British Columbia Hydro and Power Authority

2016/17
ANNUAL SERVICE PLAN REPORT

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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. As an organization, we have a huge impact on the lives of the people of British Columbia and we are working together to uphold this responsibility and become the most trusted, innovative utility company in North America - smart about power in all we do.

The 2016/17 Annual Service Plan Report outlines BC Hydro's performance on the strategies and measures set out in our 2016/17 – 2018/19 Service Plan. It details how we are meeting the objectives in the Government Mandate Letter and aligning with the Taxpayer Accountability Principles.

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, 2017 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 2016/17 - 2018/19 Service Plan was released and any significant limitations in the reliability of the information are identified in the report.

The BC Hydro 2016/17 Annual Service Plan Report compares the Corporation's actual results to the expected results identified in the 2016/17 - 2018/19 Service Plan. I am accountable for those results as reported.

W.J. Brad Bennett, O.B.C.
Chair, Board of Directors

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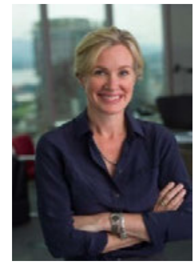
Chair, Board of Directors and Chief Executive Officer Letter



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, 2017. 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.

BC Hydro is on track to deliver the 2013 10 Year Rates Plan, while making investments 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 maintain and upgrade our aging infrastructure, while expanding the system to ensure that our electricity remains affordable, reliable and clean for the long term. The Site C Clean Energy Project, one of the largest infrastructure projects in British Columbia's history, is progressing on time and on budget 20 months into construction phase.

Clean, abundant electricity is vital to British Columbia's economic prosperity and our quality of life. As an organization, we have a huge impact on the lives of the people in B.C. and with that role comes the responsibility to maintain the trust and respect of our customers and stakeholders. We have enhanced the services we provide to our customers and will continue to focus on making it easier for our customers to do business with us over the upcoming year.

BC Hydro works closely with the Ministry of Energy and Mines to ensure alignment with government policy expectations through regular meetings and updates. These are held between the Executive, the Minister and his staff and the Board Chair, as appropriate, to discuss progress on achievement of the 10 Year Rates Plan and actions identified in the Government Mandate Letter (*highlights in Appendix C: Crown Corporations Mandate and Actions Summary*). Updates are provided to the Board of Directors annually through a Taxpayer Accountability Report which documents actions to support the Taxpayer Accountability Principles. With respect to organizational governance and shareholder engagement, the development and responsibilities of Directors and the Executive are outlined in *Appendix B: Additional Information*.

We're proud of our accomplishments this year. We will continue to work together to deliver reliable, affordable and clean electricity to our customers, and to ensure that everyone goes home safely, every day.

W.J. Brad Bennett, O.B.C.
Chair, Board of Directors

Jessica McDonald
President and Chief Executive Officer

Purpose of the Organization

BC Hydro's mission is to provide our customers with reliable, affordable and clean electricity throughout British Columbia, safely. 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 over 79,000 kilometres of transmission and distribution lines. We are proud of our partnership with the independent power sector in British Columbia which operates over 110 projects across the province including biomass, hydro, wind and solar.

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 and Mines 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 Province's 2007 BC Energy Plan
- *The 2010 Clean Energy Act (CEA)*

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 Context

British Columbia has among the lowest electricity rates in North America. The 10 Year Rates Plan announced in November 2013 provides a framework to keep rates affordable and predictable for our customers while we make investments to upgrade aging infrastructure and expand our system to ensure electricity stays reliable and clean for the long term.

This year, BC Hydro filed the Fiscal 2017 – Fiscal 2019 Revenue Requirements Application with the British Columbia Utilities Commission. Many of our industrial customers had been facing declining prices for the commodities they produce, which could result in $3.5 billion less in expected revenue for BC Hydro over the 10 Year Rates Plan period. To avoid passing these issues along our customers, we found new ways to reduce our costs even further while preparing this application. These efforts included identifying $33 million in operational savings to reinvest in priority areas like safety, customer service and storm response. Our efforts to find efficiencies throughout our business enabled us to keep rates low and predictable for our customers, consistent with the 10 Year Rates Plan.

We are proud of these efforts and are now seeing a number of developments that signal a positive shift. Market prices for commodities are increasing and major investments in the oil and gas industry are moving forward.

We saw record electricity consumption this winter. Consumption in December 2016 was 14.8 per cent higher than December 2015 due to colder weather, and on January 3, 2017 between 5 p.m. and 6 p.m., BC Hydro set a new record for power consumption when demand for electricity peaked at over 10,126 megawatts. This was the highest demand in our history. We are fortunate to have a large system that provides firm, flexible power. It allows us to respond to spikes in electricity demand, which means that the power will be there on the coldest, darkest days, as we experienced this winter.

In August 2016, the Province announced its Climate Leadership Plan. This plan focuses on reducing greenhouse gas emissions, including an emphasis on low-carbon electrification.. In introducing measures to help our customers reduce greenhouse gas emissions, we will build on our strong conservation programs.

BC Hydro continues to expect significant long-term growth across all customer classes and tracked within 0.3 per cent of the May load forecast, as of the end of fiscal 2017. As British Columbia's population and economy continue to grow, it is a crucial time to build and reinvest in a system that is reliable and clean so that we can meet current and future needs, all while keeping rates low.

BC Hydro's electricity system was largely built in the 1960s, 1970s and 1980s and we are investing 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 completed 540 capital projects at a total cost of $6.4 billion which is 0.94 per cent under budget overall. This year, capital projects placed in-service totalled $1.5 billion, including projects to renew and expand our generation, transmission and distribution system.

To ensure economic and social benefits for ratepayers, BC Hydro manages our capital portfolio with an emphasis on cost consciousness, respect for the environment and communities in which we work, and strengthening our relationships with First Nations. There are more than 850 British Columbia companies that are directly working with BC Hydro on our capital projects.

After nearly two years into the construction phase of the project, Site C continues to be on time and on budget. This year marked the completion of site preparation activities at the dam site – including the completion of a 1,600-person worker accommodation lodge – the start of work by the main civil works contractor Peace River Hydro Partners, and the award of the turbines and generators contract to Voith Hydro. As of March 2017, there were 2,252 people working on the Site C Clean Energy Project, including 1,814 workers from B.C. (81 per cent of the total workforce), approximately 200 Aboriginal workers and 709 from the Peace River Regional District. During the year, BC Hydro reached agreements related to Site C with Doig River First Nation, Halfway River First Nation, McLeod Lake Indian Band and Dene Tha' First Nation. We reached community agreements with the City of Fort St. John and the District of Hudson's Hope.

