British Columbia Hydro and Power Authority

2023/24 Annual Service Plan Report

AUGUST 2024

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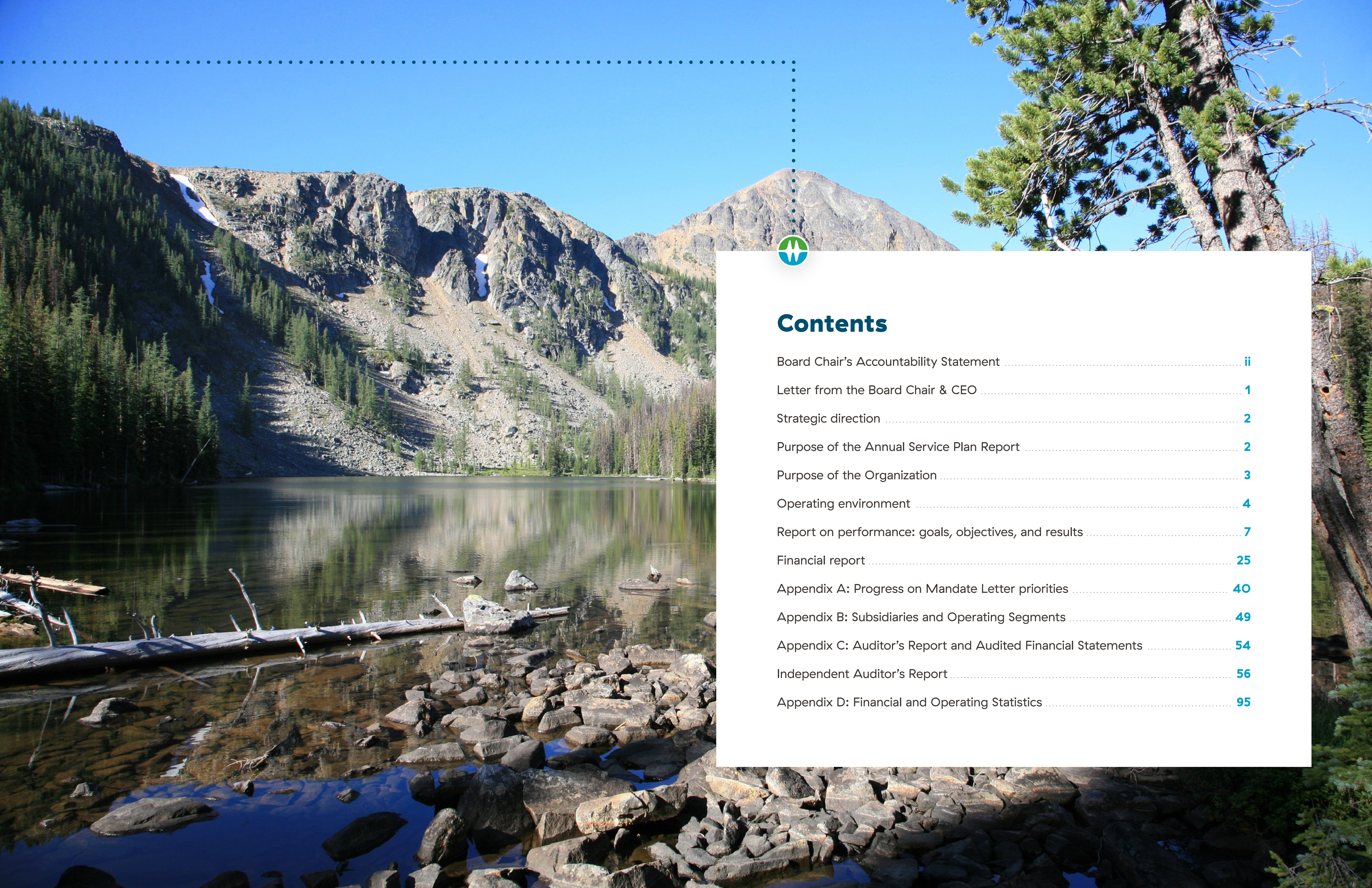
Board Chair's Accountability Statement

The BC Hydro 2023/24 Annual Service Plan Report compares the organization's actual results to the expected results identified in the 2023/24–2025/26 Service Plan published in 2023. The Board is accountable for those results as reported.

Signed on behalf of the Board by:

Lori Wanamaker
Board Chair, BC Hydro



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Letter from the Board Chair & CEO

On behalf of the Board of Directors and all BC Hydro employees, we are pleased to submit BC Hydro's Annual Service Plan Report for the year ending March 31, 2024. This letter provides an overview of highlights from the past year, as well as information on BC Hydro's reporting relationship as a Crown Corporation.

Climate change continued to affect our business in the form of more instances of extreme weather in 2023/24. Despite drought, wildfires, and major storms, our hydroelectric system operated safely and reliably across a wide range of conditions and weather events. When outages occurred, our crews worked around the clock to restore power to customers as soon as possible.

In January 2024, we released our updated 10-Year Capital Plan, which included an unprecedented level of investment to build out B.C.'s electricity system to power a growing clean economy. Towards the end of 2023/24, the B.C. Utilities Commission (BCUC) accepted our 2021 Integrated Resource Plan which outlined actions BC Hydro will take to meet growing demand and expand our system and supply. As we enter into the final stages of the Site C project, we continued to manage Site C within the approved budget of $16 billion. Throughout the year, construction progressed and as of March 2024 the project is now over 85 percent complete. In 2023 we invested approximately $4.3 billion to upgrade aging assets and build new infrastructure to meet growing demand.

While making significant investments in our system, BC Hydro upheld the important responsibility of keeping electricity affordable for our customers, particularly at a time when many British Columbians are struggling with the effects of global inflation and high interest rates. In 2023/24 we advanced various initiatives to help our customers save money on their electricity bills. Among these included approval of a new flat rate for transmission customers to encourage electrification, approval of a new optional time-of-date rate for customers who can shift usage to lower price periods, and doubling our reward for the Team Power Smart Reduction Challenge.

BC Hydro has made important progress towards our goal of advancing reconciliation with First Nations. Developing an **UNDRIP Implementation Plan** in partnership with First Nations provides us with a solid framework to build upon and concrete actions we can take towards achieving this goal. In 2023/24 we reached $196.8 million in direct contract awards to Indigenous designated businesses, and over 83 percent of our workforce completed cultural awareness training. We also engaged with First Nations on our Call for Power and through this engagement developed a First Nations participation model that requires all projects under the Call to have a minimum of 25 percent First Nations ownership, which is a first for our province. The Plan has provided us with a clear and exciting vision for where we are going in the years ahead in our work with First Nations across British Columbia (B.C.)

BC Hydro worked closely with the Ministry of Energy, Mines and Low Carbon Innovation (EMLI) to ensure alignment with Government policy expectations through regular meetings and updates. These were held between BC Hydro and EMLI Executives, as well as with the Minister and her staff, as appropriate, to discuss priority actions to deliver on BC Hydro's mandate. BC Hydro also participated in the BC Hydro Task Force focused on how to ensure reliable, affordable, and emissions-free energy for future generations.

We are proud of our accomplishments this year. We will continue to work together to ensure that our workforce goes home safely, every day, while we work towards our vision of a cleaner, more sustainable future for all British Columbians.

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Lori Wanamaker
Board Chair

Chris O'Riley

Chris O'Riley
President & CEO

Purpose of the Annual Service Plan Report

This annual service plan report has been developed to meet the requirements of the Budget Transparency and Accountability Act (BTAA), which sets out the legislative framework for planning, reporting and accountability for Government organizations. Under the BTAA, a Minister Responsible for a government organization is required to make public a report on the actual results of that organization's performance related to the forecasted targets stated in the service plan for the reported year.

Strategic direction

The strategic direction set by Government in 2020 and expanded upon in the Board Chair's **2021/22 Mandate Letter** from the Minister Responsible shaped the goals, objectives, performance measures and financial plan outlined in the **BC Hydro 2023/24—2025/26 Service Plan** and the actual results reported on in this annual report.

Purpose of the Organization

BC Hydro is one of the largest electric utilities in Canada and our mission is to safely provide our customers with reliable, affordable, and clean electricity. We generate and provide electricity to 95 percent of B.C.'s population and serve approximately five million people. We also offer electric vehicle charging at our 170 fast charging ports at 86 sites across the province and have over 9,000 customers enrolled in our net metering program designed for those who generate electricity for their own use. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometres of transmission and distribution lines, and 125 contracts with independent power producers.

BC Hydro's vision of a cleaner, more sustainable future for all British Columbians is advanced through our **Five-Year Strategy**, which includes four goals to move BC Hydro forward:

1. Energize our province
2. Control our costs
3. Strengthen our resilience and agility
4. Advance reconciliation with Indigenous Peoples

As a provincial Crown Corporation, the owner and sole shareholder of BC Hydro is the Province of B.C. BC Hydro reports to the Provincial Government through the Minister of Energy, Mines and Low Carbon Innovation. Government's expectations are expressed through the following legislation and policies:

- **The Hydro and Power Authority Act**
- **The Utilities Commission Act**
- **The BC Hydro Public Power Legacy and Heritage Contract Act**
- **The Clean Energy Act**
- **CleanBC**
- **CleanBC Roadmap to 2030**

The Hydro and Power Authority Act gives BC Hydro its mandate to generate, manufacture, conserve, supply, acquire, and dispose of power and related products. In 2022, our statutory purposes were expanded by regulation to add the promotion of the use of electricity, including for the purpose of reducing greenhouse gas emissions.

Powerex Corp. (Powerex) and **Powertech Labs Inc.** (Powertech) are two wholly-owned operating subsidiaries of BC Hydro. Powerex is a key participant in wholesale energy markets across North America, trading wholesale power and natural gas, environmental products (renewable energy credits or other similar products), carbon products (allowances and other similar products), ancillary energy services and financial energy products. Powertech is internationally recognized for its technical expertise in a range of fields related to the electric utility and clean energy industries and offers services and solutions to energy clients, including BC Hydro, and other sectors globally. For more information on Powerex, Powertech, and other active and inactive subsidiaries, see Appendix B: Subsidiaries and Operating Segments.

Operating environment

As a utility that operates in a high hazard industry, we keep safety and reliability at the centre of everything we do. Our job is to safely keep the lights on for the people of B.C., and that means that every person working for BC Hydro and interacting with our system goes home safely each day. It has been more than 13 years since our last employee fatality in August 2010.

In 2023/24, climate change and extreme weather events continued to affect our business. Another significant wildfire season occurred in 2023/24 resulting in impacts to 1,400 power poles and nearly 90 kilometres of power lines connecting more than 20,000 customers. Hotter than normal temperatures increased demand for electricity to power air conditioning and fans, and a new summer record of 8,400 megawatts was set this year for BC Hydro's highest August peak hourly demand.

Record drought conditions across much of the north and southeast of the province in summer and fall 2023 also led to lower water inflows to the generation system. BC Hydro experts worked to manage these difficult conditions by using storage and planning releases to provide protection to downstream river flows and optimizing energy production by BC Hydro generation resources. BC Hydro has experienced similarly low water levels at our reservoirs in the past, and while this year was challenging, careful reservoir management, forecasting of inflows and optimization of other levers such as imports meant the power needs of B.C. were met.

The fall and winter storms left hundreds of thousands without power, but British Columbians benefited from our integrated, provincial electricity system with BC Hydro restoring electricity to 99 percent customers within 24 hours in most cases. In January 2024, despite record-high electricity demand during an extreme cold snap, BC Hydro was also able to meet record domestic demand and still export 200 megawatts of power to support our neighbours in Alberta following an electrical grid alert from the Alberta Electrical Systems Operator.

Throughout 2023/24, BC Hydro supported the Province's CleanBC Roadmap to 2030, which commits B.C. to building a stronger economy for people throughout the province by drawing on BC Hydro's supply of renewable, clean and affordable hydroelectric power to reduce greenhouse gas (GHG) emissions. In March 2024, the B.C. Utilities Commission (BCUC) accepted our **2021 Integrated Resource Plan** (IRP), in support of B.C.'s legislated GHG reduction targets, electrification goals, and the drive to shift from fossil fuels to clean electricity to help combat climate change.

Global inflation and high interest rates continued to put pressure on British Columbians and our economy in 2023/24. For BC Hydro, this has resulted in higher costs—including to our capital projects—which we continued to manage through prudent financial planning, including working to minimize ratepayer impacts from large swings in interest rates. After adjusting for inflation, electricity in B.C. cost the same in 2023/24 as it did back in 1978.

BC Hydro's electricity system was largely built in the 1960s, 1970s, and 1980s and we invested approximately $4.3 billion in 2023/24 to upgrade aging assets and build new infrastructure to meet increased demand for our clean electricity from population growth and electrification. Each year, there are hundreds of BC Hydro capital projects underway that, together, make up one of the largest expansions of electrical infrastructure in B.C.'s history. During 2023/24, BC Hydro capital projects placed in-service totaled $1.6 billion, including projects to renew and expand our generation, transmission, and distribution systems.

In January 2024 we released our expanded **10-Year Capital Plan**, which outlined a further $36 billion in community and regional infrastructure investments, which is a 50 percent increase in investments over our previous capital plan, excluding Site C. In our 2021 IRP we also estimated we will need about 3,000 gigawatt hours per year of new renewable generation from large projects that can connect directly to our system starting as early as 2028. To address this need, in June 2023 we announced we are moving forward with a call for new sources of clean, affordable electricity. This is the first call for power in 15 years and includes requirements for at least 25 percent First Nations equity ownership in projects.

In 2023/24 we continued to pursue meaningful, long-term relationships with First Nations across the province. Pursuant to the historic passing of the Declaration on the Rights of Indigenous Peoples Act in November 2019, in March 2024 BC Hydro released its **United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) Implementation Plan**, following robust consultations with First Nations. The plan outlines the actions BC Hydro is taking or will take to incorporate the principles of UNDRIP into our business, expanding on the significant relationship building that has taken place. We also continued to work to implement the Calls to Action of the Truth and Reconciliation Commission and the Draft Principles that Guide the Province of B.C.'s Relationship with Indigenous Peoples into our business.

Safety is always top of mind and BC Hydro is continually monitoring our progress to improve the safety of our employees, contractors, and members of the public.

Report on performance: goals, objectives, and results

The following goals, objectives and performance measures have been restated from the 2023/24—2025/26 service plan. For forward-looking planning information, including current targets for 2024/25—2026/27, please see the latest service plan on the **BC Budget website**.

Goal 1

Deliver reliable power safely

Objective 1.1: BC Hydro will safely and reliably meet the electricity requirements of our customers by prudently planning and investing in the system.

As a utility that operates in a high hazard industry, our goal continues to be that everyone goes home safely, every day. By continuing to make strategic investments to expand our system and maintain aging infrastructure, we will ensure we can continue to safely provide our customers with reliable and clean electricity.

KEY RESULTS

- No employee fatalities or serious disabling injuries in 2023/24.
- Announced $21 billion under our expanded **10-Year Capital Plan** to invest in existing assets across our system to ensure it can continue to serve future generations.
- In March 2024, the BCUC accepted our 2021 Integrated Resource Plan (IRP), which anticipates BC Hydro's load and resource needs and guides decisions on our electricity system in the future.

SUMMARY OF PROGRESS MADE IN 2023/24

Safety is an overarching, organization-wide, core value at BC Hydro, and preventing serious injury incidents and meeting our target of Zero Fatalities and Serious Disabling Injuries remained a top priority in 2023/24. Our investments in safety have improved our safety performance to zero fatal employee incidents since 2010. We have continued to improve our systematic approach to safety through our Safety Framework and how we learn from our performance. For example, we completed improvements to our Safety Incident Management Process, which helps us more effectively and efficiently learn from safety incidents, including those that had the potential for serious injury or fatality. We have also increased leadership engagement with workers by conducting field Safe Work Observations across the organization. Further, we built on our risk management approach by moving forward key safety programs like Arc Flash and advanced our use of data from incidents and Safe Work Observations to support conversations with leadership and workers about preventing serious incidents and our most common sources of injury.

Although the impacts of climate change have resulted in more frequent extreme weather events, we maintained customer reliability through monitoring and planning for overall system reliability. In 2023/24, BC Hydro successfully responded to major storms, wildfires, and periods of extreme heat or cold. Throughout the year, BC Hydro completed an increased number of planned outages to conduct maintenance work to protect system reliability and undertook strategic vegetation management to address high risk tree-related outages.

Objective 1.2: BC Hydro will meet the evolving expectations of our customers by improving our service.

This objective emphasizes our continued commitment to meet the rising expectations of our customers.

KEY RESULTS

- Achieved a 91 percent customer satisfaction score based on our quarterly customer surveys.
- Provided Customer Crisis Fund grants to support 6,193 residential customers experiencing difficulty paying their bills.
- Received the **Highest Customer Service** award (government category) from SQM Group.[i]

SUMMARY OF PROGRESS MADE IN 2023/24

We worked to consistently improve customer experience and meet growing customer expectations and once again, exceeded our Customer Satisfaction Index threshold in 2023/24. This result reflects our ongoing efforts in ensuring high service reliability for our customers, continued commitment to customer service and improvements in our customer communications. BC Hydro provided over 6,000 Customer Crisis Fund grants to customers facing emergency financial situations and disconnection with financial assistance to pay their bills.

Performance measures and related discussion

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[1a] Zero Fatality & Serious Disabling Injury [1, 2]	0	0	0
[1b] Lost Time Injury Frequency (LTIF) [3, 4]	0.86	0.74	0.79

Data source: BC Hydro Incident Management System

[1] Measure of electrical contact, fall from height, mechanical energy or transportation incidents that have resulted in a loss of life or an injury resulting in a permanent disability for which a disability pension has been received or is expected. BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.

i SQM is the third-party company which performs BC Hydro's customer satisfaction surveys. They also complete surveys for several other organizations and benchmark over 500 leading North American call centres against each other on an annual basis. For more information: **https://www.sqmgroup.com/awarding/award-winners-year**.

² PM 1a targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as 0. This PM waws also renamed "Fatality & Permanently Disabling Injury" in the 2024/25 Service Plan.

³ Number of employee injury incidents resulting in lost time (beyond the day of injury) per 200,000 hours worked.

⁴ PM 1b was replaced by the new measure "Serious Injury or Fatality Potential Incident Frequency" in the 2024/25 service plan. This new measure includes "near miss" incidents and will help further focus BC Hydro's efforts on preventative measures.

Zero Fatality and Serious Disabling Injury is a measure of electrical contact, fall from height, mechanical energy or transportation incidents that have resulted in a loss of life or an injury resulting in a permanent disability for which a disability pension has been received or is expected. In 2022/23, BC Hydro achieved its performance target.

BC Hydro did not meet our Lost Time Injury Frequency (LTIF) target for 2023/24, with 49 lost time injuries overall; however, LTIF has improved from 0.86 in 2022/23 to 0.79 in 2023/24. Our LTIF performance of 0.79 is also BC Hydro's best year-end result since this measure has been reported through our Annual Service Plan Reports, excluding 2020/21 (a pandemic-related anomaly). Forty-six lost time injuries or fewer would have resulted in the measure being achieved.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[1c] System Average Interruption Duration Index (SAIDI) [1, 2]	3.14	3.35	3.56
[1d] System Average Interruption Frequency Index (SAIFI) [3, 4]	1.50	1.38	1.56

Data source: BC Hydro reliability information is collected in a centralized database that allows outage records to be reviewed by managers regularly to ensure accuracy.

¹ Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year (excluding major events)

² PM 1c targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as 3.35 hours.

³ Total number of sustained interruptions experienced by an average customer in a year (excluding major events)

⁴ PM 1d targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as 1.38.

Our 2023/24 SAIDI result was six percent above the target of 3.35 but within the allowable range of 10 percent so the target is considered met. Performance within 10 percent is considered acceptable given the estimation uncertainty, the wide range of variations in weather patterns and uncontrollable elements that can significantly disrupt the electrical system.

BC Hydro did not meet its 2023/24 target for SAIFI, with a result 13 percent above the target of 1.38. BC Hydro completed a high number of planned outages to maintain system reliability, which impacted our SAIDI and SAIFI performance. BC Hydro focused on providing customers with advance notice of planned outages to minimize impacts. In addition, the impacts from the serious wildfire situation from May to August negatively affected reliability performance due to trees and vegetation coming into contact with our system and smoke increasing transmission line failures.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[1e] Key Generating Facility Forced Outage Factor (%) [1, 2]	1.05	1.80	1.13

Data source: BC Hydro Unit Status Recording Systems managed by the Asset Performance Planning team.

¹ Total forced outage time in a period relative to the total number of hours in the same period, over a 60-month rolling average. BC Hydro's seven key generating facilities represent those plants with installed capacity greater than 200MW.

² PM 1e targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as 1.70 percent.

BC Hydro achieved our target to remain below 1.80 per cent for Key Generating Facility Forced Outage Factor with a result of 1.13 per cent, demonstrating the continued effectiveness of our maintenance and capital investment programs.

Key Generating Facility Forced Outage Factor measures the percentage of time key generating units are unavailable due to internal unplanned causes. This measure is an important way to understand the ongoing reliability of BC Hydro's generating system. Annually, the Forced Outage Factor can be relatively volatile, and applying the historical 60-month rolling average smooths the range to provide a more stable measure for which targets can be set.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[1f] Customer Satisfaction Index (CSAT) [1, 2]	89	85	91

Data source: BC Hydro's Customer Satisfaction Index which measures customer satisfaction of BC Hydro's three main customer groups (residential, commercial, and key accounts). The index is comprised of the five key drivers of satisfaction weighted equally across the three customer types.

¹ Percentage of customers satisfied or very satisfied.

2 PM 1f targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as 85 percent.

The Customer Satisfaction (CSAT) Index measure gauges the degree to which BC Hydro is meeting customers' electricity and service needs. Residential and commercial customer 2023/24 CSAT index scores were relatively consistent with previous years' results. The stable target for the CSAT index reflects that customers' service needs are being met; however, continued effort is necessary to address gaps in specific areas, as well to meet customer's changing expectations from their interactions with other organizations. In the near term, BC Hydro does not have any planned investments that would result in a sustained increased to the index.

Goal 2

Energize our province

Objective 2.1: BC Hydro will help electrify the province’s economy and encourage customers to use our clean electricity.

This objective focuses on our efforts in supporting our customers to switch to BC Hydro’s clean electricity in support of our **Electrification Plan** to electrify B.C.’s growing economy.

KEY RESULTS

- Exceeded our 2023/24 target for new or expanded commercial or industrial load by over 500 megawatts (MW) and connected over 35,000 new customers to our system.
- Completed the North Coast expression of interest to identify future customer demand for BC Hydro’s clean electricity.
- Received BCUC approval on a new flat rate for BC Hydro’s transmission service customers that will replace current stepped rates, helping to remove a barrier to electrification.
- As of March 2024, installed 170 fast charging ports at 86 sites in our network, representing a 70 percent increase in charging ports and 18 percent increase in locations since 2021.
- Announced close to $10 billion in new electrification and greenhouse gas reduction efforts in our expanded **10-Year Capital Plan**.

SUMMARY OF PROGRESS MADE IN 2023/24

In 2023/24, BC Hydro continued to make progress on supporting the energy transition. We exceeded our target for New Connected Commercial and Industrial Load as a result of higher activity in the commercial and small industrial sectors. We also nearly achieved our target for the Load Growth Supporting CleanBC performance measure. To support more customers to make the switch to clean electricity, we continued to make investments through our $260 million Electrification Plan in three key areas: transportation, buildings, and industry.

This year we also worked diligently to make clean electricity an even more attractive option for customers and reduce the time it takes to connect to our system. For example, the BCUC approved our proposal for a new flat rate for transmission customers which removes the stepped charge for higher usage—one of the barriers to industrial electrification. To help speed up the connection process for new customers, BC Hydro increased our distribution capital budget by $157 million in 2023/24.

Objective 2.2: BC Hydro will support achieving British Columbia's climate action targets.

This objective highlights the work BC Hydro undertakes to support the Province's CleanBC Roadmap to 2030 and efforts to reduce GHG emissions.

KEY RESULTS

- Grew our **Peak Saver** program to more than 41,500 participating customers and introduced a limited time double the incentive promotion for the Team Power Smart Reduction Challenge to encourage more customers to step up their energy efficiency efforts in support of CleanBC.
- BC Hydro low-income customers saved approximately five gigawatt hours of electricity from BC Hydro's energy efficiency programs and products. As a result, participating customers saved a total of $621,000 on their annual electricity bills. BC Hydro invested approximately $15 million on these low-income supports.
- The BCUC accepted BC Hydro's proposal to offer optional time-of-day pricing to residential customers, which encourages customers to shift their electricity use to periods when demand for electricity is lower and there is more system capacity by offering a lower price for electricity used during these times.
- Released our inaugural **Environmental, Social, and Governance (ESG) Report** which outlines BC Hydro's commitments and progress in each of these important areas.

SUMMARY OF PROGRESS MADE IN 2023/24

In 2023/24, BC Hydro continued to make progress on increasing the use of clean electricity in B.C. to help meet the Province's climate targets. While BC Hydro fell slightly short of our 2023/24 target of emissions reductions from clean industries and fuel switching, we once again exceeded our target for emissions reductions from our own operations. Our inaugural ESG Report was released in August which outlined the steps BC Hydro is taking to continue its long history of contributing to the growth, well-being, and economic prosperity of B.C. We also saw strong results from our conservation efforts in 2023/24.

Performance measure(s) and related discussion

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[2a] Load Growth Supporting CleanBC (Gigawatt hours per year (GWh)) [1, 2]	739	1,500	1,431

Data source: The data sources for this measure vary depending on the sector as follows: transportation, residential and commercial buildings, upstream gas and gas pipelines, and other industry (including mining, LNG, district energy, and new clean industry).

[1] Cumulative gigawatt hours since 2020/21

[2] PM 2a was replaced by two new measures in the 2024/25 service plan: "Number of Public Electric Vehicle Charging Ports in Operation" and "Residential Electrification Program Participation." These new measures provide insight into how we are supporting our residential customers through the energy transition.

BC Hydro narrowly missed achieving its 2023/24 target of 1,500GWh for the Load Growth Supporting CleanBC. This result was largely due to factors outside BC Hydro's control such as customer delays in certain large fuel switching projects coming online.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[2b] New Connected Commercial and Industrial Load (Megawatts (MW)) [1, 2]	535	500	1,093

Data source: BC Hydro's Energy Analytics Solution, Customer Care System, and Customer Service Staff.

[1] Cumulative additional MW from new or expanded commercial and industrial load since 2020/21.

[2] PM 2b targets for 2024/25 and 2025/26 were stated in the 2023/24 service plan as 625MW and 750MW, respectively.

Our 2023/24 result of 1,093 cumulative MW from new or expanded commercial or industrial load significantly exceeded the 500 MW target. This result was due to more activities in the commercial and small industrial sectors than we anticipated when the target was set. Industrial projects account for most of the expected load growth and consequently, changes to in-service dates and load requirements can significantly impact this metric.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[2c] GHG Emissions Reduction Electrification (millions tonnes CO2e/year) [1, 2]	0.48	1.00	0.91

Data source: BC Hydro program records and load increases.

[1] Cumulative GHG emissions reductions from fuel switching and clean industries since 2020/21.

[2] PM was replaced by two new measures in the 2024/25 service plan: “Number of Public Electric Vehicle Charging Ports in Operation” and “Residential Electrification Program Participation.” These new measures provide insight into how we are supporting our residential customers through the energy transition.

BC Hydro fell slightly short of its 2023/24 target of 1.00 million tonnes CO2e per year and finished the year with a result of 0.91 million tonnes CO2e per year. As was the case with the Load Growth Supporting CleanBC performance measure, this result was also largely due to factors outside BC Hydro’s control, including customer delays to larger fuel switching projects in the mining, oil and gas, and liquefied natural gas sectors.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[2d] GHG Emissions Reduction—BC Hydro Operations (%) [1, 2]	50	43	61

Data source: The data for this metric is collected by various BC Hydro groups as follows: Environment and Asset Planning (sulfur hexafluoride (SF6)/CH4); Supply Chain (paper use and air travel); Fleet Services (vehicle emissions); Properties (buildings); Asset Planning, Power Acquisitions and Treasury (Non-Integrated Areas and Independent Power Producers); and Operations (thermal).

[1] Cumulative GHG reductions from BC Hydro operations since 2007.

[2] PM 2d targets for 2024/25 and 2025/26 were stated in the 2023/24 service plan as 44 percent and 45 percent, respectively.

BC Hydro exceeded our 2023/24 target due to lower than forecasted generation from biomass facilities and the Fort Nelson generating station. GHG Emissions Reduction—BC Hydro Operations measures BC Hydro’s progress in reducing GHG emissions related to our own operations. Targets for this metric have been set to allow BC Hydro to exceed the 16 per cent provincial GHG emissions reduction target from 2007 levels by 2025.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[2e] Clean Electricity Standard (%) [1, 2]	100	100	100

Data source: BC Hydro retail sales, metered output of BC Hydro-owned generation, and contracted resources and net clean deliveries associated with Powerex.

[1] BC Hydro generates and acquires clean energy to meet BC Hydro domestic sales on the integrated grid on a cumulative basis over a four calendar-year period. As this is a new measure, there are not yet four years of data available; so 2023/24measures cumulative results from January 1, 2021 to December 31, 2023.

[2] PM 2e targets were updated in the 2024/25 service plan to “met.” The measure is considered met if the result is 100 percent.

BC Hydro achieved its 2023/24 target of 100 percent Clean Electricity Standard. As this was a new measure in the 2023/24 Service Plan, there are not yet four years of data available, so 2023/24 measures cumulative results from January 2021 to December 2023.This metric helps confirm BC Hydro’s ability to support provincial GHG emission reduction targets and CleanBC objectives while securing the Province’s competitive position when offering surplus hydro capabilities to customers in external jurisdictions. Due to ongoing adverse hydro conditions, there is risk to the achievement of the 2024/25 target.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[2f] Customer Interconnection Studies Completed on Time (%) [1, 2]	96	80	87

Data source: The target study delivery date for the various interconnection studies phases are compared to the actual completion dates to determine the percentage of customer interconnection studies completed on time.

[1] Completion of interconnection studies to allow customers to connect to BC Hydro’s system.

[2] PM 2f targets for 2024/25 and 2025/26 were both stated in the 2023/24 service plan as 80 percent.

BC Hydro exceeded its 2023/24 target of 80 percent through strong management of customer timelines and proactively identifying risks. Although we have exceeded this target in 2022/23 and 2023/24, we have maintained a target of 80 percent for future years given the increasing volume and complexity of the interconnection studies (including related to housing growth and industrial electrification) and external factors, including changes initiated by customers and/or third parties and additional time required to accommodate feedback from stakeholders.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[2g] Demand Side Management Capacity (MW) [1, 2]	96	110	152

Data source: BC Hydro's Demand Side Management Plan, which is subject to BCUC review and approval.

