BC Hydro and Power Authority

2024/25
Annual Service Plan Report

August 2025

For more information on BC Hydro please contact us at:

333 Dunsmuir Street

Vancouver. BC

V6B 5R3

Lower Mainland

604 BCHYDRO

(604 224 9376)

Outside Lower Mainland

1 800 BCHYDRO

(1 800 224 9376)

Or visit our website at: bchydro.com

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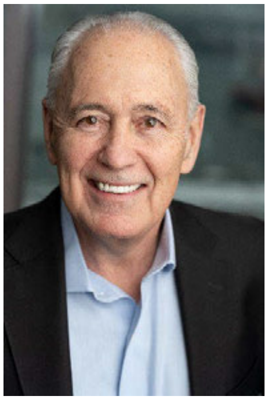
Board Chair's Accountability Statement



The BC Hydro and Power Authority 2024/25 Annual Service Plan Report compares the organization's actual results to the expected results identified in the 2024/25 – 2026/27 Service Plan published in 2024.The Board is accountable for those results as reported.

Signed on behalf of the Board by:

Glen Clark
Board Chair
August 13, 2025

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Letter from the Board Chair & CEO

On behalf of the Board of Directors and all of BC Hydro, we are pleased to present BC Hydro's Annual Service Plan Report for the fiscal year ending March 31, 2025. This year's report reflects on a period of meaningful progress amid global uncertainty, and reaffirms our commitment to delivering reliable and affordable electricity. At the same time, it highlights our efforts to grow British Columbia's economy, advance reconciliation with First Nations, and support the people and communities we serve.

The demand for electricity continues to grow – and that's why we are expanding both our electricity supply and the infrastructure that delivers power to homes, businesses and fast-growing communities through the province.

The [2024 Call for Power] marked the opening of the next chapter in B.C.'s energy generation future. Through this competitive process, we awarded electricity purchase agreements to 10 new renewable energy projects, which together will generate enough power for approximately 500,000 homes. These projects will deliver electricity at a significantly lower cost than our last call for power in 2010 (adjusted for inflation), and each includes First Nations equity ownership between 49 and 51 percent.

We also achieved a major milestone at Site C, which began generating electricity in this year. Of the six generating units, four began operating this year. Site C will play a critical role in meeting electricity demand.

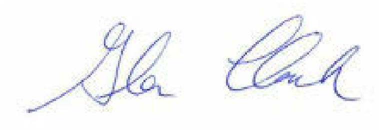
In parallel, we launched a new $700 million Energy Efficiency Plan in 2024/25, significantly increasing investments in energy-saving tools, technologies, programs and rebates. These measures are expected to deliver 2,000 gigawatt hours in electricity savings – enough to power approximately 200,000 homes – and will save customers at least $80 million annually.

In 2024/25, we also advanced work on our largest Capital Plan to date: a $36 billion, 10-year investment to modernize and expand B.C.'s generation, transmission, and distribution infrastructure. This work will help strength our economy while creating skilled jobs and long-term economic benefits across the province.

While we are investing billions in our electrical system, affordability remains a central priority. Our rates remain among the lowest in North America, and this year, we introduced an optional residential time-of-day rate and an optional residential flat rate to provide customers with more choices and new opportunities to save on their bills. We also eliminated higher rates in non-integrated areas that are not connected to BC Hydro's main transmission grid to promote more equitable access to electricity for all British Columbians.

Planning for extreme weather is increasingly important. From powerful storms that cause outages, to wildfires threatening infrastructure, and droughts affecting how we manage our system, these events are having a growing impact. Our crews continue to respond quickly and effectively, restoring power safely, and planning for a wide range of operating conditions to ensure reliability for our customers.

We are proud of what we accomplished this year. As we look ahead, we will continue to invest in the infrastructure, innovation and partnerships that will drive B.C.'s economy forward.



Glen Clark
Board Chair
August 13, 2025

Charlotte Mitha
President & CEO
August 13, 2025

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 2024 and expanded upon in the Board Chair's 2023 Mandate Letter from the Minister Responsible shaped the goals, objectives, performance measures and financial plan outlined in BC Hydro's 2024/25 – 2026/27 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 is publicly owned by the people of British Columbia. We generate and provide electricity to 95 percent of B.C.'s population and serve approximately five million people. The electricity we generate and deliver to customers throughout the province powers our economy and quality of life.

As a provincial Crown Corporation, BC Hydro reports to the Provincial Government through the Minister of Energy and Climate Solutions. 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
- The Clean Power Action Plan
- Powering Our Future: BC's Clean Energy Strategy
- CleanBC and the 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[1] 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

At BC Hydro, safety, service and reliability are our top priorities. As a utility operating in a high-hazard industry, we are committed to ensuring that every employee, contractor, and person interacting with our system returns home safely each day.

Electricity demand is increasing in British Columbia driven by population growth, housing construction, increased industrial development, and a shift from fossil fuels to renewable electricity in homes and businesses. With 98% of our electricity in B.C. coming from renewable sources, electrification offers consumers and industry a pathway to grow the economy and reduce carbon emissions.

With more people needing our renewable electricity, we've taken steps to balance affordability for customers while making critical investments to maintain and grow our power system. 2024/25 was a year of decisive steps forward in planning for our energy future while mitigating rising costs and economic uncertainty where possible. In delivering on our commitments and responsibilities to British Columbians, we continued to implement our $36 billion Capital Plan to sustain and grow our power system, create jobs, and drive economic growth across the province. These investments are essential to ensure a reliable and sustainable power supply for the future. At the same time, we focused on finding ways to keep electricity affordable for British Columbians, providing stability as we navigated changing economic conditions.

As our customers energy needs evolve and increasingly turn to our renewable electricity, we've worked hard to find new ways to connect customers to our system, help them manage their electricity use, and provide choices that save money and encourage British Columbians to reduce their emissions. This includes continuing to evolve our customer affordability toolkit (e.g. more rate options, low-income conservation programs, flexible payment options, and our customer crisis fund).

In December 2024, we welcomed a new Board Chair and, in March 2025, Chris O'Riley, BC Hydro's longest-serving CEO, announced his retirement, effective August 2025. Charlotte Mitha will serve as our new President & CEO, beginning on August 1, 2025. Tariffs, and the resulting economic flux from Canada's largest trading partner, the United States, created

[1] *As per Provincial direction, the terms clean electricity, clean energy, and clean power are used in this report to be consistent with the language used in BC Hydro's 2024/25 Service Plan, which was published in February 2024*

uncertainty in British Columbia, emphasizing BC Hydro’s important role in supporting our economy and building for our energy security. Through times of transition and uncertainty, our dedicated and highly skilled workforce consistently demonstrated our ability to continue to deliver safe and reliable power while taking decisive action to respond to the changing environment and support key policy priorities.

The impacts of climate change and severe weather continued to affect BC Hydro's operations. In 2024, over 1.4 million customers experienced weather-related power outages, the most in BC Hydro's history. The unprecedented number of outages was primarily due to three powerful storms that hit the South Coast and Vancouver Island in November and December. These storms were among the five largest in the past decade, resulting in about one million customer outages combined. Despite a record-breaking number of outages due to severe weather, BC Hydro crews were able to restore power more quickly, with three-quarters of customers who experienced an unplanned outage rating BC Hydro’s response time as good or very good.

Wildfires continued to be a threat to our infrastructure, with approximately $15 million in response and repair costs. In 2024/25, we continued to collaborate with other agencies to monitor and manage forest fire risks. Crews underwent regular training and maintained an inventory of essential materials for quick deployment in affected areas. Managing vegetation on and near electrical rights-of-way has become increasingly important to minimize the risk of outages caused by falling trees and branches.

Weather and inflow conditions that affect BC Hydro’s reservoirs are variable from year-to-year. Some years they are higher or lower than average and the variation can change seasonally. Starting in fall 2022, British Columbia has experienced a historic drought that continued to impact BC Hydro’s reservoirs in 2024/25. With the rain in the fall of 2024, the drought designations were removed for most of B.C.’s basins and the seasonal water supply forecasts for the Columbia and Williston reservoirs improved. Reservoir conditions continued to evolve based on rainfall and snowpack and we continued to plan for a range of inflow and operating conditions, as we have done for decades.

In 2024/25 we remained committed to strengthening relationships with Indigenous communities, creating economic opportunities, and advancing reconciliation. Our United Nations Declaration of the Rights of Indigenous Peoples (UNDRIP) Action Plan guided our efforts to ensure First Nations see meaningful benefits from our work to deliver safe and reliable power in British Columbia. This included advancing First Nations procurement, employment, and ownership opportunities.

Report on Performance: Goals, Objectives, and Results

The following goals, objectives and performance measures have been restated from the 2024/25 – 2026/27 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, safe and reliable operations supported by strategic investments to strengthen our system are key to ensuring we provide our customers with clean electricity that they can count on to meet their energy needs.

Key results

- No employee fatalities or permanently disabling injuries in 2024/25.
- Increased hazard tree and edge tree removals by more than 100% compared to five-year averages to improve reliability during severe weather events.
- Conducted 10 public safety risk assessments province-wide, following Canadian Dam Association guidelines, to evaluate public access near our infrastructure and identify opportunities to enhance safety.

Summary of progress made in 2024/25

Safety remains our priority at BC Hydro, meeting our target of zero Fatalities and Permanently Disabling Injuries in 2024/25. It has now been nearly 15 years since our last employee fatality in 2010. This year, we enhanced our Safety Framework to better learn from incidents and we improved our risk awareness and response through a revised management review processes and a new Serious Incident Management Standard.

This year, we completed work on our Distribution Action Plan to improve safety and reliability across our operations, in response to a review of the BC Hydro vault explosion in February 2023. It focused activities on preventing future incidents, as well as recommendations related to process changes, tool enhancements, and worker and public safety. This included BC Hydro's approach to the management of safety incidents, the role culture plays in BC Hydro's safety performance, and enhancements to the broad maintenance program applied to the distribution portfolio including different key systems and tools. At the end of F2025, all planned activities have been successfully completed and the project has been closed.

We worked closely with our unions in 2024/25 to improve our Joint Health and Safety Committee (JHSC) structure, ensuring safety issues were escalated to senior leadership more easily and resolved faster. Employees had ongoing opportunities to contribute to safety by submitting Safe Work Observations and identifying safety incidents and near misses. We also updated to our Contractor Safety Program, including our contractor evaluation and monitoring processes. Meanwhile, our management team demonstrated industry-wide safety leadership by taking on active roles on Electricity Canada safety committees.

We worked to mitigate the impacts of trees and vegetation on our system, a leading cause of outages during severe weather events, to ensure safety, prevent outages, and reduce fire risks. In 2024/25, we expanded our hazard tree removal program and developed a strategy to ensure we continue to have enough certified utility arborists to complete this work going forward.

We also implemented safety measures at high-traffic public recreation areas, including a parking reservation system at Buntzen Lake during peak season to maintain emergency access, manage visitor capacity, and alleviate traffic congestion. We strengthened safety partnerships with municipalities, collaborating with the City of Mission to reduce traffic risks at the Stave Falls boat launch.. Additionally, we improved monitoring of public use risks around our infrastructure by creating a comprehensive database to track hazards and corrective actions, supporting accountability and continuous improvement.

Objective 1.2: BC Hydro will meet the evolving expectations of our customers

This objective emphasizes our continued commitment to integrate customer perspectives as we continue to advance and modernize our rates, service, and planning in order to meet their evolving expectations.

Key results

- Achieved a 92 percent customer satisfaction score based on our quarterly customer surveys.
- Completed customer and stakeholder engagement to design three rate structure proposals for residential rate design, the Distribution Extension Policy, and the self-generation (net-metering) and community-generation of solar power rate.
- Launched the HydroHome app to give customers enhanced insights into their energy use, improve energy literacy, and support smarter energy choices. More than 60,000 customers downloaded the app in 2024/25.
- Announced rebates of up to $5,000 on eligible grid-connected solar panels and up to an additional $5,000 for battery storage systems to qualifying residential customers.
- Filed a submission with the BCUC for approval of changes to BC Hydro's self-generation program and introduction of community-generation of solar power to respond to customer feedback.

Summary of progress made in 2024/25

In 2024/25 we remained committed to meeting the needs of our residential, commercial, and industrial customers. We exceeded our Customer Satisfaction Index threshold once again, maintaining a stable trend in recent years. The HydroHome app demonstrates our dedication to ensuring we continue to make technology and tools available to help customers understand and manage their energy use. Along with other programs and offers, this app is an example of how we provide valuable insights and tips, making it easier for customers to optimize their energy consumption at home. These achievements reflect our robust engagement with customers and our ongoing efforts to make it easier for customers to do business with us.

Our submission to the BCUC in March 2025, for approval of new rates for self-generation and community-generation of solar power, responded to feedback we received from customers. It will allow customers to install larger energy generating facilities and support community-based generation facilities where customers can subscribe to a share of the generation from the facility. In 2024/25, we also received BCUC approval for a new optional residential time-of-day rate and an optional residential flat rate, which will provide customers with more choice and options to save money on their electricity bills.

Performance measure(s) and related discussion

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[1a] Fatality & Permanently Disabling Injury1[1]	0	0	0
[1b] Serious Injury or Fatality Potential Incident Frequency[2]	N/A	0.27	0.23

Data source: BC Hydro Incident Management System
[1] Loss of life or the injury has resulted in a permanent disability. BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.
[2] Incidents per 100 employees per year. This metric will only measure incidents where hazard exposure had a realistic potential to result in a fatality, life-threatening or life-altering situations for employees, as defined by WorkSafeBC.

Fatality & Permanently Disabling Injury is a count of incidents where there has been a loss of life, a serious physical injury or a psychological injury to an employee that has resulted in a permanent disability as a direct result of a workplace incident. In 2024/25, BC Hydro achieved its performance target.

Serious Injury or Fatality Potential Incident Frequency is the number of incidents that had a reasonable likelihood of resulting in serious injuries or fatalities that have occurred per 100 employees, over the last 12 months. In 2024/25, BC Hydro achieved its performance target, which helps confirm the effectiveness of the existing interventions.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[1c] System Average Interruption Duration Index (SAIDI)[1, 2]	3.56	3.35	3.67
[1d] System Average Interruption Frequency Index (SAIFI)[1,3]	1.56	1.38	1.48

Data source: BC Hydro Distribution Outage Data Warehouse System and Asset Registry
[1] Reliability targets are based on specific values, however performance within 10 percent is considered acceptable given the reliability projection modelling uncertainty, the wide range of variations in weather patterns, and the uncontrollable elements that can significantly disrupt the electrical system. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.
[2] Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year (excluding major events).
[3] Total number of sustained interruptions experienced by an average customer in a year (excluding major events).

Our 2024/25 SAIDI result was 9.6 percent above the target of 3.35 and our 2024/25 SAIFI result was 7.2 percent above the target of 1.38. Both results are within the allowable range of 10 percent so the targets are 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.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[1e] Key Generating Facility Forced Outage Factor (%)[1]	1.13	1.70	1.43

Data Source: BC Hydro Unit Status Recording Systems managed by the Asset Performance Planning team
[1] Key generating facilities include: Bridge River, GM Shrum, Kootenay Canal, Mica, Peace Canyon, Revelstoke, and Seven Mile

BC Hydro achieved our target to remain below 1.70 percent for Key Generating Facility Forced Outage Factor with a result of 1.43 percent, 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	2023/24 Actual	2024/25 Target	2024/25 Actual
[1f] CSAT Index[1]	91	85	92

Data Source: BC Hydro customer satisfaction surveys
[1] Percentage of customers satisfied or very satisfied. Customer Satisfaction Index (CSAT) is an index measuring customer satisfaction of BC Hydro's three main customer groups (residential, commercial, and industrial). The index is comprised of the five key drivers of satisfaction weighted equally across the three customer types.

The Customer Satisfaction (CSAT) Index measure gauges the degree to which BC Hydro is meeting customers' electricity and service needs. Despite the challenging economic and political climate, overall CSAT score exceeded our 2024/25 target with all three CSAT customer groups (residential, commercial, and industrial) trending slightly higher than previous year's 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 our customers to use our clean electricity.

This objective focuses on our ongoing efforts to encourage our customers to switch to BC Hydro's clean electricity in support of our Electrification Plan.

Key results

- Completed a flagship fleet electrification project with a customer in the Comox Valley, to replace a fleet of eight waste collection trucks with fully electric models. This reduced emissions by 480 tonnes of CO2 annually, the equivalent of taking 104 cars off the road.
- Added 418 public charging ports to our public EV charging network across British Columbia. This is over a 240% increase in charging ports in 2024/25 and more than tripled the number of charging ports in our network.
- Received BCUC approval to update our Distribution Extension Policy. The updated policy will encourage electrification, support investments in affordable housing and reduce costs for many distribution customer connection projects.
- Received BCUC approval for a new optional residential time-of-day rate and an optional residential flat rate and eliminated higher non-integrated area rates. This will provide customers with more choice and options to save money on their electricity bills.

Summary of progress made in 2024/25

In 2024/25, BC Hydro received BCUC approval for three new rates, offering customers more choices and ways to save money, while promoting the use of our renewable electricity. The time-of-day rate offers lower rates for off-peak electricity use. The optional flat rate provides a single rate as customers increase their use of renewable electricity, falling between the Tier 1 and Tier 2 energy charges under the tiered rate structure, giving customers that use more electricity options to save money. Additionally, the BCUC approved changes to eliminate higher non-integrated area (areas that are not connected to BC Hydro's main transmission grid) rates, saving customers in 14 non-integrated communities money on their bills.

Our EV charging network grew in 2024/25 to 591 ports at 144 sites across B.C., with 85% being fast chargers. We completed the B.C. Electric Highway, in partnership with the Province, with public fast chargers every 150 km along major highways. BC Hydro operates 70% of these sites. BC Hydro was also named one of the best-rated EV charging networks in North America by ChargeHub.

We updated our Distribution Extension Policy for the first time since 2008. The Distribution Extension Policy sets out how costs are allocated between new and existing customers for new or upgraded connections to the BC Hydro distribution system. In the last four years, customer connections requests have increased and are expected to continue to increase. The new policy was approved by BCUC in 2024/25 and provides cost certainty for customers. It will encourage larger multi-unit developments, affordable housing, and electrification across the province.

We also continued our support for decarbonization this year through our Industrial Electrification Program. We provided more than $1.0M in study incentives and $12M in capital incentives, reducing 98,000 tCO_2e/year. Additionally, $4.7M in incentives were assigned to two major oil and gas projects to reduce over 1,700,000 tCO_2e/year by 2030.

