British Columbia Hydro and Power Authority

2017/18
ANNUAL SERVICE PLAN REPORT

July 2018

BRITISH COLUMBIA

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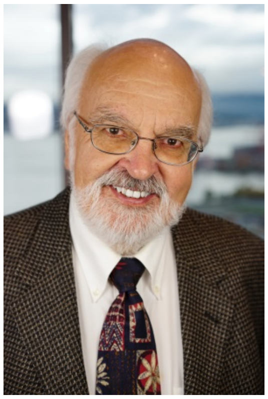
Board Chair's Accountability Statement



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 deliver reliable, affordable and clean electricity to our four million customers, safely. 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, 2018, 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 September 2017 *2017/18 - 2019/20 Service Plan* was released and any significant limitations in the reliability of the information are identified in the report.

The *BC Hydro 2017/18 Annual Service Plan Report* compares the Corporation's actual results to the expected results identified in the *2017/18 - 2019/20 Service Plan* created in September 2017, and details how we are meeting the objectives in the Government Mandate Letter. I am accountable for those results as reported.

Kenneth G. Peterson

Executive Board Chair

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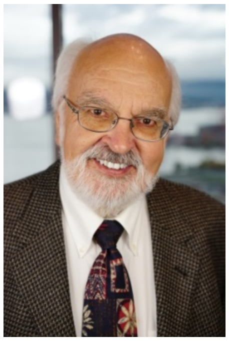
Executive Board Chair/President and Chief Operating Officer Letter



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, 2018. 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.

Affordable, reliable 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 over $2 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 are working with the Province on a comprehensive review of the Corporation to keep electricity rates low and predictable over the long-term, while ensuring BC Hydro has the resources it needs to continue to provide reliable, clean and safe electricity. We have also enhanced 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.

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 Government 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. Fiscal 2017/18 marked the first fiscal year in at least a decade that BC Hydro has successfully achieved its full complement of Service Plan performance metric targets – a significant accomplishment. We will continue to work together to ensure that everyone 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 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 120 projects across the province, including biomass, hydro, wind and solar. Our electricity generation is 98 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 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 2010 Clean Energy Act (CEA)
- The Province's 2007 BC Energy Plan

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 and Operating Environment

While British Columbia's electricity rates remain among the most competitive in North America, BC Hydro has the important responsibility to keep electricity rates affordable for our customers. To support this goal, BC Hydro applied for a rate freeze as part of its Revenue Requirements Application for Fiscal 2017 – Fiscal 2019 with the BC Utilities Commission (BCUC), our independent regulator. While the BCUC did not approve the rate freeze, BC Hydro advanced a number of affordability initiatives this year to help our customers save money. This included relaunching the Winter Payment Plan, which allows customers to pay high winter bills over a period of six months, and the establishment of the Low Income Advisory Council. This group provided substantial input into the development of the new Customer Crisis Fund, a three year pilot approved by the BCUC in November 2017, which will provide a bill credit that will not need to be repaid for our customers who find themselves in a crisis.

In the summer of 2017, British Columbia experienced devastating wildfires in the central and southern Interior parts of the province and a state of emergency was declared. The wildfires caused power outages for over 49,000 customers, as well as significant damage to BC Hydro's system, including 371 distribution poles, 261 spans of wire, 159 cross arms, 54 transmission structures and 51 transformers. More than 100 crews worked to make repairs to damaged infrastructure and restore power for our customers. To further support affected customers, we introduced the Wildfire Evacuee Assistance program for residential and commercial customers affected by evacuation orders. This program provided automatic credits to more than 33,000 customer accounts for electricity consumed during the evacuation period.

In December 2017, there were two major ice storms in the eastern Fraser Valley, causing outages for over 160,000 BC Hydro customers. Over 450 power line technicians (PLTs) and electricians from across British Columbia worked around the clock to fix dozens of broken poles, damaged transformers, ice-encased equipment and wire spans in very dangerous conditions. Despite the challenging conditions, the majority of customers were without power for less than 24 hours, and half of all customers were restored within four hours.

We continued to manage our costs, implementing $33 million of cost reductions identified in Fiscal 2017. These reductions mitigated rate impacts to our customers and enabled ongoing investment in priority areas such as maintenance, safety and customer service. Our domestic base operating costs have been limited to an average increase of 1.2 per cent per year from Fiscal 2017 to Fiscal 2019, even though most of these costs are subject to inflationary pressures that exceed this amount.

BC Hydro continued to track well against the current Load Forecast. In Fiscal 2017/18, load was 0.5 per cent higher than forecast. As British Columbia's population and economy continue to grow, it is a crucial time to reinvest in a system that will help power the new 21st century economy.

BC Hydro's electricity system was largely built in the 1960s, 1970s and 1980s and we continue to invest over $2 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 493 capital projects at a total cost of $6.9 billion which is 0.40 per cent over budget overall. During Fiscal 2017/18, capital projects placed in-service totaled $1.6 billion, including projects to renew and expand our generation, transmission and distribution system.

Construction of Site C has been underway since July 2015; this past year included significant construction and procurement activities. On average, there were 2,148 people working on the project over Fiscal 2017/18. BC Hydro continued implementation of community benefit agreements and agreements with Indigenous groups. All provincial and federal regulatory agencies noted that environmental compliance had improved throughout the year.

Site C is a large and complex project that has faced many challenges impacting the budget and schedule. This fiscal year, we encountered some construction issues on the project; consequently, river diversion was deferred to 2020. BC Hydro presented a revised budget of $10.7 billion to our Board of Directors in December 2017, and received approval in January 2018.

The BC Utilities Commission conducted an independent review of the Site C project this year. The Province of British Columbia announced its decision to proceed with the project in December 2017.

As part of planning for both the current and future needs of our customers, we continued to focus on our renewed customer service strategy, with the goal of making it easier to do business with us. Our ongoing efforts resulted in an 86 per cent customer satisfaction score in Fiscal 2017/18. In February 2018, we launched the new Enterprise Billing Infrastructure Project that improved the reliability of our invoicing system and introduced a new bill design to our customers. The new bill is easier to understand, offers our customers key insights into their electricity use to help them make smart energy choices and gives a clear explanation of electricity costs.

BC Hydro's extensive electricity system, along with our reinvestment and expansion plans, means a significant number of Indigenous communities across the province are, or will be, impacted by our infrastructure. We continue to work to develop and sustain positive long-term relationships and better understand Indigenous interests so that their priorities are recognized in our capital programs and business operations. We are developing a vision of how to incorporate the United Nations Declaration on the Rights of Indigenous Peoples and the Calls to Action of the Truth and Reconciliation Commission into our business. Through our work with Indigenous peoples, we have been recognized as a leader in Progressive Aboriginal Relations, achieving gold certification since 2012. This year, we completed our submission for Progressive Aboriginal Relations certification for a further three years.

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. This year, BC Hydro had zero employee fatalities or serious injuries and our goal continues to be that everyone goes home safely, every day.

Report on Performance

BC Hydro continued to focus on achieving the objectives outlined in the Government 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, Strategies, 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 2017/18 – 2019/20 Service Plan created in September 2017.

The goals and measures below track our progress on delivering the identified priorities for Fiscal 2017/18.

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 2017/18 Annual Service Plan Report compares the Corporation's 2017/18 actual results to the expected results in the 2017/18 – 2019/20 Service Plan created in September 2017.

Goal 1: Set the Standard for Reliable and Responsive Service

Objective

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.

Strategies

- Ensure the reliability of the generation, transmission and distribution system by effectively implementing capital and maintenance programs to manage overall asset health and secure supply to meet customer load throughout the year.
- Identify and address vulnerabilities in our operating system and develop well practiced emergency response plans to improve overall system reliability.
- Through external benchmarking of North American transmission interconnection practices, review and implement appropriate recommendations to meet customer requirements as identified in the Industrial Electricity Policy Review.
- Continue to make it easier for customers to do business with us through a series of customer facing improvements such as increased mobile access, enabling more self-service features, expanding in-person service areas, and enhanced service training for employees.
- Help customers make smart energy management choices by supporting them with rates and programs including opportunities for conservation and efficiency, as well as low carbon electrification.
- Sustain the highest, gold-level, certification under the Progressive Aboriginal Relations program by maintaining leading practices focused on Aboriginal employment, business development, community investment and community engagement.
- Through early engagement and emphasizing collaboration, respect and mutually beneficial relationships with First Nations, BC Hydro will better incorporate Indigenous perspectives and interests in the delivery of our capital projects and define a future together where our business needs and First Nations' interests are aligned.

Performance Measures

Performance Measure(s)[1]		2015/16 Actuals	2016/17 Actuals	2017/18 Target	2017/18 Actuals	2018/19 Target	2019/20 Target
1.a	SAIDI (System Average Interruption Duration Index[2] [Total outage duration (in hours) experienced by an average customer in a year]	3.01	3.28	3.30	3.07	3.30	3.25[3]
1.b	SAIFI (System Average Interruption Frequency Index)[2] [Number of sustained disruptions per year (excluding major events)]	1.48	1.59	1.40	1.51	1.40	1.40
1.c	Key Generating Facility Forced Outage Factor [4]	1.64	1.78	2.0	1.81	1.80	1.80
1.d	CSAT Index [Customer Satisfaction Index: % of customers satisfied or very satisfied]	87.0	87.0	85.0	86.0	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 https://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html

[2] Reliability targets are based on specific values, however performance within 10 per cent is considered acceptable given the wide range of variations in weather patterns and the uncontrollable elements that can significantly disrupt the electrical system. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

[3] Target was lowered in the February 2018 Service Plan to reflect improved performance and expectations in a number of areas including long-term historic reliability trending, current year performance, previous years' investments and future years' investment plans.

[4] The Key Generating Facility Forced Outage Factor is reported as a five year rolling average. A forced outage occurs when a major generating unit fails to start on demand and/or fails to remain in service until shutdown. The Key Generating Facility Forced Outage Factor shows the trend of how the assets are performing and aligns with how asset management investment decisions are made to maintain asset reliability that is reflected in a low Forced Outage Factor.

[5] BC Hydro attained a gold level designation from the Canadian Council for Aboriginal Business in Fiscal 2015/16, which was valid for a three year period. In Fiscal 2019, BC Hydro will apply for the next certification.

Discussion

Reliability

Reliability is measured using the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). In Fiscal 2017/18, we continued to ensure the reliability of the system by effectively implementing capital and maintenance programs to manage overall asset health addressing and developing well practiced emergency response plans to improve overall system reliability.

- Targeted deployment of automated reclosers and switches to affordably reduce sustained customer outages.

- Analyzed system performance data on outage trends to identify priority areas for hazard tree removals to help manage the frequency of tree-related outages.
- Operationalized the internal use of a new emergency mass notification system and trained 225 employees on incident command and response procedures. We also completed two emergency response exercises: one to test our response to cyber and physical security attacks; and a second to assess our evacuation procedure at a dam site.
- As a result of our response to the 2017 wildfires, improvements were made to enhance situational awareness and crew safety.

BC Hydro continues to report on the Key Generating Facilities Forced Outage Factor. The Key Facilities are BC Hydro's seven largest generating stations which produce over 90 per cent of the company's generation and do not include supply from Independent Power Producers. This measure provides information on the effectiveness of BC Hydro's maintenance and capital investment programs in achieving an acceptable level of performance from those facilities. Highlights from our plans to manage forced outages to remain within an acceptable range include:

- Sustainment of a forced outage Root Cause Analysis approach that includes forced outage investigations and risk mitigation measures to ensure appropriate risk management checks and balances are in place.
- Continued implementation of predictive maintenance tasks to help identify failures before they occur.

BC Hydro achieved the target to remain below 2.0 per cent for Key Generating Facility Forced Outage Factor with a result of 1.81 per cent.

Service

The Customer Satisfaction Index (CSAT) measure gauges the level of customer support in meeting their electricity needs. In Fiscal 2017/18, we continued to ensure that we have strong customer support by focusing on our renewed customer service strategy, with the goal of making it easier to do business with us. Key accomplishments include:

- Launched the new Enterprise Billing Infrastructure that improves reliability of our invoicing systems and provides easier to understand paper and digital bills. In Fiscal 2017/18, we reached the milestone of one million customers choosing paperless billing.
- Our winter affordability campaign reached over 240,000 customers and resulted in nearly 50,000 customers signing up for an automated high consumption alert email.
- Established the Low Income Advisory Council to provide continuing review, general advice and recommendations on how we develop, improve and communicate business practices with customers. This group provided substantial input into the development of our new Customer Crisis Fund.
- Delivered customer-focused training to over 1,000 employees through a variety of online and in-person courses and workshops.
- Expanded in-person customer service to include our Prince George office. This is now offered in four communities.

- Completed an external transmission interconnection process benchmarking study which concluded that BC Hydro's performance is consistent with our utility peers in North America. BC Hydro has shared the study findings with customers and industry associations. The study identified a number of areas for further improvements, such as streamlining the interconnection process, creation of a dedicated interconnections project delivery team, and a more flexible and customized planning process. Key recommendations to improve BC Hydro's interconnection process from the benchmarking study have been completed.

Indigenous Relations

Working closely with First Nations to build better, more transparent and collaborative relationships is important to us and aligns with the criteria to maintain our Progressive Aboriginal Relations gold designation. We continued to seek to develop and sustain positive long-term relationships and better understand Indigenous interests so that those priorities can be incorporated, where possible, into our capital planning and projects and business operations. This year, BC Hydro:

- Continued to implement our Statement of Indigenous Principles, and developed an approach for incorporating the United Nations Declaration on the Rights of Indigenous Peoples and the Calls to Action of the Truth and Reconciliation Commission into our business.
- Provided contracting opportunities for First Nations community-owned businesses or partnerships of approximately $123 million through our capital projects.
- Continued to provide Indigenous people with employment on our capital projects. For example, while the number fluctuated depending on the nature of the work, the Site C project employed between 219 and 389 Indigenous people during Fiscal 2017/18.
- Hired more than 50 Indigenous employees, including a number of PLT apprenticeships, and continued to provide skill building training to Indigenous candidates, including driver's license training and support for educational pre-requisite and certificates.
- Supported numerous community activities to address Indigenous peoples' interests, including environmental, archaeology and cultural programs, as well as education and business development opportunities for Indigenous youth.

Goal 2: Ensure Rates are Among the Most Affordable in North America

Objective

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

Strategies

- Advance proceedings before the BCUC, including the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application and the Rate Design Application, and prudently implement actions to control costs.
- Freeze rates while a comprehensive review of the Corporation is conducted and provide recommendations to Government for a refreshed plan to keep electricity rates affordable and predictable.
- Participate fully and transparently in the BCUC inquiry into the Site C Clean Energy Project.
- Continue development of a refreshed Integrated Resource Plan in consultation with stakeholders and prudently implement the 10 Year Capital Plan so that our customers can continue to receive clean, reliable and affordable electricity.
- Improve how we operate by focusing on safety, operational excellence, efficiency and reliability by enhancing work delivery methods as well as resourcing and supply chain strategies.
- Maintain scalable, robust, and consistent project delivery practices to actively manage project risks and apply industry best practices to deliver projects on time and on budget.