Also part of planning for both the current and future needs of our customers, we continued to focus this year on our renewed customer service strategy, with the goal of making it easier for customers to do business with us. This has prompted further process improvements and training, including more options for customers to connect with us in person. These efforts are making a difference: our customer satisfaction score reached a five-year high of 87 per cent this year. BC Hydro also continues to help customers make smart energy choices through our conservation and energy management programs and through tools like smart meters, which provide customers with information about their electricity consumption.

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 continues to focus on achieving the objectives outlined in the Government Mandate Letter and aligning with the Taxpayer Accountability Principles. For specific details on fulfillment of the Government Mandate Letter, please refer to *Appendix C: Crown Corporations Mandate and Action Summary*.

Under the Taxpayer Accountability Principles, BC Hydro has implemented its action plan with regular communications between the CEO, Board Chair, the Minister and Deputy Minister; quarterly reporting to the Board of Directors; and, alignment of its Service Plan and Annual Service Plan Report with the spirit and intent of the Taxpayer Accountability Principles. Examples of specific outcomes this year include:

- Identification of $33 million in operational savings to reinvest in priority areas of the business like safety, customer service and storm response.
- Continued adherence to the Province’s compensation guidelines for public sector employees.
- Completion of the first Impact Benefits Agreements, reflecting BC Hydro’s commitment to meaningful long-term relationships with area First Nations, as part of the Site C Clean Energy Project.
- The decision from the British Columbia Utilities Commission on Module 1 of the 2015 Rate Design Application, following 14 months of BC Hydro’s engagement with stakeholders and customers to obtain feedback on current rate designs and potential rate design options.
- Completion of the roll-out of the new Business Account Services team, which provides enhanced services for small and medium businesses, property management firms and First Nations governments.
- Requirement for all BC Hydro employees to take an annual online course to ensure they are familiar and compliant with the Code of Conduct, which reflects the intent of the Taxpayer Accountability Principles.

Goals, Strategies, Measures and Targets

BC Hydro's mission is: To provide our customers with reliable, affordable, clean electricity throughout B.C., safely. We have continued to implement our strategies to achieve our four goals and 12 performance measures as set out in the 2016/17 – 2018/19 Service Plan. The goals and measures below track our progress on delivering the identified priorities for 2016/17. 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 2016/17 Annual Service Plan Report compares the Corporation's 2016/17 actual results to the expected results in the 2016/17 – 2018/19 Service Plan.

Goal 1: Set the Standard for Reliable and Responsive Service

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.
- Make it easier for customers to do business with us through a series of internal and external improvements such as bills that are easier to read, access to critical information including outages, and customer-focused training for our staff to enhance the overall customer service experience.
- Explore innovative energy conservation solutions such as load curtailment rates.
- Sustain 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 improve the transparency of its operations and identify their interests in the delivery of our capital projects.

Performance Measures 1-5[1]

Performance Measure	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Target	2016/17 Actual	2017/18 Target	2018/19 Target
SAIDI (duration)[2] [total outage duration (in hours) experienced by an average customer in a year]	3.59	3.07	3.01	3.22	3.28[3,4]	3.30	3.30
SAIFI (frequency)[2] [Number of sustained disruptions per year] (excluding major events)	1.56	1.30	1.48	1.40	1.59[3,4]	1.40	1.40
Key Generating Facility Forced Outage Factor[5]	1.62	1.51	1.64	2.00	1.78	2.0	1.8
CSAT Index [Customer Satisfaction Index: % of customers satisfied or very satisfied]	85.0	86.0	87.0	85.0	87.0	85.0	85.0
Progressive Aboriginal Relations Designation	Gold	Gold	Gold	Gold	Gold	Gold	Gold

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

[2] Annual targets are based on a number of factors including long-term historic reliability trending, current year performance, previous years' investments and future years' investment plans. The recent years' actual reliability performance (F2014-F2017), aging assets, and capital constraints required an adjustment to the previously established reliability targets for F2018 and F2019.

Note: 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 uncontrollable elements that can significantly disrupt the electrical system. BC Hydro measures reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measure is therefore based on data that excludes major events.

[3] Extensive capital programs in 2016/17 resulted in increased planned outages that impacted reliability.

[4] 2016/17 experienced more challenging weather conditions that resulted in increased outages and outage durations that impacted reliability.

[5] A forced outage occurs when a generating unit is unable to start generating or does not stay on line as long as needed. Forced Outage Factor is defined as the total forced outage time in a period relative to the total number of hours in the same period (usually one year). Annually, the Forced Outage Factor can be relatively volatile and through applying the historical five year rolling average it can smooth the range to provide a more stable measure for which targets can be set. Therefore, the strategy is to keep the Force Outage Factor below 2% of the total number of hours per year. There are seven Key Generating Facilities, representing those plants with installed capacity greater than 200MW. Together they provide 80% of the average annual electricity generated by BC Hydro's facilities. This measurement shows the trend of how the assets are performing and aligns with how asset management investments decisions are made to maintain asset reliability that is reflected in a low forced outage factor.

Discussion

Reliability

BC Hydro continues to ensure the reliability of the system by effectively implementing capital and maintenance programs to manage overall asset health, addressing vulnerabilities in our system and developing well practiced emergency response plans.

- Focused vegetation management programs helped to manage the frequency of tree-related outages.
- Targeted deployment of automated reclosers reduced sustained outages.
- Information from Smart Meter Infrastructure and automated devices along with other technological improvements enabled system flexibility and better outage management.
- Continued to mature our emergency response readiness, including updating existing and creating new plans, assigning and training over 1,500 employees in an emergency response role, and having over 80 per cent of our staff complete our basic security and emergency preparedness course. We also completed a number of drills and exercises including two company-wide exercises testing our procedures related to earthquake response and recovery.
- Upgraded our enterprise-wide security system (LENEL) software to prepare for future growth and established company-wide security threat levels and processes to communicate threats and procedures to employees and contractors.

This fiscal year, BC Hydro began reporting Key Generating Facilities Forced Outage Factor. The Key Facilities are the seven largest generating stations which produce over 80 per cent of BC Hydro's energy. 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:

- Development of a new forced outage Root Cause Analysis approach that includes process and training that will enhance our ability to accurately identify the root cause of failures.
- Implementation of enhanced forced outage investigation and risk mitigation measures to ensure appropriate risk management checks and balances are in place.
- Continued implementation of predicative 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 1.78 per cent.

Service

BC Hydro made a number of improvements focused on making it easier for customers to do business with us, including:

- Launch of the new "Pay Now" self-service capability which allows customers receiving an electronic bill notice to pay their bill directly.
- Launch of an Express Connect web enablement portal that allows customers to submit 24/7 connection requests at their convenience through their online profile.

