British Columbia Hydro and Power Authority

2021/22
Annual Service Plan Report

August 2022

For more information on the BC Hydro contact:

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

Published by BC Hydro

Board Chair's Accountability Statement

The *BC Hydro 2021/22 Annual Service Plan Report* compares the corporation's actual results to the expected results identified in the *2021/22 – 2023/24 Service Plan* created in April 2021. The Board is accountable for those results as reported.

Doug Allen
Board Chair
July 29, 2022

Table of Contents

Board Chair's Accountability Statement 3

Letter from the Board Chair & President & CEO 5

Purpose of the Annual Service Plan Report 7

Purpose of the Organization 7

Strategic Direction 8

Operating Environment 8

Report on Performance: Goals, Objectives, Measures and Targets 10

Financial Report 21

- Management's Discussion and Analysis 21
- Capital Expenditures 36

Appendix A: Additional Information 43

Appendix B: Subsidiaries and Operating Segments 44

- Active Subsidiaries 44

Appendix C: Auditor's Report and Audited Financial Statements 47

Appendix D: Financial and Operating Statistics 115

Letter from the Board Chair & President & CEO

On behalf of the Board of Directors and all BC Hydro employees, we are pleased to submit BC Hydro's Annual Service Plan Report for the year ending March 31, 2022. This letter provides an overview of highlights from the past year, as well as information on BC Hydro's reporting relationship as a Crown Corporation.

The COVID-19 pandemic continued to present challenges for BC Hydro and our customers. However, it reinforced our role as an essential service, providing clean, reliable and affordable electricity to our customers more important than ever. Throughout the year, we supported the Province and our customers to help B.C.'s economy recover from the impacts of COVID-19.

While we navigated the extraordinary developments of the pandemic, we have the important responsibility of keeping electricity rates affordable for our customers and funding necessary investments in our system. To ensure British Columbians continue to receive the reliable and clean electricity that is vital to the province's economic prosperity and climate objectives, we invested approximately $3.5 billion in 2021/22 to upgrade aging assets and build new infrastructure.

Throughout the year, we managed Site C within the updated cost estimate of $16 billion. Despite the ongoing challenges of the COVID-19 pandemic, project construction progressed and the project is now more than 60 per cent complete.

We acted upon the outcomes and recommendations from the Comprehensive Review of BC Hydro to position BC Hydro for future success while meeting the Province's climate goals and controlling our costs to keep rates affordable for British Columbians. To make it easier and more affordable for people to efficiently use more of B.C.'s clean electricity instead of fossil fuels to power their homes, businesses and vehicles, we launched our Electrification Plan – A clean future powered by water. The plan proposes new programs and incentives to advance the switch from fossil fuels to clean electricity in homes and buildings, vehicles and fleets, businesses and industry and to attract new innovative industries to B.C. We also continued to advance affordability initiatives to help our customers save money on their electricity bills and focussed on making it easier for our customers to do business with us.

BC Hydro worked closely with the Ministry of Energy, Mines and Low Carbon Innovation (EMLI) to ensure alignment with Government policy expectations through regular meetings and updates. These were held between BC Hydro and EMLI Executives, as well as with the Minister and his staff, as appropriate, to discuss actions identified by the Province. With respect to organizational governance and shareholder engagement, the development and responsibilities of Directors and the Executive are outlined in *Appendix A: Additional Information.*

We are proud of our accomplishments this year. We will continue to work together to ensure that our workforce goes home safely, every day, while delivering reliable, affordable, clean electricity to our customers.

Doug Allen

Board Chair
July 29, 2022

Chris O’Riley

President & CEO
July 29, 2022

Purpose of the Annual Service Plan Report

The Annual Service Plan Report is designed 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, the Crown Corporation's Board is required to report on the actual results of the Crown's performance related to the forecasted targets documented in the previous year's Service Plan.

Purpose of the Organization

BC Hydro's mission is: we are here to safely provide our customers with reliable, affordable, clean electricity. We are one of the largest energy suppliers in Canada, generating and delivering electricity to 95 per cent of the population of British Columbia. We operate an integrated system backed by 30 hydroelectric plants and two thermal generating stations, as well as approximately 80,000 kilometres of transmission and distribution lines. Our partnership with B.C.'s clean energy industry encompasses approximately 125 generation projects across the province, including biomass, hydro, wind and solar generating facilities. Our electricity generation is 97.4 per cent clean.

As a provincial Crown Corporation, the owner and sole shareholder of BC Hydro is the Province of British Columbia. BC Hydro reports to the Provincial Government through the Minister of EMLI and the Government's expectations are expressed through the Board Chair's 2021-22 Mandate Letter and the following legislation and policy:

- The *Hydro and Power Authority Act*
- The *Utilities Commission Act*
- The *BC Hydro Public Power Legacy and Heritage Contract Act*
- The *Clean Energy Act (CEA)*
- CleanBC

The *Hydro and Power Authority Act* gives BC Hydro its mandate to generate, manufacture, conserve, supply, acquire, and dispose of power and related products.

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 as technical experts in a range of fields related to the electric utility and clean energy industries and offers services and solutions to energy clients, including BC Hydro, and other sectors globally. For more information on Powerex, Powertech and other active and inactive subsidiaries, see *Appendix B: Subsidiaries and Operating Segments*.

Strategic Direction

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

Operating Environment

As a utility that operates in a high hazard industry, safety is always top of mind and our goal continues to be that everyone goes home safely, every day. We are continuously working to improve our performance by sustaining and strengthening our Safety and Compliance Framework.

In 2021/22, climate change and extreme weather continued to affect our business. In late June 2021, intense heat led to three days of record-breaking summer electricity demand on BC Hydro's system. On June 29, 2021, BC Hydro set a record for summer power consumption when demand peaked at 8,516 megawatts, shattering the record that was set before the heat wave began by more than 600 megawatts.

In the summer of 2021, British Columbia once again experienced devastating wildfires, with hundreds of wildfires burning across the northern and southern interior parts of the province. Working in coordination with the BC Wildfire Service, our crews worked hard to protect critical circuits and mountaintop communication sites threatened by fire to maintain system performance. The wildfires caused outages for our customers and significant damage to our infrastructure. Restoration efforts were made in relatively short order and our crews rebuilt more than 680 distribution poles and 55 transmission structures.

Between November 13-15, 2021, an atmospheric river caused storms that brought heavy winds, flooding and landslides to southern B.C. The storm caused catastrophic damage to BC Hydro infrastructure and more than 258,000 customers lost power. Despite extensive damage in some areas, crews were able to restore power to approximately 85 per cent of customers affected within 48 hours. In areas affected by evacuation orders, BC Hydro worked closely with local authorities and safety agencies to confirm when power could be restored safely.

BC Hydro crews worked around the clock to rebuild infrastructure that was damaged by landslides and flooding caused by the storm, replacing transmission structures, power lines and wires in many areas of the province. For example, along the Highway 8 corridor, our crews needed to replace 87 power poles and 14 transformers.

To support our customers affected by wildfire and flooding events, we waived electricity charges for residential and small business customers that had been under an evacuation order for five days or more. We also waived their last bills, and any charges to establish a new electric service when they rebuild, if not covered by their insurance

The storm also caused significant inflows into reservoirs at BC Hydro facilities and increased inflows downstream of the facilities. The inflows in several basins were the highest on record for the storm period and triggered temporary flood alerts for people and businesses that were impacted by high river levels. BC Hydro experts worked behind the scenes to manage reservoir levels and plan releases of water from reservoirs to reduce the magnitude and volume of downstream flows to help protect the public and property.

We also saw peak electricity consumption this year. On December 27, 2021, the demand for electricity hit an all-time high of 10,902 megawatts, the highest in our history. We are fortunate to have a large, flexible system that enables us to respond to increased electricity demand, which means that the power will be there on the hottest and coldest days, as we experienced this year.

As B.C.'s economy began to gradually recover from the impacts of the global COVID-19 pandemic, along with the extreme weather experienced throughout the province – intense heat in the summer and very cold temperatures in December 2021 – the demand for electricity increased by six per cent in 2021/22, compared to 2020/21. As we responded to the increased electricity demand, our financial position continued to be stable, and we prudently managed all costs to maintain affordable rates for our customers. We also continued to build our resilience against cyber and physical attacks on our system.

BC Hydro's electricity system was largely built in the 1960s, 1970s and 1980s and we invested approximately $3.5 billion last year to upgrade aging assets and build new infrastructure. There are hundreds of BC Hydro capital projects underway that, together, make up one of the largest expansions of electrical infrastructure in British Columbia's history. During 2021/22, BC Hydro capital projects placed in-service totaled $1.4 billion, including projects to renew and expand our generation, transmission and distribution systems.

Report on Performance: Goals, Objectives, Measures and Targets

Goal 1: Safety Above All

Objective 1.1: Safety at BC Hydro is a core value. We are committed to ensuring our workforce goes home safely every day, and that the public is safe around our system.

Key Highlights

- As of March 31, 2022, BC Hydro had gone over 11 years without a fatality - maintaining the longest period without a fatality in over 30 years of recorded data.
- 98 per cent of corrective actions were closed on or before the scheduled due date, compared to a target of 97 per cent.
- Managed COVID-19 risk, major province-wide weather events and an extreme wildfire season without major impacts to our safety performance.

Performance Measures[1]	2020/21 Actuals	2021/22 Target	2021/22 Actuals	2022/23 Target	2023/24 Target
1.a Zero Fatality & Serious Disabling Injury[2] [Loss of life or the injury has resulted in a permanent disability]	0	0	1	0	0
1.b Lost Time Injury Frequency [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	0.62	0.76	0.87	0.74	0.74
1.c Timely Completion of Corrective Actions (%)	99	97	98	98	98

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/toolbar/about/accountability_reports/financial_reports/annual_reports.html.
[2] Zero Fatality & Serious Disabling Injury – BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.

Discussion of Results

In 2021/22, BC Hydro achieved its performance target for Timely Completion of Corrective Actions but did not achieve its targets for the Zero Fatality & Serious Disabling Injury and Lost Time Injury Frequency performance measures.

BC Hydro's investments in safety have improved our safety performance to zero fatalities since 2010. However, due to a serious employee electrical contact incident in June 2021 that resulted in a permanent disability, BC Hydro did not achieve its 2021/22 Zero Fatality & Serious Disabling Injury target.

Preventing serious injury incidents and meeting our ongoing target of Zero Fatalities & Serious Disabling Injuries remains our top priority. In 2022/23, we will complete corrective actions related to this incident and further increase our efforts on key safety programs related to electrical hazards; this includes the continuing implementation of the arc flash program. BC Hydro is also focused on revising our current safety incident management processes to improve how we learn from safety incidents.

We finished 2021/22 with a lost time injury frequency rate of 0.87, a return to our five-year average, compared to a target of 0.76. This represents an increase in thirteen lost time injuries compared to 2020/21, and six lost time injuries above our target. With our employees returning to the office, we observed six lost time injuries in office workers, compared to zero in 2020/21, and an increase in field worker lost time injuries - 43 compared to 36 in 2020/21.

We continue to see an overall decline in lost time injuries related to slips, trips, falls and ergonomics; however, this hazard continues to be the largest single contributor of lost time injuries. Consistent with the previous year and with other Electricity Canada member initiatives, in 2021/22, BC Hydro did not include lost time injuries related to COVID-19 in the lost time injury frequency calculation. In 2022/23, we will work with operational teams to make proactive safety improvements in areas such as job pre-planning and hazard identification and training to support supervisors in the daily execution of their safety responsibilities.

In 2021/22, 98 per cent of the corrective actions were closed on or before the due date, compared to a target of 97 per cent, as we continue to address systemic safety issues and risks. This marks four consecutive years with results at or above 97 per cent.

In 2021/22, BC Hydro continued to comply with public health orders related to the COVID-19 pandemic that dictated changes to field work and most office employees worked from home. The extreme wildfires during the summer months and the November 2021 atmospheric river that resulted in province-wide catastrophic flooding were managed without major impacts to our safety performance.

Goal 2: Set the Standard for Reliable and Responsive Service

Objective 2.1: BC Hydro will reliably meet the evolving expectations of our customers by prudently planning and investing in the system, improving our service and advancing reconciliation with Indigenous Peoples.

Key Highlights

- Targets for our customer reliability measures, System Average Interruption Duration Index and System Average Interruption Frequency Index, were met despite experiencing several challenging weather events throughout the year.
- Maintained a Customer Satisfaction Index result of 91 per cent, with consistent results across all three customer segments: residential, commercial, and key accounts. In the first full year of surveying, customers in Non-Integrated Areas reported a satisfaction index result of 86 per cent.
- BC Hydro obtained our fourth consecutive gold level Progressive Aboriginal Relations designation from the Canadian Council for Aboriginal Business, demonstrating our commitment to implementing leading Indigenous Relations practices across the areas of leadership, community relationships, business development and employment.

Performance Measures[1]	2020/21 Actuals	2021/22 Target	2021/22 Actuals	2022/23 Target	2023/24 Target
2.a SAIDI (System Average Interruption Duration Index)[2] [Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year (excluding major events)]	3.27	3.20	3.50	3.17[3]	3.17[3]
2.b SAIFI (System Average Interruption Frequency Index)[2] [Total number of sustained interruptions experienced by an average customer in a year (excluding major events)]	1.49	1.40	1.54	1.38	1.38
2.c Key Generating Facility Forced Outage Factor (%)[4]	1.21	1.80	1.03	1.80	1.80
2.d CSAT (Customer Satisfaction Index)[5] [% of customers satisfied or very satisfied]	91.0	85.0	91.0	85.0	85.0
2.e Progressive Aboriginal Relations Certification[6]	Gold	Gold	Gold	Gold	Gold

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/toolbar/about/accountability_reports/financial_reports/annual_reports.html.

[2] Reliability targets are based on specific values, however performance within 10 per cent 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 reports reliability under

normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measure is therefore based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.
[3] The 2022/23 and 2023/24 SAIDI targets were adjusted upward to 3.30 and 3.35 respectively in the 2022/23 – 2024/25 Service Plan
[4] Key Generating Facility Forced Outage Factor is reported as a five-year rolling average and defined as the total forced outage time in a period relative to the total number of hours in the same period (usually one year).
[5] CSAT is an index measuring customer satisfaction of BC Hydro's three main customer groups (residential, commercial, and key accounts). The index is comprised of the five key drivers of satisfaction weighted equally across the three customer types.
[6] Progressive Aboriginal Relations is a certification program administered by the Canadian Council for Aboriginal Business. It is renewed on a three-year cycle.

Discussion of Results

Reliability

Customer reliability is reported using the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). At the end of the third quarter this year, we had forecasted that our SAIDI and SAIFI targets were not going to be met. However, calmer weather patterns in the fourth quarter resulted in better reliability performance and we were able to meet our annual targets, within the 10 per cent margin. Although we again experienced increasingly challenging weather events throughout the year, we continued to maintain customer reliability through monitoring and planning for overall system reliability.

In 2021/22, BC Hydro:

- Successfully responded to an increased number of winter storms that tested our capability to respond to major events.
- Completed a high number of planned outages to maintain system reliability and focused on providing customers with advance notice of outages to minimize impacts.
- Addressed complex challenges related to multiple catastrophic events including wildfires, flooding, a transmission cable failure and physical and cyber security incidents to ensure ongoing system reliability and resilience.
- Updated over 150 emergency and continuity plans that support operations both in the preparation for, and response to, any significant disruptive events that may impact our ability to meet operational and business needs.

BC Hydro continues to report on the Key Generating Facility Forced Outage Factor as an important measure of the ongoing reliability of the generating system. There are seven Key Generating Facilities, representing those plants with installed capacity greater than 200 MW[1]. Together, they provide 90 per cent of the average annual electricity generated by BC Hydro's facilities. This measure demonstrates the continued effectiveness of BC Hydro's maintenance and capital investment programs.

[1] The Waneta Generating Station is not included in the Forced Outage Factor Performance Measure because BC Hydro does not manage or operate the facility.

In 2021/22, BC Hydro focussed on the following to ensure the reliability of the Key Generating Facilities:

- Continued to prioritize sustaining capital investments.
- Continued to focus on returning equipment to service in a timely manner, minimizing the duration of forced outages and the impacts on the power system.
- Maintained our focus on preventing unplanned downtime by proactively assessing condition and performance through engineering evaluations.
- Performed a root cause analysis when outages occurred to understand the cause and prevent reoccurrences of similar outages.

BC Hydro achieved the target to remain below 1.80 per cent for Key Generating Facility Forced Outage Factor with a result of 1.03 per cent.

Service

The Customer Satisfaction Index (CSAT) measure gauges the level of customer satisfaction in meeting their electricity needs. Our 2021/22 CSAT result of 91.0 per cent, the same result as 2020/21, reflects our ongoing efforts in ensuring high customer reliability, continued commitment to customer services and improvements in our customer communications. In 2021/22, BC Hydro:

- Provided 2,348 Customer Crisis Fund grants to customers facing emergency financial situations and disconnection with financial assistance of up to $600 to pay their bills to enable the continued supply of electricity.
- Implemented tariff changes to allow electricity charges to be waived for residential and small business customers under evacuation orders in place for at least five days, in response to increasing wildfire and flooding events. BC Hydro also waived customers' last bills, and charges to establish a new electric service when they rebuild, if not covered by their insurance.
- Increased BC Hydro's electric vehicle fast charging network to 112 fast chargers at 78 sites.

Indigenous Relations

BC Hydro continued to advance reconciliation by incorporating the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP), the Calls to Action of the Truth and Reconciliation Commission and the Draft Principles that Guide the Province of British Columbia's Relationship with Indigenous Peoples into our business by working more collaboratively with Indigenous Nations.

BC Hydro has been a recognized leader in Indigenous Relations, achieving our fourth consecutive Gold certification under the Canadian Council for Aboriginal Business's Progressive Aboriginal Relations program since 2012. This demonstrates BC Hydro's commitment to implementing leading Indigenous Relations practices across the areas of leadership, community relationships, business development and employment. BC Hydro is one of 18 companies in Canada to achieve Gold status, and one of only two utilities at the Gold level.

BC Hydro continued to seek, develop and sustain positive long-term relationships and to better understand Indigenous interests so that these priorities were recognized in our capital projects, programs and operations activities. This year, BC Hydro:

- Provided over $150.2 million in contracts to Indigenous designated businesses.
- Hired 39 Indigenous people into full-time, part-time regular and temporary positions; of these, eight individuals were hired into full-time positions throughout the company.
- Awarded 36 Indigenous students from across the province with scholarships and bursaries to advance their education, totalling approximately $160,000.

