British Columbia Hydro and Power Authority

2024/25

THIRD QUARTER REPORT

FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2024

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three and nine months ended December 31, 2024, and should be read in conjunction with the 2023/24 Annual Service Plan Report and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three and nine months ended December 31, 2024. Certain comparative figures have been restated as described in Note 2 of the Unaudited Condensed Consolidated Interim Financial Statements.

All financial information is expressed in Canadian dollars unless otherwise specified.

This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of the Company. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

Highlights

- Net income for the three months ended December 31, 2024 was $210 million, $66 million lower than the same period in the prior fiscal year primarily driven by lower regulatory account additions (i.e., lower deferred amounts which result in lower net income), partially offset by lower finance charges, lower operating expenses and higher revenues. Net income for the nine months ended December 31, 2024 was $324 million, $20 million lower than the same period in the prior fiscal year primarily driven by higher finance charges, lower revenues and lower regulatory account additions, partially offset by lower operating expenses.

- Total revenues for the three months ended December 31, 2024 were $1.96 billion, $56 million (or 3 per cent) higher than the same period in the prior fiscal year, primarily as a result of higher domestic revenue due to a 2.3 per cent bill increase approved by the British Columbia Utilities Commission (BCUC) effective April 1, 2024 and higher domestic sales volumes. Total revenues for the nine months ended December 31, 2024 were $5.32 billion, $76 million (or 1 per cent) lower than the same period in the prior fiscal year, primarily as a result of lower trade revenues partially offset by higher domestic revenues.

- Energy costs for the three and nine months ended December 31, 2024 were $733 million and $2.16 billion, respectively, $300 million (or 29 per cent) and $638 million (or 23 per cent) lower than the same periods in the prior fiscal year. The lower energy costs were primarily due to a decrease in market purchases, mainly driven by lower import volumes of electricity at lower average prices compared to the same periods in the prior fiscal year.

- Water inflows (energy equivalent) to the system for the nine months ended December 31, 2024 were below the historic average, although higher than the same period in the prior fiscal year. The below average water inflows for the first nine months of fiscal 2025 were due to ongoing drought conditions, including well below average snowpack in the spring of 2024. As at December 31, 2024, system energy storage was tracking close to the historic average, and higher than December 31, 2023, due to higher inflows during the current quarter due to rain in the fall and net electricity imports that have already occurred.

- The net regulatory asset balance as at December 31, 2024 was $2.31 billion compared to $1.85 billion as at March 31, 2024. Significant changes to the regulatory accounts during the nine months ended December 31, 2024 included a $267 million addition to the Cost of Energy Variance Accounts, a $115 million addition to the Demand-Side Management Account, a $107 million net addition to Non-Current Pension Costs Account, a $104 million addition to the Debt Management Account, a $102 million addition to the Site C Variance Costs Account, and an $83 million addition to the Inflationary Pressures Account. These additions were partially offset by a $329 million reduction to the combined balance in the Rate Smoothing Account and Trade Income Deferral Account primarily as a result of higher than planned trade income, and $143 million of amortization.

- Capital expenditures, before contributions in aid of construction, for the three and nine months ended December 31, 2024 were $949 million and $3.04 billion, a $97 million and $379 million decrease, respectively, compared to the same periods in the prior fiscal year. During the three months ended December 31, 2024, the Site C generating station commenced operation of Units 1 and 2 and $12.66 billion was transferred from Unfinished Construction to Property, Plant and Equipment in-service and depreciation commenced. The Site C Project is on track to be completed within the approved schedule and the approved $16 billion budget.

Consolidated Results of Operations

($ in millions)	*For the three months ended December 31* **2024**	2023	Change	*For the nine months ended December 31* **2024**	2023	Change
Total Revenues	**$ 1,957**	$ 1,901	$ 56	**$ 5,322**	$ 5,398	$ (76)
Operating Expenses	**$ 1,626**	$ 1,829	$ (203)	**$ 4,702**	$ 5,089	$ (387)
Net Income	**$ 210**	$ 276	$ (66)	**$ 324**	$ 344	$ (20)
Capital Expenditures	**$ 949**	$ 1,046	$ (97)	**$ 3,037**	$ 3,416	$ (379)
GWh Sold (Domestic)	**15,203**	14,644	559	**40,942**	39,861	1,081

($ in millions)	***As at December 31, 2024***	*As at March 31, 2024*	Change
Total Assets and Regulatory Balances	**$ 52,167**	$ 49,442	$ 2,725
Shareholder's Equity	**$ 7,993**	$ 7,696	$ 297
Net Debt	**$ 31,930**	$ 29,294	$ 2,636
Debt to Equity	**80 : 20**	79 : 21	n/a
Number of Domestic Customer Accounts	**2,246,214**	2,220,056	26,158

Revenues

For the three months ended December 31, 2024, total revenues of $1.96 billion were $56 million (or 3 per cent) higher than the same period in the prior fiscal year. The increase for the three months ended December 31, 2024 was primarily due to higher domestic revenues of $73 million, partially offset by lower trade revenues of $17 million.

For the nine months ended December 31, 2024, total revenues of $5.32 billion were $76 million (or 1 per cent) lower than the same period in the prior fiscal year. The decrease for the nine months ended December 31, 2024 was primarily due to lower trade revenues of $281 million, partially offset by higher domestic revenues of $205 million.

for the three months ended December 31	($ in millions) 2024	2023	(gigawatt hours) 2024	2023
Revenues				
Residential	**$ 664**	$ 641	**5,346**	5,267
Light industrial and commercial	**524**	503	**4,924**	4,825
Large industrial	**242**	230	**3,719**	3,640
Other sales	**172**	155	**1,214**	912
Domestic Revenues	**1,602**	1,529	**15,203**	14,644
Trade Revenues[1]	**355**	372	**5,062**	5,064
Revenues	**$ 1,957**	$ 1,901	**20,265**	19,708

for the nine months ended December 31	($ in millions) 2024	2023	(gigawatt hours) 2024	2023
Revenues				
Residential	**$ 1,636**	$ 1,569	**13,199**	13,084
Light industrial and commercial	**1,512**	1,472	**14,157**	14,097
Large industrial	**703**	659	**10,805**	10,391
Other sales	**483**	429	**2,781**	2,289
Domestic Revenues	**4,334**	4,129	**40,942**	39,861
Trade Revenues[1]	**988**	1,269	**15,507**	16,837
Revenues	**$ 5,322**	$ 5,398	**56,449**	56,698

[1]In accordance with IFRS 9, Financial Instruments, certain energy costs are reclassified to trade revenue and netted against revenues which reduces trade revenues.

Domestic Revenues

Domestic revenues for the three months and nine months ended December 31, 2024, were $1.60 billion and $4.33 billion, respectively, $73 million (or 5 per cent) and $205 million (or 5 per cent), respectively, higher compared to the same periods in the prior fiscal year. The increase was primarily due to a 2.30 per cent bill increase approved by the BCUC effective April 1, 2024, and higher sales volumes compared to the same periods in the prior fiscal year.

