22A - 23A (G = A - F)
Regulatory assets/liabilities included in rate base							
Foreign Exchange Losses	$ 40,982	$ -	$ -	$ (2,157)	$ (2,157)	$ 38,825	$ 2,157
Deferred Energy Conservation	7,527	-	1,384	(1,582)	(197)	7,329	197
Deferred Foreign Exchange on Fuel	401	-	(620)	-	(620)	(218)	620
Asset Disposal	273	-	-	(19)	(19)	254	19
Isolated Systems Supply Cost Variance Deferral Account	8,955	(9,038)	12,142	-	12,142	12,059	(3,104)
Deferred Power Purchase Savings	(140)	-	-	36	36	(104)	(36)
Business Systems Transformation Program [5]	6,686	-	-	-	-	6,686	-
2018 Revenue Deficiency	(1)	-	-	-	-	(1)	-
2019 Revenue Deficiency	77	-	-	-	-	77	-
Hydraulic Resource Optimization	(5,712)	-	-	-	-	(5,712)	-
Frequency Converter	(702)	-	(229)	-	(229)	(931)	229
Total deferred charges included in rate base	**$ 58,346**	**$ (9,038)**	**$ 12,677**	**$ (3,722)**	**$ 8,956**	**$ 58,264**	**$ 82**
Rate Stabilization Plan	52,324	8,685	(13,603)	-	(13,603)	47,407	4,917
Supply Cost Variance deferral	190,401	-	80,871	-	80,871	271,272	(80,871)
Electrification Cost Deferral [1]	-	-	704	-	704	704	(704)
Regulatory assets/liabilities that earn interest	**242,725**	**8,685**	**67,972**	**-**	**67,972**	**319,383**	**(76,658)**
Removal Provision	(21,973)	-	(5,551)	4,728	(823)	(22,796)	823
Insurance Proceeds	(4,180)	-	-	130	130	(4,049)	(130)
Retirement Asset Pool	35,302	-	4,838	-	4,838	40,140	(4,838)
Regulatory assets/liabilities net in property, plant and equipment	**9,150**	**-**	**(713)**	**4,858**	**4,145**	**13,295**	**(4,145)**
Holyrood Thermal Generating Station Accelerated Depreciation	-	-	(9,843)	-	(9,843)	(9,843)	9,843
Phase Two Hearing Costs	1,364	-	-	-	-	1,364	-
Muskrat Falls Power Purchase Agreement Sustaining Capital	536	-	4,444	-	4,444	4,979	(4,444)
Muskrat Falls Export Revenue Recognition Deferral [2]	25,757	-	(12,478)	-	(12,478)	13,279	12,478
Power Purchase Expense Recognition [2]	165,728	-	274,560	-	274,560	440,288	(274,560)
Reliability and Resource Adequacy	2,343	-	296	-	296	2,639	(296)
Business Systems Transformation Program [3]	1,027	-	1,511	-	1,511	2,538	(1,511)
Regulatory assets/liabilities excluded from rate base [2,3]	**196,755**	**-**	**258,490**	**-**	**258,490**	**455,245**	**(258,490)**
Total regulatory assets and liabilities	**$ 506,976**	**$ (352)**	**$ 338,426**	**$ 1,137**	**$ 339,563**	**$ 846,186**	**$ (339,210)**

Note 1: In Order No. P.U.33 (2023), the Board approved Hydro's proposal to establish an account to defer costs related to electrification initiatives effective January 1, 2023. The definition per Order No. PU.33 (2023) states that the account may earn interest at a monthly rate equivalent to the mid-point of the Company's allowed rate of return on rate base and will not be included in rate base until otherwise ordered by the Board. The account shall also be credited with any related funds, contributions or grants, and charged with specified costs pertaining to the electrification program and major studies. Per Hydro, no amounts pertaining to the interest component, operating costs, and revenues were charged to the account in 2023. Hydro has noted that these balances are not considered material but will be recorded through true-up adjustments in fiscal 2025.

Note 2: Power Purchase Expense Recognition and Muskrat Falls Export Revenue Recognition represent timing differences in revenue and expense recognition and are excluded from rate base.

Note 3: Also excluded from rate base is the portion of the Business Systems Transformation Program deferral that has not been approved for recovery per Order. No. P.U. 27 (2022).

Realized foreign exchange losses

Hydro continued to amortize costs associated with foreign exchange losses consistent with past practices.

Conservation Demand Management ("CDM") program

In Order No. P.U. 22 (2017), the Board approved Hydro's CDM Deferral account. In Order No. P.U.33 (2022), the Board approved the proposal to allow deferral of CDM costs incurred for customers on the Labrador Interconnected System in the CDM Cost Deferral Account and noted that Hydro stated it would apply for a revised account definition to align the amortization period between the utilities, but did not approve the proposed deferral of costs associated with the delivery of the electrification programs on the Island Interconnected system.

Subsequently, in Order No. P.U.37(2022), the Board approved revisions to the CDM deferral and cost recovery adjustment definition. The Board approved Hydro's request to increase the amortization period of annual CDM costs from seven to ten years effective as of January 1, 2023 for both historical balances and annual charges. The Board also approved Hydro's proposed modifications to the CDM Cost Deferral Account definition to allow for deferral of costs associated with CDM programs for customers on the Labrador Interconnected System beginning January 1, 2023, including a portion of the Rural Deficit allocation related to CDM investments for Hydro Rural customers. Recovery of the annual amortizations of costs in the CDM account for the Island Interconnected System and Rural Isolated Systems shall be through an annual application to the Board in accordance with Hydro's approved CDM Cost Recovery Adjustment. Recovery of deferred program costs for the Labrador Interconnected System will be dealt with through Hydro's General Rate Applications.

Deferred foreign exchange on fuel

Hydro purchases a significant amount of fuel for the Holyrood Thermal Generating Station in US dollars. Hydro noted that there are regulatory mechanisms that allow Hydro to defer variances in

fuel prices, including foreign exchange fluctuations. According to Hydro the foreign exchange deferral is a change in accounting required due to adoption of IFRS. Prior to IFRS, Hydro recorded the full amount of the foreign exchange gain or loss in inventory. Upon adoption of IFRS, Hydro segregated the foreign exchange gain or loss which would require immediate charge to the company's profit and loss instead of inventory. In order to keep accounting for the RSP consistent with prior years, Hydro created a regulatory asset/liability to segregate the foreign exchange gain or loss until the fuel is consumed at which time the fuel inventory used and the relevant deferred foreign exchange on inventory would be realized and flow through the relevant regulatory mechanisms (e.g. RSP). In Order No. P.U. 30 (2019), the Board approved revised RSP rules to clarify that No. 6 fuel costs in Canadian dollars reflect foreign exchange gains and losses.

Asset disposal

In Order No. P.U. 49 (2016), the Board ordered that Hydro recognize a regulatory asset of $0.4 million related to the Sunnyside transformer that was disposed of in 2014. Hydro is required to recover the deferred asset in rate base and amortize the asset over a 22.4-year period, which commenced in 2015. Hydro is required to exclude the new Sunnyside transformer from rate base until the Sunnyside Transformer Original Asset Deferral has been fully amortized.

Isolated Systems Supply Cost Variance Deferral Account

Pursuant to Order No. P.U. 22 (2017), the Board approved the Supply Cost Deferrals which included the Energy Supply, Holyrood Conversion and Isolated Systems Supply Deferrals. Per Order P.U.33 (2021), the Energy Supply and Holyrood Conversion Deferrals were discontinued as at October 31, 2021 with the account maintained to provide a timely recovery of historic balances. There was no change to the Isolated Systems Supply Cost Variance Deferral Account ("ISSCVDA") in Order No. P.U. 33 (2021).

During 2022, Hydro recorded a balance of $9.0 million owing from customers in the ISSCVDA (2021 – ($2.5 million)), this was an increase of $11.5 million in comparison to 2021. The increase to the ISSCVDA is primarily due to the average increase of 12.9 cents/kWh in the actual fuel price in comparison to the 2019 Test Year. In Order No. P.U. 7(2023), the Board approved the recovery of this balance in the deferral account.

During 2023, Hydro recorded a balance of $12.1 million owing from customers in the ISSCVDA (2022 - $9.0 million), this was an increase of $3.1 million in comparison to 2022. The increase to the ISSCVDA is primarily due to the average increase of 16.9 cents/kWh in the actual fuel price in comparison to the 2019 Test Year. In Order No. P.U. 10(2024), the Board approved the recovery of this balance in the deferral account.