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

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

Key results

- Launched a competitive Call for Power. The 10 successful renewable energy projects will produce electricity at a significantly lower cost than projects in our last call for renewable power in 2010.
- Announced our new $700 million energy efficiency plan, to provide tools and resources to support customers to make more energy efficient choices and save on their electricity bills.
- Consulted with industry on the industrial load curtailment program design, which would provide incentives to large industrial customers to voluntarily reduce or shift electricity consumption during peak periods, so that it can be ready to launch when the program is required.
- Scaled up demand response programs to reduce electricity usage during peak times. This year, our Peak Saver residential program participation has grown from 48,000 customers to more than 90,000, and the demand response for business program has grown from 20 customers to approximately 700.

Summary of progress made in 2024/25

In 2024/25, we launched our first competitive Call for Power in 15 years. We awarded 30-year electricity purchase agreements to 10 renewable energy projects that will generate approximately 5,000 gigawatt hours of electricity annually. That's enough to power 500,000 new homes and increase BC Hydro's current supply by 8%. The weighted average levelized price for these successful projects is $74 per megawatt hour (in 2024$), which is around 45% lower than the contracts awarded in our last call for renewable power in 2010, after adjusting for inflation. Each of the 10 projects has First Nations asset ownership between 49% and 51%.

In 2024/25, we also accelerated efforts to meet growing demand through energy efficiency and reducing electricity use during peak times. Our new Energy Efficiency Plan outlines investments over the next three years in tools, technology, and programs to help customers make energy-efficient choices and shift their energy use from peak times. This investment represents a 60% increase over our previous budget and is expected to generate up to 2,000 gigawatt hours of savings, equivalent to powering 200,000 homes.

We advanced our Capital Plan, to ensure customers can continue to receive reliable, renewable, and affordable electricity. In 2024/25 we completed work to bring key projects into service including those to preserve the penstock concrete foundations at the Bridge River Generating Station, modernize the control systems at the Mica Creek Generating Station, upgrade control systems for generating units 1-10 at the G.M. Shrum Generating Station, and energize the Capilano Substation upgrade, among other projects.

The results in this section also show progress on the key strategies listed in the Service Plan for Objective 2.1, to help electrify the province's economy and encourage our customers to use our clean electricity, including the implementation of our F22-F26 Electrification Plan.

Performance measure(s) and related discussion

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[2a] Number of Public Electric Vehicle (EV) Charging Ports in Operation[1]	N/A	550	591

Data source: Electric vehicle network management system

[1] This metric measures the total number of BC Hydro owned and operated public electric vehicle charging ports in operation.

BC Hydro exceeded our 2024/25 target with 591 public electric vehicle charging ports in operation. Number of Public EV Charging Ports in Operation provides insight into how we are supporting our customers through the energy transition, particularly with regards to electric vehicle deployment. Using BC Hydro's reliable, clean electricity to power a growing network of charging stations across the province will make it easier for more British Columbians to switch to an EV.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[2b] Residential Electrification Program Participation[1]	N/A	160,000	268,544

Data Source: Product participation databases

[1] Residential electrification program includes customer enrollment in the following products: Team Power Smart Challenge, HydroHome, heat pumps, EV Power Management, Peak Saver, and Time of Day Rate.

BC Hydro exceeded our 2024/25 target with total participation at 268,544. Residential Electrification Program Participation measures the number of our residential customers who enroll in optional energy efficiency products that support the energy transition and provides a good proxy for residential customers' overall engagement in fuel switching and energy transition.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[2c] New Connected Commercial and Industrial Load (Megawatts (MW))[1]	1,093	625	1,518

Data Source: BC Hydro 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

Our 2024/25 result of 1,518 cumulative MW from new or expanded commercial or industrial load significantly exceeded the 625 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	2023/24 Actual	2024/25 Target	2024/25 Actual
[2d] GHG Emissions Reduction – BC Hydro Operations (%)[1]	60	44	56

Data Source: Collected by various BC Hydro groups, including: Environment (sulfur hexafluoride (SF6)/CH4); Supply Chain (paper use and air travel); Fleet Services (vehicle emissions); Properties (buildings); Asset Planning (Non-Integrated Areas and Independent Power Producers); and Operations (thermal).
[1] Cumulative GHG reductions from BC Hydro operations since 2007

BC Hydro exceeded our 2024/25 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 measure are set to exceed the interim reduction target of 16% by 2025 and the Provincial industrial reduction target of 38-43% by 2030, both relative to baseline levels.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[2e] 100% Clean Electricity Standard[1]	100%	Met	Met

Data Sources: BC Hydro domestic 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 from January 1, 2021 to December 31, 2024. The measure is considered met if the result is 100% or greater.

BC Hydro met its 2024/25 target of 100% Clean Electricity Standard. 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. The 100% Clean Electricity Standard requires the generation, procurement, or import of clean energy in a quantity at least equal to 100 percent of the domestic sales for energy in BC plus any energy exports made by Powerex represented as being sourced from clean supply over a four-calendar year period. A multiple year period is required to balance annual variations in load and hydrology and is similar to how this is measured in other jurisdictions.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[2f] Customer Interconnection Studies Completed on Time (%)[1]	87	80	95

Data Source: BC Hydro Interconnections group
[1] Completion of interconnection studies to allow customers to connect to BC Hydro's system.

BC Hydro exceeded its 2024/25 target of 80 percent through strong management of customer timelines and proactively identifying risks. Although we have exceeded this target from 2022/23 to 2024/25, we have maintained a target of 80 percent for future years given the increasing volume and complexity of the interconnection studies.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[2g] Demand Side Management Capacity (MW)[1]	152	150	171

Data Source: BC Hydro Conservation and Energy Management group
[1] Annual new incremental capacity (MW) savings from the energy conservation portfolio.

BC Hydro continued to have strong performance from our energy efficiency and conservation initiatives and exceeded the 2024/25 Demand Side Management Capacity target of 150 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 work to balance affordable rates for customers while making prudent investments to maintain and expand our system.

Key results

- Filed a two-year Revenue Requirements Application with the BCUC, consistent with Direction No. 9 from the Province to the BCUC, requesting an annual average bill increase of 3.75% for the next two years, keeping rate increases below cumulative inflation between 2017/18 and 2026/27.
- Installed energy savings products in over 4,800 income qualified homes through our Energy Conservation Assistance Program and distributed over 9,000 free Energy Savings Kits to help save energy and make homes more comfortable.

- Safely began generating power at Site C, bringing four generating units into operation in 2024/25 year.
- Supported over 2,400 households in accessing home energy efficiency retrofits through the CleanBC Energy Savings Program, in partnership with the Province of BC. BC Hydro provided assistance specifically for participants at income level 1[2]

Summary of progress made in 2024/25

This year, BC Hydro advanced rate proposals to the BCUC to balance customer affordability with supporting critical system investments. In March 2025, we filed a two-year Revenue Requirements Application for Fiscal 2026-2027, consistent with Direction No. 9 from the Province to the BCUC, requesting an annual average bill increase of 3.75%. With rates set for the next two years, cumulative rate increases from 2017/18 and 2026/27 are projected to be 12.4% below cumulative inflation.

Site C began generating reliable electricity for British Columbians this year. With four generating units generating power in 2024/25, the project remains on track to have all six units operational in 2025 within the approved 2021 budget. When complete, Site C will provide enough renewable electricity to power about 500,000 homes and increase BC Hydro's supply by 8%.

In 2024/25, we refined our systematic project delivery approach ensuring our projects are completed safely, on time, on budget, and to high standards. We expanded the use of external service providers, established small Steering Committees for high-priority projects, and increased approval thresholds with regulatory bodies and our Board of Directors. This reduced costs and implementation time to deliver projects in our Capital Plan. We also received regulatory exemptions for six substation projects, accelerating their timelines. Additionally, we improved procurement and supply chain management practices, such as bulk ordering major equipment with long lead times and outline agreements for repeat work, which shortened our procurement cycles and reduced costs.

We also continued our work to support low-income customers with programs and incentives to keep electricity affordable. In 2024/25, we invested $31 million in our Low-Income energy efficiency program, dedicated to helping low-income customers reduce their electricity bills through energy efficiency improvements at no cost to them.

[2] (income levels are based on the combined income of all adults in a home and the number of people, including children who live there. For example, a one-person house would need a pre-tax income of $47,007 or less to qualify for income level 1).

Performance measure(s) and related discussion

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[3a] Affordable Bills – Residential[1]	1st quartile	1st quartile	1st quartile
[3b] Affordable Bills – Commercial[1]	1st quartile	1st quartile	1st quartile
[3c] Affordable Bills – Industrial[2]	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] 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.

[2] 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 2024/25, 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	2023/24 Actual	2024/25 Target	2024/25 Actual
[3d] Project Budget to Actual Cost: Cumulative Five Years (% variance)[1]	+1.28	Within ±5% of budget	+2.29

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 because it has its own specific cost and schedule performance measures, and the size of the Site C Project would dominate the results of this measure making the results less meaningful.

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 212 capital projects at a total cost of $2.806 billion, which is 2.29 percent above the aggregated budget of $2.743 billion and within the target of ±5 percent of budget.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[3e] Site C – Cost[1]	$16 billion	$16 billion	$16 billion
[3f] Site C – Schedule[2]	First Unit: December 2024	First Unit: December 2024	First Unit: October 2024

Data Sources: 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 approved budget. The output from the Cost Risk Analysis is identified and compared to the approved budget for the project of $16 billion.

[2] Estimated unit power date. The output from the Schedule Risk Analysis is identified and compared to the approved first unit power for the project of December 2024 and last unit power for the project of November 2025.

BC Hydro remains on track to complete Site C within the approved budget of $16 billion. The first unit was brought into service ahead of approved schedule in October 2024. The project is on track within the approved schedule to bring the final unit into service in 2025.

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.

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

Key results

- Enhanced response capabilities to weather-related power outages. Despite a record-breaking number of outages due to severe weather, 90% of affected customers had power restored within 24 hours, with approximately 75% restored in under 12 hours.
- Piloted fire-resistant pole wraps on transmission lines between Fort Nelson and the Alberta border to shield power poles from flames while allowing for evaporation to prevent decay.
- Received positive results on our Mandatory Reliability Standards audit, conducted every three years by the Western Electricity Coordinating Council for the BCUC. This validated our progress to ensure the reliability and security of the bulk power system in British Columbia over the past three years.

Summary of progress made in 2024/25

The 2024 wildfire season caused significant infrastructure damage, including the loss of 57 transmission structures and 53 distribution poles. While the severity, timing and duration of wildfire seasons are difficult to predict, preparation remains essential. We collaborated with agencies to monitor fire risks and maintained key equipment inventories, such as power poles and associated hardware, for quick response.

Attracting and retaining talent is essential to being able to deliver safe and reliable power to British Columbians. In 2024/25, we refreshed our outreach programs, attended career events, rolled out our employee value proposition, and redesigned our career website. We also focused on maintaining a stable workforce with low resignation and retirement rates through new pension resources, wellbeing campaigns, and leadership training initiatives.

Additionally, we enhanced our cybersecurity by implementing a new enterprise-wide operating model for more coordinated risk management, while also improving how we assess vendors for cyber risks and conducted an executive-level cyber incident crisis response exercise to improve our crisis response strategy.

Performance measure(s) and related discussion

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[4a] Employee Engagement Index (points)[1]	74	At or above the engagement score of the BC Public Service	74

Data source: confidential biennial employee engagement survey administered by an external service provider.
[1] At or above the score of the BC Public Service, which is 67 points.

BC Hydro's Employee Engagement Survey is conducted every two years and the next survey will be in 2025/26. 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 in 2022, which is our benchmark for this survey.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[4b] Workforce Diversity (%)			
• Women[1]	32.1	≥ 31.8	32.1
• Visible Minority[1]	30.4	≥ 29.9	29.9
• Indigenous[2]	4.2	Progress towards 5%	3.9
• Persons with Disabilities[2]	4.8	Progress towards 10%	4.4

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] Targets for these groups are set to be at or exceed the available workforce in B.C.
[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 2024/25. We met our targets for representation of women and visible minorities; however, we did not meet the stated targets for, Indigenous employees, or employees with disabilities in our workforce.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[4c] Inclusion and Diversity Training (% complete)	100	95	97

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

BC Hydro exceeded its 2024/25 target and achieved 97 percent participation of people leaders in inclusion and diversity leadership training. The cumulative total of people leaders trained since launched in September 2020 is over 1,700.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[4d] Cyber Security Ranking amongst Canadian Peers[1]	N/A	Upper quartile	Upper quartile

Data source: BitSight Security Rankings
[1] The 11 Canadian peers BC Hydro is benchmarked against includes: SaskPower, Hydro One, TransAlta, Nova Scotia Power, Hydro-Quebec, NB Power, Manitoba Hydro, Nalcor Energy, Atco Ltd., Northwest Territories Power Corporation, and Ontario Power Generation.

BC Hydro met its 2024/25 target of upper quartile indicating our performance in addressing cyber risk to be top three among its Canadian peers. Cyber Security Ranking Amongst Canadian Peers is an industry-recognized measure of preparedness to withstand cybersecurity incidents.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[4e] Number of Hazard Trees Removed on the Distribution System	N/A	25,000	33,296

Data source: Spatial Asset Management

BC Hydro exceeded its 2024/25 target with 33,296 hazard trees removed. Trees are often the largest single source of customer interruptions, resulting in up to half of all customer hours lost annually. Managing hazard trees is critical to the safe and reliable operation of our system and reduces the potential impact to customers during extreme weather events.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[4f] Mandatory Reliability Standards Non-Compliance Reduction (%)[1]	80	80	84

Data source: BC Hydro Safety and Compliance group. 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

BC Hydro exceeded its 2024/25 target for reduction in Mandatory Reliability Standards non-compliances, with a result of an 84 percent non-compliance reduction since 2020/21, compared to a target of 80 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.

Constructing and operating our electricity system has left lasting impacts on Indigenous peoples, cultures, traditions, and ways of life which we deeply regret. Developing mutually beneficial relationships with First Nations is critical to our ongoing approach to operating and growing our system of clean electricity.

Key results

- Reached, renewed, or extended Relationship Agreements with seven First Nations to create sustainable benefits to the Nations through directed procurement and other interests. In 2024/25 we issued $258 million in directed procurement contracts to First Nations with which we have Agreements.
- Established the United Nations Declaration Advisory Committee and hired a UN Declaration Advisor to provide advice and guidance to implement the principles of the United Nations Declaration of the Rights of Indigenous Peoples (UNDRIP) into our business.
- Launched a training program for people leaders in our organization to strengthen understanding of First Nations cultures and our commitment to reconciliation.
- Launched our Station Upgrade for Renewable Energy Integration (SUREI) program to deliver the microgrid upgrades that are required to integrate renewable energy into Non-Integrated Area (NIA) microgrids.
- Advanced a project to install an 8 MWh battery energy storage system at Anahim Lake. The system will be connected to the Ulkatcho First Nation solar plant and is estimated to meet the community's energy demand for up to 70 days in the summer.

Summary of progress made in 2024/25

BC Hydro continued its commitment to strengthening relationships with Indigenous communities, creating economic opportunities, and advancing reconciliation in 2024/25. Of the 10 successful 2024 Call for Power projects, 9 included 51% equity ownership by First Nations. This represents $2.5 billion to $3 billion of ownership by First Nations in new renewable energy projects in the province.

BC Hydro serves 14 NIA communities across B.C., primarily First Nations communities who have historically paid more for their electricity service because they are off-grid and served by higher cost diesel generators. This year, the BCUC approved our application to eliminate higher rates for residents living in NIA communities. This will help to reduce their bills by up to an average of $160 per year.

In 2024/25, we advanced work to connect these NIAs communities to the local grid. This requires extensive upgrades to existing substations, including installing microgrid control and battery energy storage systems. This year we launched the Station Upgrade for Renewable Energy Integration (SUREI) program, budgeting $200 million over 10 years to complete these upgrades. The program emphasizes collaboration with First Nations, communities, and suppliers while recognizing the unique needs of each NIA.

Additionally, in June 2024 we filed our 2024 Fort Nelson Long-Term Resource Plan Application. Long-term resource plans are the earliest we can engage with First Nations on meeting our customers' future electricity needs. We worked with the Prophet River First Nation and the Fort Nelson First Nation to gather information prior to the development of the plan and the Fort Nelson First Nation provided BC Hydro with a letter supporting the near-term actions recommended in the plan.

Performance measure(s) and related discussion

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[5a] Indigenous Procurement ($ billion)	1.359	1.425	1.617

Data source: BC Hydro Supply Chain group

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 $1.617 billion in direct contracts to Indigenous-designated businesses, exceeding the 2024/25 target of $1.425 billion.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[5b] Indigenous Awareness Training at BC Hydro (% complete)	84	85	89

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

BC Hydro exceeded its 2024/25 target for Indigenous Awareness Training with a result of 89 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.

Performance Measure	2023/24 Actual	2024/25 Target	2024/25 Actual
[5c] Partnership Accreditation in Indigenous Relations Certificate[1]	Gold	Gold	Gold

Data source: The Progressive Aboriginal Relations certification program is overseen by the Canadian Council for Aboriginal Business. It is reviewed on a three-year cycle.

[1] Previously known as the Progressive Aboriginal Relations (PAR) Certificate

In 2024/25, BC Hydro was awarded the Partnership Accreditation in Indigenous Relations (PAIR) Gold Certification from the Canadian Council for Aboriginal Business for the fifth consecutive time. BC Hydro has attained the highest, gold-level designation since 2012. This certification demonstrates BC Hydro's continued commitment to advancing 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.

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, 2025 and should be read in conjunction with the 2024/25 Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2025 and 2024.

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, 2025 was $587 million, $264 million (or 82 per cent) higher than the prior fiscal year. This variance was primarily driven by government directed customer affordability credits (affordability credits) recognized in the prior year which decreased prior fiscal year net income by $326 million, partially offset by higher operational costs in the current fiscal year due to inflation and expanded operational requirements.
- Total revenue for the year ended March 31, 2025 was $7.48 billion, $347 million (or 5 per cent) higher than the prior fiscal year, primarily as a result of higher domestic revenues, partially offset by lower trade revenues. Domestic revenues were higher primarily due to $326 million in affordability credits recognized in the prior fiscal year which decreased prior fiscal year domestic revenues, a 2.30 per cent customer bill increase approved by the British Columbia Utilities Commission (BCUC) effective April 1, 2024, and domestic sales volumes being 1,341 GWh (or 2 per cent) higher than the prior fiscal year. Trade revenues were lower due to lower average sales prices and sales volumes.
- Energy costs for the year ended March 31, 2025 were $2.86 billion, $861 million (or 23 per cent) lower than the prior fiscal year. The lower energy costs were primarily due to a decrease in market purchases, mainly driven by lower electricity import costs as a result of lower average purchase prices and lower import volumes. Net electricity import volumes for the year ended March 31, 2025 were 8,356 GWh, 5,243 GWh (or 39 percent) lower than the prior fiscal year of 13,599 GWh primarily due to lower impacts from the drought.