Since its launch, the portal has significantly reduced customer administration and call wait times, and improved connection cycle times.

- Improvement of access to critical billing information by developing new billing and consumption data download functionality within MyHydro to support all customers.
- Customer-focused training and alignment of services with a focus on the customer experience, including expansion of direct service for small, medium business and First Nation customers. This enables more customer inquiries to be routed directly to the group specializing in these customer areas, rather than the primary call centre.
- Expansion of in-person service to include Dunsmuir, Edmonds and Vernon offices.
- Pilot of a number of innovative conservation solutions to understand how these solutions could help meet long-term energy and capacity needs, for example trials of residential and commercial demand response initiatives.
- Conducted an external transmission interconnection process benchmarking study that concluded that BC Hydro's performance is consistent with our utility peers in North America. The study also recommended some areas of further improvements. BC Hydro has shared the study findings and our plan to improve interconnection processes with customers and industry associations.
- Significant improvements in overall storm outage response times by using a number of tools to help predict and prepare for storms. In fiscal 2017, despite experiencing a challenging procession of heavy storms, 62 per cent of customers who experienced an outage due to a storm had their power restored in less than four hours and 86 per cent under eight hours. These are significant improvements over recent years.

Recognizing that we have a shared future together, we are focused on strengthening our relationships with First Nations in B.C., particularly in the locations where we have existing and planned infrastructure. This year, BC Hydro:

- Continued to strengthen relationships by understanding more about First Nations interests and established five-year work plans with specific First Nations to address those interests.
- Extended our Statement of Aboriginal Principles to our contractors to widen the means by which we are building relationships and contributing to the well-being of First Nation communities.
- Continued to provide First Nations with employment on our capital projects. For example, while the number fluctuates depending on the nature of the work, at any one time there are between 100 and 200 Aboriginal employees working on the Site C Clean Energy Project.
- Provided contracting opportunities for First Nations community-owned businesses or partnerships of approximately $210 million through our capital projects.
- Supported 124 Aboriginal candidates in preliminary and prerequisite training initiatives and hired 52 Aboriginal employees.

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

BC Hydro customers will continue to have low, predictable rates while we efficiently manage our costs and make important investments to maintain and expand our system.

Strategies

- Prudently implement the Integrated Resource Plan recommendations and the 10 Year Capital Plan while keeping electricity rates low and predictable which will be reflected in the Revenue Requirements and Rate Design Applications to the BC Utilities Commission.
- 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.
- Build Site C - a third dam and generating station on the Peace River, which is the most cost-effective way to meet the long–term need for energy and dependable capacity - on time and on budget.
- Implement a scalable and consistent project delivery practice to actively manage project risks and apply industry best practices to deliver projects on time and on budget.

Performance Measures 6-7[1]

Performance Measure	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Target[2]	2016/17 Actual	2017/18 Target	2018/19 Target
Competitive Rates[2]	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile	1st quartile
Project Budget to Actual Cost[3]	-4.75% on $3.33 billion[4]	-1.83% on $3.94 billion[5]	-0.18% on $6.49 billion[6]	Within +5% to -5% of budget excluding project reserve amounts	-0.94% on $6.36 billion	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

[1] Performance Measure definitions, rationales, data sources, and benchmarking information are available at www.bchydro.com/performance.

[2] Based on BC Hydro's ranking in the residential category in the annual HydroQuebec 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 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. Annually, BC Hydro reflects the past five years' performance in delivering capital projects. 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 financial range.

[4] This is a five year rolling data set reflecting 2009/10 to 2013/14. Large Distribution projects and Properties projects were not included.

[5] This is a five year rolling data set reflecting 2010/11 to 2014/15. Large Distribution projects and Properties projects were not included.

[6] This is a five year rolling data set reflecting 2011/12 to 2015/16. Large Distribution projects managed by Project Delivery, the Smart Metering and Infrastructure Program and Properties projects were included.

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 being consistently ranked in the first quartile, based on analysis of Hydro Quebec's annual report, "Comparison of Electricity Rates in Major North American Cities."

Over the last five years, BC Hydro has completed 540 capital projects at a total cost of $6.4 billion, which is 0.94 per cent under budget overall. BC Hydro measures its performance in delivering capital projects with the Project Budget to Actual Cost measure. Since its introduction in 2015/16, we have consistently met our yearly targets.

Our accomplishments this year reflect our prudent implementation of the Integrated Resource Plan recommendations and our well-planned investments to upgrade our system.

- BC Hydro's Fiscal 2017 – Fiscal 2019 Revenue Requirements Application is currently before the British Columbia Utilities Commission for review. BC Hydro submitted the application in July 2016 in alignment with the 10 Year Rates Plan. The British Columbia Utilities Commission approved interim, refundable rate increases of 4 per cent effective April 1, 2016 and 3.5 per cent effective April 1, 2017.
- In January 2017, BC Hydro received a decision from the British Columbia Utilities Commission on our 2015 Rate Design Application. The decision approved all of the key proposals for residential, commercial and industrial rate designs.
- In January 2017, the British Columbia Utilities Commission approved the renewal of two Electricity Purchase Agreements, noting that energy pricing for each of the two agreements is cost-effective. The 2013 Integrated Resource Plan contemplated the renewal of run-of-river Electricity Purchase Agreements.

We have improved how we operate by focusing on safety, operational excellence, efficiency and reliability by enhancing the following work delivery methods:

- In fiscal 2017, BC Hydro's Work Smart program, which improves our processes by employing Lean methodologies, undertook 12 projects across the company. These projects, in which employees are empowered to develop and implement enhanced processes through a structured framework, generated an estimated 19,000 annual capacity hours gained. Capacity hours gained means that staff time was made available for higher value tasks as a result of implementing the Work Smart solutions. Since the program started in fiscal 2015, an estimated 47,000 annual capacity hours have been gained throughout the organization.
- Implementing Category Management which is an approach for optimizing the overall benefits, including total life cycle cost, 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.
- The design and implementation of new business processes and SAP information technology for supply chain functions through the Supply Chain Application Project. Among other things the new processes and system will make it more efficient to procure goods and services and manage materials across BC Hydro.