Performance Measures

Performance Measure(s)[1]	2015/16 Actuals	2016/17 Actuals	2017/18 Target	2017/18 Actuals	2018/19 Target	2019/20 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]	-0.18% on $6.49 billion	-0.94% on $6.36 billion	Within +5% to -5% of budget excluding project reserve amounts	+0.40% on $6.9 billion	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

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

[2] Based on BC Hydro's ranking in the residential category in the annual Hydro Quebec Report on Electricity Rates in North America. 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 to determine BC Hydro's ranking. Based on this same methodology, BC Hydro's rates for medium commercial and industrial customers rank fifth and seventh lowest in the report.

[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.

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 for Fiscal 2017/18, based on analysis of Hydro Quebec's annual report, 2017 Comparison of Electricity Rates in Major North American Cities.

We advanced a number of proceedings in Fiscal 2017/18 with our independent regulator, the British Columbia Utilities Commission (BCUC) to ensure our customers benefit from affordable and predictable rates, including:

- In March 2018, the BCUC approved rate increases of 4 percent, 3.5 per cent and 3 percent for Fiscal years 2017, 2018 and 2019, respectively. While our request to freeze rates for Fiscal 2019 was not approved by the BCUC, the approval of a 3 per cent rate increase for that year is consistent with the 10 Year Rates Plan.
- The BCUC Inquiry into the Site C Project commenced in early August and the BCUC delivered its final report on November 1, 2017. BC Hydro fully and transparently participated in this process. After considering the BCUC's findings, the Province of B.C. made the decision that the Site C Project would proceed.

- We received approval for the first phase of its Supply Chain Applications Project, which will result in a fully integrated supply chain at BC Hydro.

Over the last five years, BC Hydro has successfully completed 493 capital projects at a total cost of $6.9 billion, which is 0.40 per cent over the budget overall, and well within the +5% to -5% target. BC Hydro measures its performance in delivering capital projects with the Project Budget to Actual Cost measure. Since its introduction in Fiscal 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 Fiscal 2017/18, we completed several additional initiatives to optimize our project delivery practices and enhance our work delivery methods:

- In Fiscal 2017/18, the overall BC Hydro organization was restructured around functions of Plan-Build-Operate-Support. In particular, this new structure brings all of the electricity planning and asset management groups together under one Integrated Planning business group, and the entire field and system operating groups under Operations. This new structure will facilitate collaboration, efficiency, safety and innovation.
- BC Hydro continued to focus on its Work Smart program, which improves our processes by employing Lean methodologies, and undertook nine projects across the company in Fiscal 2017/18. These projects, in which employees are empowered to develop and implement enhanced processes through a structured framework, generated an estimated 33,000 hours of staff effort which could be 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.
- Introduced additional project performance reports that enabled us to have better insight into key drivers of project performance, which enhanced our project cost and milestone forecasting. We also developed a set of new options that allow us to perform risk-based scaling of our project management practices, which will reduce the duration of some activities on our projects.

Construction on the Site C project has been underway since July 2015. As of March 31, 2018, the project has spent $2.4 billion and has financial commitments—contracts and agreements—totalling almost $6 billion. Key accomplishments this year included:

- **Construction activities:** Over the last year, approximately 107,000 cubic metres of merchantable trees were cleared, processed and transported to local mills. On-site access roads were built and public road improvements were completed. On the north bank, mass excavation activities to stabilize the slope continued. Excavation of the south bank drainage tunnel, excavation of the spillway and placement of roller-compacted concrete in the powerhouse and spillway progressed. The turbines and generators and substation contractors mobilized to site.

- **On-site workers:** As of March 2018, there were 2,124 people working on the Site C project, including 1,804 workers from B.C. (85 per cent of the total workforce), approximately 213 Indigenous workers, 256 women and 598 workers from the Peace River Regional District.
- **Community benefits:** In February 2018, the $20-million BC Hydro Peace Agricultural Compensation Fund was launched and in March 2018, BC Hydro provided $48,000 to non-profit organizations in the Peace Region through its Generate Opportunities Fund.
- **Safety:** Lost time injuries and contractor near miss incidents occurred. BC Hydro worked with contractors to educate them on our safety culture and to increase their focus on worker safety.
- **Project oversight:** To ensure the Site C project is developed on time and on budget, 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

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

Strategies

- Implement the Integrated Resource Plan recommendations to secure an affordable and clean supply of power to meet future customer needs.
- Explore opportunities for BC Hydro and independent power producers to work together in the development of a new, low-carbon economy under the Memorandum of Understanding with Clean Energy BC. Implement our energy conservation and energy management plan, which will exceed the Clean Energy Act requirement to meet at least two-thirds of future demand growth by 2020.
- Provide customers with the opportunity to access clean, renewable power to displace the use of higher carbon energy sources.
- Continue to provide opportunities for First Nations located in remote Indigenous communities that are not integrated with the BC Hydro system through established renewable energy programs.

Performance Measures

Performance Measure(s)[1]		2015/16 Actuals	2016/17 Actuals	2017/18 Target	2017/18 Actuals	2018/19 Target	2019/20 Target
3.a	Energy Conservation Portfolio (New incremental GWh/year)[2]	1,000	733	600	741	800[3]	700[3]
3.b	Clean Energy (%)	98.2	98.4	93.0	98.0	93.0	93.0
3.c	New Clean Supply (%)[4]	100	100	100	100	100	100

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

[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] Updated information on the timing of energy savings from lighting regulations is incorporated into the plan, resulting in increased targets of 800 GWh/year (gigawatt-hours per year) in 2018/19, and 700 GWh in 2019/20.

[4] 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.

Discussion

In Fiscal 2017/18 BC Hydro continued to meet the *Clean Energy Act* objectives and the Clean Energy and New Clean Supply performance measure targets, and continued to provide opportunities for First Nations. The following accomplishments supported this goal:

- Met the Province’s Climate Leadership Plan requirement of acquiring 100 per cent of new supply for the integrated grid from clean or renewable sources.
- Announced the advancement of five clean energy projects through the Standing Offer and Micro Standing Offer programs. These projects consist of wind, hydro and solar resources. The projects were selected because they are part of Impact Benefit Agreements and/or well advanced projects in the process that have significant First Nations involvement.
- Executed renewal of Electricity Purchase Agreements for three hydro projects, two of which have been approved by the BCUC.
- Entered into an agreement to purchase the remaining two-thirds share of the Waneta facility from Teck. This share would be leased back to Teck for 20 to 30 years. The transaction is being reviewed by the BCUC.

BC Hydro continued to strengthen our energy efficiency and conservation programs. In Fiscal 2017/18, we exceeded the Energy Conservation Portfolio target of 600 GWh/yr due to higher residential program participation, a higher volume of industrial strategic energy management projects, and also higher than planned savings from a lighting regulation.

Goal 4: Safety Above All

Objective

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.

Strategies

- Continually refresh the five-year safety plan to ensure the priority risk areas are identified and implement safety improvement projects that drive towards:
  - Achieving zero fatalities and zero disabling injuries. Examples of projects include: the use of Safety Stops, accounting for full extension of reach in minimum approach distances, and increased use of line guards and cover up; Life Saving Rules training and competency assessments; and implementing arc flash work methods, training and personal protective equipment to reduce burns and injuries.
  - Year-over-year reduction in lost time injuries and medical aid injuries. Examples of projects include: the knife cut reduction program and the field/plant ergonomics program.
  - Meeting new regulatory requirements. Examples of projects include: asbestos management and abatement in our generation plants, substations and underground ducts; procedures, training and equipment to ensure safe work in confined spaces; and revising work procedures to manage lead and silica hazards.
  - Building a culture to achieve excellence in safety. Examples of investments include: regular reviews of safety incidents by senior management team; timely implementation of corrective actions that reduce risk of injuries; and completion of Safe Work Observations that identify hazards before injuries occur.
  - Building corporate systems and tools supporting excellence in safety. Examples of projects include: Field Access to Safety Information which improves both the ease of access and quality of safety information; and improved safety analytics capabilities.

Performance Measures

Performance Measure(s)[1]	2015/16 Actuals	2016/17 Actuals	2017/18 Target	2017/18 Actuals	2018/19 Target	2019/20 Target
4.a Zero Fatality & Serious Injury [Loss of life or the injury has resulted in a permanent disability]	0	0	0	0	0	0
4.b Lost Time Injury Frequency [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.14	1.04	0.90	0.88	0.85	0.80
4.c Timely Completion of Corrective Actions (%)	80	96	93	100	93[2]	95[2]

[1] Performance Measure descriptions, rationale, data source information and benchmarking are available online at https://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html.
[2] The definition of Timely Completion of Corrective Actions was changed in the 2018/19-2020/21 Service Plan, published in February 2018, to the percentage of safety corrective actions closed on or before the scheduled due date on an annual basis, with an aim to improve over time. The 2018/19 and 2019/20 targets have been adjusted accordingly.

Discussion

Overall, our safety results in Fiscal 2017/18 continued the trend of year-over-year improvement compared to previous years. We are in the third year of implementing our five year safety plan.

As of March 31, 2018, BC Hydro had gone 1,239 days without a serious (permanently disabling) injury, and 2,784 days without a fatality. 1,239 days is the longest period without a serious injury or fatality in over 30 years of recorded data. BC Hydro's investments in safety initiatives have improved its safety performance to zero fatalities since 2010 and improved its frequency of serious injuries to once every 28 months. We continue to develop and implement various elements of the Safety & Health Management System aligned to the requirements of the ISO 45001 standard.

We finished Fiscal 2017/18 with a lost time injury frequency result of 0.88, compared to a target of 0.90. This improvement is most significant in the Operations group, which saw a 43 per cent reduction in its lost time injury frequency compared to the previous fiscal year. We believe our increased focus on the stay-at-work/return-to-work program and the senior management incident review calls are contributing to a safer culture.

We also saw 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 is one and a half times what was reported last fiscal; our contractor near miss and good catch reporting is more than three times what was reported last fiscal. These are excellent results as near miss and good catch reporting is a leading indicator of a strong safety culture and provides the opportunity to implement corrective actions to improve our safety performance.

In Fiscal 2017/18, 100 per cent of the corrective actions were completed within 30 days of the due date. The primary drivers for this improvement were: the corrective action governance team which supports the creation and implementation of complex corrective 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 leadership focus on ensuring corrective actions are completed in a timely manner.

Through our regular reviews of our risk profile and analysis of our safety incident data, we will continue our efforts to keep our workers, contractors and the public safe.

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, 2018 (fiscal 2018) and should be read in conjunction with the Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2018 and 2017.

The Company applies accounting standards as prescribed by the Province of British Columbia (the Province) which combines the accounting principles of International Financial Reporting Standards (IFRS) with regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (ASC 980), except as specified in Treasury Board Regulation B.C. Reg 146/2011 section 5(3) (collectively the Prescribed Standards). All financial information is expressed in Canadian dollars unless otherwise specified.

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

HIGHLIGHTS

- Net income for the year ended March 31, 2018 was $684 million which was the same as the prior year. Domestic revenues were $328 million higher than the prior fiscal year primarily due to higher average customer rates reflecting an average rate increase as approved by the British Columbia Utilities Commission (BCUC) of 3.5 per cent effective April 1, 2017. This was partially offset by $138 million higher domestic energy costs mainly due to higher planned purchases from Independent Power Producers, $48 million higher finance charges, $37 million higher personnel expenses, $35 million higher amortization and depreciation, $34 million higher other costs, and $20 million less costs eligible to be capitalized.

- Water inflows to the system during fiscal 2018 were 98 per cent of average compared to 101 per cent of average in the prior fiscal year. The below average inflows in fiscal 2018 compared to the prior fiscal year were the result of dry weather in the Peace region, partially offset by higher snowmelt contribution in the Columbia region.

- Capital expenditures, before contributions in aid of construction, for the year ended March 31, 2018 were $2,473 million, a $29 million increase over the prior fiscal year. 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, Ruskin Dam Safety and Powerhouse Upgrade, Distribution Wood Poles Replacements, W.A.C. Bennett Dam Riprap Upgrade, Horne Payne Substation Upgrade, and Kamloops Substation.

CONSOLIDATED RESULTS OF OPERATIONS

for the years ended March 31 ($ in millions)		**2018**		2017		Change
Total Revenues	**$**	**6,237**	$	5,874	$	363
Net Income	**$**	**684**	$	684	$	-
Capital Expenditures	**$**	**2,473**	$	2,444	$	29
Payment to the Province	**$**	**159**	$	259	$	(100)
GWh Sold (Domestic)		**57,173**		57,652		(479)

as at March 31 ($ in millions)		**2018**		2017		Change
Total Assets	**$**	**33,742**	$	31,888	$	1,854
Shareholder's Equity	**$**	**5,456**	$	4,909	$	547
Retained Earnings	**$**	**5,347**	$	4,822	$	525
Debt to Equity		**79 : 21**		80 : 20		n/a
Number of Domestic Customer Accounts		**2,018,044**		1,987,963		30,081
Total Reservoir Storage (GWh)		**10,877**		14,526		(3,649)

REVENUES

Total revenues after regulatory account transfers for the year ended March 31, 2018 were $6,237 million, an increase of $363 million or 6 per cent compared to the prior fiscal year. The increase includes higher domestic revenues of $328 million and higher trade revenues of $35 million. The table below shows revenues before regulatory account transfers, the amount of regulatory account transfers, and total revenues after regulatory account transfers.

	(in millions)				*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31		**2018**		2017	**2018**	2017	**2018**	2017
Domestic Revenues								
Residential	**$**	**2,097**	$	2,012	**18,150**	18,068	**$ 115.54**	$ 111.36
Light industrial and commercial		**1,860**		1,800	**18,874**	18,968	**98.55**	94.90
Large industrial		**811**		770	**13,440**	13,177	**60.34**	58.44
Other sales		**437**		428	**6,709**	7,439	**65.14**	57.53
Total Domestic Revenues Before Regulatory Transfers		**5,205**		5,010	**57,173**	57,652	**91.04**	86.90
Rate smoothing and energy deferral regulatory transfers		**322**		189	**-**	-	**-**	-
Total Domestic Revenues	**$**	**5,527**	$	5,199	**57,173**	57,652	**$ 96.67**	$ 90.18
Trade Revenues								
Gross electricity and gas	**$**	**1,272**	$	1,348	**34,595**	36,574	**$ 34.76**	$ 33.44
Less: forward electricity and gas purchases		**(562)**		(673)	**-**	-	**-**	-
Total Trade Revenues [1]	**$**	**710**	$	675	**34,595**	36,574	**$ 20.52**	$ 18.46
Total Revenues	**$**	**6,237**	$	5,874	**91,768**	94,226	**$ 67.96**	$ 62.34

[1] Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer and this is reflected in the cost of energy table.
[2] 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

Domestic revenues for the year ended March 31, 2018 were $5,527 million, an increase of $328 million, or 6 per cent, compared to the prior fiscal year. Before regulatory account transfers, the increase over the prior fiscal year was $195 million, or 4 per cent, of which $165 million was driven by higher average customer rates that reflect the 3.5 per cent rate increase effective April 1, 2017, as approved by the BCUC. Large industrial revenues were also higher due to incremental volumes in the oil and gas sector and wood manufacturing sector.