Domestic sales volumes for the three and nine months ended December 31, 2024, were 559 GWh (or 4 per cent) and 1,081 GWh (or 3 per cent) higher than the same periods in the prior fiscal year. Excluding electricity exports (included in Other Sales), sales volumes for the three and nine months ended December 31, 2024, were 401 GWh (or 3 per cent) and 1,005 GWh (or 3 per cent) higher than the same periods in the prior fiscal year.

Trade Revenues

Total trade revenues for the three and nine months ended December 31, 2024 were $355 million and $988 million, respectively, a decrease of $17 million (or 5 per cent) and $281 million (or 22 per cent), respectively, compared to the same periods in the prior fiscal year. The decrease was primarily driven by lower average sales prices and sales volumes.

Operating Expenses

For the three months ended December 31, 2024, total operating expenses of $1.63 billion were $203 million (or 11 per cent) lower than the same period in the prior fiscal year. The decrease was primarily due to lower energy costs of $300 million, partially offset by higher amortization and depreciation of $40 million, materials and external services costs of $39 million, and higher personnel expenses of $28 million.

For the nine months ended December 31, 2024, total operating expenses of $4.70 billion were $387 million (or 8 per cent) lower than the same period in the prior fiscal year. The decrease was primarily due to lower energy costs of $638 million and lower grants, taxes and other costs of $38 million, partially offset by higher materials and external services costs of $148 million, higher personnel expenses of $78 million, and higher amortization and depreciation of $69 million.

Energy Costs

Energy costs are comprised of electricity and gas purchases, water rentals and transmission charges. Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand, and environmental and social impacts.

	($ in millions)		*(gigawatt hours)*	
for the three months ended December 31	**2024**	2023	**2024**	2023
Energy Costs				
Purchases from Independent Power Producers	**$ 346**	$ 358	**3,098**	3,220
Market purchases[1]	**180**	421	**6,547**	8,922
Non-Treaty storage and Co-ordination Agreements	**38**	56	**-**	-
Other expenses	**13**	12	**29**	33
Electricity and gas purchases	**577**	847	**9,674**	12,175
Water rental payments (hydro generation)[2]	**71**	96	**11,657**	8,683
Transmission charges	**85**	90	**-**	-
Energy Costs	**$ 733**	$ 1,033	**21,331**	20,858

	($ in millions)		*(gigawatt hours)*	
for the nine months ended December 31	**2024**	2023	**2024**	2023
Energy Costs				
Purchases from Independent Power Producers	**$ 1,005**	$ 1,056	**10,687**	11,217
Market purchases[1]	**606**	1,154	**22,153**	26,603
Non-Treaty storage and Co-ordination Agreements	**37**	23	**-**	-
Other expenses	**36**	31	**81**	78
Electricity and gas purchases	**1,684**	2,264	**32,921**	37,898
Water rental payments (hydro generation)[2]	**213**	290	**26,923**	22,051
Transmission charges	**267**	248	**-**	-
Energy Costs	**$ 2,164**	$ 2,802	**59,844**	59,949

[1]Market purchases are comprised of the cost of importing energy to meet domestic load requirements and energy costs associated with BC Hydro's energy trading subsidiary, Powerex. Market purchases include physical and financial transaction costs whereas the volumes only include physical transactions.

[2]Water rental payments are based on the previous calendar year's actual hydro generation volumes and the volumes reported in this table are based on actual fiscal year hydro generation volumes.

Energy Costs

Energy costs for the three and nine months ended December 31, 2024 were $733 million and $2.16 billion, respectively, $300 million (or 29 per cent) and $638 million (or 23 per cent) lower than the same periods in the prior fiscal year.

Electricity and gas purchases for the three and nine months ended December 31, 2024 were $577 million and $1.68 billion, respectively, $270 million (or 32 per cent) and $580 million (or 26 per cent) lower than the same periods in the prior fiscal year. The decrease in costs was primarily due to a decrease in market purchases, mainly driven by lower imports of electricity at lower average prices compared to the same periods in the prior fiscal year.

Water rental payments for the three and nine months ended December 31, 2024 were $71 million and $213 million, respectively, $25 million (or 26 per cent) and $77 million (or 27 per cent) lower than the same periods in the prior fiscal year. Water rental payments are based on the prior calendar year's hydro generation volumes, and hydro generation volumes were lower in calendar 2023 compared to calendar 2022 due to lower water inflows.

Water Inflows and Reservoir Storage

Water inflows (energy equivalent) to the system for the nine months ended December 31, 2024 were below the historic average, although higher than the same period in the prior fiscal year. The below average water inflows for the first nine months of fiscal 2025 were due ongoing drought conditions, including well below average snowpack in the spring of 2024. As at December 31, 2024, system energy storage was tracking close to the historic average, and higher than December 31, 2023, due to higher inflows during the current quarter due to rain in the fall and net electricity imports that have already occurred.

Variability in inflows, Electricity Purchase Agreement deliveries, domestic load, operation of storage reservoirs, and generating unit and transmission outages can all impact whether BC Hydro is a net importer or exporter of electricity in any given year. BC Hydro has been a net exporter of electricity in 8 of the previous 15 fiscal years.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three and nine months ended December 31, 2024 were $227 million and $672 million, respectively, $28 million (or 14 per cent) and $78 million (or 13 per cent) higher than the same periods in the prior fiscal year due to higher labour costs including an increase in the number of employees primarily to support capital and maintenance projects, compensation increases commensurate to the public sector mandate, and higher current service pension costs attributed to lower pension discount rates, higher headcount and salary.

Materials and External Services

Materials and External Services primarily include materials, supplies, and contractor fees.

Materials and external services for the three months ended December 31, 2024 were $277 million, $39 million (or 16 per cent) higher than the same period in the prior fiscal year primarily due to inflationary pressures from vegetation management and fuel, higher maintenance costs, higher technology costs, partially offset by a decrease in rebates for electric vehicles provided by BC Hydro.

Materials and external services for the nine months ended December 31, 2024 were $783 million, $148 million (or 23 per cent) higher than the same period in the prior fiscal year primarily due to inflationary pressures from vegetation management and fuel, higher costs incurred on Demand-Side Management, higher maintenance costs and higher technology costs.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and depreciation of right-of-use assets. Amortization and depreciation expense for the three months and nine months ended December 31, 2024 were $310 million and $869 million, respectively, $40 million (or 15 per cent) and $69 million (or 9 per cent) higher than the same periods in the prior fiscal year primarily due to additional property, plant and equipment placed in-service related to the Site C project, including the dam, spillway, powerhouse, and the first two generating units of the generating station.

