British Columbia Hydro and Power Authority

2018/19
ANNUAL SERVICE PLAN REPORT

July 2019

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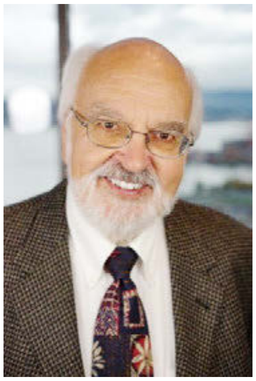
Executive Board Chair's Accountability Statement



BC Hydro is a provincial Crown Corporation, owned by the people of British Columbia. We operate an integrated system of generation, transmission and distribution infrastructure to safely provide reliable, affordable and clean electricity to our customers throughout British Columbia. The electricity we generate and deliver to customers throughout the province powers our economy and quality of life.

This report was prepared under the Board's direction in accordance with the *Budget Transparency and Accountability Act* and the B.C. Reporting Principles. The Board and Management are accountable for the contents of the report and how it is reported. The Board is also responsible for ensuring internal controls are in place to measure information and report accurately and in a timely fashion.

All significant assumptions, policy decisions, events and identified risks, as of March 31, 2019 have been considered in preparing the report. The report contains estimates and interpretive information that represent the best judgment of management. Any changes in mandate direction, goals, strategies, measures or targets made since the *2018/19 - 2020/22 Service Plan* was released and any significant limitations in the reliability of the information are identified in the report.

The *BC Hydro 2018/19 Annual Service Plan Report* compares the corporation's actual results to the expected results identified in the *2018/19 - 2020/21 Service Plan* created in February 2018. I am accountable for those results as reported.

Kenneth G. Peterson
Executive Board Chair

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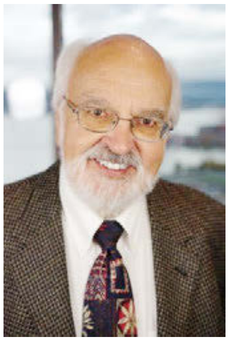
Executive Board Chair/President and Chief Operating Officer Report Letter



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, 2019. 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.

Reliable, affordable and clean electricity is vital to British Columbia's economic prosperity and our quality of life. BC Hydro continues to invest in our system to ensure it is there to support British Columbia's growing population and economy. We are investing approximately $3 billion per year to upgrade aging assets and build new infrastructure so that our customers continue to receive reliable and clean electricity.

We have the important responsibility to keep electricity rates affordable for our customers, while funding necessary investments in our electricity system. To support this goal, we worked with the Province to complete Phase 1 of the Comprehensive Review of the corporation and developed a new five year rates forecast to keep electricity rates low and predictable over the long-term. We have also continued to enhance the affordability programs we provide to our customers and will continue to focus on making it easier for our customers to do business with us.

We are working with the Province on Phase 2 of the Comprehensive Review to ensure that BC Hydro is well-positioned to maximize opportunities flowing from shifts taking place in the global and regional energy sectors, technological change and climate action. Phase 2 will also focus on BC Hydro's role in implementing electrification initiatives critical to CleanBC, the Province's plan to reach its 2030 climate targets through reduction of greenhouse gas emissions in transportation, buildings and industry.

BC Hydro works closely with the Ministry of Energy, Mines and Petroleum Resources to ensure alignment with government policy expectations through regular meetings and updates. These are held between the Executive, the Minister and her staff and the Executive Board Chair, as appropriate, to discuss actions identified in the Board Chair's Mandate Letter. 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're 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 and clean electricity to our customers.

Kenneth G. Peterson *Executive Board Chair*	*Chris O'Riley* *President and Chief Operating Officer*

Purpose of the Annual Service Plan Report

The Annual Service Plan Report (ASPR) 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 to safely provide our customers with reliable, affordable and clean electricity throughout British Columbia. 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 79,000 kilometres of transmission and distribution lines. Our partnership with B.C.'s clean energy industry encompasses over 130 projects across the province, including biomass, hydro, wind and solar. Our electricity generation is 97.8 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 Energy, Mines and Petroleum Resources and the Government's expectations are expressed through the annual Mandate Letter to the Board Chair and the following legislation, policy and instructions:

- 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 subsidiaries of BC Hydro. Powerex is a key participant in energy markets across North America, buying and selling wholesale power, renewable and low-carbon energy and products, natural gas, ancillary services and financial energy products. Powertech is internationally recognized for providing research and development, testing, technical services and advanced technology services to clients around the world, including BC Hydro. For more information on Powerex, Powertech and other active and inactive subsidiaries, see *Appendix A: Subsidiaries and Operating Segments*.

Strategic Direction

The strategic direction set by Government in 2017 and expanded upon in the Board Chair's Mandate Letter from the Minister Responsible in 2018 shaped the 2018/19-2020/21 Service Plan and the results reported in this ASPR.

The following table highlights the key goals, objectives or strategies that support the key priorities of Government identified in the 2018/19-2020/21 BC Hydro Service Plan:

Government Priorities	BC Hydro Aligns with These Priorities By:
Making life more affordable	• Ensuring our customers will benefit from affordable, predictable rates while managing our costs, exploring innovative solutions to support our customers and making investments to maintain and expand our electricity system. (Objective 2.1)
Delivering the services people count on	• Reliably meeting the electricity requirements of customers, responding to their evolving expectations by planning and investing in the system to meet future needs, and consistently improving our service. (Objective 1.1)
A strong, sustainable economy	• Implementing our 10 Year Capital Plan so that our customers can continue to receive clean, reliable and affordable electricity. (Strategy under Objective 2.1) • Supporting the creation of a roadmap for the future of B.C. energy that will drive innovation and the electrification of B.C.'s economy, expand energy efficiency and conservation programs, generate new energy responsibly and sustainably, and create lasting good jobs across the province. (Strategy under Objective 3.1)

Operating Environment

In the summer of 2018, the Province announced it would launch a comprehensive two-phase review of BC Hydro to keep electricity rates affordable and to position BC Hydro for future success. To help make electricity more affordable for our customers, we worked with the Province throughout the year to complete Phase 1 of the review, which included a full examination of our business, with an emphasis on cost consciousness. The key outcomes of the review were enhanced regulatory oversight of BC Hydro and the development of a new five-year rates forecast that reflected cost and revenue strategies to keep rates affordable.

BC Hydro is regulated by the British Columbia Utilities Commission (BCUC). As the independent regulator of BC Hydro, the BCUC is responsible for ensuring that our customers receive safe, reliable and non-discriminatory energy services at fair rates. Phase 1 of the review restored the authority of the BCUC to oversee key aspects of our business, including allowing the BCUC to review and make decisions on BC Hydro's costs, proposed rate increases, integrated resource planning and almost all regulatory accounts, programs and capital projects.

We worked with the Province to develop the new five-year rates forecast, identifying a number of strategies to help keep rates affordable over the long term for our customers. BC Hydro filed its Fiscal 2020 to Fiscal 2021 Revenue Requirements Application with the BCUC in February 2019, reflecting the new rates forecast from Phase 1 of the Comprehensive Review. The Application includes several measures we have undertaken to help keep rates low for our customers, including limiting projected base operating costs to below the forecast rate of provincial inflation.

In the summer of 2018, British Columbia once again experienced devastating wildfires, with hundreds of wildfires burning across the northern and southern interior parts of the province. By square kilometre affected, 2018 was the largest fire year on record in B.C. The wildfires caused outages for our customers and significant damage in the Telegraph Creek and Burns Lake areas. Much of the distribution infrastructure in Telegraph Creek was lost, but excellent restoration efforts were made in relatively short order. To support affected customers, BC Hydro relaunched its wildfire assistance program—providing bill credits to customers evacuated due to wildfires. For customers who lost their homes, we waived all charges from their last bill.

On December 20, 2018, a severe windstorm hit British Columbia's South Coast, causing extensive damage to BC Hydro infrastructure. This was the most damaging storm in BC Hydro's history and was unlike any previous weather event we had encountered. The storm left more than 730,000 customers without power. More than 400,000 customers in the Lower Mainland and Fraser Valley were impacted. Vancouver Island and the Gulf Islands were the hardest hit with nearly 350,000 customers without power. With more than 1,500 spans of wire, 300 power poles, 650 cross-arms and 280 transformers that needed to be repaired or replaced, responding to the storm required BC Hydro's single biggest mobilization of staff, contractors and resources.

BC Hydro is proud of how our company responded and the quick restoration of the majority of our customers. Within the first 24 hours, BC Hydro had restored power to over 550,000 customers. The breadth of damage and access issues on Vancouver Island and the Gulf Islands due to trees on the roads made restoration efforts in those locations particularly challenging, causing repairs to take significantly longer than normal. All customers impacted by the storm were restored by December 31.

BC Hydro's electricity system was largely built in the 1960s, 1970s and 1980s and we continue to invest approximately $3 billion annually 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. Over the last five years, BC Hydro delivered 426 capital projects at a total cost of $8.03 billion, which is 0.34 per cent over budget overall. During 2018/19, capital projects placed in-service totaled $3.6 billion, including projects to renew and expand our generation, transmission and distribution systems, and the acquisition of the remaining two thirds of the Waneta Dam.

It is only possible to meet the needs of our customers and to invest in our system if our employees and workforce can execute their work safely. As a utility that operates in a high hazard industry, safety is always top of mind and we are continuously working to improve our performance through understanding hazards and ensuring appropriate design of assets and related work procedures, while building our safety culture and competencies. Our goal continues to be that everyone goes home safely, every day.

BC Hydro is proud of our responses to these external events that had the potential to affect our performance. Due to thoughtful planning and prudent decision-making, BC Hydro managed each risk and continued to safely deliver reliable, affordable, and clean electricity throughout B.C.

Report on Performance

BC Hydro continued to focus on achieving the objectives outlined in the Board Chair's Mandate Letter and aligning to Government's key commitments to British Columbians: making life more affordable, delivering the services people count on and building a strong sustainable economy.

To demonstrate strong public sector governance, we implemented our action plan with regular communications between the President and Chief Operating Officer (COO), Executive Board Chair, the Minister and Deputy Minister, and quarterly and annual performance reporting to the Board of Directors.

Goals, Objectives, Measures and Targets

BC Hydro's mission is: to safely provide our customers with reliable, affordable, clean electricity throughout B.C. We have continued to implement our strategies to achieve our four goals and 13 performance measures as set out in the 2018/19 – 2020/21 Service Plan. The goals and measures below track our progress on delivering the identified priorities for Fiscal 2018/19.

BC Hydro management is responsible for measuring performance against targets, and results are reported to the Board on a quarterly basis, and publicly in the Annual Service Plan Report.

The BC Hydro 2018/19 Annual Service Plan Report compares the Corporation's 2018/19 actual results to the expected results in the 2018/19 – 2020/21 Service Plan.

Goal 1: Set the Standard for Reliable and Responsive Service

Objective 1.1:

BC Hydro will reliably meet the electricity requirements of customers and respond to their evolving expectations by planning and investing in the system to meet future needs and by consistently improving our service.

Key Highlights:

Key reliability, service and Indigenous Relations accomplishments include:

- Customer reliability measure results, System Average Interruption Duration Index and System Average Interruption Frequency Index, were better than target due to fewer substation and transmission outages.

- Customer Satisfaction Index increased two per cent compared to our 2017/18 results, due to improvements across all three customer segments: residential, commercial and key accounts.

- BC Hydro obtained our third consecutive gold level Progressive Aboriginal Relations designation from the Canadian Council of Aboriginal Business, demonstrating our progress in implementing leading practices across the areas of leadership, community relationships, business development and employment.

Performance Measure(s)[1]	2016/17 Actuals	2017/18 Actuals	2018/19 Target	2018/19 Actuals	2019/20 Target	2020/21 Target
1.a SAIDI (System Average Interruption Duration Index)[2] [Total outage duration (in hours) of sustained interruptions experienced by an average customer in a year]	3.28	3.07	3.30	2.96	3.25	3.20
1.b [SAIFI (System Average Interruption Frequency Index) [2] [Total number of sustained interruptions experienced by an average customer in a year (excluding major events)]	1.59	1.51	1.40	1.35	1.40	1.40
1.c Key Generating Facility Forced Outage Factor[3]	1.78	1.81	1.80	1.61	1.80	1.80
1.d CSAT Index[4] [Customer Satisfaction Index: % of customers satisfied or very satisfied]	87.0	86.0	85.0	87.7	85.0	85.0
1.e Progressive Aboriginal Relations Designation[5]	Gold	Gold	Gold	Gold	Gold	Gold

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at www.bchydro.com/performance.

[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 system reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measures are 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] Key Generating 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).

[4] Customer Satisfaction Index (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.

[5] The Canadian Council for Aboriginal Business' Progressive Aboriginal Relations (PAR) Program is a certification program designed to help Canadian businesses benchmark, improve and signal their commitment to progressive relationships with Indigenous communities, businesses and people. It evaluates four areas of performance including: leadership actions; employment; business development; and community relations. PAR certification provides a high degree of assurance to First Nations communities, as the designation is supported by an independent, third party verification and is determined by a jury comprised of Indigenous business people. BC Hydro was recertified at the gold level for a further three years in 2018/19.

Discussion

Reliability
Customer reliability is reported using the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). In 2018/19, we met both targets for SAIDI and SAIFI, which exclude major events. We continued to monitor and plan for the all-events reliability of the system by effectively implementing capital and maintenance programs to manage overall asset health, targeting the worst performing circuits with the most efficient reliability solutions and developing well-practiced emergency response plans to improve overall system reliability. SAIDI's 2020/21 target was lowered in the 2019/20-2021/22 Service Plan to align with improved historical performance, trends resulting from investment, planning and process improvements.

In 2018/19, BC Hydro:

- Targeted deployment of automated reclosers and switches to affordably avoid and reduce sustained customer outages.
- Analyzed system performance data on all-events outage trends to identify priority areas for targeted and efficient system improvements and hazard tree removals to help manage the frequency of outages.
- Developed and applied new physical security standards to capital projects and implemented risk-prioritized security improvements at existing facilities, enhancing our security systems and meeting new physical security regulatory requirements.
- Developed a hazard mapping tool and a mobile earthquake damage assessment application to provide real time information to support worker safety and response prioritization and coordination. The wildfires and December storm tested our capabilities to respond to and recover from significant events.

BC Hydro continues to report on the Key Generating Facilities 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 megawatts (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. In 2018/19, BC Hydro continued to focus on the following:

- Launching field responses as soon as events occur to ensure that equipment is returned to service in a timely manner.
- Completing formal investigations for each forced outage to ensure that future events are prevented or mitigated. Where needed, maintenance and predictive analytics programs are refined.
- Giving priority to Key Generating stations as part of our overall capital plan to ensure their ongoing reliability.

BC Hydro achieved the target to remain below 1.80 per cent for Key Generating Facility Forced Outage Factor with a result of 1.61 per cent.

[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.

Service

The Customer Satisfaction Index (CSAT) measure gauges the level of customer support in meeting their electricity needs. Our 2018/19 CSAT result of 87.7 per cent, an improvement over the previous two years, reflects our ongoing efforts in ensuring high customer reliability, continued commitment to customer service and improvements in our customer communications.

- During 2018/19, BC Hydro made a number of key improvements to customer service, including repatriation of customer service functions that had previously been outsourced, and continued focus on improving our service. Since repatriation,
    - Average customer response wait time in our contact centre decreased by 59 per cent, compared to the 12 months prior to repatriation.
    - The quality of service in the contact centre also improved. At year end, we achieved a Transactional CSAT of 95 per cent compared to a target of 90 per cent. First Contact Resolution also improved with actual results of 77 per cent, compared to a target of 73 per cent.
- Extended contact centre hours following the December 2018 storm to manage high volume of customer calls related to outages.
- Updated the online MyHydro customer portal to improve customer functionality on mobile devices.
- Brought the operations of BC Hydro's electric vehicle DC Fast Charging network in-house, decreasing average station downtime from over 12 days to 24 hours. Customer calls related to electric vehicle charging are now being handled by the BC Hydro contact centre.
- Launched the Customer Crisis Fund as a three year pilot. The Customer Crisis Fund provides a grant of up to $600 to eligible customers experiencing temporary financial hardship and facing disconnection of their BC Hydro service. In 2018/19, 1,909 customers received grants totaling $715,000.
- Implemented key recommendations from the 2017/18 benchmarking study to improve BC Hydro's interconnection process by developing a streamlined process for low-complexity customer projects and improving efficiency in moving projects from the System Impact Study stage to the Facilities Study stage. We also improved coordination of the interconnections projects with the project delivery groups to better meet our customers' needs.

Indigenous Relations

Working closely with First Nations communities to build stronger, more open and collaborative relationships is an important priority for us and aligns with the criteria required to maintain our Progressive Aboriginal Relations gold designation. In 2018/19, we obtained our third consecutive gold-level certification, demonstrating our progress to implement leading practices across the areas of leadership, community relationships, business development and employment. BC Hydro is one of 17 companies in Canada to achieve gold status, and one of only two utilities at the gold designation level.

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

- Continued to implement our Statement of Indigenous Principles, and further incorporated the United Nations Declaration on the Rights of Indigenous Peoples and the Calls to Action of the Truth and Reconciliation Commission into our business. These documents are embedded within the Indigenous Awareness Training that we have implemented for all employees.
- Provided approximately $130 million worth of contracting opportunities for First Nations community-owned businesses and partnerships, primarily through our capital projects.
- Continued to provide Indigenous people with employment on our capital projects. For example, the Site C project contractors employed between 163 and 333 Indigenous people (9-11 per cent of the contractor workforce) during 2018/19.
- Hired 60 Indigenous employees[2] for roles on various teams throughout the company, including Safety, Engineering, Apprenticeship, Customer Service and work experience programs related to trades and career exploration. Additionally, 25 scholarships and bursaries were awarded to Indigenous students pursuing post-secondary studies.

Goal 2: Help make electricity more affordable for our customers

Objective 2.1:

BC Hydro customers will benefit from affordable, predictable rates while we manage our costs, explore innovative solutions to support our customers and make investments to maintain and expand our electricity system.

Key Highlights:

Key accomplishments include:

- BC Hydro residential rates were again ranked in the first quartile for 2018/19, based on analysis of Hydro Quebec's annual report, 2018 Comparison of Electricity Rates in Major North American Cities.
- BC Hydro participated fully in Phase 1 of the Comprehensive Review, and through this review developed a new five-year rates forecast that reflects cost and revenue strategies to keep rates affordable. The new five-year forecast rate forecast is 20 per cent below the forecast rate of provincial inflation for the period.
- Over the last five years, BC Hydro successfully delivered 426 capital projects at a total cost of $8.03 billion, which is 0.34 per cent over budget overall and within the target of +/- 5 per cent of budget.

[2] The addition of 60 hires in 2018/19 contributes to building on the 2.8 per cent Indigenous employee population at BC Hydro.

Performance Measure(s)[1]		2016/17 Actuals	2017/18 Actuals	2018/19 Target	2018/19 Actuals	2019/20 Target	2020/21 Target
2.a	Competitive Rates[2]	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile
2.b	Project Budget to Actual Cost[3]	-0.94% on $6.36 billion[4]	+0.40% on $6.9 billion[5]	Within +5% to -5% of budget excluding project reserve amounts	+0.34% on $8.03 billion[6]	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 is available online at www.bchydro.com/performance.
[2] BC Hydro calculates a relative index for each usage level within the residential category and then calculates an average of the index to create an overall ranking. The rankings of the 22 participating utilities are then divided 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] The data includes Generation, Transmission Line and Substation, and large Distribution projects managed by Project Delivery, and the Smart Metering and Infrastructure Program and Properties projects for the last five years. This is a five year rolling data set of actual costs compared to original approved full scope implementation budgets not including project reserve amounts, for capital projects that were put into service during the period. The +/- 5 per cent target is the same over the plan period, as it is the objective to have the entire project portfolio in-service within this actual cost range.
[4] This represents projects that went into service for the five-year period 2012/13 to 2016/17.
[5] This represents projects that went into service for the five-year period 2013/14 to 2017/18.
[6] This represents projects that went into service for the five-year period 2014/15 to 2018/19.

Discussion

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 rates again being ranked in the first quartile (third) for 2018/19, based on analysis of Hydro Quebec's annual report, 2018 Comparison of Electricity Rates in Major North American Cities.

Phase 1 of the Comprehensive Review restored the authority of the BCUC, our independent regulator, to oversee key aspects of our business, including the ability to review and make decisions on BC Hydro's costs, proposed rate increases, integrated resource planning and almost all regulatory accounts, programs and capital projects. Though our request to freeze rates for 2018/19 was not approved by the BCUC, we advanced applications with the regulator to ensure our customers benefit from affordable and predictable rates. In February 2019, we filed the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application with the BCUC, reflecting the new rates forecast from Phase 1 of the Comprehensive Review. The Application reflects several measures we have undertaken to help keep rates low for our customers, including limiting base operating costs to be below the forecast rate of provincial inflation.