In addition, there were $133 million higher regulatory account transfers related to the Rate Smoothing account, Non-Heritage Deferral Account (NHDA), and Heritage Deferral Account (HDA). Variances between actual and planned load are deferred to the NHDA and variances between actual and planned other energy sales are deferred to the HDA and NHDA. Changes to regulatory account balances are discussed in the *Regulatory Transfers* section.

Trade Revenues

Powerex, a wholly owned subsidiary of the Company, is an active participant in western energy markets, buying and selling wholesale power, natural gas, ancillary services, clean and renewable power, and other environmental 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's trade activities earn income to lower the Company's customer rates 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, 2018 were $710 million, an increase of $35 million or 5 per cent compared with the prior fiscal year. The increase in trade revenues related to an increase in the average energy sales price primarily during the first half of the year, driven by increased demand in California largely due to a series of heatwaves resulting in high prices in that region.

Variances between actual and planned trade revenues are transferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the year ended March 31, 2018, total operating expenses after regulatory account transfers were $4,900 million which were $315 million higher than the prior fiscal year. The increase over the prior fiscal year was primarily due to higher energy costs of $173 million, $37 million higher personnel expenses, $35 million higher amortization and depreciation, $34 million higher other costs, and $20 million less costs eligible to be capitalized.

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 after regulatory transfers for the year ended March 31, 2018 were $2,267 million, $173 million or 8 per cent higher than the prior fiscal year. The increase was primarily due to higher domestic energy costs of $138 million and higher trade energy costs of $35 million. The table below shows energy costs before regulatory account transfers, the amount of regulatory account transfers, and total energy costs after regulatory account transfers.

for the years ended March 31	*(in millions)* **2018**	2017	*(gigawatt hours)* **2018**	2017	*($ per MWh)* [2] **2018**	2017
Domestic Energy Costs						
Water rental payments (hydro generation)[1]	**$ 324**	$ 346	**48,525**	48,483	**$ 6.68**	$ 7.14
Purchases from Independent Power Producers	**1,312**	1,213	**14,354**	13,644	**91.40**	88.90
Other electricity purchases - Domestic	**3**	3	**150**	131	**20.00**	22.90
Gas and transportation for thermal generation	**12**	18	**91**	74	**131.87**	243.24
Transmission charges and other expenses	**16**	25	**115**	118	**-**	-
Columbia River Treaty Related Agreements	**(41)**	(23)	**-**	-	**-**	-
Allocation from (to) trade energy	**(11)**	2	**(557)**	138	**21.74**	28.15
Total Domestic Energy Costs Before Regulatory Transfers	**1,615**	1,584	**62,678**	62,588	**25.77**	25.31
Energy deferral regulatory transfers	**131**	24	**-**	-	**-**	-
Total Domestic Energy Costs	**$ 1,746**	$ 1,608	**62,678**	62,588	**$ 27.86**	$ 25.69
Trade Energy Costs						
Gross electricity and remarketed gas	**$ 774**	$ 880	**34,146**	36,179	**$ 22.40**	$ 24.04
Less: forward electricity and gas purchases	**(562)**	(673)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**212**	207	**-**	-	**-**	-
Transmission charges and other expenses	**278**	262	**-**	-	**-**	-
Allocation (to) from domestic energy	**11**	(2)	**557**	(138)	**21.74**	28.15
Total Trade Energy Costs Before Regulatory Transfers	**501**	467	**34,703**	36,041	**14.44**	12.96
Trade net margin regulatory transfer	**20**	19	**-**	-	**-**	-
Total Trade Energy Costs	**$ 521**	$ 486	**34,703**	36,041	**$ 15.01**	$ 13.48
Total Energy Costs	**$ 2,267**	$ 2,094	**97,381**	98,629	**$ 23.28**	$ 21.23

[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 for the year ended March 31, 2018 were $1,746 million, an increase of $138 million or 9 per cent compared to the prior fiscal year. The significant variances from the prior fiscal year, before regulatory account transfers, were mainly due to $99 million higher purchases from Independent Power Producers as an increased number of Independent Power Producers were in operation in the current fiscal year. This was partially offset by lower water rental payments of $22 million, mainly due to the elimination of the higher Tier 3 water rental rate which was phased out during calendar 2017, and higher recoveries of $18 million from water transactions associated with the Columbia River Treaty related agreements.

In addition, there were $107 million higher regulatory account transfers related to the HDA and NHDA. Variances between actual and planned domestic energy costs are transferred to the HDA and NHDA. Changes to regulatory account balances are discussed in the *Regulatory Transfers* section.

Trade Energy Costs

Total trade energy costs before regulatory account transfers for the year ended March 31, 2018 were $501 million, an increase of $34 million or 7 per cent compared with the same period in the prior fiscal year. The increase in trade energy costs was primarily driven by higher transmission charges and other expenses. The increase was partly offset by a decrease in the average energy purchase volume and average energy purchase price for the period.

Variances between actual and planned trade energy costs are transferred to the TIDA.

Water Inflows and Reservoir Storage

Water inflows (energy equivalent) to the system during fiscal 2018 were 98 per cent of average compared to 101 per cent of average in the prior fiscal year. The below average inflows in fiscal 2018 compared to the prior fiscal year were the result of dry weather in the Peace region, partially offset by higher snowmelt contribution in the Columbia region.

Total reservoir storage as at March 31, 2018 was 10,877 GWh, a decrease of 3,649 GWh compared to total reservoir storage as at March 31, 2017 of 14,526 GWh due to dry weather and a reduction in overall inflows, and strong electricity prices which resulted in more exports. Total reservoir storage declined below the low end of the 10-year historical range (12,086 to 19,548 GWh between 2008 and 2017) due to the same reasons described above.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the year ended March 31, 2018 were $578 million, $37 million higher than the prior fiscal year primarily due an increase in current service pension costs as a result of a change in the forecasting methodology which was directed by the BCUC.

Materials and External Services

Expenditures on materials and external services for the year ended March 31, 2018 were $615 million, comparable to materials and external services of $608 million in the prior fiscal year.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and the amortization of certain regulatory assets and liabilities. For the year ended March 31, 2018, amortization and depreciation expense was $1,267 million, $35 million higher than the prior fiscal year primarily due to higher depreciation of property, plant and equipment due to an increase in assets in service offset against lower amortization of regulatory accounts. For the year ended March 31, 2018, the amortization and depreciation expense included $437 million (2017 - $449 million) of amortization of regulatory account balances, which is the regulatory mechanism to recover the regulatory account balances in rates.

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, 2018 were $243 million, $9 million higher than the prior fiscal year primarily due to increased property values, and increased revenues from electricity sales.

Other Costs, Net of Recoveries

Other costs, net of recoveries primarily include gains and losses on the disposal of assets, certain cost recoveries classified as operating costs, and dismantling costs. For the year ended March 31, 2018, other costs net of recoveries were $89 million, $34 million higher than the prior fiscal year. The increase was primarily due to higher provisions, higher asset related costs incurred from asset write-offs, and higher dismantling costs that were expensed as planned in the current period, but drew down the balance in a regulatory account during the same period in 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. Certain overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS Property, Plant & Equipment regulatory account. These transfers are amortized over 40 years which approximates the composite average life of the Property, Plant & Equipment. In addition, starting in fiscal 2013, the ongoing impact of this change is being included in rates over a 10-year period through transfers to the IFRS Property, Plant & Equipment Regulatory Account as approved by the BCUC. As such, each year, 1/10th more of ineligible costs will be charged to operating costs such that by the end of year ten, all ineligible costs will be charged to operating costs.

Capitalized costs for the year ended March 31, 2018 were $159 million, $20 million lower than the prior fiscal year. The decrease in capitalized costs is consistent with the additional ineligible costs being charged to operating costs as noted above.

FINANCE CHARGES

Finance charges for the year ended March 31, 2018 were $653 million, $48 million higher than the prior fiscal year. The increase was primarily due to higher volume of long-term debt borrowings, higher lease charges, and higher long-term and short-term interest rates. This increase was partially offset by higher interest during construction costs which were capitalized.

REGULATORY TRANSFERS

The Company presents its results and financial position under the Prescribed Standards. Under the Prescribed Standards, the Company applies the principles of IFRS combined with ASC 980 to reflect the rate-regulated environment in which the Company operates. These Prescribed Standards allow for the deferral of costs and recoveries that under IFRS may otherwise be included in the determination of total comprehensive income. The deferred amounts are either recovered or refunded through future rate adjustments.

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)		**2018**		2017
Energy Deferral Accounts				
Heritage Deferral Account	**$**	**(60)**	$	(31)
Non-Heritage Deferral Account		**(122)**		(17)
Trade Income Deferral Account		**(21)**		(15)
		(203)		(63)
Forecast Variance Accounts				
Total Finance Charges		**(26)**		(12)
Rate Smoothing		**327**		201
Non-Current Pension Costs		**(123)**		(130)
Debt Management		**29**		(187)
Other		**41**		43
		248		(85)
Capital-Like Accounts				
Demand-Side Management		**82**		97
IFRS Property, Plant & Equipment		**90**		112
		172		209
Non-Cash Accounts				
Environmental Provisions & Costs		**0**		(24)
First Nations Provisions & Costs		**20**		18
Other		**(3)**		(1)
		17		(7)
Amortization of regulatory accounts		**(437)**		(440)
Interest on regulatory accounts		**61**		75
Net change in regulatory accounts	**$**	**(142)**	$	(311)

For the year ended March 31, 2018, there was a net reduction of $142 million to the Company's regulatory accounts compared to a net reduction of $311 million in the prior fiscal year. The net regulatory asset balance as at March 31, 2018 was $5,455 million compared to $5,597 million as at March 31, 2017.

Net reductions to the regulatory accounts during the year ended March 31, 2018 included:

- Net amortization of $437 million. Amortization is the regulatory mechanism to recover the regulatory account balances in rates;

- $203 million to the energy deferral accounts, primarily due to lower purchases from Independent Power Producers and finance lease expenses, higher recoveries from Columbia River Treaty-related agreements, lower electricity purchases from market and higher trade net income; and

- $123 million to the Non-Current Pension Costs Regulatory Accounts, primarily due to a reduction in post-retirement benefit plan liability as a result of the 50% reduction in Medical Service Plan premiums partially offset by an increase due to a reduction of the discount rate.

These net reductions were partially offset by:

- $327 million of additions to the Rate Smoothing Regulatory Account to smooth the impacts of the rate increases during the 10 Year Rates Plan period;

- $90 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;

- $82 million of planned additions to the Demand-Side Management Regulatory Account, which support energy conservation; and

- Interest on regulatory accounts of $61 million.

Net regulatory account balances are as follows:

as at March 31 (in millions)	**2018**	2017
Energy Deferral Accounts		
Heritage Deferral Account	**$ (104)**	$ (53)
Non-Heritage Deferral Account	**463**	756
Trade Income Deferral Account	**127**	194
	486	897
Forecast Variance Accounts		
Total Finance Charges	**(139)**	(215)
Rate Smoothing	**815**	488
Non-Current Pension Costs	**304**	485
Debt Management	**(158)**	(187)
Other	**91**	21
	913	592
Capital-Like Accounts		
Demand-Side Management	**903**	916
Smart Metering & Infrastructure	**239**	261
IFRS Property, Plant & Equipment	**1,025**	962
Site C	**472**	453
Capital Project Investigation Costs	**15**	20
	2,654	2,612
Non-Cash Accounts		
Environmental Provisions & Costs	**261**	294
First Nations Provisions & Costs	**518**	532
IFRS Pension	**535**	574
Other	**88**	96
	1,402	1,496
Net Regulatory Asset	**$ 5,455**	$ 5,597

BC Hydro has regulatory mechanisms in place to collect 25 of 28 regulatory accounts in use or with balances at March 31, 2018 in rates over various periods, which represent approximately 76 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 2017/18-2019/20 was originally filed in February 2017 and a revised plan was filed in September 2017 with forecast net income for fiscal 2018 remaining unchanged at $698 million.

The table below provides an overview of BC Hydro's fiscal 2018 financial performance results, relative to its September 2017 Service Plan forecast.

Consolidated Statement of Operations

(in millions)	**Actual** 2017	**Actual** 2018	**2018 Service Plan**[2] 2018	**Variance to 2018 Service Plan**[2]
Revenues				
Domestic	$ 5,199	$ 5,527	$ 5,474	$ 53
Trade	675	710	824	(114)
	5,874	6,237	6,298	(61)
Expenses				
Operating Costs				
Cost of energy	2,094	2,267	2,382	115
Other operating expenses				
Personnel expenses, materials and external services[1]	946	1,012	1,017	5
Amortization	1,232	1,267	1,231	(36)
Finance charges	605	653	661	8
Grants and taxes	234	243	239	(4)
Other	79	111	71	(40)
	5,190	5,553	5,600	47
Net Income	$ 684	$ 684	$ 698	$ (14)

[1] *These amounts are net of capitalized overhead and recoveries.*
[2] *Column may not add due to rounding.*

Net income for fiscal 2018 was $684 million, $14 million lower than the 2017/18-2019/20 Service Plan filed in September 2017 of $698 million. The lower net income was mainly the result of higher capital asset write-offs.

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.

In accordance with Order in Council No. 589/2016, the fiscal 2017 Payment to the Province was $259 million and was paid in March 2017. As a result, the Payment for fiscal 2018 will be $159 million and the Company has accrued $159 million as at March 31, 2018 (2017 - $nil).

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the year ended March 31, 2018 was $1,725 million, compared with cash flow provided by operating activities of $1,327 million in the prior fiscal year. The increase was mainly due to higher domestic revenue primarily due to higher average customer rates and higher consumption, lower cash flow used from changes in working capital, partially offset against higher domestic energy costs driven by higher purchases from Independent Power Producers.

The long-term debt balance net of sinking funds as at March 31, 2018 was $20,182 million compared to $19,845 million as at March 31, 2017. The increase was primarily to fund capital expenditures and mainly a result of an increase in long-term bond issuances for net proceeds of $1,156 million ($1,200 million par value) and net foreign exchange losses of $26 million. This increase was partially offset by lower revolving borrowings of $785 million, long-term bond redemptions totaling $40 million par value, amortization of premiums of $9 million, and sinking fund income of $9 million.