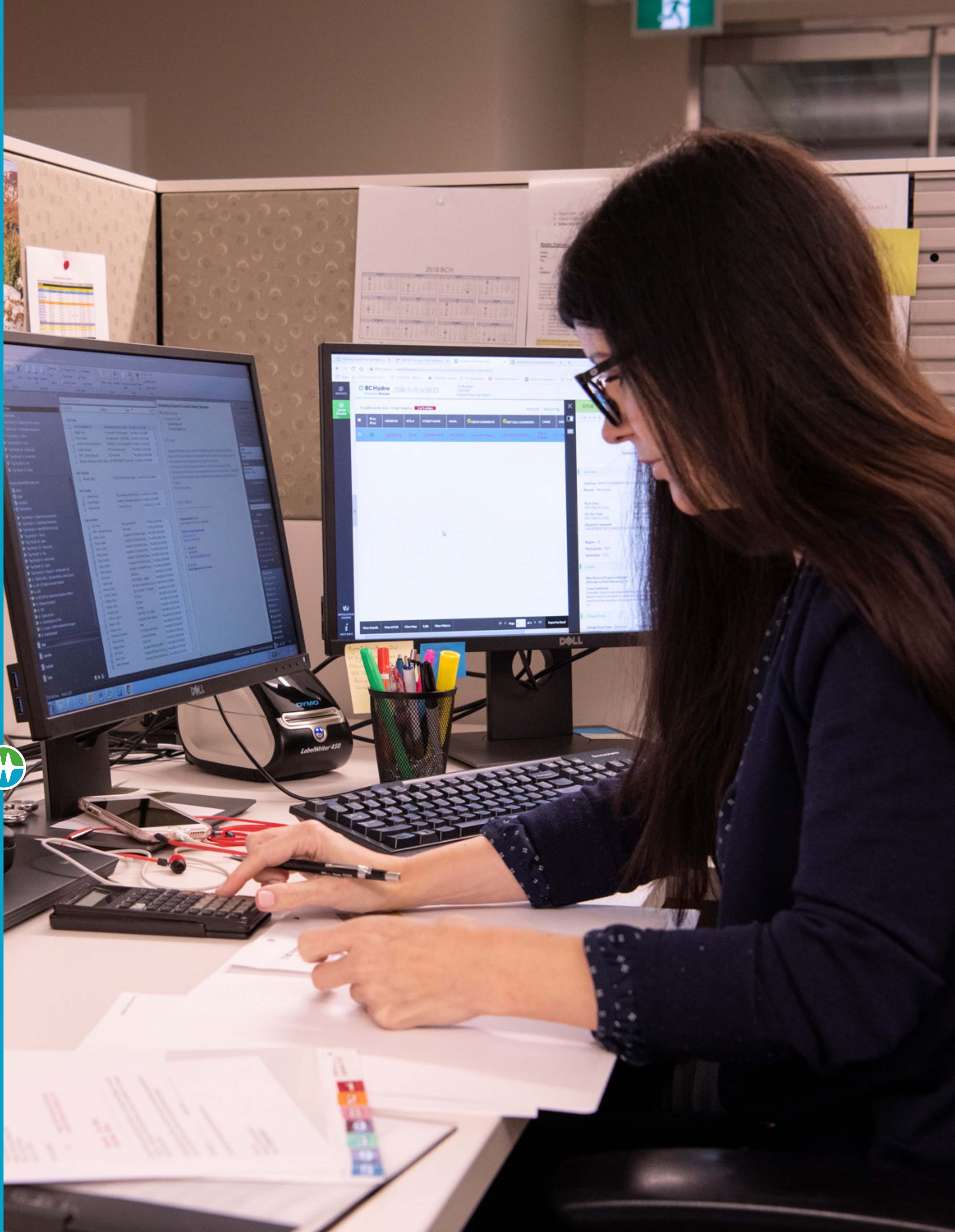
[1] Annual new incremental capacity (MW) savings from the energy conservation portfolio.

[1] PM 2g targets were updated in the 2024/25 service plan to 150MW and 210MW, respectively given incremental demand side management activities.

BC Hydro continued to have strong performance from our energy efficiency and conservation initiatives and exceeded the 2023/24 Demand Side Management Capacity target of 110 MW. We continued to offer programs to support low-income customers, as well as customers in the non-integrated areas, and improved affordability for participating customers by helping them be more energy efficient and reduce their bills.

Goal 3

Control our costs



Objective 3.1: BC Hydro will manage costs to provide affordable and competitive rates.

This objective reinforces our efforts to maintain affordability while making strategic investments in our system.

KEY RESULTS

- Initiated customer engagement on a range of **possible new rate options for residential customers** to allow customers to decide what rate plan best suits their individual needs.
- Expanded our **Energy Conservation Assistance Program** to include portable air conditioners to support vulnerable customers who meet the income qualification requirements of the program. BC Hydro installed more than 4,000 units in 2023/24.
- Maintained rankings in the first quartile for affordable bills, based on Hydro-Québec's annual report on North American electricity rates.
- Completed various key components of the Site C Clean Energy Project, including the earthfill dam, Highway 29 realignment, and diversion tunnel conversion within budget.

SUMMARY OF PROGRESS MADE IN 2023/24

In 2023/24 BC Hydro balanced affordability for our customers with significant required investment in our electricity system to maintain reliability and meet future demand. Our actions to keep rates low for our customers have resulted in our residential, commercial, and industrial rates being ranked in the first quartile for 2023/24, based on analysis of Hydro Québec's annual report, "**2023 Comparison of Electricity Rates in Major North American Cities.**"

This year, BC Hydro continued to improve our project and portfolio performance, by leveraging historical project delivery information to support decision making and timely delivery of projects within budget. We also focused on streamlining processes to reduce cost and accelerate schedules for small capital projects that meet defined criteria, such as pre-existing alternatives analysis or where the scope has low complexity and/or risk.

Construction on Site C has been underway since July 2015. By the end of 2023/24, the project was approximately 85 per cent complete and remained on track to have all six generating units fully in-service by late 2025. Various major components of the project were completed this year, including the earthfill dam, Highway 29 realignment, and conversion of one of the two tunnels diverting the Peace River around the construction site. The tunnel conversion is a key requirement in advance of reservoir filling, which is scheduled to begin in late summer 2024. BC Hydro continued to manage the Site C project within the $16 billion budget and schedule which were approved in 2021.

Performance measure(s) and related discussion

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[3a] Affordable Bills—Residential [1,2]	1st quartile	1st quartile	1st quartile
[3b] Affordable Bills—Commercial [1,2]	1st quartile	1st quartile	1st quartile
[3a] Affordable Bills—Industrial [1,3]	1st quartile	1st quartile	1st quartile

Data source: Hydro-Québec's annual report on North American electricity rates, "Comparison of Electricity Prices in Major North American Cities."

[1] PM 3a, 3b, and 3c targets for 2024/25 and 2025/26 were all stated in the 2023/24 service plan as the first quartile.

[2] BC Hydro calculates the Affordable Bills performance measure for residential and commercial customers as the median consumption level for residential and commercial customer classes compared to the equivalent power consumption sub- \category. The rankings of the 22 participating utilities are then allocated into quartiles. The 1st quartile ranking represents the six utilities that have the lowest monthly electricity bills on April 1 of a given year.

[3] BC Hydro measures affordability within the industrial category based on the largest consumption level.

Our actions to keep rates low for our customers have resulted in our residential, commercial, and industrial rates all again being ranked in the first quartile for 2023/24, based on analysis of Hydro Québec's report. BC Hydro balances affordability for our customers with significant required investment in our electricity system, including operating and capital expenditures that support safety and reliable service.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[3d] Project Budget to Actual Cost: Cumulative Five Years1 [1,2]	-2.64% on $3.553 billion	±5% of budget excluding project reserves	+1.28% on $2.382 billion

Data source: BC Hydro Capital Infrastructure Project Delivery

[1] This measure compares actual project costs at completion to the original approved expected cost budget for the project, not including project reserve amounts, for capital projects that were put into service during the five-year rolling period. Site C is not included in this measure and has its own specific cost and schedule performance measures.

[2] PM 3d targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as within ±5 percent of budget excluding project reserve amounts.

BC Hydro has consistently met its yearly target of being within ±5 percent of the project budget, excluding project reserve amounts. Over the last five years, BC Hydro successfully delivered 208 capital projects at a total cost of $2.413 billion, which is 1.28 per cent above the aggregated budget of $2.382 billion and within the target of ±5 percent of budget.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[3e] Site C—Cost [1,2]	$16 billion	$16 billion	$16 billion
[3f] Site C—Schedule [3,4]	First Unit: December 2024	First Unit: December 2024	First Unit: December 2024

Data source: quantitative information from the Project Risk Register; estimates developed by the project's Estimating, Scheduling and Cost team; input from risk owners and subject matter experts; and output from our risk software

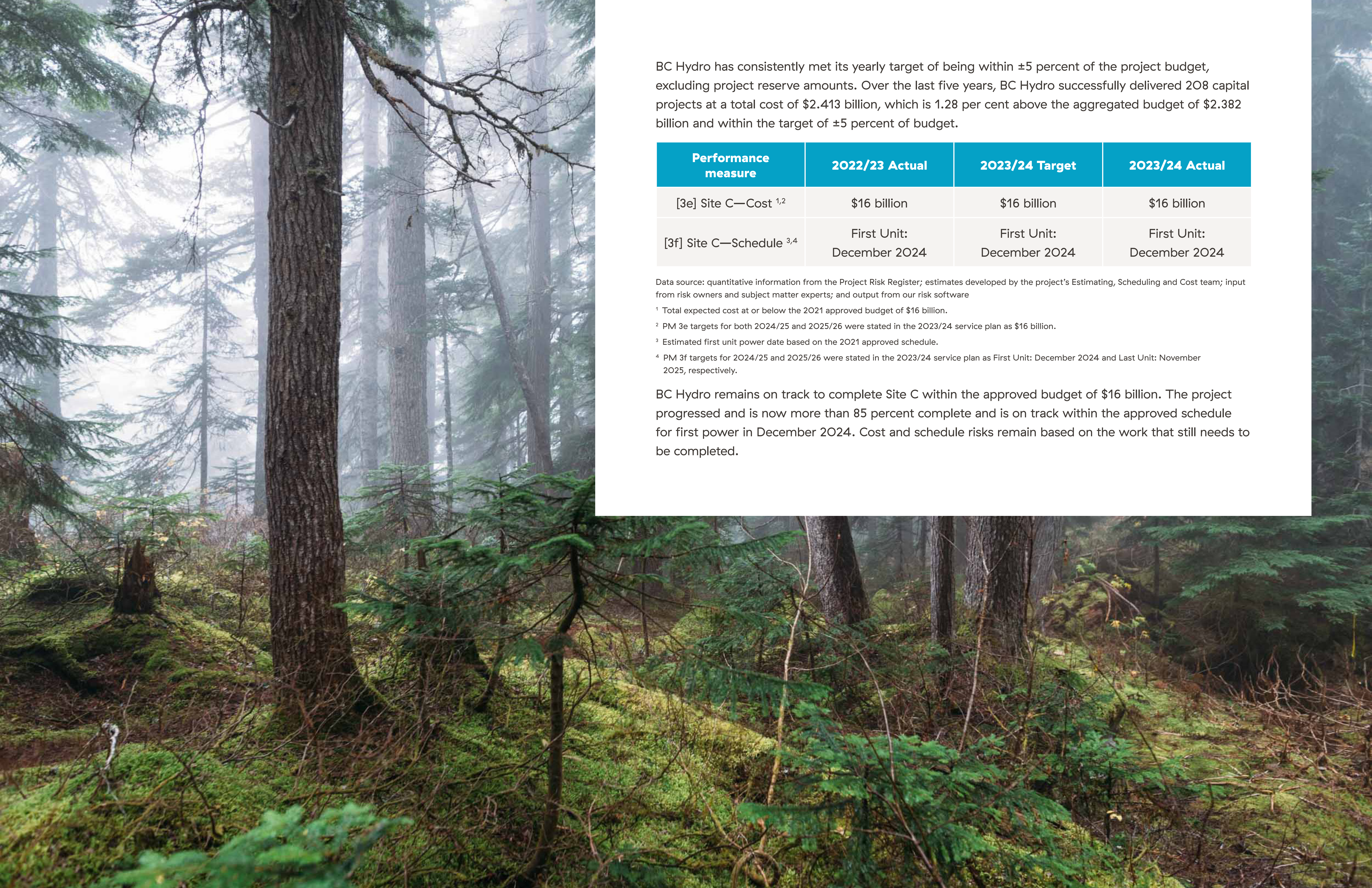
[1] Total expected cost at or below the 2021 approved budget of $16 billion.

[2] PM 3e targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as $16 billion.

[3] Estimated first unit power date based on the 2021 approved schedule.

[4] PM 3f targets for 2024/25 and 2025/26 were stated in the 2023/24 service plan as First Unit: December 2024 and Last Unit: November 2025, respectively.

BC Hydro remains on track to complete Site C within the approved budget of $16 billion. The project progressed and is now more than 85 percent complete and is on track within the approved schedule for first power in December 2024. Cost and schedule risks remain based on the work that still needs to be completed.



Goal 4

Strengthen our resilience and agility

Objective 4.1: BC Hydro will enhance resilience to threats like cybersecurity attacks, impacts of climate change, natural disasters, and other challenging conditions.

As external factors increasingly add to the complexity of our work, this objective ensures we are prepared to address challenges and continue to serve our customers.

KEY RESULTS

- Replaced more that 1,400 power poles and nearly 90 kilometres of power lines to restore power to more than 20,000 customers affected by the 2023 wildfire season.
- In November 2023, restored power to 99 percent of the more than 232,000 customers affected by severe windstorms on the South Coast within 24 hours.
- Achieved an overall employee engagement score above the B.C. public service's overall engagement score, which is our benchmark for this survey.
- Achieved 100 percent participation rate for BC Hydro people leaders in inclusion and diversity leadership training.

SUMMARY OF PROGRESS MADE IN 2023/24

A robust set of resiliency strategies, such as our expanded vegetation management plan, increased used of LIDAR technology, and cyber security investments, helped prepare BC Hydro to mitigate threats on multiple fronts in 2023/24. Enhanced preparedness for climate threats and extreme weather events ensured that we continued to serve our customers in the face of drought conditions, wildfires, major storms, and a record winter peak. When outages did occur, BC Hydro crews worked around the clock to repair and replace affected infrastructure and restore power to customers as soon as possible.

BC Hydro remained committed to developing a diverse workforce that represents the communities that we serve. An engaged, diverse workforce offers different perspectives which supports sound decision-making and strengthens BC Hydro's ability to respond to the various threats we face. In 2023/24 we exceeded our targets for employee engagement and women and visible minority representation in our workforce, and 100 percent of our people leaders completed diversity and inclusion training.

Performance measure(s) and related discussion

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[4a] Employee Engagement Index (%) [1,2]	83 (Above Global Utility Index)	At or above industry benchmark	74 (Above B.C. Public Service overall engagement score)

Data source: Confidential biennial employee engagement survey administered by an external service provider.

[1] PM 4a targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as at or above industry benchmark.

[2] BC Hydro benchmarks against the 2022 B.C. public service work environment survey score which is 67 points.

BC Hydro's Employee Engagement Survey is conducted every two years. In 2023/24 we invited over 7,400 employees to complete the survey, and more than 5,100 responded. Our engagement score of 74 points (out of 100) is seven points higher than the B.C. public service's overall engagement score, which is our benchmark for this survey. For 2023/24 onwards, BC Hydro changed its industry benchmark from the Global Utility Index to the B.C. Public Service work environment survey, allowing us to better compare our performance against other organizations competing for the B.C. labour market.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[4b] Workforce Diversity (%) [1, 2]			
Women	32.6	30	32.1
Visible minority	28.0	25	30.4
Indigenous People	4.0	4.6	4.2
Persons with disabilities	3.7	Progress toward 10	4.8

Data source: Employees are asked to respond to an optional survey, administered and confidentially maintained by an external service provider on behalf of BC Hydro, requesting them to self-identify as a member of the designated groups when they join BC Hydro. BC Hydro measures the participation of the four designated groups by their representation as compared to the available workforce in B.C.

[1] PM 4b targets for 2024/25 and 2025/26 were stated in the 2023/24 service plan as 30, 25, 4.9 and progress towards 10; and 30, 25, 5.0, and 10, respectively.

[2] We define progress as an increase in percentage to the first decimal place.

BC Hydro saw variations in performance under the Workforce Diversity measure in 2023/24. We exceeded our targets for representation of women and visible minority employees in our workforce, and increased the percentage of persons with disabilities employed by BC Hydro from 3.7 percent in 2022/23 to 4.8 percent in 2023/24. The total of self-identified Indigenous employees in our workforce rose to 4.2 percent, which was below our 2023/24 target but is still higher than the available B.C. workforce of 3.9 percent in the occupations that we hire.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[4c] Inclusion and Diversity Leadership Training (% complete) [1]	73	100	100

Data source: Results are determined by tracking participation of BC Hydro people leaders in the LEAD-133VT—Inclusive Leadership and LEAD-133—Inclusive Leadership for Crew Leads courses at BC Hydro.

[1] PM 4c targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as 100 percent. However, targets were revised in the 2024/25 service plan to 95 percent, given successes to date and that this target this still represents a very high completion rate for a non-mandatory course.

BC Hydro achieved its 2023/24 target of 100 percent participation of people leaders in inclusion and diversity leadership training. In 2023/24, 21 virtual instructor-led sessions, and 19 in-person crew lead sessions were delivered, for a total of 40 sessions. This is an increase of 16 sessions compared to previous years. As a result, over 600 people leaders were trained in 2023/24, bringing the cumulative total of people leaders trained since launched in September 2020 to over 1,700.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[4d] Operations Training Hours [1,2]	49	30	41

Data source: Results are measured by tracking employee time in BC Hydro SAP system.

[1] Average hours per Operations technical employee incremental to safety training

[2] PM 4d was removed in the 2024/25 service plan since the incremental funding was limited to 2021/22 and 2022/23. This measure has been replaced with two new measures related to cybersecurity and hazard trees—both significant threats to BC Hydro's reliable operations.

BC Hydro exceeded its 2023/2024 target with a result of 41 average hours of annual training completed by Operations technical employees. This result was mainly due to the onboarding of new employees. While this will no longer be a Service Plan measure starting in 2024/25, BC Hydro will continue to monitor sustainment of Operations technical training internally.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[4e] Mandatory Reliability Standards Non-Compliance Reduction (%) [1,2]	80	70	80

Data source: BC Hydro business groups. Reliability Standards incidents are reported to the Reliability Standards Assurance team and investigated to determine if the incident is reportable to Western Electricity Coordinating Council.

[1] Non-compliance reduction compared to 2020/21.

[2] PM 4e targets for 2024/25 and 2025/26 were stated in the 2023/24 service plan as 80 percent and 85 percent, respectively.

BC Hydro exceeded its 2023/24 target for reduction in Mandatory Reliability Standards non-compliances, with a result of an 80 percent non-compliance reduction since 2020/21, compared to a target of 70 percent. Throughout the year, BC Hydro strengthened its Mandatory Reliability Standards program by implementing improvements in processes, controls, and training to address non-compliances experienced in the past, adding additional resources and making ongoing program investments.

Goal 5

Advance reconciliation with Indigenous Peoples

Objective 5.1: BC Hydro will advance reconciliation by continuing to invest in and build mutually beneficial and stronger relationships with Indigenous communities.

Advancing reconciliation is a long-standing priority for BC Hydro. Mutually beneficial relationships with First Nations are critical to operating and growing our system of clean electricity.

KEY RESULTS

- In March 2024, BC Hydro released our **United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) Implementation Plan** which identifies the concrete actions we have been taking and will take going forward together with First Nations to incorporate the principles of the UNDRIP into our business. This plan is a living document that will evolve as we continue to engage with First Nations.
- Engaged almost 100 First Nations, including over 650 participants across 31 information and engagement sessions to inform the development of the **Call for Power**.
- Completed the North Coast electrification **Expression of Interest** to identify industrial electrification interest and early insight to inform possible First Nations co-ownership.
- Exceeded our Indigenous procurement target by $109 million.
- **Signed a partnership agreement** in August 2023 with the Province of B.C. in the Community Energy Diesel Reduction (CEDR) Program, administered by the New Relationship Trust (NRT) to support First Nations in BC Hydro's Non-Integrated Areas (NIAs) in advancing energy efficiency projects to reduce reliance on diesel-generated electricity in these remote areas. In 2023/24, three First Nations communities applied for energy efficiency funding through CEDR.

SUMMARY OF PROGRESS MADE IN 2023/24

BC Hydro continued to seek, develop, and sustain positive long-term relationships and to better understand First Nations' perspectives on our operations so that these priorities were recognized in our capital projects, programs, and activities. Pursuant to the historic passing of the Declaration on the Rights of Indigenous Peoples Act in November 2019, BC Hydro released its UNDRIP Implementation Plan, following extensive consultations with First Nations. The plan outlines the actions BC Hydro is taking or will take to incorporate the principles of UNDRIP into our business, expanding on the significant relationship building that has taken place.

BC Hydro also continued to support First Nations participation in our business through direct procurement opportunities and advancing discussions on co-ownership and equity opportunities for new infrastructure. BC Hydro exceeded our target for direct Indigenous procurement by $109 million in 2023/24. As part of our Call for Power, we are including specific requirements of at least 25 percent First Nations equity ownership for any accepted project, as well as evaluation credits that acknowledge economic benefits to non-equity holding First Nations. This approach to procuring new electricity is a first in BC Hydro's history. In spring 2023 we also completed the Expression of Interest phase to help advance planning for new transmission infrastructure in North Coast. The new line would travel through the traditional territories of 14 First Nations and BC Hydro recognizes an opportunity to partner together with First Nations on electrification. BC Hydro continues to engage with participating First Nations to explore potential models for co-ownership of this transmission line.

Eight self-identified Indigenous university graduates joined our **Indigenous Professionals In Development Program** for six-month rotations across various divisions to gain on-the-job experience and apply for BC Hydro roles. In 2023/24, BC Hydro hired 29 people who self-identify as Indigenous into full-time, part-time regular and temporary positions; of these, seven individuals were hired into full-time positions throughout the company. We also awarded 35 scholarships for self-identified Indigenous students valued at $5,000 for full-time students; two bursaries valued at $2,000; and one Randy Brandt Award valued at $8,000.[ii]

Performance measure(s) and related discussion

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[5a] Indigenous procurement ($ billion) [1,2]	1.162	1.25	1.359

Data source: Report generated by BC Hydro's Supply Chain team which includes the value of direct and indirect procurement, contracts issued, and contract spend.

[1] Cumulative beginning in 2014/15.

[2] PM 5a targets for 2024/25 and 2025/26 were stated in the 2023/24 service plan as $1.36 billion and $1.425 billion, respectively. However, BC Hydro adjusted its targets upward in the 2024/25 service plan to $1.425 billion (2024/25) and $1.525 billion (2025/26) given it is higher forecasted values for direct Indigenous procurement contracts.

ii For further information on BC Hydro's scholarship and bursary programs please visit: **https://www.bchydro.com/community/indigenous-relations/opportunities/individuals/donations_sponsorships.html**

Consistent with BC Hydro's Indigenous Contract and Procurement policy this measure demonstrates BC Hydro's support for the long-term economic interests of First Nations in B.C. by committing to directed procurement opportunities.

Since 2014, BC Hydro has awarded $1.359 billion in direct contracts to Indigenous-designated businesses, exceeding the 2023/24 target of $1.25 billion. As a result, future years' targets have been adjusted upward. Additional economic and community benefits flowing from direct and indirect Indigenous procurements are not captured by this metric.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[5b] Indigenous employment (%) [1,2]	4.0	4.6	4.2

Data source: Employees respond to an optional survey, administered and confidentially maintained by an external service provider on behalf of BC Hydro, requesting them to self-identify as a member of the designated groups when they join BC Hydro. BC Hydro measures the participation of the designated groups by their representation as compared to the available workforce in B.C.

[1] PM 5b was removed from the 2024/25 service plan given that this metric was already measured under PM 4b (Workforce Diversity).

Increasing representation of self-identified Indigenous employees at BC Hydro supports reconciliation by ensuring the inclusion of Indigenous voices and perspectives in our work. In 2023/24, BC Hydro gained 26 self-identified Indigenous employees, bringing the total percentage of self-identified Indigenous employees in our workforce to 4.2 percent. A net increase of 55 self-identified Indigenous employees or more would have resulted in the measure being achieved. The percentage of employees who self-identify as Indigenous at BC Hydro has already exceeded the 3.9 percent of the available B.C. workforce, but we have continued to set a higher target given our larger responsibility as a Crown corporation to advance reconciliation.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[5c] Indigenous Awareness Training at BC Hydro (% complete) [1]	74	63	84

Data source: Employee participation in BC Hydro's INDIG-101 and/or INDIG-201 courses.

[1] PM 5c targets for 2024/25 and 2025/26 were stated in the 2023/24 service plan as 71 percent and 80 percent, respectively. However, BC Hydro adjusted its targets upward in the 2024/25 service plan to 85 percent for both 2024/25 and 2025/26 since previous targets were already exceeded.

BC Hydro exceeded its 2023/24 target for Indigenous Awareness Training with a result of 84 percent of employees having completed either INDIG-101 or INDIG-201. This result demonstrates employees' increased interest in cultural awareness and obtaining tools to advance reconciliation in their daily work. BC Hydro remains committed to ensuring as many employees as possible participate in this training.

Performance measure	2022/23 Actual	2023/24 Target	2023/24 Actual
[5d] Progressive Aboriginal Relations Certificate [1,2]	Gold	Gold	Gold

Data source: Canadian Council for Aboriginal Business.

[1] The The Progressive Aboriginal Relations certification program is overseen by the Canadian Council for Aboriginal Business. It is reviewed on a three-year cycle.

[2] PM 5d targets for both 2024/25 and 2025/26 were stated in the 2023/24 service plan as Gold.

In 2021/22, BC Hydro obtained our fourth consecutive gold certification under the Canadian Council for Aboriginal Business's Progressive Aboriginal Relations program. BC Hydro has attained the highest, gold-level designation since 2012. This certification demonstrates BC Hydro's commitment to implementing leading reconciliation practices across the areas of leadership, community relationships, business development, and employment. BC Hydro is one of only 22 companies in Canada to achieve gold designation. BC Hydro submitted its application for our fifth certification in March 2024 and we expect to receive results in fall 2024.

Financial report

For the auditor's report and audited financial statements, see Appendix C. These documents can also be found on the BC Hydro website.

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 year ended March 31, 2024 and should be read in conjunction with the 2023/24 Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2024 and 2023. Certain comparative figures have been restated as described in Note 2 of the Audited Consolidated 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 year ended March 31, 2024 was $323 million, $37 million lower than the prior fiscal year. In March 2024, government issued a directive to BC Hydro to provide affordability credits to customers as of March 31, 2024, based on their consumption in fiscal 2024. This resulted in a $326 million decrease in revenues and a corresponding decrease in net income in fiscal 2024 compared to the cost–of–living credits issued to customers in the prior fiscal year of $315 million, which accounts for $11 million of the net income decrease. The remaining net income decrease of $26 million was primarily driven by various net cost increases compared to the prior fiscal year.
- Total revenue for the year was $7.13 billion, $1.35 billion lower than the prior year. The primary reason for the decrease was a $869 million decrease in trade revenues due to lower trading sales volumes and lower average sales prices. There was a similar decrease in the cost of energy associated with trading activity such that trade margin was consistent with the prior year.
- Water inflows to the system for the year ended March 31, 2024 were significantly below average and lower than the prior fiscal year. The below average water inflows were due to below average snowpack in spring of 2023 and significant drought across BC Hydro's basins over the summer and in subsequent months. The lower inflows were a major driver that resulted in BC Hydro net electricity imports of 13,603 GWh in the current fiscal year compared to net electricity exports of 1,629 GWh in the prior fiscal year. This resulted in a reduction in domestic revenues and an increase in energy costs for the year ended March 31, 2024 compared to the prior fiscal year. Variability in inflows, EPA 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 years.
- The use of regulatory accounts is common amongst regulated utility industries throughout North America. The net regulatory asset balance (i.e., amount recoverable from ratepayers) as at March 31, 2024 was $1.85 billion, $385 million (or 26%) higher than the prior fiscal year. The primary reason for the increase was due to additions to the Cost of Energy Variance Accounts mainly due to higher net electricity import costs as a result of the drought, partially offset by a reduction to the Trade Income Deferral Account mainly due to higher trade income than planned.
- Capital expenditures, before contributions in aid of construction, for the year ended March 31, 2024 were $4.26 billion, a $344 million increase over the prior fiscal year primarily due to higher investments in expanding our Distribution system, replacing ageing assets and higher volumes of customer connection projects.

Consolidated results of Operations

for the years ended March 31 ($ in millions)		**2024**		2023		Change
Total Revenues	**$**	**7,131**	$	8,478	$	(1,347)
Net Income	**$**	**323**	$	360	$	(37)
Capital Expenditures	**$**	**4,263**	$	3,919	$	344
GWh Sold (Domestic)		**55,413**		59,880		(4,467)

as at March 31 ($ in millions)		**2024**		2023		Change
Total Assets and Regulatory Balances	**$**	**49,442**	$	45,786	$	3,656
Shareholder's Equity	**$**	**7,696**	$	7,356	$	340
Net Debt	**$**	**29,294**	$	26,630	$	2,664
Debt to Equity		**79 : 21**		78:22		n/a
Number of Domestic Customer Accounts		**2,220,056**		2,188,693		31,363

Revenues

For the year ended March 31, 2024, total revenues of $7.13 billion, were $1.35 billion (or 16 per cent) lower than the prior fiscal year. The decrease was due to lower trade revenues of $869 million and lower domestic revenues of $478 million.

for the twelve months ended March 31	*($ in millions)* 2024	2023	*(gigawatt hours)* 2024	2023
Revenues				
Residential	**$ 2,129**	$ 2,146	**19,171**	19,547
Light industrial and commercial	**1,913**	1,840	**19,205**	19,247
Large industrial	**866**	848	**14,032**	13,437
Other sales	**596**	1,148	**3,005**	7,649
Domestic Revenues	**5,504**	5,982	**55,413**	59,880
Trade Revenues[1]	**1,627**	2,496	**20,985**	27,141
Revenues	**$ 7,131**	$ 8,478	**76,398**	87,021

[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

For the year ended March 31, 2024, domestic revenues were $5.50 billion, $478 million (or 8 per cent) lower than the prior fiscal year. The decrease was primarily due to the lower electricity exports (a component of Other sales) in the current year as a result of low water inflows because of the below average 2022/23 snowpack and persistently dry conditions across BC Hydro's basins over the summer and in subsequent months. The decrease in revenues was partially offset by the 2.20 per cent bill increase approved by the British Columbia Utilities Commission (BCUC) effective April 1, 2023.

Domestic sales volumes were 4,467 GWh (or 7 per cent) lower than the prior fiscal year. Excluding electricity exports, domestic sales volumes were 541 GWh (or 1 per cent) higher than the prior fiscal year.

Trade revenues

For the year ended March 31, 2024, trade revenues were $1.63 billion, $869 million (or 35 percent) lower than the prior fiscal year. Trade revenues were lower due to lower sales volumes and average sales prices.

Operating expenses

For the year ended March 31, 2024, total operating expenses of $6.79 billion as disclosed in Note 5 of the Audited Consolidated Financial Statements were $327 million (or 5 per cent) higher than the prior fiscal year. The increase was primarily due to higher materials and external services of $166 million and higher energy costs of $151 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.

for the twelve months ended March 31	*($ in millions)* 2024	2023	*(gigawatt hours)* 2024	2023
Energy Costs				
Purchases from Independent Power Producers	**$ 1,381**	$ 1,421	**13,667**	15,409
Market purchases[1]	**1,597**	1,591	**37,942**	31,679
Non-Treaty storage and Co-ordination Agreements	**3**	(170)	**-**	-
Other expenses	**47**	51	**118**	121
Electricity and gas purchases	**3,028**	2,893	**51,727**	47,209
Water rental payments (hydro generation)[2]	**362**	358	**31,614**	45,311
Transmission charges	**335**	323	**-**	-
Energy Costs	**$ 3,725**	$ 3,574	**83,341**	**92,520**

[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.

Energy costs

Energy costs for the year ended March 31, 2024 were $3.73 billion, $151 million (or 4 per cent) higher than the prior fiscal year.

Electricity and gas purchases for the year ended March 31, 2024 were $3.03 billion, $135 million (or 5 per cent) higher than the prior fiscal year. The increase in costs was primarily due to higher Non-treaty Storage and Coordination agreements costs due to fewer net water releases in the current year compared to the prior year. The cost of market purchases were consistent with the prior year but included significantly higher costs from importing electricity to meet domestic load requirements as a result of a below average 2022/23 snowpack and persistently dry conditions across BC Hydro's basins over the summer and in subsequent months, partially offset by lower energy costs from trading activities.

Water rental payments and Transmission charges for the year ended March 31, 2024 were $362 million and $335 million, respectively, comparable to the $358 million and $323 million, respectively, in the prior fiscal year.

Water inflows and reservoir storage

Water inflows (energy equivalent) to the system for the year ended March 31, 2024 were significantly below average and lower than the prior fiscal year. Almost every month of fiscal year 2024 saw below average inflows in both the Columbia and Peace. Cumulative precipitation at Williston and Kinbasket reservoirs from October 2022 through September 2023 was the lowest out of 63 years of records. This is not the first time BC Hydro has experienced conditions like these. The worst drought on record for BC Hydro's system was a four-year period in the 1940s.