Grants, Taxes and Other Costs

The Company is a Crown corporation and therefore no Canadian provincial or federal income tax is payable. However, the Company pays provincial and local government taxes and grants in lieu of property taxes to municipalities, regional districts, and rural area jurisdictions. In addition, Powerex, a subsidiary of BC Hydro, pays taxes relating to trading activity in the United States.

Other costs primarily include environmental provisions for the remediation of polychlorinated biphenyl (PCB) and asbestos, gains and losses on the disposal of assets, certain cost recoveries related to operating costs, and dismantling costs.

Total grants, taxes and other costs for the three months ended December 31, 2024, were $103 million, comparable to the $112 million in the same period in the prior fiscal year.

Total grants, taxes and other costs for the nine months ended December 31, 2024 were $288 million, $38 million (or 12 per cent) lower than the same period in the prior fiscal year primarily due to a decrease in environmental provisions as a result of an update in estimated future costs.

Capitalized Costs

Capitalized costs include costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Capitalized costs for the three and nine months ended December 31, 2024 were $24 million and $74 million, respectively, comparable to the $23 million and $68 million, respectively, in the same periods in the prior fiscal year.

Finance Charges

Finance charges for the three months ended December 31, 2024 were $263 million, a decrease of $207 million (or 44 per cent) compared to the same period in the prior fiscal year. The decrease was primarily due to gains on interest rate hedges used to economically hedge the interest rates on future debt issuances in the current period as compared to losses in the same period in the prior fiscal year. This is partially offset by lower interest capitalized during construction due to the dam, spillway, powerhouse, and the first two generating units of the Site C generating station being transferred from Unfinished Construction to Property, Plant and Equipment in-service.

Finance charges for the nine months ended December 31, 2024 were $751 million, an increase of $264 million (or 54 per cent) compared to the same period in the prior fiscal year. The increase was primarily due to losses on interest rate hedges used to economically hedge the interest rates on future debt issuances in the current period as compared to gains in the same period in the prior fiscal year, and a higher volume of debt.

Regulatory Transfers

In accordance with IFRS 14, *Regulatory Deferral Accounts*, the Company separately presents regulatory balances and related net movements on the Condensed Consolidated Interim Statements of Financial Position and the Condensed Consolidated Interim Statements of Comprehensive Income.

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with BCUC orders, including to better match costs and benefits for different generations of customers, and to defer differences between forecast and actual costs or revenues to future periods. Deferred amounts are included in customer rates in future periods, subject to approval by the BCUC, and have the effect of adjusting net income.

Net regulatory account transfers are comprised of the following:

($ in millions)	For the three months ended December 31 2024	2023	For the nine months ended December 31 2024	2023
Regulatory Additions (Reductions)/ Transfers:				
Cost of Energy Variance Accounts				
Heritage Deferral Account	**$ 59**	$ 70	**$ 94**	$ 117
Non-Heritage Deferral Account	**(76)**	230	**141**	693
Biomass Energy Program Variance	**(16)**	(22)	**(28)**	(28)
Low Carbon Fuel Credits Variance	**-**	(2)	**31**	(15)
Other	**57**	44	**29**	28
	24	320	**267**	795
Other Cash Variance Accounts				
Trade Income Deferral Account	**26**	(12)	**(17)**	(247)
Total Finance Charges	**14**	11	**18**	34
Inflationary Pressures	**32**	16	**83**	43
Electrical Vehicle Rebate	**16**	105	**48**	46
Remediation	**12**	(90)	**36**	(58)
Project Write-off Costs	**3**	3	**4**	4
Site C Variance Costs	**102**	-	**102**	-
Other	**23**	28	**57**	24
	228	61	**331**	(154)
Non-Cash Variance Accounts				
Non-Current Pension Costs	**(54)**	544	**107**	275
PEB Current Pension Costs	**(7)**	(8)	**(21)**	(25)
Debt Management	**(39)**	321	**104**	(3)
Other	**3**	(1)	**4**	(1)
	(97)	856	**194**	246
Benefit Matching Accounts				
Demand-Side Management	**38**	34	**115**	75
First Nation Costs	**-**	1	**16**	16
Site C	**1**	1	**(5)**	5
CIA Amortization	**(1)**	(1)	**(4)**	(4)
Cloud Costs	**16**	8	**42**	17
Other	**1**	-	**2**	1
	55	43	**166**	110
Non-Cash Accounts				
Environmental Provisions	**(13)**	7	**(39)**	(9)
First Nations Provisions	**5**	5	**(2)**	-
	(8)	12	**(41)**	(9)
Rate Smoothing Accounts				
Rate Smoothing	**(117)**	-	**(312)**	-
Amortization of regulatory accounts	**(44)**	(77)	**(143)**	(241)
Interest on regulatory accounts	**(3)**	(3)	**(1)**	(15)
Net increase in regulatory accounts	**$ 38**	$ 1,212	**$ 461**	$ 732

For the nine months ended December 31, 2024, there was a net increase of $461 million (or 25%) in the net regulatory balances compared to a net increase of $732 million in the same period in the prior fiscal year. The net regulatory asset balance as at December 31, 2024 was $2.31 billion compared to $1.85 billion as at March 31, 2024.

Significant changes to the regulatory accounts during the nine months ended December 31, 2024 included a $267 million addition to the Cost of Energy Variance Accounts primarily due to higher net system electricity imports as a result of the drought, partially offset by lower independent power purchase costs, a $115 million addition to the Demand-Side Management Account for planned expenditures, a $107 million net addition to Non-Current Pension Costs Account primarily due to a decrease in discount rates, and updated funding valuation, partially offset by higher asset returns, a $104 million addition to the Debt Management Account primarily due to a net decrease in the fair value of interest rate hedges resulting from a decrease in forward interest rates, a $102 million addition to the Site C Variance Costs Account due to the variances from plan in depreciation and interest during construction as a result of assets going into service earlier than planned, and a $83 million addition to the Inflationary Pressures Account. These additions were partially offset by a $329 million reduction to the combined balance in the Rate Smoothing Account and Trade Income Deferral Account primarily as a result of higher than planned trade income, and $143 million of amortization (which is the regulatory mechanism to recover the regulatory account balance in rates).

BC Hydro has or has applied for regulatory mechanisms to collect 37 of 42 regulatory accounts with balances as at December 31, 2024 in rates over various periods. For the remaining 5 regulatory accounts, BC Hydro will apply for a recovery mechanism at a future date when a recovery mechanism is required.

Liquidity and Capital Resources

Cash flow provided by operating activities for the nine months ended December 31, 2024 was $70 million, compared to $503 million in the same period in the prior fiscal year. The decrease was primarily due to lower cash from changes in working capital, partially offset by higher interest payments.

The long-term debt balance net of sinking funds as at December 31, 2024 was $32.06 billion compared to $29.39 billion as at March 31, 2024. The increase was mainly a result of the issuances of long-term bonds for net proceeds of $4.21 billion (net of redemptions). This is partially offset by a decrease in revolving borrowings of $1.58 billion. The increase in the long-term debt balance net of sinking funds was primarily to fund capital expenditures and to manage working capital.