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)		**2018**		2017
Transmission lines and substations replacements and expansion	**$**	**479**	$	515
Generation replacements and expansion		**544**		585
Distribution system improvements and expansion		**515**		449
General, including technology, vehicles and buildings		**230**		232
Site C		**705**		663
Total Capital Expenditures	**$**	**2,473**	$	2,444

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: Interior to Lower Mainland Transmission Line, Horne Payne Substation Upgrade, Kamloops Substation, Transmission Wood Structure and Framing Replacement, South Fraser Transmission Relocation, Fernie Substation Upgrade, South Surrey Area Reinforcement, Campbell River Substation Capacity Upgrade, Peace Region Electric Supply, Peace Region Load Shedding Remedial Action Scheme, Barnard 60kV Circuit Breaker and Relay Building, Kidd 2 T1 Emergency Replacement, and Bear Mountain Terminal Load Capacity Increase.

Generation capital expenditures include expenditures for the following projects: John Hart Generating Station Replacement, Ruskin Dam Safety and Powerhouse Upgrade, W.A.C. Bennett Dam Riprap Upgrade, Cheakamus Unit 1 and Unit 2 Generator Replacement, Bridge River 2 Units 5 and 6 Upgrade, Bridge River 1 Unit Transformers T1 & T2 Replacement, G.M. Shrum G1-G10 Control System Upgrade, and Bridge River 1 Unit Switchgear Replacement.

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 technology projects, various building development programs, and vehicles.

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.

BC Hydro Fiscal 2017-2019 Revenue Requirements Application

In July 2016, BC Hydro filed an F17-F19 Revenue Requirements Application to approve its revenue requirements for a three-year test period covering fiscal 2017 to fiscal 2019. The Application requested 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 alignment with the 10 Year Rates Plan.

The Province then provided BC Hydro with a new Mandate Letter with the expectation that BC Hydro would freeze rates for fiscal 2019, work with the Province to conduct a comprehensive review of BC Hydro’s activities, and develop a refreshed plan to keep electricity rates low and predictable over the long-term.

On November 8, 2017, BC Hydro filed an Application amending our original Application and requesting a 0 per cent rate increase for fiscal 2019.

On March 1, 2018, the BCUC issued its decision on BC Hydro’s RRA (Order No. G-47-18). In the decision, the BCUC approved final rate increases for fiscal 2017, 2018 and 2019 of 4 per cent, 3.5 per cent and 3 per cent respectively, declining BC Hydro’s amended request to freeze rates for fiscal 2019.

BC Hydro Waneta Transaction

On October 30, 2017, BC Hydro submitted an Application to the BCUC under section 44.2 of the Utilities Commission Act with respect to BC Hydro’s intention to purchase Teck Metals Ltd.’s (Teck) two-third interest in the Waneta Dam and associated assets for $1.2 billion. The purchase includes a lease agreement which would allow Teck to continue using the facility to supply power to Teck’s smelter at fixed prices for a 20-year period, with a 10-year extension option. The Waneta dam is located near the mouth of the Pend d’Oreille River near Trail, BC, and has a generating capacity of 2,670 GWh per year. BC Hydro currently owns a one-third interest in the facility and its generation.

The evidentiary portion of the BCUC regulatory process for the Application is substantially complete.

BC Hydro requires approval by the BCUC no later than August 1, 2018 as a condition of the purchase agreement between BC Hydro and Teck.

Electricity Purchase Agreements

In October and November 2017, BC Hydro submitted separate applications under section 71 of the *Utilities Commis*sion Act for two electricity purchase agreements: (i) the Doran Taylor Project, a 5.6 MW run of river hydroelectric plant near Port Alberni, and (ii) Eagle Lake C2 Micro Hydro Project, a 0.2 MW micro generation project in West Vancouver. The BCUC issued Orders E-6-18 accepting the Doran Taylor Electricity Purchase Agreement renewal for filing on February 9, 2018, and Order E-11-18 accepting the Eagle Lake C2 EPA for filing on March 29, 2018. BC Hydro also filed the biomass extension agreements signed with Armstrong Wood Waste and Northwest Energy Williams Lake with the BCUC on February 27, 2018. The BCUC has initiated a proceeding to review both of these agreements.

Capital Expenditures and Projects Review

The BCUC initiated an inquiry in May 2016 to review the regulatory oversight of BC Hydro’s capital expenditures and projects. At BC Hydro’s request, the BCUC scheduled the proceeding to commence following the Fiscal 2017 – Fiscal 2019 Revenue Requirements Application decision. BC Hydro submitted our initial proposal in April 2018, addressing the specific scope items agreed to by BC Hydro and interveners, which included draft updated capital filing guidelines. These draft guidelines expand 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.

The BCUC has issued information requests, and held a workshop in May 2018 on BC Hydro’s proposed guidelines. BC Hydro will submit a revised proposal in June 2018 as required reflecting input from the workshop.

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 2017-2019 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 45 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 energy cost 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 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 2018, overall energy delivered from Independent Power Projects was slightly lower than forecast, primarily due to lower than forecast generation for wind projects, delays in reaching commercial operations for projects in development, and lower than planned thermal generation. Lower than forecast generation from these projects was partially offset by higher than forecast generation from several hydro projects.

Interest Rates

A portion of BC Hydro's existing debt is subject to changes to interest rates (variable rate debt) 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, 2018, approximately 16 per cent of existing debt had a maturity of one year or less and is recognized as variable rate debt.

In addition, BC Hydro is exposed to interest rate risk on future long-term debt issuances. In an effort to reduce variability in interest expense on future long-term debt issuances and lock in long-term interest rates, BC Hydro has hedged $4.9 billion (approximately 58 per cent) of its forecast long-term debt issuances over the remaining 10 Year Rates Plan period.

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 2018 forecast net income for fiscal 2019 at $712 million which is consistent with the amount required by Order in Council No. 590.

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 2019 assumes average water inflows (100 per cent of average), domestic sales of 52,664 GWh, average market energy prices of US $21.43/MWh, short-term interest rates of 1.72 per cent, and a US dollar exchange rate of US $0.8088.

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 2019. 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 2018
Customer Load [1]	+/-1%	$35	52,102 GWh	51,023 GWh	52,102 GWh
Interest rates	+/- 100 basis points	$35	1.33% [2]	0.87% [2]	1.33% [2]
Electricity/Gas trade margins [3]	+/-10%	$20	$215	$127	$209
Hydro generation [4]	+/-1%	$10	49,352 GWh	41,230 GWh	47,926 GWh
Exchange rates (US/ CDN)	+/- $0.01	$5	$0.95 [5]	$0.76 [5]	$0.78[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 for fiscal 2018 are the Bank of Canada average daily rates. Prior to fiscal 2018, exchange rates were the annual daily average US Dollar noon rates.

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 the financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)). 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 7, 2018. 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 financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)). The 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	Ryan Layton
President and Chief Operating Officer	Acting Chief Financial Officer

Vancouver, Canada
June 7, 2018

INDEPENDENT AUDITORS' 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:

We have audited the accompanying consolidated financial statements of British Columbia Hydro and Power Authority, which comprise the consolidated statement of financial position as at March 31, 2018, the consolidated statements of comprehensive income, changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with the financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)), and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of British Columbia Hydro and Power Authority as at March 31, 2018 and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with the financial reporting provisions prescribed by the Province of British Columbia pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* and Section 9.1 of the *Financial Administration Act* (see Note 2(a)).

KPMG LLP

Chartered Professional Accountants
Vancouver, Canada
June 7, 2018

AUDITED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

for the years ended March 31 (in millions)	**2018**	2017
Revenues		
Domestic	**$ 5,527**	$ 5,199
Trade	**710**	675
	6,237	5,874
Expenses		
Operating expenses (Note 5)	**4,900**	4,585
Finance charges (Note 6)	**653**	605
Net Income	**684**	684
OTHER COMPREHENSIVE INCOME (LOSS)		
Items Reclassified Subsequently to Net Income		
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 19)	**57**	(11)
Reclassification to income of derivatives designated as cash flow hedges (Note 19)	**(30)**	(11)
Foreign currency translation gains (losses)	**(5)**	6
Other Comprehensive Income (Loss)	**22**	(16)
Total Comprehensive Income	**$ 706**	$ 668

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

as at March 31 (in millions)	**2018**	2017
ASSETS		
Current Assets		
Cash and cash equivalents (Note 8)	**$ 42**	$ 49
Accounts receivable and accrued revenue (Note 9)	**810**	808
Inventories (Note 10)	**144**	185
Prepaid expenses	**167**	162
Current portion of derivative financial instrument assets (Note 19)	**174**	144
	1,337	1,348
Non-Current Assets		
Property, plant and equipment (Note 11)	**25,083**	22,998
Intangible assets (Note 12)	**591**	601
Regulatory assets (Note 13)	**5,892**	6,127
Derivative financial instrument assets (Note 19)	**156**	215
Other non-current assets (Note 14)	**683**	599
	32,405	30,540
	$ 33,742	$ 31,888
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Note 15)	**$ 1,621**	$ 1,190
Current portion of long-term debt (Note 16)	**3,344**	2,878
Current portion of derivative financial instrument liabilities (Note 19)	**112**	60
	5,077	4,128
Non-Current Liabilities		
Long-term debt (Note 16)	**17,020**	17,146
Regulatory liabilities (Note 13)	**437**	530
Derivative financial instrument liabilities (Note 19)	**66**	41
Contributions in aid of construction	**1,874**	1,765
Post-employment benefits (Note 18)	**1,474**	1,566
Other non-current liabilities (Note 20)	**2,338**	1,803
	23,209	22,851
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**5,347**	4,822
Accumulated other comprehensive income	**49**	27
	5,456	4,909
	$ 33,742	$ 31,888

Commitments and Contingencies (Notes 11 and 21)

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 Losses on Cash Flow Hedges	Total Accumulated Other Comprehensive Income	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2016	$ 77	$ (34)	$ 43	$ 60	$ 4,397	$ 4,500
Payment to the Province (Note 17)	-	-	-	-	(259)	(259)
Comprehensive Income (Loss)	6	(22)	(16)	-	684	668
Balance as at March 31, 2017	83	(56)	27	60	4,822	4,909
Payment to the Province (Note 17)	-	-	-	-	(159)	(159)
Comprehensive Income (Loss)	(5)	27	22	-	684	706
Balance as at March 31, 2018	$ 78	$ (29)	$ 49	$ 60	$ 5,347	$ 5,456

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

for the years ended March 31 (in millions)	**2018**	2017
Operating Activities		
Net income	**$ 684**	$ 684
Regulatory account transfers (Note 13)	**(295)**	(129)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 13)	**437**	440
Amortization and depreciation expense (Note 7)	**830**	783
Unrealized (gains) losses on mark-to-market	**80**	(204)
Employee benefit plan expenses	**105**	113
Interest accrual	**795**	757
Other items	**135**	114
	2,771	2,558
Changes in:		
Accounts receivable and accrued revenue	**46**	(159)
Prepaid expenses	**(29)**	11
Inventories	**40**	(28)
Accounts payable, accrued liabilities and other non-current liabilities	**(320)**	(367)
Contributions in aid of construction	**115**	110
Other non-current assets	**(103)**	(39)
	(251)	(472)
Interest paid	**(795)**	(759)
Cash provided by operating activities	**1,725**	1,327
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(2,123)**	(2,513)
Cash used in investing activities	**(2,123)**	(2,513)
Financing Activities		
Long-term debt:		
Issued (Note 16)	**1,156**	1,340
Retired (Note 16)	**(40)**	-
Receipt of revolving borrowings	**7,749**	10,046
Repayment of revolving borrowings	**(8,536)**	(9,583)
Payment to the Province (Note 17)	**-**	(585)
Other items	**62**	(27)
Cash provided by financing activities	**391**	1,191
Increase (decrease) in cash and cash equivalents	**(7)**	5
Cash and cash equivalents, beginning of year	**49**	44
Cash and cash equivalents, end of year	**$ 42**	$ 49

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, 2018 AND 2017

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) including BC Hydro's one third interest in the Waneta Dam and Generating Facility (Waneta). All intercompany transactions and balances are eliminated on consolidation.

The Company accounts for its one third interest in Waneta as a joint operation. BC Hydro has classified Waneta as a joint operation on the basis that fundamental operating and investing decisions relating to Waneta require unanimous approval by each co-owner. The consolidated financial statements include the Company's proportionate share in Waneta, including its share of any liabilities and expenses incurred jointly with Teck Metals Ltd. (Teck) and its revenue from the sale of the output in relation to Waneta.

NOTE 2: BASIS OF PRESENTATION

(a) Basis of Accounting

These consolidated financial statements have been prepared in accordance with the significant accounting policies as set out in Note 4. These policies have been established based on the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). In accordance with the directive issued by the Province's Treasury Board, BC Hydro is to prepare these consolidated financial statements in accordance with the accounting principles of International Financial Reporting Standards (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 application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the British Columbia Utilities Commission (BCUC) for inclusion in future customer rates. Such regulatory costs and recoveries would be included in the determination of comprehensive income in the absence of regulatory deferral.

BC Hydro's accounting policies with respect to its regulatory accounts are disclosed in Note 4(a) and the impact of the application of ASC 980 on these consolidated financial statements is described in Note 13.

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 7, 2018.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for natural gas inventories in Note 4(j), financial instruments that are accounted for according to the financial instrument categories as defined in Note 4(k) and the post-employment benefits obligation as described in Note 4(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 the Prescribed Standards 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 18 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 IAS 39, *Financial Instruments: Recognition and Measurement*. 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 BCUC is considered probable, BC Hydro defers such costs in advance of a final decision of the BCUC. If the BCUC subsequently denies the application for regulatory treatment, the remaining deferred amount is recognized immediately in comprehensive income.

NOTE 3: CHANGES IN ACCOUNTING POLICIES

Effective April 1, 2017, the Company adopted the following amendments to IFRS standards, which impacted disclosures in the consolidated financial statements.

- Amendments to IAS 7, *Statement of Cash Flows* – see additional supplemental cash flow information relating to financing activities in Note 16.

NOTE 4: 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. Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

BC Hydro applies the principles of ASC 980 to reflect the impacts of the rate-regulated environment in which BC Hydro operates (see Note 13). Generally, this results in the deferral and amortization of costs and recoveries to allow for adjustment of future customer rates. 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.

These accounting policies support BC Hydro's rate regulation and regulatory accounts have been established through ongoing application to, and approval by, the BCUC.