At March 31, 2024, system energy storage is tracking above the ten-year historical average as a result of significant electricity imports that occurred during the year to support domestic load requirements and in anticipation of lower than normal water inflows in fiscal 2025 as a result of a below average 2023/24 snowpack . System energy storage at March 31, 2024 was higher than at March 31, 2023.

Personnel expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the year ended March 31, 2024 were $819 million, $57 million (or 7 per cent) higher than the prior fiscal year primarily due to higher labour costs including compensation increases commensurate to the public sector mandate and an increase in the number of employees.

Materials and external services

Materials and external services primarily includes materials, supplies, and contractor fees. Expenditures on materials and external services for the year ended March 31, 2024 were $923 million, $166 million (or 22 per cent) higher than the prior fiscal year primarily due to BC Hydro providing rebates for electric vehicles, inflationary pressures from vegetation management and fuel, higher costs incurred on Demand-Side Management 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. For the year ended March 31, 2024, amortization and depreciation expense was $1.07 billion, $19 million (or 2 per cent) higher than the prior fiscal year primarily due to additional property, plant and equipment placed in service.

Grants and taxes

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.

Total grants and taxes for the year ended March 31, 2024 were $316 million, $20 million (or 7 per cent) higher than the prior fiscal year primarily due to an increase in the assessed values of the land parcels for the electrical power grid.

Other costs, net of recoveries

Other costs, net of recoveries primarily includes 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. For the year ended March 31, 2024, other costs net of recoveries were $25 million, $80 million (or 76 per cent) lower than the prior fiscal year primarily due higher insurance proceeds recognized.

Capitalized costs

Capitalized costs consist of costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Capitalized costs for the year ended March 31, 2024 were $92 million, which is comparable to the $86 million in the prior fiscal year.

Finance charges

Finance charges for the year ended March 31, 2024 were $516 million, an increase of $20 million (or 4 per cent) compared to the prior fiscal year. The increase was primarily due to higher interest rates on short-term borrowings, higher volume of debt, and lower realized gains on future debt hedges settled during the year. The increase was partially offset by higher interest capitalized to assets under construction and lower foreign exchange losses.

Regulatory transfers

In accordance with IFRS 14, Regulatory Deferral Accounts, the Company separately presents regulatory balances and related net movements on the Consolidated Statements of Financial Position and the Consolidated 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:

for the years ended March 31 (in millions)	2024	2023
Cost of Energy Variance Accounts		
Heritage Deferral Account	$ 79	$ (121)
Non-Heritage Deferral Account	1,183	51
Biomass Energy Program Variance	(52)	(40)
Low Carbon Fuel Credits Variance	(15)	(22)
Other	46	(60)
	1,241	(192)
Other Cash Variance Accounts		
Trade Income Deferral Account	(538)	(747)
Total Finance Charges	56	19
Inflationary Pressures	66	(57)
Electrical Vehicle Rebate	(70)	-
Other	95	34
	(391)	(751)
Non-Cash Variance Accounts		
Non-Current Pension Costs	(8)	(155)
PEB Current Pension Costs	(35)	(22)
Debt Management	(163)	(201)
Other	-	6
	(206)	(372)
Benefit Matching Accounts		
Demand-Side Management	128	101
First Nations Costs	16	15
Site C	(85)	6
CIA Amortization	(5)	(5)
Other	36	12
	90	129
Non-Cash Provisions		
Environmental Provisions	(22)	(35)
First Nations Provisions	6	34
	(16)	(1)
Amortization of regulatory accounts	(317)	(246)
Interest on regulatory accounts	(16)	(11)
Net increase (decrease) in regulatory accounts	$ 385	$ (1,444)

For the year ended March 31, 2024, there was a net increase of $385 million (or 26%) to the Company's regulatory accounts compared to a net reduction of $1.44 billion in the prior fiscal year. The net regulatory asset balance as at March 31, 2024 was $1.85 billion compared to $1.47 billion as at March 31, 2023.

Significant changes to the net regulatory asset balance during the year ended March 31, 2024 included a $1.24 billion addition to the Cost of Energy Variance Accounts primarily due to higher electricity imports as a result of the drought and a $128 million addition to the Demand-Side Management Account for planned expenditures. The significant net additions were partially offset by a $538 million reduction to the Trade Income Deferral Account due to higher trade income than planned, $317 million in amortization (which is the regulatory mechanism to recover the regulatory account balances in rates), and a $163 million reduction to the Debt Management Regulatory Account primarily due to a net increase in the fair value of interest rate hedges resulting from an increase in forward interest rates.

Net regulatory account balances are as follows:

as at March 31 (in millions)	2024	2023
Cost of Energy Variance Accounts		
Heritage Deferral Account	$ 49	$ (32)
Non-Heritage Deferral Account	1,092	(110)
Biomass Energy Program Variance	(127)	(75)
Low Carbon Fuel Credits Variance	(63)	(48)
Other	12	(33)
	963	(298)
Other Cash Variance Accounts		
Trade Income Deferral Account	(1,736)	(1,190)
Total Finance Charges	88	45
Inflationary Pressures	7	(58)
Electrical Vehicle Rebate	(71)	-
Other	99	76
	(1,613)	(1,127)
Non-Cash Variance Accounts		
Non-Current Pension Costs	(892)	(854)
PEB Current Pension Costs	(65)	(38)
Debt Management	(114)	67
Other	11	12
	(1,060)	(813)
Benefit Matching Accounts		
Demand-Side Management	870	858
First Nations Costs	3	19
Site C	502	566
CIA Amortization	58	63
Smart Metering & Infrastructure	109	130
Other	48	12
	1,590	1,648
Non-Cash Provisions		
Environmental Provisions	219	240
First Nations Provisions	471	466
	690	706
IFRS Transition Accounts		
IFRS Pension	306	344
IFRS Property, Plant & Equipment	976	1,007
	1,282	1,351
Net Regulatory Assets	$ 1,852	$ 1,467

BC Hydro has or has applied for regulatory mechanisms to collect 35 of 40 regulatory accounts with balances at March 31, 2024 in rates over various periods.

Comparison with Service Plan

The Budget Transparency and Accountability Act requires that BC Hydro file a service plan each year. BC Hydro's 2023/24–2025/26 Service Plan (Service Plan) was filed in February 2023 with planned net income for 2023/24 of $712 million.

The table below provides an overview of BC Hydro's 2023/24 financial results, relative to its Service Plan.

(in millions) *For the year ended March 31,*	Actual 2024	Service Plan[2] 2024	Variance to Service Plan
Revenues			
Domestic	$ 5,504	$ 6,355	$ (851)
Trade	1,627	2,155	(528)
	7,131	8,510	(1,379)
Expenses			
Operating Costs			
Cost of energy	3,725	4,226	501
Other operating expenses			
Personnel expenses, materials and external services [1]	1,605	1,439	(166)
Amortization	1,071	1,078	7
Grants and taxes	316	315	(1)
Other	70	110	40
Finance charges	516	633	117
	7,303	7,801	498
Net Income (Loss) Before Movement in Regulatory Balances	(172)	709	(881)
Net movement in regulatory balances	495	3	492
Net Income	$ 323	$ 712	$ (389)

[1] These amounts are net of capitalized costs and recoveries.
[2] Certain amounts have been reclassified between domestic revenues, trade revenues and cost of energy to align with a change in accounting policy described in Note 2 of the Audited Consolidated Financial Statements.

Net income for 2023/24 was $323 million, compared to planned net income of $712 million in the Service Plan filed in February 2023. Many variances, including those related to revenues, cost of energy, amortization, finance charges and others are deferred to regulatory accounts pursuant to BCUC orders, and do not impact net income. The lower net income was primarily due to $326 million in affordability credits, which was reflected as a decrease in domestic revenue, and higher than planned operating costs which were not subject to deferral to regulatory accounts.

Liquidity and capital resources

Cash flow provided by operating activities for the year ended March 31, 2024 was $976 million, compared to $2.60 billion in the prior fiscal year. The decrease of $1.63 billion was mainly due to the cost of higher net electricity imports due to the drought conditions in B.C. whereas in the prior year BC Hydro was a net electricity exporter.

The long-term debt balance net of sinking funds as at March 31, 2024 was $29.39 billion compared to $26.78 billion as at March 31, 2023. The increase was mainly a result of an increase in revolving borrowings of $1.97 billion and an increase in net long-term bond issuances (net of redemptions) for net proceeds of $662 million. The increase 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 years ended March 31 (in millions)	2024	2023
Transmission lines and substations replacements and expansion	**$ 540**	$ 504
Generation replacements and expansion	**462**	334
Distribution system improvements and expansion	**771**	633
General, including technology, vehicles and buildings	**316**	261
Site C Project	**2,174**	2,187
Total Capital Expenditures[1]	**$ 4,263**	$ 3,919

[1]Total capital expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the Consolidated Statements of Cash Flows because the expenditures above include accruals.

Capital expenditures increased by $344 million for the year ended March 31, 2024 compared to the prior fiscal year primarily due to higher investments in expanding our Distribution system, replacing ageing assets and higher volumes of customer connection projects. Capital expenditures for the year ended March 31, 2024 were within the BC Hydro Board approved amounts.

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: Peace to Kelly Lake Stations Sustainment, Transmission Wood Structure and Framing Replacements, Natal—60–138 kV Switchyard Upgrade, Transmission Corrective Capital Restorations, Mainwaring Station Upgrade, and Treaty Creek Terminal—Transmission Load Interconnection (KSM).

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, Bridge River 1—Penstock Concrete Foundation Refurbishment, Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment, Lake Buntzen 1—Penstock Exterior Recoat, Ash River Extend Life of Steel Penstock, and Ruskin—Left Abutment Slope Sinkhole Remediation.

Distribution system improvements and expansion included capital expenditures on customer driven work, end of life asset replacements, and system expansion and improvements.

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

Site C incurred capital expenditures across the project, primarily for work areas such as right bank foundation enhancements, generating station and spillways, main civil works, turbines and generators, and for 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.

Regulatory applications

On April 21, 2023, the BCUC issued an initial decision on BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (F2023—F2025 RRA) and subsequently on June 19, 2023, the BCUC issued its final decision. In its final decision, the BCUC approved a bill increase of 2.2 per cent for fiscal 2024.

The decisions also directed BC Hydro to file for approval of the levels of the new Trade Income Rate Rider (TIRR) and the Deferral Account Rate Rider (DARR), annually, commencing in fiscal 2025. On February 20, 2024, the BCUC issued its decision on BC Hydro's Application for Approval to Set the Fiscal 2025 Deferral Account Rate Rider and Trade Income Rate Rider and Reconsideration Related to the Trade Income Rate Rider. The BCUC approved the requested DARR refund to customers of 2.5 per cent and TIRR refund to customers of 2.3 per cent for fiscal 2025. The resulting bill increase for fiscal 2025 is 2.3 per cent.

Performance based regulation

On December 21, 2023 BC Hydro filed with the BCUC its Performance Based Regulation plan to be used for rate-setting, starting April 1, 2025, as well as a Request for Reconsideration of Performance Based Regulation (Reconsideration). The Reconsideration proposed a continuation of Cost of Service for rate-setting until further order of the BCUC. On March 15, 2024, the BCUC issued its decision approving BC Hydro to file its revenue requirements applications based on a forecast cost of service approach until further order of the BCUC. BC Hydro is also required to file a report by the end of December 2028 assessing whether its operating environment has changed such that Performance Based Regulation has become feasible.

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 benefits. These are influenced by several elements, which are generally categorized into the following seven factors:

- Hydro generation;
- Customer demand;
- Electricity imports/exports;
- Trade margin;
- Deliveries from electricity purchase agreements;
- Interest rates; and
- Discount rates—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 the availability of skilled workers, commercial negotiations with contractors, first unit commissioning delay, design changes due to unknown field conditions, and potential inflationary related risks. 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 March 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.

Hydro generation

The amount of generation available influences BC Hydro's financial results by changing the amount of surplus energy we have available to export (or need to import to meet domestic load). The amount of available generation is driven primarily by the amount and timing of inflows (hydrology) into BC Hydro-dispatched plants and reservoirs and initial reservoir storage conditions prior to seasonal snow melt (freshet). Lower water inflows can significantly reduce hydro generation and can have a material impact on BC Hydro's cost of energy in the current and future years.

The range of inflows, year to year, can significantly influence available generation: over 14,500 GWh (or approximately +/- 13 per cent of current domestic demand) can separate the wettest years from the driest. The amount of available generation, seasonally, is also impacted by the availability of both BC Hydro and Independent Power Producer generating assets and by BC Hydro's operation of system storage.

Water inflows (energy equivalent) to the system for the year ended March 31, 2024 were significantly below average and lower than the prior fiscal year driven by dry conditions and below average inflows across the province in all months from July 2023 to March 2024, except for February 2024.

Customer demand

Customer demand for electricity is generally forecast to increase in the long term as B.C.'s population and economy continue to grow. However, long term projections of customer load entail inherent uncertainty, particularly in this time of energy transition and global economic unpredictability. In particular, large industrial customers can have significant variability in load as a result of the pace and extent of electrification or changing supply and demand balances in world commodity markets and related commodity prices. In addition, there can be variability for residential and commercial customers due to changes in the rate of population growth, changes in the types of residential and commercial buildings constructed, changes in end-use technology, general economic conditions, and the rate of uptake in Demand-Side Management programs.

There can also be short-term fluctuations in customer load due to timing of new large customer facility start-up, electrification project implementation and existing customer facility closures and restarts. Temperature can have an impact on residential load and to a lesser extent, commercial and light industrial load, with colder or warmer years resulting in higher demand for electrical heating or air conditioning than in average years.

Excluding electricity exports, domestic load volumes for the year ended March 31, 2024, were 1 per cent higher compared to the prior fiscal year. Recent economic concerns related to inflation, increased interest rates, and market conditions for large industrial customers may continue to impact electricity demand.

Electricity imports/exports

Electricity imports/exports are impacted by electricity and gas prices and volumes. Electricity and gas prices and volumes, themselves, are variable and a function of gas and electricity market fundamentals and water inflows.

For the year ended March 31, 2024, net electricity imports were 13,603 GWh compared to net electricity exports of 1,629 GWh in the prior fiscal year.

Trade margin

Trade margin is affected by numerous factors which can differ from year to year. Volumes and prices are variable and are impacted by supply and demand, transmission and transport availability or constraints.

For the year ended March 31, 2024, trade revenues decreased due to lower trading sales volumes and lower average sales prices. There was a similar decrease in the cost of energy associated with trading activity such that trade margin was consistent with the prior year.

Deliveries from Electricity Purchase Agreements (EPAs)

Energy delivered under EPAs has a different cost than both energy generated by BC Hydro and energy purchased or sold in energy markets. Therefore, as the proportion of energy deliveries from EPAs changes, BC Hydro's cost of energy changes. BC Hydro's portfolio of EPAs includes a significant portion of hydro and wind resources and the amount of generation under these contracts is driven by weather patterns, hydrology, and other operational factors that impact deliveries, which may vary significantly from year to year.

For the year ended March 31, 2024, overall energy delivered from EPAs was lower than forecast. Although all resource types delivered less energy than expected, the largest shortfall was due to lower than forecast deliveries from storage hydro generation projects.

Interest rates

A portion of BC Hydro's existing debt will be impacted by changes to interest rates for debt with a remaining term to maturity of one year or less, which results in variability in interest expense. Variability in interest expense on borrowings is influenced by both the volume of debt BC Hydro requires and the interest rate paid on that debt. BC Hydro accepts this variability in return for the savings obtained from normally lower short-term rates and for cash/debt management purposes, within policy limits and parameters established by its liability risk management annual strategic plan.

As at March 31, 2024, approximately 16% per cent of the Company's existing net debt had a maturity of one year or less and is exposed to changes to interest rates at the time of refinancing.

BC Hydro is also exposed to interest rate risk on future long-term debt issuances. To reduce variability in interest expense on future long-term debt issuances and lock in interest rates related to future long-term debt issuances, as at March 31, 2024, BC Hydro had interest rate hedges in place with an aggregate notional principal of $2.88 billion, hedging a portion of its forecast long-term debt issuances out to and including 2026/27.

Discount rates—post-employment benefit plans

Discount rates are one of the actuarial assumptions used to determine post-employment benefit liabilities, which are sensitive to changes in discount rates. An increase in discount rates will decrease post-employment benefit liabilities and a decrease in discount rates will increase post-employment benefit liabilities.

The discount rates for the year ended March 31, 2024 were lower than the prior year due to lower AA Canadian corporate bond yields.

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 February 2024 planned net income for 2024/25 at $712 million which is consistent with the amount required by Order in Council No. 123. There are various cost pressures that may impact 2024/25 net income. In addition, net income for the period 2025/26—2026/27 is planned at $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. The forecast for 2024/25 assumed average water inflows (100 per cent of average) based on hydrology forecasts before the 2023/24 snowpack measurement, domestic sales of 56,581GWh, average market energy prices of US $87.41/MWh, short-term interest rates of 4.25per cent, and a Canadian to US dollar exchange rate of US $0.7617.

The recent increases in 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, with the risk of further delays and cost escalations.

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 risks to the financial forecast, annual generation from a hydroelectric system is inherently variable as it depends on inflows.

The annual system surplus (i.e., the difference between generation and load) averaged 2,563 GWh for the five fiscal years prior to 2023/24, ranging from a deficit of 2,605 GWh in 2018/19 to a surplus of 10,699 GWh in 2020/21.

BC has generally been in drought since the summer of 2022, which had reduced overall inflows and associated energy. The extremely low snowpack in both the Columbia and Peace basins in the spring of 2024 is likely to create similar inflow and energy challenges for 2024/25 as 55% of the BC Hydro owned or contracted energy in the system comes from the Columbia and Peace basins.

Given the low spring 2024 snowpack, future hydro generation is likely to be below average for 2024/25. However, large variability in system inflows associated with spring and summer precipitation (from drought to flooding) can still result in significantly different amounts of generation relative to the current period. 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.

The effect of climate change on annual inflows is uncertain and long-term planning will consider increasing occurrences of wider variation in annual system inflows. Planning criteria, which determine the resources needed in the system, will be reviewed as part of developing the next Integrated Resource Plan. It is possible that this will conclude that more resources are needed, or that changes to reservoir operation are needed.

Capital Expenditures

Projects over $50 million

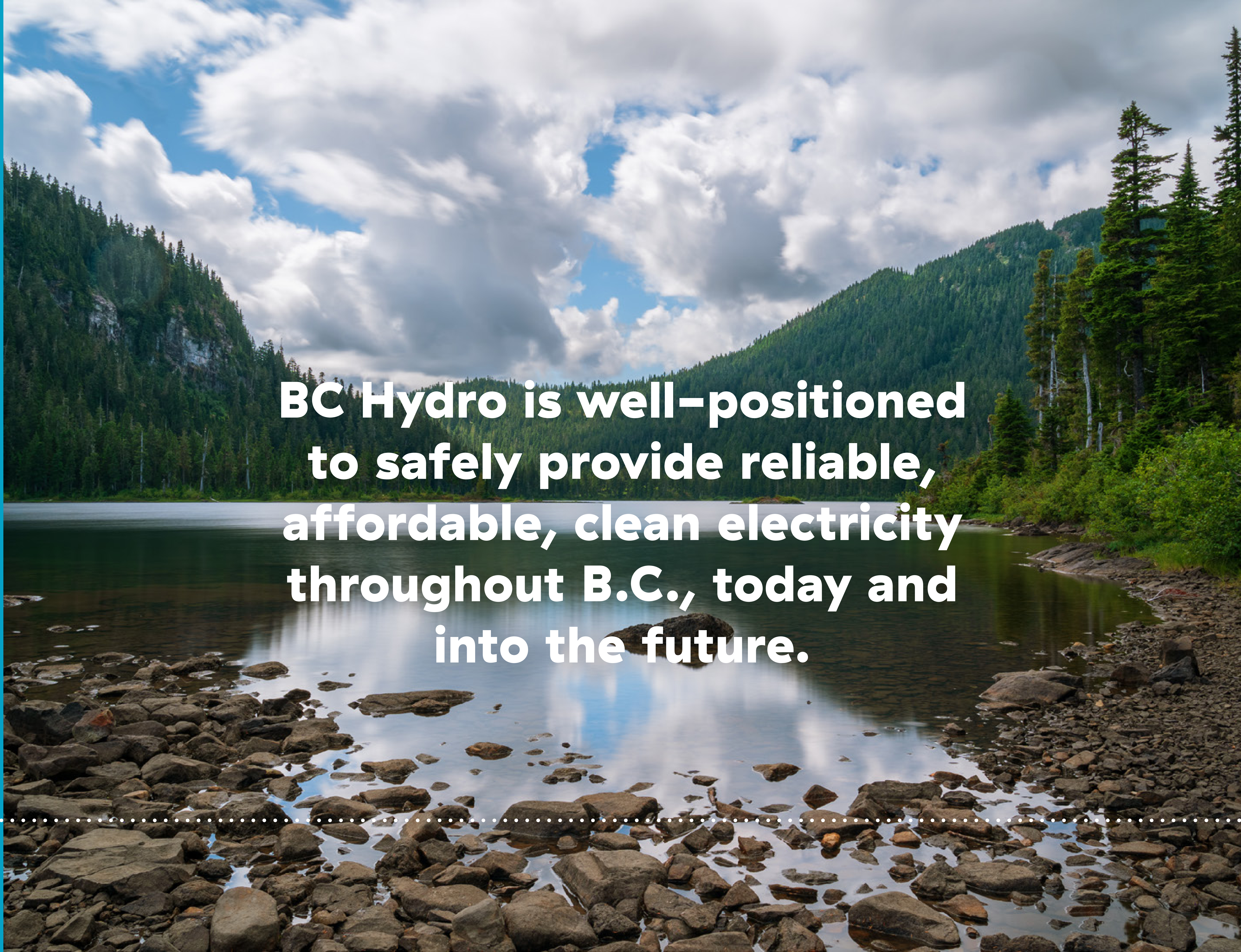
BC Hydro has the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. These projects have been approved by the Board of Directors.

Major Capital Projects (over $50 million)	Targeted completion date (calendar year)	Project cost to Mar 31, 2024 ($ millions)	Estimated cost to complete ($ millions)	Anticipated total cost ($ millions)
Projects recently put into service				
5LO63 Telkwa Relocation Project This project increased the reliability and reduced the safety risks of the 500kV radial transmission line (5L063) that provides service for customers in Northwest British Columbia. A portion of the 5L063 line was relocated away from the current area of unstable terrain.	2023 In-service	$51	$2	$53
Street Light Replacement Program The program converted approximately 95,000 BC Hydro owned and maintained High Pressure Sodium and Mercury Vapour street lights to Light Emitting Diode (LED) street lights. This was required to meet federal polychlorinated biphenyl (PCB) environmental regulations by the end of 2025, manage increasing operations and maintenance costs, and better meet our customers' expectations.	2023 In-service	$59	$4	$63
Various Sites—NERC Critical Infrastructure Protection Implementation Project for Cyber Assets This project was required to install equipment and establish processes, practices, and procedures to ensure that BC Hydro was compliant with the Critical Infrastructure Protection (CIP) CIP-003-7 and revised CIP-003-8 Mandatory Reliability Standards on all low impact Bulk Electric System Cyber Assets.	2023 In-service	$52	$4	$56
Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment Project This project addressed safety and environmental risks by improving the reliability of the Coquitlam tunnel gates for control of water conveyance from the Coquitlam Reservoir to Buntzen Lake Reservoir.	2023 In-service	$61	$6	$67
Wahleach Refurbish Generator Project This project improved the reliability of the generator at Wahleach Generating Facility. The scope included replacement of the stator and rotor poles, refurbishment of the remaining major components, and a combination of new, replacement, and refurbishment of the auxiliary components. The project also included the installation of a new powerhouse crane and structural upgrades to the powerhouse building.	2023 In-service	$55	$6	$61

Major Capital Projects (over $50 million)	Targeted completion date (calendar year)	Project cost to Mar 31, 2024 ($ millions)	Estimated cost to complete ($ millions)	Anticipated total cost ($ millions)
Ongoing				
Capilano Substation Upgrade Project This project will address the existing asset health, reliability, safety, and environmental issues associated with the Capilano Substation, and ensure that the capacity of the substation meets the long term area needs. The project will also introduce a 25kV source to enable 25kV voltage conversion and facilitate the execution of other future substation projects in the North Shore area.	2024 Targeted in-service	$69	$18	$87
G.M. Shrum (GMS) G1 to 10 Control System Upgrade This project will replace the controls equipment, provide full remote-control capability from the control center, and rectify deficiencies in the current system. The condition of the legacy controls for the GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of available spare parts and decreasing reliability. The controls are well beyond their expected life, which causes operating problems and increases the risk of damage to major equipment.	2024 Targeted in-service	$70	$5	$75
Mica Modernize Controls Project This project will address the reliability, maintainability, and operability of the Units 1-4 exciters, governors, unit controls and control room controls at the Mica Creek Generating Station.	2024 Targeted in-service	$52	$4	$56
Vancouver Island Radio System Project This project will replace the end-of-life BC Hydro telecommunication system on Vancouver Island with a modernized system to improve reliability and increase communication capacity. Upgrades are being completed at 38 substations and microwave repeater sites and the project includes installation of a new microwave radio link.	2024 Targeted in-service	$48	$5	$53
Bridge River 1—Penstock Concrete Foundation Refurbishment This project will address safety and reliability risks of the four penstocks at the Bridge River 1 Generating Station by refurbishing the penstock supports and concrete foundations, and installing slope stabilization measures.	2025 Targeted in-service	$39	$33	$72
Natal—60-138 kV Switchyard Upgrade Project This project is to address reliability, regulatory and safety risks at the Natal substation as the 60-138kV switchyard equipment is at end-of-life and requires replacement.	2025 Targeted in-service	$53	$48	$101
Ruskin—Left Abutment Slope Sinkhole Remediation Project This project will address the left abutment slope instability and remediate the sinkhole issues adjacent to the Ruskin Generating Station to mitigate dam safety risks.	2025 Targeted in-service	$22	$49	$71

Major Capital Projects (over $50 million)	Targeted completion date (calendar year)	Project cost to Mar 31, 2024 ($ millions)	Estimated cost to complete ($ millions)	Anticipated total cost ($ millions)
Site C Project*** This project will construct a third dam and a hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years. *Planned in-service date for all units. **Site C project total anticipated cost and project cost to date include capital costs, charges subject to regulatory deferral and certain operating expenditures. ***As approved in June 2021, the Site C project budget is $16 billion with a project in-service date of calendar year 2025. BC Hydro continues to manage significant risks to the project and continues to work with the Project Assurance Board, Mr. Milburn, Ernst & Young Canada, and the Technical Advisory Board to manage these project risks.	2025* Targeted in-service	$13,223	$2,777	$16,000**
Mainwaring Station Upgrade Project This project is required to maintain the reliability of the Mainwaring substation, and address safety and environmental risks at the substation.	2026 Targeted in-service	$33	$121	$154
Sperling Substation Metalclad Switchgear Replacement Project This project will address the existing asset health, reliability and safety risks associated with the 12kV 60 series feeder section and the bulk oil breaker in the 12 kV 70/80 series feeder section, insufficient electrical clearances in the 60 series feeder section, and arc flash safety risks associated with the 12kV indoor metalclad switchgear.	2026 Targeted in-service	$48	$28	$76
Minette—Transmission Load Interconnection Project This project is to facilitate the interconnection of a customer's facility to BC Hydro's Minette Substation. Under BC Hydro's standards tariffs and policies, the customer is required to pay a portion of this project's costs. *The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $20M.	2027 Targeted in-service	$2	$70	$72*
Treaty Creek Terminal—Transmission Load Interconnection (KSM) Project This project is to facilitate the interconnection for construction power for the planned Kerr-Sulphurets-Mitchell (KSM) Mine to BC Hydro's transmission system. Under BC Hydro's standard tariffs and policies, the customer is required to pay a portion of this project's costs. A future project is planned to supply power for the full mine. *The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $87M.	2027 Targeted in-service	$43	$125	$168*

Major Capital Projects (over $50 million)	Targeted completion date (calendar year)	Project cost to Mar 31, 2024 ($ millions)	Estimated cost to complete ($ millions)	Anticipated total cost ($ millions)
Burrard Switchyard—Control Building Upgrade Project This project will address the need of constructing a new control building, establish the communication system, and install the new protection and control equipment for the Burrard switchyard.	2028 Targeted in-service	$4	$53	$57
Kootenay Canal Modernize Controls Project This project will address reliability, maintainability, and safety of the Kootenay Canal facility by replacing the aged control equipment, exciters, and select governor mechanical components for the four Kootenay Canal generating units.	2028 Targeted in-service	$8	$53	$61
Peace to Kelly Lake Stations Sustainment Project This project is required to maintain the reliability of BC Hydro's bulk transmission system by replacing station assets within the Peace to Kelly Lake transmission system that are at end-of-life.	2028 Targeted in-service	$61	$283	$344
Prince George to Terrace Capacitors Project This project is required to increase the transfer capacity of the North Coast transmission system to meet growing customer service requests in the region. *The total cost represents the gross cost of the project and has not been netted for estimated Federal government contributions of $97M nor a customer's contribution of $4M.	2028 Targeted in-service	$31	$551	$582*
John Hart Dam Seismic Upgrade Project This project will address dam safety risks at the John Hart dam and will significantly improve the overall seismic withstand of the dam structure, the reliability of the spillway gates system, and address inflow imbalance issues between the Ladore dam and John Hart dam.	2029 Targeted in-service	$200	$713	$913
Bridge River 1 Replace Units 1—4 Generators / Governors Project This project will address the deteriorating condition of the aging generators, governors, excitors, and control systems at the Bridge River 1 generating station. The project will improve reliability, restore licensed flow and generation capacity, and increase operating flexibility of the generating station.	2030 Targeted in-service	$16	$297	$313



BC Hydro is well-positioned to safely provide reliable, affordable, clean electricity throughout B.C., today and into the future.

Appendix A

Progress on Mandate Letter priorities

The following is a summary of progress made on priorities as stated in the 2021/22 and 2023 Mandate Letters from the Minister Responsible.

2021/22 Mandate Letter priority	Status as of March 31, 2024
Provide leadership in advancing CleanBC's climate and economic development objectives, including electrification, fuel switching, and energy efficiency initiatives in the built environment, transportation, mining, oil and gas, and other sectors.	**Ongoing** ○ Between Fiscal 2022 (starting April 1, 2021) and Fiscal 2024 (ending March 31, 2024), BC Hydro has invested over $65 million to advance its Electrification Plan and promote fuel switching in homes and buildings, transportation, and industries. ○ As of March 31, 2024, these investments have resulted in an emissions reduction of 239 kilotonnes of CO2e per year, 388 GWH per year in additional energy consumption, and 75 MW in demand growth across the buildings, transportation, and industry sectors. ○ On March 6, 2024, the BCUC issued its decision accepting the 2021 Integrated Resource Plan (IRP) (including new information included in our 2023 signposts update), which anticipates BC Hydro's load and resource needs and guides decisions on our electricity system in the future. The flexible plan supports B.C.'s legislated greenhouse gas reduction targets, electrification goals and the drive to shift from fossil fuels to clean electricity to help combat climate change.
Keep electricity affordable by ensuring that rates do not increase above inflation, on a cumulative basis, over the next decade.	**Ongoing** ○ BC Hydro rates are currently 16.5 percent lower than the cumulative rate of inflation over the past seven years (starting 2017–18). ○ Adjusting for inflation, electricity in B.C. costs the same today as it did back in 1978. ○ In Hydro-Québec's 2023 Comparison of Electricity Prices in Major North American Cities report, BC Hydro's residential, commercial, and industrial rates all rank in the first quartile, demonstrating the affordability of BC Hydro rates compared to North American counterparts.