Capital Expenditures

Capital expenditures include property, plant and equipment and intangible assets. Capital expenditures, before contributions-in-aid of construction, were as follows:

	For the three months ended December 31		*For the nine months ended December 31*	
($ in millions)	**2024**	2023	**2024**	2023
Transmission lines and substation replacements and expansion	**$ 186**	$ 141	**$ 596**	$ 424
Generation replacements and expansion	**167**	117	**434**	342
Distribution system improvements and expansion	**233**	205	**689**	582
General, including technology, vehicles and buildings	**62**	83	**223**	216
Site C Project	**301**	500	**1,095**	1,852
Total Capital Expenditures	**$ 949**	$ 1,046	**$ 3,037**	$ 3,416

The decrease in capital expenditures of $97 million and $379 million, respectively, for the three and nine months ended December 31, 2024 compared to the same period in the prior fiscal year was primarily due to Site C Project expenditures, as major scopes of work were completed in the prior fiscal year, resulting in less construction costs for the current year. Annual capital expenditures can vary depending on the timing and scope of projects. The decrease in Site C Project capital expenditures was offset primarily by increases in Transmission lines and substation replacements and expansion, mainly for Prince George to Terrace Capacitors and Peace to Kelly Lake Stations Sustainment, Distribution system improvements and expansion increases were mainly for customer driven work, and Generation increases were mainly for John Hart Dam Seismic Upgrade and Ruskin – Left Abutment Slope Sinkhole Remediation.

Transmission lines and substation replacements and expansion included capital expenditures on transmission overhead lines, cables, substations, telecommunication systems, and transmission power equipment. Key capital expenditures included the following projects/programs: Prince George to Terrace Capacitors, Peace to Kelly Lake Stations Sustainment, Mainwaring Station Upgrade, Transmission Wood Structure and Framing Replacements, Various Sites – Transmission Corrective Capital Restorations, and Natal – 60-138 kV Switchyard Upgrade.

Generation replacements and expansion included capital expenditures on dam safety projects as well as on generating facilities and related major equipment such as turbines, generators, governors, exciters, transformers, and circuit breakers. Key capital expenditures included the following projects: John Hart Dam Seismic Upgrade, Ruskin – Left Abutment Slope Sinkhole Remediation, Comox – Puntledge Flow Control Improvements, Bridge River 1 – Penstock Concrete Foundation Refurbishment, and La Joie – Dam Improvements.

Distribution system improvements and expansion included capital expenditures on customer driven work, end of life asset replacements, the Various Sites – EV Charging Infrastructure Implementation program, and system expansion and improvements.

General included capital expenditures on other technology projects, various building development programs, and vehicles.

Site C incurred capital expenditures across the project, primarily for work areas such as balance of plant, generating station and spillways, main civil works, turbines and generators, worker accommodations, project management and support services, and interest during construction.

Rate Regulation

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, and earn an allowed net income.

Risk Management

BC Hydro is exposed to numerous risks, which can result in safety, environmental, financial, reliability and reputational impacts. This section of the MD&A discusses risks that may impact financial performance.

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of BCUC-approved regulatory accounts. The use of regulatory accounts is common amongst regulated utility industries throughout North America. Regulatory accounts assist in matching costs and benefits for different generations of customers, and to defer for future recovery in rates the differences between planned and actual costs or revenues that arise due to uncontrollable events. BC Hydro's approach to the recovery of its regulatory accounts is included in the Fiscal 2023 – Fiscal 2025 Revenue Requirements Application.

In addition, information on risks and opportunities that could significantly impact BC Hydro meeting its objectives are outlined at bchydro.com/serviceplan.

Significant Financial Risks

The largest sources of variability in BC Hydro's financial performance are typically domestic and trade revenue, cost of energy, finance charges and changes to post-employment benefit costs. These are influenced by several elements, which generally fall into the following seven categories: hydro generation, customer demand, electricity imports/exports, trade margin, deliveries from electricity purchase agreements, interest rates, and discount rates for post-employment benefit plans.

While meeting domestic customer demand, environmental regulations and treaty obligations, BC Hydro attempts to operate the system to take maximum advantage of market energy prices – buying from the markets when prices are low and selling when prices are high. In so doing, BC Hydro seeks to optimize the combined effects of these elements and reduce the net cost of energy for our domestic customers.

In addition to the seven factors identified above, the Site C Project continues to manage significant potential risks including commercial negotiations with contractors. The Site C Project Assurance Board (which is comprised of independent members and some of the current BC Hydro board members) is tasked with ensuring that the Site C Project is completed on time and on budget, and that risks are appropriately identified, managed and reported on an ongoing basis. As of December 31, 2024, the total Project forecast remains at the $16 billion approved July 2021 budget and is expected to achieve the in-service of all generating units by end of 2025 per the approved schedule.

This section should be read in conjunction with the risks disclosed in the Risk Management section in the Management's Discussion and Analysis presented in the 2023/24 Annual Service Plan Report for the year ended March 31, 2024. In addition, information on risks and opportunities that could significantly impact BC Hydro meeting its objectives is outlined at www.bchydro.com/serviceplan.

Future Outlook

The Budget Transparency and Accountability Act requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in March 2025 forecast net income for 2024/25 at $572 million which is $140 million (or 20 per cent) lower than the amount in the previous Service Plan (i.e. $712 million) primarily due to higher forecast Operating Expenses. Net income for 2025/26 – 2027/28 is forecast to be $712 million annually.

The Company's financial performance can fluctuate significantly due to the factors discussed in the preceding section, many of which are non-controllable. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts.

Uncertainty around inflation and interest rates could have a sustained adverse impact on BC Hydro's future performance if they were to cause a decrease in customer load, volatility in electricity/gas trade margins, interest rate volatility, difficulty accessing debt, project delays and project cost escalations. In addition, geopolitical factors have caused negative disruptions to supply chains which are resulting in project delays and project cost escalations. There is significant uncertainty surrounding the potential for United States tariffs and policy direction via Executive Orders. Potential United States and any resulting retaliatory Canadian tariffs will have significant implications for federal and provincial economies and to BC Hydro's load, revenue, trade, supply chains, and ability to deliver capital projects.

The uncertainty related to these economic concerns limit the ability to predict the ultimate adverse impact of the economy on BC Hydro's performance, financial condition, results of operations and cash flows.

As an example of uncertainty to in the financial forecast, annual generation from a hydroelectric system is inherently variable as it depends on water inflows.

The annual system surplus (i.e., the difference between generation and load) averaged 925 GWh for the five fiscal years prior to 2024/25, ranging from a deficit of 10,430 GWh in 2023/24 to a surplus of 10,699 GWh in 2020/21.