(b) Revenue

Domestic revenues comprise sales to customers within the province of British Columbia and sales of firm energy outside the province under long-term contracts that are reflected in the Company's domestic load requirements. Other sales outside the province are classified as trade.

Revenue is recognized at the time energy is delivered to the Company's customers, the amount of revenue can be measured reliably and collection is reasonably assured. Revenue is determined on the basis of billing cycles and also includes accruals for electricity deliveries not yet billed.

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.

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, for the sale of products, the significant risks and rewards of ownership transfer to the buyer, and for the sale of services, those services are rendered.

(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.

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 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. A financial asset is impaired if evidence indicates that a loss event has occurred after the initial recognition of the asset, and that the loss event had a negative effect on the estimated future cash flows of that asset that can be estimated reliably.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the asset's original effective interest rate. An impairment loss in respect of an available-for-sale financial asset is calculated by reference to its fair value.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net income. Any cumulative loss in respect of an available-for-sale financial asset previously recognized in other comprehensive income and presented in unrealized gains/losses on available-for-sale financial assets in equity is transferred to net income.

An impairment loss is reversed if the reversal can be related to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost and available-for-sale financial assets that are debt securities, the reversal is recognized in net income.

(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 19). 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, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities as defined by the standard. 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 fair value through profit or loss 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 available-for-sale are subsequently measured at fair value, with changes in those fair values recognized in other comprehensive income until realized or impaired. Financial assets classified as held-to-maturity, loans and receivables, and financial liabilities classified as other financial liabilities are subsequently measured at amortized cost using the effective interest method of amortization less any impairment. Derivatives, including embedded derivatives that are not closely related to the host contract and are separately accounted for are generally classified as fair value through profit or loss and recorded at fair value in the statement of financial position.

The following table presents the classification of financial instruments in the various categories:

Category	**Financial Instruments**
Financial assets and liabilities at fair value through profit or loss	Short-term investments Derivatives not in a hedging relationship
Loans and receivables	Cash Restricted cash Accounts receivable and other receivables
Held to maturity	US dollar sinking funds
Other financial liabilities	Accounts payable and accrued liabilities Revolving borrowings Long-term debt (including current portion due in one year) Finance lease obligations, First Nations liabilities and other liabilities presented in other long-term liabilities

(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 19.

(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 recorded using the mark-to-market method of accounting 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.

Derivative financial instruments are also used by Powerex to manage economic exposure to market risks relating to commodity prices. Derivatives used for energy trading activities that are not designated as hedges are recorded using the mark-to-market method of accounting 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 held to maturity. 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 sinking fund income.

(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).

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.

Unearned revenue also includes tariff supplemental charges related to a transmission line due in advance of electricity being delivered and are due at the time the customer connects to the transmission line. The unearned revenue is recognized as revenue over the customers' expected term of service.

(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, if 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 cost 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 21.

(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

The Company has 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 Interpretations Not Yet Adopted

A number of new standards, and amendments to standards and interpretations, are not yet effective for the year ended March 31, 2018, 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:

Revenue from Contracts with Customers

IFRS 15, *Revenue from Contracts with Customers* replaces existing standards IAS 18, *Revenue*, IAS 11, *Construction Contracts* and IFRIC 18, *Transfers of Assets from Customers* for annual periods beginning on or after January 1, 2018. The IFRS 15 recognition model is based on the principle of the transfer of control rather than the transfer or risks and rewards used under IAS 18. IFRS 15 applies a five-step model to determine when to recognize revenue and determine the measurement of the revenue. The application of the new model may impact the timing (point-in-time versus over time) and the amount of revenue recognized.

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.

The Company has performed detailed analysis on each of its revenue streams that is within the scope of the new standard through review of the underlying contracts with customers to determine the impact of IFRS 15 on the consolidated financial statements. A significant portion of the Company's revenue is generated from providing electricity goods and services. The Company will continue to recognize electricity revenue over time as the Company's customers simultaneously receive and consume the electricity as it is provided. The adoption of IFRS 15 will have no material impact on any revenue stream with the exception of accounting for the Skagit River Agreement (refer to note 4(m)). The adoption of the new standard will impact the measurement of the transaction price due to a significant customer financing component under the Skagit River Agreement.

The Company will adopt IFRS 15 effective April 1, 2018, using the modified retrospective approach. Upon adoption, the Company will recognize the cumulative effect of initially applying the new standard. The effect identified to date is an increase in the Heritage Deferral Account's liability balance by $319 million related to the Skagit River Agreement, and a corresponding decrease in the unearned revenue liability account. On an ongoing basis, there will be financial statement presentation changes relating to unearned revenue and changes in the measurement of revenue and interest charges relating to the Skagit River Agreement. The consolidated financial statements will also include enhanced disclosure relating to significant judgments used in evaluating how and when revenues are recognized and information relating to contract liabilities. The adoption of the new standard will not have a significant impact on BC Hydro's operations.

Financial Instruments

IFRS 9, *Financial Instruments* replaces IAS 39, *Financial Instruments: Recognition and Measurement* for annual periods beginning on or after January 1, 2018. The key changes are:

- IFRS 9 replaces the existing IAS 39 rules-based requirements for classification and measurement of financial assets with a model that is driven by cash flow characteristics and the business model in which an asset is held.
- The financial asset impairment model moves from the 'incurred loss' model in IAS 39 to a single, forward-looking 'expected loss' model. The expected-loss impairment model requires recognition of expected credit losses sooner than under IAS 39.
- A revised approach to hedge accounting that more closely aligns hedge accounting with risk management activities undertaken by companies; however, entities may elect to continue to apply the hedge accounting in IAS 39.

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.

The Company will adopt IFRS 9 effective April 1, 2018, using the modified retrospective approach. BC Hydro will continue to apply the hedge accounting requirement of IAS 39. Upon adoption of IFRS 9, the credit loss allowance is expected to increase and the Company is currently in the process of assessing the magnitude of the impact on the consolidated financial statements. On an ongoing basis, the financial statements will also include additional disclosure.

Leases

IFRS 16, *Leases* replaces the existing standard IAS 17, *Leases* and IFRIC 4*, Determining Whether an Arrangement Contains a Lease* for annual periods beginning on or after January 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 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.

The effective date for BC Hydro is April 1, 2019 with early adoption permitted. The Company is assessing the effect of adoption of IFRS16 in its consolidated financial statements.

Investments in Associates and Joint Ventures, and Employee Benefits

The Company does not have any plans to early adopt any of the following amended standards:

- Amendments to IAS 28, *Investments in Associates and Joint Ventures* (effective April 1, 2019)
- Amendments to IAS 19, *Employee Benefits* (effective April 1, 2019)

The effective date for BC Hydro is April 1, 2019 with early adoption permitted. The Company is assessing the effect of adoption of these two standards in its consolidated financial statements.

NOTE 5: OPERATING EXPENSES

(in millions)	**2018**	2017
Electricity and gas purchases	**$ 1,775**	$ 1,576
Water rentals	**319**	349
Transmission charges	**173**	169
Personnel expenses	**578**	541
Materials and external services	**615**	608
Amortization and depreciation (Note 7)	**1,267**	1,232
Grants and taxes	**243**	234
Other costs, net of recoveries	**89**	55
Less: Capitalized costs	**(159)**	(179)
	$ 4,900	$ 4,585

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2018 AND 2017

NOTE 6: FINANCE CHARGES

(in millions)		**2018**		2017
Interest on long-term debt	**$**	**828**	$	767
Interest on finance lease liabilities		**45**		25
Less: Other recoveries		**(91)**		(94)
Capitalized interest		**(129)**		(93)
	$	**653**	$	605

Capitalized interest presented in the table above is after regulatory transfers. Actual interest capitalized to property, plant and equipment and intangible assets before regulatory transfers was $109 million (2017 - $81 million). The effective capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 4.1 per cent (2017 - 4.1 per cent).

NOTE 7: AMORTIZATION AND DEPRECIATION

(in millions)		**2018**		2017
Depreciation of property, plant and equipment	**$**	**746**	$	705
Amortization of intangible assets		**84**		78
Amortization of regulatory accounts		**437**		449
	$	**1,267**	$	1,232

NOTE 8: CASH AND CASH EQUIVALENTS

(in millions)		**2018**		2017
Cash	**$**	**11**	$	25
Short-term investments		**31**		24
	$	**42**	$	49

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2018 AND 2017

NOTE 9: ACCOUNTS RECEIVABLE AND ACCRUED REVENUE

(in millions)		**2018**		2017
Accounts receivable	**$**	**477**	$	526
Accrued revenue		**170**		138
Restricted cash		**77**		28
Other		**86**		116
	$	**810**	$	808

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

NOTE 10: INVENTORIES

(in millions)		**2018**		2017
Materials and supplies	**$**	**142**	$	145
Natural gas trading inventories		**2**		40
	$	**144**	$	185

There were no materials and supplies inventory impairments during the years ended March 31, 2018 and 2017. 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 $82 million (2017 - $84 million).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2018 AND 2017

NOTE 11: PROPERTY, PLANT AND EQUIPMENT

(in millions)	Generation	Transmission	Distribution	Land & Builidings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at March 31, 2016	$ 7,518	$ 7,071	$ 5,765	$ 650	$ 866	$ 2,410	$ 24,280
Net additions (transfers)	342	480	419	52	116	969	2,378
Disposals and retirements	(31)	(13)	(35)	(6)	(50)	(15)	(150)
Balance at March 31, 2017	7,829	7,538	6,149	696	932	3,364	26,508
Net additions (transfers)	877	404	447	109	115	933	2,885
Disposals and retirements	(176)	(16)	(36)	(4)	(29)	(23)	(284)
Balance at March 31, 2018	$ 8,530	$ 7,926	$ 6,560	$ 801	$ 1,018	$ 4,274	$ 29,109
Accumulated Depreciation							
Balance at March 31, 2016	$ (1,048)	$ (735)	$ (755)	$ (97)	$ (260)	$ -	$ (2,895)
Depreciation expense	(203)	(209)	(186)	(23)	(78)	-	(699)
Disposals and retirements	16	7	9	5	47	-	84
Balance at March 31, 2017	(1,235)	(937)	(932)	(115)	(291)	-	(3,510)
Depreciation expense	(212)	(217)	(192)	(24)	(88)	-	(733)
Disposals and retirements	172	7	11	3	24	-	217
Balance at March 31, 2018	$ (1,275)	$ (1,147)	$ (1,113)	$ (136)	$ (355)	$ -	$ (4,026)
Net carrying amounts							
At March 31, 2017	$ 6,594	$ 6,601	$ 5,217	$ 581	$ 641	$ 3,364	$ 22,998
At March 31, 2018	$ 7,255	$ 6,779	$ 5,447	$ 665	$ 663	$ 4,274	$ 25,083

(i) The Company includes its one-third interest in Waneta with a net book value of $674 million (2017 - $695 million) in Generation assets. Depreciation expense on the Waneta asset for the year ended March 31, 2018 was $21 million (2017 - $20 million).

On August 1, 2017, BC Hydro agreed to exercise its option to purchase the remaining two-thirds interest of Waneta from Teck for $1.2 billion. The purchase agreement includes a 20 year agreement, at fixed prices, providing Teck with a leasehold interest in the two-thirds portion of Waneta. This will enable Teck to use the electricity generated from its interest in Waneta to continue to serve its Trail smelter. Teck has an option to extend the agreement for a further 10 years. Completion of the purchase is subject to a number of conditions, including approval by the BCUC. BC Hydro requires approval by the BCUC no later than August 1, 2018 as a condition of the purchase agreement between BC Hydro and Teck.

(ii) Included within Distribution assets are the Company's portion of utility poles with a net book value of $1,052 million (2017 - $972 million) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2018 was $27 million (2017 - $25 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 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 2018 or fiscal 2017.

(iv) The Company has contractual commitments to spend $5,542 million on major property, plant and equipment projects (on individual projects greater than $50 million) as at March 31, 2018, which includes $1.2 billion relating to the purchase of the remaining two-thirds share of the Waneta from Teck.

Leased assets

Property, plant and equipment under finance leases of $695 million (2017 - $388 million), net of accumulated amortization of $54 million (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 March 31, 2016	$ 240	$ 149	$ 437	$ 19	$ 58	$ 903
Net additions (transfers)	5	19	48	7	(7)	72
Disposals and retirements	-	-	(13)	(2)	-	(15)
Balance at March 31, 2017	245	168	472	24	51	960
Net additions (transfers)	3	18	48	26	(12)	83
Disposals and retirements	-	-	(2)	(5)	(3)	(10)
Balance at March 31, 2018	$ 248	$ 186	$ 518	$ 45	$ 36	$ 1,033
Accumulated Amortization						
Balance at March 31, 2016	$ -	$ (63)	$ (220)	$ (11)	$ -	$ (294)
Amortization expense	-	(24)	(54)	-	-	(78)
Disposals and retirements	-	-	13	-	-	13
Balance at March 31, 2017	-	(87)	(261)	(11)	-	(359)
Amortization expense	-	(23)	(61)	-	-	(84)
Disposals and retirements	-	-	1	-	-	1
Balance at March 31, 2018	$ -	$ (110)	$ (321)	$ (11)	$ -	$ (442)
Net carrying amounts						
At March 31, 2017	$ 245	$ 81	$ 211	$ 13	$ 51	$ 601
At March 31, 2018	$ 248	$ 76	$ 197	$ 34	$ 36	$ 591

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: 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. For the year ended March 31, 2018, the impact of regulatory accounting has resulted in a net decrease to total comprehensive income of $142 million (2017 - $311 million net decrease) which is comprised of an increase to net income of $51 million (2017 - $108 million decrease) and a decrease to other comprehensive income of $193 million (2017 - $203 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 2017*	*Addition / (Reduction)*	*Interest*	*Amortization*	*Net Change*	***As at March 31 2018***
Regulatory Assets						
Non-Heritage Deferral Account	756	$ (122)	$ 26	$ (197)	$ (293)	**$ 463**
Trade Income Deferral Account	194	(21)	5	(51)	(67)	**127**
Demand-Side Management	916	82	-	(95)	(13)	**903**
First Nations Provisions & Costs	532	20	5	(39)	(14)	**518**
Non-Current Pension Costs	485	(123)	-	(58)	(181)	**304**
Site C	453	-	19	-	19	**472**
CIA Amortization	91	(3)	-	-	(3)	**88**
Environmental Provisions & Costs	294	-	(2)	(31)	(33)	**261**
Smart Metering & Infrastructure	261	-	10	(32)	(22)	**239**
IFRS Pension	574	-	-	(39)	(39)	**535**
IFRS Property, Plant & Equipment	962	90	-	(27)	63	**1,025**
Rate Smoothing	488	327	-	-	327	**815**
Other Regulatory Accounts	121	44	3	(26)	21	**142**
Total Regulatory Assets	6,127	294	66	(595)	(235)	**5,892**
Regulatory Liabilities						
Heritage Deferral Account	53	60	5	(14)	51	**104**
Foreign Exchange Gains and Losses	66	4	-	(39)	(35)	**31**
Debt Management	187	(29)	-	-	(29)	**158**
Total Finance Charges	215	26	-	(102)	(76)	**139**
Other Regulatory Accounts	9	(1)	-	(3)	(4)	**5**
Total Regulatory Liabilities	530	60	5	(158)	(93)	**437**
Net Regulatory Asset	$ 5,597	$ 234	$ 61	$ (437)	$ (142)	**$ 5,455**

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(in millions)	*As at April 1 2016*	*Addition / (Reduction)*	*Interest*	*Amortization*	*Net Change*	*As at March 31 2017*
Regulatory Assets						
Non-Heritage Deferral Account	917	(17)	36	(180)	(161)	756
Trade Income Deferral Account	249	(15)	9	(49)	(55)	194
Demand-Side Management	908	97	-	(89)	8	916
First Nations Provisions & Costs	541	18	5	(32)	(9)	532
Non-Current Pension Costs	674	(130)	-	(59)	(189)	485
Site C	436	-	17	-	17	453
CIA Amortization	92	(1)	-	-	(1)	91
Environmental Provisions & Costs	358	(24)	(1)	(39)	(64)	294
Smart Metering & Infrastructure	283	-	11	(33)	(22)	261
IFRS Pension	612	-	-	(38)	(38)	574
IFRS Property, Plant & Equipment	872	112	-	(22)	90	962
Rate Smoothing	287	201	-	-	201	488
Other Regulatory Accounts	95	42	2	(18)	26	121
Total Regulatory Assets	6,324	283	79	(559)	(197)	6,127
Regulatory Liabilities						
Heritage Deferral Account	24	31	3	(5)	29	53
Foreign Exchange Gains and Losses	69	(3)	-	-	(3)	66
Debt Management	-	187	-	-	187	187
Total Finance Charges	305	12	-	(102)	(90)	215
Other Regulatory Accounts	18	2	1	(12)	(9)	9
Total Regulatory Liabilities	416	229	4	(119)	114	530
Net Regulatory Asset	$ 5,908	$ 54	$ 75	$ (440)	$ (311)	$ 5,597

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.