Goal 3: Help Keep Electricity Bills Affordable for our Customers

Objective 3.1: BC Hydro will help keep electricity bills affordable by managing our costs, exploring innovative solutions to support our customers and making cost-effective investments to maintain and expand our electricity system.

Key Highlights

- BC Hydro's residential, commercial and industrial rates were ranked in the first quartile, based on an analysis of Hydro Quebec's annual report, 2021 Comparison of Electricity Rates in North America.
- Filed the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application with the BC Utilities Commission (BCUC) requesting a bill decrease of 1.4 per cent starting April 1, 2022.
- Over the last five years, BC Hydro successfully delivered 234 capital projects at a total cost of $4.14 billion, which is 4.76 per cent under the aggregated budget of $4.35 billion and within the target of +/- 5 per cent of budget.
- Implemented all 17 recommendations resulting from Peter Milburn's independent review of the Site C project to improve project oversight and governance.

Performance Measures[1]	2020/21 Actuals	2021/22 Target	2021/22 Actuals	2022/23 Target	2023/24 Target
3.a Affordable Bills – Residential[2]	N/A[3]	1st quartile	1st quartile	1st quartile	1st quartile
3.b Affordable Bills – Commercial[2]	N/A[3]	1st quartile	1st quartile	1st quartile	1st quartile
3.c Affordable Bills – Industrial[4]	N/A[3]	1st quartile	1st quartile	1st quartile	1st quartile
3.d Project Budget to Actual Cost[5]	-3.64% on $4.05 billion[6]	Within +5% to -5% of budget excluding project reserve amounts	-4.76% on $4.35 billion[7]	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at . www.bchydro.com/toolbar/about/accountability_reports/financial_reports/annual_reports.html.
[2] As of 2021/22, 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 from Hydro Quebec's annual report on North American electricity rates. The rankings of the 22 participating utilities are then allocated into quartiles. The 1st quartile ranking represents the six utilities that have the lowest monthly electricity bills on April 1 of a given year.
[3] These measures were introduced in the 2021/22 – 2023/24 Service Plan.
[4] BC Hydro measures affordability within the industrial category based on the largest consumption level from Hydro Quebec's annual report on North American electricity rates.
[5] This measure compares actual project costs at completion to the original approved full scope implementation budgets, not including project reserve amounts, for capital projects that were put into service during the five-year rolling period. This measure includes Dam Safety, Generation, Transmission Line, Substation as well as major Distribution and Property projects, managed by BC Hydro Capital Infrastructure Project Delivery.
[6] This represents projects that went into service for the five-year period 2016/17 to 2020/21.
[7] This represents projects that went into service for the five-year period 2017/18 to 2021/22.

Discussion of Results

BC Hydro prudently manages all costs to maintain affordable rates for our customers, including operating and capital expenditures. Our ongoing actions to keep rates low for our customers have resulted in our residential, commercial and industrial rates being ranked in the first quartile for 2021/22, based on analysis of Hydro Quebec's annual report, 2021 Comparison of Electricity Rates in Major North American Cities.

On August 31, 2021, BC Hydro filed the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application with the BCUC, requesting an average annual bill increase of only 1.1 percent – below the rate of forecasted provincial rate of inflation over the three-year period. This application reflects our efforts to continue to deliver safe and reliable power, while keeping electricity affordable for our customers.

BC Hydro measures its performance in delivering capital projects with the Project Budget to Actual Cost measure. Since its introduction in 2015/16, BC Hydro has consistently met its yearly target of being within +5 per cent to -5 per cent of the project budget, not including project reserve amounts. Over the last five years, BC Hydro successfully delivered 234 capital projects at a total cost of $4.14 billion, which is 4.76 per cent under the aggregated budget of $4.35 billion and within the target of +/- 5 per cent of budget.

In 2021/22, BC Hydro's Project Delivery group actively managed approximately 300 projects. We continued to improve our project and portfolio performance reports, including a data analytics initiative to better leverage historical project delivery information to support decision-making and timely delivery of projects within budget. We also continued to focus on streamlining processes to reduce cost and accelerate schedules for projects that meet defined criteria, such as pre-existing alternatives analysis or where the scope has low complexity and/or risk.

In 2021/22, we undertook the following initiatives to manage our supply chain and mitigate risks and cost pressures caused by the COVID-19 pandemic, extreme weather events and global transportation and logistics issues:

- Increased inventory levels and placed earlier orders for frequently used materials and products to maintain the system and respond to adverse weather events.
- Negotiated longer-term strategic contracts to moderate cost increases and transparency on price changes. Agreements with specialty distributors for products such as electrical components, IT hardware and field consumables also provided benefits in managing upstream supply chains, manufacturers, logistics, monitoring market conditions and aggregated inventories.

Construction on Site C has been underway since July 2015. The project is more than 60 per cent complete and remains on track to have all six generating units fully in-service by late 2025.

BC Hydro continued to manage Site C within the updated cost estimate of $16 billion. The delays and impacts related to the COVID-19 pandemic remain the largest contributors to the cost increase in the project budget.

All 17 recommendations from Peter Milburn's independent review of the project were implemented by September 30, 2021.

As of March 31, 2022, the project had contractual commitments of $10.8 billion, of which $8.8 billion has been spent since the project began and $2.0 billion remains committed on executed contracts and agreements. Key accomplishments this year included:

- **Construction activities:** Despite the ongoing challenges of the COVID-19 pandemic for a second year, project construction continued to progress on the following: powerhouse, penstocks, intakes and spillways; placement of material in the earthfill dam and excavations for the approach channel; all six segments of Highway 29; and reservoir clearing. In addition, the dam and core buttress and the steel structure/enclosure for the powerhouse were completed. The second and final 500 kilovolt, 75 km transmission line was also completed.
- **Right bank foundation enhancements:** BC Hydro completed the installation of the planned 48 piles located within the spillways stilling basin required to increase the stability under the structures on the right bank, including the powerhouse, spillways and future dam core area. In January 2022, the installation of the planned 48 piles located in the powerhouse tailrace area began.

- **COVID-19 response:** BC Hydro continued to work closely with local government, First Nations and the health authority to ensure worker and public safety at Site C, while managing the impacts of the COVID-19 pandemic.

  In March 2021, the Site C project began administering COVID-19 vaccinations for workers through the onsite medical clinic. In October 2021, BC Hydro announced it would require proof of vaccination from all BC Hydro employees and from all other individuals working at BC Hydro facilities, including those working at Site C.

  As of January 10, 2022, all employees and contractors including Site C workers were required to have two doses of an approved COVID-19 vaccine.

- **Project workforce:** In March 2022, there were 4,430 people working on the Site C project, including 3,124 workers from B.C. (71 per cent of the total workforce), 337 Indigenous workers, 447 women, and 798 workers from the Peace River Regional District. In July 2021, the project saw an annual workforce peak of 5,108, the highest number in 2021/22.

- **Indigenous relations**: Throughout the year, BC Hydro worked with Nations affected by Site C to strengthen relationships and to work collaboratively to find solutions to issues important to their communities. A key mechanism for engagement has been the Environmental Forum, which brings Nations and BC Hydro together to share information, collaborate and seek input and involvement on environmental mitigation plans and monitoring programs. Seven Environmental Forums were held, covering various topics including: methylmercury, fish passage, aggregate sources, permitting and beaver monitoring. The Culture and Heritage Resources Committee has been meeting since 2013 to address cultural impacts. Three meetings took place this year with a focus on the travelling exhibit, the video project, viewpoint signage and community artifact displays.

  Since the beginning of the project, more than $600 million in procurement opportunities have been awarded to Indigenous designated companies.

- **Community benefits:** BC Hydro distributed $71,000 to 10 non-profit organizations in the Peace Region as part of the Generate Opportunities Fund. By the end of March 2022, BC Hydro had provided more than $585,000 in total to 67 projects.

  In addition, 38 Peace Region agricultural projects received $917,000 in funding through the BC Hydro Peace Agricultural Compensation Fund. As of March 2022, more than $1.6 million in total has been distributed to 72 projects.

- **Project oversight:** The Site C Project Assurance Board continued to provide independent expert advice on the project. There were 13 Project Assurance Board meetings and eight workshops on specific topics held in 2021/22.

  In May 2021, the Province announced a restructured Site C Project Assurance Board to strengthen its independence and increase its expertise. These changes helped bolster the skillset of the Board to ensure it provides independent advice to the Province and our Board of Directors.

The Project Assurance Board continues to receive monthly updates from the Technical Advisory Board and from the Independent Dam Experts on a quarterly basis.

In addition, EY Canada continues to provide an independent project assurance function and assist with identifying project risks and implementing effective mitigation strategies.

The project also continues to work with Mr. Peter Milburn to ensure the 17 recommendations that were implemented as of September 30, 2021, continue to be sustained.

Goal 4: Help Make Renewable, Clean Power British Columbia's Leading Energy Source

Objective 4.1: BC Hydro will encourage the use of its renewable, clean power for electrification to reduce greenhouse gas emissions and will continue to invest in its energy-efficiency and conservation programs.

Key Highlights

- The energy savings from energy efficiency and conservation initiatives of 661 gigawatt hours per year (GWh/year) were approximately 32 per cent higher than the target of 500 GWh/year, due to higher than planned savings across the portfolio.
- Continued to exceed our Clean Energy performance target of 93.0 per cent, with 97.4 per cent of electricity generated from clean or renewable resources.
- To advance the switch from fossil fuels to clean electricity in homes and buildings, vehicles and fleets, businesses and industry, and to attract new innovative industries to B.C., BC Hydro launched our Electrification Plan – A clean future powered by water.
- Submitted the Integrated Resource Plan to the BCUC that includes the long-term plan and the near-term actions that BC Hydro intends to carry out to ensure that we can meet the future electricity needs of our customers.
- Launched a heat pump incentive program to help residential customers with the costs of retrofitting their fossil fueled home heating systems to ones powered by BC Hydro's clean energy.

Performance Measures[1]	2020/21 Actuals	2021/22 Target	2021/22 Actuals	2022/23 Target	2023/24 Target
4.a Energy Conservation Portfolio (New incremental GWh/year)[2]	801	500	661	500	500
4.b Clean Energy (%)	98.0	93.0	97.4	93.0	93.0

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/toolbar/about/accountability_reports/financial_reports/annual_reports.html.
[2] Annual targets are part of a Demand Side Management Plan that is subject to BCUC review and approval.

Discussion of Results

BC Hydro continued to have strong performance from our energy efficiency and conservation initiatives and exceeded the Energy Conservation Portfolio target of 500 GWh/yr. Offers and programs to support low income and residential customers, as well as customers in the non-integrated areas, continued in 2021/22 and improved affordability for participating customers by helping them be more energy efficient and reduce their bills.

We continued to exceed our Clean Energy performance measure target. This measure represents the objective in the *Clean Energy Act* that at least 93 per cent of electricity generation in the province is from clean or renewable resources.

BC Hydro's Electrification Plan, filed as part of our Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, provides a framework for our work to attract innovative new industries to British Columbia and promote B.C.'s clean energy advantage, including reducing the time and cost for new customers to connect to our grid.

In December 2021, we submitted the Integrated Resource Plan to the BCUC. The Integrated Resource Plan includes the long-term plan and the near-term actions that BC Hydro intends to carry out to ensure that we can meet the future electricity needs of our customers over a 20-year planning horizon. The plan includes electrification scenarios to show how BC Hydro will take advantage of our clean electricity to support the Province's CleanBC climate action and economic growth objectives.

As part of the CleanBC plan, to reduce or eliminate the use of diesel generation, we continued to work with Indigenous communities to advance the development of clean energy generation projects such as solar, stored hydro, run-of-river hydro and biomass projects.

BC Hydro also supported the Indigenous Clean Energy Opportunities Review. The Review was launched by the Province in November 2021, in collaboration with the First Nations Leadership Council and First Nations Energy and Mining Council, to identify and support new clean energy opportunities for Indigenous peoples related to CleanBC, Phase 2 of the Comprehensive Review of BC Hydro and the BCUC Inquiry on Indigenous Utilities.

Financial Report

For the auditor's report and audited financial statements, see Appendix C. These 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, 2022 and should be read in conjunction with the 2021/22 Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2022 and 2021.

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

- The net income for the year ended March 31, 2022 was $668 million, $20 million lower than the prior fiscal year.
- The net regulatory balance as at March 31, 2022 was $2.91 billion, $1.37 billion lower than prior fiscal year.
- The BC Utilities Commission (BCUC) issued its decision (Decision) on BC Hydro's Fiscal 2022 Revenue Requirements Application (F2022 RRA) on June 17, 2021. The Decision resulted in a Fiscal 2022 customer bill increase of 1.0 per cent which resulted in a $52 million increase in domestic revenues for the year ended March 31, 2022.
- Domestic sales volumes for the year ended March 31, 2022 were 2,312 GWh (or 5 per cent) higher than the prior fiscal year. This increase was primarily weather-related (warmer temperatures in the summer and colder temperatures in December) and due to the economy gradually recovering from the impacts of COVID-19. There remains significant uncertainty with the pandemic's impacts on electricity demand.
- Capital expenditures, before contributions in aid of construction, for the year ended March 31, 2022 were $3.48 billion, a $268 million increase over the prior fiscal year. The increase in capital expenditures for the year ended March 31, 2022 compared to the same period in the prior year was primarily due to Site C expenditures which can fluctuate based on the timing of work performed.

Consolidated Results of Operations

for the years ended March 31 ($ in millions)		**2022**		2021		Change
Total Revenues	**$**	**7,591**	$	6,414	$	1,177
Net Income	**$**	**668**	$	688	$	(20)
Capital Expenditures	**$**	**3,475**	$	3,207	$	268
GWh Sold (Domestic)		**53,452**		51,140		2,312

as at March 31 ($ in millions)		**2022**		2021		Change
Total Assets and Regulatory Balances	**$**	**42,734**	$	40,383	$	2,351
Shareholder's Equity	**$**	**7,046**	$	6,367	$	679
Retained Earnings	**$**	**6,994**	$	6,326	$	668
Debt to Equity		**78 : 22**		80 : 20		n/a
Number of Domestic Customer Accounts		**2,156,202**		2,118,299		37,903

Revenues

For the year ended March 31, 2022, total revenues of $7.59 billion, were $1.18 billion (or 18 per cent) higher than the prior fiscal year. The increase was due to higher trade revenues of $795 million and higher domestic revenues of $382 million.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [1]	
for the years ended March 31	**2022**	2021	**2022**	2021	**2022**	2021
Revenues						
Residential	**$ 2,342**	$ 2,210	**19,440**	18,983	**$ 120.47**	$ 116.42
Light industrial and commercial	**1,952**	1,830	**19,029**	18,091	**102.58**	101.16
Large industrial	**854**	762	**13,312**	12,438	**64.15**	61.26
Other sales	**471**	435	**1,671**	1,628	**-**	-
Domestic Revenues	**5,619**	5,237	**53,452**	51,140	**105.12**	102.41
Trade Revenues	**1,972**	1,177	**31,267**	32,640	**68.71**	42.52
Revenues	**$ 7,591**	$ 6,414	**84,719**	83,780	**$ 89.60**	$ 76.56

[1] The Trade $ per MWh represents the gross $ per MWh of physical transactions and does not include financial transactions.

Domestic Revenues

For the year ended March 31, 2022, domestic revenues were $5.62 billion, $382 million (or 7 per cent) higher than the prior fiscal year. The increase was due to a combination of higher domestic sales and higher average rates that reflect the 1.0 per cent rate approved by the British Columbia Utilities Commission (BCUC) effective April 1, 2021, as well as lower revenues in the first six months of prior year due to the COVID-19 relief program grants and waivers provided to customers.

Domestic sales volumes were 2,312 GWh (or 5 per cent) higher than the prior fiscal year. This includes a 5 per cent increase in Light Industrial and Commercial sales volumes due to increased business activity, as the economy gradually recovers from the impacts of COVID-19. Large Industrial sales volumes were also higher by 7 per cent, mainly in the pulp and paper and oil and gas sectors reflecting increased production and an improved energy market, as well as higher production in the chemical sector and wood manufacturing sector, as economic conditions improved. Higher Residential sales volumes of 2 per cent were primarily driven by warmer temperatures in summer and colder temperatures in December.

Trade Revenues

For the year-ended March 31, 2022, total trade revenues were $1.97 billion, $795 million (or 68 per cent) higher than the prior fiscal year. The increase in trade revenues was primarily driven by higher average sales prices for the year.

Operating Expenses

For the year ended March 31, 2022, total operating expenses of $5.79 billion were $896 million (or 18 per cent) higher than the prior fiscal year. The increase was primarily due to higher energy costs of $733 million, higher materials and external services of $82 million, higher amortization and depreciation of $70 million, higher grants and taxes of $32 million, and higher personnel costs of $25 million. This was partially offset by lower other costs (net of recoveries) of $40 million.

Energy Costs

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals, transmission and other 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.

Total energy costs for the year ended March 31, 2022 were $3.00 billion, $733 million (or 32 per cent) higher than the prior fiscal year. The increase was primarily due to higher trade energy costs of $487 million and higher domestic energy costs of $246 million.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31	**2022**	2021	**2022**	2021	**2022**	2021
Energy Costs						
Water rental payments (hydro generation)[1]	**$ 345**	$ 295	**47,072**	49,441	**$ 7.33**	$ 5.97
Purchases from Independent Power Producers	**1,522**	1,403	**16,824**	14,630	**90.47**	95.90
Gas and transportation for thermal generation	**3**	4	-	-	-	-
Transmission charges and other expenses	**49**	38	**119**	109	**-**	-
Non-Treaty storage and co-ordination agreements	**17**	(50)	**-**	-	**-**	-
Domestic Energy Costs	**1,936**	1,690	**64,015**	64,180	**30.24**	26.33
Trade Energy Costs	**1,066**	579	**26,177**	25,098	**45.45**	26.44
Energy Costs	**$ 3,002**	$ 2,269	**90,192**	89,278	**$ 33.28**	$ 25.41

[1]Water rental payments are based on the previous calendar year's generation volumes. The volumes are actual hydro generation during the period. The $ per MWh is a simple average calculation and does not reflect actual water rental rates during the period.
[2]The Trade $ per MWh represents the gross $ per MWh of physical transactions and does not include financial transactions.

Domestic Energy Costs

Domestic energy costs for the year ended March 31, 2022 were $1.94 billion, $246 million (or 15 per cent) higher than the prior fiscal year. The increase in costs was primarily due to higher purchases from Independent Power Producers (IPPs) driven by higher energy deliveries mainly from two IPPs due to changes to their operations in the current year that increased the amount of energy available for sale to BC Hydro as well as an increased number of IPPs in operations in the current year. There were also higher Non-Treaty Storage and Co-ordination agreements costs due to fewer net water releases in the current year compared to higher net water releases in the prior year.