British Columbia was in a drought that reduced overall inflows and associated generation (energy) in 2023/24 and 2024/25. The low snowpack in both the Columbia and Peace basins in the spring of 2024 resulted in similar inflow and energy challenges as last year as 55% of the BC Hydro owned or contracted energy comes from the Columbia and Peace basins. Rain in the fall of 2024 mitigated some of the drought impacts for this fiscal year and while the effect of the drought is still significant in 2024/25, it is forecast to be less than in 2023/24. Hydro generation remains forecast to be below average for the balance of 2024/25. However, large variability in system inflows can still result in significantly different amounts of generation relative to the current period and, subsequently, affect cost of energy. Cost of energy may be higher due to imports in times of deficit and domestic revenues may be higher due to exports in times of surplus. Variability in seasonal and annual surplus or deficit amounts affects BC Hydro's cost of energy, domestic revenues, and financial performance.

Unaudited Condensed Consolidated Interim Statements of Comprehensive Income

(in millions)	*For the three months ended December 31* **2024**	2023	*For the nine months ended December 31* **2024**	2023
Revenues (Note 3)				
Domestic	**$ 1,602**	$ 1,529	**$ 4,334**	$ 4,129
Trade	**355**	372	**988**	1,269
Revenues	**1,957**	1,901	**5,322**	5,398
Expenses				
Operating expenses (Note 4)	**1,626**	1,829	**4,702**	5,089
Finance charges (Note 5)	**263**	470	**751**	487
Net Income (Loss) Before Movement in Regulatory Balances	**68**	(398)	**(131)**	(178)
Net movement in regulatory balances (Note 9)	**142**	674	**455**	522
Net Income	**210**	276	**324**	344
Other Comprehensive Income				
Items Reclassified Subsequently to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 14)	**19**	(15)	**29**	(1)
Reclassification to income of derivatives designated as cash flow hedges (Note 14)	**(43)**	8	**(60)**	16
Foreign currency translation gain (loss)	**33**	(18)	**35**	(9)
Items That Will Not Be Reclassified Subsequently to Net Income				
Actuarial gain (loss) on post employment benefits	**78**	(519)	**(35)**	(201)
Other Comprehensive Income (Loss) before movement in regulatory balances	**87**	(544)	**(31)**	(195)
Net movements in regulatory balances (Note 9)	**(104)**	538	**6**	210
Other Comprehensive Income (Loss)	**(17)**	(6)	**(25)**	15
Total Comprehensive Income	**$ 193**	$ 270	**$ 299**	$ 359

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Unaudited Condensed Consolidated Interim Statements of Financial Position

(in millions)	***As at December 31* 2024**	*As at March 31* 2024
Assets		
Current Assets		
Cash and cash equivalents	**$ 126**	$ 96
Restricted cash	**32**	45
Accounts receivable and accrued revenue	**895**	984
Inventories (Note 7)	**510**	391
Prepaid expenses	**138**	184
Current portion of derivative financial instrument assets (Note 14)	**194**	267
	1,895	1,967
Non-Current Assets		
Property, plant and equipment (Note 8)	**42,299**	40,108
Right-of-use assets	**1,182**	1,209
Intangible assets (Note 8)	**655**	641
Derivative financial instrument assets (Note 14)	**120**	145
Other non-current assets (Note 10)	**433**	419
	44,689	42,522
Total Assets	**46,584**	44,489
Regulatory Balances (Note 9)	**5,583**	4,953
Total Assets and Regulatory Balances	**$ 52,167**	$ 49,442
Liabilities and Equities		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 1,626**	$ 1,912
Current portion of long-term debt and revolving borrowings (Note 11)	**4,442**	4,740
Current portion of unearned revenues and contributions in aid	**135**	109
Current portion of derivative financial instrument liabilities (Note 14)	**149**	305
Customer credits	**81**	326
	6,433	7,392
Non-Current Liabilities		
Long-term debt (Note 11)	**27,891**	24,897
Lease liabilities	**1,262**	1,330
Derivative financial instrument liabilities (Note 14)	**185**	224
Unearned revenues and contributions in aid	**2,979**	2,768
Post-employment benefits (Note 13)	**784**	692
Other non-current liabilities (Note 15)	**1,370**	1,342
	34,471	31,253
Total Liabilities	**40,904**	38,645
Regulatory Balances (Note 9)	**3,270**	3,101
Total Liabilities and Regulatory Balances	**44,174**	41,746
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**7,999**	7,677
Accumulated other comprehensive loss	**(66)**	(41)
	7,993	7,696
Total Liabilities, Regulatory Balances, and Shareholder's Equity	**$ 52,167**	$ 49,442

Commitments (Note 8)

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Unaudited Condensed Consolidated Interim Statements of Changes in Equity

(in millions)	Cumulative Translation Reserve	Unrealized Loss on Cash Flow Hedges	Total Accumulated Other Comprehensive Loss	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2023	$ 10	$ (68)	$ (58)	$ 60	$ 7,354	$ 7,356
Comprehensive Income	-	15	15	-	344	359
Balance as at Deccember 31, 2023	$ 10	$ (53)	$ (43)	$ 60	$ 7,698	$ 7,715
Balance as at April 1, 2024	$ 10	$ (51)	$ (41)	$ 60	$ 7,677	$ 7,696
Distribution to the Province	-	-	-	-	(2)	(2)
Comprehensive Income (Loss)	6	(31)	(25)	-	324	299
Balance as at December 31, 2024	$ 16	$ (82)	$ (66)	$ 60	$ 7,999	$ 7,993

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Unaudited Condensed Consolidated Interim Statements of Cash Flows

For the nine months ended December 31 (in millions)	**2024**	2023 Adjusted - (Note 2)
Operating Activities		
Net income	**$ 324**	$ 344
Regulatory account transfers (Note 9)	**(455)**	(522)
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 6)	**869**	800
Losses (Gains) on derivative financial instruments	**(195)**	59
Post-employment benefit plan expenses	**55**	57
Interest accrual	**834**	748
Other items	**75**	18
	1,507	1,504
Changes in working capital and other assets and liabilities (Note 16)	**(358)**	(68)
Interest paid	**(1,079)**	(933)
Cash provided by operating activities	**70**	503
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(2,655)**	(2,976)
Cash used in investing activities	**(2,655)**	(2,976)
Financing Activities		
Long-term debt issued (Note 11)	**4,217**	862
Long-term debt retired (Note 11)	**(10)**	(200)
Receipt of revolving borrowings	**6,498**	7,338
Repayment of revolving borrowings	**(8,117)**	(5,524)
Payment of principal portion of lease liability	**(67)**	(65)
Settlement of hedging derivatives	**114**	147
Other items	**(20)**	(26)
Cash provided by financing activities	**2,615**	2,532
Increase in cash and cash equivalents	**30**	59
Cash and cash equivalents, beginning of period	**96**	148
Cash and cash equivalents, end of period	**$ 126**	$ 207

See Note 16 for cash flow supplement

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2024

Note 1: Reporting Entity

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown Corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia. The head office of the Company is 333 Dunsmuir Street, Vancouver, British Columbia.