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, currently at 5 per cent, is an additional charge on customer bills and is currently used to recover the balances in the energy deferral accounts.

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.

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.

Trade Income is defined as the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of BC Hydro's subsidiaries except Powerex, less the amount that BC Hydro's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero.

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, the majority of 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 (e.g. the current test period is fiscal 2017-2019).

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 their 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 estimated 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 have been 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.

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 be 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.

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IFRS PENSION

Unamortized experience gains and losses on the pension and other post-employment benefit plans recognized at the time of transition to the Prescribed Standards were deferred to this regulatory account to allow for recovery in future rates. The account balance is amortized 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 the Prescribed Standards. 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. The account balance will be fully recovered by the end of the 10 Year Rates Plan in fiscal 2024.

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 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.

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: Storm Restoration Costs, Real Property Sales, Capital Project Investigation Costs, Arrow Water Systems Provisions, Arrow Water Systems (Costs), Dismantling Cost, PEB Current Pension Costs Regulatory Account and Amortization of Capital Additions.

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NOTE 14: OTHER NON-CURRENT ASSETS

(in millions)		**2018**		2017
Non-current receivables	**$**	**245**	$	278
Sinking funds		**182**		179
Other		**256**		142
	$	**683**	$	599

Non-Current Receivables

Included in the non-current receivables balance are $191 million of receivables (2017 - $184 million) attributable to contributions-in-aid and tariff supplemental charges related to a transmission line. The contributions-in-aid 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. The tariff supplemental charges receivable are due in equal monthly installments plus interest until November 2020. The tariff supplemental charges receivable are subject to interest at a floating rate equivalent to the Company's weighted average cost of debt which is currently 4.1 per cent. The current portion of the receivables related to the transmission line is $11 million (2017 - $24 million) and has been recorded within accounts receivable and accrued revenue.

Included in the non-current receivables balance is a $28 million (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. The direction also allows BC Hydro to establish a regulatory account in which BC Hydro would transfer the impact of any defaults or impairments on these deferred payments to allow recovery in future rates.

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 as held to maturity, and include the following investments:

(in millions)		**2018**			2017	
		Carrying Value	**Weighted Average Effective Rate[1]**		Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$**	**114**	**3.2 %**	$	114	3.5 %
Other provincial government and crown corporation bonds		**68**	**3.4 %**		65	3.5 %
	$	**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 long-term portion of prepaid expenses from the Site C Project of $229 million (2017 - $115 million).

NOTE 15: ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in millions)		**2018**		2017
Accounts payable	**$**	**259**	$	224
Accrued liabilities		**995**		792
Current portion of other long-term liabilities (Note 20)		**154**		115
Dividend payable (Note 17)		**159**		-
Other		**54**		59
	$	**1,621**	$	1,190

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 $4,500 million and is included in revolving borrowings. At March 31, 2018, the outstanding amount under the borrowing program was $2,053 million (2017 - $2,838 million).

For the year ended March 31, 2018, the Company issued bonds for net proceeds of $1,156 million (2017 - $1,340 million) and a par value of $1,200 million (2017 - $1,350 million), a weighted average effective interest rate of 2.9 per cent (2017 - 2.4 per cent) and a weighted average term to maturity of 20.3 years (2017 - 18.9 years).

For the year ended March 31, 2018, the Company redeemed bonds with par value of $40 million (2017 - no bond maturities).

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

(in millions)	2018 Canadian	2018 US	2018 Euro	2018 Total	2018 Weighted Average Interest Rate[1]	2017 Canadian	2017 US	2017 Euro	2017 Total	2017 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
2021	1,100	-	-	1,100	7.5	1,100	-	-	1,100	7.5
2022	526	-	-	526	7.8	526	-	-	526	7.8
2023	500	-	-	500	6.8	-	-	-	-	-
1-5 years	3,331	258	-	3,589	6.2	2,871	267	-	3,138	6.1
6-10 years	2,860	644	418	3,922	3.2	2,460	666	376	3,502	3.9
11-15 years	1,610	-	219	1,829	4.5	1,910	-	-	1,910	4.6
16-20 years	-	387	-	387	7.4	-	400	197	597	5.2
21-25 years	3,273	-	-	3,273	4.3	1,250	-	-	1,250	4.9
26-30 years	2,565	-	-	2,565	3.7	4,588	-	-	4,588	3.9
Over 30 years	2,830	-	-	2,830	3.3	2,230	-	-	2,230	3.4
Bonds	16,469	1,289	637	18,395	4.3	15,309	1,333	573	17,215	4.4
Revolving borrowings	1,817	236	-	2,053	1.3	2,284	554	-	2,838	0.6
	18,286	1,525	637	20,448		17,593	1,887	573	20,053	
Adjustments to carrying value resulting from discontinued hedging activities	17	22	-	39		20	24	-	44	
Unamortized premium, discount, and issue costs	(107)	(11)	(5)	(123)		(56)	(12)	(5)	(73)	
	$ 18,196	$ 1,536	$ 632	$ 20,364		$ 17,557	$ 1,899	$ 568	$ 20,024	
Less: Current portion	(2,850)	(494)	-	(3,344)		(2,324)	(554)	-	(2,878)	
Non-current long-term debt	$ 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, 2018 in a net asset position of $105 million (2017 - $41 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

(in millions)	**2018**	2017
Cross-Currency Swaps		
Euro dollar to Canadian dollar - notional amount[1]	**€ 402**	€ 402
Euro dollar to Canadian dollar - weighted average contract rate	**1.47**	1.47
Weighted remaining term	**10 years**	11 years
Foreign Currency Forwards		
United States dollar to Canadian dollar - notional amount[1]	**US$ 1,012**	US$ 1,241
United States dollar to Canadian dollar - weighted average contract rate	**1.22**	1.26
Weighted remaining term	**7 years**	6 years

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

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The following bond locks and forward swap contracts were in place at March 31, 2018 with a net asset position of $83 million (2017 - $194 million). Such contracts are used to lock in interest rates on future Canadian denominated debt issues. The contracts outstanding relate to $4,875 million of planned 10 and 30 year debt to be issued on dates ranging from June 2018 to September 2022.

(in millions)	**2018**	2017
Bond Locks		
Canadian dollar - notional amount[1]	**$ 1,250**	$ 400
Weighted forecast borrowing yields	**3.20%**	2.92%
Weighted remaining term	**< 1 year**	< 1 year
Forward Swaps		
Canadian dollar - notional amount[1]	**$ 3,625**	$ 3,200
Weighted forecast borrowing yields	**3.22%**	2.92%
Weighted remaining term	**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 19.

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Reconciliation for liabilities arising from financing activities:

($millions)	**Balance, March 31, 2017**	**Issued**	**Redemptions**	**Foreign exchange movement**	**Other[1]**	**Payment of finance lease obligations**	**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
	$ 20,243	$ 8,905	$ (8,576)	$ 20	$ 457	$ (20)	$ 21,029

[1] Other in finance lease obligation includes new finance lease obligations

NOTE 17: 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 income, 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, 2018, and March 31, 2017 was as follows:

(in millions)	**2018**	2017
Total debt, net of sinking funds	**$ 20,182**	$ 19,845
Less: Cash and cash equivalents	**(42)**	(49)
Net Debt	**$ 20,140**	$ 19,796
Retained earnings	**$ 5,347**	$ 4,822
Contributed surplus	**60**	60
Accumulated other comprehensive income	**49**	27
Total Equity	**$ 5,456**	$ 4,909
Net Debt to Equity Ratio	**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.

In accordance with Order in Council No. 589/2016, the fiscal 2017 Payment to the Province was $259 million and was paid in March 2017. As a result, the Payment for fiscal 2018 will be $159 million and the Company has accrued $159 million as at March 31, 2018 (2017 - $nil).

NOTE 18: 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 at March 31, 2018 and 2017 is recognized in the following line items in the statement of comprehensive income prior to any capitalization of employment costs attributable to property, plant and equipment and intangible asset additions and prior to the application of regulatory accounting:

	Pension Benefit Plans		**Other Benefit Plans**		**Total**	
(in millions)	**2018**	2017	**2018**	2017	**2018**	2017
Current service costs charged to personnel operating costs	**$ 86**	$ 88	**$ 15**	$ 16	**$ 101**	$ 104
Net interest costs charged to finance costs	**45**	49	**17**	17	**62**	66
Total post-employment benefit plan expense	**$ 131**	$ 137	**$ 32**	$ 33	**$ 163**	$ 170

Actuarial gains and losses recognized in other comprehensive income are $nil (2017 - $nil). As per Note 13, in accordance with Prescribed Standards and as approved by the BCUC, actuarial gains and losses, as summarized in Note 18(c) below, are deferred to the Non-Current Pension Costs Regulatory Account.

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(b) Information about the Company's defined benefit plans as at March 31, in aggregate, is as follows:

(in millions)	**Pension Benefits Plans 2018**	**Pension Benefits Plans** 2017	**Other Benefits Plans 2018**	**Other Benefits Plans** 2017	**Total 2018**	**Total** 2017
Defined benefit obligation of funded plans	**$ (4,654)**	$ (4,431)	**$ -**	$ -	**$ (4,654)**	$ (4,431)
Defined benefit obligation of unfunded plans	**(164)**	(160)	**(272)**	(435)	**(436)**	(595)
Fair value of plan assets	**3,616**	3,460	**-**	-	**3,616**	3,460
Plan deficit	**$ (1,202)**	$ (1,131)	**$ (272)**	$ (435)	**$ (1,474)**	$ (1,566)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2018 and fiscal 2017 in accordance with IFRIC 14, *The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction*.

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

	Pension Benefit Plans		Other Benefit Plans	
(in millions)	**2018**	2017	**2018**	2017
Defined benefit obligation				
Opening defined benefit obligation	**$ 4,591**	$ 4,385	**$ 435**	$ 441
Current service cost	**86**	88	**15**	16
Interest cost on benefit obligations	**202**	236	**17**	17
Benefits paid[1]	**(180)**	(175)	**(13)**	(13)
Employee contributions	**38**	35	**-**	-
Actuarial losses (gains)[2]	**81**	22	**(182)**	(26)
Defined benefit obligation, end of year	**4,818**	4,591	**272**	435
Fair value of plan assets				
Opening fair value	**3,460**	3,169	n/a	n/a
Interest income on plan assets[3]	**157**	187	n/a	n/a
Employer contributions	**42**	40	n/a	n/a
Employee contributions	**38**	35	n/a	n/a
Benefits paid[1]	**(173)**	(170)	n/a	n/a
Actuarial gains (losses)[2,3]	**92**	199	n/a	n/a
Fair value of plan assets, end of year	**3,616**	3,460	-	-
Accrued benefit liability	**$(1,202)**	$(1,131)	**$ (272)**	$ (435)

[1] *Benefits paid under Pension Benefit Plans include $15 million (2017 - $14 million) of settlement payments.*

[2] *Actuarial gains/losses are included in the Pension Costs regulatory account and for fiscal 2018 are comprised of $92 million of experience gains on return of plan assets and $101 million of net actuarial gains on the benefit obligations due to BC Medical Services Plan premium reduction changes, offset by discount rate changes.*

[3] *Actual income on defined benefit plan assets for the year ended March 31, 2018 was $249 million (2017 - $386 million).*

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

	Pension Benefit Plans		Other Benefit Plans	
	2018	2017	**2018**	2017
Discount rate				
Benefit cost	**3.68%**	3.81%	**3.92%**	3.72%
Accrued benefit obligation	**3.56%**	3.68%	**3.54%**	3.92%
Rate of return on plan assets	**3.68%**	3.81%	**n/a**	n/a
Rate of compensation increase				
Benefit cost	**3.00%**	3.35%	**3.00%**	3.35%
Accrued benefit obligation	**3.00%**	3.00%	**3.00%**	3.00%
Health care cost trend rates				
Weighted average health care cost trend rate	**n/a**	n/a	**4.57%**	5.03%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**3.47%**	4.29%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	**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			
	Target Allocation	**Min**	**Max**	**2018**	2017
Equities	56%	41%	76%	**56%**	61%
Fixed interest investments	29%	19%	39%	**29%**	26%
Real estate	10%	5%	15%	**9%**	8%
Infrastructure and renewable resources	5%	0%	10%	**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 2019 is expected to amount to $43 million. The expected benefit payments to be paid in fiscal 2019 in respect to the unfunded defined benefit plans are $21 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 2018	One percentage point decrease 2018
Effect on current service costs	$ -	$ -
Effect on defined benefit obligation	5	(6)

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

		2018	
($ in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	$ - 510	$ -27
Discount rate	1% decrease	+ 650	+37
Longevity	1 year	+/- 104	+/- 3

NOTE 19: FINANCIAL INSTRUMENTS

FINANCIAL RISKS

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.