In addition, there were higher water rental payments which are based on the prior calendar year's hydro generation volumes and were driven by higher water inflows in the prior calendar year.

Trade Energy Costs

Total trade energy costs for the year ended March 31, 2022 were $1.07 billion, an increase of $487 million (or 84 per cent) compared with the prior fiscal year. The increase in trade energy cost was primarily driven by higher average purchase prices for the period.

Water Inflows and Reservoir Storage

Water inflows (energy equivalent) to the system for the year ended March 31, 2022 were above average but lower than the prior fiscal year. The above average water inflows for the year ending March 31, 2022 were due to above average snowmelt into both Kinbasket Reservoir (Columbia River Basin) and Williston Reservoir (Peace River Basin) in the spring of 2021 and offset by below average precipitation to the Williston system during the summer of 2021.

Reservoir storage (system energy) is tracking above the ten-year historic average due to net above average inflows across the fiscal year. System energy storage at March 31, 2022 was slightly lower than at March 31, 2021.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the year ended March 31, 2022 were $736 million, $25 million (or 4 per cent) higher than the prior fiscal year primarily due to higher current service pension costs attributed to lower pension discount rates which are based on rates at the beginning of the year.

Materials and External Services

Materials and External Services primarily includes materials, supplies, and contractor fees. Expenditures on materials and external services for the year ended March 31, 2022 were $672 million, $82 million (or 14 per cent) higher than the prior fiscal year primarily due to higher spend for work programs including vegetation work mainly due to less work performed in the prior year due to delays from COVID-19, higher spend to support compliance with the Mandatory Reliability Standards Program in British Columbia, and higher Demand-Side Management program costs.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, right-of-use assets, and amortization of intangible assets. For the year ended March 31, 2022, amortization and depreciation expense was $1.08 billion, $70 million (or 7 per cent) higher than the prior fiscal year primarily due to additional property, plant and equipment placed in service and higher depreciation as a result of a change in the estimated useful lives of BC Hydro’s property, plant, and equipment. The change in estimated useful lives was based on the result from a depreciation study that was completed in fiscal 2022.

Grants and Taxes

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

Total grants and taxes for the year ended March 31, 2022 were $286 million, $32 million (or 13 per cent) higher primarily due to higher taxes relating to trading activity in the United States.

Other Costs, Net of Recoveries

Other costs, net of recoveries primarily includes gains and losses on the disposal of assets, certain cost recoveries related to operating costs, and dismantling costs. For the year ended March 31, 2022, other costs net of recoveries were $97 million, $40 million (or 29 per cent) lower than the prior fiscal year. The decrease was primarily due to an increase in environmental provisions in the prior year related to the remediation of polychlorinated biphenyl (PCB) and asbestos, partially offset by higher project and asset write-offs.

Capitalized Costs

Capitalized costs consist of costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Capitalized costs for the year ended March 31, 2022 were $78 million, which is comparable to the $72 million in the prior fiscal year.

Finance Charges

Finance charges for the year ended March 31, 2022 were $521 million, $297 million (or 133 per cent) higher than the prior fiscal year. The increase was primarily due to lower unrealized gains on future debt hedges used to economically hedge the interest rates on future debt issuances in the current year as compared to the prior year. As at March 31, 2022, $3.73 billion in remaining active future debt hedges (2021 – $3.23 billion) increased in value by $230 million during the fiscal year due to increasing forward interest rates (2021 - $571 million increase due to increasing forward interest rates). These future debt hedges were placed to lock in the interest rate on our future debt issuances. The increase was partially offset by lower interest rates for long-term debt that was refinanced and short-term borrowings.

Regulatory Transfers

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

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. The use of regulatory accounts is common amongst regulated North American utility industries. 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 to future periods differences between forecast and actual costs or revenues. 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)	**2022**	2021
Cost of Energy Variance Accounts		
Heritage Deferral	**$ 38**	$ 146
Non-Heritage Deferral	**(28)**	(114)
Load Variance	**(79)**	(33)
Biomass Energy Program Variance	**(26)**	(13)
Low Carbon Fuel Credits Variance	**(31)**	-
Trade Income Deferral	**(264)**	(155)
	(390)	(169)
Forecast Variance Accounts		
Non-Current Pension Costs	**(668)**	(50)
Debt Management	**(153)**	(516)
Real Property Sales	**(15)**	(11)
Total Finance Charges	**26**	(62)
Other	**46**	31
	(764)	(608)
Capital-Like Accounts		
Demand-Side Management	**94**	81
Site C	**3**	(2)
IFRS Property, Plant & Equipment	**0**	22
	97	101
Non-Cash Accounts		
Environmental Provisions & Costs	**(1)**	54
First Nations Provisions & Costs	**15**	21
CIA Amortization	**(5)**	(5)
	9	70
Amortization of regulatory accounts	**(330)**	(141)
Interest on regulatory accounts	**12**	19
Net decrease in regulatory accounts	**$ (1,366)**	$ (728)

For the year ended March 31, 2022, there was a net reduction of $1.37 billion to the Company's regulatory accounts compared to a net reduction of $728 million in the prior fiscal year. The net regulatory asset balance as at March 31, 2022 was $2.91 billion compared to $4.28 billion as at March 31, 2021.

Net reductions to the regulatory accounts during the year ended March 31, 2022 included a $668 million reduction to the Non-Current Pension Costs Account primarily due to a decrease in the post-employment benefit plan liabilities as a result of an increase in discount rates and a higher rate of return on pension plans assets, a $330 million reduction due to Amortization, a $264 million reduction to the Trade Income Deferral Account due to higher than planned trade income, a $153 million of reduction to the Debt Management Regulatory Account as a result of a net increase in the fair value of interest rate hedges resulting from an increase in the forward interest rates, partially offset by net additions of $37 million in the remaining regulatory accounts.

Net regulatory account balances are as follows:

as at March 31 (in millions)		**2022**		2021
Cost of Energy Variance Accounts				
Heritage Deferral	**$**	**105**	$	65
Non-Heritage Deferral		**(185)**		(153)
Load Variance		**33**		110
Biomass Energy Program Variance		**(40)**		(14)
Low Carbon Fuel Credits Variance		**(30)**		-
Trade Income Deferral		**(504)**		(227)
		(621)		(219)
Forecast Variance Accounts				
Non-Current Pension Costs		**(669)**		114
Debt Management		**286**		449
Real Property Sales		**32**		46
Total Finance Charges		**39**		(61)
Other		**91**		27
		(221)		575
Capital-Like Accounts				
Demand-Side Management		**868**		881
Smart Metering & Infrastructure		**151**		173
IFRS Property, Plant & Equipment		**1,039**		1,070
Site C		**542**		523
		2,600		2,647
Non-Cash Accounts				
Environmental Provisions & Costs		**234**		294
First Nations Provisions & Costs		**469**		486
IFRS Pension		**382**		421
CIA Amortization		**68**		73
		1,153		1,274
Net Regulatory Asset	**$**	**2,911**	$	4,277

BC Hydro has or has applied for regulatory mechanisms to collect all regulatory accounts with balances at March 31, 2022 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 2021/22-2023/24 Service Plan (Service Plan) was filed in April 2021 with forecast net income for 2021/22 of $712 million.

The table below provides an overview of BC Hydro's 2021/22 financial results, relative to its Service Plan.

(in millions)		Actual		Service Plan[2]		Variance to Service Plan
For the year ended March 31,		**2022**		**2022**		
Revenues						
Domestic	$	5,619	$	5,527	$	92
Trade		1,972		1,121		851
		7,591		6,648		943
Expenses						
Operating Costs						
Cost of energy		3,002		2,389		(613)
Other operating expenses						
Personnel expenses, materials and external services [1]		1,308		1,317		9
Amortization		1,079		1,033		(46)
Grants and taxes		286		274		(12)
Other		119		101		(18)
Finance charges		521		552		31
		6,315		5,667		(649)
Net Income Before Movement in Regulatory Balances		1,276		981		294
Net movement in regulatory balances		(608)		(269)		(339)
Net Income	$	668	$	712	$	(44)

[1] These amounts are net of capitalized costs and recoveries.

[2] Column may not add due to rounding.

Net income for 2021/22 was $668 million, compared to forecast net income of $712 million in the Service Plan filed in April 2021. 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 mainly due to higher operating costs as a result of higher than planned project and asset write-offs that were not subject to deferral to regulatory accounts.

Liquidity and Capital Resources

Cash flow provided by operating activities for the year ended March 31, 2022 was $2.42 billion, compared with $1.84 billion in the prior fiscal year. The increase was mainly due to higher cash from changes in working capital and higher trade income.

The long-term debt balance net of sinking funds as at March 31, 2022 was $25.74 billion compared to $24.78 billion as at March 31, 2021. The increase was mainly a result of an increase in net long-term bond issuances (net of redemptions) for net proceeds of $1.04 billion. The increase was primarily to fund capital expenditures and to manage working capital.

Capital Expenditures

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

for the years ended March 31 (in millions)		**2022**		2021
Transmission lines and substations replacements and expansion	**$**	**436**	$	369
Generation replacements and expansion		**351**		301
Distribution system improvements and expansion		**572**		572
General, including technology, vehicles and buildings		**192**		240
Site C Project		**1,924**		1,725
Total Capital Expenditures	**$**	**3,475**	$	3,207

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

The increase in capital expenditures of $268 million for the year ended March 31, 2022 compared to the same period in the prior fiscal year was primarily due to Site C Project expenditures, which can fluctuate based on the timing of work performed. The Site C Project cost forecast remains at the $16 billion budget with an in-service date in calendar 2025 as approved in June 2021.

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: Transmission Wood Structure and Framing Replacements, Capilano Substation Upgrade, Various Sites –NERC (North American Electric Reliability Corporation) CIP (Critical Infrastructure Protection)-003v7 Implementation, Mount Lehman Substation Upgrade, Clayburn Substation Upgrade, and Sperling Substation Metalclad Switchgear Replacement.

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: Waneta Unit 3 Life Extension, Mica Replace Units 1 to 4 Generator Transformers, Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment, Puntledge Recoat Interior and Exterior of Steel Penstock, Fort Nelson – Unit 1 Engine Replacement, and John Hart Dam Seismic Upgrade.

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

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

Site C incurred capital expenditures across the project, primarily for work areas such as generating station and spillways, main civil works, turbines and generators, right bank foundation enhancements, highway realignment and for worker accommodations, project management and support services and interest during construction.

Rate Regulation

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy, and earn an annual rate of return.

Regulatory Applications

The BCUC issued its Decision on BC Hydro's F2022 RRA on June 17, 2021. The Decision resulted in a Fiscal 2022 customer bill increase of 1.0 per cent which resulted in a $52 million increase in domestic revenues for the year ended March 31, 2022.

On August 31, 2021, BC Hydro filed a three-year revenue requirements application with the BCUC, seeking an annual average bill increase of 1.1 per cent for the next three years. To recover our planned expenditures, BC Hydro requested a net bill decrease of 1.4 per cent on April 1, 2022, followed by net bill increases of 2.0 per cent on April 1, 2023 and 2.7 per cent on April 1, 2024. The Application sought additional operating funding for investments in Mandatory Reliability Standards, vegetation management and cybersecurity. The Application also sought funding for BC Hydro's Electrification Plan to increase low carbon electrification, attract additional customer load and connect customers more efficiently. On February 22, 2022, the BCUC issued Order No. G-47-22, which approved our requested bill decrease of 1.4 per cent consisting of a rate increase of 0.62 per cent and Deferral Account Rate Rider of negative 2.0 per cent for fiscal 2023 on an interim basis. BC Hydro expects a decision on the application by the end of fiscal 2023.

Performance Based Regulation

On December 21, 2021 the BCUC issued its decision on Performance Based Regulation directing BC Hydro to file, no later than December 31, 2023, a proposal for a Performance Based Regulation Plan for BC Hydro covering years starting with Fiscal 2026. The BCUC has directed that this proposal include, among other things, a Plan covering at least five years and proposed indices/formulas that would be used to set controllable costs where possible.

Risk Management

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

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of BCUC-approved regulatory accounts. 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, domestic and trade energy cost, and finance charges. These are influenced by several elements, which are generally categorized into the following six factors:

- Hydro generation;
- Customer demand;
- Electricity/gas trade margins;
- Deliveries from electricity purchase agreement contracts;
- Interest rates; and
- Discount rates – Post Employment Benefit Plans.

Neither a high nor a low value of any of these individual factors is intrinsically positive or negative for BC Hydro's financial results. It is the specific combination of these factors in any given year which has an impact.

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 customers.

In June 2021, the Province's Treasury Board approved a revised $16 billion budget and a new in-service date of 2025 for the Site C Project. The approved budget and schedule addressed significant cost pressures and delays faced by the Site C Project due to the COVID-19 pandemic, as well as the right bank foundation enhancements and other cost pressures prior to the COVID-19 pandemic. The Site C Project continues to manage significant potential risks including the ongoing continuation of the COVID-19 pandemic, commercial negotiations with contractors, design changes due to unknown field conditions, availability of skilled workers, and obtaining remaining authorizations for the completion of the Project. BC Hydro implemented all the recommended actions in the Milburn Report by September 30, 2021 which have resulted in enhancing the independence, mandate and expertise of the Site C Project Assurance Board and strengthening the risk and commercial management processes on the Project. 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.

Hydro Generation

The amount of generation available influences BC Hydro's financial results by changing the amount of surplus energy we have available to export (or need to import to meet domestic load). The amount of available generation is driven primarily by the amount and timing of inflows (hydrology) into BC Hydro-dispatched plants and reservoirs, and initial reservoir storage conditions prior to seasonal snow melt (freshet).

The range of inflows, year to year, can significantly influence available generation: over 14,000 GWh (or approximately 25 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.

Customer Demand

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

There can also be short-term fluctuations in customer load due to timing of new large customer facility start-up 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.

Domestic load volumes for the year ended March 31, 2022 were approximately 5 per cent higher compared to the prior fiscal year. This increase was primarily due to global, national and provincial economies recovering from the COVID-19 pandemic and weather-related factors (warmer temperatures in the summer and colder temperatures in December). The uncertainty associated with the pandemic may continue to impact electricity demand.

Electricity/Gas Trade Margins

Electricity and gas trade margins are impacted by electricity and gas prices. Electricity and gas prices, themselves, are variable and a function of gas and electricity market fundamentals.

Deliveries from Electricity Purchase Agreement Contracts (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 average energy cost 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, 2022, overall energy delivered from EPAs was higher than forecast. Although hydro and wind projects delivered more energy than expected, the higher than forecast deliveries from these projects were partially offset by lower than forecast deliveries from biomass and thermal generation projects.

Interest Rates

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

As at March 31, 2022, approximately 13 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 long-term debt issuance, as at March 31, 2022, BC Hydro had interest rate hedges in place with an aggregate notional principal of $3.7 billion, hedging a portion of its forecast long-term debt issuances out to and including 2025/26.

Discount Rates – Post-Employment Benefit Plans Current Service Costs

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

Future Outlook

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in February 2022 forecast net income for 2022/23 at $712 million which is consistent with the amount required by Order in Council No. 123.

The Company's earnings 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 2022/23 assumes average water inflows (100 per cent of average), domestic sales of 53,626 GWh, average market energy prices of US $51.18/MWh, short-term interest rates of 0.50 per cent, and a Canadian to US dollar exchange rate of US $0.7981.

The COVID-19 pandemic continues to adversely impact global activity and has contributed to significant volatility in financial markets. The pandemic could have a sustained adverse impact on economic and market conditions and could adversely impact BC Hydro's future performance if it were to cause a prolonged decrease in customer load, volatility in electricity/gas trade margins, interest rate volatility, difficulty accessing debt, project delays and project cost escalations.

While BC Hydro engages in emergency preparedness (including business continuity planning) to mitigate risks, the persisting uncertainty of this situation limits the ability to predict the ultimate adverse impact of COVID-19 on BC Hydro's performance, financial condition, results of operations and cash flows.

Earnings Sensitivity

The following table shows the estimated effect on net income of changes in some key variables, before regulatory account transfers. The analysis is based on business conditions and generation volumes forecast for 2022/23. Each separate item in the sensitivity analysis assumes the others are held constant. While these sensitivities are applicable to the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitude of changes.

The volatility between BC Hydro's plan and actual results are mostly mitigated through the use of BCUC-approved regulatory accounts.

Factor	Change	Approximate change in 2022/23 earnings before regulatory account transfers (in millions)	5 year high	5 year low	2021/22
Hydro generation [1]	+/- 1%	$20	49,796 GWh	40,382 GWh	48,065 GWh
Customer demand [2]	+/- 1%	$25	53,452 GWh	51,140 GWh	53,452 GWh
Electricity/gas trade margins [3]	+/- 10%	$30	$906	$209	$906
Purchases from EPAs [4]	+/- 1%	$10	16,824 GWh	14,248 GWh	16,824 GWh
Interest rates -variable debt [5]	+/- 100 basis points	$35	2.01%	0.53%	0.56%
Interest rates – hedges of future debt issuances [6]	+/- 100 basis points	+$450/-$550	10-yr 2.62% 30-yr 2.74%	10-yr 1.22% 30-yr 1.64%	10-yr 2.03% 30-yr 2.36%
Discount rates - Post-employment benefit plan current service costs [7]	+/- 100 basis points	+$19/-$26	4.38%	3.33%	4.38%

[1] Assumes a change in hydro generation is offset by a corresponding change in system imports or exports.

[2] Assumes a percentage change is applied equally to all customer classes. Assumes a change in customer load is offset by a corresponding change in system imports or exports.

[3] Trade revenues less trade energy costs (in millions).

[4] Assumes a change in purchases from EPAs is offset by a corresponding change in system imports or exports.

[5] Interest rates are the annual daily average Canadian short-term interest rates (3-month Canadian Dollar Offered Rate). The values in the 5-year high and low columns are the high and low of the annual averages and not the high and low of all daily rates during the 5-year period.

[6] Relates to unrealized gains/(losses) on interest rate hedges of future debt issuances. The hedging gains and losses serve to offset variation in annual interest rate costs when amortized through the Debt Management Regulatory Account (DMRA). Sensitivity is

based on notional value of hedges outstanding and market forward interest rates as at March 31, 2022. Interest rates are the annual daily average 10-year and 30-year spot swap rates. The values in the 5-year high and low columns are the high and low of the annual average rates and not the high and low of all daily rates during the 5-year period. Spot swap rates are used as an indicative proxy for the purposes of this table. Actual DMRA interest rate sensitivity is dependent on the market forward bond yields and market forward swaps rates specific to each future debt hedge outstanding at a given point in time.