The condensed consolidated interim financial statements (interim financial statements) of BC Hydro include the accounts of BC Hydro and its wholly-owned operating subsidiaries including Powerex Corp. (Powerex), and Powertech Labs Inc. (Powertech), (collectively with BC Hydro, the Company). All intercompany transactions and balances are eliminated on consolidation.

Note 2: Basis of Presentation

Basis of Accounting

These interim financial statements have been prepared by management in accordance with the principles of IAS 34, *Interim Financial Reporting,* and except as described below, were prepared using the same accounting policies as described in BC Hydro's 2023/24 Annual Service Plan Report.

These interim financial statements should be read in conjunction with the BC Hydro's 2023/24 Annual Service Plan Report.

These interim financial statements were approved on behalf of the Board of Directors on February 13, 2025.

BC Hydro changed its prior year's comparative figures for the receipt and repayment of revolving borrowings on the statement of cash flows to exclude foreign exchange revaluation gains and losses with respect to revolving borrowings. The change resulted in classification differences in the statement of cash flows in financing activities and operating activities but had no impact to net income or to the statements of changes in equity, and financial position.

The impact of the change on the comparative periods is as follows:

	For the nine months ended December 31, 2023		
(in millions)	As originally reported	Adjustment	As Adjusted
Operating Activities			
Other items	$ 47	$ (29)	$ 18
Cash provided by operating activities	532	(29)	503
Financing Activities			
Receipt of revolving borrowings	8,218	(880)	7,338
Repayment of revolving borrowings	(6,433)	909	(5,524)
Cash provided by financing activities	2,503	29	2,532

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
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Note 3: Revenue

The Company disaggregates revenue by revenue type and customer class, which are considered to be the most relevant revenue information for management to consider in allocating resources and evaluating performance.

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2024**	2023	**2024**	2023
Domestic				
Residential	**$ 664**	$ 641	**$ 1,636**	$ 1,569
Light industrial and commercial	**524**	503	**1,512**	1,472
Large industrial	**242**	230	**703**	659
Other sales	**172**	155	**483**	429
Total Domestic	**1,602**	1,529	**4,334**	4,129
Total Trade[1]	**355**	372	**988**	1,269
Total Revenue	**$ 1,957**	$ 1,901	**$ 5,322**	$ 5,398

[1] Includes revenues of $143 million and $341 million recognized under IFRS 9, *Financial Instrument* s for the three and nine months ended December 31, 2024, respectively (2023 - ($27 million) and ($225 million), respectively).

Note 4: Operating Expenses

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2024**	2023	**2024**	2023
Electricity and gas purchases	**$ 577**	$ 847	**$ 1,684**	$ 2,264
Water rentals	**71**	96	**213**	290
Transmission charges	**85**	90	**267**	248
Personnel expenses	**227**	199	**672**	594
Materials and external services	**277**	238	**783**	635
Amortization and depreciation (Note 6)	**310**	270	**869**	800
Grants, taxes and other costs	**103**	112	**288**	326
Capitalized costs	**(24)**	(23)	**(74)**	(68)
	$ 1,626	$ 1,829	**$ 4,702**	$ 5,089

Note 5: Finance Charges

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2024**	2023	**2024**	2023
Interest on debt	**$ 284**	$ 261	**$ 834**	$ 748
Interest on lease liabilities	**11**	11	**34**	34
Interest on defined benefit plan obligations	**9**	11	**26**	31
Mark-to-market losses (gains) on derivative financial instruments	**(42)**	318	**97**	(7)
Capitalized interest	**(31)**	(125)	**(303)**	(346)
Other	**32**	(6)	**63**	27
	$ 263	$ 470	**$ 751**	$ 487

Note 6: Amortization and Depreciation

(in millions)	*For the three months ended December 31* **2024**	2023	*For the nine months ended December 31* **2024**	2023
Depreciation of property, plant and equipment	**$ 269**	$ 228	**$ 744**	$ 678
Depreciation of right-of-use assets	**21**	21	**64**	62
Amortization of intangible assets	**20**	21	**61**	60
	$ 310	$ 270	**$ 869**	$ 800

Note 7: Inventories

(in millions)	***As at December 31*** **2024**	*As at March 31* 2024
Materials and Supplies and Environmental Products	**$ 284**	$ 252
Natural Gas and Certain Carbon Products	**226**	139
	$ 510	$ 391

Note 8: Property, Plant and Equipment and Intangible Assets

Property, plant and equipment and intangible asset additions, before contributions in aid of construction, for the three and nine months ended December 31, 2024 were $949 million and $3.04 billion, respectively (2023 - $1.05 billion and $3.42 billion, respectively).

As of December 31, 2024, the Company had contractual commitments to spend $1.28 billion on major property, plant and equipment projects (for individual projects greater than $20 million).

Note 9: Rate Regulation

Regulatory Accounts

The Company has established various regulatory accounts through rate regulation or with the expected approval of the British Columbia Utilities Commission (BCUC). In the absence of rate regulation, these amounts would be reflected in total comprehensive income. The net movement in regulatory balances related to total comprehensive income is as follows:

(in millions)	*For the three months ended December 31* **2024**	2023	*For the nine months ended December 31* **2024**	2023
Net increase in regulatory balances related to net income	**$ 142**	$ 674	**$ 455**	$ 522
Net increase (decrease) in regulatory balances related to OCI	**(104)**	538	**6**	210
	$ 38	$ 1,212	**$ 461**	$ 732

For each regulatory account, the amount reflected in the Net Change column in the following table represents the impact on comprehensive income for the applicable period. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
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(in millions)	*As at April 1 2024*	*Addition (Reduction)/ Transfers*	*Interest* [1]	*Amortization*	*Net Change*	***As at December 31 2024***
Regulatory Assets						
Heritage Deferral Account	$ 49	$ 94	$ 2	$ 6	$ 102	**$ 151**
Non-Heritage Deferral Account	1,092	141	37	118	296	**1,388**
Demand-Side Management	870	115	-	(90)	25	**895**
First Nations Provisions & Costs	474	14	-	(12)	2	**476**
Site C	502	(5)	9	-	4	**506**
CIA Amortization	58	(4)	-	-	(4)	**54**
Environmental Provisions & Remediation	208	(3)	-	(9)	(12)	**196**
Smart Metering & Infrastructure	109	-	3	(19)	(16)	**93**
Inflationary Pressures	7	83	1	-	84	**91**
IFRS Pension	306	-	-	(29)	(29)	**277**
IFRS Property, Plant & Equipment	976	-	-	(24)	(24)	**952**
Total Finance Charges	88	18	-	(10)	8	**96**
Cloud Costs	47	42	2	-	44	**91**
Project Write-off Costs	48	4	2	(2)	4	**52**
Site C Variance Costs	-	102	1	-	103	**103**
Other Regulatory Accounts	119	66	2	(25)	43	**162**
Total Regulatory Assets	4,953	667	59	(96)	630	**5,583**
Regulatory Liabilities						
Trade Income Deferral Account	1,736	17	49	-	66	**1,802**
Rate Smoothing	-	312	4	-	316	**316**
Debt Management	114	(104)	-	14	(90)	**24**
Biomass Energy Program Variance	127	28	4	14	46	**173**
Low Carbon Fuel Credits Variance	63	(31)	1	7	(23)	**40**
Non-Current Pension Costs	892	(107)	-	22	(85)	**807**
PEB Current Pension Costs	65	21	-	(6)	15	**80**
Electric Vehicle Rebate	71	(48)	1	-	(47)	**24**
Other Regulatory Accounts	33	(26)	1	(4)	(29)	**4**
Total Regulatory Liabilities	3,101	62	60	47	169	**3,270**
Net Regulatory Assets	$ 1,852	$ 605	$ (1)	$ (143)	$ 461	**$ 2,313**