Deferred power purchases

In 1997, the Board ordered Hydro to defer $1.1 million related to reduced purchase power rates resulting from the interconnection of communities in the area of L'Anse au Clair to Red Bay to the Hydro-Quebec system and amortize the balance over a 30-year period.

Business system deferral

As per Order Nos. P.U. 23 (2019) and P.U. 30 (2019), the Board approved the deferral of business system transformation program costs commencing in 2018.

As per Order No. P.U. 27 (2022), the Board approved the recovery of a portion of the deferred costs up to the end of 2022, which totaled $6.7 million, through customer rates to be established in Hydro's next general rate application.

Hydraulic resource optimization

In Order No. P.U. 49 (2018), a deferral account to capture the revenues and costs associated with the hydraulic optimization activities was approved.

Frequency converter

In Order No. P.U. 35 (2020), the Board approved the deferral of the cumulative revenue requirement impact associated with the loss on the sale of a frequency converter, commencing December 2019. The disposition of the cumulative revenue requirement impact included in the deferral account balance will be addressed as part of Hydro's next general rate application.

New deferral accounts

Accelerated depreciation Holyrood thermal generating station

In Order Nos. P.U. 33 (2021) and P.U. 4 (2022), the Board approved Hydro's proposal to establish an account to defer, for future recovery, any difference in excess of ±$2.5 million, between the accelerated depreciation expense for Holyrood thermal generating station in 2022 and 2023 and the accelerated depreciation expense included in the approved 2019 test year.

In 2022, the Holyrood accelerated depreciation expense was $0.2 million lower than the 2019 Test Year depreciation resulting in a regulatory liability of $nil.

In 2023, the Holyrood accelerated depreciation expense was $12.3 million lower (2022 - $0.2 million lower) than the 2019 Test Year depreciation resulting in a regulatory liability of $9.8 million (2022 - $nil). The disposition of the balance of this deferral account is to be determined in a future Board Order.

Muskrat Falls PPA sustaining capital

In Order No. P.U. 33 (2021), the Board approved Hydro's proposal to defer contributions required to be made by Hydro for sustaining capital investments pursuant to the Muskrat Falls PPA with recovery to be addressed in Hydro's next general rate application.

Power purchase expense recognition

In Order No. P.U. 9 (2021) and Order No. P.U. 33 (2021), the Board approved Hydro's proposal to deviate from IFRS to allow recognition of expenses related to the purchase of energy in

accordance with the commercial terms of the Muskrat Falls Power Purchase Agreement and Labrador-island Link Transmission Funding Agreement.

Muskrat Falls export revenue recognition

Under the Muskrat Falls PPA, 30 days following the calendar year end, Hydro is able to monetize an amount of undelivered Schedule II energy at an Annual Average Sales Price of Muskrat Falls energy exports for the previous year. In Order Nos. P.U. 33 (2021) and P.U. 4 (2022), the Board approved Hydro's proposal to recognize an estimate of the monetized energy in the year in which the energy was exported by Muskrat Falls, rather than waiting until Hydro can monetize in the following year.

In 2022, the first year in which it was approved, Hydro recorded an estimate of $25.8 million (2021 - $nil).

In 2023, Hydro reversed the prior year estimate upon actual monetization of the 2022 undelivered Scheduled II energy and recorded an estimate of the monetization of 2023 undelivered Schedule II energy of $13.3 million.

Electrification cost deferral

In Order No. P.U. 33 (2023), the Board approved Hydro's proposal to establish an account to defer costs related to electrification initiatives effective January 1, 2023. The transfer of the net book value and unamortized contributions as of January 1, 2023 for the electric vehicle charging stations approved for recovery in Order No. P.U. 30 (2021) to the Electrification Cost Deferral Account was also approved. As per the definition set out in Schedule A of Order No. P.U. 33 (2023), the account shall be increased (reduced) by an interest charge (credit) on the balance in the account at the beginning of the month, at a monthly rate equivalent to the mid-point of the Company's allowed rate of return on rate base. The account will not be included in the Company's calculation of rate base until otherwise ordered by the Board. The account shall also be credited with any related funds, contributions or grants, and charged with specified costs pertaining to the electrification program and major studies. Per Hydro, no amounts pertaining to the interest component, operating costs, and revenues were charged to the account in 2023. Hydro has noted that these balances are not considered material but will be recorded through true-up adjustments in fiscal 2025.

The balance for 2023 per Return 11 was $0.7 million (2022 - $nil). This amount was excluded from rate base and had no impact on the total deferred charges.

Conclusion and recommendation

We have completed our procedures in the review of Hydro's 2022 and 2023 charges (credits) to and amortization of the other deferral accounts and note the following:

- **We acknowledge that Hydro's regulatory assets/liabilities include significant regulated deferral balances. In 2022 and 2023, the balance of the regulatory assets/liabilities totaled $507 million and $846 million, respectively. We understand that Hydro has plans to address these deferrals. These plans were not**

specifically part of this review. However, we encourage the Board to continue monitoring deferrals in future filings.

- **Based upon our analysis, we noted that recovery of Phase II hearing costs, the reliability and resource adequacy balance, Muskrat Falls Power Purchase Agreement sustaining capital, Holyrood thermal generating station accelerated depreciation, electrification cost deferral, and a portion of the business systems transformation program have not yet been approved by the Board. These deferral accounts have been appropriately excluded from rate base.**

- **We also note that power purchase expense recognition deferral represents a timing difference in expense recognition and is appropriately excluded from rate base.**

- **Finally, we note that the Muskrat Falls export revenue recognition deferral represents a timing difference in revenue recognition and is appropriately excluded from rate base.**

11. Muskrat Falls Power Purchase Agreement and Transmission Funding Agreement

Scope

Charges relating to the MFPPA came into effect November, 2021 and the charges relating to the Transmission Funding Agreement became effective April, 2023. The costs relating to these agreements are billed to Hydro each month based on a forecast and are trued up on a quarterly basis to reflect actual costs. Review and explain the process and controls that Hydro has in place to ensure the actual costs are captured appropriately and are reflective of the agreements.

Procedures

Our review of the processes and controls Hydro has in place pertaining to the MFPPA and TFA included the following procedures:

a) Review the MFPPA and TFA to understand the roles and responsibilities of relevant parties.

b) Obtained process narratives for the preparation of monthly invoices and quarterly true-up adjustments for both the MFPPA and TFA.

c) Observed walkthroughs of the monthly invoicing process for the MFPPA and TFA completed by the Team Lead Finance Lower Churchill PS Support Services and the Controller Lower Churchill & Senior Manager Capital.

d) Conducted testing procedures on the monthly invoicing and quarterly-true up process for both the MFPPA and the TFA. A sample size of two monthly invoices and one quarterly invoice per year was selected for both agreements. As payments under the TFA did not commence until April 2023, no testing was required for fiscal 2022.

Analysis

Muskrat Falls Power Purchase Agreement

Purpose and structure

The Labrador Transmission Corporation (“LTC”) was incorporated in November 2013. LTC was formed to design, construct, finance, operate and maintain the Labrador Transmission Assets (“LTA”) which includes two 315-kV High Voltage alternating current transmission lines connecting the Muskrat Falls hydroelectric generating facility (“MF Plant”), owned by Muskrat Falls Corporation (“MFCo”), with the Labrador-Island Link, the Churchill Falls hydroelectric generating facility (“CF Plant”), and Hydro’s Labrador transmission assets.

Upon the commissioning of MF Plant in 2021, Hydro, MFCo and LTC entered into the Generator Interconnection Agreement ("GIA"). The GIA governs the development and operation of the LTA. Under the terms of the GIA, LTC will recover all costs associated with the LTA from Muskrat Falls.

In November 2013, Hydro entered into a power purchase agreement with Muskrat Falls for the sale of energy and capacity from the MF Plant. Under the PPA, Muskrat Falls recovers all costs incurred under the GIA. Charges relating to the PPA came into effect in November 2021.

Figure 75 – PPA Commercial Agreement Structure

Under the PPA, Hydro is required to make Base Block Payments to MFCo which include the Base Block Capital Costs Recovery and the estimated O&M costs for the operating monthly. The estimated O&M costs are adjusted on a quarterly basis. The figure below outlined the process and components of the Base Block Payments.