The Site C Clean Energy Project is the most cost-effective way to meet the long-term need for energy and dependable capacity. In 2016/17, key accomplishments included:

- **Site preparation**: Commenced in July 2015 and was substantially completed this year. As of March 31, 2017, 2,470 hectares of land were cleared, 10 million cubic metres of material were excavated, the temporary construction bridge was put into service, a 1,600 person worker accommodation facility was constructed, the temporary construction power and substation were installed, and public and on-site access roads were built and improved. The Main Civil Works Contractor began work on North Bank Excavation, the Right Bank Drainage Tunnel and the Right Bank Cofferdam, and completed the Moberly River Construction Bridge and the Roller-Compacted Concrete Batch Plant.
- **Procurement activities**: Resulted in the award of many small and large contracts with commitments totaling approximately $4.0 billion as at March 31, 2017.
- **On-site workers**: Reached 2,252 by March 2017, of which 1,814 or 81 per cent, were from British Columbia.
- **Aboriginal business opportunities and employment:** By the end of fiscal 2017, $150 million in procurement commitments had been made to First Nations companies, and joint ventures including First Nations companies, and approximately 200 First Nations employees and contractors were working on the project.
- **Impact Agreements:** BC Hydro has reached project impact agreements with a number of First Nations, including Doig River First Nation, Halfway River First Nation, McLeod Lake Indian Band and Dene Tha' First Nation.

Our scalable and consistent project delivery practice yielded the following accomplishments:

- In November 2016, BC Hydro received the 2016 Project Management Office of the Year Global Award from the Project Management Institute (PMI) – which compared our project delivery practices and Project Management Office to other companies around the world.
- In February 2016, we had a second organizational project management maturity model (OPM3) assessment (Industry standard PMI Assessment) completed by an independent party in which we received a score of 91 per cent out of 100 per cent. This assessment compared our project delivery practices to best practices. This was the highest score ever given globally by a certified PMI OPM3 auditor.

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

BC Hydro will strengthen its legacy of renewable, clean power and energy conservation investments by implementing its energy conservation plan and by identifying and securing new competitively priced energy and capacity options to meet future customer needs.

Strategies

- Meet the *Clean Energy Act* objective that at least 93 per cent of electricity generation be from renewable, clean resources by implementing the Integrated Resource Plan recommendations, including renewing expiring electricity purchase agreements (EPAs) on a cost of service basis and by implementing the Memorandum of Understanding with Clean Energy BC which includes exploring opportunities to acquire dependable capacity resources through the Standing Offer Program.
- Implement the energy conservation plan, which will exceed the *Clean Energy Act* objective to meet at least two-thirds of future demand growth through conservation and other energy management measures by 2020.
- Continue to provide opportunities for First Nations in non-integrated areas through established renewable energy programs.

Performance Measures 8-9[1]

Performance Measure	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Target	2016/17 Actual	2017/18 Target	2018/19 Target
Energy Conservation Portfolio (New Incremental GWh/year)[2]	500	700	1,000	700	733	600[3]	700[3]
Clean Energy (%)[4]	97.1	97.9	98.2[5]	93.0	98.4	93.0	93.0

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

[2] Reflects the annual new incremental electricity savings resulting from 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). This was a new measure introduced for 2016/17; however, historical information has been provided for context.

[3] Updated customer information on the timing of thermo-mechanical pulp (TMP) projects is incorporated into the plan resulting in the 2017/18 target of 600 GWh, followed by an increased target of 700 GWh in 2018/19, and a return to 600 GWh in 2019/20.

[4] The Clean Energy performance measure represents the minimum threshold generation output in accordance with the B.C. Government's requirement that at least 93 per cent of electricity generation in the province be from clean or renewable resources. BC Hydro's forecast is based on expected generation and is consistent with previous years. This year's actual was the highest BC Hydro has achieved.

[5] Previously reported as 98.3 in the 2015/16 Annual Service Plan Report. Prior years' results were calculated based on the latest available data and may be different than previously stated.

Discussion

BC Hydro continues to meet the *Clean Energy Act* objectives by implementing the 2013 Integrated Resource Plan recommendations. We also continue to provide opportunities for First Nations in non-integrated areas through established renewable energy programs. In fiscal 2017, 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, including pursuing acquisitions under the Standing Offer Program.
- Initiated Integrated Resource Plan recommendations with an optimization process for the Standing Offer Program and Micro-Standing Offer Program to reflect future system needs, consider recent advancements in technology and align with the 2013 10 Year Rates Plan.
- The British Columbia Utilities Commission approved the renewal of two Electricity Purchase Agreements in January 2017.
- Filed our Fiscal 2017 – Fiscal 2019 Revenue Requirements Application for review with the British Columbia Utilities Commission.
- Throughout fiscal 2017, BC Hydro worked with Kwadacha First Nation to ensure the successful completion of a biomass facility in Fort Ware that would provide clean and renewable energy to displace a portion of the diesel generation currently used to electrify the community.

This fiscal year, BC Hydro began reporting New Incremental Energy Conservation Portfolio Energy Savings. This measure replaces the previous Cumulative Demand Side Management Energy Savings. BC Hydro continues to implement our plan to achieve or exceed the *Clean Energy Act* target to meet at least 66 per cent of incremental demand from 2008 to 2020 through conservation. This new metric is a better reflection of performance within the operating period because it is based on the new incremental energy savings from programs, codes and standards and conservation rates that are implemented within the period. In some cases, the implementation date for anticipated codes and standards can shift, which will cause actual incremental energy savings to vary from the targets that have been set for the period.

Goal 4: Safety Above All

BC Hydro's number one priority is ensuring its workforce goes home safely every day and that the public is safe around our system.

Strategies

- Implement the five-year safety strategy with key elements that include:
  - Maintaining a culture where safety is a core value through demonstrating seen and felt safety leadership; supporting the courage to intervene where anyone can stop unsafe work; improving safety awareness and communication; and, learning from injury and near miss incidents to prevent re-occurrence.

- Enhance frontline accountability for safety by establishing clear roles and accountabilities; developing a leading-class safety management system; and, continuing to leverage the joint health and safety committees to identify hazards and risks.
- Strengthening safety competencies for employees and contractors around our: Life Saving Rules, Arc flash, asbestos and confined space hazards; improving job planning, hazard identification and the use of multiple barriers; and providing frontline and crew leadership training.
- Incorporating safety into the strategy and planning process by reviewing and considering safety risks to our employees, contractors and the public in maintenance budgets and designs for capital projects.

Performance Measures 10-12[1]

Performance Measure	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Target	2016/17 Actual	2017/18 Target	2018/19 Target
Zero Fatality & Serious Injury[2] [Loss of life or the injury has resulted in a permanent disability]	0	1[3]	0	0	0	0	0
Lost Time Injury Frequency[2,4,5] [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.11	1.00	1.14	1.00	1.04	0.90	0.85[6]
Timely Completion of Corrective Actions (%)[7,8]	84%	78%	80%	85%	96%	93%[9]	95%

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

[2] BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.