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 2018 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, sinking fund investments, and derivative instruments. It is also exposed to credit risk related to accounts receivable arising from its day-to-day electricity and natural gas sales in and outside British Columbia and its non-current receivables. 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 classified as held-to-maturity and carried on the statement of financial position at amortized cost of $182 million. The maximum credit risk exposure for these U.S. dollar sinking funds as at March 31, 2018 is their fair value of $201 million. The Company manages credit risk through a Board-approved risk management policy. Exposures to credit risks are monitored on a regular basis.

(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 a Board-approved 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 a Board-approved 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

The Company is exposed to commodity price risk as fluctuations in electricity prices and natural gas prices could have a materially adverse effect on its financial condition. 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.

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. Powerex enters into commodity derivative contracts to manage commodity price risk. These risks are managed within defined limits that are regularly reviewed by the Board of Directors of Powerex.

Categories of Financial Instruments

Finance charges, including interest income and expenses, for financial instruments disclosed in the following note, are prior to the application of regulatory accounting for the years ended March 31, 2018 and 2017 (except where noted).

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at March 31, 2018 and 2017. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

	2018		2017		**2018**	2017
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value	**Interest Income (Expense) recognized in Finance Charges**	Interest Income (Expense) recognized in Finance Charges
Financial Assets and Liabilities at Fair Value Through Profit or Loss:						
Cash equivalents - short-term investments	**$ 31**	**$ 31**	$ 24	$ 24	**$ -**	$ -
Loans and Receivables:						
Accounts receivable and accrued revenue	**810**	**810**	808	808	**-**	-
Non-current receivables	**245**	**228**	278	282	**13**	12
Cash	**11**	**11**	25	25	**-**	-
Held to Maturity:						
Sinking funds – US	**182**	**201**	179	197	**8**	8
Other Financial Liabilities:						
Accounts payable and accrued liabilities	**(1,621)**	**(1,621)**	(1,190)	(1,190)	**-**	-
Revolving borrowings	**(2,053)**	**(2,053)**	(2,838)	(2,838)	**(21)**	(16)
Long-term debt (including current portion due in one year)	**(18,311)**	**(20,814)**	(17,186)	(19,601)	**(775)**	(742)
First Nations liabilities (non-current portion)	**(399)**	**(652)**	(394)	(549)	**(17)**	(17)
Finance lease obligations (non-current portion)	**(653)**	**(653)**	(197)	(197)	**(18)**	(19)
Other liabilities	**(409)**	**(416)**	(336)	(342)	**-**	-

The carrying value of cash equivalents, 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.

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

(in millions)	**2018 Fair Value**	2017 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ 51**	$ 68
Foreign currency contracts (cash flow hedges for €EURO denominated long-term debt)	**48**	(27)
	99	41
Non-Designated Derivative Instruments:		
Interest rate contracts	**83**	194
Foreign currency contracts	**6**	-
Commodity derivatives	**(36)**	23
	53	217
Net asset	**$ 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)	**2018**	2017
Current portion of derivative financial instrument assets	**$ 174**	$ 144
Current portion of derivative financial instrument liabilities	**(112)**	(60)
Derivative financial instrument assets, non-current	**156**	215
Derivative financial instrument liabilities, non-current	**(66)**	(41)
Net asset	**$ 152**	$ 258

For designated cash flow hedges for the year ended March 31, 2018, a gain of $1 million (2017 - $nil) related to the ineffective portion was recognized in finance charges and then transferred to the Total Finance Charges Regulatory Account.

For designated cash flow hedges for the year ended March 31, 2018, a gain of $57 million (2017 - loss of $11 million) was recognized in other comprehensive income. For the year ended March 31, 2018, $30 million (2017 - $11 million) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange losses (2017 - losses) recorded in the year.

For interest rate contracts not designated as hedges with an aggregate notional principal of $4.9 billion (2017 - $3.6 billion), used to economically hedge the interest rates on future debt issuances, there was a $41 million decrease (2017 - $194 million increase) in the fair value of these contracts for the year ended March 31, 2018. For the interest rate contracts with an aggregate notional principal of $1.8 billion (2017 - $800 million) associated with debt issued to date, there was a $12 million increase (2017 - $7 million decrease) in the fair value of contracts that settled during the year ended March 31, 2018. The net decrease for the year ended March 31, 2018 of $29 million in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had a liability balance of $158 million as at March 31, 2018.

For foreign currency contracts not designated as hedges for the year ended March 31, 2018, a loss of $2 million (2017 - gain of $1 million) was recognized in finance charges with respect to foreign currency contracts for cash management purposes. For foreign currency contracts not designated as hedges, primarily relating to foreign currency contracts for U.S. revolving borrowings, for the year ended March 31, 2018, such contracts had a loss of $53 million (2017 - gain of $18 million) which was recognized in finance charges. These economic hedges offset $56 million of foreign exchange revaluation gains (2017 - loss of $17 million) recorded in finance charges with respect to U.S. revolving borrowings for the year ended March 31, 2018.

For commodity derivatives not designated as hedges, a net loss of $67 million (2017 - loss of $1 million) was recorded in trade revenue for the year ended March 31, 2018.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)		**2018**		2017
Deferred inception loss, beginning of the year	**$**	**36**	$	48
New transactions		**(12)**		(12)
Amortization		**(1)**		(1)
Foreign currency translation (gain) loss		**(1)**		1
Deferred inception loss, end of the year	**$**	**22**	$	36

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)		**2018**		2017
Current	**$**	**433**	$	494
Past due (30-59 days)		**32**		31
Past due (60-89 days)		**7**		7
Past due (More than 90 days)		**12**		1
		484		533
Less: Allowance for doubtful accounts		**(7)**		(7)
	$	**477**	$	526

At the end of each reporting year, a review of the provision for doubtful accounts is performed. It is an assessment of the potential amount of domestic and trade accounts receivable which will not be paid by customers after 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

A substantial majority of the Company's counterparties associated with its trading activities are in the energy sector. This industry concentration has the potential to impact the Company's overall exposure to credit risk in that the counterparties may be similarly affected by changes in economic, regulatory, political, and other factors. The Company manages credit risk by authorizing trading transactions within the guidelines of the Company's risk management policies, by monitoring the credit risk exposure and credit standing of counterparties on a regular basis, and by obtaining credit assurances from counterparties to which they are entitled under contract.

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, 2018			
Derivative commodity assets	$ 36	$ 2	$ 34
Derivative commodity liabilities	72	2	70
As at March 31, 2017			
Derivative commodity assets	$ 90	$ 1	$ 89
Derivative commodity liabilities	67	1	66

With respect to these financial assets, the Company assigns credit limits for counterparties based on evaluations of their financial condition, net worth, regulatory environment, cost recovery mechanisms, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically and a detailed credit analysis is performed at least annually. Further, the Company has tied a portion of its contracts to master agreements that require security in the form of cash or letters of credit if current net receivables and replacement cost exposure exceed contractually specified limits.

The following table outlines the distribution, by credit quality, of financial assets associated with trading activities that are neither past due nor impaired:

As at March 31, 2018	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	84	0	16	100
Assets from trading activities	94	0	6	100

As at March 31, 2017	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	87	0	13	100
Assets from trading activities	100	0	0	100

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2018 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, 2018. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2018 has been used.

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(in millions)	**Carrying Value**	**Fiscal 2019**	**Fiscal 2020**	**Fiscal 2021**	**Fiscal 2022**	**Fiscal 2023**	**Fiscal 2024** ***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)	$ 1,384	$ (1,384)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	20,572	(4,125)	(901)	(1,789)	(1,145)	(1,085)	(23,124)
Lease obligations	665	(54)	(54)	(54)	(54)	(54)	(1,091)
Other long-term liabilities	825	(44)	(97)	(61)	(62)	(53)	(1,827)
Total Non-Derivative Financial Liabilities	23,446	(5,607)	(1,052)	(1,904)	(1,261)	(1,192)	(26,042)
Derivative Financial Liabilities							
Forward foreign exchange contracts used for hedging	8						
Cash outflow		-	-	-	-	-	(337)
Cash inflow		-	-	-	-	-	335
Interest rate swaps used for hedging	97	(51)	(1)	(10)	(24)	(14)	-
Net commodity derivative assets and liabilities	36	(36)	(15)	(11)	-	-	-
Total Derivative Financial Liabilities	141	(87)	(16)	(21)	(24)	(14)	(2)
Total Financial Liabilities	23,587	(5,694)	(1,068)	(1,925)	(1,285)	(1,206)	(26,044)
Derivative Financial Assets							
Cross currency swaps used for hedging	(48)						
Cash outflow		(14)	(14)	(14)	(14)	(14)	(665)
Cash inflow		5	5	5	5	5	664
Forward foreign exchange contracts used for hedging	(59)						
Cash outflow		(204)	-	-	-	-	(382)
Cash inflow		258	-	-	-	-	403
Other forward foreign exchange contracts designated at fair value	(6)						
Cash outflow		(307)	-	-	-	-	-
Cash inflow		307	-	-	-	-	-
Interest rate swaps used for hedging	(180)	84	41	60	-	-	-
Total Derivative Financial Assets	(293)	129	32	51	(9)	(9)	20
Net Financial Liabilities	**$ 23,294**	**$ (5,565)**	**$(1,036)**	**$(1,874)**	**$(1,294)**	**$(1,215)**	**$ (26,024)**

MARKET RISKS

(a) Currency Risk

Sensitivity Analysis
A $0.01 strengthening (weakening) of the U.S. dollar against the Canadian dollar at March 31, 2018 would otherwise have a negative (positive) impact of $1 million on net income 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 13) 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, 2018 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, 2018 would otherwise have a negative (positive) impact on net income of $25 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 13) 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, 2018 would otherwise have a positive impact on net income of $550 million and a decrease of 100 basis points in interest rates at March 31, 2018 would otherwise have a negative impact on net income of $700 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, 2018 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.

BC Hydro's subsidiary Powerex trades and delivers energy and associated products and services throughout North America. As a result, the Company has exposure to movements in prices for commodities Powerex trades, 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 Board-approved risk management policies, which limit components of and overall market risk exposures, pre-define approved products and mandate regular reporting of exposures.

The Company's Risk Management Policy 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. Powerex uses an industry standard Monte Carlo VaR model to determine the potential change in value of its forward trading portfolio over a 10-day holding period, within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR as an estimate of other 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-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, Powerex uses additional measures to supplement the use of VaR to estimate other price risk. These include the use of a Historic VaR methodology, stress tests and notional limits for illiquid or emerging products.

Powerex's VaR, calculated under this methodology, was approximately $6 million at March 31, 2018 (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.
- Level 3 - inputs are those that are not based on observable market data.

The following tables present the financial instruments measured at fair value for each hierarchy level as at March 31, 2018 and 2017:

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)

As at March 31, 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 March 31, 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 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 energy 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.

There were no transfers between Level 1 and 2 during the period (2017 – 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, 2018 and 2017:

(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**

(in millions)		
Balance as at April 1, 2016	**$**	**56**
Net loss recognized		(3)
New transactions		(6)
Transfer from Level 3 to Level 2		(2)
Existing transactions settled		(8)
Balance as at March 31, 2017	**$**	**37**

During the period, energy derivatives with a carrying amount of $7 million (2017 - $2 million) were transferred from Level 3 to Level 2 as the Company now uses observable price quotations.

Level 3 fair values for energy 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.

Powerex holds congestion products and structured power transactions that require the use of unobservable inputs when observable inputs are unavailable. Congestion products are valued using forward spreads at liquid hubs that include adjustments for the value of energy at different locations relative to the liquid hub as well as other adjustments that may impact the valuation. Option pricing models are used when the congestion product is an option. Structured power transactions are valued using standard contracts at a liquid hub with adjustments to account for the quality of the energy, the receipt or delivery location, and delivery flexibility where appropriate. Significant unobservable inputs include adjustments for the quality of the energy and the transaction location relative to the reference standard liquid hub.

During the year ended March 31, 2018, unrealized losses of $3 million (2017 - gains of $8 million) were recognized on Level 3 derivative commodity assets held at March 31, 2018. During the year ended March 31, 2018, unrealized losses of $11 million (2017 - gains of $1 million) were recognized on Level 3 derivative commodity liabilities held at March 31, 2018. These gains and losses are recognized in trade revenues.

Methodologies and procedures regarding Powerex's energy trading Level 3 fair value measurements are determined by Powerex's Risk Management group. Level 3 fair values are calculated within Powerex's Risk Management policies for trading activities based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, Level 3 fair value measurements are reviewed and validated by Powerex's Risk Management and Finance departments on a regular basis.

NOTE 20: OTHER NON-CURRENT LIABILITIES

(in millions)	**2018**	2017
Provisions		
Environmental liabilities	**$ 317**	$ 339
Decommissioning obligations	**53**	52
Other	**55**	12
	425	403
First Nations liabilities	**416**	409
Finance lease obligations	**665**	219
Unearned revenue	**577**	551
Other liabilities	**409**	336
	2,492	1,918
Less: Current portion, included in accounts payable and accrued liabilities	**(154)**	(115)
	$ 2,338	$ 1,803

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

	Environmental	**Decommissioning**	**Other**	**Total**
Balance at March 31, 2016	**$ 390**	**$ 56**	**$ 10**	**$ 456**
Made during the period	-	-	2	2
Used during the period	(25)	(3)	-	(28)
Reversed during the period	(1)	-	-	(1)
Changes in estimate	(29)	(2)	-	(31)
Accretion	4	1	-	5
Balance at March 31, 2017	**$ 339**	**$ 52**	**$ 12**	**$ 403**
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**	**$ 55**	**$ 425**

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.

The undiscounted cash flow related to the Company's environmental liabilities, which will be incurred between fiscal 2019 and 2045, is approximately $378 million and was determined based on current cost estimates. A range of discount rates between 1.6 per cent to 2.24 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 $80 million (2017 - $80 million), which will be settled between fiscal 2019 and 2054. The undiscounted cash flows are then discounted by a range of discount rates between 1.6 per cent to 2.24 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:

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

Other Liabilities

Other liabilities consist of 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 21: 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 $51,223 million of which approximately $116 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 $1,361 million accounted for as obligations under capital leases. The total BC Hydro combined payments are estimated to be approximately $1,543 million for less than one year, $6,027 million between one and five years, and $43,653 million for more than five years and up to 58 years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $1,554 million extending to 2034. The total Powerex energy purchase commitments are estimated to be approximately $390 million for less than one year, $910 million between one and five years, and $254 million for more than five years. Powerex has energy sales commitments of $316 million extending to 2027 with estimated amounts of $194 million for less than one year, $116 million between one and five years, and $6 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 support operations. The agreements cover periods of up to 70 years, and the aggregate minimum payments are approximately $938 million. Payments are $65 million for less than one year, $135 million between one and five years, and $738 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 any loss exposure that may ultimately be incurred may differ materially from management's current estimates. Management has not disclosed the ranges of expected outcomes due to the potentially adverse effect on the negotiation process for these claims.