[7] Discount rate based on the yields of AA Canadian Corporate bonds.

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 $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2022 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Projects Recently Put Into Service				
Peace Region Electricity Supply (PRES) Project This project was needed to provide sufficient transmission system capacity to serve load growth and increase the reliability of electricity supply to existing customers in the South Peace. This project facilitated reductions in provincial greenhouse gas emissions by enabling electrification of natural gas production, processing, and compression. **The total cost represents the gross cost of the project and has not been netted for potential Federal Government contributions.*	2021 In-Service	$214	$2	$216*
LNG Canada Load Interconnection Project This project was to facilitate the interconnection of LNG Canada's facility. A new double circuit 287kV transmission line was constructed from Minette Substation (MIN) to LNG Canada's facility and system reinforcements at MIN were also implemented. Under BC Hydro's standard tariffs, the customer was required to pay for 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 $24M.*	2021 In-Service	$79	$3	$82*

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2022 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Projects Recently Put Into Service				
Bridge River 2 Upgrade Units 7 and 8 Project This project replaced the two generators and other related equipment to restore the historical operating capacity. Units 7 and 8 were placed into service in 1960, were unreliable and in poor and unsatisfactory condition.	2021 In-Service	$72	$6	$78
Downtown Vancouver Electricity Supply: West End Strategic Property Purchase This project acquired property rights to build and connect a new underground substation that will upgrade the aging electricity system in downtown Vancouver.	2022 Completed	$73	$1	$74
Ongoing				
Mica Replace Units 1 to 4 Generator Transformers Project This project will address the reliability and safety risks of the Unit 1-4 Generator Step-up Unit transformers at the Mica Generating Station, which are nearing end of life. There is a heightened reliability and safety risk from continuing to operate these transformers in an underground powerhouse as they age.	2022 Targeted In-Service	$66	$14	$80

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2022 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
G.M. Shrum (GMS) G1 to 10 Control System Upgrade This project will replace the controls equipment, provide full remote-control capability from the control center, and rectify deficiencies in the current system. The condition of the legacy controls for the GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of available spare parts and decreasing reliability. The controls are well beyond their expected life, which causes operating problems and increases the risk of damage to major equipment.	2022 Targeted In-Service	$63	$12	$75
Wahleach Refurbish Generator Project This project will improve the reliability of the generator at Wahleach Generating Facility, and its scope includes replacement of the stator and rotor poles, refurbishment of the remaining major components, and a combination of new, replacement, and refurbishment of the auxiliary components. The project also includes the installation of a new powerhouse crane and structural upgrades to the powerhouse building.	2023 Targeted In-Service	$38	$13	$51
Mount Lehman Substation Upgrade Project This project will increase the firm capacity of the Mount Lehman Substation to address safety and asset health concerns at both the Clayburn and Sumas Way substations.	2023 Targeted In-Service	$43	$15	$58

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2022 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Street Light Replacement Program The program will convert approximately 95,000 BC Hydro owned and maintained High Pressure Sodium and Mercury Vapour street lights to Light Emitting Diode (LED) street lights. This is required to meet federal polychlorinated biphenyl (PCB) environmental regulations by the end of 2025, manage increasing operations and maintenance costs, and better meet our customers' expectations. Lights have started to be converted and conversions will be completed in 2023.	2023 Targeted In-Service	$34	$41	$75
5L063 Telkwa Project This project will increase the reliability and reduce the safety risks of the 500kV radial transmission line (5L063) that provides service for customers in Northwest British Columbia. A portion of the 5L063 line will be relocated away from the current area of unstable terrain.	2023 Targeted In-Service	$26	$40	$66
Mica Modernize Controls Project This project will address the reliability, maintainability, and operability of the Units 1-4 exciters, governors, unit controls and control room controls at the Mica Creek Generating Station.	2023 Targeted In-Service	$38	$18	$56
Various Sites – NERC CIP-003v7 Implementation Project This project is required to install equipment and establish processes, practices, and procedures to ensure that BC Hydro is compliant with the Critical Infrastructure Protection (CIP) CIP-003-7 and revised CIP-003-8 Mandatory Reliability Standards on all low impact Bulk Electric System Cyber Assets.	2023 Targeted In-Service	$19	$41	$60

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2022 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Capilano Substation Upgrade Project This project will address the existing asset health, reliability, safety, and environmental issues associated with the Capilano Substation, and to ensure that the capacity of the substation meets the long term area needs. The project will also introduce a 25kV source to enable 25kV voltage conversion and facilitate the execution of other future substation projects in the North Shore area.	2024 Targeted In-Service	$30	$57	$87
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 will be completed at 38 substations and microwave repeater sites and the project will also include installation of a new microwave radio link.	2024 Targeted In-Service	$33	$20	$53
Natal – 60-138 kV Switchyard Upgrade Project This project is to address reliability, regulatory and safety risks at the Natal substation as the 60-138kV switchyard equipment is at end of life and requires replacement.	2025 Targeted In-Service	$6	$78	$84

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2022 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Site C Project*** This project will construct a third dam and a hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years. **Planned in-service date for all units.* ***Site C project anticipated total cost and project cost to date include capital costs, charges subject to regulatory deferral and certain operating expenditures.* ****The approved updated project cost estimate is $16 billion with a project in-service date of calendar year 2025 (first and last generating unit in-service in December 2024 and 2025, respectively). BC Hydro continues to manage significant risks to the project such as the ongoing COVID-19 pandemic and the potential impacts to on-site construction activities. The Site C Project continues to work with the Project Assurance Board, Mr. Milburn, Ernst & Young Canada, and the Technical Advisory Board to manage these project risks.*	2025* Targeted In-Service	$8,809	$7,191	$16,000**
Sperling Substation (SPG) Metalclad Switchgear Replacement Project This project will address the existing asset health, reliability and safety risks associated with the 12kV 60 series feeder section and the bulk oil breaker in the 12 kV 70/80 series feeder section, insufficient electrical clearances in the 60 series feeder section, and arc flash safety risks associated with the 12kV indoor metalclad switchgear.	2026 Targeted In-Service	$17	$37	$54

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to Mar 31, 2022 ($ millions)	Estimated Cost to Complete ($ millions)	Anticipated Total Cost ($ millions)
Treaty Creek Terminal – Transmission Load Interconnection (KSM) Project The project is to facilitate the interconnection for construction power for the Kerr-Sulphurets-Mitchell (KSM) Mine to BC Hydro's transmission system. Under BC Hydro's standard tariffs, the customer is required to pay for 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 $37M.*	2026 Targeted In-Service	$9	$100	$109*

Appendix A: Additional Information

Organizational Overview

BC Hydro has offices throughout British Columbia and our employees operate in some of the most difficult terrain in the world. Our transmission system connects with transmission systems in Alberta and Washington State, which improves overall reliability of the system and provides opportunities for trade. Our largest offices are located in Burnaby, Cranbrook, Kamloops, Nanaimo, Prince George, Revelstoke, Surrey, Vancouver, Vernon and Victoria. Information about BC Hydro's organization and operating environment can be found at: http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html

Corporate Governance

BC Hydro is governed by a Board of Directors that is accountable to the Minister Responsible for the implementation of Government direction. The Board's direction is implemented by management, who carries out the day-to-day operations of the Corporation under the supervision of the Chief Executive Officer. For more information on Corporate Governance, please refer to: https://www.bchydro.com/toolbar/about/who_we_are/board_of_directors.html

To support Director training and development, an orientation program is aimed at increasing their familiarity with the Corporation, our industry, and the unique responsibilities of Crown Corporation Directors, as well as equipping them with sufficient information and resources to make fully informed decisions. The program utilizes materials and resources that inform Directors on the Corporation's corporate governance framework, its businesses, operations and current issues and strategies. Directors are also provided with ongoing development opportunities that include special site visits to provide them with additional insight into the Corporation's operations.

To promote awareness and understanding of the standards of conduct that BC Hydro expects, the Board of Directors has approved a Code of Conduct Policy and management has implemented a similar policy applicable to contractors (the Contractor Standards for Ethical Conduct). These documents provide general guidance on standards of conduct, including guidelines on conflict of interest, as well as requirements associated with confidential information, entertainment and gifts, environment and safety and use of BC Hydro property. They also allow exemptions from their requirements to be granted in extraordinary circumstances, and where it is clearly in the best interests of BC Hydro to do so. This is supplemented by guidance available from BC Hydro's Ethics Officer, as well as an independent Code Advisor for Directors and senior members of the executive.

Appendix B: Subsidiaries and Operating Segments

Active Subsidiaries

BC Hydro has created or retained a number of subsidiaries for various purposes, including holding licenses in other jurisdictions, to manage real estate holdings and to manage various risks.

As wholly owned subsidiaries, and like BC Hydro itself, Powerex Corp. and Powertech Labs Inc. follow best practices in corporate governance and subsidiary activities align with BC Hydro's mandate, strategic priorities and fiscal plan.

Powerex Corp.

Powerex Corp., an energy marketer, is a wholly owned corporate subsidiary of BC Hydro and a key participant in wholesale energy markets across North America. Powerex's business consists of 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.

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

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

Powerex operates in competitive and complex wholesale energy-markets, which can cause net income in any given year to vary significantly. Market, economic and weather conditions, reduced hydro system flexibility, unrealized mark-to-market gains or losses and the strength of the Canadian dollar can materially impact Powerex net income. Over the previous five years, Powerex's net income has ranged from $140 million to $441 million (2017/18 to 2021/22). For more information, visit powerex.com

Board of Directors:

- Catherine Roome - Chair
- Len Boggio
- Sam Drier
- Marilyn Mauritz
- Chris O'Riley

Powertech Labs Inc.

Powertech Labs Inc., operating in Surrey since its inception in 1979, is a wholly owned subsidiary of BC Hydro. Powertech is internationally recognized as technical experts in a range of fields related to the electric utility and clean energy industries and offers services and solutions including performance and type testing, asset lifecycle management solutions, engineering studies, and power system modelling and analysis to energy clients, including BC Hydro, and other sectors globally. Powertech is also a technical leader in hydrogen energy, providing certification, performance, and safety testing services for hydrogen components and systems, as well as the design and construction of innovative hydrogen vehicle refueling systems.

The President and CEO of Powertech reports to Powertech's Chair of the Board. The Powertech Board is chaired by BC Hydro's President and CEO and its Directors include senior Executives and Directors of BC Hydro.

Over the last five years, Powertech's revenue has ranged from $43 million to $48 million (2017/18 to 2021/22) with a net income (loss) in the range of $-1 million to $3 million. For more information, visit powertechlabs.com.

Board of Directors:

- Chris O'Riley - Chair
- Melissa Holland
- Vasee Navaratnam
- John Nunn
- David Wong

Other Subsidiaries

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

BCHPA Captive Insurance Company Ltd.

Procures insurance products and services on behalf of BC Hydro.

Columbia Hydro Constructors Ltd.

Administers and supplies the labour force to specified projects.

Tongass Power and Light Company

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

Nominee Holding Companies and/or Inactive/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, 2022, these other subsidiaries consisted of the following:

1. British Columbia Hydro International Limited
2. British Columbia Power Exchange Corporation
3. British Columbia Power Export Corporation
4. British Columbia Transmission Corporation
5. Columbia Estate Company Limited*
6. Edmonds Centre Developments Limited*
7. Fauquier Water and Sewerage Corporation
8. Hydro Monitoring (Alberta) Inc.*
9. Victoria Gas Company Limited
10. Waneta Holdings (US) Inc.*
11. 1111472 BC Ltd.

Appendix C: Auditor's Report and Audited Financial Statements

Management Report

The consolidated financial statements of British Columbia Hydro and Power Authority (BC Hydro) are the responsibility of management and have been prepared in accordance with International Financial Reporting Standards. The preparation of financial statements necessarily involves the use of estimates which have been made using careful judgment. In management's opinion, the consolidated financial statements have been properly prepared within the framework of the accounting policies summarized in the consolidated financial statements and incorporate, within reasonable limits of materiality, all information available at June 9, 2022. The consolidated financial statements have also been reviewed by the Audit, Finance & Capital 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 and appropriate delegation of authority and segregation of responsibilities within the organization. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit, Finance & Capital Committee.

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

The Board of Directors, through the Audit, Finance & Capital Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit, Finance & Capital 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 to review the financial statements before recommending approval by the Board of Directors. The internal and external auditors have full and open access to the Audit, Finance & Capital Committee, with and without the presence of management.

Chris O'Riley
President and Chief Executive Officer

David Wong
Executive Vice President, Finance, Technology, Supply Chain and Chief Financial Officer

Vancouver, Canada
June 9, 2022

OFFICE OF THE
Auditor General
of British Columbia

623 Fort Street
Victoria, British Columbia
Canada V8W 1G1
P: 250.419.6100
F: 250.387.1230
www.bcauditor.com

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of the British Columbia Hydro and Power Authority, and
To the Minister of Energy, Mines and Low Carbon Innovation, Province of British Columbia

Opinion

I have audited the accompanying consolidated financial statements of the British Columbia Hydro and Power Authority ("the group"), which comprise the consolidated statement of financial position at March 31, 2022, and the consolidated statements of comprehensive income, changes in equity and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

In my opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the group as at March 31, 2022, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

I conducted my audit in accordance with Canadian generally accepted auditing standards. My responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Consolidated Financial Statements section of my report. I am independent of the group in accordance with the ethical requirements that are relevant to my audit of the consolidated financial statements in Canada, and I have fulfilled my other ethical responsibilities in accordance with these requirements. I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my opinion.

Other Accompanying Information

Management is responsible for the other information. The other information comprises the information included in the Annual Service Plan Report, but does not include the consolidated financial statements and my auditor's report thereon. The Annual Service Plan Report is expected to be made available to us after the date of this auditor's report.

My opinion on the consolidated financial statements does not cover the other information accompanying the financial statements and I do not express any form of assurance conclusion thereon.

In connection with my audit of the consolidated financial statements, my responsibility is to read the other information that I have obtained prior to the date of my auditor's report and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or my knowledge obtained during the audit or otherwise appears to be materially misstated.

When I read the Annual Service Plan Report, if I conclude that there is a material misstatement therein, I am required to report that matter to those charged with governance.

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

Those charged with governance are responsible for the oversight of the financial reporting process. Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of the consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting when the group will continue its operations for the foreseeable future.

Auditor's Responsibilities for the Audit of the Consolidated Financial Statements

My objectives are to obtain reasonable assurance about whether the group's 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 my 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 aggregate, they could reasonably be expected to influence the economic decision of users taken on the basis of these consolidated financial statements.

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

- Identify and assess the risks of material misstatement of the consolidated 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 my opinion. The risk of not detecting a material misstatement resulting from fraud is higher than 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 group'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 group's ability to continue as a going concern. If I conclude that a material uncertainty exists, I am required to draw attention in my auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify my opinion. My conclusions are based on the audit evidence obtained up to the date of my auditor's report. However, future events or conditions may cause the group to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the group to express an opinion on the consolidated financial statements. I am responsible for the direction, supervision and performance of the group audit and I remain solely responsible for my audit opinion.

I 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 I identify during my audit.

I also provide those charged with governance with a statement that I have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on my independence, and where applicable, related safeguards.

Lisa Moore, CPA, CA
Principal

Victoria, British Columbia, Canada
June 9, 2022

Audited Financial Statements

Consolidated Statements of Comprehensive Income

for the years ended March 31 (in millions)		**2022**		2021
Revenues (Note 4)				
Domestic	**$**	**5,619**	$	5,237
Trade		**1,972**		1,177
		7,591		6,414
Expenses				
Operating expenses (Note 5)		**5,794**		4,898
Finance charges (Note 6)		**521**		224
Net Income Before Movement in Regulatory Balances		**1,276**		1,292
Net movement in regulatory balances (Note 15)		**(608)**		(604)
Net Income		**668**		**688**
OTHER COMPREHENSIVE INCOME				
Items That Will Be Reclassified to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 23)		**(34)**		(74)
Reclassification to income of derivatives designated as cash flow hedges (Note 23)		**39**		118
Foreign currency translation losses		**(12)**		(51)
Items That Will Not Be Reclassified to Net Income				
Actuarial gain		**776**		156
Other Comprehensive Income before movement in regulatory balances		**769**		**149**
Net movements in regulatory balances (Note 15)		**(758)**		(124)
Other Comprehensive Income		**11**		25
Total Comprehensive Income	**$**	**679**	$	713

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Financial Position

(in millions)		**As at March 31, 2022**		As at March 31, 2021
ASSETS				
Current Assets				
Cash and cash equivalents (Note 8)	**$**	**99**	$	37
Restricted cash (Note 8)		**-**		6
Accounts receivable and accrued revenue (Note 9)		**802**		827
Inventories (Note 10)		**199**		182
Prepaid expenses		**156**		152
Current portion of derivative financial instrument assets (Note 23)		**315**		87
		1,571		1,291
Non-Current Assets				
Property, plant and equipment (Note 11)		**34,038**		31,677
Right-of-use assets (Note 12)		**1,248**		1,317
Intangible assets (Note 13)		**705**		688
Derivative financial instrument assets (Note 23)		**242**		30
Other non-current assets (Note 14)		**540**		605
		36,773		34,317
Total Assets		**38,344**		35,608
Regulatory Balances (Note 15)		**4,390**		4,775
Total Assets and Regulatory Balances	**$**	**42,734**	$	40,383
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities (Note 16)	**$**	**1,760**	$	1,589
Current portion of long-term debt (Note 17)		**3,292**		3,329
Current portion of unearned revenues and contributions in aid (Note 20)		**100**		93
Current portion of derivative financial instrument liabilities (Note 23)		**228**		235
		5,380		5,246
Non-Current Liabilities				
Long-term debt (Note 17)		**22,659**		21,651
Lease liabilities (Note 19)		**1,327**		1,352
Derivative financial instrument liabilities (Note 23)		**177**		78
Unearned revenues and contributions in aid (Note 20)		**2,418**		2,261
Post-employment benefits (Note 22)		**893**		1,528
Other non-current liabilities (Note 24)		**1,355**		1,402
		28,829		28,272
Total Liabilities		**34,209**		33,518
Regulatory Balances (Note 15)		**1,479**		498
Total Liabilities and Regulatory Balances		**35,688**		34,016
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**6,994**		6,326
Accumulated other comprehensive loss		**(8)**		(19)
		7,046		6,367
Total Liabilities, Regulatory Balances, and Shareholder's Equity	**$**	**42,734**	$	40,383

Commitments and Contingencies (Notes 11 and 25)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

Doug Allen
Board Chair

Len Boggio, FCPA, FCA, ICD.D
Chair, Audit, Finance & Capital Committee

Consolidated Statements of Changes in Equity

(in millions)	Cumulative Translation Reserve	Unrealized Income (Loss) on Cash Flow Hedges	Total Accumulated Other Comprehensive Loss	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2020	$ -	$ (44)	$ (44)	$ 60	$ 5,638	$ 5,654
Comprehensive Income	(19)	44	25	-	688	713
Balance as at March 31, 2021	(19)	-	(19)	60	6,326	6,367
Comprehensive Income	6	5	11	-	668	679
Balance as at March 31, 2022	$ (13)	$ 5	$ (8)	$ 60	$ 6,994	$ 7,046

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

for the years ended March 31 (in millions)	**2022**	2021
Operating Activities		
Net income	**$ 668**	$ 688
Regulatory account transfers (Note 15)	**608**	604
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 7)	**1,079**	1,009
Unrealized gains on derivative financial instruments	**(235)**	(375)
Post-employment benefits expense	**146**	128
Interest accrual	**786**	834
Other items	**74**	48
	3,126	2,936
Changes in working capital and other assets and liabilities (Note 18)	**166**	(174)
Interest paid	**(877)**	(923)
Cash provided by operating activities	**2,415**	1,839
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(3,127)**	(2,913)
Cash used in investing activities	**(3,127)**	(2,913)
Financing Activities		
Long-term debt issued (Note 17)	**1,568**	2,502
Long-term debt retired (Note 17)	**(526)**	(1,100)
Receipt of revolving borrowings	**8,733**	8,046
Repayment of revolving borrowings	**(8,744)**	(7,979)
Payment of principal portion of lease liability	**(82)**	(79)
Settlement of hedging derivatives	**(151)**	(369)
Other items	**(24)**	(25)
Cash provided by financing activities	**774**	996
Increase (decrease) in cash and cash equivalents	**62**	(78)
Cash and cash equivalents, beginning of year	**37**	115
Cash and cash equivalents, end of year	**$ 99**	$ 37

See Note 18 for Cash flow supplement - changes in liabilities arising from financing activities

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

Note 1: Reporting Entity

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

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

Note 2: Basis of Presentation

(a) Basis of Accounting

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). The significant 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 9, 2022.