In addition, BC Hydro began developing and analyzing a number of potential rate design options that will help make customers' electricity bills more affordable and advance greenhouse gas emission reductions.

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 budget, less project reserve funds. In 2018/19, significant projects that went into service included John Hart Powerhouse Replacement, W.A.C. Bennett Dam Rip Rap, Horne Payne Substation Upgrade and a new Kamloops substation.

In 2018/19, we completed additional initiatives to improve our project delivery practices and our work delivery methods:

- BC Hydro continued to focus on its Work Smart program, which improves our processes by employing Lean methodologies; we undertook 32 projects across the company in 2018/19. These projects, in which employees are empowered to develop and implement enhanced processes through a structured framework, are estimated to generate at least 23,600 worker capacity hours gained, which are applied to other priorities.

- Continued to implement Category Management, an approach for optimizing the overall benefits for the key categories of goods and services that BC Hydro purchases. Category Management incorporates strategy development, business process improvements, sourcing, contract management and supplier management.

- BC Hydro continued to implement the Supply Chain Applications project which will provide technology and new business processes to help achieve the capabilities needed to fully operationalize the Supply Chain and Fleet business model.

- Improved our project and portfolio performance reports to support better decision-making and timely delivery of projects within budget. We also implemented scalable project management practices and applied them to 17 projects, which reduced the duration and costs of our projects.

- Implemented the North American Electric Reliability Corporation standards for Critical Infrastructure Protection version 5, which improved protection of our critical infrastructure. This initiative brought BC Hydro into compliance with the latest standards and enhanced the operating and delivery practices for ongoing compliance.

Construction on the Site C project has been underway since July 2015. As of March 31, 2019, the project has total commitments of $6.6 billion, of which $3.5 billion has been spent since the project began and $3.1 billion remains on executed contracts and agreements. Key accomplishments this year included:

- **Construction activities:** Over the last year, construction activities accelerated substantially, particularly the roller-compacted concrete placement work on the powerhouse buttress and the excavations required in advance of river diversion in 2020. The roller-compacted concrete buttress for the Site C powerhouse was completed on October 5, 2018, 10 days ahead of schedule. Work on the first diversion tunnel started in August 2018, and the second tunnel started in September 2018.

Of particular note, we successfully resolved various issues with our main civil works contractor that dated back to early 2017. The settlement agreement, which was finalized in July 2018, includes at-risk incentive payments to the contractor if and when they meet critical project milestones. It also includes advancing some critical construction activities and purchasing additional key equipment. Most importantly, the settlement includes an updated contractual schedule. This is crucial for the project to reach its goal of achieving river diversion in 2020 and to meet the 2024 in-service date.

In September 2018, after eight months of consultation and engagement with Indigenous groups and property owners, BC Hydro announced the new alignment for Highway 29 at Cache Creek East.

In February 2019, the first of more than 400 transmission towers was raised. These towers will support the two new 500kV transmission lines leading from the Site C substation to the Peace Canyon generating station.

- **On-site workers:** As of March 2019, there were 3,674 people working on the Site C project, including 2,894 workers from B.C. (79 per cent of the total workforce), 333 Indigenous workers, 400 women and 794 workers from the Peace River Regional District.

- **Community benefits:** In April 2018, BC Hydro announced that construction was underway on a project to build 50 new affordable housing units in Fort St. John. In August 2018, a new daycare opened in Fort St. John, funded in part by BC Hydro. Overall in 2018/19, BC Hydro provided $119,844 to non-profit organizations in the Peace Region through its Generate Opportunities Fund.

- **Safety:** Site C remains a complex, multi-work front, multi-employer project with significant safety hazards both on-site and off-site. There continues to be strong safety and regulatory performance, with improving safety results over the year, including out-performing WorkSafeBC comparators in the electric utilities, major construction, and forestry industries. In late 2018, BC Hydro consolidated the safety and security teams into a single group, allowing for operational decisions closer to site and resulting in better solutions as safety and security issues often overlap.

- **Project oversight:** To ensure the Site C project is developed on time and on budget, an independent expert Project Assurance Board advises the Site C Project Board. Twelve meetings were held in 2018/19. In addition, BC Hydro retained EY Canada to provide an independent project assurance function and assist with identifying project risks and implementing effective mitigation strategies.

Goal 3: Continue British Columbia's Leading Commitment to Renewable Clean Power

Objective 3.1:

BC Hydro will strengthen its legacy of renewable, clean power and conservation investments by expanding its energy-efficiency and conservation programs to include low-carbon electrification and by identifying and securing new, sustainable, responsibly generated, competitively priced energy and capacity options to meet future customer needs.

Key Highlights:

Key accomplishments include:

- The energy savings from energy efficiency and conservation programs of 868 gigawatt-hours per year (GWh/year) was 9 per cent higher than the target of 800 GWh/year due to higher than planned savings in the residential and industrial sectors.
- We continued to exceed our Clean Energy performance measure target of 93 percent, with a result of 97.8 per cent of electricity in the province generated from clean or renewable resources.
- BC Hydro signed one new energy purchase agreement with Tsilhqot'in Solar Farm, which is 100 per cent clean.

Performance Measure(s)[1]		2016/17 Actuals	2017/18 Actuals	2018/19 Target	2018/19 Actuals	2019/20 Target	2020/21 Target
3a.	Energy Conservation Portfolio (New incremental GWh/year)[2]	733	741	800	868	700	700
3b.	Clean Energy (%)	98.4	98.0	93.0	97.8	93.0	93.0
3c.	New Clean Supply (%)[3]	100	100	100	100	--[4]	--[4]

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance

[2] Reflects the annual new incremental electricity savings resulting from Demand Side Management (DSM) portfolio results including programs, codes and standards and conservation rates. This metric is a reflection of performance within the current period and as such is not impacted by past performance and/or adjustments made to energy savings in prior years (e.g., persistence, evaluations, measurement and verification).

[3] New Clean Supply reflects the percentage of projects that are designated as clean or renewable in considering new supply agreements for all greenfield generation projects entered into during the year. The target is that 100 per cent of new supply projects for the integrated grid for the year come from clean or renewable sources

[4] This performance measure was removed from the 2019/20-2021/22 Service Plan; therefore targets are not included.

Discussion

We continued to meet the *Clean Energy Act* objectives, the Clean Energy and New Clean Supply performance measure targets, and continued to provide opportunities for First Nations.

BC Hydro continued to have strong performance from our energy efficiency and conservation programs and exceeded the Energy Conservation Portfolio target of 800 GWh/yr. Highlights include increasing residential expenditures in the Low Income and the Home Renovation Rebate Programs to support affordability, as well as introducing a new program for diesel-dependent communities in the Non-Integrated Areas. BC Hydro is working collaboratively with the communities not connected to our system, the Province and the Government of Canada to implement solutions for reducing diesel reliance and greenhouse gas emissions.

As an outcome of Phase 1 of the Comprehensive Review, BC Hydro indefinitely suspended the Standing Offer Program and began developing a Biomass Energy Program, in order to manage our energy procurement costs. As a result, BC Hydro stopped accepting new applications or awarding any new electricity purchase agreements under the Standing Offer or Micro Standing Offer Programs, with the exception of five proposed Indigenous-related projects. Through the Biomass Energy Program, BC Hydro will be acquiring energy from certain biomass facilities at prices and volumes that are lower than current contracts.

The New Clean Supply performance measure was removed from the 2019/20–2021/22 Service Plan. BC Hydro will develop a new measure next year to support and align with the Government's new CleanBC plan.

Goal 4: Safety Above All

Objective 4.1:

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:

Key accomplishments include:

- As of March 31, 2019, BC Hydro had gone 1,605 days without a serious (permanently disabling) injury, and 3,150 days without a fatality. 1,605 days is the longest period without a serious permanently disabling injury or fatality in over 30 years of recorded data.
- 98 per cent of corrective actions resulting from safety incident reviews were completed within 30 days of the due date compared to a target of 93 per cent.
- A significant increase in the number of near miss and good catch incidents being reported compared to the previous fiscal year. Our employee near miss and good catch reporting saw a 50 per cent increase and our contractor near miss and good catch reporting saw a 130 per cent increase over last fiscal year.

Performance Measure(s)[1]	2016/17 Actuals	2017/18 Actuals	2018/19 Target	2018/19 Actuals	2019/20 Target	2020/21 Target
4a. Zero Fatality & Serious Injury[2] [Loss of life or the injury has resulted in a permanent disability]	0	0	0	0	0	0
4b. Lost Time Injury Frequency [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.04	0.88	0.85	0.87	0.80	0.80
4c. Timely Completion of Corrective Actions (%)	96	93[3]	93	98	95	95

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance

[2] Zero Fatality and Serious Injury – BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.

[3] Previously reported as 100 per cent in the 2017/18 Annual Service Plan report, based on the previous definition for Timely Completion of Actions: the percentage of safety corrective actions closed within 30 days of the original scheduled due date on an annual basis.

Discussion

Overall in 2018/19, we made good progress in meeting some of our safety targets; however, more work needs to be done as we continue to see near misses involving electricity that could have seriously injured our employees. We are in the fourth year of implementing our five-year safety plan.

BC Hydro's investments in safety initiatives have improved our safety performance to zero fatalities since 2010. To reduce electrical contact injuries, work continued on our Opportunity to Reduce Electrical Hazards projects for Limits of Approach Revisions, and Arc Flash.

We finished 2018/19 with a lost time injury frequency rate of 0.87, compared to a target of 0.85. A significant number of lost time injuries were related to body mechanics—slips, trips, falls and ergonomics. Of the lost time injuries we experienced, 69 per cent were in our Operations group. In 2019/20, we will expand the ergonomics program to Line Operations, the group with the most ergonomic lost time injuries this past year.

In 2018/19, 98 per cent of the corrective actions were completed within 30 days of the due date compared to a target of 93 per cent. The primary drivers for exceeding our target were: the corrective action governance team which supports the creation and implementation of complex correction actions; the incident review calls between senior management and the responsible manager to further support the creation of better corrective actions while also identifying and addressing systemic issues; and continued leadership focus on ensuring corrective actions are completed in a timely manner.

During 2018/19, we continued with the implementation of the Safety and Health Management System. We documented system standards, defined safety roles and responsibilities, and established a clear process for conducting job hazard assessments. We also conducted a number of activities to reduce public safety incidents, such as training for targeted trades associations and first responders, and attendance at external events to educate the public about the hazards of electricity.

Financial Report

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, 2019 (fiscal 2019) and should be read in conjunction with the audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2019 and 2018.

On November 7, 2018, the Province issued an order through Treasury Board (BC Reg 231/2018) that rescinded a previous order, which directed BC Hydro to follow Prescribed Standards (as defined below). The Company changed its financial reporting framework to the International Financial Reporting Standards (IFRS) in the fiscal 2019 Consolidated Financial Statements. The transition date was April 1, 2017. Previously, the Company prepared its consolidated financial statements in accordance with the accounting principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations,* except as specified in Treasury Board Regulation B.C. Reg 146/2011 section 5(3) (collectively the Prescribed Standards). The prior year amounts have been restated to conform to IFRS. For more information on the Company's transition to IFRS, please see Notes 2 and 24 of the audited Consolidated Financial Statements for the years ended March 31, 2019 and 2018.

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

- In February 2019, the Province released the Comprehensive Review of BC Hydro: Phase 1 Final Report. The report outlines a number of actions that enhance regulatory oversight of BC Hydro while still enabling the Province to advance social, economic, and environmental priorities. The key outcomes include:
    - The Province has repealed a number of regulations that restricted the BCUC's decision making in the past. Moving forward, this will enable the BCUC to review and make decisions on BC Hydro's costs, proposed rate increases and almost all regulatory accounts, programs, and capital projects.
    - The Province accepted the recommendation that BC Hydro cease using the Rate Smoothing Regulatory Account (RSRA) and write-off the balance in the account in fiscal 2019. BC Hydro expensed the entire $1.04 billion RSRA balance within net movement in regulatory balances as at December 31, 2018 (see note 14 in the Consolidated Financial Statements).

- The Company adopted IFRS, including adoption of IFRS 14 *Regulatory Deferral Accounts* (IFRS 14) in the fiscal 2019 Consolidated Financial Statements. The transition date was April 1, 2017. The main impact of IFRS 14 was to segregate the net income effect of all changes in regulatory balances to a separate section on the Consolidated Statement of Comprehensive

Income (Loss) called net movements in regulatory balances. Previously, the changes in regulatory balance were included within each financial statement line item on the Consolidated Statement of Comprehensive Income (Loss).

- The net loss for fiscal 2019 was $428 million, compared to a net income of $684 million in the prior year. The net loss was primarily due to the write-off of the balance in the RSRA of $1.04 billion as discussed above. The write-off in the balance of the RSRA in the third quarter and the decision to cease using the account in the future resulted in a combined decrease to net income of $1.14 billion compared to the fiscal 2019 forecast net income in BC Hydro's Service Plan for fiscal 2018/19-2020/21 filed in February 2018.

- The net income before movement in regulatory balances was $691 million in fiscal 2019, compared to $633 million in the prior fiscal year. The increase was primarily attributed to higher trade income of $308 million, higher domestic revenues of $209 million; lower other costs net of recovery of $46 million and lower domestic energy costs of $42 million. This was partially offset by higher finance charges of $362 million, higher amortization and depreciation of $63 million, higher materials and external services of $57 million, and higher personnel costs of $39 million.

- Water inflows to the system during fiscal 2019 were 87 per cent of average compared to 98 per cent of average in the prior fiscal year. The lower water inflows in fiscal 2019 compared to the same period in the prior fiscal year were the result of significantly below average spring 2018 snowpack in the Peace region, followed by persistent dry weather across the province from June 2018 to March 2019. Total reservoir storage as at March 31, 2019 was 8,698 GWh, a decrease of 2,179 GWh compared to total reservoir storage as at March 31, 2018 of 10,877 GWh. The decrease in reservoir storage level was the result of lower water inflows, and high winter loads driven by colder than average weather in the fourth quarter. As a result of the below average inflows and low reservoir storage levels, the Company had more market energy purchases in the second half of the fiscal year.

- Capital expenditures, before contributions in aid of construction, for fiscal 2019 were $3.83 billion, a $1.35 billion increase over the prior fiscal year and includes $1.20 billion related to the purchase of the remaining two-thirds interest in the Waneta Dam and Generating Facility. BC Hydro continues to invest significantly in capital projects/programs to refurbish its ageing infrastructure and build new assets for future growth, including Site C, John Hart Generating Station Replacement, Downtown Vancouver Electricity Supply: West End Strategic Property Purchase, Distribution Wood Poles Replacements, Peace Region Electricity Supply, and Bridge River 2 Units 5 and 6 Upgrade.

CONSOLIDATED RESULTS OF OPERATIONS

for the years ended March 31 ($ in millions)		**2019**		2018		Change
Total Revenues	**$**	**6,573**	$	5,954	$	619
Net Income (Loss)	**$**	**(428)**	$	684	$	(1,112)
Capital Expenditures	**$**	**3,826**	$	2,473	$	1,353
Payment to the Province	**$**	**59**	$	159	$	(100)
GWh Sold (Domestic)		**54,643**		57,173		(2,530)

as at March 31 ($ in millions)		**2019**		2018		Change
Total Assets and Regulatory Balance	**$**	**35,672**	$	33,681	$	1,991
Shareholder's Equity	**$**	**4,947**	$	5,447	$	(500)
Retained Earnings	**$**	**4,934**	$	5,421	$	(487)
Debt to Equity		**82 : 18**		79 : 21		n/a
Number of Domestic Customer Accounts		**2,049,157**		2,018,044		31,113
Total Reservoir Storage (GWh)		**8,698**		10,877		(2,179)

REVENUES

In fiscal 2019, total revenues of $6.57 billion, were $619 million higher than the prior fiscal year. The increase was due to higher trade revenues of $410 million and higher domestic revenues of $209 million.

	(in millions)				*(gigawatt hours)*		*($ per MWh)* [1]	
for the years ended March 31		**2019**		2018	**2019**	2018	**2019**	2018
Domestic Revenues								
Residential	**$**	**2,127**	$	2,097	**18,000**	18,150	**$ 118.17**	$ 115.54
Light industrial and commercial		**1,925**		1,860	**19,007**	18,874	**101.28**	98.55
Large industrial		**873**		811	**13,896**	13,440	**62.82**	60.34
Surplus Sales		**115**		139	**2,230**	5,072	**51.57**	27.41
Other sales		**392**		316	**1,510**	1,637	-	-
Total Domestic Revenues	**$**	**5,432**	$	5,223	**54,643**	57,173	**$ 99.41**	$ 91.35
Trade Revenues								
Gross electricity and gas	**$**	**1,752**	$	1,272	**28,158**	34,595	**$ 54.21**	$ 34.76
Less: forward electricity and gas purchases		**(611)**		(541)	-	-	-	-
Total Trade Revenues	**$**	**1,141**	$	731	**28,158**	34,595	**$ 40.52**	$ 21.13
Total Revenues	**$**	**6,573**	$	5,954	**82,801**	91,768	**$ 79.38**	$ 64.88

[1] The Trade $ per MWh represents the gross $ per MWh of physical transactions and does not include financial transactions. The Total Trade $ per MWh is a simple average calculation and does not reflect actual trade energy prices during the period.

Domestic Revenues

In fiscal 2019, domestic revenues were $5.43 billion, an increase of $209 million, or 4 per cent, compared to the prior fiscal year. This increase was mainly driven by higher average customer rates that reflect the 3.0 per cent rate increase effective April 1, 2018, as approved by the British Columbia Utilities Commission (BCUC). Revenue was also higher due to other sales, which include revenues related to the sale of two-thirds of the production from the Waneta Dam and Generating Facility. Further, large industrial revenues were higher, primarily due to increased production in the oil and gas sector. These higher revenues were partly offset by lower surplus sales.

Trade Revenues

Powerex Corp., a wholly owned subsidiary of the Company, 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.

The Company's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex Corp.'s trade activities earn income to keep the Company's customer rates low and to help balance its system by being able to import energy to meet domestic demand when there is a supply shortage and exporting energy when there is a supply surplus. Exports are made only after ensuring domestic demand requirements are met.

Total trade revenues for the year ended March 31, 2019 were $1.14 billion, an increase of $410 million or 56 per cent compared with the prior fiscal year. The increase in trade revenues was primarily driven by higher average energy sales prices for the period.

OPERATING EXPENSES

In fiscal 2019, total operating expenses of $4.70 billion were $199 million higher than the prior fiscal year. The increase over the prior fiscal year was primarily due to higher amortization and depreciation expense of $63 million, higher trade energy costs of $102 million, higher materials and external services of $57 million, higher personnel costs of $39 million, and higher grants and taxes of $27 million. This was partially offset by lower other costs, net of recoveries, of $46 million, and lower domestic energy costs of $42 million.

Energy Costs

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and 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 in fiscal 2019 were $2.20 billion, $60 million (or 3 per cent) higher than the prior fiscal year. The increase was primarily due to higher trade energy costs of $102 million, partially offset by lower domestic energy costs of $42 million.

for the years ended March 31	*(in millions)* **2019**	2018	*(gigawatt hours)* **2019**	2018	*($ per MWh)*[2] **2019**	2018
Domestic Energy Costs						
Water rental payments (hydro generation)[1]	**$ 332**	$ 324	**42,187**	48,525	**$ 7.87**	$ 6.68
Purchases from Independent Power Producers	**1,247**	1,312	**14,248**	14,354	**87.52**	91.40
Other electricity purchases - Domestic	**125**	3	**2,036**	150	**61.39**	20.00
Gas and transportation for thermal generation	**13**	12	**190**	91	**68.42**	131.87
Transmission charges and other expenses	**13**	16	**103**	115	**-**	-
Non-Treaty storage and co-ordination agreements	**(182)**	(41)	**-**	-	**-**	-
Allocation from (to) trade energy	**25**	(11)	**650**	(557)	**52.83**	21.74
Total Domestic Energy Costs	**$ 1,573**	$ 1,615	**59,414**	62,678	**$ 26.48**	$ 25.77
Trade Energy Costs						
Gross electricity and remarketed gas	**$ 967**	$ 774	**29,475**	34,146	**$ 33.18**	$ 22.40
Less: forward electricity and gas purchases	**(611)**	(541)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**356**	233	**-**	-	**-**	-
Transmission charges and other expenses	**293**	278	**-**	-	**-**	-
Allocation (to) from domestic energy	**(25)**	11	**(650)**	557	**52.83**	21.74
Total Trade Energy Costs	**$ 624**	$ 522	**28,825**	34,703	**$ 21.65**	$ 15.04
Total Energy Costs	**$ 2,197**	$ 2,137	**88,239**	97,381	**$ 24.90**	$ 21.94

[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 $ per MWh represents the gross unit cost per physical electricity and gas transaction. The Total Trade $ per MWh is a simple average calculation and does not reflect actual trade energy prices during the period.*

Domestic Energy Costs

Domestic energy costs in fiscal 2019 were $1.57 billion, $42 million or 3 per cent lower than the prior fiscal year. The decrease in costs was primarily due to higher recoveries from net water releases associated with the Non-Treaty storage and co-ordination agreements. In addition, there were lower costs from IPPs largely driven by fewer deliveries from hydro-generating IPPs due to lower inflows as a result of a cold and dry winter. The decrease in costs was partially offset by higher market electricity purchases due to lower water inflows which constrained BC Hydro’s and IPP generation.