[3] The 2014/15 actual reflects that a serious injury from an electrical contact occurred November 2014.

[4] Focusing on Lost Time Injury Frequency encourage managers to identify modified work duties for job categories and locations where workers experience injury, enabling injured workers to stay on the job while they recover. The earlier an injured worker is able to safely return to productive employment and maintain his or her positive connection to the workplace, the more likely he or she is of obtaining maximum recovery. With the increased granularity this metric provides, the organization is better able to focus its efforts on managing the hazards that can lead to Lost Time injuries.

[5] Prior years' results have been calculated based on the latest available data and may be different than previously stated.

[6] Target was originally reported as 0.80 in 2016/17-2018/19 Service Plan. A less aggressive target was set to allow for longer implementation period of field ergonomics program which a significant proportion of the injuries experienced at BC Hydro.

[7] Timely Completion of Corrective Actions defined as the percentage of safety corrective actions closed within 30 days of the original scheduled due date on an annual basis

[8] A new measure, Timely Completion of Corrective Actions, was introduced for 2016/17. Historical information has been provided for context.

[9] Target was originally reported as 90% 2016/17-2018/19 Service Plan. A more aggressive target was set to reflect the significant strides BC Hydro has made to the timely completion of corrective actions.

Discussion

BC Hydro is in our second year of implementing our five year safety strategy. In fiscal 2017, we achieved the following key accomplishments:

- Completed training and assessing the competency associated with BC Hydro's Life Saving Rules of approximately 800 of our power line technicians and electricians. This work was initiated in 2015/2016 and was completed this fiscal year.
- Continued our programs to reduce hazards associated with arc flash, working in confined spaces and exposure to asbestos which supports our objective of zero fatalities and serious injuries as well as ensuring that BC Hydro is complaint with WorkSafeBC regulations.
- Implemented a field/plant ergonomics program in materials management and fleet services to reduce musculoskeletal injuries, the most common type of injury resulting in lost time at BC Hydro. Initial indications from our safety data suggest that the project is resulting in a reduction of musculoskeletal injuries within those teams. A customized strategy and implementation plan was also developed in fiscal 2017 for our Training, Development and Generation business group.
- Upgraded the system (Incident Management System) that tracks our safety incidents, investigations and corrective actions to meet requirements introduced as part of new WorkSafeBC regulations (Bill 9). The upgrade also focused on improving ease of use for employees and contractors, as well as enabling effective reporting of hazardous conditions.
- Implemented a document repository, SafeHub, which improves ease of access and provides a single source of safety documentation for front line employees. This initiative is part of our efforts to implement a leading-class safety management system.
- Implemented a program to reduce electrical contact incidents by clarifying requirements and rules for the use of class 0 rubber gloves.
- Updated fire resistant clothing and eye protection standards to ensure consistent application across BC Hydro.
- Developed and implemented a consistent program for managing contractor safety. The program defines responsibilities for BC Hydro employees and provides mandatory tools and templates to maintain consistent implementation. Implemented contractor requirements for "Certificate of Recognition" (COR) and Alcohol & Drug policies.
- Enhanced Safety Business Planning process to support the various BC Hydro business groups in understanding and integrating Safety Improvement Projects into their own financial and resource plans.

Overall, BC Hydro had better safety results in fiscal 17 than in the previous year. BC Hydro had zero fatalities and serious injuries in fiscal 16 and 17. This is the first time in 35 years that we have had consecutive years without a fatality or serious injury.

BC Hydro finished fiscal 17 with a 1.04 Lost Time Injury Frequency rate which narrowly missed its target of 1.00. The projects in the five year safety plan that contributed to the better results include: our field/plant ergonomics program in materials management and fleet operational groups; our knife cut reduction program which introduced better cut resistant gloves and more appropriate/safer cutting tools for the job; and our winter hazard injury reduction program.

Finally, the timely completion of corrective actions had a result of 96 per cent in fiscal 17. This is a significant improvement from the fiscal 16 result of 79 per cent. The primary drivers for this improvement were:

1) the formation of the corrective action governance team which supported the creation and implementation of complex corrective actions;
2) the initiation of the 72-hour 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
3) elevated 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, 2017 (fiscal 2017) and should be read in conjunction with the Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2017 and 2016.

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) (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, 2017 was $684 million, $29 million higher than the prior fiscal year net income of $655 million. Domestic revenues were $143 million higher than the prior fiscal year primarily due to higher average customer rates reflecting an average interim rate increase as approved by the British Columbia Utilities Commission (BCUC) of 4 per cent effective April 1, 2016. Finance charges were $147 million lower than the prior fiscal year primarily due to lower interest charges on electricity purchase agreements accounted for as finance leases, higher interest during construction which is capitalized, and lower long-term and short-term interest expense. This was offset by $183 million higher domestic energy costs mainly due to higher planned purchases from Independent Power Producers and $47 million higher asset related costs incurred from asset disposals, retirements, and removals, and dismantling costs that were expensed as planned in the current fiscal year, but drew down the balance in a regulatory account in the prior fiscal year.

- Water inflows to the system during fiscal 2017 were 101 per cent of average compared to 97 per cent of average in the prior fiscal year. The above average inflows in fiscal 2017 were the result of higher precipitation and snowmelt across the province.

- Capital expenditures, before contributions in aid of construction, for the year ended March 31, 2017 were $2,444 million, a $138 million increase over the prior fiscal year. BC Hydro continues to invest significantly in capital projects to refurbish its ageing infrastructure and build new assets for future growth, including Site C Clean Energy project, John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, Distribution Wood Poles Replacements program, W.A.C. Bennett Dam Riprap Upgrade project, Big Bend Substation project, and Horne Payne Substation Upgrade project.