2021/22 Mandate Letter priority	Status as of March 31, 2024

Continue delivering affordability measures that support BC's Poverty Reduction Strategy, including demand-side management programs targeted to low-income customers, in a manner consistent with new and emerging CleanBC policies.	**Ongoing**
	○ In 2023/24, BC Hydro provided Customer Crisis Fund support to 6,193 customers.
	○ In 2023/24, BC Hydro low-income customers saved approximately five gigawatt hours of electricity from BC Hydro's energy efficiency programs and products. As a result, participating customers saved a total of $621,000 on their annual electricity bills. BC Hydro invested approximately $15 million on these low-income supports.
	○ In 2023/24, over 2,800 households went through the Energy Conservation Assistance Program and over 10,000 households received an energy saving kit.
	○ On June 28, 2023, the Government of B.C. announced it was providing $10 million in funding to expand the Energy Conservation Assistance Program to include portable air conditioners to support vulnerable customers who meet the income qualification requirements of the program. BC Hydro installed more than 4,000 units in 2023/24.
	○ In Fiscal 2024, BC Hydro partnered with the Province to co-fund the CleanBC Income Qualified Program energy efficiency measures.
	○ BC Hydro's Indigenous Communities Conservation Program (ICCP) supports Indigenous communities looking to improve the energy efficiency and comfort of their homes. In 2023/24:
	  ○ Three Indigenous communities installed free energy-saving products and completed basic home condition assessments in 185 homes with support from the ICCP Home Energy Check-up.
	  ○ Four Indigenous communities, as well as the Aboriginal Housing Management Association, completed energy efficiency upgrades in 153 homes with support from the ICCP Home Energy Upgrade Rebates. Projects underway encompass an additional 132 homes.
	○ BC Hydro's Social Housing Retrofit Support Program offers funding to social housing providers to investigate and implement energy efficiency projects and rebates to install energy-saving products.
	○ BC Hydro also continues to support low-income customers through:
	  ○ Flexible payment options including equal payment plans, one-time payment deferrals, and interest-free repayment of overdue balances;
	  ○ Not disconnecting residential customers for non-payment during periods of extreme cold temperatures.
	○ In 2023/24 BC Hydro began working with the Province in the redesign of the Social Housing program for non-housing providers that will deliver an integrated energy efficiency and electrification offer. BC Hydro continues to administer the Province's CleanBC Social Housing Incentive Program.

Maintain or improve customer satisfaction by providing timely and responsive service	**Ongoing** BC Hydro's customer service satisfaction results of 91 percent in 2021/22, 89 percent in 2022/23, and 91 percent in 2023/24 have exceeded our annual target of 85 percent. Strong customer satisfaction reflects BC Hydro's ongoing efforts in ensuring customer reliability and continued commitment to customer service and improving customer communications.

2021/22 Mandate Letter priority	Status as of March 31, 2024
Safely complete the Site C project within the lowest cost and approved schedule, and implement the recommendations of the Milburn Report, reports from independent dam safety experts, other directions from the Minister responsible, and provide quarterly progress and other reporting to Treasury Board and the BC Utilities Commission.	**Complete** ○ Implemented all 17 recommendations resulting from Peter Milburn's independent review of the Site C project to improve project oversight and governance as of September 30, 2021. **Ongoing** ○ As of March 2024, the project was approximately 85 per cent complete and remained on track to have all six generating units in-service in 2025. ○ In 2023/24, BC Hydro continued to manage the Site C project within the 2021 approved $16 billion budget. Major milestones in 2023/24 included completion of: the earthfill dam in July 2023, Highway 29 realignment in July 2023, and tunnel conversion process in September 2023. ○ Safety performance on this project continues to be good, with BC Hydro employees and Site C contractors outperforming against the latest WorkSafeBC statistics for the heavy and road construction sector. ○ There were 12 Site C Project Assurance Board meetings, 23 workshops, and 27 site tours held with external parties and First Nations in 2023/24. BC Hydro continues to work collaboratively with the Project Assurance Board, special advisor Peter Milburn, Ernst and Young Canada, the Technical Advisory Board, and independent international dam experts to report on project progress and actively manage ongoing project risks.

2021/22 Mandate Letter priority	Status as of March 31, 2024
Continue to implement government direction resulting from the Comprehensive Review of BC Hydro. Priority initiatives for 2021/22 should include: ○ Supporting the implementation of the BC Hydrogen Strategy; ○ Expanding BC Hydro's network of electric vehicle DC fast-charging stations; ○ Supporting clean technology innovation through Powertech; ○ Increasing industrial electrification by making it easier and faster for customers to connect to the electricity grid; and ○ Re-investing new low carbon fuel standard credit revenues in transportation electrification infrastructure, incentives and programs.	**Ongoing** **Hydrogen** ○ In September 2023, Powertech acquired the intellectual property for high-pressure, high-volume hydrogen distribution and mobile refueling technologies and is actively investing in further development of related products. Powertech also established a subsidiary in United States (Powertech USA, Inc.) which enables Powertech to access a broader pool of both employees and customers, and to expand its contribution to the hydrogen economy. Powertech is the only North American company that provides an integrated fueling solution from the outlet of hydrogen production to the inlet of the vehicles. ○ Powertech obtained a $20 million commercial loan from BC Hydro to be used partially to expand its hydrogen infrastructure business. This includes developing new standardized products such as trailers, mobile refuelers, and heavy-duty refueling stations focussed on transportation application. **Electric Vehicle Charging** ○ As of March 2024, BC Hydro had 170 fast charging ports across 86 sites. Most charging ports have a capacity of 50kW, but many of the charging ports added in the last year are 100kW. BC Hydro has started to add 180-kilowatt dual chargers to the network, with the first in service in February 2024. ○ BC Hydro's EV Infrastructure Deployment Plan was updated and now targets 1,150 charging ports in-service by the end of fiscal year 2027, compared to the previous plan of 325 ports by the end of 2025. **Powertech Clean Technology Innovation** ○ Powertech is working with BC Hydro to execute BC Hydro's Vehicle to Grid (V2G) test plan for electric buses focussing on charging, discharging, and grid feedback. Concurrently, Powertech is aiding BC Hydro in transitioning to an energy-use-based billing system for electric vehicle users. ○ Powertech continues to support BC Hydro in expanding its electric vehicle charging network by testing charging equipment, procuring transformer kiosks, warehousing equipment and branding it in preparation of deployment. **Connections** BC Hydro is actively working to improve our customer connections process. Key achievements in 2023/24 include: ○ Increasing our distribution growth capital project budget by $157 million. ○ Engaging customers on potential changes to BC Hydro's Distribution Extension Policy. ○ Having 102 Distribution Design and Customer Connection frontline positions filled or in active recruitment since 2022/23 to improve connection timelines. ○ Improving the industrial interconnections process by expanding use of internal and external contractor resources and assessing customer interest in electrification to inform infrastructure plans for the North Coast. ○ Implementing a number of business process improvements including: streamlined customer onboarding, streamlined delivery of low risk low complexity design work, program management for strategic customer programs, and solutions derived from a lean end-to-end design process review. ○ Identifying cluster studies opportunities to optimize our transmission system planning and achieve cost efficiency among multiple customer interconnections. Piloting new opportunities for customers to be part of interconnection solution, for example, with interim interruptible service, sharing infrastructure among customers, and customer build of infrastructure. **Transportation Electrification** In 2023/24, BC Hydro started to administer the CleanBC Go Electric Passenger Vehicle Rebate Program on behalf of the Province. This Program is funded by proceeds from the sale of low carbon fuel standard credits issued to BC Hydro for the supply of electricity for electric vehicle (EV) charging at residential buildings with fewer than 5 dwelling units.

<table>
<tr><th>2021/22 Mandate Letter priority</th><th>Status as of March 31, 2024</th></tr>
<tr><td>Develop a short-term electrification plan that builds on the key results of the Comprehensive Review of BC Hydro and supports CleanBC.</td><td>Complete

In 2021, BC Hydro launched its five-year Electrification Plan, A clean future powered by water, to make it easier and more affordable for people to efficiently use more of B.C.'s clean electricity instead of fossil fuels to power their homes, businesses, and vehicles. These actions are expected to result in an additional 3,100 gigawatt hours of load and reducing GHG emissions by 930,000 tonnes per year by the end of Fiscal 2026.</td></tr>
<tr><td>Working with customers, develop efficient and flexible rate proposals for BC Utilities Commission review that will incent greenhouse gas emission reductions and keep rates affordable.</td><td>Complete

○ On December 12, 2023, the B.C. Utilities Commission (BCUC) accepted BC Hydro's proposal to offer optional time-of-day pricing to residential customers. Optional time-of-day pricing helps encourage customers to shift their electricity use to periods when demand for electricity is lower and there is more system capacity by offering a lower price for electricity used during these times. This optional rate will be available to customers as early as June 2024.
○ On December 15, 2023, the BCUC approved a new flat rate for BC Hydro's transmission service customers that will help remove a barrier to electrification.

Ongoing

BC Hydro continues to explore and engage with customers about potential changes to the current residential tiered rate and other rate options that support our customers' diverse energy needs.</td></tr>
<tr><td>Actively market 100% clean energy through Powerex to realize new trading opportunities and income for the benefit of BC Hydro ratepayers.</td><td>Ongoing

In January 2021, Powerex adopted a Clean Energy Trade Standard in light of the growing importance of delivering clean power to its customers. The Standard ensures that exports of clean energy from the BC Hydro system cannot be backfilled with emitting resources, whether within the province or imported, to serve BC Hydro load</td></tr>
<tr><td>Partner with the Province and the federal government to implement the CleanBC Remote Community Energy Strategy to help remote communities, with a focus on Indigenous communities, reduce diesel use and replace it with clean energy.</td><td>Ongoing

○ Since the release of the CleanBC Plan, BC Hydro has been working with non-integrated area (NIA) First Nations to advance nine clean energy projects across the province to reduce reliance on diesel.
○ Since 2023, BC Hydro has been engaging with NIA First Nations' energy leaders to collaborate and seek feedback on BC Hydro's NIA Strategy (formerly the diesel reduction strategy).
○ In August 2023, BC Hydro entered into a partnership with the Province of BC and the New Relationship Trust to administer BC Hydro's energy efficiency incentive funding for NIA communities under the Community Energy Diesel Reduction (CEDR) program. Through this partnership, we work closely with NRT staff to support First Nations in BC Hydro's Non-Integrated Areas in advancing energy efficiency projects to reduce reliance on diesel-generated electricity in these remote areas.
○ BC Hydro provides enabling support to NIA Indigenous communities through the Indigenous Climate Action Network (I-CAN), a program administered by the Coastal First Nations Great Bear Initiative in partnership with the Province of BC, and the Government of Canada.
○ As of fall 2023, through the knowledge and experience gained from ongoing work with Indigenous developers, BC Hydro has drafted an NIA community renewable energy offer (NIA CREO) to advance efforts to replace diesel using renewable energy sources.</td></tr>
<tr><td>Work with the Province to secure additional federal funding and bring into service transmission projects that will reduce or avoid greenhouse gas emissions and help meet its climate goals.</td><td>Ongoing

○ BC Hydro submitted four applications to the federal Critical Minerals Infrastructure Fund for transmission study and infrastructure support. Discussions to secure funding for the proposed new lines in the North Coast and North Montney are ongoing.</td></tr>
</table>

2021/22 Mandate Letter priority	Status as of March 31, 2024
Support the development of a climate-aligned energy framework for B.C.	**Ongoing** ○ In support of the development by government of a climate-aligned energy framework, BC Hydro participated in a government-utility scenario analysis exercise that analyzed quantitative scenarios aimed at meeting CleanBC emission requirements. ○ The BC Hydro Task Force provided input on items for inclusion in government's climate-aligned energy framework.

Actively participate in the BC Hydro Task Force to accelerate the electrification of B.C.'s economy by powering more homes, businesses and industries with renewable electricity, address climate change and meet the targets set out in the CleanBC Plan and BC Hydro's Electrification Plan.	**Ongoing**
	○ The Premier's BC Hydro Task Force, announced in March 2023, was created to provide both near-term and medium-term strategic advice to enable this transition to ensure reliable, affordable, and emissions-free energy for future generations.
	○ The Task Force focused on three key areas:
	  ○ Improving the speed of permitting and delivery of required infrastructure.
	  ○ Modernizing regulatory framework to better align with government priorities while protecting ratepayers.
	  ○ Identifying, enabling and accelerating economic opportunities in clean energy.
	○ In October 2023, the Task Force provided initial recommendations to government for early targeted actions focused on accelerating the planned acquisition of new clean or renewable energy resources. BC Hydro is working with government to explore options for implementation of these and other Task Force recommendations.

Continue to implement BC Hydro's Electrification Plan to attract new innovative industries to B.C. and advance the switch from fossil fuels to clean electricity in homes and buildings, vehicles and fleets, businesses and industry.	○ Between Fiscal 2022 (starting April 1, 2021) and Fiscal 2024 (ending March 31, 2024), BC Hydro has invested over $65 million to advance its **Electrification Plan** and promote fuel switching in homes and building, transportation and industries. ○ As of March 31, 2024, these investments have resulted in an emissions reduction of 239 kilotonnes of CO_2e per year, 388 GWh per year in additional energy consumption and 75 MW in demand growth across the buildings, transportation, and industry sectors. ○ Under the Load Attraction Program seven clean technology projects have been funded to-date, with an additional five in progress. Non-resource-based sectors provide among the greatest growth potential in BC, with significant economic benefits realized through sector diversification, preparing for the clean economy, and creating jobs in communities seeing declines in the resource sectors. Opportunities include hydrogen production, carbon capture, fuel cell and battery manufacturing, data centers, agritech and aquaculture.

2021/22 Mandate Letter priority	Status as of March 31, 2024

Work with the Ministry of Energy, Mines and Low Carbon Innovation to co-develop targeted programs to support clean energy and efficiency upgrades for low-income and multi-unit residential buildings	**Ongoing**
	○ In 2023/24, BC Hydro provided Customer Crisis Fund support to 6,193 customers.
	○ In 2023/24, BC Hydro low-income customers saved approximately five gigawatt hours of electricity from BC Hydro's energy efficiency programs and products. As a result, participating customers saved a total of $621,000 on their annual electricity bills. BC Hydro invested approximately $15 million on these low-income supports.
	○ In 2023/24, over 2,800 households went through the Energy Conservation Assistance Program and over 10,000 households received an energy saving kit.
	○ The BC Hydro and FortisBC Indigenous Communities Conservation Program (ICCP) supports Indigenous communities looking to improve the energy efficiency and comfort of their homes. In 2023/24:
	  ○ Three Indigenous communities installed free energy-saving products and completed basic home condition assessments in 185 homes with support from the ICCP Home Energy Check-up.
	  ○ Four Indigenous communities, as well as the Aboriginal Housing Management Association, completed energy efficiency upgrades in 153 homes with support from the ICCP Home Energy Upgrade Rebates. Projects underway encompass an additional 132 homes.
	○ BC Hydro began developing a new collaborative energy efficiency and electrification incentive program in 2023/24 in partnership with the Province of BC and FortisBC to serve grid-connected (i.e., Integrated area) Indigenous communities and organizations.
	○ In 2023/24 BC Hydro and the Province began working in partnership with industry stakeholders to collaborate on the design of a new integrated energy efficiency program specifically for multi-unit residential buildings (MURBs) to address their unique needs.
	○ In 2023/24 BC Hydro began working with the Province in the redesign of the Social Housing program for non-housing providers that will deliver an integrated energy efficiency and electrification offer. BC Hydro continues to administer the Province's CleanBC Social Housing Incentive Program.
	○ In 2023/24 BC Hydro partnered with the Province to co-fund the CleanBC Income Qualified Program energy efficiency measures.

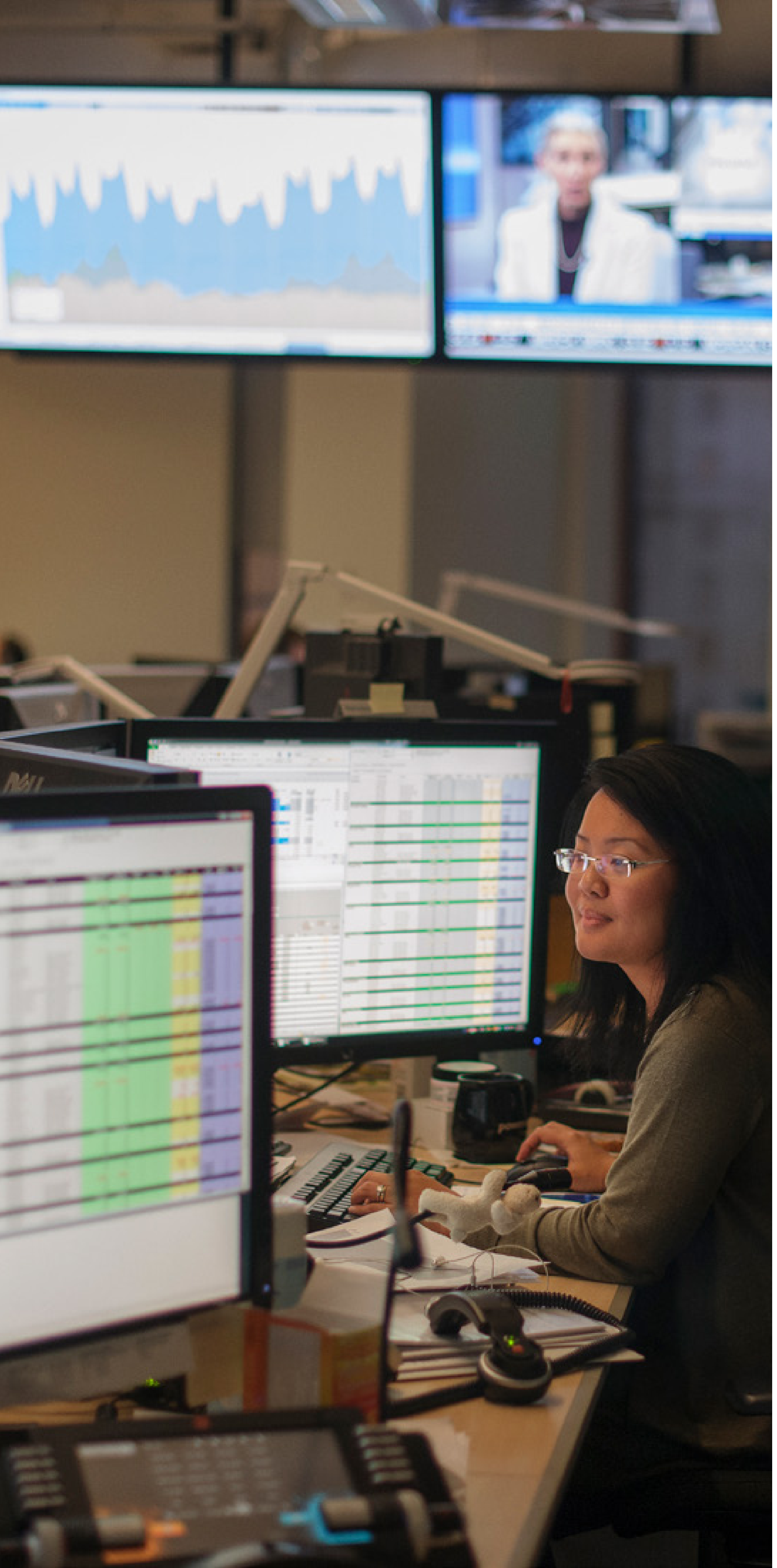
Support the Province's goal of completing B.C.'s Electric Highway by 2024 and target of 10,000 public EV charging stations by 2030 by leading station deployment, working with other parties and providing clean, reliable electricity to power vehicles and stations.	**Ongoing** ○ As of March 2024, BC Hydro had 170 fast charging ports across 86 sites. Most charging ports have a capacity of 50kW, but many of the charging ports added in the last year are 100kW. BC Hydro has started to add 180-kilowatt dual chargers to the network, with the first in service in February 2024. ○ BC Hydro's EV Infrastructure Deployment Plan was updated and now targets 1,150 charging ports in-service by the end of fiscal year 2027, compared to the previous plan of 325 ports by the end of 2025. ○ Over 70 percent of the EV charging stations assigned to BC Hydro for the Electric Highway by 2024 were in service by March 2024.
Work with the Ministry of Energy, Mines and Low Carbon Innovation to co-develop programs that encourage efficient use of electricity in the transportation sector.	**Ongoing** ○ In 2023/24, BC Hydro started to administer the CleanBC Go Electric Passenger Vehicle Rebate Program on behalf of the Province. This Program is funded by proceeds from the sale of low carbon fuel standard credits issued to BC Hydro for the supply of electricity for electric vehicle (EV) charging at residential buildings with fewer than 5 dwelling units. ○ BC Hydro continued to administer the Province's CleanBC Go Electric EV Charger Rebate Program for homes, workplaces, and multi-unit residential buildings. The program provides rebates for the purchase and installation of EV chargers and infrastructure.

2021/22 Mandate Letter priority	Status as of March 31, 2024
Identify and advance Indigenous ownership opportunities in future electricity generation and transmission investments to advance reconciliation and support economic self-determination.	**Ongoing** ○ Following the announcement of the launch of the Call for Power in June 2023, BC Hydro engaged with First Nations and industry on the design of the Call. From their input and feedback, BC Hydro established a requirement for a minimum of 25 percent First Nations ownership for each project under the Call. This is the first for B.C. and took into account First Nations interests in clean energy opportunities. ○ Completed the North Coast Expression of Interest process for building a new transmission line from Prince George to Terrace to help build capacity and electrify northwest B.C. The new line would travel through the traditional territories of 14 First Nations and BC Hydro recognizes an opportunity to partner together with First Nations on electrification. BC Hydro continues to engage with participating First Nations to explore potential models for co-ownership of this transmission line.
Continue to make improvements to accelerate the process for new residential and industrial customer connections to support the Province's affordable housing and industrial decarbonization priorities.	**Ongoing** BC Hydro is actively working to improve our customer connections process. Key achievements in 2023/24 include: ○ Increasing our distribution growth capital project budget by $157 million; ○ Engaging customers on potential changes to BC Hydro's Distribution Extension Policy. ○ 102 Distribution Design and Customer Connection frontline positions filled or in active recruitment since 2022/23 to improve connection timelines. ○ Implementing a number of business process improvements including: streamlined customer onboarding, streamlined delivery of low risk low complexity design work, program management for strategic customer programs, and solutions derived from a lean end-to-end design process review. ○ Completed the North Coast Expression of Interest to help advance planning for new transmission infrastructure in North Coast. The new line would travel through the traditional territories of 14 First Nations and BC Hydro recognizes an opportunity to partner together with First Nations on electrification. BC Hydro continues to engage with participating First Nations to explore potential models for co-ownership of this transmission line. ○ Improving the industrial interconnections process by expanding use of internal and external contractor resources and assessing regional customer interest in electrification to inform infrastructure plans for the North Coast. ○ Identified cluster studies opportunities to optimize our transmission system planning and achieve cost efficiency among multiple customer interconnections. ○ Piloted new opportunities for customers to be part of interconnection solution, for example, with interim interruptible service, sharing infrastructure among customers, and customer build of infrastructure.
Continue to make improvements to accelerate and expand efforts to support the Province's goal of providing all B.C. communities with access to high-speed internet connectivity by 2027, while maintaining cost effectiveness and reliability for BC Hydro ratepayers, and safety for workers.	**Ongoing** ○ BC Hydro has reached an agreement with the Ministries of Water, Land, and Resource Stewardship and Citizens' Services to sub-tenure Crown land property rights to speed up permit requirements for connectivity projects. ○ BC Hydro continues to lead the Broadband Connectivity Working Group with telecommunications companies, and the Ministries of Energy, Mines, and Low Carbon Innovation, Citizens' Services, and Water, Land, and Resource Stewardship to improve transparency, communication, and process.

Appendix B

Subsidiaries and Operating Segments

Active subsidiaries



Active subsidiary

Powerex Corp

Operating out of Vancouver, B.C., Powerex Corp. (Powerex) is a wholesale energy marketer whose activities include trading electricity, environmental products, natural gas, and related financial and physical energy products and services in North America.

Powerex was incorporated in Canada on December 13, 1988 under the BC Corporations Act (formerly the Company Act of BC) and commenced operations on April 1, 1989. Powerex is a wholly–owned corporate subsidiary of BC Hydro, a Crown corporation of the Province of British Columbia.

Through its contractual agreements with BC Hydro, Powerex supports BC Hydro's system requirements by importing and exporting energy. Powerex also markets, through a contractual agreement with the Province, the Canadian Entitlement to the Downstream Power Benefits under the Columbia River Treaty.

The Chief Executive Officer (CEO) of Powerex reports directly to the Board of Directors of Powerex. The Chair of the Powerex Board ensures the Board of BC Hydro is informed of Powerex's key strategies and business activities. The Powerex CEO also informs the BC Hydro President & CEO and Executive Team of Powerex's key strategies and business activities.

Powerex operates in competitive and complex wholesale energy–markets, which can cause net income in any given year to vary significantly. Market, economic, and weather conditions; reduced hydro system flexibility; unrealized mark–to–market gains or losses; and the strength of the Canadian dollar can materially impact Powerex net income. Over the past five years (2019/20 to 2023/24), Powerex's net income has ranged from $192 million to $1,052 million. For more information, visit **powerex.com**.

Board of Directors

Catherine Roome
Chair

Sam Drier

Amanda Hobson

Marilyn Mauritz

Doug Allen

Chris O'Riley

Active subsidiary

Powertech Labs Inc.

Powertech Labs Inc., based in Surrey, British Columbia since its inception 1988 is a wholly owned subsidiary of BC Hydro. Operating as a commercial entity, Powertech supports innovation through three main businesses lines: testing services, engineering services and Hydrogen infrastructure. Powertech provides innovative solutions, specialized testing, and technical expertise to global industry partners, contributing to a safe and sustainable energy future. Internationally recognized for its technical leadership in various fields related to electric utilities and sustainable energy industries, Powertech Labs is also a leader in hydrogen technology. It has extensive experience designing and producing innovative hydrogen vehicle refueling and transportation systems, playing a key role in BC Hydro's commitment to supporting the Province's B.C. Hydrogen Strategy. Powertech has supplied 100 percent of hydrogen station technology in B.C. and approximately 90 percent of Canada.

Powertech Labs has an active subsidiary, Powertech USA, Inc., which is a wholly owned, unregulated commercial subsidiary that began operations on September 1, 2023. Located in Boston, Massachusetts, Powertech USA focuses on developing hydrogen transport and fueling infrastructure solutions. This expansion has been realized through the strategic acquisition of emerging technology from a US entity, and the adoption of a key group of professionals developing this technology.

For the reporting fiscal year, Powertech USA's actual revenue is $2.1 million, and incurred expenditures of $4.3 million, resulting in a net loss of $2.2 million. This compares to a budget revenue of $3.1 million, and a projected net loss of $4.8 million. The lower expenditures compared to budget were due to the capitalisation of assets and IP acquisition, as well as the establishment costs of Powertech USA being expensed by Powertech Labs Inc. There are no previous fiscal year revenues, expenditures, or net income to report.

The President and CEO of Powertech reports to Powertech's Board of Directors through its Chair. The Powertech Board is chaired by BC Hydro's President and CEO and its Directors include persons with business, utility and energy industry experience to ensure the appropriate balance of expertise and perspectives necessary for overseeing a commercial enterprise. Over the last five years (2019/20 to 2023/24), Powertech's revenue has ranged from $49 million to $63 million with overall results ranging from a net loss of $1 million to net income of $5.4 million. For more information, visit **powertechlabs.com**.

Board of Directors

Chris O'Riley
Chair

Melissa Holland

Vasee Navaratnam

John Nunn

David Wong

Other subsidiaries

BC Hydro has created or retained a number of other subsidiaries for various purposes, including holding licences in other jurisdictions, to manage real estate holdings, and to manage various risks. Three of these subsidiaries are considered active:

BCHPA Captive Insurance Company Ltd.

Procures insurance products and services on behalf of BC Hydro.

Columbia Hydro Constructors Ltd.

Administers and supplies the labour force to specified projects.

Tongass Power and Light Company

Provides electrical power to Hyder, Alaska from Stewart, B.C. due to its remoteness from the Alaska electrical system.

Nominee holding companies and/or inactive subsidiaries/dormant subsidiaries

BC Hydro's remaining subsidiaries either serve as nominee holding companies (indicated with an *) or are considered to be inactive/dormant. The inactive/dormant subsidiaries do not carry on active operations. As of March 31, 2024, these other subsidiaries consisted of the following:

- British Columbia Hydro International Limited
- British Columbia Power Exchange Corporation
- British Columbia Power Export Corporation
- British Columbia Transmission Corporation
- Columbia Estate Company Limited*
- Edmonds Centre Developments Limited*
- Fauquier Water and Sewerage Corporation
- Hydro Monitoring (Alberta) Inc.*
- Victoria Gas Company Limited
- Waneta Holdings (US) Inc.*
- 1111472 BC Ltd

Appendix C

Auditor's Report and Audited Financial Statements

Management report

The consolidated financial statements of British Columbia Hydro and Power Authority (BC Hydro) are the responsibility of management and have been prepared in accordance with International Financial Reporting Standards. The preparation of financial statements necessarily involves the use of estimates which have been made using careful judgment. In management's opinion, the consolidated financial statements have been properly prepared within the framework of the accounting policies summarized in the consolidated financial statements and incorporate, within reasonable limits of materiality, all information available at June 6, 2024. The consolidated financial statements have also been reviewed by the Audit and Finance Committee and approved by the Board of Directors. Financial information presented elsewhere in this Annual Service Plan Report is consistent with that in the consolidated financial statements.

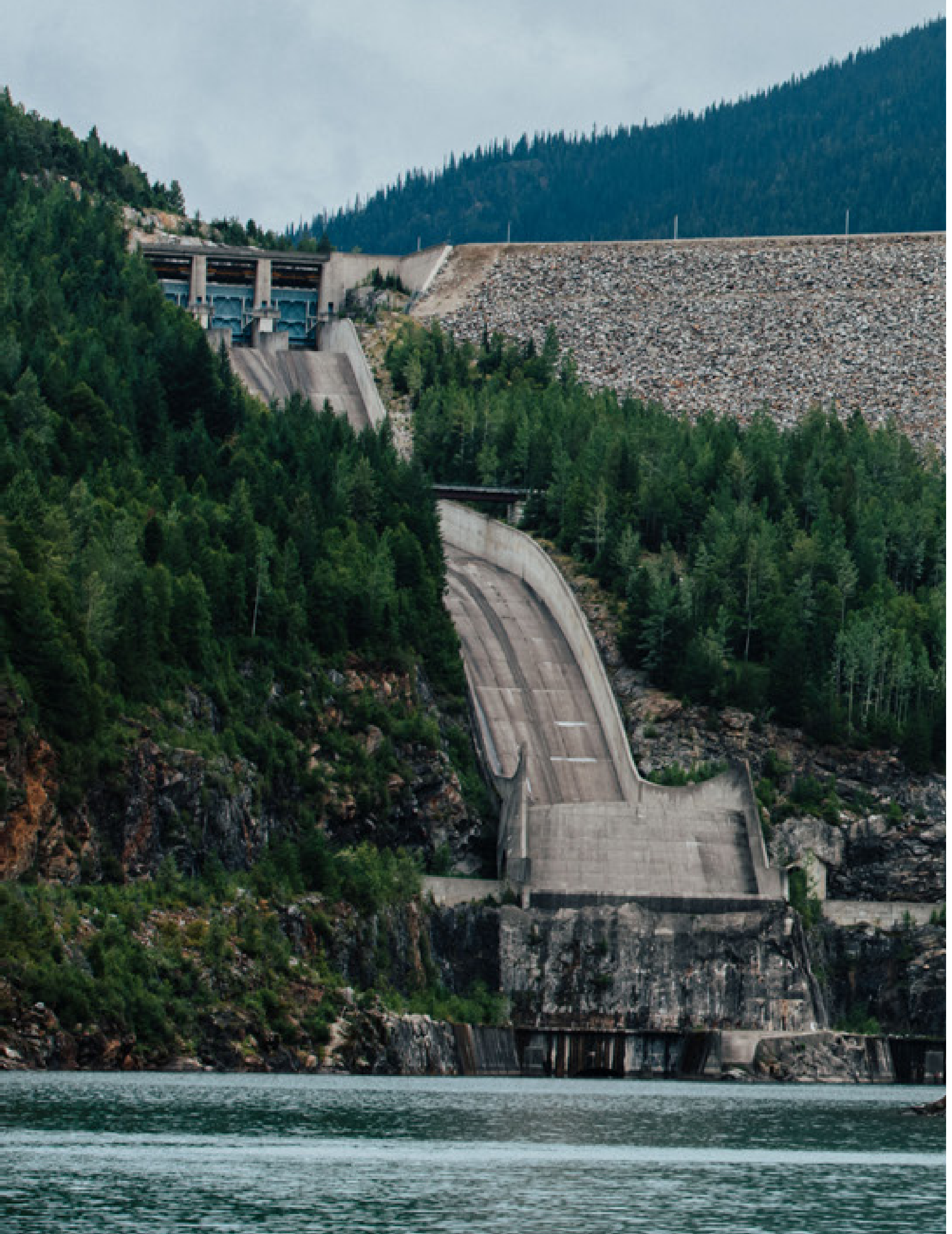
Management maintains systems of internal controls designed to provide reasonable assurance that assets are safeguarded and that reliable financial information is available on a timely basis. These systems include formal written policies and procedures, careful selection and training of qualified personnel, appropriate delegation of authority, and segregation of responsibilities within the organization. An internal audit function independently evaluates the effectiveness of internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee.