Trade Energy Costs

Total trade energy costs in fiscal 2019 were $624 million, an increase of $102 million or 20 per cent compared with the prior fiscal year. The increase in trade energy costs was primarily driven by higher prices for electricity purchases, partly offset by a decrease in average energy purchase volumes for the period.

Water Inflows and Reservoir Storage

Water inflows to the system during fiscal 2019 were 87 per cent of average compared to 98 per cent of average in the prior fiscal year. The lower water inflows in fiscal 2019 were from the result of significantly below average spring 2018 snowpack in the Peace region, followed by persistent dry weather across the province from June 2018 to March 2019.

Total reservoir storage as at March 31, 2019 was 8,698 GWh, a decrease of 2,179 GWh compared to total reservoir storage as at March 31, 2018 of 10,877 GWh. This resulted below average inflows across the summer and through the winter, strong energy prices resulting in higher exports in July and August, and high winter loads driven by colder than average weather in February 2019 and the first half of March 2019.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the year ended March 31, 2019 were $630 million, $39 million higher than the prior fiscal year primarily due an increase in the number of full time employees and higher employee benefit costs. The increased number of full time employees was primarily due to BC Hydro's Workforce Optimization program and Accenture repatriation, which replaced external service providers with internal staff to reduce costs and deliver on our business objectives.

Materials and External Services

Expenditures on materials and external services for the year ended March 31, 2019 were $707 million, $57 million higher than the prior fiscal year primarily due to higher operating costs associated with operating two Electricity Purchase Agreements that were capital leases for the full year (the two Electricity Purchase Agreements became operational during the latter half of fiscal 2018). Additionally, there were higher Demand Side Management expenditures partially offset by a reduction in costs as a result of BC Hydro's Workforce Optimization program.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, and amortization of intangible assets. For the year ended March 31, 2019, amortization and depreciation expense was $880 million, $63 million higher than the prior fiscal year primarily due to the property, plant and equipment placed in service in fiscal 2019 and purchase of the remaining two-thirds interest in the Waneta Dam and Generating Facility.

Grants and Taxes

As a Crown Corporation, the Company is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts, and school tax to the Province on certain assets. Total grants and taxes for the year ended March 31, 2019 were $268 million, $27 million higher than the prior fiscal year primarily due to increased property values, and higher grants associated with increased revenues from energy sales.

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, 2019, other costs net of recoveries were $84 million, $46 million lower than the prior fiscal year. The decrease was primarily due to lower dismantling costs, lower asset write-offs, and lower expenses related to provisions compared to the prior fiscal year.

Capitalized Costs

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Capitalized costs for the year ended March 31, 2019 were $70 million, comparable to $69 million in the prior fiscal year.

FINANCE CHARGES

Finance charges for the year ended March 31, 2019 were $1.19 billion, $362 million higher than the prior fiscal year. The increase was primarily due to mark-to-market losses on future debt hedges used to economically hedge the interest rates on future debt issuances, higher volume of long-term debt borrowings, and higher short term interest rates. This increase was partially offset by higher interest during construction costs which were capitalized.

REGULATORY TRANSFERS

In accordance with IFRS 14, the Company separately presents regulatory balances and related net movements on the Consolidated Statements of Financial Position and the Consolidated Statements of Comprehensive Income (Loss).

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with BCUC orders, to better match costs and benefits for different generations of customers, smooth out the rate impact of large non-recurring costs, and defer to future periods differences between forecast and actual costs or revenues. Regulatory accounts allow the Company to defer certain types of revenue and cost variances through transfers to and from the accounts which are then 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)	**2019**	2018
Energy Deferral Accounts		
Heritage Deferral Account	**$ (95)**	$ (61)
Non-Heritage Deferral Account	**(170)**	(123)
Trade Income Deferral Account	**(321)**	(21)
	(586)	(205)
Forecast Variance Accounts		
Total Finance Charges	**53**	(24)
Rate Smoothing (RSRA)	**(815)**	327
Non-Current Pension Costs	**240**	(123)
Debt Management	**321**	29
Storm Restoration Costs	**19**	16
Other	**42**	25
	(140)	250
Capital-Like Accounts		
Demand-Side Management	**111**	82
IFRS Property, Plant & Equipment	**67**	90
	178	172
Non-Cash Accounts		
Environmental Provisions & Costs	**(1)**	-
First Nations Provisions & Costs	**22**	20
Other	**(5)**	(3)
	16	17
Amortization of regulatory accounts	**(442)**	(437)
Interest on regulatory accounts	**28**	61
Net change in regulatory accounts	**$ (946)**	$ (142)

For the year ended March 31, 2019, there was a net reduction of $946 million to the Company's regulatory accounts compared to a net reduction of $142 million in the prior fiscal year. The net regulatory asset balance as at March 31, 2019 was $4.19 billion compared to $5.14 billion as at March 31, 2018.

Net reductions to the regulatory accounts during the year ended March 31, 2019 included:

- $815 million to the RSRA as BC Hydro determined that collection of the RSRA was no longer probable and therefore BC Hydro expensed the entire balance. The expense of $1.04 billion recorded during the year ended March 31, 2019 was comprised of the $815 million balance in the account as at April 1, 2018 and $229 million deferred in the account during the year ended March 31, 2019 prior to the write-off;

- $586 million to the energy deferral accounts, primarily due to higher trade net income, lower purchases from Independent Power Producers, higher recoveries from Non-Treaty storage and co-ordination agreements, partially offset by higher electricity purchases from market; and

- Net amortization of $442 million. Amortization is the regulatory mechanism to recover the regulatory account balances in rates.

These net reductions were partially offset by:

- $321 million of additions to the Debt Management Regulatory Account primarily as a result of unrealized losses on active interest rate hedges, as mentioned in the finance charge section above, due to a decrease in forward interest rates during the latter half of the fiscal year partially offset by realized gains incurred;

- $240 million of additions to the Non-Current Pension Costs Regulatory Account due to a decrease in the discount rate used to measure the pension liability and also changes in the actuarial assumptions in the post-employment benefit plans;

- $111 million of planned additions to the Demand-Side Management Regulatory Account; and

- $67 million of planned additions to the IFRS Property, Plant & Equipment Regulatory Account for smoothing the rate impact of overhead costs not eligible for capitalization under IFRS as they are not considered directly attributable to the construction of capital assets.

Net regulatory account balances are as follows:

as at March 31 (in millions)		**2019**		2018
Energy Deferral Accounts				
Heritage Deferral Account	**$**	**(485)**	$	(423)
Non-Heritage Deferral Account		**76**		462
Trade Income Deferral Account		**(259)**		127
		(668)		166
Forecast Variance Accounts				
Total Finance Charges		**20**		(134)
Rate Smoothing		**-**		815
Non-Current Pension Costs		**486**		304
Debt Management		**163**		(158)
Storm Restoration Costs		**58**		47
Other		**126**		44
		853		918
Capital-Like Accounts				
Demand-Side Management		**915**		903
Smart Metering & Infrastructure		**217**		239
IFRS Property, Plant & Equipment		**1,064**		1,025
Site C		**491**		472
Capital Project Investigation Costs		**10**		15
		2,697		2,654
Non-Cash Accounts				
Environmental Provisions & Costs		**227**		261
First Nations Provisions & Costs		**505**		518
IFRS Pension		**497**		535
Other		**83**		88
		1,312		1,402
Net Regulatory Asset	**$**	**4,194**	$	5,140

BC Hydro has or has applied for regulatory mechanisms to collect 23 of 25 regulatory accounts in use or with balances at March 31, 2019 in rates over various periods, which represent approximately 88 per cent of the net regulatory asset balance.

COMPARISON WITH SERVICE PLAN

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan for fiscal 2018/19-2020/21 was filed in February 2018 with forecast net income for fiscal 2019 at $712 million.

The table below provides an overview of BC Hydro's fiscal 2019 financial results, relative to its February 2018 Service Plan.

(in millions)	**Actual**		**Adjusted**	**2018/19 to 2020/21 Service Plan**[3]	**Variance to 2018/19-2020/21 Service Plan**[3]
	2019	Adjustment[2]	2019	2019	
Revenues					
Domestic	$ 5,432	$ 219	$ 5,651	$ 5,689	$ (38)
Trade	1,141	-	1,141	635	506
	6,573	219	6,792	6,324	468
Expenses					
Operating Costs					
Cost of energy	2,197	586	2,783	2,276	(507)
Other operating expenses					
Personnel expenses, materials and external services [1]	1,240	(193)	1,047	1,053	6
Amortization	880	422	1,302	1,266	(36)
Finance charges	1,186	(490)	696	705	9
Grants and taxes	268	-	268	245	(23)
Other	111	1,013	1,124	66	(1,058)
	5,882	1,338	7,220	5,611	(1,609)
Net Income (Loss) Before Movement in Regulatory Balances	691	(1,119)	(428)	712	(1,140)
Net Movement in Regulatory Balances	(1,119)	1,119	-	-	-
Net Income (Loss)	$ (428)	$ -	$ (428)	$ 712	$ (1,140)

[1] *These amounts are net of capitalized overhead and recoveries.*
[2] *These adjustments are related to allocating the regulatory transfers between the financial statement line items under the Prescribed Standards to allow for comparison against the 2019 Service Plan filed in February 2018.*
[3] *Column may not add due to rounding.*

Net loss for fiscal 2019 was $428 million, compared to forecast net income of $712 million in the 2018/19-2020/21 Service Plan filed in February 2018. The net loss was primarily due to the write-off of the balance in the RSRA (included within net movement in regulatory balance in the actual column and within other in the adjusted column in the table above). The write-off in the balance of RSRA in the third quarter and the decision to cease using the account in the future resulted in a combined decrease to net income of $1.14 billion compared to the fiscal 2019 forecast net income in the BC Hydro's Service Plan for fiscal 2018/19-2020/21 filed in February 2018.

PAYMENT TO THE PROVINCE

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

The fiscal 2018 Payment to the Province was $159 million and was paid in June 2018. As a result, the Payment for fiscal 2019 will be $59 million and the Company has accrued $59 million as at March 31, 2019.

As at March 31, 2019, the Company's net debt to equity ratio was 82:18, which was higher than the net debt to equity ratio of 79:21 as at March 31, 2018. The higher net debt to equity ratio was primarily due to the write-off of the RSRA balance. The Company is forecasting a net debt to equity ratio of 80:20 in fiscal 2020. The Company will continue working toward achieving the 60:40 net debt to equity ratio.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the year ended March 31, 2019 was $1.87 billion, compared with $1.73 billion in the prior fiscal year. The increase was mainly due to higher trade income, higher domestic revenue primarily due to higher average customer rates, partially offset by higher operating expenses and interest costs.

The long-term debt balance net of sinking funds as at March 31, 2019 was $22.18 billion compared to $20.18 billion as at March 31, 2018. The increase was mainly a result of an increase in net long-term bond issuances (net of redemptions) for net proceeds of $1.13 billion and higher revolving borrowings of $892 million, which was primarily used to fund capital expenditures.

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)		**2019**		2018
Transmission lines and substations replacements and expansion	**$**	**431**	$	479
Generation replacements and expansion		**372**		544
Distribution system improvements and expansion		**504**		515
General, including technology, vehicles and buildings		**183**		230
Waneta 2/3 interest acquisition		**1,219**		-
Site C		**1,117**		705
Total Capital Expenditures	**$**	**3,826**	$	2,473

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.

Transmission lines and substation capital expenditures includes expenditures on the following projects/programs: Downtown Vancouver Electricity Supply: West End Strategic Property Purchase, Peace Region Electricity Supply, Fort St. John and Taylor Electric Supply, Transmission Wood Structure and Framing Replacement, North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Version 5 Compliance Impact to T&D Stations, UBC Load Increase Stage 2, Horne Payne Substation Upgrade, Kamloops Substation, Access Program, and Feeder Section Retrofits.

Generation capital expenditures include expenditures on the following projects: John Hart Generating Station Replacement, Bridge River 2 Units 5 and 6 Upgrade, Ruskin Dam Safety and Powerhouse Upgrade, Cheakamus Unit 1 and Unit 2 Generator Replacement, Bridge River 2 – Strip and Recoat Penstock 1 Interior, Mica Powerhouse Cranes Upgrade, G.M. Shrum G1-G10 Control System Upgrade, W.A.C Bennett Dam Riprap Upgrade, John Hart Dam Seismic Upgrade, and Mica Townsite Augment Accommodations Capacity.

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

General capital expenditures include expenditures on the Supply Chain Applications project, vehicles, various building development programs, and technology projects.

Waneta 2/3 interest acquisition is BC Hydro's purchase of Teck Resources Ltd.'s (Teck) two-third interest in the Waneta Dam and associated assets for $1.20 billion. As a result, the Company holds 100% interest in the Waneta Dam and Generating Facility.

Site C project expenditures relate to site preparation, clearing for reservoir and transmission lines, engineering and design, main civil works, generating station and spillway, as well as social and land programs.

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.

Capital Expenditures and Projects Review

The BCUC initiated a review in May 2016 to review the regulatory oversight of BC Hydro's capital expenditures and projects. BC Hydro submitted our current proposal in June 2018, which included draft Capital Filing Guidelines. These draft Guidelines expand upon the previous capital project filing guidelines by including the review of capital expenditures and projects in a revenue requirements proceeding, and better aligning capital project regulatory applications with our current capital planning processes.

In November 2018, an intervener filed evidence arguing for a different approach for the BCUC's regulatory oversight of BC Hydro's capital expenditures and projects. In response to this evidence, BC Hydro filed our own rebuttal evidence in February 2019. The next steps in the process include BCUC and intervener information requests in June 2019 on our evidence, with a Decision expected by the end of summer 2019.

Supply Chain Applications Project Application

In December 2016, BC Hydro submitted the Supply Chain Applications Project Phase One Application under section 44.2 for acceptance of Project's Definition Phase capital expenditures for a new SAP IT platform to meet BC Hydro's current and future business needs, and provide benefits for supply chain activities throughout BC Hydro. The Project's total cost is estimated to be between $71 million and $79 million with a planned in service date in the fourth quarter of fiscal 2020.

On April 9, 2019, the BCUC issued Order No. G-78-19, finding that Phase 2 of the Project was in the public interest, and approved BC Hydro to complete the Implementation Phase of the Project.

Mandatory Reliability Standards Reliability Coordinator Registration Application

In September 2018, BC Hydro submitted an application to the Western Electricity Coordinating Council, who acted as an administrator for BCUC, to register for the Reliability Coordinator function in British Columbia. A reliability coordinator is required in order to preserve reliability of the interconnected bulk electric system for compliance with mandatory reliability standards. The existing Reliability Coordinator has announced that they will no longer provide these services in British Columbia at the end of 2019, and BC Hydro considers itself best positioned to assume this role.

In February 2019, the BCUC issued a timetable for review of BC Hydro's application, which required BC Hydro to submit key documents to registered interveners for review and comment. Interveners' comments were received on April 26, 2019. BC Hydro expects to be approved for the role of Reliability Coordinator in British Columbia in August 2019, and to begin by September 1, 2019.

BC Hydro's Fiscal 2020-2021 Revenue Requirements Application

In February 2019, BC Hydro filed an Application with the BCUC to approve its revenue requirements for a two year test period covering fiscal 2020 and fiscal 2021. In the Application, BC Hydro requested rate increases of 6.85 per cent for fiscal 2020 and 0.72 per cent for fiscal 2021. BC Hydro has also requested a reduction of the Deferral Account Rate Rider from 5 per cent to nil, resulting in a net bill impact for customers of 1.76 per cent for fiscal 2020 and 0.72 per cent for fiscal 2021. The BCUC issued Order No. G-45-19 on March 1, 2019, approving the rate increases and reduction to the Deferral Account Rate Rider on an interim basis effective April 1, 2019.

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, to smooth the impact of large, non-recurring costs 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 2020-2021 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 generally fall into the following five categories:

- Energy availability;

- Domestic demand for energy;
- Energy market prices;
- Deliveries from electricity purchase agreement contracts; and
- Interest rates.

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

While meeting domestic 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 doing so, BC Hydro attempts to optimize the combined effects of these elements and reduce the net energy cost for our customers.

Energy Availability

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) and enabling our ability to take advantage of short-term market price variations. The amount of available generation is driven primarily by hydrology - the amount and timing of inflows into BC Hydro-dispatched plants and reservoirs. The range of inflows, year to year, can significantly influence available generation: over 15,000 GWh (or approximately 25 per cent of current domestic demand) separates the wettest years from the driest in the most recent 46 years in BC Hydro's records. To a less significant extent, the amount of available generation 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.

Domestic Demand for Energy

Electricity demand is generally forecast to increase as B.C.'s population and economy continue to grow. However, long term projections of electricity demand entails 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 general economic conditions and the rate of uptake in demand-side management programs.

There can also be short term fluctuations in electricity demand due to timing of new large customer facility start-up and existing customer facility closures and restarts. Weather can have a significant impact on residential load with colder years resulting in higher demand for electrical heating than in average or warm years.

Energy Market Prices

The cost of energy and the revenue from trade market activity all depend on energy market prices which are variable and impacted by gas and electricity market fundamentals.

Deliveries from Electricity Purchase Agreement Contracts

Energy delivered under electricity purchase agreement contracts has a different cost than both energy generated by BC Hydro and energy purchased or sold in energy markets. Therefore, as the proportion deliveries comprised of electricity purchase agreement contract energy changes, BC Hydro's average energy cost changes. BC Hydro's portfolio of electricity purchase agreement contracts 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. In fiscal 2019, overall energy delivered from Independent Power Projects was lower than forecast. In particular, biomass, non-storage hydro and wind projects delivered less energy than expected. Lower than forecast generation from these projects was partially offset by higher than forecast generation from thermal generation and storage hydro projects.

Interest Rates

A portion of BC Hydro's existing debt will be impacted by the changes to interest rates for debt with short remaining term to maturity, 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.

As at March 31, 2019, approximately 14 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.

In addition, BC Hydro is 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 long-term interest rates, as at March 31, 2019 BC Hydro had hedges in place with an aggregate notional principal of $6.1 billion, hedging a significant portion of its forecast long-term debt issuances out to and including Fiscal 2025.

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 2019 forecast net income for fiscal 2020 at $712 million which is consistent with the amount required by Order in Council No. 051.

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, interest rates, and foreign exchange rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The forecast for fiscal 2020 assumes average water inflows (100 per cent of average), domestic sales of 53,567 GWh, average market energy prices of US $25.88/MWh, short-term interest rates of 2.37 per cent, and a Canadian to US dollar exchange rate of US $0.7910.

EARNINGS SENSITIVITY

The following table shows the estimated effect on earnings of changes in some key variables, before regulatory account transfers. The analysis is based on business conditions and production volumes forecast for fiscal 2020. 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 earnings before regulatory account transfers (in millions)	5 year high	5 year low	Fiscal 2019
Customer load [1]	+/-1%	$35	52,413 GWh	51,023 GWh	52,413 GWh
Interest rates[6]	+/- 100 basis points	$35	2.01% [2]	0.87% [2]	2.01% [2]
Electricity/Gas trade income [3]	+/-10%	$20	$517	$127	$517
Hydro generation [4]	+/-1%	$10	49,352 GWh	41,230 GWh	42,340 GWh
Exchange rates (USD/CAD)	+/- $0.01	$5	$0.88 [5]	$0.76 [5]	$0.76[5]

[1] Assumes percentage change is applied equally to all customer classes. Assumes change in customer load is offset by corresponding change in net market electricity sales (i.e. increase in customer load is offset by decrease in net market electricity sales).

[2] Interest rates are the annual daily average Canadian short-term interest rates (3-month Canadian Dollar Offered Rate).