(b) Basis of Measurement

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

(c) Functional and Presentation Currency

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

(d) Key Assumptions and Significant Judgments

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

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Information about significant areas of judgment, estimates and assumptions in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is as follows:

(i) Retirement Benefit Obligation

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

(ii) Provisions and Contingencies

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

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

(iii) Financial Instruments

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

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

(iv) Right-of-Use Leases

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

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

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

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

(vi) Rate Regulation

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

(vii) Revenues

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

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

Note 3: Significant 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 balances are assessed to no longer be probable based on management's judgment, 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 statement 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.

Domestic revenues comprise sales to customers within the province of British Columbia, and sales of energy outside the province that are under long-term contracts. Sales that are surplus to domestic load requirements and other sales outside the province are classified as trade.

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 comprise 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 – 65
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 and are not subject to amortization. Other intangible assets include California carbon allowances which are not amortized because they are used to settle obligations arising from carbon emissions regulations. 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**.** Impairment of cash and cash equivalent and restricted cash is evaluated by reference to the credit quality of the underlying financial institution.

(ii) Non-Financial Assets

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

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

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

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

(h) Cash and Cash Equivalents

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

(i) Restricted Cash

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

(j) Inventories

Inventories are comprised primarily of natural gas, materials and supplies and environmental products. Natural gas inventory is valued at fair value less costs to sell and is included in Level 2 of the fair value hierarchy (refer to Note 10). Materials and supplies and environmental product inventories are valued at the lower of cost determined on a weighted average basis and net realizable value. The cost of materials and supplies comprises all costs of purchase, costs of conversion and other directly attributable costs incurred in bringing the inventories to their present location and condition. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated selling expenses.

(k) Financial Instruments

(i) Financial Instruments – Recognition and Measurement

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

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

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

(ii) Classification and Measurement of Financial Instruments

Short-term investments	FVTPL
Derivatives not in a hedging relationship	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 23.

(v) Derivative Financial Instruments

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

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

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

(vi) Hedges

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

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

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

(l) Investments Held in Sinking Funds

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

(m) Unearned Revenues

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

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

(n) Government Grants

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

(o) Contributions in Aid of Construction

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

(p) Post-Employment Benefits

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

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

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

(q) Provisions

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

Decommissioning Obligations

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

Environmental Expenditures and Liabilities

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

Legal

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

(r) Leases

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(s) Taxes

The Company is a Crown corporation and therefore no Canadian provincial or federal income tax is payable. However, the Company pays provincial and local government taxes and grants in lieu of property taxes to municipalities, regional districts, and rural area jurisdictions. In addition, Powerex, a subsidiary of BC Hydro, pays taxes relating to trading activity 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, 2022, and have not been applied in preparing these consolidated financial statements. The following new and amended standards become effective for the Company's annual periods beginning on or after the dates noted below:

- Amendments to IAS 1*, Presentation of Financial Statements* (effective April 1, 2023)
- Amendments to IAS 8, *Accounting Policies, Changes in Accounting Estimates and Errors* (effective April 1, 2023)
- Amendments to IAS 16, *Property, Plant and Equipment* (effective April 1, 2022)
- Amendments to IAS 37*, Provisions, Contingent Liabilities and Contingent Assets* (effective April 1, 2022)
- Amendments to IFRS 3*, Business Combinations* (effective April 1, 2022)
- Amendments to IFRS 9*, Financial Instruments* (effective April 1, 2022)
- IFRS 17, *Insurance Contracts* (effective April 1, 2023)

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

Note 4: Revenues

Disaggregated Revenue

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

(in millions)		**2022**		2021
Domestic				
Residential	**$**	**2,342**	$	2,210
Light industrial and commercial		**1,952**		1,830
Large industrial		**854**		762
Other sales		**471**		435
Total Domestic		**5,619**		5,237
Total Trade[1]		**1,972**		1,177
Total Revenue	**$**	**7,591**	$	6,414

[1] Includes revenue recognized under IFRS 9, *Financial Instruments* (2022 - $811M ; 2021 - $490M).

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, 2022 was $757 million (2021 - $781 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, 2022**		March 31, 2021
Unearned revenues (Note 20)	**$**	**322**	$	322
Contributions in aid (Note 20)		**2,196**		2,032
Customer deposits		**22**		9
	$	**2,540**	$	2,363

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

The following table reconciles the changes in the contract liabilities balances during the years ended March 31, 2022 and 2021:

(in millions)		Contract Liabilities
Balance at April 1, 2020	**$**	**2,197**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(118)
Increases due to cash received, excluding amounts recognized as revenue during the period		278
Other[1]		6
Balance at March 31, 2021		**2,363**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(130)
Increases due to cash received, excluding amounts recognized as revenue during the period		278
Other[1]		29
Balance at March 31, 2022	**$**	**2,540**

[1] Other includes finance charges and foreign exchange adjustments

Remaining Performance Obligations

The following table includes revenue expected to be recognized in the future related to the performance obligations that are unsatisfied (or partially unsatisfied) as at March 31, 2022.

(in millions)		Less than 1 year		Between 1 and 5 years		More than 5 years		Total
Energy sales	$	82	$	63	$	8	$	153
Contributions in aid		60		247		1,889		2,196
Skagit River Agreement		30		119		1,157		1,306
Other		46		99		44		189
	$	218	$	528	$	3,098	$	3,844

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

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

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

Note 5: Operating Expenses

(in millions)		**2022**		2021
Electricity and gas purchases	**$**	**2,388**	$	1,774
Water rentals		**346**		295
Transmission charges		**268**		200
Personnel expenses		**736**		711
Materials and external services		**672**		590
Amortization and depreciation (Note 7)		**1,079**		1,009
Grants and taxes		**286**		254
Other costs, net of recoveries		**97**		137
Capitalized costs		**(78)**		(72)
	$	**5,794**	$	4,898

Note 6: Finance Charges

(in millions)		**2022**		2021
Interest on long-term debt	**$**	**786**	$	834
Interest on lease liabilities		**45**		48
Interest on defined benefit plan obligations (Note 22)		**56**		64
Mark-to-market gains on derivative financial instruments (Note 23)		**(150)**		(519)
Other		**43**		23
Capitalized interest		**(259)**		(226)
	$	**521**	$	224

The capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 3.1 per cent (2021 - 3.4 per cent).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

Note 7: Amortization and Depreciation

(in millions)		**2022**		2021
Depreciation of property, plant and equipment (Note 11)	**$**	**893**	$	831
Depreciation of right-of-use assets (Note 12)		**96**		95
Amortization of intangible assets (Note 13)		**90**		83
	$	**1,079**	$	1,009

Note 8: Cash and Cash Equivalents, and Restricted Cash

(in millions)		**March 31, 2022**		March 31, 2021
Cash	**$**	**27**	$	3
Short-term investments		**72**		34
Restricted Cash		**-**		6
	$	**99**	$	43

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, 2022**		March 31, 2021
Accounts receivable	**$**	**451**	$	469
Accrued revenue		**261**		258
Other		**90**		100
	$	**802**	$	827

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

Note 10: Inventories

(in millions)	**March 31, 2022**	March 31, 2021
Materials and supplies	**$ 188**	$ 178
Natural gas trading inventories	**11**	4
	$ 199	$ 182

There were no materials and supplies inventory impairments during the years ended March 31, 2022 and 2021. Natural gas inventory held in storage is measured at fair value less costs to sell and therefore, not subject to impairment testing.

Inventories recognized as an expense during the year amounted to $116 million (2021 - $74 million).

Note 11: Property, Plant, and Equipment

(in millions)	Generation	Transmission	Distribution	Land & Builidings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at April 1, 2020	$ 9,671	$ 7,642	$ 6,439	$ 784	$ 917	$ 6,269	$ 31,722
Net additions	118	481	535	67	88	1,838	3,127
Disposals and retirements	(5)	(15)	(33)	(1)	(26)	-	(80)
Impairments	-	-	-	-	-	(9)	(9)
Balance at March 31, 2021	9,784	8,108	6,941	850	979	8,098	34,760
Net additions	293	434	517	33	68	2,034	3,379
Disposals and retirements	(25)	(13)	(40)	(1)	(35)	-	(114)
Impairments	-	-	-	-	(12)	(57)	(69)
Balance at March 31, 2022	$ 10,052	$ 8,529	$ 7,418	$ 882	$ 1,000	$ 10,075	$ 37,956
Accumulated Depreciation							
Balance at April 1, 2020	$ (688)	$ (678)	$ (593)	$ (84)	$ (252)	$ -	$ (2,295)
Depreciation expense	(269)	(231)	(217)	(28)	(86)	-	(831)
Disposals and retirements	2	7	7	1	26	-	43
Balance at March 31, 2021	(955)	(902)	(803)	(111)	(312)	-	(3,083)
Depreciation expense	(268)	(257)	(231)	(27)	(110)	-	(893)
Disposals and retirements	11	6	10	-	29	-	56
Impairments	-	-	-	-	2	-	2
Balance at March 31, 2022	$ (1,212)	$ (1,153)	$ (1,024)	$ (138)	$ (391)	$ -	$ (3,918)
Net carrying amounts							
At March 31, 2021	$ 8,829	$ 7,206	$ 6,138	$ 739	$ 667	$ 8,098	$ 31,677
At March 31, 2022	$ 8,840	$ 7,376	$ 6,394	$ 744	$ 609	$ 10,075	$ 34,038

(i) Included within Distribution assets are the Company's portion of utility poles with a net book value of $1.21 billion (2021 - $1.19 billion) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2022 was $33 million (2021 - $30 million).

(ii) The Company received government grants arising from the Columbia River Treaty related to three dams built by the Company in the mid-1960s to regulate the flow of the Columbia River. The grants were made to assist in financing the construction of the dams. The grants were deducted from the carrying amount of the related dams. In addition, the Company received, in the current year and prior years, government grants for the construction of transmission lines and has deducted the grants received from the cost of the asset. BC Hydro received government grants of $7 million during the year ended March 31, 2022 (2021 - $25 million).

(iii) The Company has contractual commitments to spend $2.07 billion on major property, plant and equipment projects (on individual projects greater than $20 million) as at March 31, 2022.

(iv) As a result of a depreciation study that was conducted on property, plant and equipment, the estimated useful lives of various assets were changed. The changes in estimated useful lives have been accounted for prospectively and were effective April 1, 2021. The changes in estimated useful lives resulted in an increase to depreciation expense of $34 million for the year ended March 31, 2022 for which a regulatory asset, as directed by the BC Utilities Commission (BCUC), has been established in the Depreciation Study regulatory account. As a result of having higher depreciation expense in the current year there will be lower depreciation expense in future years related to the effected assets than would have otherwise been the case.

(v) The Company recognized impairments, mainly to unfinished construction assets, as a result of events that have caused the construction of the asset to no longer be viable.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

Note 12: Right-of-Use Assets

(in millions)	Long-term energy purchase agreements	Property	Equipment/ Other	Total
Cost				
Balance at April 1, 2020	$ 1,978	$ 61	$ 3	$ 2,042
Net additions	6	-	4	10
Disposals and retirements	-	(3)	-	(3)
Balance at March 31, 2021	1,984	58	7	2,049
Net additions	29	-	-	29
Disposals and retirements	-	-	(3)	(3)
Balance at March 31, 2022	$ 2,013	$ 58	$ 4	$ 2,075
Accumulated Depreciation				
Balance at April 1, 2020	$ (613)	$ (22)	$ (2)	$ (637)
Depreciation expense	(90)	(4)	(2)	(96)
Disposals and retirements	-	1	-	1
Balance at March 31, 2021	(703)	(25)	(4)	(732)
Depreciation expense	(91)	(5)	-	(96)
Disposals and retirements	-	1	-	1
Balance at March 31, 2022	$ (794)	$ (29)	$ (4)	$ (827)
Net carrying amounts				
At March 31, 2021	$ 1,281	$ 33	$ 3	$ 1,317
At March 31, 2022	$ 1,219	$ 29	$ -	$ 1,248

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

Note 13: Intangible Assets

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at April 1, 2020	$ 289	$ 121	$ 362	$ 49	$ 116	$ 937
Net additions	31	27	114	2	(79)	95
Disposals and retirements	-	(3)	(1)	-	-	(4)
Balance at March 31, 2021	320	145	475	51	37	1,028
Net additions	9	8	60	14	15	106
Disposals and retirements	-	-	-	-	-	-
Balance at March 31, 2022	$ 329	$ 153	$ 535	$ 65	$ 52	$ 1,134
Accumulated Amortization						
Balance at April 1, 2020	$ (1)	$ (69)	$ (189)	$ -	$ -	$ (259)
Amortization expense	(2)	(16)	(65)	-	-	(83)
Disposals and retirements	-	1	1	-	-	2
Balance at March 31, 2021	(3)	(84)	(253)	-	-	(340)
Amortization expense	(1)	(19)	(70)	-	-	(90)
Disposals and retirements	-	-	1	-	-	1
Balance at March 31, 2022	$ (4)	$ (103)	$ (322)	$ -	$ -	$ (429)
Net carrying amounts						
At March 31, 2021	$ 317	$ 61	$ 222	$ 51	$ 37	$ 688
At March 31, 2022	$ 325	$ 50	$ 213	$ 65	$ 52	$ 705

Land rights consist primarily of statutory rights of way acquired from the Province in perpetuity. 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

Note 14: Other Non-Current Assets

(in millions)		**March 31, 2022**		March 31, 2021
Non-current receivables	**$**	**134**	$	138
Sinking funds		**210**		203
Non-current Site C prepaid expenses		**184**		253
Other		**12**		11
	$	**540**	$	605

Non-Current Receivables

Included in the non-current receivables balance are $119 million of receivables (2021 - $122 million) attributable to other contributions receivable from a vendor to aid in the construction of a transmission system. The contributions are to be received in 16 annual payments of approximately $11 million, adjusted for inflation. The fair value of the receivable was initially measured using an estimated inflation rate and a 4.6 per cent discount rate.