- Water inflows (energy equivalent) to the system for the year ended March 31, 2025 were below the historic average, although higher than the prior fiscal year. The below average water inflows for fiscal 2025 were due to the drought conditions, including well below average snowpack in the spring of 2024. As at March 31, 2025, system energy storage was tracking close to the historic average.
- The net regulatory asset balance as at March 31, 2025 was $2.52 billion compared to $1.85 billion as at March 31, 2024. Significant changes to the regulatory accounts during the year ended March 31, 2025 included net additions of $1.01 billion in regulatory assets, partially offset by net additions of $162 million in regulatory liabilities and regulatory amortization of $188 million.
- Capital expenditures, before contributions in aid of construction, for the year ended March 31, 2025 were $4.02 billion, a $248 million decrease over the prior fiscal year. During the year ended March 31, 2025, the Site C generating station commenced operation of Units 1 to 4 (of six planned units) and $13.20 billion was transferred from Unfinished Construction to Property, Plant and Equipment in-service and started to be amortized this fiscal year. The Site C Project is on track to be completed within the approved schedule and the approved $16 billion budget.

Consolidated Results of Operations

for the years ended March 31 ($ in millions)	**2025**	2024	Change
Total Revenues	**$ 7,478**	$ 7,131	$ 347
Operating Expenses	**$ 6,399**	$ 6,787	$ (388)
Net Income	**$ 587**	$ 323	$ 264
Capital Expenditures	**$ 4,015**	$ 4,263	$ (248)
GWh Sold (Domestic)	**56,754**	55,413	1,341

($ in millions)	***As at March 31, 2025***	*As at March 31, 2024*	Change
Total Assets and Regulatory Balances	**$ 53,180**	$ 49,442	$ 3,738
Shareholder's Equity	**$ 8,254**	$ 7,696	$ 558
Net Debt	**$ 32,049**	$ 29,294	$ 2,755
Debt to Equity	**80 : 20**	79 : 21	n/a
Number of Domestic Customer Accounts	**2,256,615**	2,220,056	36,559

Revenues

For the year ended March 31, 2025, total revenues of $7.48 billion, were $347 million (or 5 per cent) higher than the prior fiscal year. The increase was due to higher domestic revenues of $545 million, partially offset by lower trade revenues of $198 million.

	($ in millions)		(gigawatt hours)	
for the twelve months ended March 31	**2025**	2024	**2025**	2024
Revenues				
Residential	**$ 2,405**	$ 2,129	**19,345**	19,171
Light industrial and commercial	**2,061**	1,913	**19,319**	19,205
Large industrial	**947**	866	**14,482**	14,032
Other sales	**636**	596	**3,608**	3,005
Domestic Revenues	**6,049**	5,504	**56,754**	55,413
Trade Revenues[1]	**1,429**	1,627	**21,787**	20,985
Revenues	**$ 7,478**	$ 7,131	**78,541**	76,398

[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, 2025, domestic revenues were $6.05 billion, $545 million (or 10 per cent) higher than the prior fiscal year. The increase was primarily due to $326 million of affordability credits recognized in the prior fiscal year which decreased prior fiscal year domestic revenues, a 2.30 per cent bill increase approved by the BCUC effective April 1, 2024, and higher sales volumes compared to the prior fiscal year.

Domestic sales volumes were 1,341 GWh (or 2 per cent) higher than the prior fiscal year. Excluding electricity exports (included in Other Sales), domestic sales volumes were 1,229 GWh (or 2 per cent) higher than the prior fiscal year.

Trade Revenues

Total trade revenues for the year ended March 31, 2025 were $1.43 billion, $198 million (or 12 per cent) lower than the prior fiscal year. The decrease was primarily driven by lower average sales prices.

Operating Expenses

Operating expenses for financial statement purposes include energy costs (electricity and gas purchases, water rentals, transmission charges), amortization and depreciation, operational costs (materials and external services and personnel costs), and other costs, net of capitalized costs. For the year ended March 31, 2025, total operating expenses of $6.40 billion were $388 million (or 6 per cent) lower than the prior fiscal year. The decrease was primarily due to lower energy costs of $861 million, partially offset by higher materials and external services of $177 million, higher amortization and depreciation of $129 million, and higher personnel costs of $97 million.

Energy Costs

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

	($ in millions)		*(gigawatt hours)*	
for the twelve months ended March 31	**2025**	2024	**2025**	2024
Energy Costs				
Purchases from Independent Power Producers	**$ 1,257**	$ 1,381	**12,920**	13,667
Market purchases[1]	**861**	1,597	**30,865**	37,942
Non-Treaty storage and Co-ordination Agreements	**37**	3	**-**	-
Other expenses	**54**	47	**120**	118
Electricity and gas purchases	**2,209**	3,028	**43,905**	51,727
Water rental payments (hydro generation)[2]	**294**	362	**39,734**	31,614
Transmission charges	**361**	335	**-**	-
Energy Costs	**$ 2,864**	$ 3,725	**83,639**	83,341

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

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

Energy costs for the year ended March 31, 2025 were $2.86 billion, $861 million (or 23 per cent) lower than the prior fiscal year.

Electricity and gas purchases for the year ended March 31, 2025 were $2.21 billion, $819 million (or 27 per cent) lower than the prior fiscal year. The decrease in costs was primarily due to a decrease in market purchases, mainly driven by lower imports of electricity at lower average prices compared to the prior fiscal year. Net electricity import volumes for the year ended March 31, 2025 were 8,356 GWh, 5,243 GWh (or 39 percent) lower than the prior fiscal year of 13,599 GWh primarily due to lower impacts from the drought.

Water rental payments for the year ended March 31, 2025 were $294 million, $68 million (or 19 per cent) lower than the prior fiscal year. Water rental payments are based on the prior calendar year's hydro generation volumes, and hydro generation volumes were lower in calendar 2023 compared to calendar 2022 due to lower water inflows.

Water Inflows and Reservoir Storage

Water inflows (energy equivalent) to the system for the year ended March 31, 2025 were below the historic average, although higher than the prior fiscal year. The below average water inflows for the current fiscal year were due to the drought conditions, primarily from the well below average snowpack in the spring of 2024. As at March 31, 2025, system energy storage was tracking close to the historic average. While BC Hydro was a net importer again in the current fiscal year, it imported less compared to the prior fiscal year.

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

Personnel Expenses

Personnel expenses include salaries, wages, and benefits for employees that deliver operational activities and programs, support capital projects and programs, and for post-employment benefits. Personnel expenses for the year ended March 31, 2025 were $916 million, $97 million (or 12 per cent) higher than the prior fiscal year primarily due to an increase in the number of employees primarily to support capital project and programs and maintenance work, compensation increases commensurate to the public sector mandate, and higher current service pension costs attributed to lower pension discount rates, and the increase in employees and salaries.

Materials and External Services

Materials and external services primarily include materials, supplies, and contractor fees to deliver operational requirements and support capital projects and programs. Materials and external services for the year ended March 31, 2025 were $1.10 billion, $177 million (or 19 per cent) higher than the prior fiscal year primarily due to higher expenditures for Demand-Side Management and higher operational costs driven by inflationary pressures and expanded requirements for maintenance, technology and other operating costs.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and depreciation of right-of-use assets. Amortization and depreciation expense for the year ended March 31, 2025 were $1.20 billion, $129 million (or 12 per cent) higher than the prior fiscal year. This was primarily due to additional property, plant and equipment placed in-service related to the Site C project, commencing in October 2024, including the dam, spillway, powerhouse, and the first four generating units of the generating station which totaled $13.20 billion in the current fiscal year.

Grants, 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, taxes and other costs for the year ended March 31, 2025 were $326 million, which is comparable to the $316 million in the prior fiscal year.

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, 2025, other costs net of recoveries were $98 million, $73 million (or 292 per cent) higher than the prior fiscal year primarily due to insurance proceeds recognized in the prior fiscal year.

Capitalized Costs

Capitalized costs include costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Capitalized costs for the year ended March 31, 2025 were $105 million, $13 million (or 14 per cent) higher than the prior fiscal year primarily due to higher costs eligible for capitalization which is consistent with the higher personnel and material and external services discussed above.

Finance Charges

Finance charges for the year ended March 31, 2025 were $1.09 billion, an increase of $578 million (or 112 per cent) compared to the prior fiscal year. The increase was primarily due to losses on interest rate hedges used to economically hedge the interest rates on future debt issuances in the current fiscal year as compared to gains in the prior fiscal year, lower capitalization of interest due to Site C assets coming into service, and a higher volume of debt.

Regulatory Transfers

In accordance with International Financial Reporting Standards (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)	**2025**	2024
Cost of Energy Variance Accounts		
Heritage Deferral Account	**$ 106**	$ 79
Non-Heritage Deferral Account	**187**	1,183
Load Variance	**75**	45
Biomass Energy Program Variance	**(36)**	(52)
Low Carbon Fuel Credits Variance	**(9)**	(15)
	323	1,240
Other Cash Variance Accounts		
Trade Income Deferral Account	**(55)**	(538)
Total Finance Charges	**39**	56
Inflationary Pressures	**104**	66
Electrical Vehicle Rebate	**54**	(70)
Project Write-off Costs	**8**	13
Remediation	**40**	52
Site C Variance Costs	**115**	-
Other	**95**	30
	400	(391)
Non-Cash Variance Accounts		
Non-Current Pension Costs	**191**	(8)
PEB Current Pension Costs	**(28)**	(35)
Debt Management	**165**	(163)
Other	**4**	-
	332	(206)
Benefit Matching Accounts		
Demand-Side Management	**186**	128
First Nations Costs	**17**	16
Site C	**(4)**	(85)
CIA Amortization	**(5)**	(5)
Cloud Costs	**61**	34
Other	**3**	3
	258	91
Non-Cash Provisions		
Environmental Provisions	**(29)**	(22)
First Nations Provisions	**4**	6
	(25)	(16)
Rate Smoothing Accounts		
Rate Smoothing	**(438)**	-
Amortization of regulatory accounts	**(188)**	(317)
Interest on regulatory accounts	**6**	(16)
Net increase in regulatory accounts	**$ 668**	$ 385

For the year ended March 31, 2025, there was a net increase of $668 million (or 36%) to the Company's regulatory accounts compared to a net increase of $385 billion in the prior fiscal year. The net regulatory asset balance as at March 31, 2025 was $2.52 billion compared to $1.85 billion as at March 31, 2024.

Significant changes to the net regulatory asset balance during the year ended March 31, 2025 included:

- $323 million addition to the Cost of Energy Variance Accounts primarily due to higher net system electricity imports as a result of the drought, partially offset by lower independent power purchase costs;
- $191 million net addition to Non-Current Pension Costs Account primarily due to a decrease in discount rates, and updated funding valuation, partially offset by higher asset returns;
- $186 million addition to the Demand-Side Management Account for expenditures;
- $165 million addition to the Debt Management Account primarily due to a net decrease in the fair value of interest rate hedges resulting from a decrease in forward interest rates;
- $115 million addition to the Site C Variance Costs Account due to the variances from plan in depreciation and interest during construction as a result of assets going into service earlier than planned; and
- $104 million addition to the Inflationary Pressures Account associated with labour, vegetation maintenance and fuel costs eligible for deferral.

Partially offset by:

- $493 million reduction to the combined balance in the Rate Smoothing Account and Trade Income Deferral Account primarily as a result of higher than planned trade income, and
- $188 million of amortization (which is the regulatory mechanism to recover the regulatory account balance in rates).

Net regulatory account balances are as follows:

as at March 31 (in millions)	**2025**	2024
Cost of Energy Variance Accounts		
Heritage Deferral Account	**$ 167**	$ 49
Non-Heritage Deferral Account	**1,494**	1,092
Load Variance	**88**	12
Biomass Energy Program Variance	**(188)**	(127)
Low Carbon Fuel Credits Variance	**(84)**	(63)
	1,477	963
Other Cash Variance Accounts		
Trade Income Deferral Account	**(1,856)**	(1,736)
Total Finance Charges	**115**	88
Inflationary Pressures	**113**	7
Electrical Vehicle Rebate	**(18)**	(71)
Project Write-off Costs	**55**	48
Remediation	**17**	(11)
Site C Variance Costs	**117**	-
Other	**133**	62
	(1,324)	(1,613)
Non-Cash Variance Accounts		
Non-Current Pension Costs	**(730)**	(892)
PEB Current Pension Costs	**(85)**	(65)
Debt Management	**33**	(114)
Other	**13**	11
	(769)	(1,060)
Benefit Matching Accounts		
Demand-Side Management	**936**	870
First Nations Costs	**3**	3
Site C	**511**	502
CIA Amortization	**53**	58
Smart Metering & Infrastructure	**88**	109
Cloud Costs	**111**	46
Other	**2**	2
	1,704	1,590
Non-Cash Provisions		
Environmental Provisions	**190**	219
First Nations Provisions	**476**	471
	666	690
Rate Smoothing Accounts		
Rate Smoothing	**(446)**	-
	(446)	-
IFRS Transition Accounts		
IFRS Pension	**268**	306
IFRS Property, Plant & Equipment	**944**	976
	1,212	1,282
Net Regulatory Assets	**$ 2,520**	$ 1,852

BC Hydro has regulatory mechanisms to collect 40 of 42 regulatory accounts with balances at March 31, 2025 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 2024/25-2026/27 Service Plan (Service Plan) was filed in February 2024 with planned net income for 2024/25 of $712 million.

The table below provides an overview of BC Hydro's 2024/25 financial results, relative to its Service Plan.

(in millions)	**Actual**	**Service Plan[2]**	**Variance to Service Plan**
For the year ended March 31,	**2025**	**2025**	
Revenues			
Domestic	$ 6,049	$ 6,529	$ (480)
Trade	1,429	1,058	371
	7,478	7,587	(109)
Expenses			
Operating Costs			
Cost of energy	2,864	3,063	199
Other operating expenses			
Personnel expenses, materials and external services [1]	1,870	1,600	(270)
Amortization	1,200	1,146	(54)
Grants and taxes	326	341	15
Other	139	124	(15)
Finance charges	1,094	793	(301)
	7,493	7,067	(426)
Net Income (Loss) Before Movement in Regulatory Balances	(15)	520	(535)
Net movement in regulatory balances	602	192	410
Net Income	$ 587	$ 712	$ (125)

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 in Fiscal 2024.

Net income for 2024/25 was $587 million, compared to planned net income of $712 million in the Service Plan filed in February 2024. 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 higher than planned other operating expenses attributed to a higher number of employees to support capital projects and programs and higher costs for expanded requirements for maintenance, which were not subject to deferral to regulatory accounts.

Forecast net income for 2024/25 in BC Hydro's 2025/26 – 2027/28 Service Plan filed in March 2025 was $572 million. Net income was higher than forecast by $15 million primarily due to higher revenues and lower other operating expenses, 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, 2025 was $806 million, compared to $974 million in the prior fiscal year. The decrease was primarily due to higher interest payments and lower cash from changes in working capital.

Net Debt as at March 31, 2025 was $32.05 billion compared to $29.29 billion as at March 31, 2024. The increase was mainly a result of the issuances of long-term bonds for net proceeds of $4.21 billion (net of redemptions) primarily to fund capital expenditures and to manage working capital. This is partially offset by a decrease in revolving borrowings of $1.48 billion.

As at March 31, 2025, the Company has a working capital deficit of $5.43 billion which is primarily due to its revolving borrowing program. The working capital deficit is considered to be in the normal course of business where the Company has access to revolving credit facilities and debt issuances through the Province to manage cash flow requirements and does not impact operations.

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)		**2025**		2024
Transmission lines and substations replacements and expansion	**$**	**874**	$	540
Generation replacements and expansion		**631**		462
Distribution system improvements and expansion		**940**		771
General, including technology, vehicles and buildings		**326**		316
Site C Project		**1,244**		2,174
Total Capital Expenditures	**$**	**4,015**	$	4,263

Capital expenditures decreased by $248 million for the year ended March 31, 2025 compared to the prior fiscal year primarily due to Site C Project expenditures as major scopes of work were completed in the prior fiscal year, resulting in less construction costs for the current fiscal year. Annual capital expenditures can vary depending on the timing and scope of projects. The decrease in Site C Project capital expenditures was partially offset by increases in other capital expenditure categories.

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

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, Ladore Spillway Seismic Upgrade, Ruskin – Left Abutment Slope Sinkhole Remediation, Comox – Puntledge Flow Control Improvements, Bridge River 1 – Penstock Concrete Foundation Refurbishment, and Mica – U1-U4 Circuit Breaker and Iso-phase Bus Replacement.

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

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

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

Rate Regulation

BC Hydro is regulated by the BCUC who is authorized to set BC Hydro’s rates.

Regulatory Applications

In accordance with the Government of B.C.’s Direction No. 9 to the BCUC, the BCUC issued Order No. G76-25, on March 26 2025, to approve a bill increase of 3.75 per cent for each of 2025/26 and 2026/27 fiscal year. The Order also included approval of the refund of the Trade Income Deferral Account in the Deferral Account Rate Rider, the establishment of a new Net Salvage Regulatory Account and recovery mechanisms for the Rate Smoothing Regulatory Account, the Inflationary Pressures Regulatory Account and the Electrification Customer Connections Regulatory Account. In addition, the BCUC approved BC Hydro’s Demand Side Management expenditures for 2024/25 to 2026/27.

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 prior to the potential application of regulatory accounts where applicable.

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;
- Electricity imports/exports;
- Customer demand;
- Trade income;
- Deliveries from electricity purchase agreements;
- Interest rates; and
- Discount rates – Post Employment Benefit Plans.

In addition to the seven factors identified above, the ongoing uncertainty surrounding United States tariff and trade policies including retaliatory measures by Canada and British Columbia is being carefully monitored to determine potential financial impacts to BC Hydro. Where applicable, the potential impacts have been included in the discussion on BC Hydro's significant financial risks below.

The Site C Project continues to manage potential risks including commercial negotiations and claims with contractors. The Site C Project Assurance Board (which is comprised of independent members and some of the current BC Hydro board members) is tasked with ensuring that the Site C Project is completed on time and on budget, and that risks are appropriately identified, managed and reported on an ongoing basis. As of March 31, 2025, 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 calendar 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 the amount of deficit energy we 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 fiscal and future years.