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

[4] Assumes change in hydro generation is offset by corresponding change in net market electricity sales (i.e. increase in hydro generation is offset by increase in net market electricity sales).

[5] Exchange rates are the Bank of Canada average daily rates. Prior to fiscal 2018, exchange rates were the annual daily average US Dollar noon rates.

[6] Sensitivity analysis related only to variable debt.

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 12, 2019. The consolidated financial statements have also been reviewed by the Audit & Finance Committee and approved by the Board of Directors. Financial information presented elsewhere in this Annual Service Plan Report is consistent with that in the consolidated financial statements.

Management maintains systems of internal controls designed to provide reasonable assurance that assets are safeguarded and that reliable financial information is available on a timely basis. These systems include formal written policies and procedures, careful selection and training of qualified personnel 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 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, comprehensive income 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 Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal controls. The Audit & Finance Committee, comprised of directors who are not employees, meets regularly with the external auditors, the internal auditors and management to satisfy itself that each group has properly discharged its responsibility to review the financial statements before recommending approval by the Board of Directors. The Audit & Finance Committee also recommends the appointment of external auditors to the Board of Directors. The internal and external auditors have full and open access to the Audit & Finance Committee, with and without the presence of management.

Chris O'Riley
President and Chief Operating Officer

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

Vancouver, Canada
June 12, 2019

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Independent Auditor's Report

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

Opinion

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

- the consolidated statements of financial position as at March 31, 2019, March 31, 2018 and April 1, 2017
- the consolidated statements of comprehensive income (loss) for the years ended March 31, 2019 and March 31, 2018
- the consolidated statements of changes in equity for the years ended March 31, 2019 and March 31, 2018
- the consolidated statements of cash flows for the years ended March 31, 2019 and March 31, 2018
- and notes to the consolidated financial statements, including a summary of significant accounting policies

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

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Entity as at March 31, 2019, March 31, 2018 and April 1, 2017 and its consolidated financial performance and its consolidated cash flows for the years ended March 31, 2019 and March 31, 2018 in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

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

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

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

Other Information

Management is responsible for the other information. Other information comprises:

— the information, other than the financial statements and the auditors' report thereon, included in the Entity's Management Discussion & Analysis.

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

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

We obtained the information, other than the financial statements and the auditors' report thereon, included in Entity's Management Discussion & Analysis as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

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

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

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

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

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

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

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

We also:

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

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

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

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

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

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

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

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

KPMG LLP

Chartered Professional Accountants

Vancouver, Canada
June 12, 2019

Audited Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

for the years ended March 31 (in millions)	**2019**	2018 (Note 24)
Revenues (Note 4)		
Domestic	**$ 5,432**	$ 5,223
Trade	**1,141**	731
	6,573	5,954
Expenses		
Operating expenses (Note 5)	**4,696**	4,497
Finance charges (Note 6)	**1,186**	824
Net Income Before Movement in Regulatory Balances	**691**	633
Net movement in regulatory balances (Note 14)	**(1,119)**	51
Net Income (Loss)	**(428)**	**684**
OTHER COMPREHENSIVE INCOME (LOSS)		
Items That Will Be Reclassified to Net Income (Loss)		
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 20)	**(24)**	57
Reclassification to income (loss) of derivatives designated as cash flow hedges (Note 20)	**8**	(30)
Foreign currency translation gains (losses)	**3**	(5)
Items That Will Not Be Reclassified to Net Income (Loss)		
Actuarial gain (loss)	**(173)**	193
Other Comprehensive Income (Loss) before movement in regulatory balances	**(186)**	**215**
Net movements in regulatory balances (Note 14)	**173**	(193)
Other Comprehensive Income (Loss)	**(13)**	22
Total Comprehensive Income (Loss)	**$ (441)**	$ 706

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in millions)	**As at March 31 2019**	As at March 31 2018 (Note 24)	As at April 1 2017 (Note 24)
ASSETS			
Current Assets			
Cash and cash equivalents (Note 8)	**$ 84**	$ 42	$ 49
Restricted cash (Note 8)	**109**	77	28
Accounts receivable and accrued revenue (Note 9)	**912**	728	761
Inventories (Note 10)	**168**	144	185
Prepaid expenses	**179**	167	162
Current portion of derivative financial instrument assets (Note 20)	**79**	174	144
	1,531	1,332	1,329
Non-Current Assets			
Property, plant and equipment (Note 11)	**27,952**	25,079	22,994
Intangible assets (Note 12)	**602**	591	601
Derivative financial instrument assets (Note 20)	**49**	156	215
Other non-current assets (Note 13)	**596**	632	560
	29,199	26,458	24,370
Total Assets	**30,730**	27,790	25,699
Regulatory Balances (Note 14)	**4,942**	5,891	6,127
Total Assets and Regulatory Balances	**$ 35,672**	$ 33,681	$ 31,826
LIABILITIES AND EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities (Note 15)	**$ 1,478**	$ 1,603	$ 1,172
Current portion of long-term debt (Note 16)	**3,121**	3,344	2,878
Current portion of unearned revenues and contributions in aid (Note 17)	**87**	85	82
Current portion of derivative financial instrument liabilities (Note 20)	**89**	112	60
	4,775	5,144	4,192
Non-Current Liabilities			
Long-term debt (Note 16)	**19,261**	17,020	17,146
Derivative financial instrument liabilities (Note 20)	**296**	66	41
Unearned revenues and contributions in aid (Note 17)	**1,905**	1,758	1,620
Post-employment benefits (Note 19)	**1,752**	1,474	1,566
Other non-current liabilities (Note 21)	**1,988**	2,021	1,516
	25,202	22,339	21,889
Total Liabilities	**29,977**	27,483	26,081
Regulatory Balances (Note 14)	**748**	751	845
Shareholder's Equity			
Contributed surplus	**60**	60	60
Retained earnings	**4,934**	5,421	4,896
Accumulated other comprehensive loss	**(47)**	(34)	(56)
	4,947	5,447	4,900
Total Liabilities, Shareholder's Equity and Regulatory Balances	**$ 35,672**	$ 33,681	$ 31,826

Commitments and Contingencies (Notes 11 and 22)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

Ken Peterson
Executive Chair

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized Income (Loss) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income (Loss)	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2017	$ -	$ (56)	$ (56)	$ 60	$ 4,896	$ 4,900
Payment to the Province (Note 18)	-	-	-	-	(159)	(159)
Comprehensive Income (Loss)	(5)	27	22	-	684	706
Balance as at March 31, 2018	(5)	(29)	(34)	60	5,421	5,447
Payment to the Province (Note 18)	-	-	-	-	(59)	(59)
Comprehensive Income (Loss)	3	(16)	(13)	-	(428)	(441)
Balance as at March 31, 2019	$ (2)	$ (45)	$ (47)	$ 60	$ 4,934	$ 4,947

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

for the years ended March 31 (in millions)	**2019**	2018
Operating Activities		
Net income (Loss)	**$ (428)**	$ 684
Regulatory account transfers (Note 14)	**504**	(295)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 14)	**442**	437
Amortization and depreciation expense (Note 7)	**880**	817
Unrealized losses on derivative financial instruments	**286**	80
Post-employment benefits expense	**106**	105
Interest accrual	**854**	795
Other items	**(22)**	108
	2,622	2,731
Changes in:		
Restricted cash	**(32)**	(48)
Accounts receivable and accrued revenue	**(131)**	94
Prepaid expenses	**(30)**	(29)
Inventories	**(23)**	40
Accounts payable, accrued liabilities and other non-current liabilities	**138**	(307)
Unearned revenue and contributions in aid	**160**	142
Other non-current assets	**18**	(103)
	100	(211)
Interest paid	**(850)**	(795)
Cash provided by operating activities	**1,872**	1,725
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(3,766)**	(2,123)
Cash used in investing activities	**(3,766)**	(2,123)
Financing Activities		
Long-term debt issued (Note 16)	**2,418**	1,156
Long-term debt retired (Note 16)	**(1,287)**	(40)
Receipt of revolving borrowings	**8,865**	7,749
Repayment of revolving borrowings	**(7,981)**	(8,536)
Payment to the Province (Note 18)	**(159)**	-
Other items	**80**	62
Cash provided by financing activities	**1,936**	391
Increase (decrease) in cash and cash equivalents	**42**	(7)
Cash and cash equivalents, beginning of year	**42**	49
Cash and cash equivalents, end of year	**$ 84**	$ 42

See Note 16 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, 2019 AND 2018

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 consolidated financial statements of BC Hydro include the accounts of BC Hydro and its principal wholly owned operating subsidiaries Powerex Corp. (Powerex), Powertech Labs Inc. (Powertech), and Columbia Hydro Constructors Ltd. (Columbia), (collectively with BC Hydro, the Company). All intercompany transactions and balances are eliminated on consolidation. On July 26, 2018, the Company completed the purchase of the remaining two-thirds interest of Waneta Dam and Generating Facility (Waneta) (Note 11). Prior to this transaction, the Company accounted for its one-third interest in Waneta as a joint operation.

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. These are the Company's first consolidated financial statements prepared in accordance with IFRS. In prior years, the Company prepared its consolidated financial statements in accordance with the accounting principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations*, except as specified in Treasury Board Regulation B.C. Reg 146/2011 section 5(3) (collectively the Prescribed Standards). The comparative figures for the prior year were restated on the adoption of IFRS. An explanation of how the transition to IFRS has affected the reported financial position, financial performance and cash flows of the Company is provided in Note 24.

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 12, 2019.

(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(o).

(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 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 19 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) 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 fulfillment of an arrangement is dependent on the use of a specific asset, and whether the arrangement conveys a right to use the asset. For those arrangements considered to be leases, or which contain an embedded lease, further judgment is required to determine whether to account for the agreement as either a finance or operating lease by assessing whether substantially all of the significant risks and rewards of ownership are transferred to the Company or remain with the counterparty to the agreement. The measurement of finance leases requires estimations of the amounts and timing of future cash flows and the determination of an appropriate discount rate.

(v) 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.

(vi) 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.

IFRS 14 *Regulatory Deferral Accounts* (IFRS 14) is restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB. IFRS 14 provides first-time adopters of IFRS an option to continue recognizing regulatory balances in accordance with the basis of accounting the first-time adopter used immediately before adopting IFRS, which in the case of the Company was the Prescribed Standards. BC Hydro has determined that certain debit and credit balances arising from rate-regulated activities qualify for the continued application of regulatory accounting treatment in accordance with IFRS 14. 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 expense or other comprehensive income 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 disposition 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 (loss) 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 statements of financial position, and are separately disclosed on the consolidated statement of comprehensive income (loss) 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) Revenue

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 either under long-term contracts or are surplus to domestic load requirements. 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 significant 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. 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 interest expense on borrowings, accretion expense on provisions and other long-term liabilities, net interest on net defined benefit obligations, interest on finance lease liabilities, foreign exchange losses and realized hedging instrument losses that are recognized in the statement of comprehensive income. 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 more than six months to prepare for their intended use.

Finance recoveries comprises income earned on sinking fund investments held for the redemption of long-term debt, foreign exchange gains and realized 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 re-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 (loss).

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.

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 (loss) 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 – 60
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, 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 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 applied 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. Natural gas inventory is valued at fair value less costs to sell and included in Level 2 of the fair value hierarchy (refer to Note 10). Materials and supplies 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), fair value through other comprehensive income (FVOCI) 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 classified as FVOCI are subsequently measured at fair value, with changes in those fair values recognized in other comprehensive income (loss) until realized or impaired. 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

The Company adopted IFRS on April 1, 2017 and has assessed the classification and measurement of financial assets and financial liabilities under IFRS 9. The original measurement categories under the Prescribed Standards and IAS 39 and the new measurement categories under IFRS 9 are summarized in the following table:

	IAS 39	**IFRS 9**
Short-term investments	FVTPL	FVTPL
Derivatives not in a hedging relationship	FVTPL	FVTPL
Cash	Loans and receivables	Amortized cost
Restricted cash	Loans and receivables	Amortized cost
Accounts receivable and other receivables	Loans and receivables	Amortized cost
US dollar sinking funds	Held to maturity	Amortized cost
Accounts payable and accrued liabilities	Other financial liabilities	Amortized cost
Revolving borrowings	Other financial liabilities	Amortized cost
Long-term debt (including current portion due in one year)	Other financial liabilities	Amortized cost
Finance lease obligations, First Nations liabilities and Other liabilities presented in Other long-term liabilities	Other financial liabilities	Amortized cost

There has been no change in the carrying value or fair value of the Company's financial instruments or to previously reported figures as a result of changes to the measurement categories in the table noted above.

(ii) 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 and internally developed valuation models which are based on models and techniques generally recognized as standard within the energy industry.

(iii) 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 20.

(iv) 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 liability management activities, the related gains or losses are included in finance charges. For foreign currency exchange risk associated with electricity and natural gas commodity transactions, the related gains or losses are included in domestic revenues. 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.

(v) 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 Revenue

Unearned revenue consists 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) 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.

(o) 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.

(p) 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 the claim will be settled 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 lawsuits. Further information regarding lawsuits in progress is disclosed in Note 22.

(q) Leases

Embedded Leases

The Company may enter into an arrangement that does not take the legal form of a lease but conveys a right to use an asset in return for a payment or series of payments. Arrangements in which a party conveys a right to the Company to use an asset may in substance be, or contain, a lease that should be accounted for as either a finance or operating lease. Determining whether an arrangement is, or contains, a lease requires an assessment of whether fulfilment of the arrangement is dependent on the use of a specific asset; and whether the arrangement conveys a right to use the asset. The right to use an asset is conveyed if the right to operate or control physical access to the underlying asset is provided or if the Company consumes substantially all of the output of the asset and the price paid for the output is neither contractually fixed per unit of output nor equal to the current market price.

Finance Leases

Leases where substantially all of the benefits and risk of ownership rest with the Company are accounted for as finance leases. Finance leases are recognized as assets and liabilities at the lower of the fair value of the asset and the present value of the minimum lease payments at the date of acquisition. Finance costs represent the difference between the total leasing commitments and the fair value of the assets acquired. Finance costs are charged to net income over the term of the lease at interest rates applicable to the lease on the remaining balance of the obligations. Assets under finance leases are depreciated on the same basis as property, plant and equipment or over the term of the relevant lease, whichever is shorter.

Operating Leases

Leases where substantially all of the benefits and risk of ownership remain with the lessor are accounted for as operating leases. Rental payments under operating leases are expensed to net income on a straight-line basis over the term of the relevant lease. Benefits received and receivable as an incentive to enter into an operating lease are recognized as an integral part of the total lease expense and are recorded on a straight-line basis over the term of the lease.

(r) Taxes

The Company pays local government taxes and grants in lieu to municipalities and regional districts. As a Crown Corporation, the Company is exempt from Canadian federal and provincial income taxes.

(s) Jointly Controlled Operations

Prior to the purchase of the remaining 2/3 interest in Waneta Dam and Generating Facility on July 26, 2018, the Company had joint ownership and control over certain assets with third parties. A jointly controlled operation exists when there is a joint ownership and control of one or more assets to obtain benefits for the joint operators. The parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, related to the arrangement. Each joint operator takes a share of the output from the assets for its own exclusive use. These consolidated financial statements include the Company's share of the jointly controlled assets. The Company also records its share of any liabilities and expenses incurred jointly with third parties and any revenue from the sale or use of its share of the output in relation to the assets.

(t) New Standards and Amendments Not Yet Adopted

A number of new standards, and amendments to standards and interpretations, are not yet effective for the year ended March 31, 2019, and have not been applied in preparing these consolidated financial statements. In particular, the following new and amended standards become effective for the Company's annual periods beginning on or after the dates noted below:

Leases

IFRS 16, *Lea*ses replaces the existing standard IAS 17, *Leases* and IFRIC 4, *Determining Whether an Arrangement Contains a Lease* and the effective date for BC Hydro is April 1, 2019. IFRS 16 combines the existing dual model of operating and finance leases under IAS 17 into a single lease model for lessees. Under the new single lease model, a lessee will recognize the lease assets and lease liabilities on the statement of financial position initially measured at the present value of the unavoidable lease payments, with the exception of leases with a duration of twelve months or less and leases with low value. IFRS 16 will also cause expenses to be higher at the beginning and lower towards the end of a lease, even when payments are consistent throughout the term.

The standard permits two methods of adoption: (i) the full retrospective method; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption.

During fiscal 2019, management has compiled all of the Company's existing lease and service contracts and reviewed the relevant agreements to identify which of these contracts are in scope of IFRS 16. In addition, management has completed a review of existing service contracts for embedded leases and has identified all operating leases. Furthermore, the Company began developing a valuation approach to measuring the right of use assets and related lease obligations for our leases and reviewed the increased accounting and disclosure requirements arising from the new leasing standard.

The Company is in the process of completing the quantification of the impact that adoption of IFRS 16 will have upon adoption. The Company intends to use the full retrospective approach of adoption resulting in restatement of prior year comparatives. The quantitative impact of adopting IFRS 16 will be provided in our first interim condensed consolidated financial statements in fiscal 2020.

Investments in Associates and Joint Ventures, Employee Benefits, and Financial Instruments

The Company does not expect to have a material impact on the consolidated financial statements upon adoption of the following amended standards effective April 1, 2019:

- Amendments to IAS 28, *Investments in Associates and Joint Ventures*
- Amendments to IAS 19, *Employee Benefits*
- Amendments to IFRS 9, *Financial Instruments*

NOTE 4: REVENUES

Disaggregate Revenue

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

(in millions)		**2019**		2018
Domestic				
Residential	**$**	**2,127**	$	2,097
Light industrial and commercial		**1,925**		1,860
Large industrial		**873**		811
Surplus sales		**115**		139
Other sales		**392**		316
Total Domestic		**5,432**		5,223
Total Trade[1]		**1,141**		731
Total Revenue	**$**	**6,573**	$	5,954

[1] Includes mark-to-market gains/(losses) from derivatives.

Contract Balances

The Company does not have any contract assets which constitutes consideration receivable from a customer that is conditional on the Company's future performance. The current and non-current receivables balances from customers as at March 31, 2019 totalled $867 million (2018 - $741 million, April 1, 2017 - $796 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, 2019**		March 31, 2018		April 1, 2017
Unearned revenues	**$**	**230**	$	210	$	179
Contributions in aid (Note 17)		**1,762**		1,633		1,519
Customer deposits		**13**		15		14
	$	**2,005**	$	1,858	$	1,712

The following table reconciles the changes in the contract liabilities balances during the years ended March 31, 2019 and 2018:

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FOR THE YEARS ENDED MARCH 31, 2019 AND 2018

		Contract Liabilities
Balance at April 1, 2017	**$**	**1,712**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(93)
Increases due to cash received, excluding amounts recognized as revenue during the period		218
Other[1]		21
Balance at March 31, 2018		**1,858**
Revenue recognized that was included in the contract liability balance at the beginning of the period		(107)
Increases due to cash received, excluding amounts recognized as revenue during the period		230
Other[1]		24
Balance at March 31, 2019	**$**	**2,005**

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, 2019.

(in millions)	Less than one year	Between one and five years	More than five years	Total
Energy sales	$ 22	$ 29	$ 18	$ 69
Contribution in aid	50	197	1,515	1,762
Skagit River Agreement	29	117	1,233	1,379
Other	53	79	45	177
	$ 154	$ 422	$ 2,811	$ 3,387

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.

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2019 AND 2018

NOTE 5: OPERATING EXPENSES

(in millions)		**2019**		2018
Electricity and gas purchases	**$**	**1,661**	$	1,610
Water rentals		**331**		324
Transmission charges		**205**		203
Personnel expenses		**630**		591
Materials and external services		**707**		650
Amortization and depreciation (Note 7)		**880**		817
Grants and taxes		**268**		241
Other costs, net of recoveries		**84**		130
Less: Capitalized costs		**(70)**		(69)
	$	**4,696**	$	4,497

NOTE 6: FINANCE CHARGES

(in millions)		**2019**		2018
Interest on long-term debt	**$**	**854**	$	795
Interest on finance lease liabilities		**42**		18
Interest on defined benefit plan obligations (Note 19)		**56**		62
Mark-to-market losses on derivative financial instruments (Note 20)		**318**		27
Other		**46**		31
Capitalized interest		**(130)**		(109)
	$	**1,186**	$	824

The effective capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 4.0 per cent (2018 - 4.1 per cent).

NOTE 7: AMORTIZATION AND DEPRECIATION

(in millions)		**2019**		2018
Depreciation of property, plant and equipment (Note 11)	**$**	**797**	$	733
Amortization of intangible assets (Note 12)		**83**		84
	$	**880**	$	817

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2019 AND 2018

NOTE 8: CASH AND CASH EQUIVALENTS, AND RESTRICTED CASH

(in millions)		**March 31, 2019**		March 31, 2018		April 1, 2017
Cash	**$**	**34**	$	11	$	25
Short-term investments		**50**		31		24
	$	**84**	$	42	$	49

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 available to the Company only upon liquidation of the investments or settlements of the trade obligations they have been pledged as security for.