Figure 76 – PPA base block payment structure

Base Block Payments		
Component	**Description**	**Occurrence**
Base Block Payments	Hydro pays MFCo for the Base Block Energy on the first day of each operating month during the supply period in the amount equal to the aggregate of: 1) the Base Block Capital Costs Recovery (per Schedule 1 of the PPA), and 2) the Estimated O&M costs for the operating month	First business day of each month
Actual Quarterly O&M Cost Accounting	MFCo delivers a notice of the Actual Quarterly O&M Cost Accounting which sets out the total actual aggregate O&M costs incurred by Muskrat for the operating months in the previous quarter.	Within 60 days after the end of each quarter
Quarterly Adjustment	Within 15 days of receipt of the Actual Quarterly O&M Cost Accounting, Hydro will pay MFCo for the amount by which the actual quarterly cost exceeds the sum of the estimated O&M costs paid during the quarter. Alternatively, if the actual quarterly costs are less than the estimated O&M costs paid by Hydro, MFCo will either pay Hydro the difference or deliver Hydro a notice authorizing Hydro to credit against the next immediate Base Block Payment.	Within 15 days of receipt of the Actual Quarterly O&M Cost Accounting

Controls

During the course of our review, we obtained process summaries of the controls Hydro has in place to ensure that actual costs are captured appropriately and are reflective of the PPA. The figure below outlines the process and controls in place by Hydro for the monthly Base Block Payments.

Figure 77 – PPA base block payment structure monthly controls

Monthly process	Estimated O&M Costs	Estimated Sustaining Capital Costs	Base block payment
Description of invoice component	Budgeted O&M Costs included in the Muskrat Falls PPA invoices are based upon the MFCo and LTC budgets.	The Sustaining Capital costs included in the Muskrat Falls PPA invoices are agreed to the most recent forecasted sustaining capital cash flow information for the period invoiced. Sustaining capital starts with the capital budgets and include forecasted changes from budget.	The Base Block Capital Cost Recovery recovers the development costs (capital and financing costs) of the MF Plant and LTA as well as the assigned Internal rate of return. The total balance for recovery is modeled by Hydro's Financial Planning team in accordance with Schedule 1 and Schedule 2 of the Muskrat Falls PPA. The model calculates the Base Block Capital Supply Price, which is the escalating supply price in dollars per MWh applied to the Base Block Energy scheduled for delivery over the supply period of the Muskrat Falls PPA.
Controls for information relied upon in invoice component	The Joint Operations Committie ("JOC") as per Article 5 of the MFPPA, participate in a review of the budget. The budgets are then approved by both the MFCo and LTC Boards of Directors. Approved budgets are provided to the Collaterial Agent and the Government of Canada for opportunity to reivew, provide questions, and comment.	The JOC as per Article 5 of the MFPPA, participate in a review of the budget.The budgets are then approved by MFCo and LTC Board of Directors. Forecasted changes from budget confirmed with the Capital Accounting team to ensure that they are in line with Capital Program Change Management Committee meeting approvals. Approved budgets are provided to the Collaterial Agent and the Government of Canada for opportunity to review, provide questions, and comment.	The model calculations are reviewed by: 1) Team Lead, Finance, Lower Churchill, 2) Controller Lower Churchill & Senior Manager Capital, and, 3) Senior Manager, Financial Commercial
Controls for review of invoice	Each month the invoices are prepared by the Team Lead, Finance Lower Churchill and reviewed by the Controller Lower Churchill &Senior Manager Capital. The invoices and calculations are sent to Hydro Regulated before the 1st of each month and received by the Controller, Regulated Hydro, Energy Marketing, Financial Services, and the Manager, Financial Reporting and Accounting (a member of the Controller, Regulated Hydro's team). Invoices are reviewed by the Manager, Financial Reporting and Accounting before being sent to the VP, Chief Financial Officer for approval for payment.		

Hydro's process and controls for the quarterly true up process are detailed below.

Figure 78 – PPA base block payment structure quarterly controls

Monthly process	Estimated O&M Costs	Estimated Sustaining Capital Costs	Base block payment
Quarterly true up process	On a quarterly basis, the Team Lead, Finance Lower Churchill prepares the Actual Quarterly O&M Cost Accounting invoice, which reflects the difference between the invoiced O&M and sustaining capital costs for Muskrat Falls and LTA for the prior quarter that were invoiced, and the actual costs incurred. They are sent to Hydro Regulated for their review and approval for payment.		N/A - not adjusted
True up controls	- These quarterly 'true-up' invoices are reviewed by the Controller Lower Churchill and Senior Manager Capital before they are provided to Hydro Regulated. - The invoices are then sent to the Controller, Regulated Hydro, Energy Marketing and Financial Services, and the Manager, Financial Reporting and Accounting (a member of the Controller Regulated Hydro's team). - Invoices are reviewed by the Manager, Financial Reporting and Accounting before being sent to the VP, Chief Financial Officer for approval for payment.		N/A - not adjusted

In addition to the control processes noted in the above figures, Hydro's team also completed additional oversight procedures. On a monthly basis, as part of the reporting process for each line of business and the consolidated entity, a variance analysis is performed on revenue and expenditures. Significant variances are investigated and explained, reviewed by the respective controllers of each line of business. This acts as another control to ensure costs are recorded accurately and in accordance with the respective commercial arrangements. In addition, common coding structures are established in the accounting system to facilitate the categorization of costs.

Walkthrough and testing

As part of our review, we participated in a walkthrough of the monthly base block payment invoicing process. During the walkthrough, Hydro explained the invoicing process and showed us how the monthly invoice amounts are derived. Subsequent to our walkthrough we requested invoices and supporting documentation for January 2022, March 2022, October 2023, and December 2023 as well as the quarterly adjustment for Q1 2022 and Q4 2023. Throughout our testing we did not identify any errors.

Transmission Funding Agreement

Purpose and structure

On November 29, 2013, Hydro entered into the TFA with Labrador-Island Link Limited Partnership ("LIL LP") and Labrador-Island Link Operating Corporation ("LIL Opco"). Under this agreement, Hydro is required to pay for the construction and operation costs of the Labrador-Island Link which carries electricity from Muskrat Falls to the Soldiers Pond terminal station to provide a secure energy supply for customers. While the agreement was signed in 2013, it did not come into effect until the commissioning of the Labrador-Island Link in April of 2023. The figure below summarizes the structure of the commercial agreement.

Figure 79 – TFA commercial agreement structure

The LIL Lease is an agreement between LIL LP and LIL Opco in which the assets and rights of the LIL are leased to LIL Opco. LIL Opco is therefore responsible for maintaining and operating the LIL on behalf of LIL LP. Under the TFA, Hydro is responsible for paying LIL Opco operating and maintenance costs, rent and $30,000 per operating year as consideration for the following commitments:

Figure 80 – TFA payment considerations

TFA payement considerations	
LIL Opco commitments	*"(i) enter into the LIL Assets Agreement, the LIL Lease, the LIL Remedies Agreement and the MPPA; and (ii) operate and maintain the LIL following the Commissioning Date in accordance with the provisions of this Agreement, the LIL Lease and the MPPA"*
LIL LP commitments	*"(i) design, engineer, construct, Commission and obtain and service the Financing for the LIL in a timely manner; (ii) enter into the LIL Assets Agreement, the LIL Lease, the LIL Remedies Agreement and the MPPA; (iii) interconnect the LIL with the LTA and with the existing transmission facilities of NLH, each in accordance with Good Utility Practice and applicable interconnection procedures; and (iv) pay all Sustaining Costs"*

As per the TFA, Hydro is required to make estimated monthly TFA payments to LIL Opco which are then adjusted to actual costs on both quarterly and annually, as needed. The figure below provides a breakdown of the process and components of the TFA payment structure.

Figure 81 – TFA payment structure

TFA payment structure		
Component	**Description**	**Occurrence**
Estimated TFA Payment Invoice for the Operating Year	LIL Opco delivers Hydro a notice setting out LIL Opco's estimate of the operating and maintenance costs, the amount of rent and the $30,000 payable to LIL Opco for the following operating year.	120 days before each operating year
Estimated Monthly TFA Payment	Hydro pays the estimated monthly TFA Payment to LIL Opco in advance on the first business day of each and every calendar month during the TFA term.	First business day of each month
Actual Quarterly TFA Payment Invoice	LIL Opco delivers Hydro the Actual Quarterly TFA Payment Invoice setting out the actual TFA payments payable for the previous quarter.	Within 15 days after the end of each quarter
Quarterly Adjustment	Within 10 days of receipt of the Actual Quarterly TFA Payment Invoice, Hydro will pay LIL Opco for the amount by which the Actual Quarterly TFA Payment exceeds the sum of the Estimated Monthly TFA Payments paid during the quarter. Alternatively, if the Actual Quarterly TFA Payment is less than the sum of the Estimated Monthly TFA Payments paid during the quarter, LIL Opco will either pay Hydro the difference or deliver Hydro a notice authorizing Hydro to credit the amount against future Estimated Monthly TFA Payments.	Within 10 days of receipt of the Actual Quarterly TFA Payment
Annual adjustment	LIL Opco delivers Hydro a notice setting out the amount of the Actual Annual TFA Payment for the prior operating year. If the actual amount is more than the estimated payments made during the year Hydro must pay LIL Opco the difference within 10 days of receiving the notice. If the actual amount is less than the estimated payments made, LIL Opco can either pay the difference to Hydro or deliver a notice authorizing Hydro to credit the difference against future estimated monthly payments.	Within 30 days after the final determination of the tax adjustment amount for the prior operating year
Further adjustments	If either party discovers an over or underpayment of TFA payments for the previous operating year they must provide the party with a notice of the over or underpayment with supporting evidence to be verified by the other party for verification. Once verified the funds are to be paid to the applicable party within 10 days.	Within 10 days of verification or dispute resolutions procedures

Controls

During the course of our review, we obtained process summaries of the controls Hydro has in place to ensure that actual costs are captured appropriately and are reflective of the agreements. The figure below outlines the process and controls in place by Hydro for the Estimated Monthly TFA Payments.