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

c) The Company and its subsidiaries have outstanding letters of credit totaling $1,167 million (2017 - $1,124 million), which includes US $12 million (2017 - US $21 million) in foreign denominated letters of credit.

NOTE 22: 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. Powerex is an active participant in western energy markets, buying and selling wholesale power, natural gas, ancillary services, clean and renewable power, and other environmental products in Canada and the United States. 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)		**2018**		2017
Consolidated Statement of Financial Position				
Prepaid expenses	**$**	**95**	$	93
Accounts payable and accrued liabilities		**222**		57
Amounts incurred/accrued during the year include:				
Water rental fees		**324**		346
Cost of energy		**111**		111
Taxes		**131**		140
Interest		**797**		760
Payment to the Province		**159**		259

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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, 2018, the aggregate exposure under this indemnity totaled approximately $292 million (2017 - $268 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)	**2018**	2017
Short-term employee benefits	**$ 4**	$ 4
Post-employment benefits	**1**	1

Major Capital Projects

Planned Projects over $50 million

BC Hydro has planned for 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 $50 million)	Targeted Completion Date (Year)	Project Cost to March 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Projects Recently Put Into Service				
Ruskin Dam Safety and Powerhouse Upgrade Improved seismically deficient dam and rehabilitation/replacement of powerhouse equipment that was brought into service between 1930 and 1950. The project included: upgrading of the right abutment; redeveloping the dam and powerhouse to meet current seismic standards for earthquakes; and replacing major generation equipment which is in poor or unsatisfactory condition.	2018 In-Service	$602	$146	$748
Ongoing and Planned				
Horne Payne Substation Upgrade Project Expand the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated feeder sections, and a new control building. This project will increase the firm capacity of the substation, add needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12kV to 25kV, and allow for the implementation of an open-loop distribution system.	2018 Targeted In-Service	$54	$39	$93

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to March 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Kamloops Substation* The project is to construct a new 100MW 138/25kV substation in the west side of Kamloops to meet expected load growth in the Kamloops service area. **Kamloops Substation was not reflected in the September 2017 Service Plan as an increase to the Anticipated Total Capital Cost from $49M to $56M was approved by the Board after the filing.*	2018 Targeted In-Service	$42	$14	$56
John Hart Generating Station Replacement Replace the existing six-unit 126 MW generating station (in operation since 1947) and add integrated emergency bypass capability to ensure reliable long-term generation and to mitigate earthquake risk and environmental risk to fish and fish habitat.	2019 Targeted In-Service	$890	$203	$1,093
Cheakamus Unit 1 and Unit 2 Generator Replacement Replace 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	$34	$40	$74
W.A.C Bennett Dam Riprap Upgrade Project This project will address inadequate erosion protection on the upstream face of the W.A.C Bennett Dam. The primary driver of the project is safety of the dam itself as well as safety of the public, property, and environment downstream.	2019 Targeted In-Service	$109	$61	$170

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to March 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
South Fraser Transmission Relocation Project* In September 2013, the Province of B.C. announced that the George Massey Tunnel would be replaced with a new bridge. The construction of the new bridge, modifications to Highway 99 and the decommissioning of the George Massey tunnel would require BC Hydro 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. 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. ** As of September 6, 2017, construction work on the South Fraser Transmission Relocation project has been suspended, pending a government review of the George Massey Tunnel Replacement project.*	TBD*	$28	$48	$76
Bridge River 2 Units 5 and 6 Upgrade Project The Bridge River 2 powerhouse Generator Units 5 and 6, which were placed in service in 1960, are in unsatisfactory condition and unreliable. This project will replace the two generators and other related equipment to restore the historical operating capacity.	2019 Targeted In-Service	$23	$63	$86

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to March 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
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. **Fort St. John and Talor Electric Supply Targeted Competion date was revised to 2020 from 2019.*	2020* Targeted In-Service	$5	$48	$53
UBC Load Increase Stage 2 Project BC Hydro is undertaking the UBC Load Increase Stage 2 project on behalf of its 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	$5	$50	$55
Mica Replace Units 1-4 Transformers Project The Unit 1-4 Generator Step-up Unit transformers at the Mica Generating Station 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. The project was initiated to address reliability and safety risks associated with operating the existing transformers.	2022 Targeted In-Service	$3	$79	$82

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to March 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
G.M. Shrum G1-G10 Control System Upgrade 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 spare parts availability and decreasing reliability. The controls are well beyond their expected life, which causes operating problems and increases the risk of damage to major equipment. The project will replace the controls equipment, provide full remote control capability from the remote control center and rectify deficiencies in the current system. **G.M. Shrum G1-G10 Control System Upgrade Anticipated Total Capital Cost was revised to $75M from $60M (Partial Implementation Funding) as planned upon approval of the third stage. The Targeted Completion Date was also revised to 2022 from 2021.*	2022* Targeted In-Service	$24	$51	$75*

Major Capital Projects (over $50 million)	Targeted Completion Date (Year)	Project Cost to March 31, 2018 ($ millions)	Estimated Cost to Complete ($ millions)	Approved Anticipated Total Capital Cost of Project ($ millions)
Site C Project Site C will be a third dam and 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 project was approved by the Provincial Government in December 2014. 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. Total cost was increased to $10,700 million from $8,775 million. Total cost includes the Project Reserve of $708 million which is held by Treasury Board.*	2024* Targeted In-Service	$2,354	$8,346	$10,700**

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 Chief Operating Officer. 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.

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.

Powerex Corp.

Powerex Corp. is a wholly-owned subsidiary of BC Hydro and a key participant in energy markets across North America, buying and supplying wholesale power, renewable and low-carbon energy and products, natural gas, ancillary services, and financial energy products. Established in 1988, its export, marketing and trade activities help optimize BC Hydro's electric system resources and provide significant economic benefits to British Columbia.

Powerex supports BC Hydro's electric system requirements through importing and exporting energy as necessary in addition to meeting its own trade commitments. Powerex also markets, through an 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 works with the BC Hydro Executive Chair and Chief Operating Officer (COO) and informs the BC Hydro President and COO and Executive team of Powerex's key strategies and business activities.

Powerex operates in complex and volatile energy-markets, which can cause net income in any given year to vary significantly. Market and economic conditions, reduced BC Hydro system flexibility, income timing differences and the strength of the Canadian dollar can materially impact Powerex net income. Over the previous five years, Powerex income has ranged from $59 million to $158 million (2013/14 to 2017/18). The 2018/19 to 2020/21 Service Plan forecast includes annual net income from Powerex of approximately $125 million per year. For more information, visit powerex.com.

Powertech Labs Inc.

Powertech Labs, 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. It 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 $44 million (2013/2014 to 2017/18) with a net income in the range of $2 million to $4 million. The 2018/19 to 2020/21 Service Plan forecast includes annual net income from Powertech of approximately $4 million per year for 2018/19 to 2020/21. For more information, visit powertechlabs.com.

Other Active Subsidiaries

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 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, 2018, 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 B.C. Ltd.
12. 1148573 B.C. Ltd.

Appendix C – Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	**2018**	2017	2016	2015	2014
Revenues					
Domestic	**$ 5,527**	$ 5,199	$ 5,056	$ 4,829	$ 4,319
Trade	**710**	675	601	919	1,073
Expenses					
Domestic energy costs	**1,746**	1,608	1,425	1,458	1,252
Trade energy costs	**521**	486	427	745	894
Other operating expenses [1]	**1,123**	1,025	937	918	901
Amortization and depreciation	**1,267**	1,232	1,241	1,205	995
Grants and taxes	**243**	234	220	209	203
Finance charges	**653**	605	752	632	598
	5,553	5,190	5,002	5,167	4,843
Net Income	**$ 684**	$ 684	$ 655	$ 581	$ 549
Property, Plant and Equipment & Intangible Assets					
At cost	**$ 30,142**	$ 27,468	$ 25,183	$ 22,998	$ 20,897
Less: Accumulated depreciation	**4,468**	3,869	3,189	2,518	1,863
Net Book Value	**$ 25,674**	$ 23,599	$ 21,994	$ 20,480	$ 19,034
Property, Plant & Equipment and Intangible Asset Expenditures					
Sustaining	**$ 1,190**	$ 1,286	$ 1,136	$ 1,005	$ 979
Growth	**1,283**	1,158	1,170	1,164	1,057
Total Property, Plant & Equipment and Intangible Asset Expenditures [2]	**$ 2,473**	$ 2,444	$ 2,306	$ 2,169	$ 2,036
Net Long-Term Debt [3]	**$ 20,140**	$ 19,796	$ 18,002	$ 16,682	$ 15,461
Retained Earnings	**$ 5,347**	$ 4,822	$ 4,397	$ 4,068	$ 3,751
Debt to Equity Ratio	**79 : 21**	80 : 20	80 : 20	80 : 20	80 : 20

1 *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.*

2 *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.*

3 *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	**2018**	2017	2016	2015	2014
Generating Capacity (megawatts)					
Hydroelectric	**11,918**	11,870	11,869	11,379	10,927
Thermal	**180**	183	175	1,120	1,120
Total	**12,098**	12,053	12,044	12,499	12,047
Peak One-Hour Integrated System Demand (megawatts)	**9,651**	10,194	9,602	9,441	10,072
Number of Customer Accounts					
Residential	**1,803,752**	1,776,503	1,751,296	1,727,945	1,709,071
Light industrial and commercial	**210,673**	207,802	205,615	203,466	201,812
Large industrial	**190**	191	185	183	177
Other	**3,429**	3,467	3,459	3,474	3,489
Trade	**182**	204	214	226	239
Total	**2,018,226**	1,988,167	1,960,769	1,935,294	1,914,788
Domestic Electricity Sold (gigawatt-hours)					
Residential	**18,150**	18,068	17,331	17,047	17,965
Light industrial and commercial	**18,874**	18,968	18,421	18,564	18,501
Large industrial	**13,440**	13,177	13,669	14,020	13,994
Other	**6,709**	7,439	7,879	1,582	2,558
Total	**57,173**	57,652	57,300	51,213	53,018
Revenues (in millions)					
Residential	**$ 2,097**	$ 2,012	$ 1,842	$ 1,712	$ 1,663
Light industrial and commercial	**1,860**	1,800	1,685	1,597	1,489
Large industrial	**811**	770	766	748	687
Other	**437**	428	464	280	275
Total Domestic Revenue Before Regulatory Transfers	**5,205**	5,010	4,757	4,337	4,114
Regulatory transfers	**322**	189	299	492	205
Total Domestic	**5,527**	5,199	5,056	4,829	4,319
Trade - electricity and gas	**710**	675	601	919	1,073
Total	**$ 6,237**	$ 5,874	$ 5,657	$ 5,748	$ 5,392
Average Revenue (per kilowatt-hour) [1]					
Residential	**11.6¢**	11.1¢	10.6¢	10.0¢	9.3¢
Light industrial and commercial	**9.9**	9.5	9.1	8.6	8.0
Large industrial	**6.0**	5.8	5.6	5.3	4.9
Average Annual Kilowatt-Hour Use Per Residential Customer Account	**10,139**	10,241	9,958	9,919	10,571
Lines In Service					
Distribution (kilometres)	**59,222**	59,078	58,765	58,518	58,317
Transmission (circuit kilometres)	**20,306**	20,278	20,176	19,792	19,322

[1] *Average revenues are before regulatory transfers.*

TOTAL REQUIREMENTS FOR ELECTRICITY, SOURCES OF SUPPLY AND WATER INFLOWS

for the years ended March 31	**2018**			2017			2016			2015			2014		
	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	**12,098**	**57,173**	**73.6**	12,053	57,652	72.7	12,044	57,300	73.7	12,499	51,213	66.0	12,047	53,018	65.0
Electricity trade		**15,046**	**19.4**		16,740	21.1		14,732	18.9		21,928	28.2		23,806	29.2
		72,219	**93.0**		74,392	93.8		72,032	92.6		73,141	94.2		76,824	94.2
Line loss and system use		**5,454**	**7.0**		4,927	6.2		5,713	7.4		4,486	5.8		4,733	5.8
		77,673	**100.0**		79,319	100.0		77,745	100.0		77,627	100.0		81,557	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,778**	**13,876**	**17.9**	2,730	15,910	20.1	2,730	14,274	18.4	2,730	10,801	13.9	2,730	13,650	16.7
Revelstoke	**2,480**	**9,082**	**11.7**	2,480	8,264	10.4	2,480	9,805	12.6	2,480	7,297	9.4	2,480	8,121	10.0
Mica	**2,746**	**8,561**	**11.0**	2,746	7,397	9.3	2,747	9,451	12.2	2,257	6,028	7.8	1,805	7,030	8.6
Kootenay Canal	**583**	**3,083**	**4.0**	583	3,330	4.2	583	2,837	3.6	583	3,304	4.4	583	2,935	3.6
Peace Canyon	**694**	**3,430**	**4.4**	694	3,887	4.9	694	3,470	4.5	694	2,678	3.4	694	3,423	4.2
Seven Mile	**805**	**3,460**	**4.5**	805	3,326	4.2	805	2,666	3.4	805	3,907	5.0	805	3,183	3.9
Bridge River	**478**	**2,216**	**2.9**	478	2,504	3.2	478	2,582	3.3	478	2,093	2.7	478	2,397	2.9
Other	**1,354**	**4,218**	**5.3**	1,354	4,118	5.1	1,352	4,267	5.5	1,352	5,122	6.6	1,352	4,589	5.6
	11,918	**47,926**	**61.7**	11,870	48,736	61.4	11,869	49,352	63.5	11,379	41,230	53.2	10,927	45,328	55.5
Thermal generation															
Burrard	**0**	**0**	**0.0**	0	0	0.0	0	24	0.0	950	26	0.0	950	84	0.1
Other	**180**	**91**	**0.1**	183	74	0.1	175	191	0.2	170	187	0.2	170	184	0.2
Purchases under long-term commitments		**18,399**	**23.7**		17,753	22.4		18,441	23.7		17,510	22.6		15,300	18.8
Purchases under short-term commitments		**10,658**	**13.7**		13,009	16.4		10,713	13.8		18,586	23.9		20,764	25.5
Other		**599**	**0.8**		(253)	(0.3)		(976)	(1.2)		88	0.1		(103)	(0.1)
	12,098	**77,673**	**100.0**	12,053	79,319	100.0	12,044	77,745	100.0	12,499	77,627	100.0	12,047	81,557	100.0
Water inflows (% of average)			**98**			101			97			102			95