NOTE 9: ACCOUNTS RECEIVABLE AND ACCRUED REVENUE

(in millions)		**March 31, 2019**		March 31, 2018		April 1, 2017
Accounts receivable	**$**	**640**	$	492	$	547
Accrued revenue		**192**		170		138
Other		**80**		66		76
	$	**912**	$	728	$	761

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

NOTE 10: INVENTORIES

(in millions)		**March 31, 2019**		March 31, 2018		April 1, 2017
Materials and supplies	**$**	**161**	$	142	$	145
Natural gas trading inventories		**7**		2		40
	$	**168**	$	144	$	185

There were no materials and supplies inventory impairments during the years ended March 31, 2019 and 2018. 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 $77 million (2018 - $82 million).

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NOTE 11: PROPERTY, PLANT AND EQUIPMENT

(in millions)	Generation	Transmission	Distribution	Land & Builidings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at April 1, 2017	$ 6,782	$ 6,623	$ 5,225	$ 590	$ 652	$ 3,364	$ 23,236
Net additions	877	404	447	109	115	933	2,885
Disposals and retirements	(167)	(10)	(24)	(3)	(8)	(23)	(235)
Balance at March 31, 2018	7,492	7,017	5,648	696	759	4,274	25,886
Net additions	2,397	516	442	30	105	241	3,731
Disposals and retirements	(10)	(10)	(31)	(1)	(10)	(17)	(79)
Balance at March 31, 2019	$ 9,879	$ 7,523	$ 6,059	$ 725	$ 854	$ 4,498	$ 29,538
Accumulated Depreciation							
Balance at April 1, 2017	$ (187)	$ (25)	$ (9)	$ (8)	$ (13)	$ -	$ (242)
Depreciation expense	(212)	(217)	(192)	(24)	(88)	-	(733)
Disposals and retirements	162	1	1	-	4	-	168
Balance at March 31, 2018	(237)	(241)	(200)	(32)	(97)	-	(807)
Depreciation expense	(255)	(225)	(201)	(26)	(90)	-	(797)
Disposals and retirements	6	3	3	-	6	-	18
Balance at March 31, 2019	$ (486)	$ (463)	$ (398)	$ (58)	$ (181)	$ -	$ (1,586)
Net carrying amounts							
At April 1, 2017	$ 6,595	$ 6,598	$ 5,216	$ 582	$ 639	$ 3,364	$ 22,994
At March 31, 2018	$ 7,255	$ 6,776	$ 5,448	$ 664	$ 662	$ 4,274	$ 25,079
At March 31, 2019	$ 9,393	$ 7,060	$ 5,661	$ 667	$ 673	$ 4,498	$ 27,952

(i) Prior to the purchase of the remaining two-thirds interest in Waneta on July 26, 2018, the Company included its one-third interest in Waneta with a net book value of $668 million (2018 - $674 million, April 1, 2017 - $695 million) in Generation assets.

On August 1, 2017, BC Hydro agreed to exercise its option to purchase the remaining two-thirds interest of Waneta from Teck Resources (Teck) for $1.20 billion. Following receipt of BCUC approval in July 2018, BC Hydro completed the transaction on July 26, 2018. The transaction has been accounted for as an asset acquisition, with the purchase price being allocated to the applicable integrated components of the property, plant and equipment acquired. The purchase agreement includes a 20 year agreement, whereby BC Hydro has contracted to sell two-thirds of the generation of Waneta to Teck. Teck has an option to extend such agreement for a further 10 years.

Depreciation expense on the Waneta assets for the year ended March 31, 2019 was $46 million (2018 - $21 million).

(ii) Included within Distribution assets are the Company's portion of utility poles with a net book value of $1.11 billion (2018 - $1.05 billion, April 1, 2017 - $972 million) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2019 was $29 million (2018 - $27 million).

(iii)The Company received government grants arising from the Columbia River Treaty related to three dams built by the Company in the mid-1960s to regulate the flow of the Columbia River. The grants were made to assist in financing the construction of the dams. The grants were deducted from the carrying amount of the related dams. In addition, the Company received, in prior years, government grants for the construction of a new transmission line and has deducted the grants received from the cost of the asset. No government grants were received in fiscal 2019 or fiscal 2018.

(iv) The Company has contractual commitments to spend $3.35 billion on major property, plant and equipment projects (on individual projects greater than $50 million) as at March 31, 2019.

Leased assets

Property, plant and equipment under finance leases of $695 million (2018 - $695 million, April 1, 2017 - $388 million), net of accumulated amortization of $77 million (2018 - $54 million, April 1, 2017 - $201 million), are included in the total amount of property, plant and equipment above.

NOTE 12: INTANGIBLE ASSETS

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at April 1, 2017	$ 243	$ 91	$ 217	$ 13	$ 51	$ 615
Net additions (transfers)	4	18	47	26	(12)	83
Disposals and retirements	-	-	(1)	(6)	(3)	(10)
Balance at March 31, 2018	247	109	263	33	36	688
Net additions	29	6	35	9	27	106
Disposals and retirements	-	-	-	(12)	-	(12)
Balance at March 31, 2019	$ 276	$ 115	$ 298	$ 30	$ 63	$ 782
Accumulated Amortization						
Balance at April 1, 2017	$ -	$ (8)	$ (6)	$ -	$ -	$ (14)
Amortization expense	-	(23)	(61)	-	-	(84)
Disposals and retirements	-	-	1	-	-	1
Balance at March 31, 2018	-	(31)	(66)	-	-	(97)
Amortization expense	-	(21)	(62)	-	-	(83)
Disposals and retirements	-	-	-	-	-	-
Balance at March 31, 2019	$ -	$ (52)	$ (128)	$ -	$ -	$ (180)
Net carrying amounts						
At April 1, 2017	$ 243	$ 83	$ 211	$ 13	$ 51	$ 601
At March 31, 2018	$ 247	$ 78	$ 197	$ 33	$ 36	$ 591
At March 31, 2019	$ 276	$ 63	$ 170	$ 30	$ 63	$ 602

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.

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NOTE 13: OTHER NON-CURRENT ASSETS

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Non-current receivables	**$ 148**	$ 194	$ 239
Sinking funds	**197**	182	179
Other	**251**	256	142
	$ 596	$ 632	$ 560

Non-Current Receivables

Included in the non-current receivables balance are $135 million of receivables (2018 - $140 million, April 1, 2017 - $145 million) attributable to contributions. 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.

Included in the non-current receivables balance is a $5 million (2018 - $28 million, April 1, 2017 - $68 million) receivable from mining customers participating in the Mining Customer Payment Plan. In February 2016, the Province issued a direction to the BCUC to establish the Mining Customer Payment Plan, which allows the operators of applicable mines to defer payment of a portion of electricity purchases for a period of up to five years.

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 at the statement of financial position date are accounted for at amortized cost, and include the following investments:

(in millions)	**March 31, 2019**		March 31, 2018		April 1, 2017	
	Carrying Value	**Weighted Average Effective Rate[1]**	Carrying Value	Weighted Average Effective Rate[1]	Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$ 126**	**2.9 %**	$ 114	3.2 %	$ 114	3.5 %
Other provincial government and crown corporation bonds	**71**	**2.9 %**	68	3.4 %	65	3.5 %
	$ 197		$ 182		$ 179	

[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.

Other

Included in the other balance is the long-term portion of prepaid expenses from the Site C Project of $235 million (2018 - $229 million, April 1, 2017 - $115 million).

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NOTE 14: 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 (loss). For the year ended March 31, 2019, the impact of regulatory accounting has resulted in a net decrease to total comprehensive income of $946 million (2018 - $142 million net decrease) which is comprised of a decrease to net income of $1.12 billion (2018 - $51 million increase) and an increase to other comprehensive income of $173 million (2018 - $193 million decrease). 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 2018*	*Addition / (Reduction)*	*Interest* [A]	*Amortization*	*Net Change* [B]	***As at March 31 2019***	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Non-Heritage Deferral Account	462	$ (170)	$ 13	$ (229)	$ (386)	**$ 76**	Note D
Trade Income Deferral Account	127	(109)	1	(19)	(127)	**-**	Note D
Demand-Side Management	903	111	-	(99)	12	**915**	1-15
Debt Management	-	163	-	-	163	**163**	9-35
First Nations Provisions & Costs	518	22	4	(39)	(13)	**505**	5-9 Note G
Non-Current Pension Costs	304	240	-	(58)	182	**486**	8-12
Site C	472	-	19	-	19	**491**	Note E
CIA Amortization	88	(5)	-	-	(5)	**83**	21
Environmental Provisions & Costs	261	(1)	(2)	(31)	(34)	**227**	Note F, G
Smart Metering & Infrastructure	239	-	9	(31)	(22)	**217**	10
IFRS Pension	535	-	-	(38)	(38)	**497**	13
IFRS Property, Plant & Equipment	1,025	67	-	(28)	39	**1,064**	33-42
Rate Smoothing[C]	815	(815)	-	-	(815)	**-**	-
Storm Restoration Costs	47	19	2	(10)	11	**58**	Note F
Total Finance Charges	-	3	-	17	20	**20**	Note F
Foreign Exchange Gains and Losses	-	(2)	-	14	12	**12**	1-10
Other Regulatory Accounts	95	37	4	(8)	33	**128**	2-5
Total Regulatory Assets	5,891	(440)	50	(559)	(949)	**4,942**	
Regulatory Liabilities							
Heritage Deferral Account	423	95	19	(52)	62	**485**	Note D
Trade Income Deferral Account	-	212	3	44	259	**259**	Note D
Foreign Exchange Gains and Losses	31	(6)	-	(25)	(31)	**-**	1-10
Debt Management	158	(158)	-	-	(158)	**-**	9-35
Total Finance Charges	134	(50)	-	(84)	(134)	**-**	Note F
Other Regulatory Accounts	5	(1)	-	-	(1)	**4**	2-5
Total Regulatory Liabilities	751	92	22	(117)	(3)	**748**	
Net Regulatory Asset	$ 5,140	$ (532)	$ 28	$ (442)	$ (946)	**$ 4,194**	

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(in millions)	*As at April 1 2017*	*Addition / (Reduction)*	*Interest* [A]	*Amortization*	*Net Change* [B]	*As at March 31 2018*	*Remaining recovery/ reversal period (years)*
Regulatory Assets							
Non-Heritage Deferral Account	756	(123)	26	(197)	(294)	462	Note D
Trade Income Deferral Account	194	(21)	5	(51)	(67)	127	Note D
Demand-Side Management	916	82	-	(95)	(13)	903	1-15
First Nations Provisions & Costs	532	20	5	(39)	(14)	518	6-9 Note G
Non-Current Pension Costs	485	(123)	-	(58)	(181)	304	9-13
Site C	453	-	19	-	19	472	Note E
CIA Amortization	91	(3)	-	-	(3)	88	22
Environmental Provisions & Costs	294	-	(2)	(31)	(33)	261	Note F, G
Smart Metering & Infrastructure	261	-	10	(32)	(22)	239	11
IFRS Pension	574	-	-	(39)	(39)	535	14
IFRS Property, Plant & Equipment	962	90	-	(27)	63	1,025	34-43
Rate Smoothing	488	327	-	-	327	815	-
Storm Restoration Costs	39	16	2	(10)	8	47	Note F
Other Regulatory Accounts	82	28	1	(16)	13	95	3-6
Total Regulatory Assets	6,127	293	66	(595)	(236)	5,891	
Regulatory Liabilities							
Heritage Deferral Account	371	61	5	(14)	52	423	Note D
Foreign Exchange Gains and Losses	66	4	-	(39)	(35)	31	1-11
Debt Management	187	(29)	-	-	(29)	158	10-35
Total Finance Charges	212	24	-	(102)	(78)	134	Note F
Other Regulatory Accounts	9	(1)	-	(3)	(4)	5	3-6
Total Regulatory Liabilities	845	59	5	(158)	(94)	751	
Net Regulatory Asset	$ 5,282	$ 234	$ 61	$ (437)	$ (142)	$ 5,140	

[A] As permitted, interest charges were accrued to certain regulatory balances at a rate of 4.0% for the year ended March 31, 2019 (2018 – 4.1%).

[B] Net Change includes a net increase to net loss of $1.12 billion (2018 – a net increase to net income of $51 million) and net decrease to other comprehensive loss of $173 million (2018 – a net decrease to other comprehensive income of $193 million).

[C] As at December 31, 2018, the entire balance of the Rate Smoothing Regulatory Account (RSRA) was expensed as BC Hydro determined that collection of the RSRA was no longer probable based on information received from the Province. This resulted in an operating expense of $1.04 billion during the year ended March 31, 2019. The operating expense was comprised of the $815 million balance in the account as at April 1, 2018 and $229 million deferred in the account from April 1, 2018 to December 31, 2018.

[D] For fiscal 2018 to fiscal 2019, the balances in these regulatory accounts were recovered in rates through the Deferral Account Rate Rider (DARR), which is an additional charge on customer bills. The DARR was 5 per cent for fiscal 2018 and fiscal 2019. In the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, BC Hydro proposed to reduce the DARR from 5 per cent to 0 per cent effective April 1, 2019 and to refund the forecasted net credit balance in the Revenue Requirements Application in these accounts over the fiscal 2020 to fiscal 2021 test period.

[E] The recovery period for this account will be determined by the BCUC as part of a future regulatory proceeding once the Site C Project is placed into service.

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[F] The forecast balances 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. The forecast balance at the end of fiscal 2019 will be recovered over fiscal 2020 to fiscal 2021 test period.

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

RATE REGULATION

On March 1, 2018, the BCUC issued Order No. G-47-18, which approved final rate increases of 4.0 per cent for fiscal 2017, 3.5 per cent for fiscal 2018, and 3.0 per cent for fiscal 2019. In addition, the BCUC directed the establishment of two new regulatory accounts, the Post Employment Benefit (PEB) Current Pension Costs Regulatory Account and the Dismantling Cost Regulatory Account and the closure of the Future Removal and Site Restoration Regulatory Account.

On February 25, 2019, BC Hydro filed the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application requesting rate increases of 6.85 per cent for fiscal 2020 and 0.72 per cent for fiscal 2021 and a reduction in the Deferral Account Rate Rider from 5 per cent to 0 per cent effective April 1, 2019. If approved, these two requests would result in a net bill increase of 1.76 per cent for fiscal 2020 and 0.72 per cent for fiscal 2021. BC Hydro proposed to reduce the Deferral Account Rate Rider to 0 per cent as the accounts it is intended to recover have a combined credit balance at March 31, 2019. Instead of the Deferral Account Rate Rider recovery mechanism, BC Hydro has proposed to refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and interest applied to the Heritage Deferral Account, the Non-Heritage Deferral Account, and the Trade Income Deferral Account over the fiscal 2020 to fiscal 2021 test period.

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. These deferred variances are recovered in rates through the Deferral Account Rate Rider (DARR). The DARR, which was set at 5 per cent for fiscal 2018 and fiscal 2019, is an additional charge on customer bills and is currently used to recover the balances in the energy deferral accounts for fiscal 2018 and fiscal 2019.

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) and load (i.e., customer demand). These deferred variances are recovered in rates through the DARR for fiscal 2018 and fiscal 2019.

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. These deferred variances are recovered in rates through the DARR for fiscal 2018 and fiscal 2019.

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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 Government 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 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. Lump sum and annual settlement costs paid pursuant to these settlements are transferred 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. A test period refers to the period covered by a revenue requirements application filing.

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 (asset) 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 12 years).

SITE C

Site C Project expenditures incurred in fiscal 2007 through the third quarter of fiscal 2015 were deferred. In December 2014, the Provincial Government 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 plans to seek BCUC approval to begin amortizing the balance of the Site C Regulatory Account once the assets are in service.

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.

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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 asset 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) 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). In addition, the account includes an annual deferral of overhead costs, ineligible for capitalization under the accounting principles of IFRS. The annual deferred amounts are amortized over 40 years beginning the year following the deferral of the expenditures.

RATE SMOOTHING

As part of the 10 Year Rates Plan, the Rate Smoothing Regulatory Account was established with the objective of smoothing rate increases over the 10 Year Rates Plan period so that there is less volatility from year to year. As part of the Comprehensive Review, BC Hydro ceased using the Rate Smoothing Regulatory Account at the end of the third quarter of fiscal 2019. The balance of the Rate Smoothing Regulatory Account was written-off in December 2018 in the amount of $1.04 billion, resulting in a net loss for BC Hydro in fiscal 2019. BC Hydro is seeking BCUC approval to close this regulatory account in fiscal 2020.

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STORM RESTORATION COSTS

This account captures the difference between certain forecast storm restoration costs in a revenue requirements application and actual storm restoration costs. Variances deferred during the current test period are recovered over the following test period.

FOREIGN EXCHANGE GAINS AND LOSSES

Foreign exchange gains and losses from the translation of specified foreign currency financial instruments are deferred. Foreign exchange gains and losses are subject to external market forces over which BC Hydro has no control. The account balance is amortized using the straight-line pool method over the weighted average life of the related debt.

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.

OTHER REGULATORY ACCOUNTS

Other regulatory asset and liability accounts with individual balances less than $50 million include the following: Real Property Sales, Capital Project Investigation Costs, Arrow Water Systems Provisions, Arrow Water Systems (Costs), Dismantling Cost, PEB Current Pension Costs, Customer Crisis Fund and Amortization of Capital Additions.

NOTE 15: ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Accounts payable	**$ 359**	$ 259	$ 224
Accrued liabilities	**908**	995	792
Current portion of other long-term liabilities (Note 21)	**100**	136	97
Dividend payable (Note 18)	**59**	159	-
Other	**52**	54	59
	$ 1,478	$ 1,603	$ 1,172

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NOTE 16: 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 $4.50 billion and is included in revolving borrowings. At March 31, 2019, the outstanding amount under the borrowing program was $2.95 billion (2018 - $2.05 billion, April 1, 2017 - $2.84 billion).

For the year ended March 31, 2019, the Company issued bonds for net proceeds of $2.42 billion (2018 - $1.16 billion) and a par value of $2.45 billion (2018 - $1.20 billion), a weighted average effective interest rate of 3.0 per cent (2018 - 2.9 per cent) and a weighted average term to maturity of 19.8 years (2018 - 20.3 years).

For the year ended March 31, 2019, the Company redeemed bonds with par value of $1.29 billion (2018 – par value of $40 million).

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

(in millions)	March 31, 2019					March 31, 2018					April 1, 2017				
	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:															
2018	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ 40	$ -	$ -	$ 40	4.9
2019	-	-	-	-	-	1,030	258	-	1,288	4.4	1,030	267	-	1,297	4.4
2020	175	-	-	175	5.3	175	-	-	175	5.3	175	-	-	175	5.3
2021	1,100	-	-	1,100	7.5	1,100	-	-	1,100	7.5	1,100	-	-	1,100	7.5
2022	526	-	-	526	7.8	526	-	-	526	7.8	526	-	-	526	7.8
2023	500	-	-	500	6.8	500	-	-	500	6.8	-	-	-	-	-
2024	200	-	-	200	5.9	-	-	-	-	-	-	-	-	-	-
1-5 years	2,501	-	-	2,501	7.2	3,331	258	-	3,589	6.2	2,871	267	-	3,138	6.1
6-10 years	3,960	668	395	5,023	3.1	2,860	644	418	3,922	3.2	2,460	666	376	3,502	3.9
11-15 years	1,610	-	207	1,817	4.5	1,610	-	219	1,829	4.5	1,910	-	-	1,910	4.6
16-20 years	-	400	-	400	7.4	-	387	-	387	7.4	-	400	197	597	5.2
21-25 years	3,273	-	-	3,273	4.3	3,273	-	-	3,273	4.3	1,250	-	-	1,250	4.9
26-30 years	5,985	-	-	5,985	3.5	2,565	-	-	2,565	3.7	4,588	-	-	4,588	3.9
Over 30 years	560	-	-	560	3.1	2,830	-	-	2,830	3.3	2,230	-	-	2,230	3.4
Bonds	17,889	1,068	602	19,559	4.1	16,469	1,289	637	18,395	4.3	15,309	1,333	573	17,215	4.4
Revolving borrowings	2,743	202	-	2,945	1.8	1,817	236	-	2,053	1.3	2,284	554	-	2,838	0.6
	20,632	1,270	602	22,504		18,286	1,525	637	20,448		17,593	1,887	573	20,053	
Adjustments to carrying value resulting from discontinued hedging activities	13	22	-	35		17	22	-	39		20	24	-	44	
Unamortized premium, discount, and issue costs	(143)	(10)	(4)	(157)		(107)	(11)	(5)	(123)		(56)	(12)	(5)	(73)	
	$ 20,502	$ 1,282	$ 598	$ 22,382		$ 18,196	$ 1,536	$ 632	$ 20,364		$ 17,557	$ 1,899	$ 568	$ 20,024	
Less: Current portion	(2,919)	(202)	-	(3,121)		(2,850)	(494)	-	(3,344)		(2,324)	(554)	-	(2,878)	
Non-current long-term debt	$ 17,583	$ 1,080	$ 598	$ 19,261		$ 15,346	$ 1,042	$ 632	$ 17,020		$ 15,233	$ 1,345	$ 568	$ 17,146	

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

The following foreign currency contracts were in place at March 31, 2019 in a net asset position of $24 million (2018 - $105 million, April 1, 2017 - $41 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Cross-Currency Swaps			
Euro dollar to Canadian dollar - notional amount[1]	**€ 402**	€ 402	€ 402
Euro dollar to Canadian dollar - weighted average contract rate	**1.47**	1.47	1.47
Weighted remaining term	**9 years**	10 years	11 years
Foreign Currency Forwards			
United States dollar to Canadian dollar - notional amount[1]	**US$ 741**	US$ 1,012	US$ 1,241
United States dollar to Canadian dollar - weighted average contract rate	**1.27**	1.22	1.26
Weighted remaining term	**8 years**	7 years	6 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, 2019 with a net liability position of $285 million (2018 – net asset of $83 million, April 1, 2017 – net asset of $194 million). Such contracts are used to lock in interest rates on future Canadian denominated debt issues. The contracts outstanding relate to $6.05 billion of planned 10 and 30 year debt to be issued on dates ranging from June 2019 to June 2024.