Figure 82 – Estimated monthly TFA payment - process and controls

Monthly process	Budgeted O&M costs of LIL Opco for the operating month	Rent of the LIL calculated in accordance with the LIL lease Agreement	$30,000 admin fee per year
Description of invoice component	The Budgeted O&M Costs included in the TFA invoices are billed based upon the LIL Opco and LIL LP budgets.	Rent of the LIL is calculated based on the LIL Lease Agreement. Rent includes the O&M costs, depreciation, return on undepreciated capital, and recovery of cost of capital for LIL calculated on an annual basis and invoiced equally each month. This amount is modelled and prepared by Hydro's Financial Planning team.	Set as per the TFA
Controls for information relied upon in invoice component	The Joint Operating Committee participates in the review of the budgets. This Joint Operating Committee is established pursuant to the Joint Operations Agreement between Nalcor and Emera. Budgets are approved by the LIL Opco and Labrador-Island Link General Partner ("LIL GP") Boards of Directors. Approved budgets are provided to the Collateral Agent and the Government of Canada for opportunity to review, provide questions and comment.	The model is reviewed by: 1) Team Lead, Finance Lower Churchill 2) Controller, Lower Churchill & Senior Manager of Capital 3) Senior Manager, Finance Commercial.	N/A - Set as per TFA
Controls for review of invoice	Each month the invoices are prepared by the Team Lead, Finance Lower Churchill and reviewed by the Controller Lower Churchill & Senior Manager Capital. The invoices and supporting calculations are sent to Hydro Regulated before the 1st of each month and received by the Controller, Regulated Hydro, Energy Marketing and Financial Services, and the Manager, Financial Reporting and Accounting. Invoices are reviewed by the Manager, Financial Reporting and Accounting before being sent to the VP, Chief Financial Officer for approval for payment.		

Hydro process and controls for the Actual Quarterly TFA Payment Invoice are detailed below.

Figure 83 – Actual Quarterly TFA Payment - process and controls

Quarterly process	Budgeted O&M costs of LIL Opco for the operating month	Rent of the LIL calculated in accordance with the LIL lease Agreement	$30,000 admin fee per year
Quarterly true up process	On a quarterly basis, Lower Churchill Finance Team Lead prepares the Actual Quarterly TFA Payment Invoice, which reflects the difference between the invoiced and actual rent and O&M costs incurred.		N/A - not adjusted
True up controls	The quarterly true-up invoices are reviewed by the Controller Lower Churchill & Senior Manager Capital. The invoices and supporting calculations are sent to Hydro Regulated and received by the Controller, Regulated Hydro, Energy Marketing and Financial Services, and the Manager, Financial Reporting and Accounting. Invoices are reviewed by the Manager, Financial Reporting and Accounting before being sent to the VP, Chief Financial Officer for approval for payment.		N/A - not adjusted

Hydro also noted that on a monthly basis, as part of the reporting process for each line of business and the consolidated entity, a variance analysis is performed on revenue and expenditures. Significant variances are investigated, explained, and reviewed by the respective controllers of each line of business. This acts as another control to ensure costs are recorded accurately and in accordance with the respective commercial arrangements. In addition, common coding structures are established in the accounting system to facilitate the categorization of costs.

Walkthrough and testing

As part of our review, we participated in a walkthrough of the Estimated Monthly TFA Payment invoicing process. During the walkthrough, Hydro explained the invoicing process and showed us how the monthly invoice amounts are derived. Subsequent to our walkthrough we requested invoices and supporting documentation for the October 2023 and December 2023 Estimated Monthly TFA Payment invoices as well as the Q4 2023 quarterly adjustment. Throughout our testing we did not identify any errors.

Conclusion and recommendation

We have completed our procedures in the review of Hydro's process and controls surrounding the MFPPA and TFA charges. As part of our procedures, we reviewed these agreements. We also obtained process narratives and observed walkthroughs of the preparation of monthly invoices and quarterly true up adjustments for both the MFPPA and TFA. We then conducted testing procedures of the monthly invoicing and quarterly true up processes. We did not note any errors in our analysis and conclude that Hydro has adequate processes and controls in place to ensure the actual costs are captured appropriately and are reflective of the agreements.

12. Key performance indicators

Scope

Review Hydro's annual report on Key Performance Indicators and any other information on initiatives and efforts targeting productivity or efficiency improvements in 2022 and 2023.

Procedures

- Reviewed how indicators are established and monitored during the year.
- Obtained analytical detail on variances in KPIs from the prior year. Assessed the reasonableness and consistency of Hydro’s explanations.
- Summarized the result of KPI's and determined whether or not they are meeting the targets.
- Obtained details on any changes to the KPIs used compared to the prior year.
- Assessed compliance with Board orders.

Analysis

In Order No. P.U. 14 (2004) Hydro was ordered to file annually with the Board a report outlining:

- a strategic overview highlighting core strategies, corporate goals and achievements;
- appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including certain specified KPI’s; and
- initiatives targeting productivity or efficiency improvements, including the status of ongoing projects and improved performance resulting from completed projects.

The 2022 annual report on strategic goals and objectives and productivity initiatives was filed with Hydro’s December 31, 2022 quarterly report, and the 2023 annual report on strategic goals and objectives and productivity initiatives was filed with Hydro’s December 31, 2023 quarterly report.

In addition to the filing requirements identified above, Order No. P.U. 14 (2009) requires the filing of a report on Hydro’s Conservation and Demand Management activities. This report is included as Return 21 in the 2022 annual financial return. For 2023, this report has been filed separately.

Strategic Goals and Objectives

The quarterly report referenced above provides information on Hydro's achievements relative to its 2022 and 2023 strategies, goals and initiatives. This section provides details on activities and outcomes relative to a broad range of initiatives undertaken during the 2022 and 2023 fiscal years.

Safety

To track their performance on this objective, Hydro continued to monitor All Injury Frequency ("AIF"), Lost Time Injury Frequency, the ratio of condition and incident reports to lost time and medical treatment injuries ("Lead/lag ratio"), and the severity rate.

According to Hydro, during 2022, the safety team focused on ensuring the safety of employees, contractors and the general public. Some key activities in the year included the following:

- Activities around reducing musculoskeletal injuries, including a rollout of Hydro's Corporate Ergonomics program.
- Promotion of new health and wellness application, to make health resources more accessible to employees.
- Improving contractor safety management.
- Targeted inspections and audits to progress the annual Safety and Health Monitoring Plan.

According to Hydro, during 2023 the safety team continued to focus on ensuring the safety of employees, contractors and the general public. Some key activities in the year included the following:

- The development of improved hazard recognition, evaluation and control processes, and injury prevention campaign initiatives.
- Improving contractor safety management.
- Targeted inspections and audits to progress the annual Safety and Health Monitoring Plan.

The results of the All Injury Frequency and Lead/lag ratio metrics have been presented in the table below:

Figure 84 – AIF and lead/lag ratio 2022 - 2023

Measurement	2022 Actual	2022 Plan	2022 Target Met	2023 Actual	2023 Plan	2023 Target Met
All Injury Frequency (AIF)	0.92	0.50	No	1.14	0.60	No
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	851:1	1,000:1	No	315:1	1000:1	No

Through our analysis of Actual verses Plan AIF and lead/lag ratios, we noted that for 2022 and 2023, Hydro did not meet its lead/lag ratio safety target or its All Frequency metric target as noted above. Further information behind these discrepancies has been summarized below.