Sinking Funds

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

(in millions)	**March 31, 2022**			March 31, 2021		
		Carrying Value	**Weighted Average Effective Rate[1]**		Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$**	**127**	**2.9 %**	$	127	1.7 %
Other provincial government and crown corporation bonds		**82**	**2.9 %**		75	1.1 %
Money market funds		**1**	**-**		1	-
	$	**210**		$	203	

[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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

Note 15: Rate Regulation

Regulatory Accounts

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

(in millions)	**2022**	2021
Net decrease in regulatory balances related to net income	**$ (608)**	$ (604)
Net decrease in regulatory balances related to OCI	**(758)**	(124)
	$ (1,366)	$ (728)

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 2021*	*Addition / (Reduction)*	*Interest[A]*	*Amortization*	*Net Change[B]*	***As at March 31 2022***	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Heritage Deferral	$ 65	$ 38	$ 2	$ -	$ 40	**$ 105**	Note C
Load Variance	110	(79)	2	-	(77)	**33**	Note C
Demand-Side Management	881	94	-	(107)	(13)	**868**	1-15
Debt Management	449	(153)	-	(10)	(163)	**286**	6-32
First Nations Provisions & Costs	486	15	2	(34)	(17)	**469**	2-9 Note F
Total Finance Charges	-	8	-	31	39	**39**	Note E
Non-Current Pension Costs	114	(66)	-	(48)	(114)	**-**	5-13
Site C	523	3	16	-	19	**542**	Note D
CIA Amortization	73	(5)	-	-	(5)	**68**	18
Environmental Provisions & Costs	294	(1)	(1)	(58)	(60)	**234**	Note E, F
Smart Metering & Infrastructure	173	-	5	(27)	(22)	**151**	7
IFRS Pension	421	-	-	(39)	(39)	**382**	10
IFRS Property, Plant & Equipment	1,070	-	-	(31)	(31)	**1,039**	30-39
Real Property Sales	46	(15)	1	-	(14)	**32**	Note G
Other Regulatory Accounts	70	77	3	(8)	72	**142**	3-7
Total Regulatory Assets	4,775	(84)	30	(331)	(385)	**4,390**	
Regulatory Liabilities							
Non-Heritage Deferral	153	28	4	-	32	**185**	Note C
Trade Income Deferral	227	264	13	-	277	**504**	Note C
Non-Current Pension Costs	-	602	-	67	669	**669**	5-13
Total Finance Charges	61	(18)	-	(43)	(61)	**-**	Note E
Other Regulatory Accounts	57	88	1	(25)	64	**121**	3-6 Note C
Total Regulatory Liabilities	498	964	18	(1)	981	**1,479**	
Net Regulatory Asset	$ 4,277	$ (1,048)	$ 12	$ (330)	$ (1,366)	**$ 2,911**	

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

(in millions)	*As at April 1 2020*	*Opening Balance Transfer* [H]	*Addition / (Reduction)*	*Interest* [A]	*Amortization*	*Net Change* [B]	*As at March 31 2021*	*Remaining recovery/ reversal period (years)*
Regulatory Assets								
Heritage Deferral	$ -	$ -	$ (3)	$ -	$ 68	$ 65	$ 65	Note C
Non-Heritage Deferral	205	-	(159)	4	(50)	(205)	-	Note C
Load Variance	-	354	(33)	7	(218)	110	110	Note C
Demand-Side Management	907	-	81	-	(107)	(26)	881	1-15
Debt Management	953	-	(516)	-	12	(504)	449	7-33
First Nations Provisions & Costs	495	-	21	2	(32)	(9)	486	3-9 Note F
Total Finance Charges	11	-	(9)	-	(2)	(11)	-	Note E
Non-Current Pension Costs	210	-	(50)	-	(46)	(96)	114	6-13
Site C	508	-	(2)	17	-	15	523	Note D
CIA Amortization	78	-	(5)	-	-	(5)	73	19
Environmental Provisions & Costs	260	-	54	(1)	(19)	34	294	Note E, F
Smart Metering & Infrastructure	195	-	-	6	(28)	(22)	173	8
IFRS Pension	459	-	-	-	(38)	(38)	421	11
IFRS Property, Plant & Equipment	1,079	-	22	-	(31)	(9)	1,070	31-40
Real Property Sales	56	-	(11)	1	-	(10)	46	Note G
Other Regulatory Accounts	70	-	29	2	(31)	-	70	1-8
Total Regulatory Assets	5,486	354	(581)	38	(522)	(711)	4,775	
Regulatory Liabilities								
Heritage Deferral	300	-	(149)	3	(154)	(300)	-	Note C
Non-Heritage Deferral	-	353	(45)	13	(168)	153	153	Note C
Trade Income Deferral	174	-	155	3	(105)	53	227	Note C
Total Finance Charges	-	-	53	-	8	61	61	Note E
Other Regulatory Accounts	7	1	11	-	38	50	57	1-3
Total Regulatory Liabilities	481	354	25	19	(381)	17	498	
Net Regulatory Asset	$ 5,005	$ -	$ (606)	$ 19	$ (141)	$ (728)	$ 4,277	

[A] As permitted, interest charges were accrued to certain regulatory balances at a rate of 3.1 per cent for the year ended March 31, 2022 (2021 – 3.4 per cent).

[B] Net Change includes a net decrease to net income of $608 million (2021 – $604 million) and net decrease to other comprehensive income of $758 million (2021 – $124 million).

[C] The balances in these regulatory accounts are recovered in rates through the Deferral Account Rate Rider (DARR), which is an additional charge on customer bills. In the Fiscal 2022 Revenue Requirement Application, the BCUC approved the requested DARR of 0 per cent (2021 – 0 per cent). In the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, the BCUC approved the requested DARR refund of 2.0 per cent for fiscal 2023 on an interim basis effective April 1, 2022. The approved rate will remain interim and is subject to refund/recovery or adjustment with interest at BC Hydro's weighted average cost of debt until further order of the BCUC. In the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, BC Hydro requested DARR refunds of 1 per cent for fiscal 2024 and 0.5 per cent for fiscal 2025.

[D] BC Hydro proposed in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application to recover the balance in this account over the forecasted weighted average expected useful life of the Site C assets of 84 years commencing in fiscal 2025.

[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 actual expenditures are incurred and transferred to the respective regulatory cost account.

[G] The balance in this account is expected to self-clear based on forecast net gains from real property sales experienced over fiscal 2020 to fiscal 2024, resulting in a forecast zero balance by the end of fiscal 2024, subject to potential interest charges.

[H] The amounts in the Opening Balance Transfer column are transfers from the Non-Heritage Deferral account to a new Load Variance account and a new Biomass Energy Program Variance account as directed by the BCUC.

Rate Regulation

BCUC issued its decision (Decision) on BC Hydro's Fiscal 2022 Revenue Requirements Application on June 17, 2021. In its Decision, the BCUC included three compliance directives impacting rates, which resulted in a Fiscal 2022 net bill increase of 1.00 per cent rather than the 1.16 per cent increase requested in the application. The BCUC Decision directed BC Hydro to establish a new Depreciation Study regulatory account and approved the closure of the Rock Bay Remediation regulatory account. As a result of the Decision, BC Hydro requested a new Low Carbon Fuel Credits Variance regulatory account in the Fiscal 2022 Revenue Requirements Application Compliance Filing, which was subsequently approved by the BCUC. The financial impact of the Decision has been incorporated in these financial statements.

In August 2021, BC Hydro applied for BCUC approval of a new Mandatory Reliability Standards Costs regulatory account. In February 2022, the BCUC approved BC Hydro's request to establish this regulatory account. The financial impact of the new Mandatory Reliability Standards Costs regulatory account request has been incorporated in these financial statements in accordance with the Company's rate regulation accounting policy, whereby BC Hydro defers amounts in advance of a final decision on the application by the BCUC based on management's estimate on the probability of acceptance and recovery in future rates.

The Low Carbon Fuel Credits Variance, Depreciation Study and Mandatory Reliability Standards Costs regulatory accounts were included within other regulatory accounts – assets in the table above.

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. Prior to fiscal 2020, these deferred variances were recovered in rates through the DARR, which was an additional charge on customer bills. The BCUC approved a reduction to the DARR from 5 per cent to 0 per cent effective April 1, 2019 and a refund of the net credit balance in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application in this account over the fiscal 2020 to fiscal 2021 test period. The BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2022 and BC Hydro requested the continued application of the DARR table mechanism in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application for periods after fiscal 2022. The DARR table mechanism is a sliding scale that determines the level of the DARR based on the forecast net balance of the cost of energy variance accounts (i.e. the Heritage Deferral account, the Non-Heritage Deferral account, the Trade Income Deferral account, the Load Variance account, the Biomass Energy Program Variance account and the Low Carbon Fuel Credits Variance Regulatory Account).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

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). Prior to fiscal 2020, these deferred variances were recovered in rates through the DARR, which was an additional charge on customer bills. The BCUC approved a reduction to the DARR from 5 per cent to 0 per cent effective April 1, 2019 and a refund of the net credit balance in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application in this account over the fiscal 2020 to fiscal 2021 test period. The BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2022 and BC Hydro requested the continued application of the DARR table mechanism in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application for periods after fiscal 2022.

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. Prior to fiscal 2020, these deferred variances were recovered in rates through the DARR, which was an additional charge on customer bills. The BCUC approved a reduction to the DARR from 5 per cent to 0 per cent effective April 1, 2019 and a refund of the net credit balance in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application in this account over the fiscal 2020 to fiscal 2021 test period. The BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2022 and BC Hydro requested the continued application of the DARR table mechanism in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application for periods after fiscal 2022.

Load Variance

In its decision to the Fiscal 2020 to Fiscal 2021 Revenue Requirement Application, the BCUC directed BC Hydro to establish a Load Variance Regulatory Account and to move all balances related to load variances from the Non-Heritage Deferral Account (NHDA) to the new account. This account is intended to capture the variance between planned and actual domestic customer load (i.e., customer demand), be categorized as one of BC Hydro's cost of energy variance accounts and have the same mechanisms for interest charges and recovery applied to it that are applicable to the NHDA. The BCUC approved the recovery of the balance through the DARR table mechanism for fiscal 2022 and BC Hydro requested continued application of the DARR table mechanism in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application for periods after fiscal 2022.

Demand-Side Management

Demand-Side Management expenditures are deferred and amortized on a straight-line basis over the anticipated 15 year period of benefit of the expenditures. 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.

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).

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 being capitalized in property, plant and equipment starting in the fourth quarter of fiscal 2015. BC Hydro requested in the Fiscal 2023 to Fiscal 2025 Revenue Requirement Application BCUC approval to begin amortizing the balance of the Site C Regulatory Account once the assets are in service in fiscal 2025 over 84 years.

Contributions in Aid (CIA) of Construction Amortization

This account captures the difference in revenue requirement impacts of the 45 year amortization period the Company uses as per a depreciation study and the 25 year amortization period determined by the BCUC.

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, 2019) 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, 2019). In addition, the account includes an annual deferral of overhead costs, ineligible for capitalization under the accounting principles of IFRS that was being phased in over 10 years and the phase in was completed in Fiscal 2021. The annual deferred amounts are amortized over 40 years beginning the year following the deferral of the expenditures.

Debt Management

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

Total Finance Charges

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

Real Property Sales

This account captures variances between forecast and actual real property gains or losses from real estate sales. The balance in this account is expected to self-clear based on forecast net gains from real property sales experienced over fiscal 2020 to fiscal 2024, resulting in a forecast zero balance by the end of fiscal 2024, subject to potential interest charges.

Other Regulatory Accounts

Other regulatory asset and liability accounts with individual balances less than $50 million include the following: Low Carbon Fuel Credits Variance, Depreciation Study and Mandatory Reliability Standards

Costs, Capital Project Investigation Costs, Project Write-off Costs, Electric Vehicle Costs, Biomass Energy Program Variance, Dismantling Cost, Mining Customer Payment Plan, Foreign Exchange Gains and Losses, Post-Employment Benefit Current Pension Costs, Customer Crisis Fund and Amortization of Capital Additions and Storm Restoration Costs.

Note 16: Accounts Payable and Accrued Liabilities

(in millions)		**March 31, 2022**		March 31, 2021
Accounts payable	**$**	**420**	$	247
Accrued liabilities		**1,125**		1,041
Current portion of lease liabilities (Note 19)		**52**		80
Current portion of other long-term liabilities (Note 24)		**112**		146
Other		**51**		75
	$	**1,760**	$	1,589

Note 17: Long-Term Debt and Debt Management

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

The Company has a commercial paper borrowing program with the Province which is limited to $5.50 billion (2021 - $4.50 billion) and is included in revolving borrowings. At March 31, 2022, the outstanding amount under the borrowing program was $2.79 billion (2021 - $2.80 billion).

For the year ended March 31, 2022, the Company issued bonds for net proceeds of $1.57 billion (2021 - $2.50 billion) and a par value of $1.58 billion (2021 - $2.20 billion), a weighted average effective interest rate of 2.4 per cent (2021 - 1.6 per cent) and a weighted average term to maturity of 21.6 years (2021 - 18.1 years).

For the year ended March 31, 2022, the Company redeemed bonds with par value of $526 million (2021 – $1.10 billion).

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

(in millions)	**March 31, 2022**					March 31, 2021				
	Canadian	**US**	**Euro**	**Total**	**Weighted Average Interest Rate[1]**	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:										
2022	**$ -**	**$ -**	**$ -**	**$ -**	**-**	$ 526	$ -	$ -	$ 526	7.8
2023	**500**	**-**	**-**	**500**	**6.8**	500	-	-	500	6.8
2024	**200**	**-**	**-**	**200**	**5.9**	200	-	-	200	5.9
2025	**10**	**-**	**-**	**10**	**5.5**	10	-	-	10	5.5
2026	**900**	**625**	**365**	**1,890**	**3.6**	900	628	389	1,917	3.6
2027	**850**	**-**	**-**	**850**	**2.4**	-	-	-	-	-
1-5 years	**2,460**	**625**	**365**	**3,450**	**3.9**	2,136	628	389	3,153	4.9
6-10 years	**6,535**	**-**	**-**	**6,535**	**2.9**	5,575	-	-	5,575	2.5
11-15 years	**-**	**375**	**192**	**567**	**5.1**	1,110	-	204	1,314	4.3
16-20 years	**1,250**	**-**	**-**	**1,250**	**4.9**	1,250	377	-	1,627	5.4
21-25 years	**4,588**	**-**	**-**	**4,588**	**3.9**	4,588	-	-	4,588	3.9
26-30 years	**5,545**	**-**	**-**	**5,545**	**2.9**	5,545	-	-	5,545	2.9
Over 30 years	**985**	**-**	**-**	**985**	**2.7**	110	-	-	110	3.4
Bonds	**$ 21,363**	**$ 1,000**	**$ 557**	**$ 22,920**	**3.4**	$ 20,314	$ 1,005	$ 593	$ 21,912	3.6
Revolving borrowings	**1,910**	**882**	**-**	**2,792**	**0.6**	906	1,897	-	2,803	0.1
	$ 23,273	**$ 1,882**	**$ 557**	**$ 25,712**		$ 21,220	$ 2,902	$ 593	$ 24,715	
Adjustments to carrying value resulting from discontinued hedging activities	**8**	**18**	**-**	**26**		9	19	-	28	
Unamortized premium, discount, and issue costs	**223**	**(8)**	**(2)**	**213**		248	(8)	(3)	237	
	$ 23,504	**$ 1,892**	**$ 555**	**$ 25,951**		$ 21,477	$ 2,913	$ 590	$ 24,980	
Less: Current portion	**(2,410)**	**(882)**	**-**	**(3,292)**		(1,432)	(1,897)	-	(3,329)	
Non-current long-term debt	**$ 21,094**	**$ 1,010**	**$ 555**	**$ 22,659**		$ 20,045	$ 1,016	$ 590	$ 21,651	

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

The following foreign currency contracts were in place at March 31, 2022 in a net liability position of $27 million (2021 – net liability of $20 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

(in millions)	**March 31, 2022**	March 31, 2021
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	**6 years**	7 years
Foreign Currency Forwards		
United States dollar (US$) to Canadian dollar - notional amount[1]	**US$ 1,279**	US$ 2,111
United States dollar to Canadian dollar - weighted average contract rate	**1.26**	1.27
Weighted remaining term	**4 years**	3 years

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

The following bond locks and forward swap contracts were in place at March 31, 2022 with a net asset position of $179 million (2021 – net liability of $125 million). Such contracts are used to lock in interest rates on future Canadian denominated debt issues. The contracts outstanding relate to $3.73 billion (2021 - $3.23 billion) of planned 10 and 30 year debt (2021 – 10 and 30 year debt) to be issued on dates ranging from June 2022 to October 2025 (2021 – June 2021 to June 2024).

(in millions)	**March 31, 2022**	March 31, 2021
Bond Locks		
Canadian dollar - notional amount[1]	**$ 575**	$ -
Weighted forecast borrowing yields	**2.48%**	-
Weighted remaining term	**< 1 year**	-
Forward Swaps		
Canadian dollar - notional amount[1]	**$ 3,150**	$ 3,225
Weighted forecast borrowing yields	**3.03%**	3.28%
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 23.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

Note 18: Supplemental Disclosure of Cash Flow Information

Change in Working Capital and Other Assets and Liabilities:

(in millions)	**2022**	2021
Restricted Cash	**$ 6**	$ 9
Accounts receivable and accrued revenue	**30**	(57)
Inventories	**(17)**	6
Prepaid expenses	**(15)**	(31)
Other non-current assets	**73**	22
Accounts payable and accrued liabilities	**(37)**	(310)
Unearned revenues and contributions in aid	**162**	168
Post-employment benefits	**(5)**	(4)
Other non-current liabilities	**(31)**	23
	$ 166	$ (174)

Non-Cash Investing Transactions:

(in millions)	**2022**	2021
Contributions in kind received for property, plant and equipment	**$ 52**	$ 56

Reconciliation for liabilities arising from financing activities:

(in millions)	**Balance, March 31, 2021**	**Issued**	**Redemptions**	**Foreign exchange movement**	**Other[1]**	**Payment**	**Balance March 31, 2022**
Long-term debt and revolving borrowings:							
Long-term debt	$ 22,177	$ 1,568	$ (526)	$ (40)	$ (20)	$ -	$ 23,159
Revolving borrowings	2,803	8,733	(8,744)	-	-	-	2,792
Total long-term debt and revolving borrowings	24,980	10,301	(9,270)	(40)	(20)	-	25,951
Lease liability (Note 19)	1,432	-	-	-	72	(125)	1,379
Vendor financing liability	333	-	-	-	22	(42)	313
Debt-related derivative liability	125	-	-	-	(153)	(151)	(179)
	$ 26,870	$ 10,301	$ (9,270)	$ (40)	$ (79)	$ (318)	$ 27,464

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

(in millions)	Balance, April 1, 2020	Issued	Redemptions	Foreign exchange movement	Other[1]	Proceeds (Payments)	Balance March 31, 2021
Long-term debt and revolving borrowings:							
Long-term debt	$ 20,943	$ 2,502	$ (1,100)	$ (152)	$ (16)	$ -	$ 22,177
Revolving borrowings	2,743	8,046	(7,979)	-	(7)	-	2,803
Total long-term debt and revolving borrowings	23,686	10,548	(9,079)	(152)	(23)	-	24,980
Lease liability (Note 19)	1,504	-	-	-	56	(128)	1,432
Vendor financing liability	348	-	-	-	29	(44)	333
Debt-related derivative liability	923	-	-	-	(429)	(369)	125
	$ 26,461	$ 10,548	$ (9,079)	$ (152)	$ (367)	$ (541)	$ 26,870

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

Note 19: Lease Liabilities

Lease costs

(in millions)	**2022**	2021
Interest on lease liabilities	**$ 45**	$ 48
Variable lease payments not included in the measurement of lease liabilities	**12**	14
Expenses relating to short-term leases and leases of low-value assets	**18**	13
	$ 75	$ 75

Amounts recognized in the statement of cash flows

(in millions)	**2022**	2021
Total cash outflow for leases	**$ 155**	$ 155

Maturity analysis

(in millions)	**March 31, 2022**	March 31, 2021
Maturity analysis - contractual undiscounted cash flows		
Less than 1 year	**$ 96**	$ 125
1 to 5 years	**380**	375
More than 5 years	**1,462**	1,526
Total Undiscounted Lease Liabilities	**$ 1,938**	$ 2,026

(in millions)	**March 31, 2022**	March 31, 2021
Current	**52**	80
Non-current	**1,327**	1,352
Total Lease Liabilities	**$ 1,379**	$ 1,432

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 13 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 for these long-term energy purchase agreement leases for the year ended March 31, 2022 was $9 million (2021 - $11 million). 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, 2022 was $2 million (2021 - $2 million).

Other leases

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

Note 20: Unearned Revenues and Contributions in Aid

(in millions)	**March 31, 2022**	March 31, 2021
Unearned revenues	**$ 322**	$ 322
Contributions in aid	**2,196**	2,032
	2,518	2,354
Less: Current portion, unearned revenues	**(40)**	(35)
Less: Current portion, contributions in aid	**(60)**	(58)
	$ 2,418	$ 2,261

Note 21: Capital Management

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

During the year, there were no changes in the approach to capital management.