The consolidated financial statements have been audited by an independent external auditor. The external auditors' responsibility is to express their opinion on whether the consolidated financial statements, in all material respects, fairly present BC Hydro's financial position, financial performance and cash flows in accordance with International Financial Reporting Standards. The Independent Auditor's Report, which follows, outlines the scope of their audit and their opinion.

The Board of Directors, through the Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit and Finance Committee, comprised of directors who are not employees, meets regularly with the external auditors, the internal auditors and management to satisfy itself that each group has properly discharged its responsibility with respect to internal controls and financial reporting. The Audit and Finance Committee reviews the consolidated financial statements and management's discussion and analysis and recommends their approval to the Board of Directors. The internal and external auditors have full and open access to the Audit and Finance Committee, with and without the presence of management.

Chris O'Riley
President and Chief Executive Officer

Ryan Layton
Executive Vice President, Finance, Technology, Supply Chain and Chief Financial Officer



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Canada
Telephone (604) 691-3000
Fax (604) 691-3031

INDEPENDENT AUDITOR'S REPORT

To the Minister of Energy, Mines and Petroleum Resources, Province of British Columbia and the Board of Directors of British Columbia Hydro and Power Authority:

Opinion

We have audited the consolidated financial statements of British Columbia Hydro and Power Authority (the "Entity"), which comprise:

— the consolidated statement of financial position as at March 31, 2024

— the consolidated statement of comprehensive income for the year then ended

— the consolidated statement of changes in equity for the year then ended

— the consolidated statement of cash flows for the year then ended

— and notes to the consolidated financial statements, including a summary of material accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Entity as at March 31, 2024 and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditor's Responsibilities for the Audit of the Financial Statements***" section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter – Comparative Information

We draw attention to Note 2(a) and Note 27 to the financial statements, which explains that certain comparative information in the consolidated statements of comprehensive income and cash flows presented for the year ended March 31, 2023 have been adjusted.

Note 2(a) and Note 27 explain the reason for the adjustments and also explain the adjustments that were applied to adjust certain comparative information in the consolidated statements of comprehensive income and cash flows.

Our opinion is not modified in respect of this matter.

Other Matter – Comparative Information

The financial statements for the year ended March 31, 2023, excluding the adjustments that were applied to adjust certain comparative information in the consolidated statements of comprehensive income and cash flows, were audited by another auditor who expressed an unmodified opinion on those financial statements on June 8, 2023.

As part of our audit of the financial statements for the year ended March 31, 2024, we also audited the adjustments that were applied to adjust certain comparative information presented in the consolidated statements of comprehensive income and cash flows for the year ended March 31, 2023. In our opinion, such adjustments are appropriate and have been properly applied.

Other than with respect to the adjustments that were applied to adjust certain comparative information in the consolidated statements of comprehensive income and cash flows, we were not engaged to audit, review or apply any procedures to the financial statements for the year ended March 31, 2023.

Accordingly, we do not express an opinion or any other form of assurance on those financial statements taken as a whole.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

— Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

— Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

— Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

— Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

— Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

— Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

— Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the group Entity to express an opinion on the financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

KPMG LLP

Chartered Professional Accountants

Vancouver, Canada
June 6, 2024

Audited financial statements

Consolidated Statements of Comprehensive Income

for the years ended March 31 (in millions)		**2024**		2023 Adjusted - (Note 27)
Revenues (Note 4)				
Domestic	**$**	**5,504**	$	5,982
Trade		**1,627**		2,496
		7,131		8,478
Expenses				
Operating expenses (Note 5)		**6,787**		6,460
Finance charges (Note 6)		**516**		496
Net Income (Loss) Before Movement in Regulatory Balances		**(172)**		1,522
Net movement in regulatory balances (Note 15)		**495**		(1,162)
Net Income		**323**		**360**
OTHER COMPREHENSIVE INCOME				
Items That Will Be Reclassified to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 23)		**17**		18
Reclassification to income of derivatives designated as cash flow hedges (Note 23)		**-**		(91)
Foreign currency translation gains		**7**		54
Items That Will Not Be Reclassified to Net Income				
Actuarial gain		**103**		251
Other Comprehensive Income before movement in regulatory balances		**127**		**232**
Net movements in regulatory balances (Note 15)		**(110)**		(282)
Other Comprehensive Income (Loss)		**17**		(50)
Total Comprehensive Income	**$**	**340**	$	310

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Financial Position

(in millions)		**As at March 31, 2024**		As at March 31, 2023
ASSETS				
Current Assets				
Cash and cash equivalents (Note 8)	**$**	**96**	$	148
Restricted cash (Note 8)		**45**		-
Accounts receivable and accrued revenue (Note 9)		**984**		894
Inventories (Note 10)		**391**		387
Prepaid expenses		**184**		186
Current portion of derivative financial instrument assets (Note 23)		**267**		494
		1,967		2,109
Non-Current Assets				
Property, plant and equipment (Note 11)		**40,108**		36,926
Right-of-use assets (Note 12)		**1,209**		1,305
Intangible assets (Note 13)		**641**		639
Derivative financial instrument assets (Note 23)		**145**		319
Other non-current assets (Note 14)		**419**		542
		42,522		39,731
Total Assets		**44,489**		41,840
Regulatory Balances (Note 15)		**4,953**		3,946
Total Assets and Regulatory Balances	**$**	**49,442**	$	45,786
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities (Note 16)	**$**	**1,912**	$	1,953
Current portion of long-term debt (Note 17)		**4,740**		2,958
Current portion of unearned revenues and contributions in aid (Note 20)		**109**		108
Current portion of derivative financial instrument liabilities (Note 23)		**305**		474
Customer credits (Note 4)		**326**		-
		7,392		5,493
Non-Current Liabilities				
Long-term debt (Note 17)		**24,897**		24,057
Lease liabilities (Note 19)		**1,330**		1,376
Derivative financial instrument liabilities (Note 23)		**224**		325
Unearned revenues and contributions in aid (Note 20)		**2,768**		2,615
Post-employment benefits (Note 22)		**692**		731
Other non-current liabilities (Note 24)		**1,342**		1,354
		31,253		30,458
Total Liabilities		**38,645**		35,951
Regulatory Balances (Note 15)		**3,101**		2,479
Total Liabilities and Regulatory Balances		**41,746**		38,430
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**7,677**		7,354
Accumulated other comprehensive loss		**(41)**		(58)
		7,696		7,356
Total Liabilities, Regulatory Balances, and Shareholder's Equity	**$**	**49,442**	$	45,786

Commitments and Contingencies (Notes 11 and 25)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

L. Wanamaker.

Lori Wanamaker
Board Chair

V. McMillan

Victoria McMillan, CPA, CA
Chair, Audit and Finance Committee

Consolidated Statements of Changes in Equity

(in millions)	Cumulative Translation Reserve	Unrealized Income (Loss) on Cash Flow Hedges	Total Accumulated Other Comprehensive Loss	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2022	$ (13)	$ 5	$ (8)	$ 60	$ 6,994	$ 7,046
Comprehensive Income (Loss)	23	(73)	(50)	-	360	310
Balance as at March 31, 2023	10	(68)	(58)	60	7,354	7,356
Comprehensive Income	-	17	17	-	323	340
Balance as at March 31, 2024	$ 10	$ (51)	$ (41)	$ 60	$ 7,677	$ 7,696

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

for the years ended March 31 (in millions)	**2024**	2023 Adjusted - (Note 27)
Operating Activities		
Net income	**$ 323**	$ 360
Regulatory account transfers (Note 15)	**(495)**	1,162
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 7)	**1,071**	1,052
Gains on derivative financial instruments	**-**	(55)
Post-employment benefits expense	**66**	98
Interest accrual	**1,018**	874
Other items	**106**	129
	2,089	3,620
Changes in working capital and other assets and liabilities (Note 18)	**(76)**	(100)
Interest paid	**(1,037)**	(919)
Cash provided by operating activities	**976**	2,601
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(3,703)**	(3,532)
Cash used in investing activities	**(3,703)**	(3,532)
Financing Activities		
Long-term debt issued (Note 17)	**862**	1,498
Long-term debt retired (Note 17)	**(200)**	(500)
Receipt of revolving borrowings	**9,673**	6,781
Repayment of revolving borrowings	**(7,748)**	(6,919)
Payment of principal portion of lease liability	**(29)**	(71)
Settlement of hedging derivatives	**147**	205
Other items	**(30)**	(14)
Cash provided by financing activities	**2,675**	980
Increase (Decrease) in cash and cash equivalents	**(52)**	49
Cash and cash equivalents, beginning of year	**148**	99
Cash and cash equivalents, end of year	**$ 96**	$ 148

See Note 18 for Cash flow supplement—changes in liabilities

See accompanying Notes to the Consolidated Financial Statements.

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 consolidated financial statements of BC Hydro include the accounts of BC Hydro and its principal wholly owned operating subsidiaries 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

(a) Basis of Accounting

These consolidated financial statements have been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board (IASB). The material accounting policies are set out in Note 3.

Effective as of April 1, 2023, BC Hydro changed its accounting policy from presenting electricity imports acquired through contracts treated as derivatives and exports in trade revenues to separately present these electricity imports as operating expenses (part of electricity and gas purchases) and electricity exports as domestic revenues. This presentation more appropriately reflects the physical flows of electricity and provides more relevant information for financial statement users. The change was driven by significant electricity imports that occurred during the year ended March 31, 2024 as a result of the prolonged drought. As a result of the change in the accounting policy, the prior year's comparative figures have been restated. The change resulted in classification differences in the statement of comprehensive income but had no impact to net income or to the statement of cash flows, changes in equity, and financial position. The impact of the change on the comparative figures is provided in Note 27.

Certain amounts in the prior year's comparative figures have been reclassified to conform to the current year's presentation.

These consolidated financial statements were approved by the Board of Directors on June 6, 2024.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for natural gas inventories in Note 3(j), financial instruments that are accounted for at fair value through profit and loss according to the financial instrument categories as defined in Note 3(k) and the post–employment benefits obligation as described in Note 3(p).

(c) Functional and Presentation Currency

The functional currency of BC Hydro and all of its subsidiaries, except for Powerex, is the Canadian dollar. Powerex's functional currency is the United States (U.S.) dollar. These consolidated financial statements are presented in Canadian dollars and financial information has been rounded to the nearest million.

(d) Key Assumptions and Significant Judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions in respect of the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those judgments, estimates, and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized in the period in which the estimates are revised and in any future periods affected. Information about significant areas of judgment, estimates and assumptions in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is as follows:

(i) Retirement Benefit Obligation

BC Hydro operates a defined benefit statutory pension plan for its employees, which is accounted for in accordance with IAS 19, Employee Benefits. Actuarial valuations are based on key assumptions which include employee turnover, mortality rates, discount rates, earnings increases and expected rate of return on retirement plan assets. Judgment is exercised in determining these assumptions. The assumptions adopted are based on prior experience, market conditions and advice of plan actuaries. Future results are impacted by these assumptions including the accrued benefit obligation and current service cost. See Note 22 for significant benefit plan assumptions.

(ii) Provisions and Contingencies

Management is required to make judgments to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37, Provisions, Contingent Liabilities and Contingent Assets. IAS 37 requires that a provision be recognized where there is a present obligation as a result of a past event, it is probable that transfer of economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Key judgments are whether a present obligation exists and the probability of an outflow being required to settle that obligation. Key assumptions in measuring recorded provisions include the timing and amount of future payments and the discount rate applied in valuing the provision.

The Company is currently defending certain lawsuits where management must make judgments, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management has obtained the advice of its external counsel in determining the likely outcome and estimating the expected costs associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

(iii) Financial Instruments

The Company enters into financial instrument arrangements which require management to make judgments to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, including whether those embedded derivatives meet the criteria to be separated from their host contract, in accordance with IFRS 9, Financial Instruments. Key judgments are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable, and for embedded derivatives, whether the economic risks and characteristics are not closely related to the host contract and a separate instrument with the same terms would meet the definition of a derivative on a standalone basis.

Valuation techniques are used in measuring the fair value of financial instruments when active market quotes are not available. Valuation of the Company's financial instruments is based in part on forward prices which are volatile and therefore the actual realized value may differ from management's estimates.

(iv) Right-of-Use Leases

The Company enters into long-term energy purchase agreements that may be considered to be, or contain a lease. In making this determination, judgment is required to determine whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

In the situation where the implicit interest rate in the lease is not readily determined, the Company uses judgment to estimate the incremental borrowing rate for discounting the lease payment. The Company's incremental borrowing rate generally reflects the interest rate that the Company would have to pay to borrow a similar amount at a similar term and with similar security. The Company estimates the lease term by considering the facts and circumstances that create an economic incentive to exercise an extension or termination option. Certain qualitative and quantitative assumptions are used when evaluating these options.

(v) Useful Life of Property, Plant and Equipment and Intangible Assets

Estimation and judgement are involved in determining useful lives and related depreciation and amortization of property, plant and equipment and intangible assets. Estimated useful lives are determined based upon the anticipated physical life of the asset, past experience with similar assets, industry averages and expectations about future events that could impact the life of the asset. Estimated useful lives are reviewed annually to ensure their reasonableness (Note 3(e) and 3(f)). The Company periodically conducts depreciation studies to assess asset useful lives.

(vi) Rate Regulation

When a regulatory account has been or will be applied for, and, in management's estimate, acceptance of deferral treatment by the British Columbia Utilities Commission (BCUC), and recovery in future rates is considered probable, BC Hydro defers such costs in advance of a final decision of the BCUC. In assessing whether deferral approval and collection in future rates is probable management considers factors such as past precedents, magnitude of the costs, impact on rates, legal enquiries, regulatory framework for cost recovery, and political environment. If the BCUC subsequently denies the application for regulatory treatment, the deferred amount is recognized immediately in comprehensive income.

(vii) Revenues

For contributions in aid of construction revenue, management must make judgments when determining the period over which revenue is recognized when the associated contracts do not specify a finite period over which service is provided.

For revenue contracts where a significant financing component is present, management must make judgments when determining the appropriate discount rate to use.

Note 3: Material Accounting Policies

BC Hydro adopted Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2) on April 1, 2023. Although the amendments did not result in any changes to the accounting policies themselves, they impacted the accounting policy information disclosed in the financial statements.

The amendments require the disclosure of "material" rather than "significant", accounting policies. The amendments also provide guidance on the application of materiality to disclosure of accounting policies, assisting entities to provide useful, entity-specific accounting policy information that users need to understand other information in the financial statements.

Management reviewed the accounting policies and made updates to the information disclosed in Note 3 Material accounting policies (2023: Significant accounting policies) in certain instances in line with the amendments.

(a) Rate Regulation

BC Hydro is regulated by the BCUC and both entities are subject to directives and directions issued by the Province. BC Hydro's rates are set on a cost of service basis. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

In January 2014, the IASB issued an interim standard, IFRS 14, Regulatory Deferral Accounts, which provides guidance on accounting for the effects of rate regulation under IFRS. This guidance allows entities that conduct rate-regulated activities to continue to recognize regulatory deferral accounts. BC Hydro has elected to adopt IFRS 14 in its consolidated financial statements. The interim standard is only intended to provide temporary guidance until the IASB completes its comprehensive project on rate-regulated activities. IFRS 14 remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding the Company's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on the Company's consolidated statements of financial position, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the BCUC. In the absence of rate-regulation, these amounts would be included in comprehensive income.

BC Hydro capitalizes as a regulatory asset, all or part of an incurred cost that would otherwise be charged to net income or other comprehensive income (OCI) if it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes and the future rates and revenue approved by the BCUC will permit recovery of that incurred cost. Regulatory liabilities are recognized for certain gains or other reductions of net allowable costs for adjustment of future rates as determined by the BCUC. In the event that the recovery of these asset balances are assessed to no longer be probable based on management's judgment or the refund of these liability balances is no longer required, the balances are recorded in the Company's consolidated statements of comprehensive income in the period when the assessment is made.

Regulatory balances that do not meet the definition of an asset or liability under any other IFRS are segregated on the consolidated statement of financial position, and are separately disclosed on the consolidated statements of comprehensive income as net movements in regulatory balances related to net income (loss) or net movements in regulatory balances related to other comprehensive income (loss). The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the BCUC's regulations and decisions.

(b) Revenues

The Company recognizes revenue when it transfers control over a promised good or service, which constitutes a performance obligation under the contract, to a customer and where the Company is entitled to consideration as a result of completion of the performance obligation. Depending on the terms of the contract with the customer, revenue recognition can occur at a point in time or over time. When a performance obligation is satisfied, revenue is measured at the transaction price that is allocated to that performance obligation, net of any customer credits issued. Amounts received from customers in advance of the performance obligation are recognized as unearned revenue until the performance obligation is satisfied.

Domestic revenues comprise sales to customers within the province of British Columbia, sales that are surplus to domestic load requirements, and certain sales of energy outside the province that are under long-term contracts. Sales outside the province besides those described above are classified as Trade revenue.

A significant portion of the Company's revenue is generated from providing electricity goods and services. Revenue is recognized over time generally using output measure or progress (i.e., kilowatt hours delivered) as the Company's customers simultaneously receive and consume the electricity goods and services as it is provided. Revenue is determined on the basis of billing cycles and includes accruals for electricity deliveries not yet billed.

The Company recognizes a financing component where the timing of payment from the customer differs from the Company's performance under the contract and where that difference is the result of the Company financing the transfer of goods and services.

Energy trading contracts that meet the definition of a financial or non-financial derivative are accounted for at fair value whereby any realized gains and losses and unrealized changes in the fair value are recognized in trade revenues in the period of change. Realized and unrealized changes in the fair value of these contracts are accounted for under IFRS 9, Financial Instruments (Note 3(k)).

Energy trading and other contracts which do not meet the definition of a derivative are accounted for on an accrual basis whereby the realized gains and losses are recognized as revenue as the contracts are settled. Such contracts are considered to be settled when control of products and services are transferred to the buyer and performance obligation is satisfied.

(c) Finance Costs and Recoveries

Finance costs are comprised of interest expense on borrowings, accretion expense on provisions and other long-term liabilities, net interest on net defined benefit obligations, interest on lease liabilities, foreign exchange losses and realized and unrealized interest and foreign exchange hedging instrument losses that are recognized in the statement of comprehensive income, excluding energy trading contracts. All borrowing costs are recognized using the effective interest rate method.

Finance costs exclude borrowing costs attributable to the construction of qualifying assets, which are assets that take six months or more to prepare for their intended use.

Finance recoveries comprises of income earned on sinking fund investments held for the redemption of long-term debt, foreign exchange gains and realized and unrealized interest and foreign exchange hedging instrument gains that are recognized in the statement of comprehensive income, excluding energy trading contracts.

(d) Foreign Currency

Foreign currency transactions are translated into the respective functional currencies of BC Hydro and its subsidiaries, using the exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies at the reporting date are translated to the functional currency at the exchange rate in effect at that date. The foreign currency gains or losses on monetary items is the difference between the amortized cost in the functional currency at the beginning of the period, adjusted for effective interest and payments during the period, and the amortized cost in the foreign currency translated at the exchange rate at the end of the reporting period. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

For purposes of consolidation, the assets and liabilities of Powerex, whose functional currency is the U.S. dollar, are translated to Canadian dollars using the rate of exchange in effect at the reporting date. Revenue and expenses of Powerex are translated to Canadian dollars at exchange rates at the date of the transactions. Foreign currency differences resulting from translation of the accounts of Powerex are recognized directly in other comprehensive income and are accumulated in the cumulative translation reserve. Foreign exchange gains or losses arising from a monetary item receivable from or payable to Powerex, the settlement of which is neither planned nor likely in the foreseeable future and which in substance is considered to form part of a net investment in Powerex by BC Hydro are recognized directly in other comprehensive income in the cumulative translation reserve.

(e) Property, Plant and Equipment

(i) Recognition and Measurement

Property, plant and equipment in service are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour and any other costs directly attributable to bringing the asset into service. The cost of dismantling and removing an item of property, plant and equipment and restoring the site on which it is located is estimated and capitalized only when, and to the extent that, the Company has a legal or constructive obligation to dismantle and remove such asset. Property, plant and equipment in service include the cost of plant and equipment financed by contributions in aid of construction. Borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset are capitalized as part of the cost of the qualifying asset. Upon retirement or disposal, any gain or loss is recognized in the statement of comprehensive income.

Unfinished construction consists of the cost of property, plant and equipment that is under construction or not ready for service. Costs are transferred to property, plant and equipment in service when the constructed asset is capable of operation in a manner intended by management.

(ii) Subsequent Costs

The cost of replacing a component of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the component will flow to the Company, and its cost can be measured reliably. The carrying amount of the replaced component is derecognized. The costs of property, plant and equipment maintenance are recognized in the statement of comprehensive income as incurred.

(iii) Depreciation

Property, plant and equipment in service are depreciated over the expected useful lives of the assets, using the straight-line method. When major components of an item of property, plant and equipment have different useful lives, they are accounted for as separate items of property, plant and equipment.

The expected useful lives, in years, of the Company's main classes of property, plant and equipment are:

Generation	15–100
Transmission	20–75
Distribution	20–60
Buildings	5–65
Equipment & other	3–35

The expected useful lives and residual values of items of property, plant and equipment are reviewed annually.

Depreciation of an item of property, plant and equipment commences when the asset is available for use and ceases at the earlier of the date the asset is classified as held for sale and the date the asset is derecognized.

(f) Intangible Assets

Intangible assets are recorded at cost less accumulated amortization and accumulated impairment losses. Land rights associated with statutory rights of way acquired from the Province that have indefinite useful lives are not subject to amortization. Intangible assets with finite useful lives are amortized over their expected useful lives on a straight line basis. These assets are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be fully recoverable.

The expected useful life for software is 2 to 10 years. Amortization of intangible assets commences when the asset is available for use and ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized.

(g) Asset Impairment

(i) Financial Assets

Financial assets, other than those measured at fair value (note 3(k)), are assessed at each reporting date to determine whether there is impairment. The Company accounts for impairment of financial assets based on a forward-looking expected credit loss model under IFRS 9, Financial Instruments. The expected-loss impairment model requires an entity to recognize the expected credit losses (ECL) when financial instruments are initially recognized and to update the amount of ECL recognized at each reporting date to reflect changes in the credit risk of the financial instruments. ECL's are measured as the difference in the present value of the contractual cash flows due to the Company under the contract and the cash flows that Company expects to receive.

For accounts receivable without a significant financing component, the Company applies the simplified approach for determining expected credit losses, which requires the Company to determine the lifetime expected losses for all accounts receivable and accrued revenue. For a non-current receivable with a significant financing component, the Company measures the expected credit loss at an amount equal to the 12-month expected credit loss at initial recognition. If the credit risk has increased significantly since initial recognition, the Company measures the expected credit loss at an amount equal to the lifetime expected credit loss. The expected lifetime credit loss provision and 12-month expected credit loss is based on historical counterparty default rates, third party default probabilities and credit ratings, and is adjusted for relevant forward looking information specific to the counterparty, when required.

(ii) Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated annually.

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of identifiable assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the cash-generating unit, or CGU). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. All of BC Hydro's assets form one CGU for the purposes of testing for impairment.

An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income. Impairment losses recognized in respect of a CGU are allocated to reduce the carrying amounts of the assets in the CGU on a pro-rata basis.

Impairment losses recognized in prior periods are assessed at the reporting date for any indications that the loss has decreased or no longer exists. Impairment reversals are recognized immediately in net income when the recoverable amount of an asset increases above the impaired net book value, not to exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

(h) Cash and Cash Equivalents

Cash and cash equivalents include unrestricted cash and units of a money market fund (short-term investments) that are redeemable on demand and are carried at amortized cost and fair value, respectively.

(i) Restricted Cash

Restricted cash includes cash balances which the Company does not have immediate access to as they have been pledged to counterparties as security for investments or trade obligations. These balances are available to the Company only upon settlement of the underlying obligations.

(j) Inventories

Inventories are comprised primarily of natural gas, materials and supplies and environmental products that include certain carbon products. Natural gas and certain carbon product inventory is valued at fair value less costs to sell and is included in Level 2 of the fair value hierarchy (refer to Note 10).

Materials and supplies and other environmental products inventories are valued at the lower of cost determined on a weighted average basis and net realizable value. The cost of materials and supplies comprises all costs of purchase, costs of conversion and other directly attributable costs incurred in bringing the inventories to their present location and condition. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated selling expenses.

(k) Financial Instruments

(i) Financial Instruments—Recognition and Measurement

All financial instruments are measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on which of the following categories the financial instrument has been classified as: fair value through profit or loss (FVTPL), and those measured at amortized cost. The Company may designate financial instruments as held at FVTPL when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis. All derivative instruments are categorized as FVTPL unless they are designated as accounting hedges.

Transaction costs are expensed as incurred for financial instruments classified or designated as fair value through profit or loss. For other financial instruments, transaction costs are included in the carrying amount. All regular-way purchases or sales of financial assets are accounted for on a settlement date basis.

Financial assets and financial liabilities classified as FVTPL are subsequently measured at fair value with changes in those fair values recognized in net income in the period of change. Financial assets and liabilities are measured at amortized cost if the business model is to hold the instrument for collection or payment of contractual cash flows and those cash flows are solely principal and interest. If the business model is not to hold the instruments, it is classified as FVTPL. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses in the impairment of financial assets.

(ii) Classification and Measurement of Financial Instruments

Short-term investments	FVTPL
Derivatives not in hedging relationship	FVTPL
Cash	Amortized cost
Restricted cash	Amortized cost
Accounts receivable and other receivables	Amortized cost
US dollar sinking funds	Amortized cost
Accounts payable and accrued liabilities	Amortized cost
Revolving borrowings	Amortized cost
Long-term debt	Amortized cost
Lease liabilities	Amortized cost
First Nation liabilities and other liabilities presented in other long-term liabilities	Amortized cost

(iii) Fair Value

The fair value of financial instruments reflects changes in the level of commodity market prices, interest rates, foreign exchange rates and credit risk. Fair value is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable willing parties who are under no compulsion to act.

Fair value amounts reflect management's best estimates considering various factors including closing exchange or over–the–counter quotations, estimates of future prices and foreign exchange rates, time value of money, counterparty and own credit risk, and volatility. The assumptions used in establishing fair value amounts could differ from actual prices and the impact of such variations could be material. In certain circumstances, valuation inputs are used that are not based on observable market data but based on internally developed valuation models which are based on models and techniques generally recognized as standard within the energy industry.

(iv) Inception Gains and Losses

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 deferred and amortized into income over the full term of the underlying financial instrument. Additional information on deferred inception gains and losses is disclosed in Note 23.

(v) Derivative Financial Instruments

The Company may use derivative financial instruments to manage interest rate and foreign exchange risks related to debt and to manage risks related to electricity and natural gas commodity transactions.

Interest rate and foreign exchange related derivative instruments that are not designated as hedges, are classified as FVTPL whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income in the period of change. For debt management activities, the related gains or losses are included in finance charges. The Company's policy is to not utilize interest rate and foreign exchange related derivative financial instruments for speculative purposes.

Commodity derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices. Commodity derivatives that are not designated as hedges are classified as FVTPL whereby instruments are recorded at fair value as either an asset or liability with changes in fair value recognized in net income. Gains or losses are included in trade revenues.

(vi) Hedges

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for unrealized gains or losses attributable to the hedged risk and recognized in net income. Changes in the fair value of the hedged item attributed to the hedged risk, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net income. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship, using the effective interest method of amortization.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income. The ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. When hedge accounting is discontinued the cumulative gain or loss previously recognized in accumulated other comprehensive income remains there until the forecasted transaction occurs. When the hedged item is a non–financial asset or liability, the amount recognized in accumulated other comprehensive income is transferred to the carrying amount of the asset or liability when it is recognized. In other cases, the amount recognized in accumulated other comprehensive income is transferred to net income in the same period that the hedged item affects net income.

Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, the hedging relationship is discontinued, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

(l) Investments Held in Sinking Funds

Investments held in sinking funds are held as individual portfolios and are classified as amortized cost. Securities included in an individual portfolio are recorded at cost, adjusted by amortization of any discounts or premiums arising on purchase, on a yield basis over the estimated term to settlement of the security. Realized gains and losses are included in finance charges.

(m) Unearned Revenues

Unearned revenues consist principally of amounts received under the agreement relating to the Skagit River, Ross Lake and the Seven Mile Reservoir on the Pend d'Oreille River (collectively the Skagit River Agreement) and other amounts received from customers for performance obligations which have not been performed.

Under the Skagit River Agreement, the Company has committed to deliver a predetermined amount of electricity each year to the City of Seattle for an 80 year period ending in fiscal 2066 in return for annual payments of approximately US$22 million for a 35 year period ending in 2021 and US$100,000 (adjusted for inflation) for the remaining 45 year period ending in 2066. The amounts received under the agreement are deferred and included in income on an annuity basis over the electricity delivery period ending in fiscal 2066. As a result of the upfront consideration received under the Skagit River Agreement, in determining the transaction price, the promised amount of consideration is adjusted for the effects of the time value of money (i.e., significant financing component). The application of the significant financing component requirement results in the recognition of interest expense over the financing period and a higher amount of revenue.

(n) Government Grants

The Company recognizes government grants when there is reasonable assurance that any conditions attached to the grant will be met and the grant will be received. Government grants related to assets are deducted from the carrying amount of the related asset and recognized in profit or loss over the life of the related asset. Grants that compensate the Company for expenses incurred are recognized in profit or loss as an offset against the originating expense in the same period in which the expenses are recognized. Non-monetary grants are recognized on the cost basis at a nominal amount.

(o) Contributions in Aid of Construction

Contributions in aid of construction are amounts paid by certain customers toward the cost of property, plant and equipment required for the extension of services to supply electricity. These amounts are recognized into revenue over the term of the agreement with the customer, or over the expected useful life of the related assets when the associated contracts do not have a finite period over which service is provided.

(p) Post-Employment Benefits

The cost of pensions and other post-employment benefits earned by employees is actuarially determined using the projected accrued benefit method pro-rated on service and management's best estimate of mortality, salary escalation, retirement ages of employees and expected health care costs. The net interest for the period is determined by applying the same market discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability at the beginning of the annual period, taking into account any changes in the net defined benefit asset or liability during the period as a result of current service costs, contributions and benefit payments. The market discount rate is determined based on the market interest rate at the end of the year on high-quality corporate debt instruments that match the timing and amount of expected benefit payments.

Past service costs arising from plan amendments and curtailments are recognized in net income immediately. A plan curtailment will result if the Company has demonstrably committed to a significant reduction in the expected future service of active employees or a significant element of future service by active employees no longer qualifies for benefits. A curtailment is recognized when the event giving rise to the curtailment occurs.

The net interest costs on the net defined benefit plan liabilities arising from the passage of time are included in finance charges. The Company recognizes actuarial gains and losses immediately in other comprehensive income.

(q) Provisions

A provision is recognized if the Company has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of economic benefits will be required to settle the obligation and a reliable estimate of the obligation can be determined. For obligations of a long-term nature, provisions are measured at their present value by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability except in cases where future cash flows have been adjusted for risk.

Decommissioning Obligations

Decommissioning obligations are legal and constructive obligations associated with the retirement of long-lived assets. A liability is recorded at the present value of the estimated future costs based on management's best estimate. When a liability is initially recorded, the Company capitalizes the costs by increasing the carrying value of the asset. The increase in net present value of the provision for the expected cost is included in finance costs as accretion (interest) expense. Adjustments to the provision made for changes in timing, amount of cash flow and discount rates are capitalized and amortized over the useful life of the associated asset. Actual costs incurred upon settlement of a decommissioning obligation are charged against the related liability. Any difference between the actual costs incurred upon settlement of the decommissioning obligation and the recorded liability is recognized in net income at that time.