Lead/lag ratio

Per Hydro, the Lead/lag Ratio for injuries represents the ratio of leading indicators—near misses, losses (with no injury), observations, and proactive safety measures—to lagging indicators—medical treatment injuries, lost time injuries and fatalities. Historically, Hydro used reporting of safety observations and hazard identification by employees and management in both the office and field through its Safe Workplace Observation Program ("SWOP") as its primary leading indicator. The purpose of such leading indicators is to help identify potential problems or opportunities before they fully materialize, allowing for proactive adjustments and interventions. Over time, Hydro observed a trend in reduced quality of entries in terms of its use and applicability for this indicator and, as a result, shifted its focus to encourage higher quality reporting in 2022 that could better support lessons learned, identify emerging trends and hazards.

Overall, in 2022 and 2023, as a result of the shift to focus on quality reporting of hazards, the number of submissions entered in the SWOP system did align with the volume originally identified when the corporate target for the lead/lag ratio was set. The number of lagging indicators remained relatively consistent compared to other recent years. As intended, this change improved the relevance of safety reports and information provided through the leading indicators; however, the decrease in the total number of leading indicators lowered the overall ratio.

In 2024, the lead/lag ratio was removed as an organizational target. This decision aligns with Electricity Canada's ("EC") safety reporting framework, which does not include the lead/lag ratio as a standard or required metric. Accordingly, Hydro has moved away from using this ratio at the corporate level in line with industry trends and to focus on more meaningful and comparable safety metrics.

All Injury Frequency

Per Hydro, the AIF is based on the total number of recordable injuries (including medical treatment injuries, lost time injuries, and fatalities), which occurred in the calendar year per 200,000 hours worked.

According to Hydro, their AIF rate target in 2022 and 2023 was based on a model not typically used in the utility industry and did not reflect industry comparisons or Hydro's own past or predictive performance; therefore, they believe the target was not set on a realistic basis. Hydro noted that during 2023, they reassessed their performance metrics with a view to update targets to better reflect performance realities and align more closely with EC benchmarks.

In 2024, Hydro began to use the Total Recordable Injury Frequency ("TRIF") Rate instead of the AIF rate. According to Hydro, TRIF is a more representative indicator of safety performance as it tracks First Aid with Restrictions, as well as Medical Treatment injuries, Lost Time injuries, and Fatalities. The AIF tracks only the latter three. The TRIF target is now set to reflect industry averages, in comparison with EC benchmarks, as well as Hydro's historical and forecasted safety performance.

Environment and Conservation

Targets used to evaluate this goal are summarized below:

Figure 85 – Environment and conservation 2022 - 2023

Measurement	2022 Actual	2022 Target	Target Met	2023 Actual	2023 Target	Target Met
Achievement of EMS targets	98%	95%	Yes	97%	95%	Yes
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	1,718 MWh	1,539 MWh	Yes	1,810 MWh	1,346 MWh	Yes

The measurement of annual energy savings from Residential and Commercial Conservation and Demand Management Programs reached its target for 2022 and for 2023.

The 2022 results are primarily due to partnerships and programs detailed below:

- The takeCHARGE partnership offers rebate programs to assist residential and commercial customers in reducing their electricity usage.
- The Hydro Residential Program relates to five programs offered jointly by Hydro and Newfoundland Power.
- takeCHARGE is partnering with the Government of Newfoundland and Labrador under the Low Carbon Leadership Funding Agreement to extend takeCHARGE's current insulation and thermostat rebate program to oil heated customers.

- Isolated Systems Community Energy Efficiency Program provides outreach, education, and energy efficient products in the remote diesel-system communities within Newfoundland and Labrador free of charge.

- Hydro's Commercial Program includes the Business Efficiency and Isolated Business Efficiency programs, which are available to business customers in Hydro's interconnected system and isolated diesel service areas.

- The Electric Vehicle Rebate Program makes electric vehicles more affordable to Newfoundlanders and Labradorians. This program was extended for a second year, with $875,000 available to help encourage the purchase of electric vehicles. Hydro offers a $2,500 rebate for battery-electric vehicles and $1,500 for plug-in hybrid electric vehicles, funded by the Provincial Government of NL.

- The Oil to Electric Rebate Program helps Newfoundlanders and Labradorians wanting to transition their homes to an electricity-based heat source from an oil-based source. This program, funded by the Provincial Government of NL, was extended for a second year and the rebate increased to $5,000 per applicant.

The 2023 results are primarily due to partnerships and programs detailed below:

- The takeCHARGE partnership offers rebate programs to assist residential and commercial customers in reducing their electricity usage.

- The Hydro Residential Program relates to five programs offered jointly by Hydro and Newfoundland Power, and one offered solely by Hydro.

- takeCHARGE continued its partnership with the Government of Newfoundland and Labrador under the Low Carbon Leadership Funding Agreement to extend takeCHARGE's current insulation and thermostat rebate program to oil heated customers.

- Isolated Systems Community Energy Efficiency Program provides outreach, education, and energy efficient products in the remote diesel-system communities within Newfoundland and Labrador free of charge.

- Hydro's Commercial Program includes the Business Efficiency and Isolated Business Efficiency programs, which are available to commercial customers in Hydro's isolated regions.

- The Electric Vehicle Rebate Program continued to make electric vehicles more affordable to Newfoundlanders and Labradorians with Hydro offering a $2,500 rebate for battery-electric vehicles and $1,500 for plug-in hybrid electric vehicles, funded by the Provincial Government of NL.

- The Oil to Electric Rebate Program helps Newfoundlanders and Labradorians wanting to transition their homes to an electricity-based heat source from an oil-based source. This program, funded by the Provincial Government of NL, was extended for another year

and was expanded to include higher incentives for heat pump installations, higher incentives for income-qualified customers, and the exclusion of standalone baseboard resistance heat as a technology option.

Key Performance Indicators

Section 2 to the December 31, 2022 quarterly report filed by Hydro includes the 2022 Annual Report on Key Performance Indicators. Appendix D to the December 31, 2023 quarterly report filed by Hydro includes the 2023 Annual Report on Key Performance Indicators. The Key Performance Indicators results for 2022 and 2023 as compared with prior years are summarized in the following table:

Figure 86 – KPIs 2018 - 2023

Category / KPIs [4]	Measure Definition	Units	2018	2019	2020	2021	2022	2023	Avg. 18-21	2022 Variance from Average	2021-2022 Variance	Avg. 19-22	2023 Variance from Average	2022-2023 Variance
Reliability														
Generation														
Weighted Capability Factor	Availability of Units for Supply	%	78.1	83.2	88.0	79.2	84.2	74.1	82.1	2.1	5.0	83.7	(9.5)	(10.1)
Weighted DAFOR	Unavailability of Units due to Forced Outage	%	7.9	2.0	1.9	11.7	3.1	12.9	5.9	(2.8)	(8.6)	4.7	8.2	9.8
Transmission														
SAIDI	Outage Duration per Delivery Point	Minutes / Point	488.7	403.6	449.2	247.0	258.0	373.1	397.1	(139.1)	11.0	339.4	33.7	115.1
SAIFI	Number of Outages per Delivery Point	Number / Point	3.9	3.4	1.7	1.9	1.9	3.0	2.7	(0.8)	0.0	2.2	0.8	1.1
SARI	Outage Duration per Interruption	Minutes / Outage	125.3	118.7	265.8	130.7	135.1	124.4	160.1	(25.0)	4.4	162.6	(38.2)	(10.8)
Distribution														
SAIDI	Average Outage Duration for Customers	Hours / Customer	19.5	15.0	17.9	21.3	17.5	16.6	18.4	(0.9)	(3.8)	17.9	(1.4)	(0.9)
SAIFI	Number of Outages for Customers	Number / Customer	6.7	5.1	4.6	6.0	4.9	6.3	5.6	(0.7)	(1.1)	5.2	1.1	1.4
End User SAIDI	Average Outage Duration for Customers	Hours / Customer	3.0	2.7	2.7	3.0	2.4	2.3	2.8	(0.4)	(0.6)	2.7	(0.4)	(0.1)
End User SAIFI	Number of Outages for Customers	Number / Customer	1.4	0.9	0.8	1.5	1.1	1.3	1.1	(0.1)	(0.4)	1.1	0.3	0.2
Under Frequency Load Shedding														
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	5	1	-	2	2	-	2	-	-	1.3	(1.3)	(2.0)
Operating														
Hydraulic Conversion Factor [1]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.429	0.425	0.434	0.427	0.427	0.424	0.429	(0.002)	-	0.4	(0.0)	(0.0)
Thermal Conversion Factor [2]	Net kWh / Barrel No. 6 HFO	kWh / BBL	592	588	586	568	573	511	584	(11)	5.0	578.8	(67.8)	(62.0)
Financial (Regulated)														
Controllable Unit Cost [3]	Controllable OM&A$ / Energy Deliveries	$ / MWh	$ 14.55	$ 14.04	$ 14.37	$ 13.78	$ 14.10	$ 15.44	$ 14.19	(0)	0.3	14.1	1.4	12.8
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$30,064	$30,173	$30,292	$28,602	$29,607	$32,390	$29,783	$ (176)	1,005.0	$ 29,669	2,722	2,783
	Generation OM&A$ / New Generation	$ / GWh	$ 8,674	$ 9,117	$ 9,640	$ 9,574	$ 9,506	$11,117	$ 9,251	$ 255	(68.0)	$ 9,459	1,658	1,611
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit	$ / Km	$ 4,266	$ 4,172	$ 4,194	$ 4,086	$ 4,229	$ 4,627	$ 4,180	$ 50	143.0	$ 4,170	457	398
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$ 3,146	$ 3,073	$ 3,079	$ 3,628	$ 3,750	$ 4,101	$ 3,232	$ 519	122.0	$ 3,383	719	351
Other														
Percent Satisfied Customers	Satisfaction Rating	Max = 100%	89%	N/A	90%	N/A	89%	N/A	90%	N/A	N/A	N/A	N/A	N/A