The debt to equity ratio at March 31, 2022, and March 31, 2021 was as follows:

(in millions)	**March 31, 2022**	March 31, 2021
Total debt, net of sinking funds	**$ 25,741**	$ 24,777
Less: Cash and cash equivalents	**(99)**	(37)
Net Debt	**$ 25,642**	$ 24,740
Retained earnings	**$ 6,994**	$ 6,326
Contributed surplus	**60**	60
Accumulated other comprehensive loss	**(8)**	(19)
Total Equity	**$ 7,046**	$ 6,367
Net Debt to Equity Ratio	**78 : 22**	**80 : 20**

Dividend Payment to the Province

In accordance with Order in Council No. 095/2014 from the Province, for the year ended March 31, 2018 and subsequent years, the payment to the Province was reduced by $100 million per year based on the payment in the immediate preceding fiscal year until it reached zero and will remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

As a result of the Order in Council, there was no dividend payment to the Province for the years ended March 31, 2022 and 2021.

Note 22: Post-Employment Benefits

The Company provides a defined benefit statutory (registered under the British Columbia Pension Benefits Standards Act) pension plan to substantially all employees, as well as supplemental arrangements which provide pension benefits in excess of statutory limits. Pension benefits are based on years of membership service and highest five-year average pensionable earnings. The plan also provides pensioners a conditional indexing fund. Employees make equal basic and indexing contributions to the plan funds based on a percentage of current pensionable earnings as prescribed by the independent actuary. The Company may contribute additional amounts as prescribed by the independent actuary. The Company is responsible for ensuring that the statutory pension plan has sufficient assets to pay the pension benefits. The supplemental arrangements are not funded. The defined benefit pension plans are administered under a defined governance structure. The pension arrangements including investment, plan benefits and funding decisions are administered by the Company's Pension Management Committee with the oversight resting with the Board of Directors. Significant changes to the plans, investment policies, and funding policies require the approval of the Board of Directors. The most recent actuarial funding valuation for the statutory pension plan was performed at December 31, 2018. The next valuation for funding purposes will be prepared as at December 31, 2021, and the results will be available in September 2022.

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 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, future inflation levels impacting future salary increases as well as future increases in healthcare costs.

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

(a) The expense for the Company's benefit plans for the years ended March 31, 2022 and 2021 is recognized in the following line items in the statement of comprehensive income prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions:

	Pension Benefit Plans		**Other Benefit Plans**		**Total**	
(in millions)	**2022**	2021	**2022**	2021	**2022**	2021
Current service costs charged to personnel expense - operating expenses	**$ 142**	$ 117	**$ 7**	$ 6	**$ 149**	$ 123
Net interest costs charged to finance costs	**49**	56	**7**	8	**56**	64
Total post-employment benefit plan expense	**$ 191**	$ 173	**$ 14**	$ 14	**$ 205**	$ 187

Actuarial gain recognized in other comprehensive income was $776 million (2021 – $156 million).

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

	Pension Benefits Plans		**Other Benefits Plans**		**Total**	
(in millions)	**March 31, 2022**	March 31, 2021	**March 31, 2022**	March 31, 2021	**March 31, 2022**	March 31, 2021
Defined benefit obligation of funded plan	**$ (5,110)**	$ (5,504)	**$ -**	$ -	**$ (5,110)**	$ (5,504)
Defined benefit obligation of unfunded plans	**(160)**	(180)	**(180)**	(217)	**(340)**	(397)
Fair value of plan assets	**4,557**	4,373	**-**	-	**4,557**	4,373
Plan deficit	**$ (713)**	$ (1,311)	**$ (180)**	$ (217)	**$ (893)**	$ (1,528)
Represented by:						
Accrued benefit plan liability	**$ (713)**	$ (1,311)	**$ (180)**	$ (217)	**$ (893)**	$ (1,528)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2022 and fiscal 2021 in accordance with IFRIC 14*, The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction*.

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

	Pension Benefit Plans		**Other Benefit Plans**	
(in millions)	**March 31, 2022**	March 31, 2021	**March 31, 2022**	March 31, 2021
Defined benefit obligation				
Opening defined benefit obligation	**$ 5,684**	$ 5,075	**$ 217**	$ 199
Current service cost	**142**	117	**7**	6
Interest cost on benefit obligations	**229**	350	**7**	8
Benefits paid[1]	**(203)**	(194)	**(5)**	(5)
Employee contributions	**46**	46	**-**	-
Actuarial losses (gains)[2]	**(628)**	290	**(46)**	9
Defined benefit obligation, end of year	**5,270**	5,684	**180**	217
Fair value of plan assets				
Opening fair value	**4,373**	3,714	**n/a**	n/a
Interest income on plan assets[3]	**180**	294	**n/a**	n/a
Employer contributions	**51**	50	**n/a**	n/a
Employee contributions	**46**	46	**n/a**	n/a
Benefits paid[1]	**(195)**	(186)	**n/a**	n/a
Actuarial gains [2,3]	**102**	455	**n/a**	n/a
Fair value of plan assets, end of year	**4,557**	4,373	**-**	-
Accrued benefit liability	**$ (713)**	$ (1,311)	**$ (180)**	$ (217)

1 Benefits paid under Pension Benefit Plans include $21 million (2021 - $16 million) of settlement payments.

2 Actuarial gains/losses are included in the Non-Current Pension Costs Regulatory Account and for fiscal 2022 are comprised of $102 million of actuarial gains on return on plan assets (2021 - $455 million actuarial gains) and $674 million of actuarial gains (2021 - $299 million actuarial losses) on the benefit obligations due to discount rate increases.

3 Actual income on defined benefit plan assets for the year ended March 31, 2022 was $282 million (2021 - $749 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, 2022	March 31, 2021	**March 31, 2022**	March 31, 2021
Discount rate				
Benefit cost	**3.40%**	3.83%	**3.14%**	3.73%
Accrued benefit obligation	**4.38%**	3.40%	**4.19%**	3.14%
Rate of return on plan assets	**3.40%**	3.83%	**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	**3.46%**	4.85%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**3.46%**	3.82%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	**n/a**	2040

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

(e) Defined benefit pension plan assets are invested prudently in order to meet the Company's pension obligations. The pension plans' 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 pension plan assets are primarily comprised of debt and equity securities and alternative investments.

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

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

	Long Term Strategic Target Allocation	**Target Range Min**	**Target Range Max**	**March 31, 2022**	March 31, 2021
Fixed interest investments	20%	15%	35%	**24%**	24%
Public equities	40%	30%	55%	**42%**	46%
Real estate	15%	5%	20%[1]	**14%**	11%
Private equities	15%	5%	20%[1]	**12%**	11%
Infrastructure and renewable resources	10%	5%	15%[1]	**8%**	8%

[1]The total cannot exeed 45%.

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

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

The Company's contribution to be paid to its funded defined benefit statutory pension plan in fiscal 2023 is expected to amount to $55 million. The expected benefit payments to be paid in fiscal 2023 in respect to the unfunded defined benefit plans are $14 million.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

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

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

Number of plan participants as at March 31, 2022		15,066
Actual benefit payments 2022	$	195
Benefits expected to be paid 2023	$	190
Benefits expected to be paid 2024	$	194
Benefits expected to be paid 2025	$	199
Benefits expected to be paid 2026	$	204
Benefits expected to be paid 2027	$	210
Benefits expected to be paid 2028-2030	$	892
Weighted average duration of defined benefits payments		14.3 years

Assumptions adopted can have a significant effect on the value of the obligations for defined benefit pension and other post-employment benefit plans and are based on historical experience and market inputs. The increase (decrease) in obligation in the following table has been determined for key assumptions assuming all other assumptions are held constant. In practice, this is unlikely to occur, as changes in some of the assumptions may be correlated. The two tables below present the sensitivity analysis of key assumptions for 2022.

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

(in millions)	One percentage point increase 2022	One percentage point decrease 2022
Effect on current service costs	$ -	$ -
Effect on defined benefit obligation	6	(5)

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

		2022	
(in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	- 522	-30
Discount rate	1% decrease	+ 666	+42
Longevity	1 year increase	+ 116	+ 3
Longevity	1 year decrease	- 120	- 3
Compensation	1% increase	+ 215	+ 20
Compensation	1% decrease	- 183	- 17

Note 23: Financial Instruments

Financial Risk Management Overview

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

The following discussion is limited to the nature and extent of risks arising from financial instruments, as defined under IFRS 7, *Financial Instruments: Disclosures*. However, for a complete understanding of the nature and extent of financial risks the Company is exposed to, this note should be read in conjunction with the Company's discussion of Risk Management found in the Management's Discussion and Analysis section of the 2021/22 Annual Service Plan Report.

(a) Credit Risk

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

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

Maximum credit risk with respect to financial assets is limited to the carrying amount presented on the consolidated statement of financial position with the exception of U.S. dollar sinking funds and non-current receivables which are classified as amortized cost and carried on the consolidated statement of financial position at $210 million and $134 million respectively. The maximum credit risk exposure for the U.S. dollar sinking funds and non-current receivables as at March 31, 2022 is their fair value of $225 million and $140 million, respectively.

(b) Liquidity Risk

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

(c) Market Risks

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

(i) Currency Risk

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

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

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

(ii) Interest Rate Risk

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

(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 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, 2022 and 2021.

	March 31, 2022		March 31, 2021		**2022**	2021
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value	**Interest Income (Expense) recognized in Finance Charges**	Interest Income (Expense) recognized in Finance Charges
Fair Value Through Profit or Loss (FVTPL):						
Cash equivalents - short-term investments	**$ 72**	**$ 72**	$ 34	$ 34	**$ -**	$ -
Amortized Cost:						
Cash	**27**	**27**	3	3	**-**	-
Restricted cash	**-**	**-**	6	6	**-**	-
Accounts receivable and accrued revenue	**802**	**802**	827	827	**-**	-
Non-current receivables	**134**	**140**	138	153	**9**	6
Sinking funds	**210**	**225**	203	233	**9**	9
Accounts payable and accrued liabilities	**(1,760)**	**(1,760)**	(1,589)	(1,589)	**-**	-
Revolving borrowings	**(2,792)**	**(2,792)**	(2,803)	(2,803)	**(4)**	(12)
Long-term debt (including current portion due in one year)	**(23,159)**	**(23,540)**	(22,177)	(24,548)	**(782)**	(822)
First Nations liabilities (non-current portion)	**(404)**	**(611)**	(404)	(741)	**(18)**	(18)
Lease liabilities (non-current portion)	**(1,327)**	**(1,327)**	(1,352)	(1,352)	**(45)**	(48)
Other liabilities	**(416)**	**(415)**	(424)	(436)	**(21)**	(23)

When the carrying value differs from fair value, the fair values of non-derivative financial instruments would be classified as Level 2 of the fair value hierarchy. The carrying value of cash equivalents, restricted cash, accounts receivable and accrued revenue, accounts payable and accrued liabilities, and revolving borrowings approximates fair value due to the short duration of these financial instruments.

Hedges

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

The following foreign currency contracts under hedge accounting were in place at March 31, 2022 in a net liability position of $23 million (2021 – net asset $16 million). Such contracts are used to hedge the principal on US$ denominated long-term debt and the principal and coupon payments on Euro€ denominated long-term debt for which hedge accounting has been applied. The hedging instruments are effective in offsetting changes in the cash flows of the hedged item attributed to the hedged risk. The main source of hedge ineffectiveness in these hedges is credit risk.

($ amounts in millions)	**March 31, 2022**	March 31, 2021
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	**6 years**	7 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	**8 years**	9 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, 2022 Fair Value**	March 31, 2021 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)	**$ 19**	$ 16
Foreign currency contract liabilities (cash flow hedges for US$ denominated long-term debt)	**(10)**	(6)
Foreign currency contract assets (cash flow hedges for EURO€ denominated long-term debt)	**-**	11
Foreign currency contract liabilities (cash flow hedges for EURO€ denominated long-term debt)	**(32)**	(5)
	(23)	**16**
Non-Designated Derivative Instruments:		
Interest rate contract assets	**180**	-
Interest rate contract liabilities	**(1)**	(125)
Foreign currency contract liabilities	**(4)**	(36)
Commodity derivative assets	**356**	88
Commodity derivative liabilities	**(356)**	(139)
	175	(212)
Net asset (liability)	**$ 152**	$ (196)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

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

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

(in millions)	**March 31, 2022**	March 31, 2021
Current portion of derivative financial instrument assets	**$ 315**	$ 87
Current portion of derivative financial instrument liabilities	**(228)**	(235)
Derivative financial instrument assets, non-current	**242**	30
Derivative financial instrument liabilities, non-current	**(177)**	(78)
Net asset (liability)	**$ 152**	$ (196)

For designated cash flow hedges for the year ended March 31, 2022, there was a loss of $39 million (2021 – loss of $72 million). The effective portion was recognized in other comprehensive income and the ineffective portion was recognized in finance charges. For the year ended March 31, 2022, $39 million (2021 –$118 million) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange gains (2021 - gains) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $3.73 billion (2021 - $3.23 billion), used to economically hedge the interest rates on future debt issuances, there was a $230 million increase (2021 - $571 million) in the fair value of these contracts for the year ended March 31, 2022. For interest rate contracts associated with debt issued, there was a $77 million decrease (2021 - $55 million) in the fair value of contracts that settled during the year ended March 31, 2022. The net increase for the year ended March 31, 2022 of $153 million (2021 - $516 million) in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had an asset balance of $286 million as at March 31, 2022.

Foreign currency contracts for cash management purposes not designated as hedges, for the year ended March 31, 2022, had a gain of $2 million (2021 – loss of $2 million) recognized in finance charges. Foreign currency contracts associated with U.S. revolving borrowings not designated as hedges, for the year ended March 31, 2022, had a gain of $19 million (2021 - loss of $175 million) recognized in finance charges. These economic hedges offset $19 million of foreign exchange revaluation losses (2021 – gains of $177 million) recorded in finance charges with respect to U.S. revolving borrowings for the year ended March 31, 2022.

For commodity derivatives not designated as hedges, a net gain of $824 million (2021 - $464 million) was recorded in trade revenue for the year ended March 31, 2022.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)		**2022**		2021
Deferred inception gain, beginning of the year	**$**	**40**	$	7
New transactions		**15**		58
Amortization		**(82)**		(24)
Foreign currency translation (gain) loss		**1**		(1)
Deferred inception (loss) gain, end of the year	**$**	**(26)**	$	40

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, 2022**		March 31, 2021
Current	**$**	**425**	$	403
Past due (30-59 days)		**24**		22
Past due (60-89 days)		**6**		6
Past due (More than 90 days)		**3**		44
		458		475
Less: Allowance for doubtful accounts		**(7)**		(6)
	$	**451**	$	469

At the end of each period, a review for doubtful accounts is performed. It is an assessment of the expected lifetime credit losses of accounts receivable at the consolidated statement of financial position date. The assessment is made by reference to age, status and risk of each receivable, current economic conditions including consideration of the impacts of COVID-19, and historical information. At March 31, 2022, there was of uncertainty and judgment regarding the impact of COVID-19 on credit risk and expected lifetime credit losses.

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, 2022			
Derivative commodity assets	**$ 356**	**$ 11**	**$ 345**
Derivative commodity liabilities	**356**	**11**	**345**
As at March 31, 2021			
Derivative commodity assets	$ 88	$ 11	$ 77
Derivative commodity liabilities	139	11	128

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2022 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, 2022. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2022 has been used.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

(in millions)	Carrying Value	Fiscal 2023	Fiscal 2024	Fiscal 2025	Fiscal 2026	Fiscal 2027	Fiscal 2028 *and thereafter*
Non-Derivative Financial Liabilities							
Total accounts payable and other payables	$ 1,450	$ (1,450)	$ -	$ -	$ -	$ -	$ -
(excluding interest accruals and current portion of lease obligations and First Nations liabilities)							
Long-term debt	26,171	(4,078)	(961)	(764)	(2,631)	(1,524)	(28,401)
(including interest payments)							
Lease obligations	1,379	(96)	(95)	(95)	(95)	(94)	(1,463)
Other long-term liabilities	835	(59)	(110)	(73)	(65)	(58)	(1,763)
Total Non-Derivative Financial Liabilities	29,835	(5,683)	(1,166)	(932)	(2,791)	(1,676)	(31,627)
Derivative Financial Liabilities							
Cross currency swaps used for hedging	32						
Cash outflow		(14)	(14)	(14)	(405)	(5)	(226)
Cash inflow		5	5	5	370	2	200
Forward foreign exchange contracts used for hedging	10						
Cash outflow		-	-	-	(337)	-	-
Cash inflow		-	-	-	325	-	-
Other forward foreign exchange contracts designated at fair value	6						
Cash outflow		(617)	-	-	-	-	-
Cash inflow		611	-	-	-	-	-
Interest rate swaps used for hedging	1	-	(1)	-	-	-	-
Net commodity derivatives	-	21	1	(30)	(11)	(8)	(2)
Total Derivative Financial Liabilities	49	6	(9)	(39)	(58)	(11)	(28)
Total Financial Liabilities	29,884	(5,677)	(1,175)	(971)	(2,849)	(1,687)	(31,655)
Derivative Financial Assets							
Forward foreign exchange contracts used for hedging	(19)						
Cash outflow		-	-	-	(99)	-	(283)
Cash inflow		-	-	-	104	-	288
Other forward foreign exchange contracts designated at fair value	(2)						
Cash outflow		(270)	-	-	-	-	-
Cash inflow		272	-	-	-	-	-
Interest rate swaps used for hedging	(180)	74	34	60	20	-	-
Total Derivative Financial Assets	(201)	76	34	60	25	-	5
Net Financial Liabilities	**$ 29,683**	**$ (5,601)**	**$ (1,141)**	**$ (911)**	**$(2,824)**	**$(1,687)**	**$ (31,650)**

MARKET RISKS

(a) Currency Risk

Sensitivity Analysis

A $0.01 strengthening (weakening) of the U.S. dollar against the Canadian dollar at March 31, 2022 would otherwise have a negative (positive) impact of $nil on net income before movement in regulatory balances. The Total Finance Charges Regulatory Account that captures all variances from forecasted finance charges (as described in Note 15) eliminates any impact on net income. 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, 2022 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 rates over the period until the next consolidated statement of financial position date.