Environmental Expenditures and Liabilities

Environmental expenditures are expensed as part of operating activities, unless they constitute an asset improvement or act to mitigate or prevent possible future contamination, in which case the expenditures are capitalized and amortized to income. Environmental liabilities arising from a past event are accrued when it is probable that a present legal or constructive obligation will require the Company to incur environmental expenditures.

Legal

The Company recognizes legal claims as a provision when it is probable that there will be a future outflow of resources required to settle the claim against the Company and the amount of the settlement can be reliably measured. Management obtains the advice of its legal counsel in determining the likely outcome and estimating the expected costs associated with legal claims. Further information regarding lawsuits in progress is disclosed in Note 25.

(r) Leases

At inception of a contract, the Company assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether the contract involves the use of an identified asset, whether the Company has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use, and has the right to direct the use of the asset. At inception or on reassessment of a contract that contains a lease component, consideration is allocated to each lease component within the contract on the basis of its relative stand-alone prices.

As a lessee, the Company recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any decommissioning and restoration costs, less any lease incentives received.

The right-of-use asset is subsequently depreciated from the commencement date to the earlier of the end of the lease term, or the end of the useful life of the asset. In addition, the right-of-use asset may be reduced due to impairment losses, if any, and adjusted for re-measurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the incremental borrowing rate.

Lease payments included in the measurement of the lease liability are comprised of:

(i) Fixed payments, including in-substance fixed payments, less any lease incentives receivable;

(ii) Variable lease payments that depend on an index or a rate, initially measured using the index or rate as at the commencement date;

(iii) Amounts expected to be payable under a residual value guarantee;

(iv) Exercise prices of purchase options if reasonably certain the option will be exercised; and

(v) Payments of penalties for terminating the lease, if the lease term reflects the lessee exercising an option to terminate the lease.

The lease liability is measured at amortized cost using the effective interest method. It is re-measured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate or assessment of the amount expected to be payable under a residual value guarantee, purchase, extension or termination option.

When the lease liability is re-measured, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

Variable lease payments not included in the initial measurement of the lease liability are charged directly to the consolidated statement of comprehensive income as an expense.

The Company elected to use the following practical expedients under IFRS 16:

(i) The Company has elected not to separate non-lease components and account for the lease and non-lease components as a single lease component for leases pertaining to generating assets (including long-term energy purchase agreements).

(ii) The Company has elected not to recognize right-of-use assets and lease liabilities for short-term leases that have a lease term of 12 months or less and leases of low-value assets.

(s) Taxes

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 and operating activities in the United States.

(t) New Standards and Amendments Not Yet Adopted

A number of amendments to standards and interpretations, are not yet effective for the year ended March 31, 2024, and have not been applied in preparing these consolidated financial statements. The following new and amended standards become effective for the Company's annual periods beginning on or after the dates noted below:

- Amendments to IAS 1, Presentation of Financial Statements (effective April 1, 2024)

- Amendments to IFRS 16, Leases (effective April 1, 2024)
- Amendments to IAS 7, Statement of Cash Flows (effective April 1, 2024)
- Amendments to IFRS 7, Financial Instruments: Disclosures (effective April 1, 2024)
- Amendments to IAS 21, The Effects of Changes in Foreign Exchange Rates (effective April 1, 2025)

The Company does not expect the adoption of the new or amended standards to have a material impact on the consolidated financial statements.

Note 4: Revenues

Disaggregated Revenue

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

(in millions)		**2024**		2023 Adjusted - (Note 27)
Domestic				
Residential	**$**	**2,129**	$	2,146
Light industrial and commercial		**1,913**		1,840
Large industrial		**866**		848
Other sales		**596**		1,148
Total Domestic		**5,504**		5,982
Total Trade[1]		**1,627**		2,496
Total Revenue	**$**	**7,131**	$	8,478

[1] Includes revenue ($554 million) recognized under IFRS 9, *Financial Instruments* (2023 - $942 million).

Contract Balances

The Company does not have any contract assets which constitute consideration receivable from a customer that is conditional on the Company's future performance. The current and non-current receivable balances from customers as at March 31, 2024 was $918 million (2023—$834 million).

Contract liabilities represent payments received for performance obligations which have not been fulfilled.

The following table reconciles the items included in the contract liabilities balance:

(in millions)		**March 31, 2024**		March 31, 2023
Unearned revenues (Note 20)	**$**	**317**	$	325
Contributions in aid (Note 20)		**2,560**		2,398
Customer credits[1]		**326**		-
Customer deposits		**83**		67
	$	**3,286**	$	2,790

[1] On March 15, 2024, the Government of B.C. issued OIC 130 in respect to Energy Affordability Credits to BC Hydro which requires BC Hydro to issue credits to eligible customers in fiscal 2025 based on their consumption in fiscal 2024. The affordability credits will be applied to customer bills in fiscal 2025.

The following table reconciles the changes in the contract liabilities balances during the years ended March 31, 2024 and 2023:

(in millions)		**Contract Liabilities**
Balance at April 1, 2022	**$**	**2,540**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(136)
Increases due to cash received, excluding amounts recognized as revenue during the period		372
Other[1]		14
Balance at March 31, 2023		**2,790**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(155)
Increases due to cash received, excluding amounts recognized as revenue during the period		635
Other[1]		16
Balance at March 31, 2024	**$**	**3,286**

1 Other includes finance charges and foreign exchange adjustments

Remaining Performance Obligations

The following table includes revenue expected to be recognized in the future related to the performance obligations that are unsatisfied (or partially unsatisfied) as at March 31, 2024.

(in millions)	Less than 1 year		Between 1 and 5 years		More than 5 years		Total	
Contributions in aid	$	66	$	266	$	2,228	$	2,560
Skagit River Agreement		30		119		1,098		1,247
Other		65		128		37		230
	$	161	$	513	$	3,363	$	4,037

The Company elected to use the performance obligation practical expedients whereby the performance obligation is not disclosed for the following:

(i) Where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance to date, revenue is recognized in the amount to which the Company has a right to invoice, or

(ii) Where the remaining performance obligations have an original expected duration of one year or less.

Note 5: Operating Expenses

(in millions)		**2024**		2023 Adjusted - (Note 27)
Electricity and gas purchases	**$**	**3,028**	$	2,893
Water rentals		**362**		358
Transmission charges		**335**		323
Personnel expenses		**819**		762
Materials and external services		**923**		757
Amortization and depreciation (Note 7)		**1,071**		1,052
Grants and taxes		**316**		296
Other costs, net of recoveries		**25**		105
Capitalized costs		**(92)**		(86)
	$	**6,787**	$	6,460

Note 6: Finance Charges

(in millions)		**2024**		2023
Interest on long-term debt	**$**	**1,018**	$	874
Interest on lease liabilities		**46**		46
Interest on defined benefit plan obligations (Note 22)		**37**		43
Mark-to-market gains on derivative financial instruments (Note 23)		**(168)**		(201)
Other		**58**		83
Capitalized interest		**(475)**		(349)
	$	**516**	$	496

The capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 3.6 per cent (2023—3.3 per cent).

Note 7: Amortization and Depreciation

(in millions)		**2024**		2023
Depreciation of property, plant and equipment (Note 11)	**$**	**911**	$	888
Depreciation of right-of-use assets (Note 12)		**80**		82
Amortization of intangible assets (Note 13)		**80**		82
	$	**1,071**	$	1,052

Note 8: Cash and Cash Equivalents and Restricted Cash

(in millions)		**March 31, 2024**		March 31, 2023
Cash	**$**	**65**	$	78
Short-term investments		**31**		70
Restricted Cash		**45**		-
	$	**141**	$	148

Restricted cash represents cash balances which the Company does not have immediate access to as they have been pledged to counterparties as security for investments or trade obligations. These balances are only available to the Company upon liquidation of the investments or settlements of the trade obligations for which they have been pledged as security.

Note 9: Accounts Receivable and Accrued Revenue

(in millions)	**March 31, 2024**	March 31, 2023
Accounts receivable	**$ 381**	$ 521
Accrued revenue	**315**	251
Other	**288**	122
	$ 984	$ 894

Accrued revenue represents revenue for electricity delivered and not yet billed.

Note 10: Inventories

(in millions)	**March 31, 2024**	March 31, 2023
Materials and supplies and Environmental Products	**$ 252**	$ 208
Natural Gas and Certain Carbon products	**139**	179
	$ 391	$ 387

There were no materials, supplies, and environmental products inventory impairments during the years ended March 31, 2024 and 2023. Natural gas and certain carbon products inventory that are held for trading are measured at fair value less costs to sell and are therefore not subject to impairment testing.

Inventories recognized as an expense during the year amounted to $227 million (2023—$139 million).

Note 11: Property, Plant, and Equipment

(in millions)	**Generation**	**Transmission**	**Distribution**	**Land & Buildings**	**Equipment & Other**	**Unfinished Construction**	**Total**
Cost							
Balance at April 1, 2022	$ 10,052	$ 8,529	$ 7,418	$ 882	$ 1,000	$ 10,075	$ 37,956
Net additions	292	303	585	37	88	2,534	3,839
Disposals and retirements	(12)	(27)	(44)	(6)	(47)	(4)	(140)
Balance at March 31, 2023	10,332	8,805	7,959	913	1,041	12,605	41,655
Net additions	327	335	621	72	149	2,668	4,172
Disposals and retirements	(14)	(32)	(53)	(1)	(34)	(20)	(154)
Balance at March 31, 2024	$ 10,645	$ 9,108	$ 8,527	$ 984	$ 1,156	$ 15,253	$ 45,673
Accumulated Depreciation							
Balance at April 1, 2022	$ (1,212)	$ (1,153)	$ (1,024)	$ (138)	$ (391)	$ -	$ (3,918)
Depreciation expense	(272)	(247)	(245)	(28)	(96)	-	(888)
Disposals and retirements	7	17	15	-	38	-	77
Balance at March 31, 2023	(1,477)	(1,383)	(1,254)	(166)	(449)	-	(4,729)
Depreciation expense	(279)	(249)	(252)	(30)	(101)	-	(911)
Disposals and retirements	10	17	16	-	32	-	75
Balance at March 31, 2024	$ (1,746)	$ (1,615)	$ (1,490)	$ (196)	$ (518)	$ -	$ (5,565)
Net carrying amounts							
At March 31, 2023	$ 8,855	$ 7,422	$ 6,705	$ 747	$ 592	$ 12,605	$ 36,926
At March 31, 2024	$ 8,899	$ 7,493	$ 7,037	$ 788	$ 638	$ 15,253	$ 40,108

(i) Included within Distribution assets are the Company's portion of utility poles with a net book value of $1.27 billion (2023—$1.24 billion) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2024 was $35 million (2023—$34 million).

(ii) The Company received government grants arising from the Columbia River Treaty related to three dams built by the Company in the mid-1960s to regulate the flow of the Columbia River. The grants were made to assist in financing the construction of the dams. The grants were deducted from the carrying amount of the related dams. In addition, the Company received, in the current year and prior years, government grants for the construction of transmission lines and electric vehicle infrastructure and has deducted the grants received from the cost of the asset. BC Hydro received government grants of $23 million during the year ended March 31, 2024 (2023—$4 million).

(iii) The Company has contractual commitments to spend $1.35 billion on major property, plant and equipment projects (on individual projects greater than $20 million) as at March 31, 2024.

Note 12: Right-of-Use Assets

(in millions)	Long-term energy purchase agreements	Property	Equipment/ Other	Total
Cost				
Balance at April 1, 2022	$ 2,013	$ 58	$ 4	$ 2,075
Net additions	123	17	-	140
Disposals and retirements	(376)	(1)	-	(377)
Balance at March 31, 2023	1,760	74	4	1,838
Net additions	26	5	-	31
Disposals and retirements	(47)	-	-	(47)
Balance at March 31, 2024	$ 1,739	$ 79	$ 4	$ 1,822
Accumulated Depreciation				
Balance at April 1, 2022	$ (794)	$ (29)	$ (4)	$ (827)
Depreciation expense	(78)	(4)	-	(82)
Disposals and retirements	376	-	-	376
Balance at March 31, 2023	(496)	(33)	(4)	(533)
Depreciation expense	(77)	(3)	-	(80)
Disposals and retirements	-	-	-	-
Balance at March 31, 2024	$ (573)	$ (36)	$ (4)	$ (613)
Net carrying amounts				
At March 31, 2023	$ 1,264	$ 41	$ -	$ 1,305
At March 31, 2024	$ 1,166	$ 43	$ -	$ 1,209

Refer to Note 19 for additional information on right-of-use assets and lease liabilities.

Note 13: Intangible Assets

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at April 1, 2022	$ 329	$ 153	$ 535	$ -	$ 52	$ 1,069
Net additions	8	10	44	-	21	83
Disposals and retirements	-	-	(6)	-	-	(6)
Balance at March 31, 2023	337	163	573	-	73	1,146
Net additions	4	17	60	1	7	89
Disposals and retirements	-	-	(34)	-	-	(34)
Balance at March 31, 2024	$ 341	$ 180	$ 599	$ 1	$ 80	$ 1,201
Accumulated Amortization						
Balance at April 1, 2022	$ (4)	$ (103)	$ (322)	$ -	$ -	$ (429)
Amortization expense	(1)	(16)	(65)	-	-	(82)
Disposals and retirements	-	-	4	-	-	4
Balance at March 31, 2023	(5)	(119)	(383)	-	-	(507)
Amortization expense	(1)	(15)	(64)	-	-	(80)
Disposals and retirements	-	-	27	-	-	27
Balance at March 31, 2024	$ (6)	$ (134)	$ (420)	$ -	$ -	$ (560)
Net carrying amounts						
At March 31, 2023	$ 332	$ 44	$ 190	$ -	$ 73	$ 639
At March 31, 2024	$ 335	$ 46	$ 179	$ 1	$ 80	$ 641

Land rights consist primarily of statutory rights of way acquired from the Province in perpetuity. Substantially all of these land rights have indefinite useful lives and are not subject to amortization. These land rights are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset value may not be recoverable.

Note 14: Other Non-Current Assets

(in millions)	**March 31, 2024**	March 31, 2023
Non-current receivables	**$ 123**	$ 134
Sinking funds	**247**	237
Non-current Site C prepaid expenses	**32**	159
Other	**17**	12
	$ 419	$ 542

Non-Current Receivables

Included in the non-current receivables balance are $107 million of receivables (2023—$116 million) from a vendor to aid in the construction of a transmission system. The contributions are to be received in 16 annual payments of approximately $11 million, adjusted for inflation. The fair value of the receivable was initially measured using an estimated inflation rate and a 4.6 per cent discount rate.

Sinking Funds

Investments held in sinking funds are held by the Trustee (the Minister of Finance for the Province) for the redemption of long-term debt. The sinking fund balances include the following investments:

(in millions)	**March 31, 2024**		March 31, 2023	
	Carrying Value	**Weighted Average Effective Rate[1]**	Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$ 145**	**4.9 %**	$ 141	4.1 %
Other provincial government and crown corporation bonds	**89**	**5.2 %**	93	4.4 %
Money market funds	**11**	**-**	-	-
Other	**2**	**-**	3	-
	$ 247		$ 237	

[1]Rate calculated on market yield to maturity.

Effective December 2005, all sinking fund payment requirements on all new and outstanding debt were removed. The existing sinking funds relate to debt that mature in fiscal 2026 and fiscal 2037.

Note 15: Rate Regulation

Regulatory Accounts

The Company has established various regulatory accounts through rate regulation and with the approval of the 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)		**2024**		2023
Net income (decrease) in regulatory balances related to net income	**$**	**495**	$	(1,162)
Net decrease in regulatory balances related to OCI		**(110)**		(282)
	$	**385**	$	(1,444)

For each regulatory account, the amount reflected in the net change column in the following regulatory tables represents the impact on comprehensive income for the applicable year. 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.

(in millions)	*As at April 1 2023*	*Addition / (Reduction)*	*Interest[A]*	*Amortization*	*Net Change[B]*	***As at March 31 2024***	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Heritage Deferral	$ -	$ 47	$ 1	$ 1	$ 49	**$ 49**	Note C
Non-Heritage Deferral	-	1,073	15	$ 4	1,092	**1,092**	Note C
Demand-Side Management	858	128	-	(116)	12	**870**	1-15
Debt Management	67	(53)	-	(14)	(67)	**-**	4-33
First Nations Provisions & Costs	485	22	1	(34)	(11)	**474**	1-9 Note G
Site C	566	(85)	21	-	(64)	**502**	Note E
CIA Amortization	63	(5)	-	-	(5)	**58**	16
Environmental Provisions & Costs	216	30	-	(38)	(8)	**208**	Note F, G
Smart Metering & Infrastructure	130	-	4	(25)	(21)	**109**	5
Inflationary Pressures	-	7	-	-	7	**7**	Note I
IFRS Pension	344	-	-	(38)	(38)	**306**	8
IFRS Property, Plant & Equipment	1,007	-	-	(31)	(31)	**976**	28-37
Total Finance Charges	45	56	-	(13)	43	**88**	Note F
Other Regulatory Accounts	165	86	5	(42)	49	**214**	Note H
Total Regulatory Assets	3,946	1,306	47	(346)	1,007	**4,953**	
Regulatory Liabilities							
Heritage Deferral	32	(32)	-	-	(32)	**-**	Note C
Non-Heritage Deferral	110	(110)	-	-	(110)	**-**	Note C
Trade Income Deferral	1,190	538	52	(44)	546	**1,736**	Note D
Debt Management	-	110	-	4	114	**114**	4-33
Biomass Energy Program Variance	75	52	3	(3)	52	**127**	Note C
Low Carbon Fuel Credits Variance	48	15	2	(2)	15	**63**	Note C
Inflationary Pressures	58	(59)	1	-	(58)	**-**	Note I
Non-Current Pension Costs	854	8	-	30	38	**892**	3-13
PEB Current Pension Costs	38	35	-	(8)	27	**65**	Note F
Electric Vehicle Rebate	-	70	1	-	71	**71**	Note I
Other Regulatory Accounts	74	(39)	4	(6)	(41)	**33**	Note H
Total Regulatory Liabilities	2,479	588	63	(29)	622	**3,101**	
Net Regulatory Asset	$ 1,467	$ 718	$ (16)	$ (317)	$ 385	**$ 1,852**	

(in millions)	As at April 1 2022	Addition / (Reduction)	Interest[A]	Amortization	Net Change[B]	As at March 31 2023	Remaining recovery/ reversal period (years)
Regulatory Assets							
Heritage Deferral Account	$ 105	$ (96)	$ 2	$ (11)	$ (105)	$ -	Note C
Load Variance	33	(32)	-	(1)	(33)	-	Note C
Demand-Side Management	868	101	-	(111)	(10)	858	1-15
Debt Management	286	(201)	-	(18)	(219)	67	5-34
First Nations Provisions & Costs	469	49	1	(34)	16	485	1-9 Note G
Site C	542	6	18	-	24	566	Note E
CIA Amortization	68	(5)	-	-	(5)	63	17
Environmental Provisions & Costs	234	15	(1)	(32)	(18)	216	Note F, G
Smart Metering & Infrastructure	151	-	5	(26)	(21)	130	6
IFRS Pension	382	-	-	(38)	(38)	344	9
IFRS Property, Plant & Equipment	1,039	-	-	(32)	(32)	1,007	29-38
Other Regulatory Accounts	213	39	4	(46)	(3)	210	Note H
Total Regulatory Assets	4,390	(124)	29	(349)	(444)	3,946	
Regulatory Liabilities							
Heritage Deferral Account	-	25	-	7	32	32	Note C
Non-Heritage Deferral Account	185	(51)	8	(32)	(75)	110	Note C
Trade Income Deferral Account	504	747	26	(87)	686	1,190	Note D
Biomass Energy Program Variance	40	40	2	(7)	35	75	Note C
Low Carbon Fuel Credits						-	Note C
Inflationary Pressures	-	57	1	-	58	58	Note I
Load Variance	-	28	-	5	33	33	Note C
Non-Current Pension Costs	669	155	-	30	185	854	4-13
Other Regulatory Accounts	81	62	3	(19)	46	127	Note H
Total Regulatory Liabilities	1,479	1,063	40	(103)	1,000	2,479	
Net Regulatory Asset	$ 2,911	$ (1,187)	$ (11)	$ (246)	$ (1,444)	$ 1,467	

A As permitted by the BCUC, interest charges were accrued to certain regulatory account balances at BC Hydro's weighted average cost of debt which was 3.6 per cent for the year ended March 31, 2024 (2023—3.3 per cent).

B Net change includes a net increase to net income of $495 million (2023—$1.16 billion net decrease) and a net decrease to other comprehensive income of $110 million (2023—$282 million).

C The balances in these regulatory accounts are recovered in rates through the Deferral Account Rate Rider (DARR), which is an additional charge or refund on customer bills and generally has a recovery period of 4 to 6 years. In its Decision on the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, the BCUC approved the requested DARR refund to customers of 1.0 per cent (2023—2.0 per cent) for fiscal 2024, effective April 1, 2023. In its Decision on the Application for Approval to Set the Fiscal 2025 Deferral Account Rate Rider, the BCUC approved the requested DARR refund to customers of 2.5 per cent for fiscal 2025, effective April 1, 2024.

D The Trade Income Deferral Account balance was recovered through the DARR in fiscal 2024 as described in footnote C above. Commencing in fiscal 2025, the balance will be recovered over a three year period, through the Trade Income Rate Rider (TIRR), which is a separate additional charge or refund on customer bills. In its Decision on the Application for Approval to Set the Fiscal 2025 Trade Income Rate Rider, the BCUC approved the requested TIRR refund of 2.3 per cent for fiscal 2025, effective April 1, 2024.

E In its Decision on the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, the BCUC approved the recovery of the balance in this account over the forecasted weighted average expected useful life of the Site C assets, currently estimated at 84 years, commencing in fiscal 2025.

F The balances forecast to be in these accounts at the end of a test period are recovered over the next test period. A test period refers to the period covered by a revenue requirements application filing.

G The First Nations Provisions & Costs and Environmental Provisions & Costs regulatory accounts include both expenditures and provisions (costs to be incurred in future years). Actual expenditures are recovered over the term identified. The provision balance becomes recoverable at such time as actual expenditures are incurred and transferred to the respective regulatory cost account.

H Other Regulatory Accounts includes various accounts with recovery periods ranging from 1 to 20 years.

I The recovery period for this account will be determined by the BCUC as part of a future regulatory proceeding.

Rate Regulation

On April 21, 2023, the BCUC issued an initial decision on BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (F2023—F2025 RRA) and subsequently on June 19, 2023, the BCUC issued its final decision. In its final decision, the BCUC approved a bill increase of 2.2 per cent for fiscal 2024.

The decisions also directed BC Hydro to file for approval of the rates for the new Trade Income Rate Rider (TIRR) and the Deferral Account Rate Rider (DARR), annually, commencing in fiscal 2025. On February 20, 2024, the BCUC issued its decision on BC Hydro's Application for Approval to Set the Fiscal 2025 Deferral Account Rate Rider and Trade Income Rate Rider and Reconsideration Related to the Trade Income Rate Rider. The BCUC approved the requested DARR refund to customers of 2.5 per cent and TIRR refund to customers of 2.3 per cent for fiscal 2025. The resulting bill increase in fiscal 2025 is 2.3 per cent. The BCUC also approved the requested Rate Smoothing Regulatory Account to capture the remainder of the TIRR balance that would otherwise have been refunded on customer bills in fiscal 2025. There is no balance in the Rate Smoothing Regulatory Account as at March 31, 2024.

On December 21, 2023 BC Hydro filed with the BCUC its Performance Based Regulation plan to be used for rate-setting, starting April 1, 2025, as well as a Request for Reconsideration of Performance Based Regulation (Reconsideration). The Reconsideration proposed a continuation of cost of service for rate-setting until further order of the BCUC. On March 15, 2024, the BCUC issued its decision approving BC Hydro to file its revenue requirements applications based on a forecast cost of service approach until further order of the BCUC. BC Hydro is required to file a report by the end of December 2028 assessing whether its operating environment has changed such that Performance Based Regulation has become feasible.

On December 22, 2023, BC Hydro submitted an application to the BCUC to request for a new Remote Communities Electrification (RCE) Repayment regulatory account. On March 8, 2024, the BCUC approved BC Hydro's request for the RCE Repayment regulatory account and recovery over the next test period. The RCE Repayment regulatory account was included within other regulatory accounts—assets in the table above and has a balance of $15 million as at March 31, 2024.

On March 7, 2024, BC Hydro submitted an application to the BCUC to request for a new Electric Vehicle Rebate regulatory account. This account is intended to capture revenue from specified low carbon fuel credits, cost of issuing electric vehicle rebates and forecast variances in program expenditures on administration and marketing. Administration and marketing costs were requested to be recovered over the following test period in the Application for Approval of the Electric Vehicle Rebate regulatory account. Revenue from specified low carbon fuel credits and cost of issuing electric vehicle rebates are expected to self-clear over time.

Heritage Deferral Account

This account is intended to mitigate the impact of certain cost and revenue variances between the forecast costs and revenues in a revenue requirements application and actual costs and revenues associated with the Company's hydroelectric and thermal generating facilities. The account balance is recovered through the DARR, which is an additional charge or refund on customer bills. In its Decision to the F2023-F2025 Revenue Requirements Application, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2024. The DARR table mechanism is a sliding scale that determines the level of the DARR based on the forecast net balance of the cost of energy variance accounts (i.e., the Heritage Deferral account, the Non-Heritage Deferral account, the Trade Income Deferral account, the Load Variance account, the Biomass Energy Program Variance account and the Low Carbon Fuel Credits Variance Regulatory Account). Commencing in fiscal 2025, the BCUC directed BC Hydro to file for approval of the DARR annually in a filing separate from the RRA to recover the cost of energy variance account balances excluding the Trade Income Deferral account. The BCUC directed that the Trade Income Deferral account be recovered through a new Trade Income Rate Rider commencing in fiscal 2025.

Non-Heritage Deferral Account

This account is intended to mitigate the impact of certain cost and revenue variances between the forecast costs and revenues in a revenue requirements application and actual costs and revenues related to items including all non-heritage energy costs (e.g., costs related to power acquisitions from Independent Power Producers). The account balance is recovered through the DARR, which is an additional charge or credit on customer bills. In its Decision to the F2023-F2025 Revenue Requirements Application, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2024. Commencing in fiscal 2025, the BCUC directed BC Hydro to file for approval of the DARR annually in a filing separate from the RRA to recover the cost of energy variance account balances.

Biomass Energy Program Variance

This account is intended to capture the variances between planned and actual energy purchase and load associated with Biomass energy purchases agreements. This account is also categorized as one of BC Hydro's cost of energy variance accounts and has the same mechanisms for interest charges and recovery applied to it that are applicable to the Non-Heritage Deferral Account. The account balance is recovered through the DARR, which is an additional charge or credit on customer bills. In its Decision to the F2023-F2025 Revenue Requirements Application, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2024. Commencing in fiscal 2025, the BCUC directed BC Hydro to file for approval of the DARR annually in a filing separate from the RRA to recover the cost of energy variance account balances.

Low Carbon Fuel Credits

This account is intended to capture the variances between planned and actual revenue from low carbon fuel credits. This account is categorized as one of BC Hydro's cost of energy variance accounts and has the same mechanisms for interest charges and recovery applied to it that are applicable to the Non-Heritage Deferral Account. The account balance is recovered through the DARR, which is an additional charge or credit on customer bills. In its Decision to the F2023-F2025 Revenue Requirements Application, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2024. Commencing in fiscal 2025, the BCUC directed BC Hydro to file for approval of the DARR annually in a filing separate from the RRA to recover the cost of energy variance account balances.

Trade Income Deferral Account

This account is intended to mitigate the uncertainty associated with forecasting the net income of the Company's trade activities. The impact is to defer the difference between the Trade Income forecast in a revenue requirements application and actual Trade Income. The account balance is recovered through the DARR, which is an additional charge or refund on customer bills. In its Decision to the F2023–F2025 Revenue Requirements Application, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2024. Commencing in fiscal 2025, the Trade Income Deferral Account will be recovered in rates, over a three year period, through the Trade Income Rate Rider (TIRR), which is a separate additional charge or credit on customer bills. The BCUC directed BC Hydro to file for approval of the TIRR annually in a filing separate from the RRA.

Inflationary Pressures

On November 18, 2022, the Province issued Order in Council No. 571, which directed the BCUC to authorize BC Hydro to establish the Inflationary Pressures Regulatory Account and transfer $74 million from the Trade Income Deferral Account to the new account. It also allowed BC Hydro to defer specified costs to the Inflationary Pressures Regulatory Account. On November 28, 2022, the BCUC issued Order No. G–341–22 as directed to authorize BC Hydro to establish the Inflationary Pressures Regulatory Account and transfer $74 million from the Trade Income Deferral Account to the new account. BC Hydro has not requested recovery of the Inflationary Pressures Regulatory Account as of March 31, 2024 but intends to request a recovery mechanism in BC Hydro's next revenue requirements application.

Demand–Side Management

Demand–Side Management expenditures include materials, direct labour and applicable portions of support costs, equipment costs, and incentives, which are not eligible for capitalization. Costs relating to identifiable tangible assets that meet the capitalization criteria are recorded as property, plant and equipment. In March 2017, the Province issued Orders in Council No. 100 and No. 101, which enable BC Hydro to pursue cost–effective electrification and allows for costs related to undertakings pursuant to Order in Council No. 101 to be deferred to the Demand–Side Management Regulatory Account. Annual additions to the Demand–Side Management Regulatory Account are amortized on a straight–line basis over the anticipated 15 year benefit period.

First Nations Provisions & Costs

The First Nations Provisions Regulatory Account includes the present value of future payments and the First Nations Costs Regulatory Account includes the payments related to agreements reached with various First Nations groups. These agreements address settlements related to the construction and operation of the Company's existing facilities and provide compensation for associated impacts. Actual lump sum and annual settlement costs paid pursuant to these settlements are transferred from the First Nations Provisions Regulatory Account to the First Nations Costs Regulatory Account. In addition, annual negotiation costs are deferred to the First Nations Costs Regulatory Account.

Forecast lump sum settlement payments are amortized over 10 years starting in the year of payment, forecast annual settlement payments are amortized in the year of payment, and actual annual negotiation costs are recovered from the First Nations Costs Regulatory Account in the year incurred. Variances between forecast and actual lump sum and annual settlement payments in the current test period are recovered over the following test period.

Non–Current Pension Costs

The Non–Current Pension Costs Regulatory Account captures variances between forecast and actual non–current service costs, such as net interest income or expense related to pension and other post–employment benefit plans. In addition, all re–measurements of the net defined benefit liability are deferred to this account. Amounts deferred during the current test period are amortized at the start of the following test period over the expected average remaining service life of the employee group (currently 13 years).

PEB Current Pension Costs

The Post–Employment Benefit (PEB) Current Pension Costs regulatory account captures variances between forecast and actual costs related to the operating cost portion of post–employment benefits current pension costs. Variances deferred during the current test period are recovered over the following test period.

Site C

Site C Project expenditures incurred in fiscal 2007 through the third quarter of fiscal 2015 were deferred. In December 2014, the Province approved a final investment decision for the Site C Project, resulting in expenditures from that point on that meet the capitalization criteria being capitalized in property, plant and equipment starting in the fourth quarter of fiscal 2015. In its Decision on the F2023–F2025 Revenue Requirements Application, the BCUC approved BC Hydro's request to begin amortizing the balance of the Site C Regulatory Account once the Site C assets are in service in fiscal 2025 over the weighted average expected useful life of the Site C assets, currently estimated at 84 years.

Contributions in Aid (CIA) of Construction Amortization

This account captures the difference in amortization between the 45 year amortization period the Company uses for financial reporting and the 25 year amortization period determined by the BCUC for revenue requirement applications.

Environmental Provisions & Costs

A liability provision and offsetting regulatory asset has been established for environmental compliance and remediation arising from the costs that will likely be incurred to comply with the Federal Polychlorinated Biphenyl (PCB) Regulations enacted under the Canadian Environmental Protection Act, the Asbestos requirements of the Occupational Health and Safety Regulations under the jurisdiction of WorkSafe BC and the remediation of environmental contamination at a property occupied by a predecessor company.