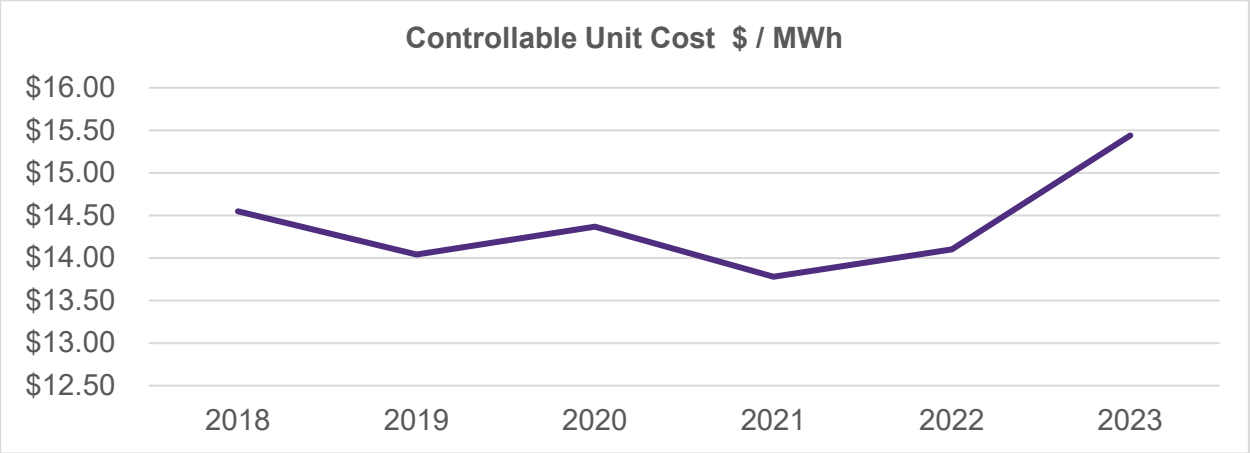
1. For the Bay d'Espoir hydroelectric plant.
2. For Holyrood thermal.
3. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.
4. Doane Grant Thornton did not independently verify the calculation of KPIs.

The following sections illustrate the trends in the actual financial metrics from 2018 to 2023.

Controllable Unit Costs:

Controllable Unit Cost is a high-level corporate KPI that tracks Hydro's operations, maintenance, and administration ("OM&A") expenses in relation to its total energy delivered, expressed as dollars per MWh. The following chart provides a line graph for years 2018 to 2023 of this KPI:

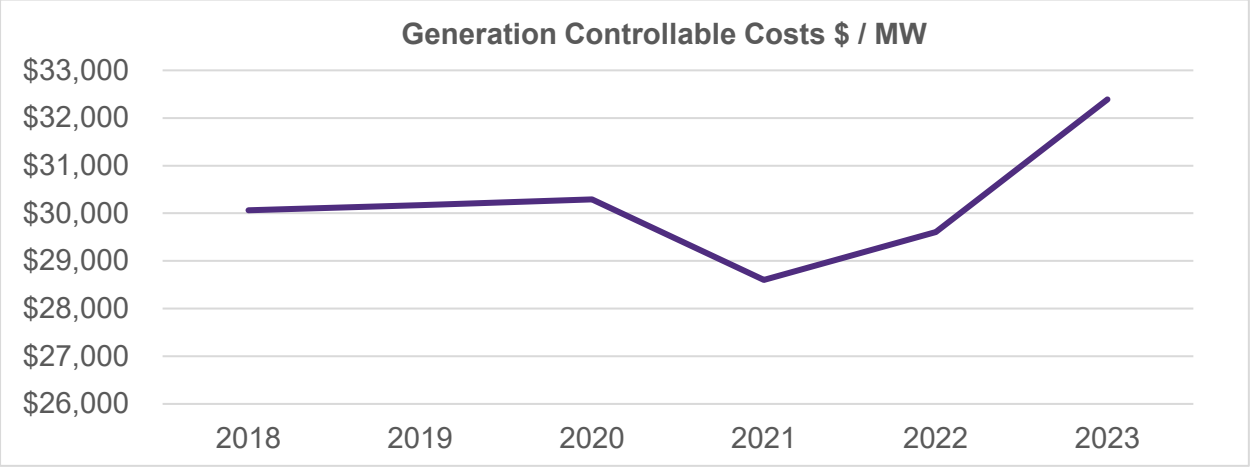
Figure 87 – Controllable unit costs $ / MWh 2018 - 2023



The increase in Controllable Unit Cost from $13.78 per MWh in 2021 to $14.10 per MWh delivered in 2022, and the increase in Controllable Unit Cost from $14.10 per MWh in 2022 to $15.44 per MWh delivered in 2023 was largely due to an increase in OM&A costs. According to Hydro, OM&A costs increased from $126.1 million in 2021 to $130.5 million in 2022, a $4.4 million increase. Further, according to Hydro, OM&A costs increased from $130.5 million in 2022 to $142.8 million in 2023, a $12.3 million increase.

Generation Controllable Costs – Installed MV

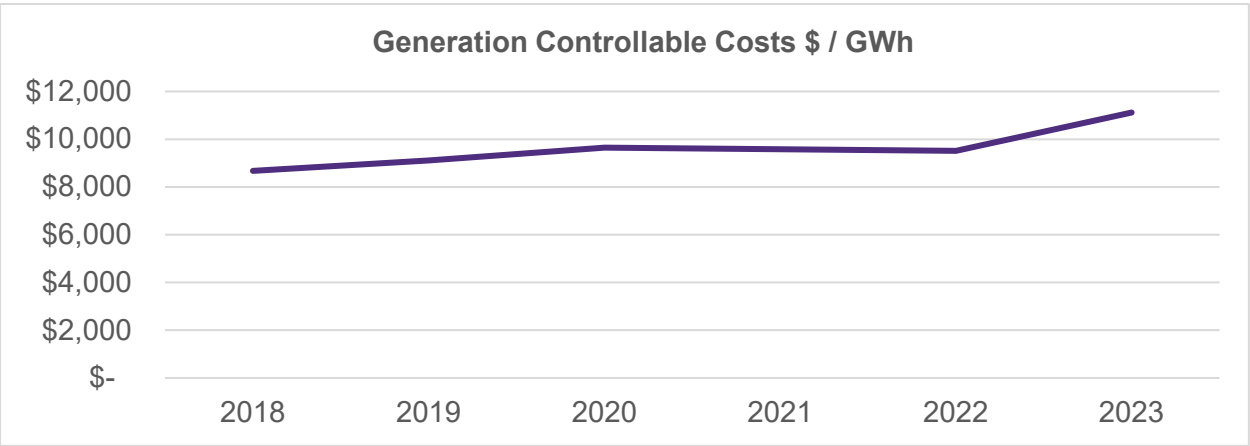
Figure 88 – Generation controllable costs $ / MW 2018 - 2023



There was an increase to Generation Controllable Costs of $1,005 per MW, from $28,602 per MW to $29,607 per MW from 2021 to 2022, and an increase to Generation Controllable Costs of $2,783 per MW from $29,607 per MW to $32,390 per MW from 2022 to 2023. Similar to the table above, the increase in Generation Controllable costs is largely attributed to an increase in OM&A costs in 2022 relative to 2021, and 2023 relative to 2022.