(b) Interest Rate Risk

For sensitivity analysis for variable rate non-derivative instruments, an increase (decrease) of 100-basis points in interest rates at March 31, 2022 would otherwise have a negative (positive) impact on net income before movement in regulatory balance of $30 million, but as a result of regulatory accounting, it would have no impact on net income or other comprehensive income. The Total Finance Charges Regulatory Account that captures all variances from forecasted finance charges (as described in Note 15) eliminates any impact on net income. This analysis assumes that all other variables, in particular foreign exchange rates, remain constant.

For the interest rate contracts, an increase of 100-basis points in interest rates at March 31, 2022 would otherwise have a positive impact on net income of $450 million and a decrease of 100 basis points in interest rates at March 31, 2022 would otherwise have a negative impact on net income before movement in regulatory balances of $560 million but as a result of regulatory accounting 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, 2022 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 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 estimates the pre-tax forward trading loss that could result from changes in commodity prices, with a specific level of confidence, over a specific time period. The Company uses an industry standard Monte Carlo VaR model to determine the potential change in value of the Company's forward trading portfolio over a 10-day holding period, within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR as an estimate of price risk has several limitations. The VaR 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 $61 million at March 31, 2022 (2021 - $19 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, 2022 and 2021:

As at March 31, 2022 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 72	$ -	$ -	$ 72
Derivatives designated as hedges	-	19	-	19
Derivatives not designated as hedges	255	209	74	538
	$ 327	$ 228	$ 74	$ 629

As at March 31, 2022 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (42)	$ -	$ (42)
Derivatives not designated as hedges	(141)	(65)	(157)	$ (363)
	$ (141)	$ (107)	$ (157)	$ (405)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

As at March 31, 2021 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 34	$ -	$ -	$ 34
Derivatives designated as hedges	-	27	-	27
Derivatives not designated as hedges	59	10	21	90
	$ 93	$ 37	$ 21	$ 151

As at March 31, 2021 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (11)	$ -	$ (11)
Derivatives not designated as hedges	(39)	(173)	(90)	(302)
	$ (39)	$ (184)	$ (90)	$ (313)

The Company's policy is to recognize level transfers at the end of each period during which the change occurred. During the year, commodity derivatives with a carrying amount of $2 million (2021– $nil) were transferred from Level 2 to Level 1.
The following table reconciles the changes in the balance of financial instruments carried at fair value on the consolidated statement of financial position, classified as Level 3, for the years ended March 31, 2022 and 2021:

(in millions)	
Balance as at April 1, 2021	**$ (69)**
Net gain recognized	24
New transactions	(11)
Existing transactions settled	(27)
Balance as at March 31, 2022	**$ (83)**

(in millions)	
Balance as at April 1, 2020	**$ (12)**
Net loss recognized	(35)
New transactions	(26)
Existing transactions settled	4
Balance as at March 31, 2021	**$ (69)**

During the year, there were no transfers of commodity derivatives (2021 – $nil) between Level 3 and Level 2.

During the year ended March 31, 2022, unrealized losses of $12 million (2021 – losses of $29 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, 2022 range between $1-$488 per MwH and a 10 percent increase/decrease in certain components of these prices would decrease/increase fair value by $67 million. A 10 percent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $6 million.

Note 24: Other Non-Current Liabilities

(in millions)	**March 31, 2022**	March 31, 2021
Provisions		
Environmental liabilities	**$ 296**	$ 326
Decommissioning obligations	**80**	87
Other	**31**	63
	407	476
First Nations liabilities	**419**	418
Other contributions	**225**	230
Other liabilities	**416**	424
	1,467	1,548
Less: Current portion, included in accounts payable and accrued liabilities	**(112)**	(146)
	$ 1,355	$ 1,402

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

(in millions)	**Environmental**	**Decommissioning**	**Other**	**Total**
Balance at April 1, 2020	**$ 309**	**$ 77**	**$ 29**	**$ 415**
Made during the period	2	-	41	43
Used during the period	(39)	(3)	(7)	(49)
Changes in estimate	51	12	-	63
Accretion	3	1	-	4
Balance at March 31, 2021	**$ 326**	**$ 87**	**$ 63**	**$ 476**
Made during the period	15	-	7	22
Used during the period	(46)	(4)	(26)	(76)
Changes in estimate	(4)	(5)	(13)	(22)
Accretion	5	2	-	7
Balance at March 31, 2022	**$ 296**	**$ 80**	**$ 31**	**$ 407**

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, 2022, the undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2022 and 2045, is approximately $357 million and was determined based on current cost estimates. A range of discount rates between 2.4 per cent and 2.5 per cent were used to calculate the net present value of the obligations.

Decommissioning Obligations

The Company's decommissioning obligation provision consists of estimated removal and destruction costs associated with certain PCB and asbestos contaminated assets and certain submarine cables. The Company has determined its best estimate of the undiscounted amount of cash flows required to settle remediation obligations at $107 million (2021 - $111 million), which will be settled between fiscal 2023 and 2053. The undiscounted cash flows, discounted by a range of discount rates between 2.4 per cent and 2.5 per cent, were used to calculate the net present value of the obligations. The obligations are re-measured at each period end to reflect changes in estimated cash flows and discount rates.

First Nations Liabilities

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

Other Contributions

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

Other Liabilities

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

Note 25: Commitments and Contingencies

Energy Commitments

BC Hydro (excluding Powerex) has long-term energy and capacity purchase contracts to meet a portion of its expected future domestic electricity requirements. The expected obligations to purchase energy under these contracts have a total value of approximately $45.67 billion of which approximately $64 million relates to the purchase of natural gas, natural gas transportation contracts and wheeling agreements. The remaining commitments are at predetermined prices.

Included in the total value of the long-term energy purchase agreements is $1.86 billion accounted for as a lease liability under Note 19. The total BC Hydro combined payments are estimated to be approximately $1.67 billion for less than one year, $6.44 billion between one and five years, and $37.56 billion for more than five years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $2.38 billion extending to 2053. The total Powerex energy purchase commitments are estimated to be approximately $1.03 billion for less than one year, $1.19 billion between one and five years, and $170 million for more than five years.

Powerex has energy sales commitments of $2.17 billion extending to 2032 with estimated amounts of $948 million for less than one year, $1.14 billion between one and five years, and $83 million for more than five years.

Lease and Service Agreements

The Company has entered into various agreements to lease facilities or assets or service agreements supporting operations. The agreements cover periods of up to 99 years, and the aggregate minimum payments are approximately $1.00 billion. Included in the total value of the lease agreements is $77 million accounted for as a lease liability under Note 19. Payments are $57 million for less than one year, $133 million between one and five years, and $814 million for more than five years.

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

Contingencies and Guarantees

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

b) Contractors have made claims against BC Hydro that allege, among other things, that delays caused by BC Hydro and project issues have increased or will increase the costs of service rendered by or to be rendered by the contractors under the contracts with BC Hydro. BC Hydro disputes the validity of the claims. Additional details of the claims are not being disclosed as they could seriously prejudice the outcome of the disputes.

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

d) The Company and its subsidiaries have outstanding letters of credit totaling $1.36 billion (2021 - $1.31 billion), which include amounts provided by the Company to secure pension plan solvency deficiency payments related to the registered pension plan. The total outstanding letters of credit also includes US $15 million (2021 - US $28 million) in foreign denominated letters of credit.

Note 26: Related Party Transactions

Subsidiaries

The principal subsidiaries of BC Hydro are Powerex and Powertech.

All companies are wholly owned and incorporated in Canada and all ownership is in the form of common shares. Operating out of Vancouver, BC, Canada, Powerex is an energy marketer, whose activities include trading wholesale power, environmental products (renewable energy credits or other similar products), carbon products (allowances and other similar products), natural gas, ancillary services, and financial 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:

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

(in millions)		**March 31, 2022**		March 31, 2021
Consolidated Statement of Financial Position				
Prepaid expenses	**$**	**101**	$	98
Right-of-use assets		**1,217**		1,247
Accounts payable and accrued liabilities		**78**		73
Lease liabilities		**1,344**		1,361

	2022	2021
Amounts incurred/accrued during the year include:		
Water rental fees	**345**	295
Cost of energy	**299**	169
Grants and Taxes	**152**	147
Interest	**786**	834
Derivatives	**162**	456
Lease payments	**100**	100
Other	**111**	135

The Company's debt is either held or guaranteed by the Province (see Note 17). Under an agreement with the Province, the Company indemnifies the Province for any credit losses incurred by the Province related to interest rate and foreign currency contracts entered into by the Province on the Company's behalf. As at March 31, 2022, the aggregate exposure under this indemnity totaled $201 million (2021 - $28 million). The Company has not experienced any losses to date under this indemnity.

The Site C Project requires the realignment of six segments of Highway 29 with a total length of approximately 30 kilometers. The highway re-alignment activities are needed for reservoir inundation which is required prior to the first generating unit in service forecasted for December 2024. The Province (Ministry of Transportation and Infrastructure) maintains effective control over the highway during the re-alignment activities and after these activities are complete. During fiscal year 2022, BC Hydro has incurred total costs of approximately $190 million (2021 – $223 million) on highway re-alignment activities, of which $104 million (2021 - $128 million) was paid directly to the Province.

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 through a public auction 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
FOR THE YEARS ENDED MARCH 31, 2022 AND 2021

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)	**2022**	2021
Short-term employee benefits	**$ 4**	$ 4
Post-employment benefits	**2**	2

Appendix D: Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	2022	2021	2020[1]	2019[2]	2018[2,3]
Revenues					
Domestic	**$ 5,619**	$ 5,237	$ 5,393	$ 5,432	$ 5,223
Trade	**1,972**	1,177	876	1,144	731
	7,591	6,414	6,269	6,576	5,954
Expenses					
Domestic energy costs	**1,936**	1,690	1,681	1,557	1,615
Trade energy costs	**1,066**	579	689	624	522
Other operating expenses[4]	**1,427**	1,366	1,372	1,292	1,302
Amortization and depreciation	**1,079**	1,009	988	949	817
Grants and taxes	**286**	254	254	266	241
Finance charges	**521**	224	1,666	1,196	824
	6,315	5,122	6,650	5,884	5,321
Net Income (Loss) Before Movement in Regulatory Balances	**1,276**	1,292	(381)	692	633
Net movement in regulatory balances	**(608)**	(604)	1,086	(1,120)	51
Net Income (Loss)	**$ 668**	$ 688	$ 705	$ (428)	$ 684
Property, Plant and Equipment, Right-of-Use Assets and Intangible Assets					
Property, Plant and Equipment	**$ 34,038**	$ 31,677	$ 29,427	$ 27,334	$ 24,439
Right-of-Use Assets	**1,248**	1,317	1,405	1,466	1,526
Intangible Assets	**705**	688	678	602	591
Net Book Value	**$ 35,991**	$ 33,682	$ 31,510	$ 29,402	$ 26,556
Property, Plant and Equipment and Intangible Asset Expenditures					
Sustaining	**$ 1,119**	$ 971	$ 955	$ 965	$ 1,190
Growth	**2,356**	2,236	2,127	2,861	1,283
Total Property, Plant and Equipment and Intangible Asset Expenditures [5]	**$ 3,475**	$ 3,207	$ 3,082	$ 3,826	$ 2,473
Net Long-Term Debt [6]	**$ 25,642**	$ 24,740	$ 23,354	$ 22,101	$ 20,140
Retained Earnings	**$ 6,994**	$ 6,326	$ 5,638	$ 4,933	$ 5,420
Debt to Equity Ratio	**78 : 22**	80 : 20	81 : 19	82 : 18	79 : 21

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

2 The Company adopted IFRS 16, *Leases* (IFRS 16) in 2019/20 and restated the comparative periods 2018/19 and 2017/18. For additional information, refer to Note 27: Explanation of Adoption of IFRS 16 in the Audited Financial Statements within the 2019/20 Annual Service Plan Report.

3 The Company adopted IFRS in 2018/19, and restated the comparative period 2017/18. For additional information, refer to Note 24: Explanation of Transition to IFRS in the Audited Financial Statements within the 2018/19 Annual Service Plan Report. Under IFRS, changes in regulatory balances are reported within the "net movements in regulatory balances".

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

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

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

OPERATING STATISTICS

for the years ended or as at March 31	**2022**	**2021**	2020[1]	2019	2018
Generating Capacity (megawatts)					
Hydroelectric	**12,027**	12,027	11,932	11,932	11,918
Thermal	**179**	177	177	177	180
Total	**12,206**	12,204	12,109	12,109	12,098
Peak One-Hour Integrated System Demand (megawatts)	**10,787**	10,076	10,577	10,045	9,651
Number of Domestic Customer Accounts					
Residential	**1,931,041**	1,896,518	1,863,569	1,833,097	1,803,752
Light industrial and commercial	**221,573**	218,196	215,063	212,446	210,673
Large industrial	**201**	202	198	195	190
Other	**3,387**	3,383	3,396	3,419	3,429
Total	**2,156,202**	2,118,299	2,082,226	2,049,157	2,018,044
Domestic Electricity Sold (gigawatt-hours)					
Residential	**19,440**	18,983	17,993	18,000	18,150
Light industrial and commercial	**19,029**	18,091	18,692	19,007	18,874
Large industrial	**13,312**	12,438	13,398	13,896	13,440
Surplus Sales	**-**	-	-	2,230	5,072
Other sales	**1,671**	1,628	1,848	1,510	1,637
Total	**53,452**	51,140	51,931	54,643	57,173

Revenues (in millions)

for the years ended March 31	**2022**	**2021**	2020[1]	2019[2]	2018[2,3]
Residential	**$ 2,342**	$ 2,210	$ 2,169	$ 2,127	$ 2,097
Light industrial and commercial	**1,952**	1,830	1,942	1,925	1,860
Large industrial	**854**	762	850	873	811
Surplus Sales	**-**	-	-	115	139
Other sales	**471**	435	432	392	316
Total Domestic	**5,619**	5,237	5,393	5,432	5,223
Trade	**1,972**	1,177	876	1,144	731
Total	**$ 7,591**	$ 6,414	$ 6,269	$ 6,576	$ 5,954

Average Revenue (per kilowatt-hour)

for the years ended or as at March 31	**2022**	**2021**	2020	2019	2018
Residential	**12.0¢**	11.6¢	12.1¢	11.8¢	11.6¢
Light industrial and commercial	**10.3**	10.1	10.4	10.1	9.9
Large industrial	**6.4**	6.1	6.3	6.3	6.0
Average Annual Kilowatt-Hour Use Per Residential Customer Account	**10,158**	10,097	9,735	9,899	10,139
Lines In Service					
Distribution (kilometres)	**60,093**	59,907	59,694	59,095	59,222
Transmission (circuit kilometres)	**20,148**	19,958	20,389	20,385	20,306

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

2 The Company adopted IFRS 16, *Leases* (IFRS 16) in 2019/20 and restated the comparative periods 2018/19 and 2017/18. For additional information, refer to Note 27: Explanation of Adoption of IFRS 16 in the Audited Financial Statements within the 2019/20 Annual Service Plan Report.

3 The Company adopted IFRS in 2018/19, and restated the comparative period 2017/18. For additional information, refer to Note 24: Explanation of Transition to IFRS in the Audited Financial Statements within the 2018/19 Annual Service Plan Report. Under IFRS, changes in regulatory balances are reported within the "net movements in regulatory balances".

TOTAL ELECTRICITY SALES AND SOURCES OF SUPPLY

for the years ended March 31	**2022**			2021			2020[2]			2019			2018		
	Generating Capacity (megawatts)	**Gigawatt-Hours**	**%**	Generating Capacity (megawatts)	Gigawatt-Hours	%	Generating Capacity (megawatts)	Gigawatt-Hours	%	Generating Capacity (megawatts)	Gigawatt-Hours	%	Generating Capacity (megawatts)	Gigawatt-Hours	%
Electricity Sales															
Domestic	**12,206**	**53,452**	**70.3**	12,204	51,140	67.6	12,109	51,931	73.2	12,109	54,643	74.6	12,098	57,173	73.6
Electricity trade[1]		**17,836**	**23.5**		19,407	25.7		14,346	20.2		14,139	19.3		15,046	19.4
		71,288	**93.8**		70,547	93.3		66,277	93.4		68,782	93.9		72,219	93.0
Line loss and system use		**4,709**	**6.2**		5,104	6.7		4,651	6.6		4,496	6.1		5,454	7.0
		75,997	**100.0**		75,651	100.0		70,928	100.0		73,278	100.0		77,673	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,857**	**15,626**	**20.6**	2,857	15,907	21.0	2,778	12,605	17.8	2,778	11,634	15.9	2,778	13,876	17.9
Revelstoke	**2,480**	**8,548**	**11.2**	2,480	9,218	12.2	2,480	7,286	10.3	2,480	8,408	11.5	2,480	9,082	11.7
Mica	**2,746**	**7,681**	**10.1**	2,746	8,669	11.5	2,746	6,262	8.8	2,746	7,625	10.4	2,746	8,561	11.0
Kootenay Canal	**583**	**2,780**	**3.7**	583	2,626	3.5	583	2,377	3.4	583	2,486	3.4	583	3,083	4.0
Peace Canyon	**694**	**3,791**	**5.0**	694	3,893	5.1	694	3,051	4.3	694	2,938	4.0	694	3,430	4.4
Seven Mile	**805**	**2,936**	**3.9**	805	3,039	4.0	805	2,842	4.0	805	3,137	4.3	805	3,460	4.5
Bridge River	**478**	**2,578**	**3.4**	478	2,219	2.9	478	2,367	3.3	478	1,996	2.7	478	2,216	2.9
Other	**1,384**	**4,125**	**5.2**	1,384	4,225	5.6	1,368	3,592	5.1	1,368	4,118	5.5	1,354	4,218	5.3
	12,027	**48,065**	**63.1**	12,027	49,796	65.8	11,932	40,382	57.0	11,932	42,342	57.7	11,918	47,926	61.7
Thermal generation	**179**	**125**	**0.2**	177	150	0.2	177	172	0.2	177	190	0.3	180	91	0.1
Purchases under long-term commitments		**16,824**	**22.1**		14,630	19.3		14,474	20.4		14,248	19.4		14,354	18.5
Purchases under short-term commitments		**119**	**0.2**		109	0.1		110	0.2		103	0.1		115	0.1
Electricity trade purchases		**11,857**	**15.6**		11,321	15.0		16,371	23.1		16,550	22.6		14,588	18.8
Other		**(993)**	**(1.3)**		(355)	(0.5)		(581)	(0.8)		(155)	(0.2)		599	0.8
	12,206	**75,997**	**100**	12,204	75,651	100.0	12,109	70,928	100.0	12,109	73,278	100.0	12,098	77,673	100.0

[1]Electricity trade represents electricity sold that is surplus to domestic load requirements and other sales that are outside the Province of British Columbia.

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