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Bond Locks			
Canadian dollar - notional amount[1]	**$ 600**	$ 1,250	$ 400
Weighted forecast borrowing yields	**3.06%**	3.17%	2.54%
Weighted remaining term	**< 1 year**	< 1 year	< 1 year
Forward Swaps			
Canadian dollar - notional amount[1]	**$ 5,450**	$ 3,625	$ 3,200
Weighted forecast borrowing yields	**3.11%**	2.76%	2.47%
Weighted remaining term	**2 years**	2 years	2 years

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

For more information about the Company’s exposure to interest rate, foreign currency and liquidity risk, see Note 20.

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SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Reconciliation for liabilities arising from financing activities:

($millions)	Balance, March 31, 2018	Issued	Redemptions	Foreign exchange movement	Other[1]	Payment (Proceeds)	Balance March 31, 2019
Long-term debt and revolving borrowings:							
Long-term debt	$ 18,311	$ 2,418	$ (1,287)	$ 2	$ (7)	$ -	$ 19,437
Revolving borrowings	2,053	8,865	(7,981)	-	8	-	2,945
Total long-term debt and revolving borrowings	20,364	11,283	(9,268)	2	1	-	22,382
Finance lease obligation (Note 20)	665	-	-	-	-	(11)	654
Vendor financing liability	320	-	-	-	27	(9)	338
Debt-related derivative liability	(182)	-	-	-	345	100	263
	$ 21,167	$ 11,283	$ (9,268)	$ 2	$ 373	$ 80	$ 23,637

($millions)	Balance, April 1, 2017	Issued	Redemptions	Foreign exchange movement	Other[1]	Payment (Proceeds)	Balance March 31, 2018
Long-term debt and revolving borrowings:							
Long-term debt	$ 17,186	$ 1,156	$ (40)	$ 20	$ (11)	$ -	$ 18,311
Revolving borrowings	2,838	7,749	(8,536)	-	2	-	2,053
Total long-term debt and revolving borrowings	20,024	8,905	(8,576)	20	(9)	-	20,364
Finance lease obligation (Note 20)	219	-	-	-	466	(20)	665
Vendor financing liability	236	-	-	-	84	-	320
Debt-related derivative liability	(235)	-	-	-	(29)	82	(182)
	$ 20,244	$ 8,905	$ (8,576)	$ 20	$ 512	$ 62	$ 21,167

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

NOTE 17: UNEARNED REVENUES AND CONTRIBUTIONS IN AID

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Unearned revenues	**$ 230**	$ 210	$ 183
Contributions in aid	**1,762**	1,633	1,519
	1,992	1,843	1,702
Less: Current portion, unearned revenues	**(40)**	(38)	(38)
Less: Current portion, contributions in aid	**(47)**	(47)	(44)
	$ 1,905	$ 1,758	$ 1,620

NOTE 18: 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, 2019, March 31, 2018 and April 1, 2017 was as follows:

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Total debt, net of sinking funds	**$ 22,185**	$ 20,182	$ 19,845
Less: Cash and cash equivalents	**(84)**	(42)	(49)
Net Debt	**$ 22,101**	$ 20,140	$ 19,796
Retained earnings	**$ 4,934**	$ 5,421	$ 4,896
Contributed surplus	**60**	60	60
Accumulated other comprehensive loss	**(47)**	(34)	(56)
Total Equity	**$ 4,947**	$ 5,447	$ 4,900
Net Debt to Equity Ratio	**82 : 18**	79 : 21	80 : 20

Payment to the Province

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

The fiscal 2018 Payment to the Province was $159 million and was paid in June 2018. As a result, the Payment for fiscal 2019 will be $59 million and the Company has accrued $59 million as at March 31, 2019.

NOTE 19: EMPLOYEE BENEFITS – POST-EMPLOYMENT BENEFIT PLANS

The Company provides a defined benefit statutory 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. 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 unfunded. The most recent actuarial funding valuation for the statutory pension plan was performed at December 31, 2015. The next valuation for funding purposes will be prepared as at December 31, 2018, and the results will be available in September 2019.

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.

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, 2019 and 2018 is recognized in the following line items in the statement of comprehensive income (loss) 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)	**2019**	2018	**2019**	2018	**2019**	2018
Current service costs charged to personnel operating costs	**$ 100**	$ 86	**$ 8**	$ 15	**$ 108**	$ 101
Net interest costs charged to finance costs	**46**	45	**10**	17	**56**	62
Total post-employment benefit plan expense	**$ 146**	$ 131	**$ 18**	$ 32	**$ 164**	$ 163

Actuarial loss recognized in other comprehensive income (loss) are $173 million (2018 – gain of $193 million).

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

(in millions)	Pension Benefits Plans March 31, 2019	March 31, 2018	April 1, 2017	Other Benefits Plans March 31, 2019	March 31, 2018	April 1, 2017	Total March 31, 2019	March 31, 2018	April 1, 2017
Defined benefit obligation of funded plan	**$ (5,035)**	$ (4,654)	$ (4,431)	**$ -**	$ -	$ -	**$ (5,035)**	$ (4,654)	$ (4,431)
Defined benefit obligation of unfunded plans	**(186)**	(164)	(160)	**(278)**	(272)	(435)	**(464)**	(436)	(595)
Fair value of plan assets	**3,747**	3,616	3,460	**-**	-	-	**3,747**	3,616	3,460
Plan deficit	**$ (1,474)**	$ (1,202)	$ (1,131)	**$ (278)**	$ (272)	$ (435)	**$ (1,752)**	$ (1,474)	$ (1,566)
Represented by:									
Accrued benefit plan liability	**$ (1,474)**	$ (1,202)	$ (1,131)	**$ (278)**	$ (272)	$ (435)	**$ (1,752)**	$ (1,474)	$ (1,566)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2019 and fiscal 2018 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:

(in millions)	Pension Benefit Plans March 31, 2019	March 31, 2018	Other Benefit Plans March 31, 2019	March 31, 2018
Defined benefit obligation				
Opening defined benefit obligation	**$ 4,818**	$ 4,591	**$ 272**	$ 435
Current service cost	**100**	86	**8**	15
Interest cost on benefit obligations	**191**	202	**10**	17
Benefits paid[1]	**(183)**	(180)	**(8)**	(13)
Employee contributions	**41**	38	**-**	-
Actuarial losses (gains)[2]	**254**	81	**(4)**	(182)
Defined benefit obligation, end of year	**5,221**	4,818	**278**	272
Fair value of plan assets				
Opening fair value	**3,616**	3,460	**n/a**	n/a
Interest income on plan assets[3]	**145**	157	**n/a**	n/a
Employer contributions	**44**	42	**n/a**	n/a
Employee contributions	**41**	38	**n/a**	n/a
Benefits paid[1]	**(176)**	(173)	**n/a**	n/a
Actuarial gains (losses)[2,3]	**77**	92	**n/a**	n/a
Fair value of plan assets, end of year	**3,747**	3,616	**-**	-
Accrued benefit liability	**$ (1,474)**	$ (1,202)	**$ (278)**	$ (272)

[1] *Benefits paid under Pension Benefit Plans include $13 million (2018 - $15 million) of settlement payments.*

[2] *Actuarial gains/losses are included in the Non-Current Pension Costs regulatory account and for fiscal 2019 are comprised of $77 million of experience gains on return of plan assets and $250 million of net actuarial losses on the benefit obligations due to discount rate changes and actuarial assumption changes.*

[3] *Actual income on defined benefit plan assets for the year ended March 31, 2019 was $222 million (2018 - $249 million).*

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(d) The significant assumptions adopted in measuring the Company's accrued benefit obligations as at each March 31 year end and April 1 are as follows:

	Pension Benefit Plans			**Other Benefit Plans**		
	March 31, 2019	March 31, 2018	April 1, 2017	**March 31, 2019**	March 31, 2018	April 1, 2017
Discount rate						
Benefit cost	**3.56%**	3.68%	3.81%	**3.54%**	3.92%	3.72%
Accrued benefit obligation	**3.33%**	3.56%	3.68%	**3.24%**	3.54%	3.92%
Rate of return on plan assets	**3.56%**	3.68%	4.00%	**n/a**	n/a	n/a
Rate of compensation increase						
Benefit cost	**3.00%**	3.00%	3.35%	**3.00%**	3.00%	3.35%
Accrued benefit obligation	**3.50%**	3.00%	3.00%	**3.50%**	3.00%	3.00%
Health care cost trend rates						
Weighted average health care cost trend rate	**n/a**	n/a	n/a	**3.58%**	4.57%	5.03%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	n/a	**2.81%**	3.47%	4.29%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	n/a	**2040**	2026	2026

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

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

		Target Range		**March 31,**	March 31,	April 1,
	Target Allocation	**Min**	**Max**	**2019**	2018	2017
Equities	55%	35%	75%	**57%**	56%	61%
Fixed interest investments	20%	15%	35%	**26%**	29%	26%
Real estate	15%	5%	20%	**10%**	9%	8%
Infrastructure and renewable resources	10%	5%	15%	**7%**	6%	5%

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.

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

The Company's contribution to be paid to its funded defined benefit plan in fiscal 2020 is expected to amount to $45 million. The expected benefit payments to be paid in fiscal 2020 in respect to the unfunded defined benefit plans are $18 million.

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 2019	One percentage point decrease 2019
Effect on current service costs	$ -	$ -
Effect on defined benefit obligation	4	(5)

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

		2019	
($ in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	-593	-34
Discount rate	1% decrease	+ 766	+48
Longevity	1 year	+/- 119	+/- 3

NOTE 20: 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 2019 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 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 statement of financial position at $197 million and $148 million respectively. The maximum credit risk exposure for the U.S. dollar sinking funds, and non-current receivables as at March 31, 2019 is their fair value of $220 million and $159 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 16). The Company's long-term debt comprises bonds and revolving borrowings obtained under an agreement with the Province. Cash from operations reduces the Company's liquidity risk. The Company does not believe that it will encounter difficulty in meeting its obligations associated with financial liabilities.

(c) Market Risks

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

(i) Currency Risk

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

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

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

(ii) Interest Rate Risk

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

(iii) Commodity Price Risk

Commodity price risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company has exposure to movements in prices for commodities including electricity, natural gas 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, 2019 and 2018 and April 1, 2017. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

	March 31, 2019		March 31, 2018		April 1, 2017		**2019**	2018
(in millions)	**Carrying Value**	**Fair Value**	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 (FVPTL):								
Cash equivalents - short-term investments	**$ 50**	**$ 50**	$ 31	$ 31	$ 24	$ 24	**$ 3**	$ -
Amortized Cost:								
Cash	**34**	**34**	11	11	25	25	**-**	-
Restricted cash	**109**	**109**	77	77	28	28	**-**	-
Accounts receivable and accrued revenue	**912**	**912**	728	728	761	761	**-**	-
Non-current receivables	**148**	**159**	194	195	239	243	**9**	11
Sinking funds	**197**	**220**	182	201	179	197	**9**	8
Accounts payable and accrued liabilities	**(1,478)**	**(1,478)**	(1,603)	(1,603)	(1,172)	(1,172)	**-**	-
Revolving borrowings	**(2,945)**	**(2,945)**	(2,053)	(2,053)	(2,838)	(2,838)	**(39)**	(20)
Long-term debt (including current portion due in one year)	**(19,437)**	**(22,480)**	(18,311)	(20,814)	(17,186)	(19,601)	**(815)**	(775)
First Nations liabilities (non-current portion)	**(391)**	**(640)**	(399)	(652)	(394)	(549)	**(17)**	(17)
Finance lease obligations (non-current portion)	**(642)**	**(642)**	(653)	(653)	(197)	(197)	**(42)**	(18)
Other liabilities	**(419)**	**(434)**	(409)	(416)	(336)	(342)	**(18)**	-

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.

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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, 2019 in a net asset position of $22 million (2018 – net asset $99 million, April 1, 2017 – net asset $41 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, 2019**		March 31, 2018		April 1, 2017
Cross- Currency Hedging Swaps						
Euro dollar to Canadian dollar - notional amount[1]	**€**	**402**	€	402	€	402
Euro dollar to Canadian dollar - weighted average contract rate		**1.47**		1.47		1.47
Weighted remaining term		**9 years**		10 years		11 years
Foreign Currency Hedging Forwards						
United States dollar to Canadian dollar - notional amount[1]	**US$**	**573**	US$	773	US$	773
United States dollar to Canadian dollar - weighted average contract rate		**1.25**		1.19		1.19
Weighted remaining term		**11 years**		9 years		10 years

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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The fair value of derivative instruments designated and not designated as hedges, was as follows:

(in millions)	**March 31, 2019 Fair Value**	March 31, 2018 Fair Value	April 1, 2017 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:			
Foreign currency contract assets (cash flow hedges for $US denominated long-term debt)	**$ 10**	$ 59	$ 72
Foreign currency contract liabilities (cash flow hedges for $US denominated long-term debt)	**-**	(8)	(4)
Foreign currency contract assets (cash flow hedges for €EURO denominated long-term debt)	**12**	48	-
Foreign currency contract liabilities (cash flow hedges for €EURO denominated long-term debt)	**-**	-	(27)
	22	99	41
Non-Designated Derivative Instruments:			
Interest rate contract assets	**25**	180	194
Interest rate contract liabilities	**(310)**	(97)	-
Foreign currency contract assets	**2**	6	-
Commodity derivative assets	**78**	36	90
Commodity derivative liabilities	**(74)**	(72)	(67)
	(279)	53	217
Net (liability) asset	**$ (257)**	$ 152	$ 258

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 statement of financial position as follows:

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Current portion of derivative financial instrument assets	**$ 79**	$ 174	$ 144
Current portion of derivative financial instrument liabilities	**(89)**	(112)	(60)
Derivative financial instrument assets, non-current	**49**	156	215
Derivative financial instrument liabilities, non-current	**(296)**	(66)	(41)
Net (liability) asset	**$ (257)**	$ 152	$ 258

For designated cash flow hedges for the year ended March 31, 2019, a loss of $24 million (2018 – gain of $57 million) was recognized in other comprehensive income. For the year ended March 31, 2019, $8 million (2018 - $30 million) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange gains on the underlying hedged item (2018 - losses) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $6.05 billion (2018 - $4.90 billion, April 1, 2017 - $3.60 billion), used to economically hedge the interest rates on future debt issuances, there was a $335 million decrease (2018 - $41 million decrease) in the fair value of these contracts for the year ended March 31, 2019. For interest rate contracts associated with debt issued, there was a $14 million increase (2018 - $12 million increase) in the fair value of contracts that settled during the year ended March 31, 2019. The net decrease for the year ended March 31, 2019 of $321 million (2018 - $29 million) in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had an asset balance of $163 million as at March 31, 2019.

For foreign currency contracts not designated as hedges for the year ended March 31, 2019, a gain of $1 million (2018 – loss of $2 million) was recognized in finance charges with respect to foreign currency contracts for cash management purposes. For foreign currency contracts not designated as hedges, which are comprised primarily of foreign currency contracts for U.S. revolving borrowings, for the year ended March 31, 2019, such contracts had a gain of $3 million (2018 - loss of $53 million) recognized in finance charges. These economic hedges offset $1 million of foreign exchange revaluation losses (2018 – gain of $56 million) recorded in finance charges with respect to U.S. revolving borrowings for the year ended March 31, 2019.

For commodity derivatives not designated as hedges, a net gain of $266 million (2018 - loss of $67 million) was recorded in trade revenue for the year ended March 31, 2019.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)		**2019**		2018
Deferred inception loss, beginning of the year	**$**	**22**	$	36
New transactions		**(43)**		(12)
Amortization		**35**		(1)
Foreign currency translation (gain) loss		**-**		(1)
Deferred inception loss, end of the year	**$**	**14**	$	22

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:

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

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Current	**$ 592**	$ 448	$ 515
Past due (30-59 days)	**31**	32	31
Past due (60-89 days)	**7**	7	7
Past due (More than 90 days)	**16**	12	1
	646	499	554
Less: Allowance for doubtful accounts	**(6)**	(7)	(7)
	$ 640	$ 492	$ 547

At the end of each period, a review of the provision for doubtful accounts is performed. It is an assessment of the expected lifetime credit losses of domestic and trade accounts receivable at the statement of financial position date. The assessment is made by reference to age, status and risk of each receivable, current economic conditions, and historical information.

Financial Assets Arising from the Company's Trading Activities

The Company's counterparties span a variety of industries. There is no significant industry concentration of credit risk. The Company's management of credit risk generally includes evaluation of counterparties' 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 use of master netting agreements and margining provisions in contracts. Counterparty exposures are monitored on a daily basis against established credit limits.

The Company enters into derivative master netting agreements or similar agreements, and presents these transactions on a gross basis under derivative commodity assets/liabilities in the Statement of Financial Position.

The following table sets out the carrying amounts of recognized financial instruments presented in the statement of financial position that are subject to the above agreements:

(in millions)	Gross Derivative Instruments	Related Instruments Not Offset	Net Amount
As at March 31, 2019			
Derivative commodity assets	**$ 78**	**$ 1**	**$ 77**
Derivative commodity liabilities	**74**	**1**	**73**
As at March 31, 2018			
Derivative commodity assets	$ 36	$ 2	$ 34
Derivative commodity liabilities	72	2	70
As at April 1, 2017			
Derivative commodity assets	$ 90	$ 1	$ 89
Derivative commodity liabilities	67	1	66

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LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2019 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, 2019. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2019 has been used.

(in millions)	**Carrying Value**	**Fiscal 2020**	**Fiscal 2021**	**Fiscal 2022**	**Fiscal 2023**	**Fiscal 2024**	**Fiscal 2025** ***and thereafter***
Non-Derivative Financial Liabilities							
Total accounts payable and other payables (excluding interest accruals and current portion of lease obligations and First Nations liabilities)	$ 1,238	$ (1,238)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	22,591	(3,928)	(1,862)	(1,218)	(1,158)	(835)	(25,846)
Lease obligations	654	(54)	(54)	(54)	(54)	(55)	(1,037)
Other long-term liabilities	829	(125)	(61)	(57)	(56)	(55)	(1,831)
Total Non-Derivative Financial Liabilities	25,312	(5,345)	(1,977)	(1,329)	(1,268)	(945)	(28,714)
Derivative Financial Liabilities							
Forward foreign exchange contracts used for hedging	-						
Cash outflow		-	-	-	-	-	(169)
Cash inflow		-	-	-	-	-	174
Interest rate swaps and bond locks used for hedging	310	(26)	(81)	(97)	(73)	(44)	(3)
Total Derivative Financial Liabilities	310	(26)	(81)	(97)	(73)	(44)	2
Total Financial Liabilities	25,622	(5,371)	(2,058)	(1,426)	(1,341)	(989)	(28,712)
Derivative Financial Assets							
Cross currency swaps used for hedging	(12)						
Cash outflow		(14)	(14)	(14)	(14)	(14)	(651)
Cash inflow		5	5	5	5	5	622
Forward foreign exchange contracts used for hedging	(10)						
Cash outflow		-	-	-	-	-	(550)
Cash inflow		-	-	-	-	-	591
Other forward foreign exchange contracts designated at fair value	(2)						
Cash outflow		(223)	-	-	-	-	-
Cash inflow		225	-	-	-	-	-
Interest rate swaps used for hedging	(25)	9	16	-	-	-	-
Net commodity derivatives	(4)	1	(12)	-	1	1	1
Total Derivative Financial Assets	(53)	3	(5)	(9)	(8)	(8)	13
Net Financial Liabilities	**$ 25,569**	**$ (5,368)**	**$ (2,063)**	**$ (1,435)**	**$ (1,349)**	**$ (997)**	**$ (28,699)**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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MARKET RISKS

(a) Currency Risk

Sensitivity Analysis
A $0.01 strengthening (weakening) of the U.S. dollar against the Canadian dollar at March 31, 2019 would otherwise have a negative (positive) impact of $1 million on net income before movement in regulatory balances but as a result of regulatory accounting 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 14) 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, 2019 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 statement of financial position date.