[1]As permitted by the BCUC, interest charges were accrued to certain regulatory balances at the Company's weighed average cost of debt of 3.7 per cent per annum for the nine months ended December 31, 2024 (2024 – 3.6 per cent).

There were no significant changes to the remaining recovery/reversal periods for the nine months ended December 31, 2024. Refer to Note 15 – Rate Regulation in the Company's 2023/24 Annual Service Plan Report.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2024

Note 10: Other Non-Current Assets

(in millions)	***As at December 31* 2024**	*As at March 31* 2024
Non-current receivables	**$ 108**	$ 123
Sinking funds	**277**	247
Non-current Site C prepaid expenses	**10**	32
Other	**38**	17
	$ 433	$ 419

Included in the non-current receivables balance are $98 million of receivables (March 31, 2024 - $107 million) from a vendor to aid in the construction of a transmission system.

Note 11: Long-Term Debt, Revolving Borrowings and Debt Management

The Company's debt comprises bonds and revolving borrowings obtained under an agreement with the Province.

The Company has a commercial paper borrowing program with the Province which is limited to $5.50 billion. At December 31, 2024, the outstanding amount under the borrowing program was $3.15 billion (March 31, 2024 - $4.73 billion).

For the three months ended December 31, 2024, the Company issued bonds for net proceeds of $647 million (2023 - $nil) and a par value of $640 million, a weighted average effective interest rate of 4.2 per cent and a weighted average term to maturity of 19.7 years. For the nine months ended December 31, 2024, the Company issued bonds for net proceeds of $4.22 billion (2023 - $862 million) and a par value of $4.2 billion (2023 - $900 million), a weighted average effective interest rate of 4.2 per cent (2023 - 4.4 per cent) and a weighted average term to maturity of 23.8 years (2023 - 20.1 years).

For the three months ended December 31, 2024, there were no bond maturities (2023 – $100 million). For the nine months ended December 31, 2024, the Company redeemed bonds at maturity with a par value of $10 million (2023 – $200 million).

Note 12: Capital Management

Orders in Council from the Province establish the basis for determining the Company's equity for regulatory purposes, as well as the annual payment to the Province (see below). Capital requirements are consequently managed through the retention of equity subsequent to the payment to the Province. For this purpose, the applicable Order in Council defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity comprises retained earnings, accumulated other comprehensive loss, and contributed surplus. The Company monitors its capital structure on the basis of its debt to equity ratio.

During the nine months ended December 31, 2024, there were no changes in the approach to capital management.

The debt to equity ratio at December 31, 2024, and March 31, 2024 was as follows:

(in millions)	***As at December 31*** **2024**	*As at March 31* 2024
Total debt, net of sinking funds	**$ 32,056**	$ 29,390
Less: Cash and cash equivalents	**(126)**	(96)
Net Debt	**$ 31,930**	$ 29,294
Retained earnings	**$ 7,999**	$ 7,677
Contributed surplus	**60**	60
Accumulated other comprehensive loss	**(66)**	(41)
Total Equity	**$ 7,993**	$ 7,696
Net Debt to Equity Ratio	**80 : 20**	79 : 21

Dividend Payment to the Province

In accordance with Order in Council No. 095/2014 from the Province, the payment to the Province will remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

As BC Hydro did not achieve a debt to equity ratio of 60:40 there was no payment for the year ended March 31, 2024. In addition, BC Hydro does not expect to make a payment for the year ending March 31, 2025.

Note 13: Post-Employment Benefits

The expense recognized for the Company's defined benefit plans prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions for the three and nine months ended December 31, 2024 was $38 million and $115 million, respectively (2023 - $36 million and $107 million, respectively).

Company contributions to the registered defined benefit pension plans for the three and nine months ended December 31, 2024 were $15 million and $46 million (2023 - $14 million and $41 million, respectively).

The plan remeasurements used a discount rate of 4.66 per cent per annum as at December 31, 2024 (December 31, 2023 - 4.63 per cent), the funding valuation membership data as at December 31, 2023, updated assumption on headcount increase and a rate of return on plan assets of positive 9.66 per cent as at December 31, 2024 (December 31, 2023 - positive 4.59 per cent).

Note 14: Financial Instruments

Categories of Financial Instruments

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at December 31, 2024, and March 31, 2024. It does not include fair value information for non-derivative financial instruments not measured at fair value if the carrying amount is a reasonable approximation of fair value which include cash and cash equivalents, restricted cash, accounts receivable and accrued revenue, accounts payable, accrued liabilities and revolving borrowings. Their carrying amount is a reasonable approximation of fair value due to the short duration of these financial instruments When the carrying value differs from fair value, the fair values of non-derivative financial instruments would be classified as Level 2 of the fair value hierarchy.

(in millions)	**December 31, 2024** Carrying Value	**December 31, 2024** Fair Value	March 31, 2024 Carrying Value	March 31, 2024 Fair Value
Amortized Cost:				
Non-current receivables	**$ 108**	**$ 110**	$ 123	$ 122
Sinking funds	**277**	**269**	247	245
Long-term debt (including current portion due in one year)	**(29,185)**	**(27,728)**	(24,907)	(22,846)
First Nations liabilities (non-current portion)	**(438)**	**(467)**	(440)	(464)
Other liabilities (non-current portion)	**(396)**	**(384)**	(404)	(390)

Hedges

The fair value of derivative instruments designated and not designated as hedges, was as follows:

(in millions)	**December 31, 2024 Fair Value**	March 31, 2024 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contract assets (cash flow hedges for US$ denominated long-term debt)	**$ 54**	$ 30
Foreign currency contract liabilities (cash flow hedges for EURO€ denominated long-term debt)	**(13)**	(17)
	41	13
Non-Designated Derivative Instruments:		
Interest rate contract assets	**59**	212
Interest rate contract liabilities	**(55)**	(21)
Foreign currency contract assets	**46**	2
Commodity derivative assets	**154**	162
Commodity derivative liabilities	**(265)**	(485)
	(61)	(130)
Net liabilities	**$ (20)**	$ (117)