Actual expenditures related to environmental regulatory provisions are transferred to the environmental cost regulatory accounts. Forecast environmental and remediation costs are amortized from the accounts each year. Variances between forecast and actual environmental and remediation expenditures in the current test period are recovered over the following test period.

Smart Metering & Infrastructure

Net operating costs incurred with respect to the Smart Metering & Infrastructure program were deferred through the end of fiscal 2016 when the project was completed. Costs relating to identifiable tangible and intangible assets that meet the capitalization criteria were recorded as property, plant and equipment or intangible assets, respectively. The balance in the regulatory account at the end of fiscal 2016 is being amortized over a period of 13 years, reflecting the remaining period of the overall amortization period of 15 years, which is based on the average life of Smart Metering & Infrastructure assets.

IFRS Pension

Unamortized experience gains and losses on the pension and other post-employment benefit plans recognized at the time of transition to IFRS as part of the Prescribed Standards (the previous accounting standards applicable to BC Hydro that were effective April 1, 2012 to March 31, 2018) were deferred to this regulatory account to allow for recovery in future rates. The account balance is amortized/recovered over 20 years on a straight-line basis beginning in fiscal 2013.

IFRS Property, Plant & Equipment

This account includes the fiscal 2012 incremental costs impacts due to the application of the accounting principles of IFRS to Property, Plant & Equipment to the comparative fiscal year for the adoption of IFRS as part of the Prescribed Standards (the previous accounting standards applicable to BC Hydro that were effective April 1, 2012 to March 31, 2018). In addition, the account includes an annual deferral of overhead costs, ineligible for capitalization under the accounting principles of IFRS that was being phased in over 10 years and the phase in was completed in fiscal 2021. The annual deferred amounts are amortized over 40 years beginning the year following the deferral of the expenditures.

Debt Management

This account captures mark-to-market gains and losses on financial contracts that economically hedge future long-term debt. The realized gains or losses are amortized over the remaining term of the associated long-term debt issuances, commencing in the test period following the test period in which the long-term debt associated with a particular hedge is issued.

Total Finance Charges

This account is intended to mitigate the impact of certain variances that arise between the forecast finance costs in a revenue requirements application and actual finance charges incurred. Variances deferred during the current test period are recovered over the following test period.

Electric Vehicle Rebate

This account is intended to capture revenue from specified low carbon fuel credits, costs of issuing electric vehicle rebates and forecast variances in program expenditures on administration and marketing. Recovery of administration and marketing costs were requested to be recovered over the following test period in the Application for Approval of the Electric Vehicle Rebate regulatory account. Revenue from specified low carbon fuel credits and costs of issuing electric vehicle rebates are expected to self-clear over time.

Other Regulatory Accounts

Other regulatory asset and liability accounts with individual balances less than $50 million include the following: Foreign Exchange Gains and Losses, Amortization of Capital Additions, Real Property Sales, Customer Crisis Fund, Electric Vehicle Public Charging, Depreciation Study, Project Write-off, Mining Customer Payment Plan, Cloud Costs, Cloud Usage Fees, Mandatory Reliability Standards Costs, Load Attraction Costs, Routine Trouble and Storm Restoration Costs, Dismantling Cost, Electrification Customer Connection Costs, Site C Variance Costs, Load Variance, Flow Through Costs, and Remote Community Electrification Repayment.

Note 16: Accounts Payable and Accrued Liabilities

(in millions)	**March 31, 2024**	March 31, 2023
Accounts payable	**$ 454**	$ 613
Accrued liabilities	**1,154**	1,087
Current portion of lease liabilities (Note 19)	**75**	72
Current portion of other long-term liabilities (Note 24)	**174**	130
Other	**55**	51
	$ 1,912	$ 1,953

Note 17: Long-Term Debt and Debt Management

The Company's long-term 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 (2023—$5.50 billion) and is included in revolving borrowings. At March 31, 2024, the outstanding amount under the borrowing program was $4.73 billion (2023—$2.76 billion).

For the year ended March 31, 2024, the Company issued bonds for net proceeds of $862 million (2023—$1.50 billion) and a par value of $900 million (2023—$1.73 billion), a weighted average effective interest rate of 4.4 per cent (2024—4.0 per cent) and a weighted average term to maturity of 20.1 years (2023—18.6 years).

For the year ended March 31, 2024, the Company redeemed bonds with a par value of $200 million (2023—$500 million).

Long-term debt, expressed in Canadian dollars, is summarized in the following table by year of maturity:

(in millions)	**March 31, 2024**					March 31, 2023				
	Canadian	**US**	**Euro**	**Total**	**Weighted Average Interest Rate[1]**	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:										
2024	**$ -**	**$ -**	**$ -**	**$ -**	**-**	$ 200	-	-	$ 200	5.9
2025	**10**	**-**	**-**	**10**	**5.5**	10	-	-	10	5.5
2026	**900**	**677**	**385**	**1,962**	**3.6**	900	676	387	1,963	3.6
2027	**850**	**-**	**-**	**850**	**2.4**	850	-	-	850	2.4
2028	**1,000**	**-**	**-**	**1,000**	**2.8**	1,000	-	-	1,000	2.8
2029	**1,500**	**-**	**-**	**1,500**	**2.8**	-	-	-	-	-
1-5 years	**4,260**	**677**	**385**	**5,322**	**3.0**	2,960	676	387	4,023	3.3
6-10 years	**5,460**	**-**	**202**	**5,662**	**3.2**	6,510	-	-	6,510	3.1
11-15 years	**-**	**406**	**-**	**406**	**7.4**	-	405	203	608	5.2
16-20 years	**3,273**	**-**	**-**	**3,273**	**4.3**	3,273	-	-	3,273	4.3
21-25 years	**6,260**	**-**	**-**	**6,260**	**3.4**	2,565	-	-	2,565	3.7
26-30 years	**3,925**	**-**	**-**	**3,925**	**3.0**	7,170	-	-	7,170	3.0
Over 30 years	**110**	**-**	**-**	**110**	**3.4**	110	-	-	110	3.4
Bonds	**$ 23,288**	**$ 1,083**	**$ 587**	**$ 24,958**	**3.4**	$ 22,588	$ 1,081	$ 590	$ 24,259	3.4
Revolving borrowings	**2,970**	**1,760**	**-**	**4,730**	**5.1**	2,115	643	-	2,758	4.5
	$ 26,258	**$ 2,843**	**$ 587**	**$ 29,688**		$ 24,703	$ 1,724	$ 590	$ 27,017	
Adjustments to carrying value resulting from discontinued hedging activities	**7**	**16**	**-**	**23**		7	18	-	25	
Unamortized premium, discount, and issue costs	**(67)**	**(6)**	**(1)**	**(74)**		(18)	(7)	(2)	(27)	
	$ 26,198	**$ 2,853**	**$ 586**	**$ 29,637**		$ 24,692	$ 1,735	$ 588	$ 27,015	
Less: Current portion	**(2,980)**	**(1,760)**	**-**	**(4,740)**		(2,315)	(643)	-	(2,958)	
Non-current long-term debt	**$ 23,218**	**$ 1,093**	**$ 586**	**$ 24,897**		$ 22,377	$ 1,092	$ 588	$ 24,057	

[1]The weighted average interest rate represents the effective rate of interest on fixed-rate bonds.

The following foreign currency contracts were in place at March 31, 2024 in a net asset position of $15 million (2023—net liability of $8 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

(in millions)	**March 31, 2024**	March 31, 2023
Cross-Currency Swaps		
Euro dollar (€) to Canadian dollar - notional amount[1]	**€ 402**	€ 402
Euro dollar to Canadian dollar - weighted average contract rate	**1.47**	1.47
Weighted remaining term	**4 years**	5 years
Foreign Currency Forwards		
United States dollar (US$) to Canadian dollar - notional amount[1]	**US$ 1,883**	US$ 1,057
United States dollar to Canadian dollar - weighted average contract rate	**1.32**	1.30
Weighted remaining term	**2 years**	4 years

[1]Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.

The following forward swap contracts were in place at March 31, 2024 with a net asset position of $191 million (2023—net asset of $175 million). Such contracts are used to lock in interest rates on future Canadian denominated debt issues. The contracts outstanding relate to $2.88 billion (2023—$2.88 billion) of planned 10 and 30 year debt (2023—10 and 30 year debt) to be issued on dates ranging from June 2024 to October 2026 (2023—June 2023 to October 2026).

(in millions)	**2024**	2023
Forward Swaps		
Canadian dollar - notional amount[1]	**$ 2,875**	$ 2,875
Weighted forecast borrowing yields	**3.57%**	3.19%
Weighted remaining term	**1 years**	1 years

[1]Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.

For more information about the Company's exposure to interest rate, foreign currency and liquidity risk, see Note 23.

Note 18: Supplemental Disclosure of Cash Flow Information

Change in Working Capital and Other Assets and Liabilities:

(in millions)	**2024**	2023
Restricted Cash	**$ (45)**	$ -
Accounts receivable and accrued revenue	**(81)**	(73)
Inventories	**(2)**	(106)
Prepaid expenses	**(14)**	(31)
Other non-current assets	**132**	25
Accounts payable and accrued liabilities	**(522)**	(109)
Unearned revenues, customer credits and contributions in aid	**485**	200
Post-employment benefits	**(3)**	(8)
Other non-current liabilities	**(26)**	2
	$ (76)	$ (100)

Non-Cash Investing Transactions:

(in millions)	**2024**	2023
Contributions in kind received for property, plant and equipment	**$ 60**	$ 55

Reconciliation for liabilities:

(in millions)	**Balance, April 1, 2023**	**Issued**	**Redemptions**	**Foreign exchange movement**	**Other[1]**	**Proceeds (Payments)**	**Balance March 31, 2024**
Long-term debt and revolving borrowings:							
Long-term debt	$ 24,257	$ 862	$ (200)	$ -	$ (12)	$ -	$ 24,907
Revolving borrowings	2,758	9,673	(7,748)	8	39	-	4,730
Total long-term debt and revolving borrowings	27,015	10,535	(7,948)	8	27	-	29,637
Lease liability (Note 19)	1,448	-	-	-	31	(74)	1,405
Vendor financing liability	290	-	-	-	33	(50)	273
Debt-related derivative liability	(175)	-	-	-	(163)	147	(191)
	$ 28,578	$ 10,535	$ (7,948)	$ 8	$ (72)	$ 23	$ 31,124

[1] Other includes new lease liability, fair value adjustments to the debt-related derivative liability, interest, and other non-cash items.

(in millions)	Balance, April 1, 2022	Issued Adjusted - (Note 27)	Redemptions Adjusted - (Note 27)	Foreign exchange movement Adjusted - (Note 27)	Other[1]	Proceeds (Payments)	Balance March 31, 2023
Long-term debt and revolving borrowings:							
Long-term debt	$ 23,159	$ 1,498	$ (500)	$ 115	$ (15)	$ -	$ 24,257
Revolving borrowings	2,792	6,781	(6,919)	82	22	-	2,758
Total long-term debt and revolving borrowings	25,951	8,279	(7,419)	197	7	-	27,015
Lease liability (Note 19)	1,379	-	-	-	186	(117)	1,448
Vendor financing liability	313	-	-	-	20	(43)	290
Debt-related derivative liability	(179)	-	-	-	(201)	205	(175)
	$ 27,464	$ 8,279	$ (7,419)	$ 197	$ 12	$ 45	$ 28,578

[1] Other includes new lease liability, fair value adjustments to the debt-related derivative liability, interest, and other non-cash items.

Note 19: Lease Liabilities

Lease costs

(in millions)	**2024**	2023
Interest on lease liabilities	**$ 46**	$ 46
Variable lease payments not included in the measurement of lease liabilities	**12**	12
Expenses relating to short-term leases and leases of low-value assets	**24**	20
	$ 82	$ 78

Amounts recognized in the statement of cash flows

(in millions)	**2024**	2023
Total cash outflow for leases	**$ 110**	$ 148

Maturity analysis

(in millions)	**March 31, 2024**	March 31, 2023
Maturity analysis - contractual undiscounted cash flows		
Less than 1 year	**$ 120**	$ 119
1 to 5 years	**435**	443
More than 5 years	**1,428**	1,479
Total Undiscounted Lease Liabilities	**$ 1,983**	$ 2,041

(in millions)	**March 31, 2024**	March 31, 2023
Current	**$ 75**	$ 72
Non-current	**1,330**	1,376
Total Lease Liabilities	**$ 1,405**	$ 1,448

Long-term energy purchase agreements

The Company has entered into some long-term energy purchase agreements that are considered to be a lease. The long-term energy purchase agreements have terms ranging from 4.5 years to 30 years with no option to renew. The lease payments are adjusted annually for changes in the consumer price index, and these amounts are included in the measurement of the lease liability. The variable lease payments/recoveries for these long-term energy purchase agreement leases for the year ended March 31, 2024 was $11 million (2023—$10 million payment). See note 26 for long-term energy purchase agreements with related parties.

Property leases

The Company leases land and building for its office space and operation use. The property leases typically run for a period of 2 years to 99 years. Some leases include an option to renew the leases for an additional period ranging from 1 year to 10 years.

Some leases require the Company to make payments that relate to the property taxes, insurance payments and operating costs; these amounts are generally determined annually. These variable lease payments for the year ended March 31, 2024 was $1 million (2023—$2 million).

Other leases

The Company also leases vehicles, office equipment and other equipment. These vehicle leases are short-term, and office and other equipment leases are short-term and/or leases of low value items. The Company has elected not to recognize right-of-use assets and lease liabilities as a result of the practical expedients used as noted in note 3(r).

Note 20: Unearned Revenues and Contributions in Aid

(in millions)	**March 31, 2024**	March 31, 2023
Unearned revenues	**$ 317**	$ 325
Contributions in aid	**2,560**	2,398
	2,877	2,723
Less: Current portion, unearned revenues	**(43)**	(44)
Less: Current portion, contributions in aid	**(66)**	(64)
	$ 2,768	$ 2,615

Note 21: 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 year, there were no changes in the approach to capital management.

The debt to equity ratio at March 31, 2024, and March 31, 2023 was as follows:

(in millions)	**March 31, 2024**	March 31, 2023
Total debt, net of sinking funds	**$ 29,390**	$ 26,778
Less: Cash and cash equivalents	**(96)**	(148)
Net Debt	**$ 29,294**	$ 26,630
Retained earnings	**$ 7,677**	$ 7,354
Contributed surplus	**60**	60
Accumulated other comprehensive loss	**(41)**	(58)
Total Equity	**$ 7,696**	$ 7,356
Net Debt to Equity Ratio	**79 : 21**	**78 : 22**

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 has not achieved a debt to equity ratio of 60:40 there was no payment for the year ended March 31, 2024 and March 31, 2023.

Note 22: Post-Employment Benefits

The Company provides a defined benefit statutory pension plan (registered under the British Columbia Pension Benefits Standards Act) to substantially all employees, as well as supplemental arrangements which provide pension benefits in excess of statutory limits. Pension benefits are based on years of membership service and highest five-year average pensionable earnings. The plan also provides pensioners a conditional indexing fund. Employees make equal basic and indexing contributions to the plan funds based on a percentage of current pensionable earnings as prescribed by the independent actuary. The Company may contribute additional amounts as prescribed by the independent actuary. The Company is responsible for ensuring that the defined benefit statutory pension plan has sufficient assets to pay the pension benefits. The supplemental arrangements are not funded. The defined benefit pension plans are administered under a defined governance structure. The pension arrangements including investment, plan benefits and funding decisions are administered by the Company's Pension Management Committee with the oversight resting with the Board of Directors. Significant changes to the plans, investment policies, and funding policies require the approval of the Board of Directors. The most recent actuarial funding valuation for the statutory pension plan was performed at December 31, 2021. The next valuation for funding purposes is required no later than December 31, 2024.

The Company also provides post-employment benefits other than pensions including limited medical, extended health, dental and life insurance coverage for retirees who have at least 10 years of service and qualify to receive pension benefits. Certain benefits, including the short-term continuation of health care and life insurance, are provided to terminated employees or to survivors on the death of an employee. These post-employment benefits other than pensions are not funded. Post-employment benefits include the pay out of benefits that vest or accumulate, such as banked vacation.

By their design, defined benefit pension plans and other post-employment benefit plans expose the Company to various risks such as investment performance, reductions in discount rates used to value the obligations, increased longevity of plan members and future inflation levels impacting future salary increases, as well as future increases in healthcare costs.

Information about the pension benefit plans and post-employment benefits other than pensions is as follows:

(a) The expense for the Company's benefit plans for the years ended March 31, 2024 and 2023 is recognized in the following line items in the statement of comprehensive income prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions:

	Pension Benefit Plans		Other Benefit Plans		Total	
(in millions)	**2024**	2023	**2024**	2023	**2024**	2023
Current service costs charged to personnel expense - operating expenses	**$ 94**	$ 110	**$ 5**	$ 5	**$ 99**	$ 115
Net interest costs charged to finance costs	**29**	36	**8**	8	**37**	44
Total post-employment benefit plan expense	**$ 123**	$ 146	**$ 13**	$ 13	**$ 136**	$ 159

Actuarial gain recognized in other comprehensive income was $103 million (2023—$251 million).

(b) Information about the Company's defined benefit plans, in aggregate, is as follows:

	Pension Benefits Plans		Other Benefits Plans		Total	
(in millions)	**March 31, 2024**	March 31, 2023	**March 31, 2024**	March 31, 2023	**March 31, 2024**	March 31, 2023
Defined benefit obligation of funded plan	**$ (5,294)**	$ (4,980)	**$ -**	$ -	**$ (5,294)**	$ (4,980)
Defined benefit obligation of unfunded plans	**(166)**	(161)	**(176)**	(171)	**(342)**	(332)
Fair value of plan assets	**4,944**	4,581	**-**	-	**4,944**	4,581
Plan deficit	**$ (516)**	$ (560)	**$ (176)**	$ (171)	**$ (692)**	$ (731)
Represented by:						
Accrued benefit plan liability	**$ (516)**	$ (560)	**$ (176)**	$ (171)	**$ (692)**	$ (731)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2024 and fiscal 2023 in accordance with IFRIC 14, The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction.

(c) Movement of defined benefit obligations and defined benefit plan assets during the year:

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	**March 31, 2024**	March 31, 2023	**March 31, 2024**	March 31, 2023
Defined benefit obligation				
Opening defined benefit obligation	**$ 5,141**	$ 5,270	**$ 171**	$ 180
Current service cost	**94**	110	**5**	5
Interest cost on benefit obligations	**309**	213	**8**	8
Benefits paid[1]	**(216)**	(213)	**(6)**	(5)
Employee contributions	**56**	47	**-**	-
Actuarial losses (gains)[2]	**76**	(286)	**(2)**	(17)
Defined benefit obligation, end of year	**5,460**	5,141	**176**	171
Fair value of plan assets				
Opening fair value	**4,581**	4,557	n/a	n/a
Interest income on plan assets[3]	**280**	182	n/a	n/a
Employer contributions	**57**	51	n/a	n/a
Employee contributions	**56**	47	n/a	n/a
Benefits paid[1]	**(207)**	(204)	n/a	n/a
Actuarial gains (losses)[2,3]	**177**	(52)	n/a	n/a
Fair value of plan assets, end of year	**4,944**	4,581	**-**	-
Accrued benefit liability	**$ (516)**	$ (560)	**$ (176)**	$ (171)

[1] Benefits paid under Pension Benefit Plans include $13 million (2023 - $19 million) of settlement payments.

[2] Actuarial gains/losses are included in the Non-Current Pension Costs Regulatory Account and for fiscal 2024 are comprised of $177 million of actuarial gains on return on plan assets (2023 - $52 million actuarial losses) and $74 million of actuarial losses (2023 - $303 million actuarial gains) on the benefit obligations mainly due to discount rate decreases.

[3] Actual income on defined benefit plan assets for the year ended March 31, 2024 was $457 million (2023 - $130 million).

(d) The significant assumptions adopted in measuring the Company's accrued benefit obligations as at each March 31 year end are as follows:

	Pension Benefit Plans		Other Benefit Plans	
	March 31, 2024	March 31, 2023	**March 31, 2024**	March 31, 2023
Discount rate				
Benefit cost	**4.96%**	4.38%	**4.92%**	4.19%
Accrued benefit obligation	**4.89%**	4.96%	**4.87%**	4.92%
Rate of return on plan assets	**4.96%**	4.38%	**n/a**	n/a
Rate of compensation increase				
Benefit cost	**3.50%**	3.50%	**3.50%**	3.50%
Accrued benefit obligation	**3.50%**	3.50%	**3.50%**	3.50%
Health care cost trend rates				
Weighted average health care cost trend rate	**n/a**	n/a	**3.47%**	3.47%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**3.47%**	3.47%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	**n/a**	n/a

The valuation cost method for the accrued benefit obligation is the projected unit credit method pro-rated on service.

(e) Defined benefit statutory pension plan assets are invested prudently in order to meet the Company's pension obligations. The pension plan's investment strategy is to hold a diversified mix of investments by asset class and geographic location in order to reduce investment-specific risk to the funded status while maximizing the expected returns to meet pension obligations. Investment of the plan's assets follows an asset/liability framework as investment is conducted with consideration of the pension obligation's sensitivity to interest rates which is a key risk factor impacting the obligation's value.

In developing the pension plan's asset mix, the Company includes, but is not limited to the following factors:

- the nature of the underlying benefit obligations, including the duration and term profile of the liabilities;
- the member demographics, including expectations for normal retirements, terminations, and deaths;
- the financial position of the pension plan;
- the diversification benefits obtained by the inclusion of multiple asset classes; and
- expected asset returns, including asset and liability correlations, along with liquidity requirements of the plan.

To implement the asset mix policy, the Company may invest in fixed interest investments (such as debt instruments), equity securities, and alternative investments. The Company's defined benefit statutory pension plan assets are primarily comprised of debt and equity securities and alternative investments.

The publicly traded equity securities are unadjusted quoted market prices in an active market (Level 1) and the publicly traded fixed interest investments generally have quoted market prices or observable market inputs for similar assets in an active market (Level 2). Alternative investments include private fund investments including infrastructure, renewable resources, real estate, mortgages and private equity and debt, all of which usually do not have quoted market prices available (Level 3). These fund assets are valued by external managers and independent valuators using accepted industry valuation methods and models.

(f) Asset allocation of the defined benefit statutory pension plan as at the measurement date:

	Long Term Strategic Target Allocation	Target Range Min	Target Range Max	March 31, 2024	March 31, 2023
Fixed interest investments	20%	15%	35%	**20%**	20%
Public equities	40%	30%	50%	**42%**	42%
Real estate	15%	10%	20%[1]	**14%**	15%
Private equities	15%	10%	20%[1]	**15%**	15%
Infrastructure and renewable resource:	10%	5%	15%[1]	**9%**	8%

[1]The total cannot exeed 50%.

Plan assets are re-balanced within ranges around target applications. The Company's expected return on plan assets is determined by considering long-term historical returns, future estimates of long-term investment returns, and asset allocations.

(g) Other information about the Company's benefit plans is as follows:

The Company's contribution to be paid to its funded defined benefit statutory pension plan in fiscal 2025 is expected to amount to $61 million. The expected benefit payments to be paid in fiscal 2025 in respect to the unfunded defined benefit plans are $19 million.

The following table presents the maturity profile of the Company's defined benefit statutory pension plan obligation:

(in millions, except weighted average duration and plan participants)

Number of plan participants as at March 31, 2024		16,119
Actual benefit payments 2024	$	207
Benefits expected to be paid 2025	$	218
Benefits expected to be paid 2026	$	222
Benefits expected to be paid 2027	$	227
Benefits expected to be paid 2028	$	232
Benefits expected to be paid 2029	$	238
Benefits expected to be paid 2030-2033	$	1,001
Weighted average duration of defined benefits payments		13.9 years

Assumptions adopted can have a significant effect on the value of the obligations for defined benefit pension and other post-employment benefit plans and are based on historical experience and market inputs. The increase (decrease) in obligation in the following table has been determined for key assumptions assuming all other assumptions are held constant. In practice, this is unlikely to occur, as changes in some of the assumptions may be correlated. The two tables below present the sensitivity analysis of key assumptions for 2024.

Assumed healthcare cost trend rates have a significant effect on the amounts recognized in net income. A one percentage point change in assumed healthcare cost trend rates would have the following effects:

		2024	
(in millions)	increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Healthcare cost trend	1 % increase	$ 7	$ -
Healthcare cost trend	1% decrease	(5)	-

The impact on the defined benefit obligation for the Pension Benefit Plans of changing certain of the major assumptions is as follows:

		2024	
(in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	-528	-32
Discount rate	1% decrease	+666	+44
Longevity	1 year increase	+108	+3
Longevity	1 year decrease	-111	-3
Compensation	1% increase	+166	+19
Compensation	1% decrease	-144	-16

Note 23: Financial Instruments

Financial Risk Management Overview

The Company is exposed to a number of financial risks in the normal course of its business operations, including market risks resulting from fluctuations in commodity prices, interest rates and foreign currency exchange rates, as well as credit risks and liquidity risks. The nature of the financial risks and the Company's strategy for managing these risks has not changed significantly from the prior year. Risk management strategies and policies are employed to ensure that any exposures to these risks are in compliance with the Company's business objectives and risk tolerance levels set out in the Company's Treasury Risk Management Policy and Liability Risk Management Annual Strategic Plan. Responsibility for the oversight of risk management is held by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

The following discussion is limited to the nature and extent of risks arising from financial instruments, as defined under IFRS 7, Financial Instruments: Disclosures. However, for a complete understanding of the nature and extent of financial risks the Company is exposed to, this note should be read in conjunction with the Company's discussion of Risk Management found in the Management's Discussion and Analysis section of the 2023/24 Annual Service Plan Report.

(a) Credit Risk

Credit risk refers to the risk that one party to a financial instrument will cause a financial loss for a counterparty by failing to discharge an obligation. The Company is exposed to credit risk related to cash and cash equivalents, restricted cash, accounts receivable, non-current receivables, sinking fund investments, and derivative instruments.

The Company manages financial institution credit risk through a Board-approved Treasury Risk Management Policy. Exposures to credit risks are monitored on a regular basis. Large customers are assessed for credit quality by taking into account external credit ratings, where available, an analysis of financial position and liquidity, past experience and other factors. The Company assigns credit limits for counterparties based on evaluations of their financial condition, net worth, credit ratings, and other credit criteria. For some customers, security over accounts receivable may be obtained in the form of a security deposit.

Maximum credit risk with respect to financial assets is limited to the carrying amount presented on the consolidated statement of financial position with the exception of U.S. dollar sinking funds and non-current receivables which are classified as amortized cost and carried on the consolidated statement of financial position at $247 million and $123 million, respectively. The maximum credit risk exposure for the U.S. dollar sinking funds and non-current receivables as at March 31, 2024 is their fair value of $245 million and $122 million, respectively.

(b) Liquidity Risk

Liquidity risk refers to the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages liquidity risk by forecasting cash flows to identify financing requirements and by maintaining a commercial paper borrowing program under an agreement with the Province (see Note 17). The Company's long-term debt comprises bonds and revolving borrowings obtained under an agreement with the Province. Cash from operations reduces the Company's liquidity risk. The Company does not believe that it will encounter difficulty in meeting its obligations associated with financial liabilities.

(c) Market Risks

Market risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk, and other price risk, such as changes in commodity prices. The Company monitors its exposure to market fluctuations and may use derivative contracts to manage these risks, as it considers appropriate.

(i) Currency Risk

Currency risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. The Company's currency risk is primarily with the U.S. dollar.

The majority of the Company's currency risk arises from long-term debt in the form of U.S. dollar denominated bonds. Energy commodity prices are also subject to currency risk as they are primarily denominated in U.S. dollars. As a result, the Company's trade revenues and purchases of energy commodities, such as electricity and natural gas, and associated accounts receivable and accounts payable, are affected by the Canadian/U.S. dollar exchange rate. In addition, all commodity derivatives and contracts priced in U.S. dollars are also affected by the Canadian/U.S. dollar exchange rate.

The Company actively manages its currency risk through its Treasury Risk Management Policy. The Company uses cross-currency swaps and forward foreign exchange purchase contracts to achieve and maintain foreign currency exposure targets.

(ii) Interest Rate Risk

Interest rate risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is exposed to changes in interest rates primarily through its variable rate debt and the active management of its debt portfolio including its related sinking fund assets and temporary investments. The Company actively manages its interest rate risk through its Treasury Risk Management Policy.

The Company uses interest rate swaps and bond locks to lock in interest rates on future debt issues to protect against rising interest rates.

(iii) Commodity Price Risk

Commodity price risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company has exposure to movements in prices for commodities including electricity, natural gas, environmental products and other associated products. Prices for electricity and natural gas fluctuate in response to changes in supply and demand, market uncertainty, and other factors beyond the Company's control.

The management of commodity price risk is governed by risk management policies with oversight from either the BC Hydro or subsidiary Board of Directors. Risk management strategies, policies and limits are designed to ensure the Company's risks and related exposures are aligned with the Company's business objectives and risk tolerance. Risk management policies and procedures are reviewed regularly to reflect changes in market conditions and the Company's activities.

Categories of Financial Instruments

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at March 31, 2024 and 2023:

	March 31, 2024		March 31, 2023		**2024**	2023
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value	**Interest Income (Expense) recognized in Finance Charges**	Interest Income (Expense) recognized in Finance Charges
Fair Value Through Profit or Loss (FVTPL):						
Cash equivalents - short-term investments	**$ 31**	**$ 31**	$ 70	$ 70	**$ 11**	$ 6
Amortized Cost:						
Cash	**65**	**65**	78	78	**-**	-
Restricted cash	**45**	**45**	-	-	**-**	-
Accounts receivable and accrued revenue	**984**	**984**	894	894	**-**	-
Non-current receivables	**123**	**122**	134	135	**5**	11
Sinking funds	**247**	**245**	237	239	**10**	10
Accounts payable and accrued liabilities	**(1,912)**	**(1,912)**	(1,953)	(1,953)	**-**	-
Revolving borrowings	**(4,730)**	**(4,730)**	(2,758)	(2,758)	**(181)**	(60)
Long-term debt (including current portion due in one year)	**(24,907)**	**(22,846)**	(24,257)	(22,800)	**(837)**	(814)
First Nations liabilities (non-current portion)	**(440)**	**(464)**	(435)	(467)	**(20)**	(18)
Lease liabilities (non-current portion)	**(1,330)**	**(1,330)**	(1,376)	(1,376)	**(46)**	(46)
Other liabilities (non-current portion)	**(404)**	**(390)**	(409)	(397)	**(19)**	(20)

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. The carrying value of cash equivalents, restricted cash, accounts receivable and accrued revenue, accounts payable and accrued liabilities, and revolving borrowings approximates fair value due to the short duration of these financial instruments.

Hedges

As permitted by the transitional provision for hedge accounting under IFRS 9, the Company has elected to continue with the hedging requirements of IAS 39, Financial Instruments: Recognition and Measurement (IAS 39) and not adopt the hedging requirements of IFRS 9.

The following foreign currency contracts under hedge accounting were in place at March 31, 2024 in a net asset position of $13 million (2023—net liability $5 million). Such contracts are used to hedge the principal on US$ denominated long–term debt and the principal and coupon payments on Euro€ denominated long–term debt for which hedge accounting has been applied. The hedging instruments are effective in offsetting changes in the cash flows of the hedged item attributed to the hedged risk. The main source of hedge ineffectiveness in these hedges is credit risk.

($ amounts in millions)	**March 31, 2024**	March 31, 2023
Cross- Currency Hedging Swaps		
EURO€ to CAD$ - notional amount[1]	**€ 402**	€ 402
EURO€ to CAD$ - weighted average contract rate	**1.47**	1.47
Weighted remaining term	**4 years**	5 years
Foreign Currency Hedging Forwards		
US$ to CAD$ - notional amount[1]	**US$ 573**	US$ 573
US$ to CAD$ - weighted average contract rate	**1.25**	1.25
Weighted remaining term	**6 years**	7 years

[1]Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.