CONSOLIDATED RESULTS OF OPERATIONS

for the years ended March 31 ($ in millions)	**2017**	2016	Change
Total Revenues	**$ 5,874**	$ 5,657	$ 217
Net Income	**$ 684**	$ 655	$ 29
Capital Expenditures	**$ 2,444**	$ 2,306	$ 138
Payment to the Province	**$ 259**	$ 326	$ (67)
GWh Sold (Domestic)	**57,652**	57,300	352

as at March 31 ($ in millions)	**2017**	2016	Change
Total Assets	**$ 31,888**	$ 30,034	$ 1,854
Shareholder's Equity	**$ 4,909**	$ 4,500	$ 409
Retained Earnings	**$ 4,822**	$ 4,397	$ 425
Debt to Equity	**80 : 20**	80 : 20	n/a
Number of Domestic Customer Accounts	**1,987,963**	1,960,555	27,408
Total Reservoir Storage (GWh)	**14,526**	16,518	(1,992)

REVENUES

Total revenues after regulatory account transfers for the year ended March 31, 2017 were $5,874 million, an increase of $217 million or 4 per cent compared to the prior fiscal year. The increase was primarily due to higher domestic revenue mainly due to higher average customer rates and higher transfers to the Rate Smoothing regulatory account to smooth the impacts of the rate increases during the 10 Year Rates Plan period. The table below show revenues before regulatory account transfers, the amount of regulatory account transfers, and total revenues after regulatory account transfers as follows:

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31	**2017**	2016	**2017**	2016	**2017**	2016
Domestic						
Residential	**$ 2,012**	$ 1,842	**18,068**	17,331	**$ 111.36**	$ 106.28
Light industrial and commercial	**1,800**	1,685	**18,968**	18,421	**94.90**	91.47
Large industrial	**770**	766	**13,177**	13,669	**58.44**	56.04
Other sales	**428**	464	**7,439**	7,879	**57.53**	58.89
Total Domestic Revenue Before Regulatory Transfers	**5,010**	4,757	**57,652**	57,300	**86.90**	83.02
Rate smoothing and energy deferral regulatory transfers	**189**	299	-	-	-	-
Total Domestic	**$ 5,199**	$ 5,056	**57,652**	57,300	**$ 90.18**	$ 88.24
Trade						
Gross electricity and gas	**$ 1,348**	$ 1,105	**36,574**	31,774	**$ 33.44**	$ 32.80
Less: forward electricity and gas purchases	**(673)**	(504)	-	-	-	-
Total Trade[1]	**$ 675**	$ 601	**36,574**	31,774	**$ 18.46**	$ 18.91
Total	**$ 5,874**	$ 5,657	**94,226**	89,074	**$ 62.34**	$ 63.51

[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, 2017 were $5,199 million, an increase of $143 million or 3 per cent compared to the prior fiscal year. The increase over the prior fiscal year was primarily due to $170 million higher residential revenues mainly due to colder weather in the third quarter and fourth quarter compared to the same period in the prior fiscal year and higher average customer rates. December 2016 through March 2017 experienced monthly average temperatures across British Columbia that were between 2.2 and 4.3 degrees Celsius lower per month than the same period in the prior fiscal year. BC Hydro set a new record for power consumption when demand for electricity peaked at 10,194 megawatts on January 3, 2017. Light industrial and commercial revenues were $115 million higher mainly due to higher average customer rates and higher usage. Higher average customer rates reflect an average interim rate increase as approved by the BCUC of 4 per cent effective April 1, 2016.

These higher revenues were partially offset by $36 million lower other sales as a result of less surplus energy sold (a component of other sales) into the market as compared to the same period in the prior fiscal year (5,756 GWh for the year ended March 31, 2017 compared to 6,277 GWh for the year ended March 31, 2016) due to a combination of both lower volumes and lower prices in fiscal 2017. The higher volumes sold in fiscal 2016 were to manage spill risk from higher storage levels built up during previous periods at the large reservoirs, as well as to maintain Arrow Lakes reservoir levels to support ferry service and facilitate industrial operations on the lakes. In addition, there were $110 million lower regulatory account transfers related to the Rate Smoothing account, Non-Heritage Deferral Account (NHDA), and Heritage Deferral Account (HDA). Changes to regulatory account balances are discussed in the *Regulatory Transfers* section.

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.

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 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. Trade outside the Company's system is made only after ensuring domestic demand requirements are met.

Total trade revenues for the year ended March 31, 2017 were $675 million, an increase of $74 million or 12 per cent compared to the prior fiscal year. The increase in revenues was primarily due to a 15 per cent increase in the volume of physical energy sold. This increase was primarily due to an outage of a key third party transmission line to California in the prior fiscal year which significantly reduced electricity export opportunities relative to the current fiscal year, and higher withdrawals of gas from storage in the current fiscal year due to colder winter temperatures.

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

OPERATING EXPENSES

For the year ended March 31, 2017, total operating expenses, after regulatory account transfers, of $4,585 million were $335 million higher than the prior fiscal year. The increase over the prior fiscal year was primarily due to higher planned purchases from Independent Power Producers and higher asset related costs incurred in the current fiscal year from asset disposals, retirements, and removals, and dismantling costs that were expensed as planned in the current fiscal year, but drew down the balance in a regulatory account in the prior fiscal year.

Cost of Energy

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, 2017 were $2,094 million, $242 million or 13 per cent higher than the prior fiscal year. The increase over the prior fiscal year was primarily due to higher planned purchases from Independent Power Producers. The table below shows energy costs before regulatory account transfers, the amount of regulatory account transfers, and total energy costs after regulatory account transfers as follows:

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31	**2017**	2016	**2017**	2016	**2017**	2016
Domestic						
Water rental payments (hydro generation)[1]	**$ 346**	$ 327	**48,483**	48,376	**$ 7.14**	$ 6.76
Purchases from Independent Power Producers	**1,213**	1,229	**13,644**	14,319	**88.90**	85.82
Other electricity purchases - Domestic	**3**	3	**131**	122	**22.90**	24.59
Gas for thermal generation	**18**	29	**74**	215	**243.24**	134.88
Transmission charges and other expenses	**25**	24	**118**	111	**-**	-
Columbia River Treaty Related Agreements	**(23)**	(15)	**-**	-	**-**	-
Allocation from (to) trade energy	**2**	-	**138**	(6)	**28.15**	24.79
Total Domestic Cost of Energy Before Regulatory Transfers	**1,584**	1,597	**62,588**	63,137	**25.31**	25.29
Energy deferral regulatory transfers	**24**	(172)	**-**	-	**-**	-
Total Domestic	**$ 1,608**	$ 1,425	**62,588**	63,137	**$ 25.69**	$ 22.57
Trade						
Gross electricity and remarketed gas	**$ 880**	$ 763	**36,179**	31,898	**$ 24.04**	$ 23.70
Less: forward electricity and gas purchases	**(673)**	(504)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**207**	259	**-**	-	**-**	-
Transmission charges and other expenses	**262**	215	**-**	-	**-**	-
Allocation (to) from domestic energy	**(2)**	-	**(138)**	6	**28.15**	24.79
Total Trade Cost of Energy Before Regulatory Transfers	**467**	474	**36,041**	31,904	**12.96**	14.86
Trade net margin regulatory transfer	**19**	(47)	**-**	-	**-**	-
Total Trade	**$ 486**	$ 427	**36,041**	31,904	**$ 13.48**	$ 13.38
Total Energy Costs	**$ 2,094**	$ 1,852	**98,629**	95,041	**$ 21.23**	$ 19.49

[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, 2017 were $1,608 million, an increase of $183 million or 13 per cent compared to the prior fiscal year. The significant variances from the prior fiscal year, before regulatory account transfers, were due to $16 million lower purchases from Independent Power Producers driven by lower deliveries from one large hydro Independent Power Producer that needed more energy for operational purposes in the current fiscal year, partially offset by higher volumes due to an increased number of Independent Power Producers in operation during the current fiscal year. In addition, there were $11 million lower gas costs primarily due to the decommissioning of the Burrard generating units at the end of fiscal 2016 and lower thermal generation due to an outage at the Fort Nelson generating station.