The carrying value of derivative instruments designated and not designated as hedges was the same as the fair value.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
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	For the three months ended December 31		For the nine months ended December 31	
(in millions)	**2024**	2023	**2024**	2023
Deferred inception gains (losses), beginning of the period	**$ 37**	$ (35)	**$ 31**	$ (15)
New transactions	**59**	69	**56**	70
Amortization	**(13)**	(5)	**(4)**	(24)
Foreign currency translation (gain) loss	2	-	2	(2)
Deferred inception gains, end of the period	**$ 85**	$ 29	**$ 85**	$ 29

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition, as defined by its transaction price, and the fair value calculated by a valuation technique or model (inception gain or loss). In addition, the Company's inception gain or loss on a contract may arise as a result of embedded derivatives which are recorded at fair value, with the remainder of the contract recorded on an accrual basis. In these circumstances, the unrealized inception gain or loss is not recognized in income immediately, but is deferred and amortized into income over the full term of the underlying financial instrument.

Fair Value Hierarchy

The following provides an analysis of financial instruments that are measured subsequent to initial recognition at fair value, grouped based on the lowest level of input that is significant to that fair value measurement.

The inputs used in determining fair value are characterized by using a hierarchy that prioritizes inputs based on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 - values are quoted prices (unadjusted) in active markets for identical assets and liabilities.

- Level 2 - inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, as of the reporting date.

  The Company determines Level 2 fair values for debt securities and derivatives using discounted cash flow techniques, which use contractual cash flows and market-related discount rates.

  Level 2 fair values for commodity derivatives are determined using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e., derived from prices). Level 2 includes bilateral and over-the-counter contracts valued using interpolation from observable forward curves or broker quotes from active markets for similar instruments and other publicly available data, and options valued using industry-standard and accepted models incorporating only observable data inputs.

- Level 3 - inputs are those that are not based on observable market data. Level 3 fair values for commodity derivatives are determined using inputs that are based on significant unobservable inputs.

  Level 3 includes instruments valued using observable prices adjusted for unobservable basis differentials such as delivery location and product quality, instruments which are valued by extrapolation of observable market information into periods for which observable market information is not yet available, and instruments valued using internally developed or non-standard valuation models.

The following tables present the financial instruments measured at fair value for each hierarchy level as at December 31, 2024 and March 31, 2024:

As at December 31, 2024 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets (liabilities) carried at fair value:				
Short-term investments	$ 29	$ -	$ -	$ 29
Derivative financial instrument assets	15	172	127	314
Derivative financial instrument liabilities	(16)	(192)	(126)	(334)
	$ 28	$ (20)	$ 1	$ 9

As at March 31, 2024 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets (liabilities) carried at fair value:				
Short-term investments	$ 31	$ -	$ -	$ 31
Derivative financial instrument assets	110	256	46	412
Derivative financial instrument liabilities	(119)	(270)	(140)	(529)
	$ 22	$ (14)	$ (94)	$ (86)

The Company's policy is to recognize level transfers at the end of each period during which the change occurred. During the nine months ended December 31, 2024, there were no commodity transfers between Level 1 to Level 2 (2023 – $nil transfers).

The following table reconciles the changes in the balance of financial instruments carried at fair value on the statement of financial position, classified as Level 3, for the nine months ended December 31, 2024 and 2023:

(in millions)	
Balance as at April 1, 2024	**$ (94)**
Realized and unrealized gains	275
Transfers	(10)
Settlements	(170)
Foreign exchange	-
Balance as at December 31, 2024	**$ 1**

(in millions)	
Balance as at April 1, 2023	**$ (255)**
Realized and unrealized gains	1,006
Transfers	-
Settlements	(844)
Foreign exchange	3
Balance as at December 31, 2023	**$ (90)**

During the period, commodity derivatives with a liability carrying amount of $10 million (2023 – no transfers) were transferred from Level 2 to Level 3.

During the three and nine months ended December 31, 2024, unrealized losses of $13 million and unrealized gains of $17 million, respectively (2023 – unrealized gains of $30 million and $110 million, respectively) were recognized on Level 3 derivative commodity instruments still on hand. These gains and losses were recognized in trade revenues.

Methodologies and procedures regarding commodity trading Level 3 fair value measurements are determined by the Company's risk management group. Level 3 fair values are calculated within the Company's risk management policies for trading activities based on underlying contractual data as well as observable and non-observable inputs. To ensure reasonability, Level 3 fair value measurements are reviewed and validated by risk management and finance departments on a regular basis.

The key unobservable inputs in the valuation of certain Level 3 financial instruments includes components of forward commodity prices and delivery or receipt volumes. A sensitivity analysis was prepared using the Company's assessment of a reasonably possible change in various components of forward prices and volumes of 10 per cent. Forward commodity prices used in determining Level 3 base fair value at December 31, 2024 range between $0.60-$270 per MWh and a 10 per cent increase/decrease in certain components of these prices would decrease/increase fair value by $181 million. A 10 per cent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $7 million.

Note 15: Other Non-Current Liabilities

(in millions)	***As at December 31* 2024**	*As at March 31* 2024
Provisions		
Environmental liabilities	**$ 268**	$ 242
Decommissioning obligations	**72**	62
Other	**88**	73
	428	377
First Nations liabilities	**455**	458
Other contributions	**213**	217
Other liabilities	**447**	464
	1,543	1,516
Less: Current portion, included in accounts payable and accrued liabilities	**(173)**	(174)
	$ 1,370	$ 1,342

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2024

Note 16: Supplemental Disclosure of Cash Flow Information

Change in Working Capital and Other Assets and Liabilities:

For the nine months ended December 31 (in millions)		**2024**		2023
Restricted Cash	**$**	**13**	$	-
Accounts receivable and accrued revenue		**107**		91
Inventories		**(105)**		(102)
Prepaid expenses		**29**		74
Other non-current assets		**27**		103
Accounts payable and accrued liabilities		**(337)**		(409)
Unearned revenues and contributions in aid		**(23)**		204
Post-employment benefits		**3**		(5)
Other non-current liabilities		**(72)**		(24)
	$	**(358)**	$	(68)

Non-Cash Investing Transactions:

For the nine months ended December 31 (in millions)		**2024**		2023
Contributions in kind received for property, plant and equipment	**$**	**75**	$	45

Note 17: Seasonality of Operating Results

Due to the seasonal nature of the Company's operations, the condensed consolidated interim statement of comprehensive income is not indicative of operations on an annual basis. Seasonal impacts of weather, including its impact on water inflows, energy consumption within the region and market prices of energy, can have a significant impact on the Company's operating results.