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

(in millions)	**March 31, 2024 Fair Value**	March 31, 2023 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)	**$ 30**	$ 29
Foreign currency contract liabilities (cash flow hedges for EURO€ denominated long-term debt)	**(17)**	(34)
	13	**(5)**
Non-Designated Derivative Instruments:		
Interest rate contract assets	**212**	199
Interest rate contract liabilities	**(21)**	(24)
Foreign currency contract asset (liabilities)	**2**	(3)
Commodity derivative assets	**162**	585
Commodity derivative liabilities	**(485)**	(738)
	(130)	19
Net (liabilities) assets	**$ (117)**	$ 14

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

The derivatives are represented on the consolidated statement of financial position as follows:

(in millions)	**March 31, 2024**	March 31, 2023
Current portion of derivative financial instrument assets	**$ 267**	$ 494
Current portion of derivative financial instrument liabilities	**(305)**	(474)
Derivative financial instrument assets, non-current	**145**	319
Derivative financial instrument liabilities, non-current	**(224)**	(325)
Net (liabilities) assets	**$ (117)**	$ 14

For designated cash flow hedges for the year ended March 31, 2024, there was a gain of $17 million (2023—gain of $18 million). The effective portion was recognized in other comprehensive income. For the year ended March 31, 2024, $nil (2023—$91 million) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange gains (2023—losses) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $2.88 billion (2023—$2.88 billion), used to economically hedge the interest rates on future debt issuances, there was a $92 million increase (2023—$69 million) in the fair value of these contracts for the year ended March 31, 2024. For interest rate contracts associated with debt issued, there was a $71 million increase (2023—$132 million) in the fair value of contracts that settled during the year ended March 31, 2024. The net increase for the year ended March 31, 2024 of $163 million (2023—$201 million) in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had a liability balance of $114 million as at March 31, 2024.

Foreign currency contracts for cash management purposes not designated as hedges, for the year ended March 31, 2024, had a loss of $1 million (2023—loss of $1 million) recognized in finance charges. Foreign currency contracts associated with U.S. revolving borrowings not designated as hedges, for the year ended March 31, 2024, had a gain of $14 million (2023—gain of $84 million) recognized in finance charges. These economic hedges offset $8 million of foreign exchange revaluation losses (2023—losses of $82 million) recorded in finance charges with respect to U.S. revolving borrowings for the year ended March 31, 2024.

For commodity derivatives not designated as hedges, a net loss of $600 million (2023—gain of $929 million) was recorded in trade revenue for the year ended March 31, 2024.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)		**2024**		2023
Deferred inception loss, beginning of the year	**$**	**(15)**	$	(26)
New transactions		**73**		70
Amortization		**(26)**		(57)
Foreign currency translation gain		**(1)**		(2)
Deferred inception gain (loss), end of the year	**$**	**31**	$	(15)

Credit risk

Domestic Electricity Receivables

A customer application and a credit check are required prior to initiation of services. For customers with no BC Hydro credit history, the Company ensures accounts are secured either by a credit bureau check, a cash security deposit, or a credit reference letter.

The value of the current domestic and trade accounts receivable, by age and the related provision for doubtful accounts are presented in the following table:

Current Domestic and Trade Accounts Receivable Net of Allowance for Doubtful Accounts

(in millions)		**March 31, 2024**		March 31, 2023
Current	**$**	**340**	$	495
Past due (30-59 days)		**33**		26
Past due (60-89 days)		**8**		6
Past due (More than 90 days)		**5**		2
		386		529
Less: Allowance for doubtful accounts		**(5)**		(8)
	$	**381**	$	521

Financial Assets Arising from the Company's Trading Activities

The Company's management of credit risk generally includes evaluation of counterparty's credit quality, establishment of credit limits, and measurement, monitoring and mitigation of exposures. The Company assesses the creditworthiness of counterparties before entering into contractual obligations, and then reassesses changes on an ongoing basis. Credit risk is managed through securing, where appropriate, corporate guarantees, cash collateral, letters of credit, or third party credit insurance, and through the use of master netting agreements and margining provisions in contracts. Counterparty exposures are monitored on a daily basis against established credit limits. The Company's counterparties span a variety of industries. There is no significant industry concentration of credit risk.

The following table sets out the carrying amounts of recognized financial instruments presented in the consolidated statement of financial position on a gross basis that are subject to derivative master netting agreements or similar agreements:

(in millions)		Gross Derivative Instruments		Related Instruments Not Offset		Net Amount
As at March 31, 2024						
Derivative commodity assets	**$**	**162**	**$**	**5**	**$**	**157**
Derivative commodity liabilities		**485**		**5**		**480**
As at March 31, 2023						
Derivative commodity assets	$	585	$	9	$	576
Derivative commodity liabilities		738		9		729

Liquidity risk

The following table details the remaining contractual maturities at March 31, 2024 of the Company's non-derivative financial liabilities and derivative financial liabilities, which are based on contractual undiscounted cash flows. Interest payments have been computed using contractual rates or, if floating, based on rates current at March 31, 2024. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2024 has been used.

(in millions)	Carrying Value	Fiscal 2025	Fiscal 2026	Fiscal 2027	Fiscal 2028	Fiscal 2029	Fiscal 2030 *and thereafter*
Non-Derivative Financial Liabilities							
Total accounts payable and other payables (excluding interest accruals and current portion of lease obligations and First Nations liabilities)	$ 1,560	$ (1,560)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	29,875	(5,631)	(2,796)	(1,613)	(1,741)	(2,228)	(28,429)
Lease obligations	1,405	(120)	(118)	(112)	(102)	(103)	(1,428)
Other long-term liabilities	884	(64)	(171)	(75)	(72)	(59)	(1,750)
Total Non-Derivative Financial Liabilities	33,724	(7,375)	(3,085)	(1,800)	(1,915)	(2,390)	(31,607)
Derivative Financial Liabilities							
Cross currency swaps used for hedging	17						
Cash outflow		(14)	(405)	(5)	(5)	(5)	(217)
Cash inflow		5	390	2	2	2	208
Other forward foreign exchange contracts designated at fair value	5						
Cash outflow		(809)	-	-	-	-	-
Cash inflow		804	-	-	-	-	-
Interest rate swaps used for hedging	21	(11)	(5)	(7)	-	-	-
Net commodity derivatives	323	(192)	(42)	(14)	(31)	(10)	(25)
Total Derivative Financial Liabilities	366	(217)	(62)	(24)	(34)	(13)	(34)
Total Financial Liabilities	34,090	(7,592)	(3,147)	(1,824)	(1,949)	(2,403)	(31,641)
Derivative Financial Assets							
Forward foreign exchange contracts used for hedging	(30)						
Cash outflow		-	(436)	-	-	-	(283)
Cash inflow		-	464	-	-	-	311
Other forward foreign exchange contracts designated at fair value	(7)						
Cash outflow		(962)	-	-	-	-	-
Cash inflow		970	-	-	-	-	-
Interest rate swaps used for hedging	(212)	157	62	-	-	-	-
Total Derivative Financial Assets	(249)	165	90	-	-	-	28
Net Financial Liabilities	**$ 33,841**	**$ (7,427)**	**$ (3,057)**	**$ (1,824)**	**$ (1,949)**	**$ (2,403)**	**$ (31,613)**

Market risks

(a) Currency Risk

Sensitivity Analysis

For changes in the U.S. dollar to Canadian dollar exchange rate, an increase (decrease) of $0.01 at March 31, 2024 would otherwise have a negative (positive) impact on net income before movement in regulatory balances of $4 million, but as a result of regulatory accounting, it would have no impact on net income or other comprehensive income as all gains and losses will be captured in the Total Finance Charges Regulatory Account or the Foreign Exchange Gains/Losses Regulatory Account. This analysis assumes that all other variables, in particular interest rates, remain constant.

This sensitivity analysis has been determined assuming that the change in foreign exchange rates had occurred at March 31, 2024 and been applied to each of the Company's exposures to currency risk for both derivative and non-derivative financial instruments in existence at that date, and that all other variables remain constant. The stated change represents management's assessment of reasonably possible changes in foreign exchange.

(b) Interest Rate Risk

Sensitivity Analysis

For variable rate non-derivative instruments, an increase (decrease) of 100-basis points in interest rates at March 31, 2024 would otherwise have a negative (positive) impact on net income before movement in regulatory balance of $46 million, but as a result of regulatory accounting, it would have no impact on net income or other comprehensive income as all gains and losses will be captured in the Total Finance Charges Regulatory Account. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant.

For the interest rate contracts, an increase of 100-basis points in interest rates at March 31, 2024 would otherwise have a positive impact on net income of $325 million and a decrease of 100 basis points in interest rates at March 31, 2024 would otherwise have a negative impact on net income before movement in regulatory balances of $400 million, but as a result of regulatory accounting, it would have no impact on net income or other comprehensive income as all gains and losses will be captured in the Debt Management Regulatory Account.

This sensitivity analysis has been determined assuming that the change in interest rates had occurred at March 31, 2024 and been applied to each of the Company's exposure to interest rate risk for non-derivative financial instruments in existence at that date, and that all other variables remain constant.

The stated change represents management's assessment of reasonably possible changes in interest rates over the period until the next consolidated statement of financial position date.

(c) Commodity Price Risk

Sensitivity Analysis

Commodity price risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in commodity prices.

The Company has exposure to movements in prices for commodities including electricity, natural gas, environmental products and associated derivative products. Prices for electricity and natural gas commodities fluctuate in response to changes in supply and demand, market uncertainty, and other factors beyond the Company's control.

The Company manages these exposures through its risk management policies, which limit components of and overall market risk exposures, pre-defined approved products and mandate regular reporting of exposures.

The Company's risk management policies for trading activities defines various limits and controls, including Value at Risk (VaR) limits, Mark-to-Market limits, and various transaction specific limits which are monitored on a daily basis. VaR is a statistical estimate of potential loss in value of the Company's positions due to adverse market movements with a specific level of confidence, over a specific time period. The Company calculates over a 10-day holding period, within a 95 per cent confidence level, resulting from normal market fluctuations.

The VaR model, an industry standard Monte Carlo model, uses historical information to determine potential future volatility and correlation, assuming that price movements in the recent past are indicative of near-term future price movements. It cannot forecast unusual events which can lead to extreme price movements. In addition, it is sometimes difficult to appropriately estimate VaR associated with illiquid or non-standard products. As a result, the Company uses additional measures to supplement the use of VaR to estimate price risk. These include the use of a Historic VaR methodology, stress tests and notional limits for illiquid or emerging products.

The VaR for commodity derivatives, calculated under this methodology, was approximately $15 million at March 31, 2024 (2023—$30 million).

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 March 31, 2024 and 2023:

As at March 31, 2024 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 31	$ -	$ -	$ 31
Derivatives designated as hedges	-	30	-	30
Derivatives not designated as hedges	110	226	46	382
	$ 141	$ 256	$ 46	$ 443

As at March 31, 2024 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (17)	$ -	$ (17)
Derivatives not designated as hedges	(119)	(253)	(140)	$ (512)
	$ (119)	$ (270)	$ (140)	$ (529)

As at March 31, 2023 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 70	$ -	$ -	$ 70
Derivatives designated as hedges	-	29	-	29
Derivatives not designated as hedges	409	218	157	784
	$ 479	$ 247	$ 157	$ 883

As at March 31, 2023 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (34)	$ -	$ (34)
Derivatives not designated as hedges	(195)	(158)	(412)	(765)
	$ (195)	$ (192)	$ (412)	$ (799)

The Company's policy is to recognize level transfers at the end of each period during which the change occurred. During the year, commodity derivatives with a negative carrying amount of $6 million (2023—$6 million) were transferred from Level 2 to Level 1.

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

(in millions)	
Balance as at April 1, 2023	**$ (255)**
Unrealized gains	201
Realized losses	(40)
Balance as at March 31, 2024	**$ (94)**

(in millions)	
Balance as at April 1, 2022	**$ (83)**
Unrealized losses	(232)
Realized gains	60
Balance as at March 31, 2023	**$ (255)**

During the year, no commodity derivatives (2023– no transfers) were transferred between Level 3 to Level 2.

During the year ended March 31, 2024, unrealized gain of $113 million (2023—loss of $246 million) were recognized on Level 3 derivative commodity financial 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 percent. Forward commodity prices used in determining Level 3 base fair value at March 31, 2024 range between $0–$526 per MWh and a 10 percent increase/decrease in certain components of these prices would decrease/increase fair value by $25 million. A 10 percent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $4 million.

Note 24: Other Non-Current Liabilities

(in millions)		March 31, 2024		March 31, 2023
Provisions				
Environmental liabilities	$	**242**	$	270
Decommissioning obligations		**62**		70
Other		**73**		39
		377		379
First Nations liabilities		**458**		452
Other contributions		**217**		221
Other liabilities		**464**		432
		1,516		1,484
Less: Current portion, included in accounts payable and accrued liabilities		**(174)**		(130)
	$	**1,342**	$	1,354

Changes in each class of provision during the financial year are set out below:

(in millions)		Environmental		Decommissioning		Other		Total
Balance at April 1, 2022	$	**296**	$	**80**	$	**31**	$	**407**
Made during the period		9		-		9		18
Used during the period		(51)		(7)		(2)		(60)
Changes in estimate		9		(5)		1		5
Accretion		7		2		-		9
Balance at March 31, 2023	$	**270**	$	**70**	$	**39**	$	**379**
Made during the period		-		-		58		58
Used during the period		(62)		(5)		(18)		(85)
Changes in estimate		26		(5)		(6)		15
Accretion		8		2		-		10
Balance at March 31, 2024	$	**242**	$	**62**	$	**73**	$	**377**

Environmental Liabilities

The Company has recorded a liability for the estimated future environmental expenditures related to present or past activities of the Company. The Company's recorded liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

At March 31, 2024, the undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2025 and 2045, is approximately $317 million and was determined based on current cost estimates. A range of discount rates between 3.3 per cent and 3.5 per cent were used to calculate the net present value of the obligations.

Decommissioning Obligations

The Company's decommissioning obligation provision consists of estimated removal and destruction costs associated with certain PCB and asbestos contaminated assets and certain submarine cables. The Company has determined its best estimate of the undiscounted amount of cash flows required to settle remediation obligations at $93 million (2023—$103 million), which will be settled between fiscal 2025 and 2053. The undiscounted cash flows, discounted by a range of discount rates between 3.3 per cent and 3.5 per cent, were used to calculate the net present value of the obligations. The obligations are re-measured at each period end to reflect changes in estimated cash flows and discount rates.

First Nations Liabilities

The First Nations liabilities consist primarily of settlement costs related to agreements reached with various First Nations groups. First Nations liabilities are recorded as financial liabilities and are measured at fair value on initial recognition with future contractual cash flows being discounted at rates ranging from 4.4 per cent to 5.0 per cent. These liabilities are measured at amortized cost and not re-measured for changes in discount rates. The First Nations liabilities are non-interest bearing.

Other Contributions

Other contributions consist of contribution from a vendor to aid in the construction of a transmission system. Contributions include payment received and also contributions to be received (refer to Note 14) and are being recognized as an offset to the applicable energy purchase costs over the life of the energy purchase agreement.

Other Liabilities

Other liabilities mainly include a contractual obligation associated with the construction of a capital project. This contractual obligation has an implicit interest rate of 7 per cent and a repayment term of 15 years commencing in fiscal 2019. This liability is measured at amortized cost and not re-measured for changes in discount rates. In addition, other liabilities also include long-term payables to other goods and service providers.

Note 25: Commitments and Contingencies

Energy Commitments

BC Hydro (excluding Powerex) has long-term energy and capacity purchase contracts to meet a portion of its expected future domestic electricity requirements. The expected obligations to purchase energy under these contracts have a total value of approximately $43.62 billion of which approximately $68 million relates to the purchase of natural gas, natural gas transportation contracts and wheeling agreements. The remaining commitments are at predetermined prices.

Included in the total value of the long-term energy purchase agreements is $1.82 billion accounted for as a lease liability under Note 19. The total BC Hydro combined payments are estimated to be approximately $1.54 billion for less than one year, $6.39 billion between one and five years, and $35.69 billion for more than five years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $3.81 billion extending to 2053 (including a purchase commitment with the Province of $2.22 billion). The total Powerex energy purchase commitments are estimated to be approximately $0.83 billion for less than one year, $1.69 billion between one and five years, and $1.29 billion for more than five years.

Powerex has energy sales commitments of $3.59 billion extending to 2033 with estimated amounts of $1.02 billion for less than one year, $1.69 billion between one and five years, and $881 million for more than five years.

Lease and Service Agreements

The Company has entered into various agreements to lease facilities or assets or service agreements supporting operations. The agreements cover periods of up to 99 years, and the aggregate minimum payments are approximately $1.35 billion. Included in the total value of the lease agreements is $164 million accounted for as a lease liability under Note 19. Payments are $92 million for less than one year, $280 million between one and five years, and $977 million for more than five years.

Refer to Note 11 for commitments pertaining to major property, plant and equipment projects.

Contingencies and Guarantees

a) Facilities and Rights of Way: the Company is subject to existing and pending legal claims relating to alleged infringement and damages in the operation and use of facilities owned by the Company. These claims may be resolved unfavourably with respect to the Company and may have a significant adverse effect on the Company's financial position. For existing claims in respect of which settlement negotiations have advanced to the extent that potential settlement amounts can reasonably be predicted, management has recorded a liability for the potential costs of those settlements. For pending claims, management believes that there is a risk that any loss exposure that may ultimately be incurred may differ materially from management's current estimates. Management has not disclosed the ranges of expected outcomes due to the potentially adverse effect on the negotiation process for these claims.

b) Due to the size, complexity and nature of the Company's operations, various other legal matters are pending. It is not possible at this time to predict with any certainty the outcome of such litigation. Management believes that any settlements related to these matters will not have a material effect on the Company's consolidated financial position or results of operations.

c) The Company and its subsidiaries have outstanding letters of credit totaling $64 million (2023—$128 million). The total outstanding letters of credit also includes US $17 million (2023—US $20 million) in foreign denominated letters of credit.

Note 26: Related Party Transactions

Subsidiaries

The principal subsidiaries of BC Hydro are Powerex and Powertech.

All companies are wholly owned and incorporated in Canada and all ownership is in the form of common shares. Operating out of Vancouver, BC, Canada, Powerex is a wholesale energy marketer, whose activities include trading electricity, environmental products, natural gas, and related financial and physical energy products in North America. Powertech offers services to solve technical problems with power equipment and systems in Canada and throughout the world.

All intercompany transactions and balances are eliminated upon consolidation.

Related Parties

As a Crown Corporation, the Company and the Province, including all ministries, crown corporations and agencies under the Province's control are considered related parties. All transactions between the Company and its related parties are considered to possess commercial substance and are consequently recorded at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

The related party transactions are summarized below:

(in millions)	March 31, 2024	March 31, 2023
Consolidated Statement of Financial Position		
Prepaid expenses	**$ 87**	$ 109
Right-of-use assets	**1,167**	1,204
Accounts payable and accrued liabilities	**92**	112
Net Derivative assets	**191**	260
Lease liabilities	**1,314**	1,342

	2024	2023
Amounts incurred/accrued during the year include:		
Water rental fees	**362**	358
Energy Purchases	**609**	419
Grants and Taxes	**170**	159
Interest	**1,018**	874
Interest and foreign exchange derivatives settlement proceeds	**(156)**	(287)
Lease payments	**59**	102
Other	**28**	75

In addition, the Company's debt is either held or guaranteed by the Province (see Note 17). Under an agreement with the Province, the Company indemnifies the Province for any credit losses incurred by the Province related to interest rate and foreign currency contracts entered into by the Province on the Company's behalf. As at March 31, 2024, the aggregate exposure under this indemnity totaled $250 million (2023—$229 million). The Company has not experienced any losses to date under this indemnity. Future contractual arrangements with the Province pertaining to energy purchases are disclosed under Note 25.

The Site C Project requires the realignment of six segments of Highway 29 with a total length of approximately 30 kilometers. The highway re-alignment activities are needed for reservoir inundation which is required prior to the first generating unit in service forecasted for December 2024. The Province (Ministry of Transportation and Infrastructure) maintains effective control over the highway during the re-alignment activities and after these activities are complete. During fiscal year 2024, BC Hydro incurred total costs of approximately $49 million (2023—$103 million) on highway re-alignment activities, of which $26 million (2023—$61 million) was paid directly to the Province. As of March 31, 2023, all six segments of Highway 29, including the new bridges, have been opened to traffic and are being operated by the Ministry of Transportation and Infrastructure.

BC Hydro is a Part 3 Fuel Supplier of British Columbia's low carbon fuel standard program and as a participant receives Low Carbon Fuel Credits from the Province, and these are sold to customers through a competitive process.

All other transactions with the Province, including all ministries, crown corporations and agencies under the Province's control occurred in the normal course of operations, and are not considered to be individually or collectively significant.

Key Management Personnel and Board Compensation

Key management personnel and board compensation includes compensation to the Company's executive management team and board of directors.

(in millions)	2024	2023
Short-term employee benefits	**$ 4**	$ 5
Post-employment benefits	**1**	2

Note 27: Adjustments to Comparative Figures

BC Hydro has changed its prior year's comparative figures for the following items:

(a) As stated in Note 2, BC Hydro has changed its accounting policy for presenting certain electricity imports and electricity exports from trade revenues to separately present electricity imports as operating expenses (part of electricity and gas purchases) and electricity exports as domestic revenues. Domestic revenues now include sales to customers within the province of British Columbia, sales that are surplus to domestic load requirements (included within other sales category in Note 4), and certain sales of energy outside the province that are under long-term contracts (included within other sales category in Note 4). Sales outside the province besides those described above are classified as Trade revenue.

The change resulted in classification differences in the statement of comprehensive income but had no impact to net income or to the statements of cash flows, changes in equity, and financial position.

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

(in millions)	*For the year ended March 31, 2023* As originally reported	Adjustment	As Adjusted
Revenues (Note 4)			
Domestic	$ 5,304	$ 678	$ 5,982
Trade	2,723	(227)	2,496
Revenues	8,027	451	8,478
Expenses			
Operating expenses (Note 5)	6,009	451	6,460
Finance charges (Note 6)	496	-	496
Net Income Before Movement in Regulatory Balances	1,522	-	1,522
Net movement in regulatory balances (Note 15)	(1,162)	-	(1,162)
Net Income	$ 360	$ -	$ 360

(b) 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:

(in millions)	*For the year ended March 31, 2023* As originally reported	Adjustment	As Adjusted
Operating Activities			
Other items	$ 47	$ 82	$ 129
Cash provided by operating activities	2,519	82	2,601
Financing Activities			
Receipt of revolving borrowings	7,438	(657)	6,781
Repayment of revolving borrowings	(7,494)	575	(6,919)
Cash provided by financing activities	1,062	(82)	980

The change also impacted the prior year's comparative figures in Note 18.

Appendix D

Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	2024	2023[1]	2022[2]	2021	2020[3]
Revenues					
Domestic	**$ 5,504**	$ 5,982	$ 5,619	$ 5,237	$ 5,393
Trade	**1,627**	2,496	1,972	1,177	876
	7,131	8,478	7,591	6,414	6,269
Expenses					
Energy costs	**3,725**	3,574	3,002	2,269	2,370
Other operating expenses[4]	**1,675**	1,538	1,427	1,366	1,372
Amortization and depreciation	**1,071**	1,052	1,079	1,009	988
Grants and taxes	**316**	296	286	254	254
Finance charges	**516**	496	521	224	1,666
	7,303	6,956	6,315	5,122	6,650
Net Income (Loss) Before Movement in Regulatory Balances	**(172)**	1,522	1,276	1,292	(381)
Net movement in regulatory balances	**495**	(1,162)	(608)	(604)	1,086
Net Income	**$ 323**	$ 360	$ 668	$ 688	$ 705
Property, Plant and Equipment, Right-of-Use Assets and Intangible Assets					
Property, Plant and Equipment	**$ 40,108**	$ 36,926	$ 34,038	$ 31,677	$ 29,427
Right-of-Use Assets	**1,209**	1,305	1,248	1,317	1,405
Intangible Assets	**641**	639	640	688	678
Net Book Value	**$ 41,958**	$ 38,870	$ 35,926	$ 33,682	$ 31,510
Property, Plant and Equipment and Intangible Asset Expenditures					
Sustaining	**$ 1,477**	$ 1,211	$ 1,119	$ 971	$ 955
Growth	**2,786**	2,708	2,356	2,236	2,127
Total Property, Plant and Equipment and Intangible Asset Expenditures [5]	**$ 4,263**	$ 3,919	$ 3,475	$ 3,207	$ 3,082
Net Long-Term Debt [6]	**$ 29,294**	$ 26,630	$ 25,642	$ 24,740	$ 23,354
Retained Earnings	**$ 7,677**	$ 7,354	$ 6,994	$ 6,326	$ 5,638
Debt to Equity Ratio	**79 : 21**	78 : 22	78 : 22	80 : 20	81 : 19

[1] In 2023/24, as described in Note 2 of the Financial Statements, BC Hydro changed its accounting policy related to the presentation of electricity imports and electricity exports. As a result, the comparative period 2022/23 was restated.

[2] In 2021/22, certain amounts have been reclassified to conform to the 2022/23 presentation.

[3] In 2019/20, certain amounts have been reclassified to conform to the 2020/21 presentation.

[4] Other operating expenses consists of personnel expenses, materials and external services, other costs (net of recoveries), and capitalized costs as per the operating expenses note in the consolidated financial statements.

[5] Total property, plant and equipment, and intangible asset expenditures are different from the amount of property, plant and equipment, and intangible asset expenditures in the Consolidated Statements of Cash Flows due to the effect of accruals related to these expenditures.

[6] Consists of long-term debt, including the current portion, net of sinking funds and cash and cash equivalents.

OPERATING STATISTICS

for the years ended or as at March 31	2024	2023[1]	2022	2021	2020[2]
Generating Capacity (megawatts)					
Hydroelectric	**12,041**	12,041	12,027	12,027	11,932
Thermal	**176**	174	179	177	177
Total	**12,217**	12,215	12,206	12,204	12,109
Peak One-Hour Integrated System Demand (megawatts)	**11,363**	10,977	10,787	10,076	10,577
Number of Domestic Customer Accounts					
Residential	**1,990,321**	1,961,208	1,931,041	1,896,518	1,863,569
Light industrial and commercial	**226,151**	223,915	221,573	218,196	215,063
Large industrial	**204**	203	201	202	198
Other	**3,380**	3,367	3,387	3,383	3,396
Total	**2,220,056**	2,188,693	2,156,202	2,118,299	2,082,226
Domestic Electricity Sold (gigawatt-hours)					
Residential	**19,171**	19,547	19,440	18,983	17,993
Light industrial and commercial	**19,205**	19,247	19,029	18,091	18,692
Large industrial	**14,032**	13,437	13,312	12,438	13,398
Other sales	**3,005**	7,649	1,671	1,628	1,848
Total	**55,413**	**59,880**	53,452	51,140	51,931

Revenues (in millions)

for the years ended March 31	2024	2023[1]	2022	2021	2020[2]
Residential	**$ 2,129**	$ 2,146	$ 2,342	$ 2,210	$ 2,169
Light industrial and commercial	**1,913**	1,840	1,952	1,830	1,942
Large industrial	**866**	848	854	762	850
Other sales	**596**	1,148	471	435	432
Total Domestic	**5,504**	**5,982**	5,619	5,237	5,393
Trade	**1,627**	2,496	1,972	1,177	876
Total	**$ 7,131**	**$ 8,478**	$ 7,591	$ 6,414	$ 6,269

Average Revenue (per kilowatt-hour)

for the years ended or as at March 31	2,024	2,023	2022	2021	2020
Residential	**11.1¢**	11.0¢	12.0¢	11.6¢	12.1¢
Light industrial and commercial	**10.0**	9.6	10.3	10.1	10.4
Large industrial	**6.2**	6.3	6.4	6.1	6.3

Average Annual Kilowatt-Hour Use Per Residential Customer Account	**9,703**	10,044	10,158	10,097	9,735
Lines In Service					
Distribution (kilometres)	**60,474**	60,289	60,093	59,907	59,694
Transmission (circuit kilometres)	**20,198**	20,192	20,148	19,958	20,389

[1] In 2023/24, as described in Note 2 of the Financial Statements, BC Hydro changed its accounting policy related to the presentation of electricity imports and electricity exports. As a result, the comparative period 2022/23 was restated.

[2] BC Hydro entered into a new energy Transfer Pricing Agreement with Powerex in 2020/21 replacing a previous agreement which was established in 2002/03. As a result, the comparative period 2019/20 was restated for presentation changes between domestic and trade revenue and cost of energy ($ and GwH).

TOTAL ELECTRICITY SALES AND SOURCES OF SUPPLY

for the years ended March 31	2024			2023[1]			2022			2021			2020[2]		
	Generating Capacity (megawatts)	**Gigawatt-Hours**	**%**	Generating Capacity (megawatts)	Gigawatt-Hours	%	Generating Capacity (megawatts)	Gigawatt-Hours	%	Generating Capacity (megawatts)	Gigawatt-Hours	%	Generating Capacity (megawatts)	Gigawatt-Hours	%
Electricity Sales															
Domestic	**12,217**	**55,413**	**79.4**	12,215	59,880	77.7	12,206	53,452	70.3	12,204	51,140	67.6	12,109	51,931	73.2
Electricity trade		**10,118**	**14.5**		12,018	15.6		17,836	23.5		19,407	25.7		14,346	20.2
		65,531	**93.9**		71,898	93.4		71,288	93.8		70,547	93.3		66,277	93.4
Line loss and system use		**4,259**	**6.1**		5,119	6.6		4,709	6.2		5,104	6.7		4,651	6.6
		69,790	**100.0**		77,017	100.0		75,997	100.0		75,651	100.0		70,928	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,857**	**8,824**	**12.6**	2,857	13,497	17.5	2,857	15,626	20.6	2,857	15,907	21.0	2,778	12,605	17.8
Revelstoke	**2,480**	**6,148**	**8.8**	2,480	9,410	12.2	2,480	8,548	11.2	2,480	9,218	12.2	2,480	7,286	10.3
Mica	**2,746**	**5,282**	**7.6**	2,746	8,733	11.3	2,746	7,681	10.1	2,746	8,669	11.5	2,746	6,262	8.8
Kootenay Canal	**583**	**2,245**	**3.2**	583	2,300	3.0	583	2,780	3.7	583	2,626	3.5	583	2,377	3.4
Peace Canyon	**694**	**2,214**	**3.2**	694	3,319	4.3	694	3,791	5.0	694	3,893	5.1	694	3,051	4.3
Seven Mile	**805**	**2,549**	**3.7**	805	2,906	3.8	805	2,936	3.9	805	3,039	4.0	805	2,842	4.0
Bridge River	**491**	**2,070**	**3.0**	491	2,588	3.4	478	2,578	3.4	478	2,219	2.9	478	2,367	3.3
Other	**1,385**	**3,641**	**5.2**	1,385	3,384	4.4	1,384	4,125	5.2	1,384	4,225	5.6	1,368	3,592	5.1
	12,041	**32,973**	**47.3**	12,041	46,137	59.9	12,027	48,065	63.1	12,027	49,796	65.8	11,932	40,382	57.0
Thermal generation	**176**	**105**	**0.2**	174	174	0.2	179	125	0.2	177	150	0.2	177	172	0.2
Purchases from Independent Power Producers		**13,667**	**19.6**		15,409	20.0		16,824	22.1		14,630	19.3		14,474	20.4
Non-integrated energy purchases		**115**	**0.2**		117	0.2		119	0.2		109	0.1		110	0.2
Market purchases		**24,288**	**34.8**		16,005	20.8		11,857	15.6		11,321	15.0		16,371	23.1
Other		**(1,358)**	**(2.1)**		(825)	(1.1)		(993)	(1.3)		(355)	(0.5)		(581)	(0.8)
	12,217	**69,790**	**100.0**	12,215	77,017	100	12,206	75,997	99.9	12,204	75,651	100.0	12,109	70,928	100.0

[1] In 2023/24, as described in Note 2 of the Financial Statements, BC Hydro changed its accounting policy related to the presentation of electricity imports and electricity exports. As a result, the comparative period 2022/23 was restated.

[2] BC Hydro entered into a new energy Transfer Pricing Agreement with Powerex in 2020/21 replacing a previous agreement which was established in 2002/03. As a result, the comparative period 2019/20 was restated for presentation changes between domestic and trade revenue and cost of energy ($ and GwH).

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