The range of inflows, year to year, can significantly influence available generation: over 14,500 GWh (or approximately +/- 12 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, 2025 were significantly below average but higher than prior fiscal year. The below average water inflows for the current fiscal year were due to the drought conditions, primarily from the well below average snowpack in the spring of 2024. As at March 31, 2025, system energy storage was tracking close to the historic average.

Electricity Imports/Exports

Electricity imports/exports are impacted by electricity and gas prices and volumes, which themselves, are variable and a function of gas and electricity market fundamentals and water inflows. Electricity and gas prices could also be impacted by the uncertainty surrounding United States tariff and trade policies including retaliatory measures by Canada and British Columbia.

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.

For the year ended March 31, 2025, net electricity imports were 8,356 GWh compared to net electricity imports of 13,599 GWh in the prior fiscal year and the average price of the electricity imports were lower than the prior year.

Customer Demand

Customer demand for electricity is generally forecast to increase in the long term as British Columbia's population and economy continue to grow. Long-term customer load projections are inherently uncertain, especially during the current energy transition and global economic volatility, which has been exacerbated by recent United States trade policy. 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. Economic downturns arising from United States tariffs may lead to reduced energy consumption from our key industrial and commercial customers, potentially lowering revenues. 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 the timing of new large customer facility start-ups, 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, 2025, were 2 per cent higher compared to the prior fiscal year.

Trade Income

Trade Income for regulatory accounting 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. In addition, the uncertainty surrounding United States tariff and trade policies including retaliatory measures by Canada and British Columbia could have impacts to Trade Income.

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, 2025, overall energy delivered from EPAs was lower than forecast. Although most resource types delivered less energy than expected, the largest shortfall was due to lower than forecast deliveries from hydro generation projects largely due to the drought conditions.

Interest Rates

BC Hydro targets to have approximately 15% of its debt as variable debt and manages variable debt within a +/- 10% range. Variable debt is impacted by changes to interest rates 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, 2025, approximately 15 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, 2025, BC Hydro had interest rate hedges in place with an aggregate notional principal of $3.48 billion, hedging a portion of its forecast long-term debt issuances out to and including 2027/28 and 2028/29.

In addition, the uncertainty surrounding United States tariff and trade policies including retaliatory measures by Canada and British Columbia could have impacts to interest rates.

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, 2025 were lower than the prior fiscal year due to the reduction in the high-quality corporate bond yields in Canada.

Future Outlook

The Budget Transparency and Accountability Act requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in March 2025 forecast net income for 2025/26 and 2026/27 at $712 million which is consistent with the amount required by Order in Council No. 485. In addition, net income for 2027/28 is forecast to be $712 million.

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 2025/26 assumes average water inflows (100 per cent of average) based on a hydrology forecast before the 2024/25 snowpack measurement data was available, domestic sales of 57,001 GWh, average market energy prices of US $65.23/MWh, short-term interest rates of 2.68 per cent, and a Canadian to US dollar exchange rate of US $0.7453.

In February 2025, the U.S. government announced plans for new tariffs on imports from Canada, prompting retaliatory tariffs from Canada and British Columbia on U.S. imports, along with other potential measures such as trade policies, duties, fees, and economic sanctions. The timing and extent of these measures remain highly uncertain. Geopolitical tensions and the escalating trade wars have intensified fears of a global economic downturn and slower economic growth. These factors carry significant implications for federal and provincial economies, as well as BC Hydro's load, revenue, trade, supply chains, interest rate risk, and ability to deliver capital projects. These economic uncertainties make it difficult to predict the ultimate adverse effects on BC Hydro’s performance, financial condition, operational results, and cash flows.

Uncertainty around water inflows could have an adverse impact on BC Hydro’s future performance. It is too early to tell if 2025/26 conditions will be dry, wet, or average. Snowpack levels are below the historical average but 2025/26 water supply will be influenced by precipitation over the remainder of the fiscal year. 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.

Capital Expenditures

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 $50 million)	**Targeted Completion Date (Calendar Year)**	**Project Cost to Mar 31, 2025 ($ millions)**	**Estimated Cost to Complete ($ millions)**	**Anticipated Total Cost ($ millions)**
Projects Recently Put into Service				
Bridge River 1 – Penstock Concrete Foundation Refurbishment This project addressed 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.	2024 In-Service	$60	$5	$65
Capilano Substation Upgrade Project This project addressed the existing asset health, reliability, safety, and environmental issues associated with the Capilano Substation, and ensured that the capacity of the substation met the long term area needs. The project introduced a 25kV source to enable 25kV voltage conversion and facilitated the execution of other future substation projects in the North Shore area.	2024 In-Service	$74	$3	$77
G.M. Shrum (GMS) G1 to 10 Control System Upgrade This project replaced the controls equipment, provided full remote-control capability from the Control Center, and rectified deficiencies in the current system.	2024 In-Service	$72	$4	$76

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2025 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
The condition of the legacy controls for the GMS generating units, which were originally installed in the 1960s and 1970s, was of growing concern due to increasing maintenance requirements, lack of available spare parts and decreasing reliability. The controls were well beyond their expected life, which caused operating problems and increased the risk of damage to major equipment.				
Mica Modernize Controls Project This project addressed the reliability, maintainability, and operability of the Units 1-4 exciters, governors, unit controls and control room controls at the Mica Creek Generating Station.	2025 In-Service	$56	$-	$56
Ongoing				
Mica Replace Units 1 to 4 Generator Transformers Project This project addressed the reliability and safety risks of the Unit 1-4 Generator Step-up Unit transformers at the Mica Generating Station, which were nearing end of life and went in-service in 2022. One of the transformers developed issues and was exchanged with a spare transformer. The Board approved the purchase and construction of infrastructure to store an additional spare transformer. The spare transformer has a long lead time and has not arrived yet.	2022 In-Service	$81	$8	$89

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2025 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
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 will remove PCB containing equipment by the December 31, 2025 Federal PCB Regulation deadline.	2025 Targeted In-Service	$74	$27	$101
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 1,150 – 1,230 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 has worked with the Project Assurance Board, Mr. Milburn, Ernst & Young Canada, and the Technical Advisory Board to manage these project risks.*	2025* Targeted In-Service	$14,380	$1,620	$16,000**

Major Capital Projects (over $50 million)	**Targeted Completion Date (Calendar Year)**	**Project Cost to Mar 31, 2025 ($ millions)**	**Estimated Cost to Complete ($ millions)**	**Anticipated Total Cost ($ millions)**
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. **The total cost represents the gross cost of the project and has not been netted for a contribution of $1M.*	2025 Targeted In-Service	$52	$6	$58*
Various Sites – EV Charging Infrastructure Implementation Program This program is required to deliver BC Hydro's portion of the Provincial Government's mandate B.C. 's Electric Highway and target of 10,000 public EV charging stations by 2030. **The total cost represents the gross cost of the project and has not been netted for the Provincial and Federal Government's funding of $8 million and $10 million, respectively.*	2025 Targeted In-Service	$72	$1	$73*
2L143 – Cable Replacement Project This project is to address reliability, environmental, and seismic risks associated with the existing transmission cable 2L143 between Horsey Substation and Esquimalt Substation and to address load growth.	2026 Targeted In-Service	$12	$88	$100

Major Capital Projects **(over $50 million)**	**Targeted Completion Date (Calendar Year)**	**Project Cost to Mar 31, 2025 ($ millions)**	**Estimated Cost to Complete ($ millions)**	**Anticipated Total Cost ($ millions)**
Comox – Puntledge Flow Control Improvements Project This project is required to address public safety risk relating to water conveyance at Comox-Puntledge; the Puntledge Diversion Reach is a heavily used public recreation area.	2026 Targeted In-Service	$40	$13	$53
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 and load growth.	2026 Targeted In-Service	$70	$84	$154
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.	2026 Targeted In-Service	$52	$77	$129
Fleetwood – Distribution Load Interconnection (SLS Servicing) Project This project is on behalf of BC Hydro's customer, the Province of BC, to supply the Surrey-Langley-Skytrain extension and will also allow BC Hydro to reinforce the flexibility and reliability of the overall distribution system. **The total cost represents the gross cost of the project and has not been netted for a customer's contribution of $81M.*	2027 Targeted In-Service	$3	$155	$158*

Major Capital Projects **(over $50 million)**	**Targeted Completion Date (Calendar Year)**	**Project Cost to Mar 31, 2025 ($ millions)**	**Estimated Cost to Complete ($ millions)**	**Anticipated Total Cost ($ millions)**
Kimberley to Marysville – Substation Relocation Project This project is to address the reliability, safety and environmental risks associated with three bulk oil circuit breakers and other station assets at Kimberley substation which have reached their end-of-life.	2027 Targeted In-Service	$5	$68	$73
Long Lake Terminal Station – Transmission Load Interconnection Project This project is to facilitate the interconnection of customers' facilities to BC Hydro's Long Lake terminal substation. Under BC Hydro's standard tariffs and policies, customers are 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 $1M.*	2027 Targeted In-Service	$8	$72	$80*
Materials Classification Facility Project This project is to complete the construction and commissioning of the new Materials Classification Facility on the BC Hydro Surrey Campus. The facility will receive, classify and process hazardous polychlorinated biphenyl (PCB) and non-hazardous waste from BC Hydro operations across the province, and process materials for safe off-site recycling or disposal.	2027 Targeted In-Service	$23	$53	$76

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2025 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
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	$4	$68	$72*
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.	2027 Targeted In-Service	$58	$18	$76
Ladore Spillway Seismic Upgrade Project This project is to replace the existing spillway gates system to address known seismic and reliability deficiencies at the Ladore dam.	2028 Targeted In-Service	$58	$315	$373
Mica – U1 – U4 Circuit Breaker and Iso-phase Bus Replacement project This project will address reliability risks at the Mica Creek Generating Station by	2028 Targeted In-Service	$22	$154	$176

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2025 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
replacing the aging and obsolete unit 1 to 4 generator circuit breakers, isolated phase buses and other ancillary equipment.				
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.*	2028 Targeted In-Service	$49	$119	$168*
Northwest – Substations Outage Mitigation Project This project is required to improve supply availability to a customer by mitigating planned line outages in the radial bulk transmission system that supplies the Northwest. Under BC Hydro's standard tariffs and policies, the customer is	2028 Targeted In-Service	$22	$67	$89*

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2025 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
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 $2M.*				
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	$114	$230	$344
Prince George to Terrace Capacitors Project This project is required to increase the transfer capacity of the North Coast bulk 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	$136	$446	$582*
Burrard Switchyard – Control Building Upgrade Project	2029 Targeted In-Service	$5	$52	$57

Major Capital Projects (over $50 million)	**Targeted Completion Date (Calendar Year)**	**Project Cost to Mar 31, 2025 ($ millions)**	**Estimated Cost to Complete ($ millions)**	**Anticipated Total Cost ($ millions)**
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.				
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	$355	$557	$912
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.	2029 Targeted In-Service	$22	$39	$61

Major Capital Projects (over $50 million)	**Targeted Completion Date (Calendar Year)**	**Project Cost to Mar 31, 2025 ($ millions)**	**Estimated Cost to Complete ($ millions)**	**Anticipated Total Cost ($ millions)**
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.	2032 Targeted In-Service	$26	$285	$311

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, 2025
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.	**Complete** • 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 about BC Hydro's electricity system in the future. The flexible plan used several load forecast scenarios including a low scenario, a reference scenario, an accelerated electrification scenario, and it 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. • In July 2024 BC Hydro announced rebates of up to $5,000 on eligible grid-connected solar panels and up to an additional $5,000 for battery storage systems to qualifying residential customers. These rebates will make it easier for British Columbians to generate their own power, reduce their bills and deliver clean energy back to the province's electricity grid. **Ongoing** • Between Fiscal 2022 (starting April 1, 2021) and Fiscal 2025 (ending March 31, 2025), BC Hydro has invested over $99 million to advance its Electrification Plan and promote fuel switching in homes and buildings, transportation, and industries. • As of March 31, 2025, these investments have resulted in an emissions reduction of 338 kilotonnes of CO2e per year, 617 GWh per year in additional energy consumption, and 114 MW in demand growth across the buildings, transportation, and industry sectors. • BC Hydro announced the expansion of its Energy Efficiency Plan in June 2024. This plan is based on achieving the energy saving targets in the 2021 Integrated Resource Plan. Through its new Energy Efficiency Plan, BC Hydro is investing over $700 million in tools, technology, programs and rebates for customers over the next three years to encourage more energy efficient choices to support the energy transition.
Keep electricity affordable by ensuring that rates do not	**Complete**

increase above inflation, on a cumulative basis, over the next decade.	• Filed a two-year Revenue Requirements Application with the BCUC, consistent with Direction No. 9 from the Province to the BCUC, requesting an annual average bill increase of 3.75% for the next two years, keeping rate increases below cumulative inflation between 2017/18 and 2026/27. **Ongoing** • In Hydro-Québec's 2024 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.

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 2024/25, BC Hydro provided Customer Crisis Fund support to 6,569 customers.
	• In 2024/25, over 4,800 households went through the Energy Conservation Assistance Program and over 9,000 households received an energy saving kit.
	• The Province and BC Hydro have worked together to implement the Free Air Conditioner (AC) Program, which started in June 2023 and has installed over 27,000 AC units in low income and medically vulnerable households. BC Hydro is continuing the delivery of the program for the most vulnerable customers, who receive a recommendation letter from their regional health authority.
	• In 2024/25, BC Hydro continued its partnership with the Province to co-fund the CleanBC Energy Savings Program for income level 1 energy efficiency participants.
	• BC Hydro's Indigenous Communities Conservation Program (ICCP) supports Indigenous communities looking to improve the energy efficiency and comfort of their homes. In 2024/25:
	  ○ Two Indigenous communities installed free energy-saving products and completed basic home condition assessments in 45 homes with support from the ICCP Home Energy Check-up.
	  ○ Three Indigenous communities, as well as the Aboriginal Housing Management Association, completed energy efficiency upgrades in 135 homes with support from the ICCP Home Energy Upgrade Rebates. Projects underway encompass an additional 155 homes.
	  ○ In 2024/25 BC Hydro worked in partnership with the Province to develop a new program launching in Fiscal 2026, to continue this work going forward.

	• 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 has been working with the Province since 2023/24 to redesign the Social Housing program for non-housing providers that will deliver an integrated energy efficiency and electrification offer. The new program will launch in fiscal year 2026. BC Hydro continues to administer the Province's CleanBC Social Housing Incentive Program.
	• 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 2024/25, BC Hydro, in partnership with the Province and FortisBC, began work on the design of a new program for Indigenous communities and governing bodies that will deliver an integrated energy efficiency, electrification, and gas offer. The new program will launch in fiscal year 2026.

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, 91 percent in 2023/24, and 92 percent in 2024/25 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.
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	**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 2025, the Site C project remained on track to have all six generating units in-service in 2025. • In 2024/25, BC Hydro continued to manage the Site C project within the 2021 approved $16 billion budget. Major milestones in 2024/25 included completing the reservoir filling in November 2024 and

reporting to Treasury Board and the BC Utilities Commission.	bringing the first four generating units into operation between October 2024 and March 2025. • 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 construction sector. • There were 10 Site C Project Assurance Board meetings, in 2024/25. BC Hydro has worked 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.
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	**Complete** • Updated BC Hydro's Distribution Extension Policy to allocate costs between new and existing customers for new or upgraded connections to the BC Hydro distribution system. The new policy was approved by BCUC in 2024/25. It provides cost certainty for customers and will encourage larger multi-unit developments, affordable housing, and electrification across the province. • In 2024/25 BC Hydro implemented a number of customer connection business process improvements including: streamlined customer onboarding, streamlined delivery of low-risk low-complexity design work, and program management for strategic customer programs. **Ongoing** Hydrogen • Powertech has established Powertech USA Inc., a wholly owned U.S. subsidiary, to expand market reach, access new talent, and tap into US market for engineering services and federal hydrogen funding opportunities. • Powertech is developing new standardized hydrogen products, including high-pressure trailers. The world's first aviation and heavy-duty refueling stations were completed in 2024/25. Of the $20M BC Hydro loan supporting this work, only $4M has been drawn, with most costs self-funded. Electric Vehicle Charging • As of March 2025, BC Hydro had 591 charging ports at 144 sites across B.C., with 85% being fast chargers. BC Hydro's charging network is expected to reach 800 in Spring 2026. Powertech Clean Technology Innovation

transportation electrification infrastructure, incentives and programs.	• Successfully executed a Vehicle-to-Grid (V2G) pilot for electric buses, enhancing grid resilience through bidirectional charging. • Supported the expansion of BC Hydro's EV fast-charging network by providing essential equipment testing, procurement, and deployment. • Launched new Battery Energy Storage System (BESS) services, assisting utilities, developers, and industrial clients in deploying storage solutions that improve grid stability, support peak shaving, and provide backup power. • Contributed to industrial electrification by conducting technical assessments and interconnection studies, helping large customers connect more efficiently to the grid. <u>Connections</u> BC Hydro is actively working to improve its customer connections process. Key achievements in 2024/25 include: • 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. • Identifying cluster studies opportunities to optimize 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. <u>Transportation Electrification</u> In 2023/24, BC Hydro started to administer the CleanBC Go Electric Passenger Vehicle Rebate Program on behalf of the Province. In 2024/25, over 14,000 applications were submitted and over $58 million in rebates paid. 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. The Government of B.C. paused it's CleanBC Go Electric Passenger Vehicle Rebate program on May 15, 2025 as it considers next steps with the program.
Develop a short-term electrification plan that builds on the key results of the Comprehensive Review	**Complete** In 2021, BC Hydro launched its five-year Electrification Plan, 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,

of BC Hydro and supports CleanBC.	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.
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.	**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 time-of-day rate launched to customers in 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. This came into effect on April 1, 2024. • On February 24, 2025, the BCUC approved a new optional flat rate for residential customers. The optional flat rate provides a single rate as customers increase their use of renewable electricity, falling between the Tier 1 and Tier 2 energy charges under the tiered rate structure, giving customer that use more electricity options to save money. • On February 24, 2025, the BCUC approved changes to eliminate higher non-integrated area rates, saving customers in 14 non-integrated communities money on their bills. **Ongoing** • In March 2025, BC Hydro filed a submission with the BCUC requesting approval of new self-generation and community generation service rates. These changes are in response to customers feedback and will help ensure that self-generation can contribute to meeting B.C.'s energy supply needs. • BC Hydro continues to explore and engage with customers about rate options that support customers' diverse energy needs.
Actively market 100% clean energy through Powerex to realize new trading opportunities and income for the benefit of BC Hydro ratepayers.	**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. The Standard is based on a four-year calendar period of which 2024/25 was the final year. Powerex met the Standard for this reporting period.