Generation Controllable Costs – New Generation

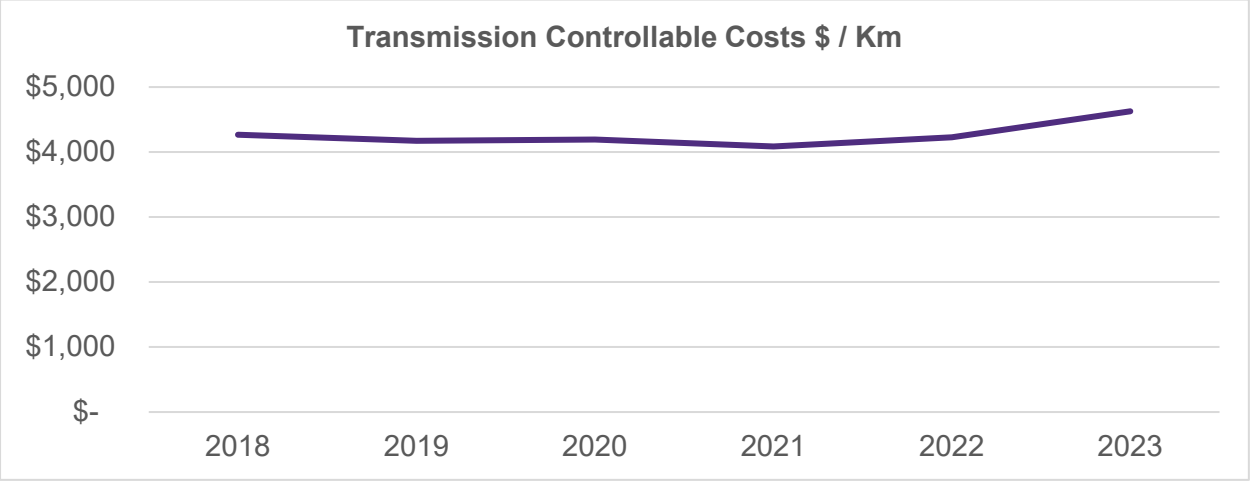
Figure 89 – Generation controllable costs $ / GWh 2018 - 2023



In 2022, there was a slight decrease to Generation Output Controllable Costs of $68 per GWh when compared to 2021. Overall, this cost remained stable when compared to the 2018-2021 period. In 2023, Generation Output Controllable Costs increased by $1,611 per GWh compared to 2022. Overall, this cost remained consistent when compared to the 2018-2022 period.

Transmission Controllable Costs:

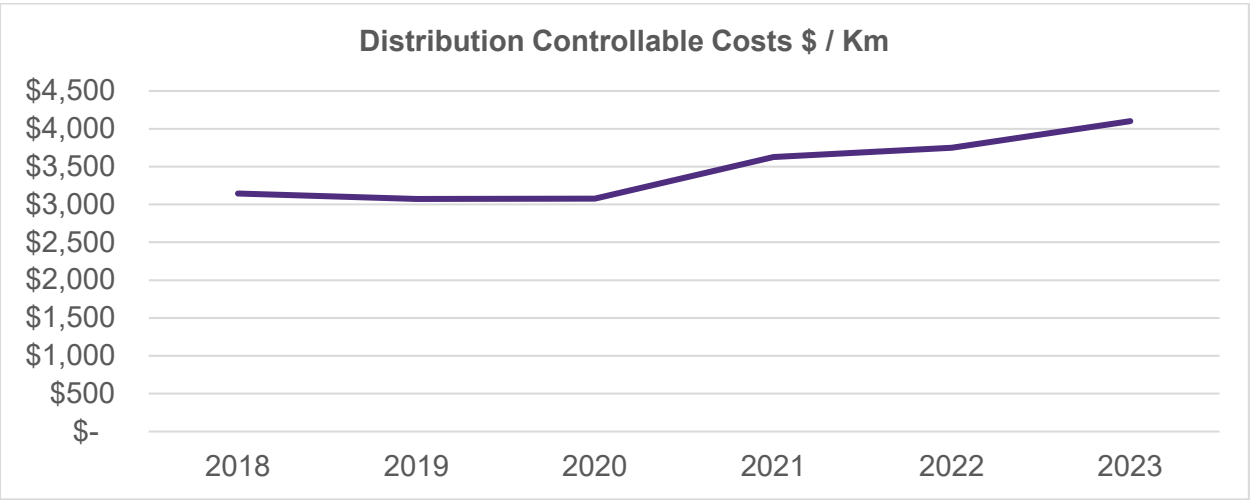
Figure 90 – Transmission controllable costs $ / Km 2018 - 2023



In 2022, Transmission Controllable costs were $4,229 per kilometre, a $143 increase from 2021, and in 2023 Transmission Controllable costs were $4,627 per kilometer, a $398 increase from 2022. These costs have remained stable over the past six years.

Distribution Controllable Costs:

Figure 91 – Distribution controllable costs $ / Km 2018 - 2023



In 2022, Hydro's Distribution Controllable Cost increased by $122 per kilometer compared to 2021, and in 2023, Hydro's Distribution Controllable Cost increased by $351 per kilometer compared to 2022. Hydro attributes these higher costs to the rural and geographically dispersed nature of its distribution system.

As consistent with prior year, Hydro reports on 18 KPIs covering the following four areas: reliability, operating, financial and customer related.

Figure 92 – Four areas of KPIs 2022 – 2023

Category	KPI	Units	2022 Target	2022 Results	Target Achieved	2023 Target	2023 Results	Target Achieved
Reliability	Weighted Capability Factor (WCF)	%	80.1	84.2	Yes	80.1	74.1	No
	Weighted DAFOR	%	5.9	3.1	Yes	7.0	12.9	No
	T-SAIDI	Minutes / Point	395.1	258.1	Yes	486.6	373.1	Yes
	T-SAIFI	Number / Point	2.6	1.9	Yes	3.4	3.0	Yes
	T-SARI [2]	Minutes / Outage	N/A	135.1	N/A	N/A	124.4	N/A
	D-SAIDI	Hours / Customer	18.9	17.5	Yes	18.5	16.6	Yes
	D-SAIFI	Number / Customer	5.6	4.9	Yes	5.5	6.3	No
	End User SAIDI	Hours / Customer	2.8	2.4	Yes	2.8	2.3	Yes
	End User SAIFI	Number / Customer	1.2	1.1	Yes	1.1	1.3	No
	Underfrequency Load Shedding	# of events	6	2	Yes	6	0	Yes
Operating	Hydraulic CF	GWh / MCM	0.433	0.427	No	0.434	0.424	No
	Thermal CF	kWh / BBL	583	573	No	583	511	No
Financial	Controllable Unit Cost	$/MWh	N/A	$14.10	N/A	N/A	$15.44	N/A
	Generation Controllable Costs	$/MW	N/A	$29,607	N/A	N/A	$32,390	N/A
	Generation Output Controllable Cost	$/GWh	N/A	$9,506	N/A	N/A	$11,117	N/A
	Transmission Controllable Cost	$/Km	N/A	$4,229	N/A	N/A	$4,627	N/A
	Distribution Controllable Cost	$/Km	N/A	$3,750	N/A	N/A	$4,101	N/A
Other	Customer Satisfaction (Residential)	Max = 100%	85%	89%	Yes	N/A	N/A	N/A

1. WCF Target is based on planned annual maintenance outages, an allowance for other short duration maintenance outages and targeted forced outage durations.

2. According to Hydro, they do not establish a restoration index target.

Further information and observations on each of the above categories has been summarized below.

Reliability

During 2022, Hydro met 9 out of the 9 reliability KPIs, and during 2023 Hydro met 5 out of the 9 reliability KPIs, as noted above. Within the reliability category, in 2023 Hydro did not achieve its target for Weighted Derated Adjusted Forced Outage Rate ("DAFOR"), which was a result of significant forced outages in the year and an increase in forced deratings. Furthermore, Hydro did not achieve its targets for Weighted Capability Factor ("WCF"), Distribution – System Average Interruption Frequency Index ("D-SAIFI"), and End User SAIFI.

Operating

The hydraulic conversion factor for Bay d'Espoir was not met in 2022 with 0.427 GWh/MCM, compared 0.433 GWh/MCM set as the Company's target, nor in 2023 with 0.424 GWh/MCM, compared 0.434 GWh/MCM set as the Company's target. Hydro noted that while generation remained maximized to the extent possible, multiple spill events in both years ultimately resulted in lost energy and therefore a reduction to the Bay d'Espoir KPI from target.