These lower costs were partially offset by $19 million higher water rental payments, which are based on the prior calendar year's generation volumes. There were higher generation volumes in calendar year 2015 than in calendar year 2014 driven by reservoir management needs.

In addition, there were $196 million higher regulatory account transfers related to the HDA and NHDA. Changes to regulatory account balances are discussed in the *Regulatory Transfers* section. Variances between actual and planned domestic cost of energy are transferred to the HDA and NHDA.

Trade Energy Costs

Trade energy costs before regulatory account transfers for the year ended March 31, 2017 were $467 million, which was comparable with trade energy costs in the prior fiscal year. Higher average gas purchase prices, which were reflective of overall higher gas prices in Western North America, were offset by a decrease in average electricity purchase prices. The decrease in average electricity purchase prices was primarily due to higher water inflows in the Pacific Northwest during the fiscal year.

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

Water Inflows and Reservoir Storage

Water inflows to the system during fiscal 2017 were 101 per cent of average compared to 97 per cent of average in the prior fiscal year. The above average inflows in fiscal 2017 were the result of higher precipitation and snowmelt across the province.

Total reservoir storage as at March 31, 2017 was 14,526 GWh, a decrease of 1,992 GWh compared to total reservoir storage as at March 31, 2016 of 16,518 GWh. The draw down in system energy storage during fiscal 2017 was a result of storage management to assist progress on capital projects at the W.A.C. Bennett Dam and to optimize for market opportunities.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the year ended March 31, 2017 were $541 million, $14 million higher than the prior fiscal year primarily due to Smart Metering & Infrastructure costs that were expensed in the current fiscal year, but were transferred to the Smart Metering & Infrastructure regulatory account in the prior fiscal year.

Materials and External Services

Expenditures on materials and external services for the year ended March 31, 2017 were $608 million, comparable to materials and external services of $605 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, 2017, amortization and depreciation expense was $1,232 million, $9 million lower than the prior fiscal year primarily due to lower amortization of regulatory accounts, partially offset by higher depreciation of property, plant and equipment due to an increase in assets in service.

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, 2017 were $234 million, $14 million higher than the prior fiscal year primarily due to increased property values, increased revenues from electricity sales, and the completion of major capital projects for which grants in lieu are paid.

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, 2017, other costs net of recoveries were $55 million, $47 million higher than the prior fiscal year. The increase was primarily due to higher asset related costs incurred from asset disposals, retirements, and removals, and dismantling costs that were expensed as planned in the current fiscal year, but were recorded in a regulatory account in the prior fiscal year. In prior fiscal years when dismantling costs were incurred, the Dismantling Cost regulatory account (formerly the Future Removal & Site Restoration Costs regulatory account) would be drawn down. At the end of the first fiscal quarter in fiscal 2017, the regulatory account was fully drawn down resulting in costs being expensed as planned rather than being recorded in the regulatory account.

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, $1/10^{th}$ 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, 2017 were $179 million, $24 million lower than the prior fiscal year primarily due to the annual reduction of the transfer of operating costs to the IFRS Property, Plant & Equipment account.

FINANCE CHARGES

Finance charges for the year ended March 31, 2017 were $605 million, $147 million lower than the prior fiscal year. The decrease was primarily due to lower long-term and short-term interest rates, lower interest charges on electricity purchase agreements accounted for as finance leases, and higher interest during construction which was capitalized. This decrease was partially offset by higher volume of long-term debt borrowings and higher interest costs on US debt due to a weaker Canadian dollar.

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 in the year the amounts are incurred or would be reflected in rates. 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, in order 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)	**2017**	2016
Energy Deferral Accounts		
Heritage Deferral Account	**$ (31)**	$ (152)
Non-Heritage Deferral Account	**(17)**	483
Trade Income Deferral Account	**(15)**	51
	(63)	382
Forecast Variance Accounts		
Total Finance Charges	**(12)**	(158)
Rate Smoothing	**201**	121
Pension Costs	**(120)**	142
Debt Management	**(187)**	-
Other	**33**	18
	(85)	123
Capital-Like Accounts		
Demand-Side Management	**97**	145
Smart Metering & Infrastructure	-	20
IFRS Property, Plant & Equipment	**112**	134
	209	299
Non-Cash Accounts		
Environmental Provisions & Costs	**(24)**	51
First Nations Provisions & Costs	**18**	14
Other	**(1)**	6
	(7)	71
Amortization of regulatory accounts	**(440)**	(472)
Interest on regulatory accounts	**75**	72
Net change in regulatory accounts	**$ (311)**	$ 475

For the year ended March 31, 2017, there was a net reduction of $311 million to the Company's regulatory accounts compared to a net addition of $475 million in the prior fiscal year. Over the past five years, fiscal 2017 was the only year with a net reduction to the regulatory accounts. The net regulatory asset balance as at March 31, 2017 was $5,597 million compared to $5,908 million as at March 31, 2016.

Net reductions to the regulatory accounts during the year ended March 31, 2017 included:

- Net amortization of $440 million which is the regulatory mechanism to recover the regulatory account balances in rates;
- Decrease of $187 million to the Debt Management regulatory account as a result of an increase in interest rates since BC Hydro's initial interest rate hedges on future debt issuances were executed;

- Decrease of $120 million to the Non-Current Pension Cost regulatory account primarily due to an actuarial gain on pension plan assets which had higher rates of return than planned; and

- Decrease of $63 million to the energy deferral accounts primarily due to the following variances from plan: lower purchases from Independent Power Producers, higher surplus sales, and higher trade income.

These net reductions were partially offset by:

- Increase of $201 million of planned additions to the Rate Smoothing regulatory account to smooth the impacts of the rate increases during the 10 Year Rates Plan period;

- Transfer of $112 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;

- Expenditure of $97 million on planned Demand-Side Management projects, which support energy conservation; and

- Interest on regulatory accounts of $75 million.