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.	**Complete** • In late 2023, BC Hydro launched the NIA Community Renewable Energy Offer (CREO) program. CREOs provide a collaborative method to develop renewable energy projects, sharing costs between BC Hydro and communities and working together with the end goal of the community selling power. CREOs include pricing and contract terms for Community Electricity Purchase Agreements, enabling BC Hydro to purchase available electricity from community projects. Through this program, BC Hydro aims to reduce project risks for community energy developers. **Ongoing** • In 2024/25, BC Hydro continued to work with non-integrated area (NIA) First Nations to advance nine renewable energy projects across the province to support economic reconciliation and reduce reliance on diesel in these communities. • BC Hydro engaged with First Nations to work towards finalizing its NIA Strategy that will guide diesel reduction actions in NIAs and focus on the three pillars of reliable, renewable, and affordable energy generation. • BC Hydro continues its relationship with the Government of B.C. 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, BC Hydro works closely with NRT staff to support First Nations in its Non-Integrated Areas in advancing energy efficiency projects to reduce reliance on diesel-generated electricity in these remote areas. • In September and October 2024 BC Hydro ran a targeted trial offer to replace refrigerators on Haida Gwaii with newer, more energy-efficient models. While this was a limited offer, the Community Energy Diesel Reduction program, administered by the New Relationship Trust in partnership with BC Hydro, the provincial government, and Coast Funds, recently updated their program to include funding for energy-efficient appliances such as refrigerators and chest freezers. • 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. • Launched the Station Upgrade for Renewable Energy Integration (SUREI) program to deliver the microgrid upgrades that are

	required to integrate renewable energy into NIA microgrids. This program budgets $200 million over 10 years to complete these upgrades. • BC Hydro is working to install, own, and operate battery energy storage systems for NIA solar projects to maximize the amount of solar power it can use in each microgrid. In Anahim Lake, BC Hydro installed an 8 MWh battery energy storage system that will be connected to the Ulkatcho First Nation solar plant through a microgrid control system, which is estimated to eliminate approximately 1 million litres of diesel on an annual basis.
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.	**Ongoing** o BC Hydro submitted four applications to the federal Critical Minerals Infrastructure Fund for transmission studies and infrastructure construction. BC Hydro received conditional approval for $25M. Discussions to secure funding for the proposed new line to the North Coast are ongoing. o In F25 BC Hydro received $20,117,709 in federal funding for the Prince George to Terrace Capacitors project.
2023 Mandate Letter Priority	**Status as of March 31, 2025**
Support the development of a climate-aligned energy framework for B.C.	**Complete** • The BC Hydro Task Force provided input on items for inclusion in government's climate-aligned energy framework. • 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. **Ongoing** • In June 2024 the Province released Powering Our Future: BC's Clean Energy Strategy. It outlines actions being taken in ten areas of focus to accelerate the shift to clean energy and create new opportunities for people and communities across the province. BC Hydro continues to work with the Province to advance work on the areas of focus in the strategy.
Actively participate in the BC Hydro Task Force to accelerate the electrification of B.C.'s economy by powering	**Complete** • The Premier's BC Hydro Task Force, announced in March 2023, was created to provide both near-term and medium-term strategic advice to help ensure reliable, affordable, and emissions-free

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.	energy for future generations. The Task Force brought together experts from government and industry, as well as Indigenous perspectives. It was a 12-month commitment, ending in Spring 2024. • Task Force outcomes related to three priority areas: 1. Improve the speed of permitting and delivering required infrastructure. o With the Task Force's input, BC Hydro accelerated the overall timeline for the spring 2024 Call for Power and, for the first time, requiring a minimum ownership partnership threshold with First Nations. 2. Modernize the regulatory framework to better align with government priorities while protecting ratepayers. o Following a robust review informed by the Task Force, in February 2024 the Province amended BC's energy objectives in the Clean Energy Act. 3. Identify, enable, and accelerate economic opportunities in clean energy. o With the Task Force's input, BC Hydro and government have taken key actions, including: (1) the $36 billion 10 Year Capital Plan, (2) the announcement in the February 2024 Budget of a First Nations Equity Financing Framework to support Indigenous investment in energy and other major projects, and (3) an agreement with the Canada Infrastructure Bank to provide Indigenous loan packages to winning bidders in BC's Call for Power.
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.	**Ongoing** • Between Fiscal 2022 (starting April 1, 2021) and Fiscal 2025 (ending March 31, 2025), BC Hydro has invested over $99 million to advance its Electrification Plan and promote fuel switching in homes and building, transportation and industries. • As of March 31, 2025, these investments have resulted in an emissions reduction of 338 kilotonnes of CO_2e per year, 617 GWh per year in additional energy consumption and 114 MW in demand growth across the buildings, transportation, and industry sectors. • Under the Load Attraction program, ten clean technology projects have been funded to date, with an additional six projects under review. In 2024/25, the first of several low carbon fuels projects supported by the Load Attraction Program neared completion, with energization planned for April 2025. BC Hydro continues to explore opportunities support diversification of the economy and

	emissions reductions, including in the sustainable materials, aquaculture, and data centres sectors.

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	**Complete**
	• In September 2024 BC Hydro launched a new integrated energy efficiency program specifically for multi-unit residential buildings (MURBs) to address their unique needs. The programs focus on whole-building retrofits including heat pumps, heat pump water heaters, lighting, windows and electrical capacity upgrades.
	Ongoing
	• In 2024/25, BC Hydro provided Customer Crisis Fund support to 6,569 customers.
	• In 2024/25, over 4,800 households went through the Energy Conservation Assistance Program and over 9,000 households received an energy saving kit.
	• The Province and BC Hydro have worked together to implement the free Air Conditioner (AC) Program, which started in June 2023 and has installed over 27,000 AC units in low income and medically vulnerable households. BC Hydro is continuing the delivery of the program for the most vulnerable customers, who receive a recommendation letter from their regional health authority.
	• In Fiscal 2025, BC Hydro continued its partnership with the Province to co-fund the CleanBC Energy Savings Program for income level 1 energy efficiency participants.
	• 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 has been working with the Province since 2023/24 to redesign the Social Housing program for non-housing providers that will deliver an integrated energy efficiency and electrification offer. The new program will launch in fiscal 2026. BC Hydro continues to administer the Province's CleanBC Social Housing Incentive Program.
	• 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 2024/25, BC Hydro, in partnership with the Province and FortisBC, began work on the design of a new program for

	Indigenous communities and governing bodies that will deliver an integrated energy efficiency, electrification, and gas offer. The new program will launch in fiscal year 2026. • In 2024/25, BC Hydro and the Province partnered to advance work on a MURB in-suite heat-pump rebate offer. The program will launch in fiscal 2026.
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.	**Complete** ○ In September 2024, BC Hydro completed the B.C. Electric Highway, in partnership with the Province, with public fast chargers every 150 km along major highways. BC Hydro operates 70% of these sites. **Ongoing** • As of March 2025, BC Hydro had 591 charging ports at 144 sites across B.C., with 85% being fast chargers. BC Hydro's charging network is expected to reach 800 in Spring 2026.
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 continued to administer the CleanBC Go Electric Passenger Vehicle Rebate Program on behalf of the Province, as it has done since 2023/24. In 2024/25, over 14,000 claims (applications) were submitted and over $58 million in rebates paid. 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. The Government of B.C. paused it's CleanBC Go Electric Passenger Vehicle Rebate program on May 15, 2025 as it considers next steps with the program. • 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..
Identify and advance Indigenous ownership opportunities in future electricity generation and transmission investments to advance reconciliation and support economic self-determination.	**Complete** ○ In April 2024 BC Hydro launched its first competitive Call for Power in 15 years and awarded 30-year electricity purchase agreements to 10 renewable energy projects in December 2024. Each of the 10 projects has First Nations asset ownership between 49% and 51%. The projects will produce electricity at lower cost than BC Hydro's last call for renewable power in 2010.

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BC Hydro worked with the Canada Infrastructure Bank (CIB) to source capital for First Nations to fund their equity ownership in successful 2024 Call for Power projects. The CIB made a loan package available to all winning bidders.
Ongoing
The Province, BC Hydro and affected First Nations are exploring co-ownership of a proposed new transmission line from Prince George to Terrace to help build capacity and electrify northwest B.C. The new line would be alongside our existing transmission line which crosses the traditional territories of 14 First Nations and the co-ownership agreement could serve as a model for future transmission projects in the province.
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<tr><td>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.</td><td>
Complete
Updated BC Hydro's Distribution Extension Policy to allocate costs between new and existing customers for new or upgraded connections to the BC Hydro distribution system. The new policy was approved by BCUC in 2024/25. It provides cost certainty for customers and will encourage larger multi-unit developments, affordable housing, and electrification across the province.
In 2024/25 BC Hydro implemented a number of customer connection business process improvements including: streamlined customer onboarding, streamlined delivery of low-risk low complexity design work, and program management for strategic customer programs.
Ongoing
BC Hydro is actively working to improve its customer connections process. Key achievements in 2024/25 include:
Implementing solutions derived from a lean end-to-end design process review.
Expanded BC Hydro's streamlined delivery of low-risk low-complexity work to include more customer segments, while also including more customer segments in our strategic customer programs. This simplified the customer connection process for these segments and reduced cycle times.
Completed the North Coast Expression of Interest in April 2023 to help advance planning for new transmission infrastructure in North Coast. The Province, BC Hydro and affected First Nations are exploring co-ownership of the proposed new transmission line from Prince George to Terrace to help build capacity and electrify northwest B.C.
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	• 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 is working with the Ministry of Citizen Services to proactively identify and perform necessary "make ready" work where telecom infrastructure is expected to be installed on BC Hydro distribution poles, resulting in shorter timelines for projects in those areas once awarded by the province to the telecom carrier. • 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. Additional opportunities now being investigated. • BC Hydro continues to lead the Broadband Connectivity Working Group with telecommunications companies, and the Ministries of Energy and Climate Solutions, Citizens' Services, and Water, Land, and Resource Stewardship to improve transparency, communication, and process.

Appendix B: Subsidiaries and Operating Segments

Active Subsidiaries

Powerex Corp

Operating out of Vancouver BC, Canada, Powerex Corp. 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 Corp. ("Powerex" or "the Company") 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 trade income. Over the previous five years (2020/21 to 2024/25), Powerex trade income has ranged from $386 million to $1,051 million. For more information, visit powerex.com.

Board of Directors:

- Catherine Roome – Chair
- Doug Allen
- Sam Drier
- Don Kayne
- Marilyn Loewen Mauritz
- Chris O'Riley

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 the majority of hydrogen station technology in B.C. and is a leading provider across Canada.

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 senior Executives and Directors of BC Hydro.

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.

Over the last five years (2020/21 to 2024/25), Powertech's net income has ranged from a net loss of $2 million to net income of $5 million. For more information, visit powertechlabs.com.

Board of Directors:

- Chris O'Riley - Chair
- Melissa Holland
- John Nunn
- David Wong
- Bruce Ralston

Other Subsidiaries

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, 2025, 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

CONSOLIDATED FINANCIAL STATEMENTS 2024/25

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, 2025. 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 IFRS Accounting 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

Vancouver, Canada
June 6, 2025

KPMG LLP
PO Box 10426 777 Dunsmuir Street
Vancouver BC V7Y 1K3
Canada
Telephone (604) 691-3000
Fax (604) 691-3031

INDEPENDENT AUDITOR'S REPORT

To the Minister of Energy and Climate Solutions, 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 statements of financial position as at March 31, 2025
- the consolidated statements of comprehensive income for the year then ended
- the consolidated statements 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 policy information

(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, 2025, 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.

Other Information

Management is responsible for the other information. Other information comprises the information, other than the financial statements and the auditor's report thereon, included in Management's Discussion and Analysis.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information, other than the financial statements and the auditor's report thereon, included in the Management's Discussion & Analysis as at the date of this auditor's report.

If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditor's report.

We have nothing to report in this regard.

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.

- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the group as a basis for forming an opinion on the group financial statements. We are responsible for the direction, supervision and review of the audit work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.

KPMG LLP

Vancouver, Canada

June 6, 2025

Audited Financial Statements

Consolidated Statements of Comprehensive Income

for the years ended March 31 (in millions)		**2025**		2024
Revenues (Note 4)				
Domestic	**$**	**6,049**	$	5,504
Trade		**1,429**		1,627
		7,478		7,131
Expenses				
Operating expenses (Note 5)		**6,399**		6,787
Finance charges (Note 6)		**1,094**		516
Net Loss Before Movement in Regulatory Balances		**(15)**		(172)
Net movement in regulatory balances (Note 16)		**602**		495
Net Income		**587**		**323**
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 24)		**54**		17
Reclassification to income of derivatives designated as cash flow hedges (Note 24)		**(88)**		-
Foreign currency translation gains		**36**		7
Items That Will Not Be Reclassified to Net Income				
Actuarial gain (loss)		**(94)**		103
Other Comprehensive Income (Loss) before movement in regulatory balances		**(92)**		**127**
Net movements in regulatory balances (Note 16)		**66**		(110)
Other Comprehensive Income (Loss)		**(26)**		17
Total Comprehensive Income	**$**	**561**	$	340

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Financial Position

(in millions)	**As at March 31, 2025**	As at March 31, 2024
ASSETS		
Current Assets		
Cash and cash equivalents (Note 8)	**$ 136**	$ 96
Restricted cash (Note 8)	**35**	45
Accounts receivable and accrued revenue (Note 9)	**820**	984
Inventories (Note 10)	**452**	391
Prepaid expenses	**230**	184
Current portion of sinking funds (Note 15)	**225**	-
Current portion of derivative financial instrument assets (Note 24)	**260**	267
	2,158	1,967
Non-Current Assets		
Property, plant and equipment (Note 11)	**42,945**	40,108
Right-of-use assets (Note 12)	**1,180**	1,209
Intangible assets (Note 13)	**651**	641
Derivative financial instrument assets (Note 24)	**106**	145
Sinking funds (Note 15)	**54**	247
Other non-current assets (Note 14)	**154**	172
	45,090	42,522
Total Assets	**47,248**	44,489
Regulatory Balances (Note 16)	**5,930**	4,953
Total Assets and Regulatory Balances	**$ 53,178**	$ 49,442
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Note 17)	**$ 2,027**	$ 1,912
Current portion of long-term debt and revolving borrowings (Note 18)	**5,284**	4,740
Current portion of unearned revenues and contributions in aid (Note 21)	**123**	109
Current portion of derivative financial instrument liabilities (Note 24)	**158**	305
Customer credits (Note 4)	**-**	326
	7,592	7,392
Non-Current Liabilities		
Long-term debt (Note 18)	**27,180**	24,897
Lease liabilities (Note 20)	**1,270**	1,330
Derivative financial instrument liabilities (Note 24)	**118**	224
Unearned revenues and contributions in aid (Note 21)	**3,069**	2,768
Post-employment benefits (Note 23)	**862**	692
Other non-current liabilities (Note 25)	**1,423**	1,342
	33,922	31,253
Total Liabilities	**41,514**	38,645
Regulatory Balances (Note 16)	**3,410**	3,101
Total Liabilities and Regulatory Balances	**44,924**	41,746
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**8,261**	7,677
Accumulated other comprehensive loss	**(67)**	(41)
	8,254	7,696
Total Liabilities, Regulatory Balances, and Shareholder's Equity	**$ 53,178**	$ 49,442

Commitments and Contingencies (Notes 11 and 26)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

Glen Clark
Board Chair and Audit and Finance Committee Chair

Consolidated Statements of Changes in Equity

(in millions)	Cumulative Translation Reserve	Unrealized Loss on Cash Flow Hedges	Total Accumulated Other Comprehensive Loss	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2023	$ 10	$ (68)	$ (58)	$ 60	$ 7,354	$ 7,356
Comprehensive Income	-	17	17	-	323	340
Balance as at March 31, 2024	10	(51)	(41)	60	7,677	7,696
Distribution to the Province	-	-	-	-	(3)	(3)
Comprehensive Income (Loss)	8	(34)	(26)	-	587	561
Balance as at March 31, 2025	$ 18	$ (85)	$ (67)	$ 60	$ 8,261	$ 8,254

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

for the years ended March 31 (in millions)	**2025**	2024
Operating Activities		
Net income	**$ 587**	$ 323
Regulatory account transfers (Note 16)	**(602)**	(495)
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 7)	**1,200**	1,071
Unrealized gains on derivative financial instruments	**(240)**	-
Post-employment benefits expense	**59**	66
Interest accrual	**1,168**	1,018
Other items	**(23)**	106
	2,149	2,089
Changes in working capital and other assets and liabilities (Note 19)	**(173)**	(78)
Interest paid	**(1,165)**	(1,037)
Income taxes paid	**(5)**	-
Cash provided by operating activities	**806**	974
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(3,514)**	(3,703)
Cash used in investing activities	**(3,514)**	(3,703)
Financing Activities		
Long-term debt issued (Note 18)	**4,217**	862
Long-term debt retired (Note 18)	**(10)**	(200)
Receipt of revolving borrowings	**8,414**	9,673
Repayment of revolving borrowings	**(9,919)**	(7,748)
Payment of principal portion of lease liability	**(75)**	(29)
Settlement of hedging derivatives	**142**	147
Other items	**(27)**	(30)
Cash provided by financing activities	**2,742**	2,675
Increase (Decrease) in cash and cash equivalents	**34**	(54)
Effect of currency translation on cash balances	**6**	2
Cash and cash equivalents, beginning of year	**96**	148
Cash and cash equivalents, end of year	**$ 136**	$ 96

See Note 19 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 Government 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.

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, 2025.

(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 increase 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 23 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.

(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) 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.

In addition, estimation and judgement are involved in determining the allocation of costs among components of major assets that are placed in service.

(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.

Note 3: Material Accounting Policies

(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 is 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.

(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 are 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	FVTPL
Cash	Amortized cost
Restricted cash	Amortized cost
Accounts receivable and other receivable	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 24.

(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 unless the asset is fully depreciated. 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 26.