In 2022, the net thermal conversion factor of 573 kWh per barrel was also unmet, being lower than the target of 583 kWh per barrel, and in 2023, the net thermal conversion factor of 511 kWh per barrel was also unmet, being lower than the target of 583 kWh per barrel. Thermal conversion factor for the Holyrood TGS is proportional to the output level of the three units and varies based on hydraulic production on the island, heating content in fuel consumed at plants, customer demand, and energy requirements. The Holyrood TGS showed a slightly increased performance in 2022 when compared to 2021 on a net heat basis, and a decreased performance in 2023 when compared to 2022 on a net heat basis.

Financial

We noted that the financial KPIs do not have targets. Per Hydro, the financial KPIs and relevant peer group data are provided to the Board in line with Board direction per Order No. P.U. 8 (2007).The KPIs provide insight on Hydro's performance in managing utility-specific costs in comparison to other companies with comparable business parameters. In the report "Peer Group Benchmarking," Hydro provided separate peer groups for KPIs relating to generation and transmission, both fully comprised of companies in the United States. According to Hydro, the purpose of calculating these metrics is to determine how Hydro's cost-management activities are performing in relation to its peer group.

Each year, in the financial update to its Quarterly Regulatory Report for the Quarter Ending December 31 of the applicable reporting year, Hydro provides its annual performance for these KPIs, as well as the most recent performance of the peer group. As highlighted by Hydro, the latest financial update shows that they have recently been outperforming their peer group in these metrics; however, Hydro does not believe that the selected peer group is an appropriate comparator on all metrics.

In the compilation of the KPIs annually, Hydro also performs an analysis of the year-over-year variance to evaluate the reasonability of the results and to understand any major drivers or trends in the financial KPIs which may be influencing the metrics year to year and/or against the peer group.

Other

The most recent Customer Satisfaction Survey was completed in 2022 and showed that 89% of customers were either very satisfied or somewhat satisfied with Hydro. The next satisfaction survey will be completed in 2024 and as such there is no target or results set for 2023.

Target and benchmark setting

For KPIs with set targets, we inquired with Hydro to understand how they assess whether the chosen target or benchmark is appropriate.

Hydro reviews their performance each year in order to establish target metrics for reliability and operating KPIs for the upcoming year. Per Hydro, consistent with other utilities, they generally utilize rolling averages to establish targets, which typically result in targets that seek to maintain reliability and operating efficiency levels. This allows Hydro to drive small, incremental changes in its performance, instead of endeavoring to further increase system reliability, which would

lead to higher costs incurred for customers. KPI targets are reviewed annually to ensure they remain relevant and aligned with evolving operational realities, regulatory expectations, and customer needs. In testing the reasonability of targets, Hydro evaluates trends in year-over-year performance and strives to balance performance improvements with cost-effectiveness and customer satisfaction.

According to Hydro, in 2024, they received feedback from customers that they consider Hydro's system to be reliable and that customers prioritize lower rates over improved reliability. Hydro believes this approach continues to be appropriate, as it is consistent with its mandate of balancing cost and reliability in providing electricity service to customers.

The below figure provides the individual rationale for each of Hydro's reliability and operating KPIs per its most recent financial update filing.

Figure 93 – Hydro's KPI rationale

KPI	2023 target setting approach per Hydro
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.
Unfrequency Load Shedding	The 2023 target is based upon previous history of performance.
Hydraulic Conversion Factor	Held at the previous target value.
Thermal Conversion Factor	2023 target was 583 kWh/bbl based on the 2019 Test Year.

Conclusion and recommendation

We have reviewed the KPI results and note the following findings:

- **Hydro did not meet their safety targets (All Injury Frequency or Lead/lag ratio) in 2022 or 2023.**
- **Hydro met their environment and conservation targets, including the achievement of EMS targets and annual energy savings from conservation and demand management programs, in 2022 and 2023.**
- **Hydro met all applicable reliability KPIs in 2022 and 5 of the 9 targets in 2023. Per Hydro, fewer targets were met in 2023 due to significant forced outages in the year and an increase in forced deratings.**
- **Hydro did not meet their operating KPI targets in 2022 or 2023. Per Hydro, while generation remained maximized to the extent possible, multiple spill events in both years ultimately resulted in lost energy and therefore a reduction to the Hydraulic Conversion factor.**
- **We understand that Hydro does not have set targets for their financial KPIs and instead compares these metrics to peer group data in line with Board direction in Order No. P.U. 8 (2007). We note that Hydro is outperforming their peer group in these metrics, however, Hydro does not believe that the selected peer group is an appropriate comparator on all metrics. As such, the Board should consider reviewing the selected peer group as part of the next general rate application.**

We have reviewed the explanations provided by Hydro for the changes and variations experienced in 2022 and 2023 and find them to be consistent with our observations and findings noted in conducting our annual financial review. There were no internal inconsistencies identified in Hydro's report.

Appendix A - Glossary of terms

Glossary of terms	
2017 Intercompany Costing Guidelines, Intercompany Costing Guidelines	The Intercompany Transaction Costing Guidelines filed by Hydro as part of their 2017 general rate application
AIF	All Injury Frequency
BAs	Bankers' Acceptances
BDE	Bay d'Espoir
Board, P.U.B	Board of Commissioners of Public Utilities
Braya	Braya Renewable Fuels
BU	Business Unit
CBPP	Corner Brook Pulp and Paper
CDM	Conservation Demand Management
CF Plant	Churchill Falls hydroelectric generating facility
CIAC	Contributions in Aid of Construction
Company, Hydro	Newfoundland and Labrador Hydro
D-SAIFI	Distribution - System Average Interruption Frequency Index
DAFOR	Derated Adjusted Forced Outage Rate
EBITDA	Earnings before interest, taxes, depreciation, and amortization
EC	Electricity Canada
ECA	Energy and Capacity Agreement
EFB	Employee future benefits
EV	Electric Vehicle
Energy Marketing, NEM	Nalcor Energy Marketing Corporation
FTE	Full-time equivalent
GIA	Generator Interconnection Agreement
GRA	General Rate Application
Holyrood TGS	Holyrood Thermal Generating Station
IFRS	International Financial Reporting Standards
Incremental Commissioning Period Imports	Importing 21,910 MWh of energy over the Maritime Link to offset declining storage after NS Block deliveries commenced and before commissioning of the Muskrat Falls Plant
Incremental Supply Period Imports	Imports that would not have been necessary if the energy and capacity available to Hydro had not been reduced by the NS Block deliveries
Incremental Supply Period Thermal Energy	Incremental Thermal Energy generated following commissioning of the Muskrat Falls Plant
Indemnity Agreement	Early NS Block Indemnification Agreement
ISSCVDA	Isolated Systems Supply Cost Variance Deferral Account
JOC	Joint Operations Committee
KPI	Key performance indicator
LAN	Local Area Network
LCDC	Lower Churchill Development Corporation

Glossary of terms	
Lead/lag ratio	Ratio of condition and incident reports to lost time and medical treatment injuries
LIL	Labrador-Island Link
LIL GP	Labrador-Island Link General Partner
LIL LP	Labrador-Island Link Limited Partnership
LIL Opco	Labrador-Island Link Operating Corporation
LTA	Labrador Transmission Assets
LTC	Labrador Transmission Corporation
MF Plant	Muskrat Falls hydroelectric generating facility
MFCo	Muskrat Falls Corporation
MFPPA, Muskrat Falls PPA, PPA	Muskrat Falls Power Purchase Agreement
Nalcor	Nalcor Energy
NS Block	Nova Scotia Block
NUG	Non-Utility Generator
OM&A	Operations, maintenance, and administration
RPP	Hydro's Resource and Production Planning team
RSP	Rate Stabilization Plan
SCVDA	Supply Cost Variance Deferral Account
SOFR	Secured Overnight Financing Rate
STI	Short-term incentive
S&P	Standard & Poor
SWOP	Safe Workplace Observation Program
TFA	Transmission Funding Agreement
TRIF	Total Recordable Injury Frequency
TRO	Transmission and Rural Operations
TY	Test year
Unavailable Commissioning Period Deferred Energy	An analysis completed by Hydro's Resource and Production Planning group indicated that approximately 25,715 MWh of energy could have been, but due to the early commencement of delivery to NS Block was not, available to be deferred by Hydro during the commissioning period
WACC	Weighted average cost of capital
WCF	Weighted Capability Factor
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