(b) Interest Rate Risk

Sensitivity analysis for variable rate non-derivative instruments
An increase (decrease) of 100-basis points in interest rates at March 31, 2019 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 14) 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, 2019 would otherwise have a positive impact on net income of $790 million and a decrease of 100 basis points in interest rates at March 31, 2019 would otherwise have a negative impact on net income before movement in regulatory balances of $980 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, 2019 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 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% 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 $10 million at March 31, 2019 (2018 - $6 million, April 1, 2017 - $8 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 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, 2019 and 2018, and April 1, 2017:

As at March 31, 2019 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 50	$ -	$ -	$ 50
Derivatives designated as hedges	-	22	-	22
Derivatives not designated as hedges	64	38	4	106
	$ 114	$ 60	$ 4	$ 178

As at March 31, 2019 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ -	$ -	$ -
Derivatives not designated as hedges	(47)	(325)	(13)	(385)
	$ (47)	$ (325)	$ (13)	$ (385)

As at March 31, 2018 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 31	$ -	$ -	$ 31
Derivatives designated as hedges	-	107	-	107
Derivatives not designated as hedges	17	201	5	223
	$ 48	$ 308	$ 5	$ 361

As at March 31, 2018 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (8)	$ -	$ (8)
Derivatives not designated as hedges	(62)	(106)	(2)	(170)
	$ (62)	$ (114)	$ (2)	$ (178)

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As at April 1, 2017 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 24	$ -	$ -	$ 24
Derivatives designated as hedges	-	72	-	72
Derivatives not designated as hedges	39	207	41	287
	$ 63	$ 279	$ 41	$ 383

As at April 1, 2017 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (31)	$ -	$ (31)
Derivatives not designated as hedges	(52)	(14)	(4)	(70)
	$ (52)	$ (45)	$ (4)	$ (101)

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 of $1 million were transferred from Level 2 to Level 1 as the Company now uses observable price quotations (2018 – no transfers).

The following table reconciles the changes in the balance of financial instruments carried at fair value on the statement of financial position, classified as Level 3, for the years ended March 31, 2019 and 2018:

(in millions)	
Balance as at April 1, 2018	**$ 3**
Net loss recognized	(34)
New transactions	8
Transfer from Level 3 to Level 2	-
Existing transactions settled	14
Balance as at March 31, 2019	**$ (9)**

(in millions)	
Balance as at April 1, 2017	**$ 37**
Net loss recognized	(31)
New transactions	(5)
Transfer from Level 3 to Level 2	(7)
Existing transactions settled	9
Balance as at March 31, 2018	**$ 3**

During the year ended March 31, 2019, there were no transfers between Level 3 and Level 2 (2018 – $7 million transferred from Level 3 to Level 2).

During the year ended March 31, 2019, unrealized losses of $14 million (2018 – losses of $14 million) were recognized on Level 3 derivative commodity financial instruments still on hand. These 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 include components of forward commodity prices and delivery or receipt volumes. A sensitivity analysis was prepared using the Company's assessment of reasonably possible changes in various components of forward prices and volumes of 10 percent. Forward commodity prices used in determining Level 3 fair value at March 31, 2019 are $7-$123 per MWh and a 10 percent increase/decrease in certain components of these prices would decrease/increase fair value by $1 million. A 10 percent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $15 million.

NOTE 21: OTHER NON-CURRENT LIABILITIES

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Provisions			
Environmental liabilities	**$ 284**	$ 317	$ 339
Decommissioning obligations	**53**	53	52
Other	**30**	70	27
	367	440	418
First Nations liabilities	**410**	401	394
Finance lease obligations	**654**	665	219
Other contributions	**238**	242	246
Other liabilities	**419**	409	336
	2,088	2,157	1,613
Less: Current portion, included in accounts payable and accrued liabilities	**(100)**	(136)	(97)
	$ 1,988	$ 2,021	$ 1,516

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

	Environmental	**Decommissioning**	**Other**	**Total**
Balance at April 1, 2017	**$ 339**	**$ 52**	**$ 27**	**$ 418**
Made during the period	-	-	47	47
Used during the period	(25)	(1)	(4)	(30)
Changes in estimate	(1)	1	-	-
Accretion	4	1	-	5
Balance at March 31, 2018	**$ 317**	**$ 53**	**$ 70**	**$ 440**
Made during the period	-	-	26	26
Used during the period	(32)	(1)	(67)	(100)
Reversed during the period	(9)	-	(1)	(10)
Changes in estimate	2	-	2	4
Accretion	6	1	-	7
Balance at March 31, 2019	**$ 284**	**$ 53**	**$ 30**	**$ 367**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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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, 2019, the undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2020 and 2045, is approximately $328 million and was determined based on current cost estimates. A range of discount rates between 1.6 per cent and 1.9 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 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 $77 million (2018 - $80 million, April 1, 2017 - $80 million), which will be settled between fiscal 2020 and 2054. The undiscounted cash flows are then discounted by a range of discount rates between 1.6 per cent and 1.9 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.

Finance Lease Liabilities

The finance lease obligations are related to long-term energy purchase agreements. The present value of the lease obligations were discounted at rates ranging from 5.6 per cent to 7.9 per cent with contract terms of 25 to 30 years expiring from 2036 until 2048. Finance lease liabilities are payable as follows:

	March 31, 2019			March 31, 2018			April 1, 2017		
(in millions)	**Future minimum lease payments**	**Interest**	**Present value of minimum lease payments**	Future minimum lease payments	Interest	Present value of minimum lease payments	Future minimum lease payments	Interest	Present value of minimum lease payments
Less than one year	**$ 54**	**$ 42**	**$ 12**	$ 54	$ 42	$ 12	$ 40	$ 18	$ 22
Between one and five years	**217**	**158**	**59**	216	161	55	84	60	24
More than five years	**1,037**	**454**	**583**	1,091	493	598	291	118	173
Total minimum lease payments	**$ 1,308**	**$ 654**	**$ 654**	$ 1,361	$ 696	$ 665	$ 415	$ 196	$ 219

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 13) 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 include a contractual obligation associated with the construction of assets. The contractual obligation has an implied interest rate of 7 per cent and a repayment term of 15 years commencing in fiscal 2019. The liability is measured at amortized cost and not re-measured for changes in discount rates.

NOTE 22: 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 $51.08 billion of which approximately $101 million relates to the purchase of natural gas and natural gas transportation contracts. The remaining commitments are at predetermined prices. Included in the total value of the long-term energy purchase agreements is $1.31 billion accounted for as obligations under capital leases. The total BC Hydro combined payments are estimated to be approximately $1.49 billion for less than one year, $6.17 billion between one and five years, and $43.42 billion for more than five years and up to 57 years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $1.82 billion extending to 2034. The total Powerex energy purchase commitments are estimated to be approximately $539 million for less than one year, $1.2 billion between one and five years, and $85 million for more than five years. Powerex has energy sales commitments of $559 million extending to 2031 with estimated amounts of $332 million for less than one year, $212 million between one and five years, and $15 million for more than five years.

Lease and Service Agreements

The Company has entered into various agreements to lease facilities or assets classified as operating leases, or service agreements supporting operations. The agreements cover periods of up to 70 years, and the aggregate minimum payments are approximately $873 million. Payments are $74 million for less than one year, $113 million between one and five years, and $686 million for more than five years.

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

Contingencies and Guarantees

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

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

c) The Company and its subsidiaries have outstanding letters of credit to secure pension plan solvency deficiency payments related to the registered pension plan totaling $1.27 billion (2018 - $1.17 billion, April 1, 2017 – 1.12 billion), which includes US $25 million (2018 - US $12 million, April 1, 2017 – US $21 million) in foreign denominated letters of credit.

NOTE 23: RELATED PARTY TRANSACTIONS

Subsidiaries

The principal subsidiaries of BC Hydro are Powerex, Powertech, and Columbia.

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. Columbia provides construction services in support of certain BC Hydro capital programs.

All intercompany transactions and balances are eliminated upon consolidation.

Related Parties

As a Crown Corporation, the Company and the Province are considered related parties. All transactions between the Company and its related parties are considered to possess commercial substance and are consequently recorded at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The related party transactions are summarized below:

(in millions)	**March 31, 2019**	March 31, 2018	April 1, 2017
Consolidated Statement of Financial Position			
Prepaid expenses	**$ 87**	$ 95	$ 93
Accounts payable and accrued liabilities	**139**	222	57

	2019	2018
Amounts incurred/accrued during the year include:		
Water rental fees	**331**	324
Cost of energy	**202**	111
Grants and Taxes	**141**	138
Interest	**854**	797
Payment to the Province	**59**	159

The Company's debt is either held or guaranteed by the Province (see Note 16). 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, 2019, the aggregate exposure under this indemnity totaled $49 million (2018 - $293 million, April 1, 2017 - $266 million). The Company has not experienced any losses to date under this indemnity.

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)	**2019**	2018
Short-term employee benefits	**$ 4**	$ 4
Post-employment benefits	**1**	1

NOTE 24: EXPLANATION OF TRANSITION TO IFRS

As stated in Note 2, these are the Company's first consolidated financial statements prepared in accordance with IFRS. As IFRS require comparative financial information, the Company has applied IFRS 1, *First-time Adoption* of IFRS on the transition date of April 1, 2017.

The accounting policies set out in Note 3 have been applied in preparing the consolidated financial statements for the year ended March 31, 2019, the comparative information presented in these consolidated financial statements for the year ended March 31, 2018 and in preparation of an opening statement of financial position at April 1, 2017.

In adopting IFRS, the Company has applied the recognition, measurement, presentation and disclosure principles of IFRS 1 in preparing its transitional adjustments and consolidated financial statements. The principles of IFRS 1 generally require that first-time adopters of a new set of accounting policies retrospectively apply all effective standards and interpretations in effect as at the reporting date. However, IFRS 1 also provides optional and mandatory exemptions to the requirement for full retrospective application of IFRS. The Company has applied the following relevant mandatory and optional exemptions in the opening IFRS consolidated statement of financial position:

IFRS mandatory exemptions:

a) Estimates

The Company's estimates under IFRS at the date of transition were consistent with estimates made under the Prescribed Standards. Estimates previously made were not revised for changes under IFRS except to reflect any difference in accounting policies.

IFRS optional exemptions:

a) Fair Value as Deemed Cost

Entities that hold items of property, plant and equipment or intangible assets used in operations subject to rate regulation are permitted under IFRS 1 to elect to use their carrying amounts as deemed cost at the date of transition to IFRS. The Company has elected to apply this exemption except for assets impacted by elections (b) and (d) in this section.

b) Leases
IFRS 1 allows entities to apply the transitional provision in IFRIC 4 – *Determining whether an Arrangement contains a Lease,* which allows the Company to determine whether an arrangement existing at the date of transition to IFRS contains a lease on the basis of facts and circumstances existing at that date. This election has been applied to all leases.

c) Cumulative Translation Differences

IAS 21, *The Effects of Changes in Foreign Exchange Rates* requires an entity to recognize foreign exchange differences arising on translation of subsidiaries with a different functional currency in other comprehensive income and accumulate these in a separate component of equity. However, IFRS 1 allows entities to not comply with these requirements for cumulative translation differences that existed at the date of transition to IFRS. This election has been applied to the operations of Powerex with all related cumulative translation differences deemed to be zero at the date of transition.

d) Decommissioning liabilities

IFRIC 1, *Changes in Existing Decommissioning, Restoration and Similar Liabilities* requires specified changes in a decommissioning, restoration or similar liability to be adjusted against the cost of the asset to which it relates with the adjusted amount depreciated prospectively over its remaining useful life. IFRS 1 provides an exemption from complying with these requirements for changes in such liabilities that occurred before the date of transition to IFRS. The Company has applied this exemption to existing asset retirement obligations recognized under the Prescribed Standards and to new obligations recognized on transition to IFRS.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2019 AND 2018

In preparing its opening statement of financial position, the Company has adjusted amounts reported previously in financial statements prepared in accordance with the Prescribed Standards. An explanation of how the transition from the Prescribed Standards to IFRS has affected the Company's financial position, and financial performance is set out in the following tables and the notes that accompany the tables. The transition to IFRS did not have a material impact to the Company's cash flows.

Reconciliation of Consolidated Statement of Financial Position

		April 1, 2017				March 31, 2018			
(in millions)	Note	Prescribed Standards	Effect of Transition	IFRS 14 Presentation Reclass[f]	**IFRS**	Prescribed Standards	Effect of Transition	IFRS 14 Presentation Reclass[f]	**IFRS**
ASSETS									
Current Assets									
Cash and cash equivalents		$ 49	$ -	$ -	**$ 49**	$ 42	$ -	$ -	**$ 42**
Restricted cash		28	-	-	**28**	77	-	-	**77**
Accounts receivable and accrued revenue	c, d	780	(19)	-	**761**	733	(5)	-	**728**
Inventories		185	-	-	**185**	144	-	-	**144**
Prepaid expenses		162	-	-	**162**	167	-	-	**167**
Current portion of derivative financial instrument assets		144	-	-	**144**	174	-	-	**174**
		1,348	(19)	-	**1,329**	1,337	(5)	-	**1,332**
Non-Current Assets									
Property, plant and equipment	a, b	22,998	(4)	-	**22,994**	25,083	(4)	-	**25,079**
Intangible assets		601	-	-	**601**	591	-	-	**591**
Regulatory assets	c, g	6,127	-	(6,127)	**-**	5,892	(1)	(5,891)	**-**
Derivative financial instrument assets		215	-	-	**215**	156	-	-	**156**
Other non-current assets	c	599	(39)	-	**560**	683	(51)	-	**632**
		30,540	(43)	(6,127)	**24,370**	32,405	(56)	(5,891)	**26,458**
Total Assets		31,888	(62)	(6,127)	**25,699**	33,742	(61)	(5,891)	**27,790**
Regulatory Balances		-	-	6,127	**6,127**	-	-	5,891	**5,891**
Total Assets and Regulatory Balances		$ 31,888	$ (62)	$ -	**$ 31,826**	$ 33,742	$ (61)	$ -	**$ 33,681**
LIABILITIES AND EQUITY									
Current Liabilities									
Accounts payable and accrued liabilities	c	$ 1,190	$ (18)	$ -	**$ 1,172**	$ 1,621	$ (18)	$ -	**$ 1,603**
Current portion of long-term debt		2,878	-	-	**2,878**	3,344	-	-	**3,344**
Current portion of unearned revenues and contributions in aid	c	-	82	-	**82**	-	85	-	**85**
Current portion of derivative financial instrument liabilities		60	-	-	**60**	112	-	-	**112**
		4,128	64	-	**4,192**	5,077	67	-	**5,144**
Non-Current Liabilities									
Long-term debt		17,146	-	-	**17,146**	17,020	-	-	**17,020**
Regulatory liabilities	c, g	530	315	(845)	**-**	437	314	(751)	**-**
Derivative financial instrument liabilities		41	-	-	**41**	66	-	-	**66**
Unearned revenues and contributions in aid of construction	c	1,765	(145)	-	**1,620**	1,874	(116)	-	**1,758**
Post-employment benefits		1,566	-	-	**1,566**	1,474	-	-	**1,474**
Other non-current liabilities	c	1,803	(287)	-	**1,516**	2,338	(317)	-	**2,021**
		22,851	(117)	(845)	**21,889**	23,209	(119)	(751)	**22,339**
Total Liabilities		26,979	(53)	(845)	**26,081**	28,286	(52)	(751)	**27,483**
Regulatory Balances		-	-	845	**845**	-	-	751	**751**
Shareholder's Equity									
Contributed surplus		60	-	-	**60**	60	-	-	**60**
Retained earnings	b, d, e, g	4,822	74	-	**4,896**	5,347	74	-	**5,421**
Accumulated other comprehensive income (loss)	e	27	(83)	-	**(56)**	49	(83)	-	**(34)**
		4,909	(9)	-	**4,900**	5,456	(9)	-	**5,447**
Total Liabilities, Shareholder's Equity and Regulatory Balances		$ 31,888	$ (62)	$ -	**$ 31,826**	$ 33,742	$ (61)	$ -	**$ 33,681**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2019 AND 2018

Reconciliation of Consolidated Statement of Comprehensive Income

for the year ended March 31, 2018 (in millions)	Note	Prescribed Standard	Effect of Transition	IFRS 14 Presentation Reclass[f]	**IFRS**
Revenues					
Domestic	c	$ 5,527	$ 18	$ (322)	**$ 5,223**
Trade		731	-	-	**731**
		6,258	18	(322)	**5,954**
Expenses					
Operating expenses	b	4,921	-	(424)	**4,497**
Finance charges	c	653	18	153	**824**
Net Income Before Movement in Regulatory Balances		684	-	(51)	**633**
Net movement in regulatory balances		-	-	51	**51**
Net Income		684	-	-	**684**
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		57	-	-	**57**
Reclassification to income of derivatives designated as cash flow hedges		(30)	-	-	**(30)**
Foreign currency translation gains (losses)		(5)	-	-	**(5)**
Items That Will Not Be Reclassified to Net Income					
Actuarial gain		-	-	193	**193**
Other Comprehensive Income (Loss) before movement in regulatory balances		22	-	193	**215**
Net movements in regulatory balances		-	-	(193)	**(193)**
Other Comprehensive Income		22	-	-	**22**
Total Comprehensive Income		$ 706	-	$ -	**$ 706**

a) Fair Value as Deemed Cost

With the application of the deemed cost exemption, the net book value of property, plant and equipment and intangible assets for BC Hydro entities subject to rate regulation at April 1, 2017 have become the opening cost of property, plant and equipment and intangible under IFRS except for finance leases and asset retirement obligation.

b) Provision Re-Measurement

Under IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*, provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate, including a reassessment in discount rates where present value of a provision has been calculated. The Company elected to use an exemption allowing decommissioning related assets to be re-measured on a simplified approach at the transition date rather than perform a full detailed calculation. As a result, the re-measurement decreased property, plant, and equipment and retained earnings by $4 million as at April 1, 2017.

c) Revenue from Contracts with Customers

Under the Prescribed Standards, BC Hydro applied IAS 18, *Revenue* which did not provide specific guidance regarding the measurement of the transaction price for a contract that includes financing provided by the customer. Under IFRS 15, *Revenue from Contracts with Customers* the transaction price for contracts that include a significant financing component is required to be adjusted for the time value of money (e.g. interest) based on the interest rate in effect at the inception of the contract.

As a result of adjusting the measurement of the transaction price due to a significant customer financing component for consideration received in advance of delivery of electricity under the Skagit River Agreement, as at April 1, 2017 there was a decrease of $334 million in the unearned revenue liability account, and increase in current portion of unearned revenues of $16 million respectively. To ensure ratepayers receive the benefit of the accounting change, the corresponding net increase of $318 million was transferred to the Heritage Deferral Account regulatory liability balance instead of adjusting retained earnings with such impact being reflected in the proposed F2020 – F2021 Revenue Requirement Application. In addition to the transition date adjustment, domestic revenue increased by $17 million, finance charge increased by $16 million, and net movement in regulatory balances in net income decreased by $1 million for the year ended March 31, 2018. The unearned revenues also decreased by $1 million, with a corresponding increase in Heritage Deferral Account regulatory liability during the year ended March 31, 2018.

Due to the new prescriptive guidance in IFRS 15 regarding recognition of receivables and related unearned revenue amounts, as at April 1, 2017 and March 31, 2018, there was a decrease of $39 million and $51 million respectively in non-current receivables within other non-current assets, a decrease in accounts receivable and accrued revenue of $14 million and $nil respectively, a decrease in unearned revenues of $50 million and $47 million respectively, and a decrease of $3 million and $5 million respectively to the Total Finance Charges regulatory liability account and a decrease to the Non-Heritage Deferral regulatory asset account of $1 million at March 31, 2018.