(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, 2025, 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 21, *The Effects of Changes in Foreign Exchange Rates* (effective April 1, 2025)
- Amendments to IFRS 7, *Financial Instruments: Disclosures* (effective April 1, 2025, April 1, 2026)
- Amendments to IFRS 9, *Financial Instruments* (effective April 1, 2025, April 1, 2026)
- Amendments to IFRS 10, *Consolidated Financial Statements* (effective April 1, 2025)
- IFRS 18, *Presentation and Disclosure in Financial Statements* (effective April 1, 2027)

The Company is currently assessing the effect of the new or amended standards 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)		**2025**		2024
Domestic				
Residential	**$**	**2,405**	$	2,129
Light industrial and commercial		**2,061**		1,913
Large industrial		**947**		866
Other sales		**636**		596
Total Domestic		**6,049**		5,504
Total Trade[1]		**1,429**		1,627
Total Revenue	**$**	**7,478**	$	7,131

[1] Includes revenue of $504 million recognized under IFRS 9, *Financial Instruments* (2024 - ($595) million) and revenue of $20 million recognized under IAS 2, Inventories (2024 - $41 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, 2025 was $762 million (2024 - $918 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, 2025**		March 31, 2024
Unearned revenues (Note 21)	**$**	**358**	$	317
Contributions in aid (Note 21)		**2,834**		2,560
Customer credits[1]		**-**		326
Customer deposits		**102**		83
	$	**3,294**	$	3,286

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

The following table reconciles the changes in the contract liabilities balances during the years ended March 31, 2025 and 2024:

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2025 AND 2024

(in millions)		Contract Liabilities
Balance at April 1, 2023	**$**	**2,790**
Revenue recognized that was included in the contract liability balance at the beginning of the year		(155)
Increases due to cash received, excluding amounts recognized as revenue during the year		635
Other[1]		16
Balance at March 31, 2024		**3,286**
Revenue recognized that was included in the contract liability balance at the beginning of the year		(166)
Increases due to cash received, excluding amounts recognized as revenue during the year		478
Other[1]		(304)
Balance at March 31, 2025	**$**	**3,294**

[1] Other includes finance charges, foreign exchange adjustments, and Energy Affordability Credits applied to customer bills.

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, 2025.

(in millions)		**Less than 1 year**		**Between 1 and 5 years**		**More than 5 years**		**Total**
Contributions in aid	$	70	$	279	$	2,485	$	2,834
Skagit River Agreement		30		119		1,068		1,217
Other		89		184		37		310
	$	189	$	582	$	3,590	$	4,361

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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2025 AND 2024

Note 5: Operating Expenses

(in millions)	**2025**	2024
Electricity and gas purchases	**$ 2,209**	$ 3,028
Water rentals	**294**	362
Transmission charges	**361**	335
Personnel expenses	**916**	819
Materials and external services	**1,100**	923
Amortization and depreciation (Note 7)	**1,200**	1,071
Grants and taxes	**326**	316
Other costs, net of recoveries	**98**	25
Capitalized costs	**(105)**	(92)
	$ 6,399	$ 6,787

Note 6: Finance Charges

(in millions)	**2025**	2024
Interest on debt	**$ 1,119**	$ 1,018
Interest on lease liabilities	**44**	46
Interest on defined benefit plan obligations (Note 23)	**35**	37
Losses (gains) on derivative financial instruments (Note 24)	**154**	(168)
Capitalized interest	**(335)**	(475)
Other	**77**	58
	$ 1,094	$ 516

The capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 3.6 per cent (2024 - 3.6 per cent).

Note 7: Amortization and Depreciation

(in millions)	**2025**	2024
Depreciation of property, plant and equipment (Note 11)	**$ 1,033**	$ 911
Depreciation of right-of-use assets (Note 12)	**86**	80
Amortization of intangible assets (Note 13)	**81**	80
	$ 1,200	$ 1,071

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2025 AND 2024

Note 8: Cash and Cash Equivalents and Restricted Cash

(in millions)		**March 31, 2025**		March 31, 2024
Cash	**$**	**58**	$	65
Short-term investments		**78**		31
Restricted Cash		**35**		45
	$	**171**	$	141

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, 2025**		March 31, 2024
Accounts receivable	**$**	**365**	$	381
Accrued revenue		**255**		315
Other		**200**		288
	$	**820**	$	984

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

Note 10: Inventories

(in millions)		**March 31, 2025**		March 31, 2024
Materials, Supplies, and Environmental Products	**$**	**301**	$	252
Natural Gas and Certain Carbon products		**151**		139
	$	**452**	$	391

There were no materials, supplies, and environmental products inventory impairments during the years ended March 31, 2025 and 2024. 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 $182 million (2024 - $227 million).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2025 AND 2024

Note 11: Property, Plant, and Equipment

(in millions)	Generation	Transmission	Distribution	Land & Buildings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at April 1, 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
Net additions	13,396	376	804	68	148	(10,866)	3,926
Disposals and retirements	(13)	(19)	(52)	-	(70)	(13)	(167)
Balance at March 31, 2025	$ 24,028	$ 9,465	$ 9,279	$ 1,052	$ 1,234	$ 4,374	$ 49,432
Accumulated Depreciation							
Balance at April 1, 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)
Depreciation expense	(358)	(260)	(269)	(36)	(110)	-	(1,033)
Disposals and retirements	12	12	18	-	69	-	111
Balance at March 31, 2025	$ (2,092)	$ (1,863)	$ (1,741)	$ (232)	$ (559)	$ -	$ (6,487)
Net carrying amounts							
At March 31, 2024	$ 8,899	$ 7,493	$ 7,037	$ 788	$ 638	$ 15,253	$ 40,108
At March 31, 2025	$ 21,936	$ 7,602	$ 7,538	$ 820	$ 675	$ 4,374	$ 42,945

(i) During the period, $13.20 billion in assets related to the Site C Project were put in-service and transferred from the Unfinished Construction category to Generation.

(ii) Included within Distribution assets are the Company's portion of utility poles with a net book value of $1.32 billion (2024 - $1.27 billion) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2025 was $36 million (2024 - $35 million).

(iii) 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 and earned government grants of $72 million during the year ended March 31, 2025 (2024 - $23 million) which were deducted from the cost of the assets.

(iv) The Company has contractual commitments to spend $1.41 billion on major property, plant and equipment projects (on individual projects greater than $20 million) as at March 31, 2025.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2025 AND 2024

Note 12: Right-of-Use Assets

(in millions)	Long-term energy purchase agreements	Property	Equipment/ Other	Total
Cost				
Balance at April 1, 2023	$ 1,760	$ 74	$ 4	$ 1,838
Net additions	26	5	-	31
Disposals, retirements and other	(47)	-	-	(47)
Balance at March 31, 2024	1,739	79	4	1,822
Net additions	52	(1)	5	56
Disposals, retirements and other	-	2	-	2
Balance at March 31, 2025	$ 1,791	$ 80	$ 9	$ 1,880
Accumulated Depreciation				
Balance at April 1, 2023	$ (496)	$ (33)	$ (4)	$ (533)
Depreciation expense	(77)	(3)	-	(80)
Disposals, retirements and other	-	-	-	-
Balance at March 31, 2024	(573)	(36)	(4)	(613)
Depreciation expense	(80)	(6)	-	(86)
Disposals, retirements and other	-	(1)	-	(1)
Balance at March 31, 2025	$ (653)	$ (43)	$ (4)	$ (700)
Net carrying amounts				
At March 31, 2024	$ 1,166	$ 43	$ -	$ 1,209
At March 31, 2025	$ 1,138	$ 37	$ 5	$ 1,180

Refer to Note 20 for additional information on right-of-use assets and lease liabilities.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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Note 13: Intangible Assets

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at April 1, 2023	$ 337	$ 163	$ 573	$ -	$ 73	$ 1,146
Net additions	4	17	60	1	7	89
Disposals, retirements, and other	-	-	(34)	-	-	(34)
Balance at March 31, 2024	341	180	599	1	80	1,201
Net additions	34	15	66	-	(15)	100
Disposals, retirements, and other	-	(28)	(17)	(1)	(9)	(55)
Balance at March 31, 2025	$ 375	$ 167	$ 648	$ -	$ 56	$ 1,246
Accumulated Amortization						
Balance at April 1, 2023	$ (5)	$ (119)	$ (383)	$ -	$ -	$ (507)
Amortization expense	(1)	(15)	(64)	-	-	(80)
Disposals, retirements, and other	-	-	27	-	-	27
Balance at March 31, 2024	(6)	(134)	(420)	-	-	(560)
Amortization expense	(1)	(16)	(64)	-	-	(81)
Disposals, retirements, and other	-	28	18	-	-	46
Balance at March 31, 2025	$ (7)	$ (122)	$ (466)	$ -	$ -	$ (595)
Net carrying amounts						
At March 31, 2024	$ 335	$ 46	$ 179	$ 1	$ 80	$ 641
At March 31, 2025	$ 368	$ 45	$ 182	$ -	$ 56	$ 651

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, 2025**		March 31, 2024
Non-current receivables	**$**	**114**	$	123
Non-current Site C prepaid expenses		**2**		32
Other		**38**		17
	$	**154**	$	172

Non-Current Receivables

Included in the non-current receivables balance are $98 million of receivables (2024 - $107 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.

Note 15: 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, 2025**			March 31, 2024		
		Carrying Value	**Weighted Average Effective Rate[1]**		Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$**	**154**	**4.5 %**	$	145	4.9 %
Other provincial government and crown corporation bonds		**67**	**4.4 %**		89	5.2 %
Money market funds		**56**	**-**		11	-
Other		**2**	**-**		2	-
	$	**279**		$	247	
Less: Current portion		**(225)**			-	
Non-current sinking funds	**$**	**54**		$	247	

[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 16: 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:

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(in millions)		**2025**		2024
Net income in regulatory balances related to net income	**$**	**602**	$	495
Net increase (decrease) in regulatory balances related to OCI		**66**		(110)
	$	**668**	$	385

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 2024*	*Addition / (Reduction)*	*Interest [A]*	*Amortization*	*Net Change*	***As at March 31 2025***	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Heritage Deferral	$ 49	$ 106	$ 5	$ 7	$ 118	**$ 167**	Note B
Non-Heritage Deferral	1,092	187	49	166	402	**1,494**	Note B
Load Variance	11	75	-	2	77	**88**	Note B
Demand-Side Management	870	186	-	(120)	66	**936**	1-15
Debt Management	-	37	-	(4)	33	**33**	3-34
First Nations Provisions & Costs	474	21	-	(16)	5	**479**	1-9 Note F
Site C	502	(4)	19	(6)	9	**511**	Note D
CIA Amortization	58	(5)	-	-	(5)	**53**	15
Environmental Provisions & Costs	208	11	-	(12)	(1)	**207**	Note E, F
Smart Metering & Infrastructure	109	-	4	(25)	(21)	**88**	4
Inflationary Pressures	7	104	2	-	106	**113**	Note E
IFRS Pension	306	-	-	(38)	(38)	**268**	7
IFRS Property, Plant & Equipment	976	-	-	(32)	(32)	**944**	27-36
Total Finance Charges	88	39	-	(12)	27	**115**	Note E
Cloud Costs	47	61	3	-	64	**111**	1-12
Project Write-off Costs	48	8	2	(3)	7	**55**	Note E
Site C Variance Costs	-	115	2	-	117	**117**	Note I
Other Regulatory Accounts	108	71	3	(31)	43	**151**	Note H
Total Regulatory Assets	4,953	1,012	89	(124)	977	**5,930**	
Regulatory Liabilities							
Trade Income Deferral	1,736	55	65	-	120	**1,856**	Note C
Rate Smoothing	-	438	8	-	446	**446**	Note E
Debt Management	114	(128)	-	14	(114)	**-**	3-34
Biomass Energy Program Variance	127	36	6	19	61	**188**	Note B
Low Carbon Fuel Credits Variance	63	9	2	10	21	**84**	Note B
Non-Current Pension Costs	892	(191)	-	29	(162)	**730**	2-13
PEB Current Pension Costs	65	28	-	(8)	20	**85**	Note E
Electric Vehicle Rebate	71	(54)	1	-	(53)	**18**	Note G
Other Regulatory Accounts	33	(31)	1	-	(30)	**3**	Note H
Total Regulatory Liabilities	3,101	162	83	64	309	**3,410**	
Net Regulatory Asset	$ 1,852	$ 850	$ 6	$ (188)	$ 668	**$ 2,520**	

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(in millions)	*As at April 1 2023*	*Addition / (Reduction)*	*Interest [A]*	*Amortization*	*Net Change*	*As at March 31 2024*	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Heritage Deferral	$ -	$ 47	$ 1	$ 1	$ 49	$ 49	Note B
Non-Heritage Deferral	-	1,073	15	4	1,092	1,092	Note B
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 F
Site C	566	(85)	21	-	(64)	502	Note D
CIA Amortization	63	(5)	-	-	(5)	58	16
Environmental Provisions & Costs	216	30	-	(38)	(8)	208	Note E, F
Smart Metering & Infrastructure	130	-	4	(25)	(21)	109	5
Inflationary Pressures	-	7	-	-	7	7	Note E
IFRS Pension	344	-	-	(38)	(38)	306	8
IFRS Property, Plant & Equipment	1,007	-	-	(31)	(31)	976	27-36
Total Finance Charges	45	56	-	(13)	43	88	Note E
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 B
Non-Heritage Deferral	110	(110)	-	-	(110)	-	Note B
Trade Income Deferral	1,190	538	52	(44)	546	1,736	Note C
Debt Management	-	110	-	4	114	114	4-33
Biomass Energy Program Variance	75	52	3	(3)	52	127	Note B
Low Carbon Fuel Credits Variance	48	15	2	(2)	15	63	Note B
Inflationary Pressures	58	(59)	1	-	(58)	-	Note E
Non-Current Pension Costs	854	8	-	30	38	892	3-13
PEB Current Pension Costs	38	35	-	(8)	27	65	Note E
Electric Vehicle Rebate	-	70	1	-	71	71	Note G
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	

[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 3.7 per cent for the year ended March 31, 2025 (2024 – 3.6 per cent).

[B] 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 *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 (2024 – 1.0 per cent) for fiscal 2025, effective April 1, 2024. In its Decision on the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC approved the requested DARR refund of 4.5 per cent for fiscal 2026, effective April 1, 2025, and a refund of 1.5 per cent for fiscal 2027.

[C] In fiscal 2025, the Trade Income Deferral Account balance was recovered 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 Deferral Account Rate Rider and Trade Income Rate Rider and Reconsideration Related to the Trade Income Rate Rider*, the BCUC approved the requested TIRR refund of 2.3 per cent for fiscal 2025, effective April 1, 2024. Commencing in fiscal 2026, the balance will be recovered through DARR, which is described in footnote B. In its Decision on the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC approved the requested the DARR refund of 4.5 per cent for fiscal 2026, effective April 1, 2025, and a of refund 1.5 per cent for fiscal 2027.

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[D] The Site C regulatory account balance is recovered commencing in fiscal 2025 over the forecasted weighted average expected useful life of the Site C assets, originally estimated at 84 years in the *Fiscal 2023 to Fiscal 2025 Revenue Requirements Application*, and updated to 86 years for *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*.

[E] 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.

[F] 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 expenditures are forecast to be incurred and transferred to the respective regulatory cost account.

[G] The Electric Vehicle Rebate regulatory account includes electric vehicle rebates, revenue from specified low carbon fuel credits, administration and marketing costs, and forecast interest. Revenue from specified low carbon fuel credits and cost of issuing electric vehicle rebates are expected to self-clear over time. The administration and marketing costs, including forecast interest, are recovered over the next test period.

[H] Other Regulatory Accounts includes various accounts with recovery periods ranging from 2 to 20 years or that will be determined by the BCUC as part of a future regulatory proceeding.

[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.

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.

On March 17, 2025, the Government of B.C. issued a Direction to the BCUC (Order in Council No. 131) under section 3 of the Utilities Commission Act which enacted Direction No. 9 to the BCUC to, among other things, issue final orders approving various rate changes. In accordance with Order in Council No. .131, on March 26, 2025, the BCUC issued Order No. G-76-25 to approve the requested bill increases of 3.75 per cent for each of fiscal 2026 and fiscal 2027, which included a DARR refund of 4.5% and 1.5% for fiscal 2026 and fiscal 2027 respectively. In addition, the Order included the refund of the Trade Income Deferral Account in the Deferral Account Rate Rider, the establishment of a new Net Salvage Regulatory Account and recovery mechanisms for the Rate Smoothing Regulatory Account, the Inflationary Pressures Regulatory Account and the Electrification Customer Connections Regulatory Account.

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 *Fiscal 2023 to Fiscal 2025 Revenue Requirements Application*, the BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2025. 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 Load Variance account, the Biomass Energy Program Variance account and the Low Carbon Fuel Credits Variance Regulatory Account). In response to the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC approved, as directed by the Government of BC in OIC 131, that the Trade Income Deferral account be recovered through the DARR table mechanism with the cost of energy variance accounts for fiscal 2026 and 2027.

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.

Load Variance

This account is intended to capture the variance between planned and actual domestic customer load (i.e., customer demand). 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.

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 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.

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.

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. In its Decision to the *Fiscal 2023 to Fiscal 2025 Revenue Requirements Application*, the BCUC directed BC Hydro, for fiscal 2025, to recover the Trade

Income Deferral Account in rates, through the Trade Income Rate Rider (TIRR), which is a separate additional charge or credit on customer bills. In response to the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC approved, as directed by the Government of BC in OIC 131, that the Trade Income Deferral account be recovered through the DARR table mechanism for fiscal 2026 and 2027.

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 Inflationary Pressure Regulatory Account. In response to the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*, the BCUC approved, as directed by the Government of BC in OIC 131, BC Hydro to recover the forecast balance, including forecast interest over the fiscal 2026 to fiscal 2027 test period.

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 *Fiscal 2023 to Fiscal 2025 Revenue Requirements Application*, the BCUC approved BC Hydro's request to begin amortizing the balance of the Site C Regulatory Account commencing in fiscal 2025 over the forecast weighted average expected useful life of the Site C assets, originally estimated at 84 years in the *Fiscal 2023 to Fiscal 2025 Revenue Requirements Application* and updated to 86 years for the *Fiscal 2026 to Fiscal 2027 Revenue Requirements Application*.

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 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.

Cloud Costs

This account is intended to capture actual cloud arrangement implementation costs that would have been capitalized for each project, had the cloud arrangement been eligible for capitalization as an intangible asset. The forecast balance in the account attributable to each forecast completed cloud arrangement is recovered over the expected term of each cloud arrangement.

Project Write-off Costs

This account is intended to capture actual project write offs in each fiscal year for which BC Hydro believes future recovery from ratepayers is appropriate. Write-off costs deferred in respect to completed fiscal years during a test period are recovered over the following test period.

Site C Variance Costs

This account is intended to capture specific variances related to amortization and finance charges on Site C assets in service, commencing fiscal 2023. The recovery period for this account will be determined by the BCUC as part of a future regulatory proceeding.

Rate Smoothing

In February 2024, the BCUC approved a Rate Smoothing regulatory account to defer an amount that would have otherwise been refunded to customers through the Trade Income Rate Rider on their bills in fiscal 2025, so that the balance could be used to lower rates in future periods. In March 2025, the BCUC approved, as directed by the Government of BC in OIC 131, that the forecast balance in the Rate Smoothing Regulatory Account be refunded, as specified, in fiscal 2026 and fiscal 2027.

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 approved to be recovered over the following test period in the BCUC decision on BC Hydro's 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, Mining Customer Payment Plan, Cloud Usage Fees, Mandatory Reliability Standards Costs, Load Attraction Costs, Routine Trouble and Storm Restoration Costs, Dismantling Cost, Electrification Customer Connection Costs, Insurance Costs, Regulatory Fees, and Remote Community Electrification Repayment.

Note 17: Accounts Payable and Accrued Liabilities

(in millions)		**March 31, 2025**		March 31, 2024
Accounts payable	**$**	**566**	$	454
Accrued liabilities		**1,174**		1,154
Current portion of lease liabilities (Note 20)		**78**		75
Current portion of other long-term liabilities (Note 25)		**149**		174
Other		**60**		55
	$	**2,027**	$	1,912

Note 18: Long-Term Debt, Revolving Borrowings, and Debt Management

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

The Company has a commercial paper borrowing program with the Province which is limited to $5.50 billion (2024 - $5.50 billion). At March 31, 2025, the outstanding amount under the borrowing program was $3.25 billion (2024 - $4.73 billion).

For the year ended March 31, 2025, the Company issued bonds for net proceeds of $4.22 billion (2024 - $862 million) and a par value of $4.20 billion (2024 - $900 million), a weighted average effective interest

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rate of 4.2 per cent (2024 - 4.4 per cent) and a weighted average term to maturity of 23.8 years (2024 - 20.1 years).

For the year ended March 31, 2025, the Company redeemed bonds at maturity with a par value of $10 million (2024 - $200 million).

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

(in millions)	**March 31, 2025**					March 31, 2024				
	Canadian	**US**	**Euro**	**Total**	**Weighted Average Interest Rate[1]**	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:										
2025	**$ -**	**$ -**	**$ -**	**$ -**	**-**	$ 10	$ -	$ -	$ 10	5.5
2026	**900**	**719**	**410**	**2,029**	**3.7**	900	677	385	1,962	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**	1,500	-	-	1,500	2.8
2030	**500**	**-**	**-**	**500**	**5.0**	-	-	-	-	-
1-5 years	**4,750**	**719**	**410**	**5,879**	**3.2**	4,260	677	385	5,322	3.0
6-10 years	**6,275**	**-**	**216**	**6,491**	**3.2**	5,460	-	202	5,662	3.2
11-15 years	**-**	**432**	**-**	**432**	**7.4**	-	406	-	406	7.4
16-20 years	**5,838**	**-**	**-**	**5,838**	**4.1**	3,273	-	-	3,273	4.3
21-25 years	**3,695**	**-**	**-**	**3,695**	**3.2**	6,260	-	-	6,260	3.4
26-30 years	**5,710**	**-**	**-**	**5,710**	**3.4**	3,925	-	-	3,925	3.0
Over 30 years	**1,210**	**-**	**-**	**1,210**	**4.1**	110	-	-	110	3.4
Bonds	**$ 27,478**	**$ 1,151**	**$ 626**	**$ 29,255**	**3.5**	$ 23,288	$ 1,083	$ 587	$ 24,958	3.4
Revolving borrowings	**2,550**	**704**	**-**	**3,254**	**2.9**	2,970	1,760	-	4,730	5.1
	$ 30,028	**$ 1,855**	**$ 626**	**$ 32,509**		$ 26,258	$ 2,843	$ 587	$ 29,688	
Adjustments to carrying value resulting from discontinued hedging activities	**6**	**15**	**-**	**21**		7	16	-	23	
Unamortized premium, discount, and issue costs	**(61)**	**(5)**	**-**	**(66)**		(67)	(6)	(1)	(74)	
	$ 29,973	**$ 1,865**	**$ 626**	**$ 32,464**		$ 26,198	$ 2,853	$ 586	$ 29,637	
Less: Current portion	**(3,451)**	**(1,423)**	**(410)**	**(5,284)**		(2,980)	(1,760)	-	(4,740)	
Non-current long-term debt	**$ 26,522**	**$ 442**	**$ 216**	**$ 27,180**		$ 23,218	$ 1,093	$ 586	$ 24,897	

[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, 2025 in a net asset position of $88 million (2024 – net asset of $15 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

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(in millions)	**March 31, 2025**	March 31, 2024
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	**3 years**	4 years
Foreign Currency Forwards		
United States dollar (US$) to Canadian dollar - notional amount[1]	**US$ 1,065**	US$ 1,883
United States dollar to Canadian dollar - weighted average contract rate	**1.32**	1.32
Weighted remaining term	**3 years**	2 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, 2025 with a net liability position of $58 million (2024 - net asset of $191 million). Such contracts are used to lock in interest rates on future Canadian denominated debt issues. The contracts outstanding relate to $3.48 billion (2024 - $2.88 billion) of planned 10 and 30 year debt (2024 - 10 and 30 year debt) to be issued on dates ranging from July 2025 to October 2028 (2024 - June 2024 to October 2026).

(in millions)	**March 31, 2025**	March 31, 2024
Forward Swaps		
Canadian dollar - notional amount[1]	**$ 3,475**	$ 2,875
Weighted forecast borrowing yields	**3.89%**	3.57%
Weighted remaining term	**1 years**	1 years

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

For more information about the Company's exposure to interest rate, foreign currency and liquidity risk, see Note 24.

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Note 19: Supplemental Disclosure of Cash Flow Information

Change in Working Capital and Other Assets and Liabilities:

(in millions)		**2025**		2024
Restricted Cash	**$**	**10**	$	(45)
Accounts receivable, accrued revenue, prepaid expenses and other non-current assets		**128**		37
Inventories		**(29)**		(2)
Accounts payable, accrued liabilities, and other non-current liabilities		**(267)**		(550)
Unearned revenues, customer credits and contributions in aid		**(16)**		485
Post-employment benefits		**1**		(3)
	$	**(173)**	$	(78)

Non-Cash Investing Transactions:

(in millions)		**2025**		2024
Contributions in kind received for property, plant and equipment	**$**	**97**	$	60

Reconciliation for liabilities:

(in millions)	**Balance, April 1, 2024**	**Issued**	**Redemptions**	**Foreign exchange movement**	**Other[1]**	**Proceeds (Payments)**	**Balance March 31, 2025**
Long-term debt and revolving borrowings:							
Long-term debt	$ 24,907	$ 4,217	$ (10)	$ 107	$ (11)	$ -	$ 29,210
Revolving borrowings	4,730	8,414	(9,919)	66	(37)	-	3,254
Total long-term debt and revolving borrowings	29,637	12,631	(9,929)	173	(48)	-	32,464
Lease liability (Note 20)	1,405	-	-	-	62	(119)	1,348
Vendor financing liability	273	-	-	-	16	(41)	248
Debt-related derivative liability (asset)	(191)	-	-	-	19	142	(30)
	$ 31,124	$ 12,631	$ (9,929)	$ 173	$ 49	$ (18)	$ 34,030

(in millions)	**Balance, March 31, 2023**	**Issued**	**Redemptions**	**Foreign exchange movement**	**Other[1]**	**Payment**	**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)	1,449	-	-	-	31	(74)	1,405
Vendor financing liability	290	-	-	-	33	(50)	273
Debt-related derivative liability (asset)	(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.

Note 20: Lease Liabilities

Lease costs

(in millions)		**2025**		2024
Interest on lease liabilities	**$**	**44**	$	46
Variable lease payments (recoveries) not included in the measurement of lease liabilities		**(14)**		12
Expenses relating to short-term leases and leases of low-value assets		**26**		24
	$	**56**	$	82

Amounts recognized in the statement of cash flows

(in millions)		**2025**		2024
Total cash outflow for leases	**$**	**131**	$	110

Maturity analysis

(in millions)		**March 31, 2025**		March 31, 2024
Maturity analysis - contractual undiscounted cash flows				
Less than 1 year	**$**	**122**	$	120
1 to 5 years		**410**		435
More than 5 years		**1,337**		1,428
Total Undiscounted Lease Liabilities	**$**	**1,869**	$	1,983

(in millions)		**March 31, 2025**		March 31, 2024
Current	**$**	**78**	$	75
Non-current		**1,270**		1,330
Total Lease Liabilities	**$**	**1,348**	$	1,405

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, 2025 were $15 million (2024 - $11 million payment). The variable rent recoveries for the year ended March 31, 2025 was mainly due to waivers of payments associated with generating unit outages. 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, 2025 were $1 million (2024 - $1 million).

Other leases

The Company leases telecom equipment and the lease liability for each item will be settled in two equal installments that are due at the first and second year anniversaries after each item becomes operational. In addition, the company has commitments to pay $8 million within two years associated with lease assets that have not yet commenced.

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 21: Unearned Revenues and Contributions in Aid

(in millions)		**March 31, 2025**		March 31, 2024
Unearned revenues	**$**	**358**	$	317
Contributions in aid		**2,834**		2,560
		3,192		2,877
Less: Current portion, unearned revenues		**(53)**		(43)
Less: Current portion, contributions in aid		**(70)**		(66)
	$	**3,069**	$	2,768

Note 22: 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, 2025, and March 31, 2024 was as follows:

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(in millions)	**March 31, 2025**	March 31, 2024
Total debt	**$ 32,464**	$ 29,637
Less: Sinking funds	**(279)**	(247)
Less: Cash and cash equivalents	**(136)**	(96)
Net Debt	**$ 32,049**	$ 29,294
Retained earnings	**$ 8,261**	$ 7,677
Contributed surplus	**60**	60
Accumulated other comprehensive loss	**(67)**	(41)
Total Equity	**$ 8,254**	$ 7,696
Net Debt to Equity Ratio	**80 : 20**	**79 : 21**

Dividend Payment to the Province

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

As BC Hydro has not achieved a debt to equity ratio of 60:40 there was no payment for the year ended March 31, 2025 and March 31, 2024.

During the year ended March 31, 2025, the Company contributed $3 million (2024 - $nil) funding to the Province to support incremental workload associated with environmental assessment and permitting resources.

Note 23: 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 and the Company make equal basic and indexing contributions to the plan funds based on a percentage of current pensionable earnings in accordance with the plan provisions and as recommended by the independent actuary. The Company may be required to contribute additional amounts as recommended 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 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 as at December 31, 2023. The valuation has been extrapolated to March 31, 2025 in accordance with IAS 19 and incorporated in these financial statements. The next valuation for funding purposes is required no later than December 31, 2026.

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 and indexing, 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, 2025 and 2024 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:

(in millions)	**Pension Benefit Plans 2025**	Pension Benefit Plans 2024	**Other Benefit Plans 2025**	Other Benefit Plans 2024	**Total 2025**	Total 2024
Current service costs charged to personnel expense - operating expenses	**$ 112**	$ 94	**$ 5**	$ 5	**$ 117**	$ 99
Net interest costs charged to finance costs	**26**	29	**9**	8	**35**	37
Total post-employment benefit plan expense	**$ 138**	$ 123	**$ 14**	$ 13	**$ 152**	$ 136

Actuarial loss recognized in other comprehensive income was $94 million (2024 – gain of $103 million).

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

(in millions)	**Pension Benefits Plans March 31, 2025**	Pension Benefits Plans March 31, 2024	**Other Benefits Plans March 31, 2025**	Other Benefits Plans March 31, 2024	**Total March 31, 2025**	Total March 31, 2024
Defined benefit obligation of funded plan	**$ (5,827)**	$ (5,294)	**$ -**	$ -	**$ (5,827)**	$ (5,294)
Defined benefit obligation of unfunded plans	**(182)**	(166)	**(177)**	(176)	**(359)**	(342)
Fair value of plan assets	**5,324**	4,944	**-**	-	**5,324**	4,944
Plan deficit	**$ (685)**	$ (516)	**$ (177)**	$ (176)	**$ (862)**	$ (692)
Represented by:						
Accrued benefit plan liability	**$ (685)**	$ (516)	**$ (177)**	$ (176)	**$ (862)**	$ (692)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2025 and fiscal 2024 in accordance with IFRIC 14*, The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction*.

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

(in millions)	Pension Benefit Plans **March 31, 2025**	Pension Benefit Plans March 31, 2024	Other Benefit Plans **March 31, 2025**	Other Benefit Plans March 31, 2024
Defined benefit obligation				
Opening defined benefit obligation	**$ 5,460**	$ 5,141	**$ 176**	$ 171
Current service cost	**112**	94	**5**	5
Interest cost on benefit obligations	**321**	309	**9**	8
Benefits paid[1]	**(224)**	(216)	**(6)**	(6)
Employee contributions	**62**	56	**-**	-
Actuarial losses (gains)[2]	**278**	76	**(7)**	(2)
Defined benefit obligation, end of year	**6,009**	5,460	**177**	176
Fair value of plan assets				
Opening fair value	**4,944**	4,581	**n/a**	n/a
Interest income on plan assets[3]	**295**	280	**n/a**	n/a
Employer contributions	**63**	57	**n/a**	n/a
Employee contributions	**62**	56	**n/a**	n/a
Benefits paid[1]	**(217)**	(207)	**n/a**	n/a
Actuarial gains[2,3]	**177**	177	**n/a**	n/a
Fair value of plan assets, end of year	**5,324**	4,944	**-**	-
Accrued benefit liability	**$ (685)**	$ (516)	**$ (177)**	$ (176)

1 Benefits paid under Pension Benefit Plans include $14 million (2024 - $13 million) of settlement payments.

2 Actuarial gains/losses are included in the Non-Current Pension Costs Regulatory Account and for fiscal 2025 are comprised of:
- $177 million of actuarial gains on return on plan assets (2024 - $177 million actuarial gains) due to higher actual return; and
- $271 million of actuarial losses (2024 - $74 million actuarial losses) on the benefit obligations mainly due to a reduction in the discount rate and reflecting the new funding valuation membership data as at December 31, 2023.

3 Actual income on defined benefit plan assets for the year ended March 31, 2025 was $472 million (2024 - $457 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, 2025	March 31, 2024	**March 31, 2025**	March 31, 2024
Discount rate				
Benefit cost	**4.89%**	4.96%	**4.87%**	4.92%
Accrued benefit obligation	**4.64%**	4.89%	**4.64%**	4.87%
Rate of return on plan assets	**4.89%**	4.96%	**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	**3.43%**	3.47%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**3.43%**	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.

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

	Long Term Strategic Target Allocation	**Target Range**		**March 31, 2025**	March 31, 2024
		Min	**Max**		
Fixed interest investments	20%	15%	35%	**21%**	20%
Public equities	40%	30%	50%	**40%**	42%
Real estate	15%	10%	20%[1]	**14%**	14%
Private equities	15%	10%	20%[1]	**15%**	15%
Infrastructure and renewable resources	10%	5%	15%[1]	**10%**	9%

[1]The total of these three 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 investments 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 2026 is expected to amount to $66 million. The expected benefit payments to be paid in fiscal 2026 in respect to the unfunded defined benefit plans are $16 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, 2025		16,608
Actual benefit payments 2025	$	212
Benefits expected to be paid 2026	$	228
Benefits expected to be paid 2027	$	233
Benefits expected to be paid 2028	$	238
Benefits expected to be paid 2029	$	244
Benefits expected to be paid 2030	$	250
Benefits expected to be paid 2031-2034	$	1,067
Weighted average duration of defined benefit 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 table below presents the sensitivity analysis of key assumptions for 2025.

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

		2025	
(in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	-598	-36
Discount rate	1% decrease	+730	+49
Longevity	1 year increase	+118	+3
Longevity	1 year decrease	-121	-3
Compensation	1% increase	+187	+22
Compensation	1% decrease	-162	-19

Note 24: 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 2024/25 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.

(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 18). The Company's 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, 2025, and March 31, 2024. It does not include fair value information for non-derivative financial instruments not measured at fair value if the carrying amount is a reasonable approximation of fair value which include cash and cash equivalents, restricted cash, accounts receivable and accrued revenue, accounts payable, accrued liabilities and revolving borrowings. Their carrying amount is a reasonable approximation of fair value due to the short duration of these financial instruments. When the carrying value differs from fair value, the fair values of the non-derivative financial instruments would be classified as Level 2 of the fair value hierarchy.

	March 31, 2025		March 31, 2024		**2025**	2024
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value	**Interest Income (Expense) recognized in Finance Charges**	Interest Income (Expense) recognized in Finance Charges
Amortized Cost:						
Non-current receivables	**$ 114**	**$ 117**	$ 123	$ 122	**$ 5**	$ 5
Sinking funds (including current portion due in one year)	**279**	**274**	247	245	**16**	10
Long-term debt (including current portion due in one year)	**(29,210)**	**(27,945)**	(24,907)	(22,846)	**(967)**	(837)
First Nations liabilities (non-current portion)	**(444)**	**(470)**	(440)	(464)	**(17)**	(20)
Other liabilities (non-current portion)	**(397)**	**(386)**	(404)	(390)	**(18)**	(19)

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, 2025 in a net asset position of $67 million (2024 - net asset of $13 million). Such contracts are used to hedge the principal on US$ 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.

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($ amounts in millions)	**March 31, 2025**	March 31, 2024
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	**3 years**	4 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	**5 years**	6 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, 2025 Fair Value**	March 31, 2024 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contract assets (cash flow hedges for US$ denominated long-term debt)	**$ 59**	$ 30
Foreign currency contract assets (cash flow hedges for EURO€ denominated long-term debt)	**14**	-
Foreign currency contract liabilities (cash flow hedges for EURO€ denominated long-term debt)	**(6)**	(17)
	67	13
Non-Designated Derivative Instruments:		
Interest rate contract assets	**41**	212
Interest rate contract liabilities	**(99)**	(21)
Foreign currency contract assets	**21**	2
Commodity derivative assets	**231**	162
Commodity derivative liabilities	**(171)**	(485)
	23	(130)
Net assets (liabilities)	**$ 90**	$ (117)

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

For designated cash flow hedges for the year ended March 31, 2025, there was a gain of $54 million (2024 - gain of $17 million). The effective portion was recognized in other comprehensive income. For the year ended March 31, 2025, $88 million (2024 – $nil million) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange losses (2024 - gains) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $3.48 billion (2024 - $2.88 billion), used to economically hedge the interest rates on future debt issuances, there was a $105 million decrease (2024 - $92 million increase) in the fair value of these contracts for the year ended March 31, 2025. For interest rate contracts associated with debt issued, there was a $60 million decrease (2024 - $71 million increase) in the fair value of contracts that settled during the year ended March 31, 2025. The net decrease for the year ended March 31, 2025 of $165 million (2024 - $163 million increase) in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had a net asset balance of $33 million as at March 31, 2025.