The impact to the statement of comprehensive income for these changes for fiscal 2018 was that finance charges increased by $2 million, domestic revenue increased by $1 million, and net movement in regulatory balances in net income increased by $1 million.

Reclassifications:

i) Current portion of contributions in aid of construction have been reclassified to a separate line item on the Statement of Financial Position. This reclassification resulted in a decrease in contributions in aid of construction of $44 million as at April 1, 2017 and $47 million as at March 31, 2018, with a corresponding increase in current portion of unearned revenues and contributions in aid.

ii) Unearned revenues have been reclassified to a separate line item on the statement of financial position. This reclassification resulted in a decrease in other non-current liabilities of $529 million as at April 1, 2017 and $555 million as at March 31, 2018, with a corresponding increase in unearned revenues and contributions in aid. There was also a reclassification for the current portion that resulted in a decrease in accounts payable of $22 million respectively as at April 1, 2017 and March 31, 2018, with a corresponding increase in current portion of unearned revenues and contributions in aid of $22 million respectively.

iii) Contributions from a vendor to aid in the construction of a transmission system have been reclassified from contributions in aid to other non-current liabilities and accounts payable for the current portion to differentiate contributions in aid from customers. This reclassification resulted in a decrease in contributions in aid of $246 million as at April 1, 2017 and $242 million as at March 31, 2018, with a corresponding increase in accounts payable and accrued liabilities of $4 million respectively and $242 million and $238 million, respectively, in other non-current liabilities.

d) Accounts Receivable

Under the Prescribed Standards, BC Hydro recognized impairments of financial assets based on the incurred loss model in accordance with IAS 39, *Financial Instruments: Recognition and Measurement*. IFRS 9, *Financial Instruments* requires that impairments are based on a forward-looking 'expected loss' model. On adoption of IFRS, accounts receivable and accrued revenues have decreased by $5 million and retained earnings decreased by $5 million at both April 1, 2017 and March 31, 2018 as compared to amounts previously presented.

e) Cumulative Translation Adjustment

In accordance with IFRS 1, the Company elected to deem all foreign currency translation differences arising on consolidation of Powerex to be nil at the date of transition, April 1, 2017. The impact of this adjustment was to increase retained earnings and decrease accumulated other comprehensive income by $83 million at April 1, 2017.

f) Regulatory Deferral Account Balances

The Company elected to adopt IFRS 14, *Regulatory Deferral Accounts*. IFRS 14 specifies the financial reporting requirements for regulatory deferral account balances that arise from rate-regulation. This standard requires the consolidated statement of comprehensive income above net movement in regulatory balances to be presented in a manner that does not include the impacts of rate-regulation. As a result, domestic revenues decreased by $322 million, operating expenses decreased by $424 million, finance charges increased by $153 million, net movement in regulatory balances in net income increased by $51 million for the year ended March 31, 2018. In addition, actuarial gain increased and net movement in regulatory balances in other comprehensive income decreased by $193 million respectively for the year ended March 31, 2018.

IFRS 14 also requires separate disclosure in the statement of financial position for the total of all regulatory deferral debit balances and the total of all regulatory deferral credit balances. The regulatory balances will distinguished from the assets and liabilities by the use of sub-totals. As a result, $6.13 billion and $5.89 billion of regulatory assets was reclassified to regulatory balances under total assets and $845 million and $751 million of regulatory liabilities was reclassified to regulatory balances under total liabilities as at April 1, 2017 and March 31, 2018 respectively.

g) Deferral of Transitional Impacts

The following transitional impacts resulted from the application of the principles of IFRS to retained earnings has been deferred for regulatory purposes. The changes have increased (decreased) regulatory assets and liabilities as follows:

(in millions)		Incremental Increase (Decrease)	
	Note	As at April 1, 2017	For the year ended March 31, 2018
Revenue from Contracts with Customers	c	(315)	-
Incremental increase (decrease) for the period		(315)	-
Total cumulative increase (decrease) as at the balance sheet date		(315)	(315)
Regulatory assets		-	(1)
Regulatory liabilities		(315)	(314)
Net regulatory increase		(315)	(315)

Major Capital Projects

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

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to March 31, 2019 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Projects Recently Put Into Service				
W.A.C Bennett Dam Riprap Upgrade Project This project addressed inadequate erosion protection on the upstream face of the W.A.C Bennett Dam. The primary driver of the project was safety of the dam itself as well as safety of the public, property, and environment downstream.	2018 In-Service	$118	$1	$119
Waneta 2/3 Interest Acqusition BC Hydro purchased Teck Resources Ltd.'s two-third interest in the Waneta Dam and associated assets in July 2018.	2018 In-Service	$1,220	$-	$1,220
Kamloops Substation This project constructed a new 100MW 138/25kV substation in the west side of Kamloops to meet expected load growth in the Kamloops service area.	2018 In-Service	$50	$2	$52
Horne Payne Substation Upgrade Project This project expanded the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated feeder sections, and a new control building. This project increased the firm capacity of the substation, added needed feeder positions, facilitated the gradual conversion of the area supply voltage from 12kV to 25kV, and allowed for the implementation of an open-loop distribution system.	2019 In-Service	$65	$8	$73

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to March 31, 2019 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Projects Recently Put Into Service				
John Hart Generating Station Replacement This project replaced the existing six-unit 126 MW generating station (in operation since 1947) and added integrated emergency bypass capability to ensure reliable long-term generation and mitigated earthquake risk and environmental risk to fish and fish habitat. **John Hart forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral.*	2019 In-Service	$958	$27	$985*
Ongoing				
Cheakamus Unit 1 and Unit 2 Generator Replacement This project replaces the two generators at Cheakamus generating station (in operation since 1957) to address their poor condition and known deficiencies, and increase the capacity of each unit from 70 MW to 90 MW.	2019 Targeted In-Service	$55	$19	$74
South Fraser Transmission Relocation Project* This project is intended to relocate certain sections of two 230kV transmission circuits (Circuit 2L62 and Circuit 2L58) from their present location adjacent to Highway 99 and in the George Massey tunnel to accommodate the replacement of the tunnel. These two 230kV circuits form a critical part of BC Hydro's transmission network supplying power to customers in Richmond, Delta and the Greater Vancouver area. *****_Construction work on the South Fraser Transmission Relocation project is currently suspended pending the government's review of the George Massey Tunnel replacement._	TBD	$30	$46	$76

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to March 31, 2019 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Bridge River 2 Units 5 and 6 Upgrade Project This project will replace the two generators and other related equipment at Bridge River 2 to restore the historical operating capacity. These two generator units were placed in service in 1960 and are in unsatisfactory condition and unreliable.	2019 Targeted In-Service	$63	$23	$86
Downtown Vancouver Electricity Supply: West End Strategic Property Purchase This project is to acquire property rights to build and connect a new underground substation that will upgrade the aging electricity system in downtown Vancouver.	2020 Targeted In-Service	$67	$14	$81
Fort St. John and Taylor Electric Supply This project will maintain adequate supply capability, reduce line losses and improve reliability to the loads in the Fort St. John and Taylor areas by re-terminating 138kV transmission lines at the new Site C switchyard, and the addition of a 75 MVA transformer and new feeder positions.	2020 Targeted In-Service	$32	$21	$53
UBC Load Increase Stage 2 Project This project is on behalf of BC Hydro’s customer, the University of British Columbia, to continue to reliably meet the growing electricity needs of its Point Grey campus and the surrounding community.	2021 Targeted In-Service	$17	$38	$55
Peace Region Electricity Supply Project This project is 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 will facilitate reductions in provincial greenhouse gas emissions by enabling electrification of natural gas production, processing, and compression.	2021 Targeted In-Service	$66	$219	$285

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to March 31, 2019 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
LNG Canada Load Interconnection Project This project is to facilitate the interconnection of LNG Canada's facility. A new double circuit 287kV transmission line will be constructed from Minette Substation (MIN) to LNG Canada's facility and system reinforcements at MIN will also be implemented. Under BC Hydro's standard tariffs, the customer is required to pay for a portion of this project's costs.	2021 Targeted In-Service	$8	$74	$82
Bridge River 2 Units 7 and 8 Upgrade Project This project will replace the two generators and other related equipment to restore the historical operating capacity. Units 7 and 8 were placed into service in 1960, are unreliable and in poor and unsatisfactory condition.	2021 Targeted In-Service	$3	$83	$86
Mica Replace Units 1-4 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	$8	$74	$82
G.M. Shrum G1-G10 Control System Upgrade This project will replace the controls equipment, provide full remote control capability from the remote 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	$34	$41	$75

Major Capital Projects (over $50 million)	Targeted Completion Date (Calendar Year)	Project Cost to March 31, 2019 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ 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 forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral. The amount includes a reserve of $708 million.*	2024* Targeted In-Service	$3,491	$7,209	$10,700**

Significant Information Technology (IT) Projects over $20 million

BC Hydro has the following IT project with capital costs expected to exceed $20 million, listed according to targeted completion date. This project has been approved by the Board of Directors.

Significant IT Projects (over $20 million in total)	Targeted Completion Date (Calendar Year)	Project Cost to March 31, 2019 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Ongoing				
Supply Chain Applications Project This project will replace BC Hydro's existing PassPort supply chain information technology (IT) system with an SAP-based IT system and make improvements to BC Hydro's supply chain business processes for third-party materials and service acquisitions. **The BCUC issued an Order, dated April 9, 2019, which accepted the expenditures to complete the Implementation Phase of the project.*	2020 Targeted In-Service	$33	$35	$68*

Appendix A – Additional Information

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 President and Chief Operating Officer (COO). For more information on Corporate Governance, please refer to: http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.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 educate and inform them on issues that are of strategic importance to the Corporation. These include special site visits to provide Directors 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 as well as 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. The Code also allows exemptions from its 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.

Code exemptions, in extraordinary circumstances, may be granted from different entities depending on the individual's role within BC Hydro. Employees may be granted exemptions by the President and COO, the President and COO and Directors may be granted exemptions by the Executive Board Chair and the Executive Board Chair may be granted an exemption by the Governance and Human Resources Board Committee. All exemptions additionally require approval from the Minister responsible for the Public Sector Employers' Council.

Organizational Overview

BC Hydro has offices throughout the communities of 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

Contact Information

See Page 2 for full contact information. More information on BC Hydro can be found at www.bchydro.com.

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 energy markets across North America. Powerex's business consists mainly of 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.

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 Benefits of 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 and COO and Executive team of Powerex's key strategies and business activities.

Powerex operates in competitive and complex energy-markets, which can cause net income in any given year to vary significantly. Market and economic conditions, reduced hydro system flexibility, unrealized mark-to-market gains or losses and the strength of the Canadian dollar can materially impact Powerex's net income. Over the previous five years, Powerex's net income has ranged from $59 million to $436 million (2014/15 to 2018/19). The 2019/20 to 2021/22 Service Plan forecast includes annual net income from Powerex of approximately $125 million per year.

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 holding expertise in a range of fields related to the electrical industry and offers services and products including: research and development, testing, technical services, software and advanced technology services to energy clients, including BC Hydro, and other sectors globally.

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

Over the last five years, Powertech's revenue has ranged from $30 million to $45 million (2014/2015 to 2018/19) with a net income in the range of $2 million to $4 million. The 2019/20 to 2021/22 Service Plan forecast includes annual net income from Powertech of approximately $4 million per year.

Other Active 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.

All the staff and management needs of the active subsidiaries below are fulfilled by BC Hydro employees, who perform these duties without additional remuneration. 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, 2019, 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 – Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	**2019[1]**	2018[1]	2017[2]	2016[2]	2015[2]
Revenues					
Domestic[1]	**$ 5,432**	$ 5,223	$ 5,199	$ 5,056	$ 4,829
Trade	**1,141**	731	675	601	919
Expenses					
Domestic energy costs[1]	**1,573**	1,615	1,608	1,425	1,458
Trade energy costs[1]	**624**	522	486	427	745
Other operating expenses[1, 3]	**1,351**	1,302	1,025	937	918
Amortization and depreciation[1]	**880**	817	1,232	1,241	1,205
Grants and taxes	**268**	241	234	220	209
Finance charges[1]	**1,186**	824	605	752	632
	5,882	5,321	5,190	5,002	5,167
Net Income Before Movement in Regulatory Balances	**691**	633			
Net movement in regulatory balances[1]	**(1,119)**	51			
Net Income (Loss)	**$ (428)**	$ 684	$ 684	$ 655	$ 581
Property, Plant and Equipment and Intangible Assets					
At cost	**$ 30,320**	$ 26,574	$ 27,468	$ 25,183	$ 22,998
Less: Accumulated depreciation	**1,766**	904	3,869	3,189	2,518
Net Book Value	**$ 28,554**	$ 25,670	$ 23,599	$ 21,994	$ 20,480
Property, Plant and Equipment and Intangible Asset Expenditures					
Sustaining	**$ 965**	$ 1,190	$ 1,286	$ 1,136	$ 1,005
Growth	**2,861**	1,283	1,158	1,170	1,164
Total Property, Plant and Equipment and Intangible Asset Expenditures [4]	**$ 3,826**	$ 2,473	$ 2,444	$ 2,306	$ 2,169
Net Long-Term Debt [5]	**$ 22,101**	$ 20,140	$ 19,796	$ 18,002	$ 16,682
Retained Earnings	**$ 4,934**	$ 5,421	$ 4,822	$ 4,397	$ 4,068
Debt to Equity Ratio	**82 : 18**	79 : 21	80 : 20	80 : 20	80 : 20

1 *The Company adopted IFRS in fiscal 2019, and restated the comparative period (fiscal 2018). For additional information, refer to Note 24: Explanation of Transition to IFRS in the Financial Statements. Under IFRS, changes in regulatory balances are reported within the "net movements in regulatory balances." For fiscal 2015 to 2017, the changes in regulatory balance were reported within each financial statement line item.*

2 *The Company prepared its consolidated financial statements in accordance with the accounting principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, Regulated except as specified in Treasury Board Regulation B.C. Reg 146/2011 section 5(3) (collectively the Prescribed Standards).*

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

4 *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.*

5 *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	**2019**	2018	2017	2016	2015
Generating Capacity (megawatts)					
Hydroelectric	**11,932**	11,918	11,870	11,869	11,379
Thermal	**177**	180	183	175	1,120
Total	**12,109**	12,098	12,053	12,044	12,499
Peak One-Hour Integrated System Demand (megawatts)	**10,045**	9,651	10,194	9,602	9,441
Number of Customer Accounts					
Residential	**1,833,097**	1,803,752	1,776,503	1,751,296	1,727,945
Light industrial and commercial	**212,446**	210,673	207,802	205,615	203,466
Large industrial	**195**	190	191	185	183
Other	**3,419**	3,429	3,467	3,459	3,474
Trade	**165**	182	204	214	226
Total	**2,049,322**	2,018,226	1,988,167	1,960,769	1,935,294
Domestic Electricity Sold (gigawatt-hours)					
Residential	**18,000**	18,150	18,068	17,331	17,047
Light industrial and commercial	**19,007**	18,874	18,968	18,421	18,564
Large industrial	**13,896**	13,440	13,177	13,669	14,020
Surplus Sales	**2,230**	5,072	5,756	6,277	14
Other sales	**1,510**	1,637	1,683	1,602	1,568
Total	**54,643**	57,173	57,652	57,300	51,213

Revenues (in millions)

for the years ended March 31	**2019[1]**	2018[1]	2017[2]	2016[2]	2015[2]
Residential	**$ 2,127**	$ 2,097	$ 2,012	$ 1,842	$ 1,712
Light industrial and commercial	**1,925**	1,860	1,800	1,685	1,597
Large industrial	**873**	811	770	766	748
Surplus Sales	**115**	139	133	174	-
Other sales	**392**	316	295	290	280
Total Domestic Revenue Before Regulatory Transfers	**5,432**	5,223	5,010	4,757	4,337
Regulatory transfers[1]			189	299	492
Total Domestic	**5,432**	5,223	5,199	5,056	4,829
Trade - electricity and gas	**1,141**	731	675	601	919
Total	**$ 6,573**	$ 5,954	$ 5,874	$ 5,657	$ 5,748

Average Revenue (per kilowatt-hour) [3]

for the years ended or as at March 31	**2019**	2018	2017	2016	2015
Residential	**11.8¢**	11.6¢	11.1¢	10.6¢	10.0¢
Light industrial and commercial	**10.1**	9.9	9.5	9.1	8.6
Large industrial	**6.3**	6.0	5.8	5.6	5.3
Average Annual Kilowatt-Hour Use Per Residential Customer Account	**9,899**	10,139	10,241	9,958	9,919
Lines In Service					
Distribution (kilometres)	**59,095**	59,222	59,078	58,765	58,518
Transmission (circuit kilometres)	**20,385**	20,306	20,278	20,176	19,792

[1] The Company adopted IFRS in fiscal 2019, and restated the comparative period (fiscal 2018). For additional information, refer to Note 24: Explanation of Transition to IFRS in the Financial Statements. Under IFRS, changes in regulatory balances are reported within the "net movements in regulatory balances." For fiscal 2015 to 2017, the changes in regulatory balance were reported within each financial statement line item.

[2] The Company prepared its consolidated financial statements in accordance with the accounting principles of IFRS, combined with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, Regulated Operations, except as specified in Treasury Board Regulation B.C. Reg 146/2011 section 5(3) (collectively the Prescribed Standards).

[3] Average revenues are before regulatory transfers.

TOTAL REQUIREMENTS FOR ELECTRICITY, SOURCES OF SUPPLY AND WATER INFLOWS

for the years ended March 31	**2019**			2018			2017			2016			2015		
	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	%
Electric System Deliveries															
Domestic	**12,109**	**54,643**	**74.6**	12,098	57,173	73.6	12,053	57,652	72.7	12,044	57,300	73.7	12,499	51,213	66.0
Electricity trade		**14,139**	**19.3**		15,046	19.4		16,740	21.1		14,732	18.9		21,928	28.2
		68,782	**93.9**		72,219	93.0		74,392	93.8		72,032	92.6		73,141	94.2
Line loss and system use		**4,496**	**6.1**		5,454	7.0		4,927	6.2		5,713	7.4		4,486	5.8
		73,278	**100.0**		77,673	100.0		79,319	100.0		77,745	100.0		77,627	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,778**	**11,634**	**15.9**	2,778	13,876	17.9	2,730	15,910	20.1	2,730	14,274	18.4	2,730	10,801	13.9
Revelstoke	**2,480**	**8,408**	**11.5**	2,480	9,082	11.7	2,480	8,264	10.4	2,480	9,805	12.6	2,480	7,297	9.4
Mica	**2,746**	**7,625**	**10.4**	2,746	8,561	11.0	2,746	7,397	9.3	2,747	9,451	12.2	2,257	6,028	7.8
Kootenay Canal	**583**	**2,486**	**3.4**	583	3,083	4.0	583	3,330	4.2	583	2,837	3.6	583	3,304	4.4
Peace Canyon	**694**	**2,938**	**4.0**	694	3,430	4.4	694	3,887	4.9	694	3,470	4.5	694	2,678	3.4
Seven Mile	**805**	**3,137**	**4.3**	805	3,460	4.5	805	3,326	4.2	805	2,666	3.4	805	3,907	5.0
Bridge River	**478**	**1,996**	**2.7**	478	2,216	2.9	478	2,504	3.2	478	2,582	3.3	478	2,093	2.7
Other	**1,368**	**4,118**	**5.5**	1,354	4,218	5.3	1,354	4,118	5.1	1,352	4,267	5.5	1,352	5,122	6.6
	11,932	**42,342**	**57.7**	11,918	47,926	61.7	11,870	48,736	61.4	11,869	49,352	63.5	11,379	41,230	53.2
Thermal generation															
Burrard	**0**	**0**	**0.0**	0	0	0.0	0	0	0.0	0	24	0.0	950	26	0.0
Other	**177**	**190**	**0.3**	180	91	0.1	183	74	0.1	175	191	0.2	170	187	0.2
Purchases under long-term commitments		**18,256**	**24.9**		18,399	23.7		17,753	22.4		18,441	23.7		17,510	22.6
Purchases under short-term commitments		**12,645**	**17.3**		10,658	13.7		13,009	16.4		10,713	13.8		18,586	23.9
Other		**(155)**	**(0.2)**		599	0.8		(253)	(0.3)		(976)	(1.2)		88	0.1
	12,109	**73,278**	**100.0**	12,098	77,673	100.0	12,053	79,319	100.0	12,044	77,745	100.0	12,499	77,627	100.0
Water inflows (% of average)			**87**			98			101			97			102