Foreign currency contracts associated with U.S. revolving borrowings not designated as hedges, for the year ended March 31, 2025, had a gain of $78 million (2024 - $14 million) recognized in finance charges. These economic hedges offset $67 million of foreign exchange revaluation losses (2024 – $8 million) recorded in finance charges with respect to U.S. revolving borrowings for the year ended March 31, 2025.

For commodity derivatives not designated as hedges, a net gain of $490 million (2024 – loss of $600 million) was recorded in trade revenue for the year ended March 31, 2025.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)		**2025**		2024
Deferred inception gains (losses), beginning of the year	**$**	**31**	$	(15)
New transactions		**56**		73
Amortization		**(20)**		(26)
Foreign currency translation (gain) loss		**3**		(1)
Deferred inception gains, end of the year	**$**	**70**	$	31

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, 2025**		March 31, 2024
Current	**$**	**322**	$	340
Past due (30-59 days)		**31**		33
Past due (60-89 days)		**8**		8
Past due (More than 90 days)		**10**		5
		371		386
Less: Allowance for doubtful accounts		**(6)**		(5)
	$	**365**	$	381

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, 2025			
Derivative commodity assets	**$ 231**	**$ 2**	**$ 229**
Derivative commodity liabilities	**171**	**2**	**169**
As at March 31, 2024			
Derivative commodity assets	$ 162	$ 5	$ 157
Derivative commodity liabilities	485	5	480

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2025 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, 2025. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2025 has been used.

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(in millions)	Carrying Value	Fiscal 2026	Fiscal 2027	Fiscal 2028	Fiscal 2029	Fiscal 2030	Fiscal 2031 *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)	$ 1,618	$ (1,618)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	32,753	(6,318)	(1,794)	(1,922)	(2,409)	(1,351)	(34,854)
Lease obligations	1,348	(123)	(114)	(103)	(104)	(88)	(1,337)
Other long-term liabilities	883	(65)	(108)	(135)	(80)	(60)	(2,175)
Total Non-Derivative Financial Liabilities	36,602	(8,124)	(2,016)	(2,160)	(2,593)	(1,499)	(38,366)
Derivative Financial Liabilities							
Cross currency swaps used for hedging	6						
Cash outflow		(5)	(5)	(5)	(5)	(5)	(212)
Cash inflow		2	2	2	2	2	220
Other forward foreign exchange contracts designated at fair value	-						
Cash outflow		(66)	-	-	-	-	-
Cash inflow		66	-	-	-	-	-
Interest rate swaps used for hedging	99	(59)	(30)	(9)	(3)	-	-
Total Derivative Financial Liabilities	105	(62)	(33)	(12)	(6)	(3)	8
Total Financial Liabilities	36,707	(8,186)	(2,049)	(2,172)	(2,599)	(1,502)	(38,358)
Derivative Financial Assets							
Cross currency swaps used for hedging	(14)						
Cash outflow		(400)	-	-	-	-	-
Cash inflow		414	-	-	-	-	-
Forward foreign exchange contracts used for hedging	(59)						
Cash outflow		(436)	-	-	-	-	(283)
Cash inflow		494	-	-	-	-	331
Other forward foreign exchange contracts designated at fair value	(21)						
Cash outflow		(619)	-	-	-	-	-
Cash inflow		642	-	-	-	-	-
Interest rate swaps used for hedging	(41)	36	-	3	3	-	-
Net commodity derivatives	(60)	67	28	14	11	8	12
Total Derivative Financial Assets	(195)	198	28	17	14	8	60
Net Financial Liabilities	**$ 36,512**	**$ (7,988)**	**$ (2,021)**	**$ (2,155)**	**$ (2,585)**	**$ (1,494)**	**$ (38,298)**

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, 2025 would otherwise have a negative (positive) impact on net income before movement in regulatory balances of $3 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, 2025 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, 2025 would otherwise have a negative (positive) impact on net income before movement in regulatory balance of $31 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, as rounded to the nearest $25 million, an increase and decrease of 100-basis points in interest rates at March 31, 2025 would otherwise have a positive impact of $450 million and a negative impact of $575 million, respectively, on net income before movement in regulatory balances. 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, 2025 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 $22 million at March 31, 2025 (2024 - $15 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, 2025 and 2024:

As at March 31, 2025 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets (liabilities) carried at fair value:				
Short-term investments	$ 78	$ -	$ -	$ 78
Derivative financial instrument assets	54	162	150	366
Derivative financial instrument liabilities	(41)	(146)	(89)	(276)
	$ 91	$ 16	$ 61	$ 168

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

The Company's policy is to recognize level transfers at the end of each period during which the change occurred. During the year, there were no commodity transfers between Level 1 and Level 2 (2024 - $6 million).

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, 2025 and 2024:

(in millions)	
Balance as at April 1, 2024	**$ (94)**
Realized and unrealized gains	377
Transfers	(10)
Settlements	(212)
Balance as at March 31, 2025	**$ 61**

(in millions)		
Balance as at April 1, 2023	**$**	**(255)**
Realized and unrealized gains		1,239
Settlements		(1,079)
Foreign exchange		1
Balance as at March 31, 2024	**$**	**(94)**

During the year, commodity derivatives with a liability carrying amount of $10 million (2024– no transfers) were transferred between Level 2 and Level 3.

During the year ended March 31, 2025, unrealized gain of $89 million (2024 – $113 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, 2025 range between $10-$466 per MwH and a 10 percent increase/decrease in certain components of these prices would decrease/increase fair value by $176 million. A 10 percent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $7 million.

Note 25: Other Non-Current Liabilities

(in millions)		**March 31, 2025**		March 31, 2024
Provisions				
Environmental liabilities	**$**	**279**	$	242
Decommissioning obligations		**83**		62
Other		**77**		73
		439		377
First Nations liabilities		**462**		458
Other contributions		**213**		217
Other liabilities		**458**		464
		1,572		1,516
Less: Current portion, included in accounts payable and accrued liabilities		**(149)**		(174)
	$	**1,423**	$	1,342

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

(in millions)	Environmental	Decommissioning	Other	Total
Balance at April 1, 2023	**$ 270**	**$ 70**	**$ 39**	**$ 379**
Made during the year	-	-	58	58
Used during the year	(62)	(5)	(18)	(85)
Changes in estimate	26	(5)	(6)	15
Accretion	8	2	-	10
Balance at March 31, 2024	**242**	**62**	**73**	**377**
Made during the year	78	9	53	140
Used during the year	(53)	(3)	(48)	(104)
Changes in estimate	5	13	(2)	16
Changes due to currency translation	-	-	1	1
Accretion	7	2	-	9
Balance at March 31, 2025	**$ 279**	**$ 83**	**$ 77**	**$ 439**

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, 2025, the undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2026 and 2086, is approximately $371 million and was determined based on current cost estimates. A range of discount rates between 2.7 per cent and 3.2 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 $130 million (2024 - $93 million), which will be settled between fiscal 2026 and 2086. The undiscounted cash flows, discounted by a range of discount rates between 2.5 per cent and 3.2 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 26: 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 $58.56 billion. Of the $58.56 billion, $16.82 billion is represented by eleven EPAs, of which ten EPAs are related to the 2024 Call for Power, entered into during fiscal 2025 that are still under development.

Included in the total value of the long-term energy purchase agreements is $1.73 billion accounted for as a lease liability under Note 20. The total BC Hydro combined payments are estimated to be approximately $1.54 billion for less than one year, $6.20 billion between one and five years, and $50.82 billion for more than five years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $4.53 billion extending to 2054 (including a purchase commitment with the Province of $2.14 billion). The total Powerex energy purchase commitments are estimated to be approximately $870 million for less than one year, $2.01 billion between one and five years, and $1.65 billion for more than five years.

Powerex has energy sales commitments of $5.28 billion extending to 2035 with estimated amounts of $1.09 billion for less than one year, $2.33 billion between one and five years, and $1.86 billion for more than five years.

Powerex is a funding participant of the Southwest Power Pool's Markets+. The Markets+ Phase 2 financing agreement is pending FERC approval. Once approved, the Company has agreed to provide future collateral of approximately $58 million which will be held by the lender as security for the Markets+ financing.

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 $1.39 billion. Payments are $117 million for less than one year, $338 million between one and five years, and $930 million for more than five years. Included in the total value of the lease and service agreements is $139 million accounted for as a lease liability under Note 20.

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 unfavorably 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. In many cases, it is not possible at this time to predict with any certainty the outcome of such litigation. For existing claims in respect of legal matters which 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. Management believes that any other 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 $55 million (2024 - $64 million). The total outstanding letter of credit also includes US $16 million (2024 - US $17 million) in foreign denominated letters of credit.

Note 27: 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:

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(in millions)	**March 31, 2025**	March 31, 2024
Consolidated Statement of Financial Position		
Prepaid expenses	**$ 94**	$ 87
Right-of-use assets	**1,110**	1,167
Accounts payable and accrued liabilities	**101**	92
Net Derivative assets (liabilities)	**(46)**	191
Lease liabilities	**1,277**	1,314

	2025	2024
Amounts incurred/accrued during the year include:		
Water rental fees	**294**	362
Energy Purchases	**380**	609
Grants and Taxes	**177**	170
Interest	**1,119**	1,018
Interest and foreign exchange derivatives settlement proceeds	**(143)**	(156)
Lease payments	**74**	59
Payment to the Province	**3**	-
Other	**(2)**	28

In addition, the Company's debt is either held or guaranteed by the Province (see Note 18). 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, 2025, the aggregate exposure under this indemnity totaled $135 million (2024 - $250 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 26.

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 were needed for reservoir inundation which was required prior to the first generating unit placed in service on October 27, 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 2025, BC Hydro incurred total costs of approximately $12 million (2024 – $49 million) on highway re-alignment activities, of which $2 million (2024 - $26 million) was incurred directly to the Province. As of March 31, 2025, 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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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)		**2025**		2024
Short-term employee benefits	**$**	**5**	$	4
Post-employment benefits		**1**		1

Appendix D: Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	**2025**	**2024**	**2023**[1]	2022[2]	2021
Revenues					
Domestic	**$ 6,049**	$ 5,504	$ 5,982	$ 5,619	$ 5,237
Trade	**1,429**	1,627	2,496	1,972	1,177
	7,478	7,131	8,478	7,591	6,414
Expenses					
Energy costs	**2,864**	3,725	3,574	3,002	2,269
Other operating expenses[3]	**2,009**	1,675	1,538	1,427	1,366
Amortization and depreciation	**1,200**	1,071	1,052	1,079	1,009
Grants and taxes	**326**	316	296	286	254
Finance charges	**1,094**	516	496	521	224
	7,493	7,303	6,956	6,315	5,122
Net Income (Loss) Before Movement in Regulatory Balances	**(15)**	(172)	1,522	1,276	1,292
Net movement in regulatory balances	**602**	495	(1,162)	(608)	(604)
Net Income	**$ 587**	$ 323	$ 360	$ 668	$ 688
Property, Plant and Equipment, Right-of-Use Assets and Intangible Assets					
Property, Plant and Equipment	**$ 42,945**	$ 40,108	$ 36,926	$ 34,038	$ 31,677
Right-of-Use Assets	**1,180**	1,209	1,305	1,248	1,317
Intangible Assets	**651**	641	639	640	688
Net Book Value	**$ 44,776**	$ 41,958	$ 38,870	$ 35,926	$ 33,682
Property, Plant and Equipment and Intangible Asset Expenditures					
Sustaining	**$ 1,813**	$ 1,477	$ 1,211	$ 1,119	$ 971
Growth	**2,202**	2,786	2,708	2,356	2,236
Total Property, Plant and Equipment and Intangible Asset Expenditures	**$ 4,015**	$ 4,263	$ 3,919	$ 3,475	$ 3,207
Net Long-Term Debt[4]	**$ 32,049**	$ 29,294	$ 26,630	$ 25,642	$ 24,740
Retained Earnings	**$ 8,261**	$ 7,677	$ 7,354	$ 6,994	$ 6,326
Debt to Equity Ratio	**80 : 20**	79 : 21	78 : 22	78 : 22	80 : 20

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 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.

4 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	**2025**	2024	2023[1]	2022	2021
Generating Capacity (megawatts)					
Hydroelectric	**13,271**	12,041	12,041	12,027	12,027
Thermal	**177**	176	174	179	177
Total	**13,448**	12,217	12,215	12,206	12,204
Peak One-Hour Integrated System Demand (megawatts)	**10,476**	11,363	10,977	10,787	10,076
Number of Domestic Customer Accounts					
Residential	**2,024,503**	1,990,321	1,961,208	1,931,041	1,896,518
Light industrial and commercial	**228,483**	226,151	223,915	221,573	218,196
Large industrial	**204**	204	203	201	202
Other	**3,425**	3,380	3,367	3,387	3,383
Total	**2,256,615**	2,220,056	2,188,693	2,156,202	2,118,299
Domestic Electricity Sold (gigawatt-hours)					
Residential	**19,345**	19,171	19,547	19,440	18,983
Light industrial and commercial	**19,319**	19,205	19,247	19,029	18,091
Large industrial	**14,482**	14,032	13,437	13,312	12,438
Other sales	**3,608**	3,005	7,649	1,671	1,628
Total	**56,754**	55,413	59,880	53,452	51,140
Net Electricity Exports/Imports (gigawatt-hours)					
Electricity exports	**726**	613	5,621	7,099	9,082
Electricity imports	**9,082**	14,212	3,988	1,120	997
Net Electricity Exports (Imports)	**(8,356)**	(13,599)	1,633	5,979	8,085
Net Electricity Export Revenues (Import Costs) (in millions)					
Electricity exports	**$ 32**	$ 27	$ 728	$ 299	$ 228
Electricity imports	**528**	1,377	644	67	27
Net Electricity Exports (Imports)	**(496)**	(1,350)	84	232	201
Revenues (in millions)					
Residential	**$ 2,405**	$ 2,129	$ 2,146	$ 2,342	$ 2,210
Light industrial and commercial	**2,061**	1,913	1,840	1,952	1,830
Large industrial	**947**	866	848	854	762
Other sales	**636**	596	1,148	471	435
Total Domestic	**6,049**	5,504	5,982	5,619	5,237
Trade	**1,429**	1,627	2,496	1,972	1,177
Total	**$ 7,478**	$ 7,131	$ 8,478	$ 7,591	$ 6,414

Average Revenue (per kilowatt-hour)

for the years ended or as at March 31	**2025**	2024	2023	2022	2021
Residential	**12.4¢**	11.1¢	11.0¢	12.0¢	11.6¢
Light industrial and commercial	**10.7**	10.0	9.6	10.3	10.1
Large industrial	**6.5**	6.2	6.3	6.4	6.1
Average Annual Kilowatt-Hour Use Per Residential Customer Account	**9,637**	9,703	10,044	10,158	10,097
Lines In Service					
Distribution (kilometres)	**60,650**	60,474	60,289	60,093	59,907
Transmission (circuit kilometres)	**20,223**	20,198	20,192	20,148	19,958

[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.

TOTAL ELECTRICITY SALES AND SOURCES OF SUPPLY

for the years ended March 31	**2025**			2024			2023[1]			2022			2021		
	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	**13,448**	**56,754**	**80.6**	12,217	55,413	79.4	12,215	59,880	77.7	12,206	53,452	70.3	12,204	51,140	67.6
Electricity trade		**8,438**	**12.0**		10,118	14.5		12,018	15.6		17,836	23.5		19,407	25.7
		65,192	**92.6**		65,531	93.9		71,898	93.4		71,288	93.8		70,547	93.3
Line loss and system use		**5,214**	**7.4**		4,259	6.1		5,119	6.6		4,709	6.2		5,104	6.7
		70,406	**100.0**		69,790	100.0		77,017	100.0		75,997	100.0		75,651	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,857**	**12,365**	**17.6**	2,857	8,824	12.6	2,857	13,497	17.5	2,857	15,626	20.6	2,857	15,907	21.0
Revelstoke	**2,480**	**7,073**	**10.0**	2,480	6,148	8.8	2,480	9,410	12.2	2,480	8,548	11.2	2,480	9,218	12.2
Mica	**2,746**	**6,247**	**8.9**	2,746	5,282	7.6	2,746	8,733	11.3	2,746	7,681	10.1	2,746	8,669	11.5
Kootenay Canal	**583**	**2,410**	**3.4**	583	2,245	3.2	583	2,300	3.0	583	2,780	3.7	583	2,626	3.5
Peace Canyon	**694**	**2,982**	**4.2**	694	2,214	3.2	694	3,319	4.3	694	3,791	5.0	694	3,893	5.1
Seven Mile	**805**	**2,415**	**3.4**	805	2,549	3.7	805	2,906	3.8	805	2,936	3.9	805	3,039	4.0
Bridge River	**491**	**2,162**	**3.1**	491	2,070	3.0	491	2,588	3.4	478	2,578	3.4	478	2,219	2.9
Site C	**767**	**1,308**	**1.9**	-	-	-	-	-	-	-	-	-	-	-	-
Other	**1,385**	**3,898**	**5.5**	1,385	3,641	5.2	1,385	3,384	4.4	1,384	4,125	5.2	1,384	4,225	5.6
	12,808	**40,860**	**58.0**	12,041	32,973	47.3	12,041	46,137	59.9	12,027	48,065	63.1	12,027	49,796	65.8
Thermal generation	**177**	**111**	**0.2**	176	105	0.2	174	174	0.2	179	125	0.2	177	150	0.2
Purchases from Independent Power Producers		**12,920**	**18.4**		13,667	19.6		15,409	20.0		16,824	22.1		14,630	19.3
Non-integrated energy purchases		**120**	**0.2**		115	0.2		117	0.2		119	0.2		109	0.1
Market purchases		**17,520**	**24.9**		24,288	34.8		16,005	20.8		11,857	15.6		11,321	15.0
Other		**(1,126)**	**(1.7)**		(1,358)	(2.1)		(825)	(1.1)		(993)	(1.3)		(355)	(0.5)
	12,985	**70,406**	**100.0**	12,217	69,790	100.0	12,215	77,017	100.0	12,206	75,997	100.0	12,204	75,651	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.