Net regulatory account balances are as follows:

as at March 31 (in millions)	**2017**	2016
Energy Deferral Accounts		
Heritage Deferral Account	**$ (53)**	$ (24)
Non-Heritage Deferral Account	**756**	917
Trade Income Deferral Account	**194**	249
	897	1,142
Forecast Variance Accounts		
Total Finance Charges	**(215)**	(305)
Rate Smoothing	**488**	287
Pension Costs	**511**	691
Debt Management	**(187)**	-
Other	**(5)**	(30)
	592	643
Capital-Like Accounts		
Demand-Side Management	**916**	908
Smart Metering & Infrastructure	**261**	283
IFRS Property, Plant & Equipment	**962**	872
Site C	**453**	436
Capital Project Investigation Costs	**20**	25
	2,612	2,524
Non-Cash Accounts		
Environmental Provisions & Costs	**294**	358
First Nations Provisions & Costs	**532**	541
Dismantling Cost	**-**	(9)
IFRS Pension	**574**	612
Other	**96**	97
	1,496	1,599
Net Regulatory Asset	**$ 5,597**	$ 5,908

BC Hydro has regulatory mechanisms in place or has applied for regulatory mechanisms in the Fiscal 2017-2019 Revenue Requirements Application to collect 25 of 27 regulatory accounts in use or with balances at March 31, 2017 in rates over various periods, which represent approximately 83 per cent of the total net regulatory asset account 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 2016/17-2018/19 was filed in February 2016 and forecast net income for fiscal 2017 at $692 million.

The table below provides an overview of BC Hydro's fiscal 2017 financial performance results, relative to its February 2016 Service Plan forecast.

Consolidated Statement of Operations

(in millions)	**Actual** 2016	**Actual** 2017	**2017 Service Plan**[2] 2017	**Variance to 2017 Service Plan**[2]
Revenues				
Domestic	$ 5,056	$ 5,199	$ 5,334	$ (135)
Trade	601	675	614	61
	5,657	5,874	5,949	(75)
Expenses				
Operating Costs				
Cost of energy	1,852	2,094	2,135	41
Other operating expenses				
Personnel expenses, materials and external services [1]	905	946	974	28
Amortization	1,241	1,232	1,202	(30)
Finance charges	752	605	627	22
Grants and taxes	220	234	230	(4)
Other	32	79	87	8
	5,002	5,190	5,256	66
Net Income	$ 655	$ 684	$ 692	$ (8)

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

[2] *Column may not add due to rounding.*

Net income for fiscal 2017 was $684 million, $8 million lower than the 2016/17-2018/19 Service Plan filed in February 2016 of $692 million. The decrease was mainly a result of Order in Council No. 590 which amended Direction No. 7 to the BCUC. This amendment states that BC Hydro's annual rate of return on deemed equity shall be an amount necessary to yield a net income of $684 million for fiscal 2017.

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, the Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The

Special Directive states that 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 July 2016, the Province issued Order in Council No. 589, which amends the Special Directive and states that BC Hydro must make a Payment to the Province of an amount no less than $259 million by June 30, 2017, as it relates to fiscal 2017. The Company paid the $259 million minimum payment to the Province in March 2017. The Payment to the Province was less than 85 per cent of the Company's net income. The Payment to Province calculation as at March 31, 2017 determined that no further payment was required due to the debt to equity ratio cap.

During fiscal 2017, the Payment to Province in respect of both fiscal 2016 and 2017 were paid to the Province, resulting in a total payment of $585 million as follows: $326 million in June 2016 related to fiscal 2016 and $259 million in March 2017 related to fiscal 2017. As a result, the Company has accrued $nil at March 31, 2017 (2016 - $326 million) for the Payment to Province, which is included in accounts payable and accrued liabilities.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the year ended March 31, 2017 was $1,327 million, compared with cash flow provided by operating activities of $1,060 million in the prior fiscal year. The increase was mainly due to higher domestic revenue primarily due to higher domestic load and higher average customer rates, as well as higher trade revenue primarily due to an increase in the physical volume of energy sold.

The long-term debt balance net of sinking funds as at March 31, 2017 was $19,845 million, compared with $18,046 million at March 31, 2016. The increase was mainly a result of an increase in long-term bond issuances for net proceeds of $1,340 million ($1,350 million par value) and revolving borrowings of $462 million. Long-term debt increased primarily to fund capital expenditures.

CAPITAL EXPENDITURES

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

for the years ended March 31 (in millions)		**2017**		2016
Transmission lines and substations replacements and expansion	**$**	**515**	$	612
Generation replacements and expansion		**585**		498
Distribution system improvements and expansion		**449**		464
General, including technology, vehicles and buildings		**232**		243
Site C Clean Energy project		**663**		489
Total Capital Expenditures	**$**	**2,444**	$	2,306

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 Transmission Wood Structure and Framing Replacement program, Big Bend Substation project, Horne Payne Substation Upgrade project, 500kV Oil-Filled Current Transformers Replacement program, Campbell River Substation Capacity Upgrade, Spacer Damper Replacement program, Meikle Wind Energy interconnection project, and property purchased for a future substation. Transmission lines and substation capital expenditures for the year ended March 31, 2017 were lower than the prior fiscal year primarily due to the following large projects which went into service in fiscal 2016: Interior to Lower Mainland Transmission Line project; Dawson Creek/Chetwynd Area Transmission project; and Surrey Area Substation project.

Generation capital expenditures include expenditures for John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, W.A.C. Bennett Dam Riprap Upgrade project, Upper Columbia Capacity Additions at Mica – Units 5 & 6, Bridge River 1 Unit Transformers T1 & T2 Replacement project, and GMS Spillway Chute Interim Upgrade project. Generation capital expenditures for the year ended March 31, 2017 were higher than the prior fiscal year primarily due to higher John Hart Generating Station Replacement project spend shifting from fiscal 2016 and higher W.A.C. Bennett Dam Riprap Upgrade project costs due to advancement of activities from fiscal 2018, partially offset by the following projects which went into service in fiscal 2016: G.M. Shrum Units 1 to 5 Turbine Replacement project; and Hugh Keenleyside Spillway Gate Reliability Upgrade project.

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 various building development programs, technology projects, and vehicles.

Site C Clean Energy project expenditures relate to site preparation, clearing, and construction of worker accommodation, and main civil works. Site C Clean Energy project expenditures for the year ended March 31, 2017 were higher than the prior fiscal year because the project commenced construction part way through fiscal 2016 whereas fiscal 2017 included a full year of construction activities. In addition, main civil works construction activities commenced in the second quarter of fiscal 2017.

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 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 in fiscal 2019 in alignment with the 10 Year Rates Plan. The BCUC has approved interim, refundable rate increases of 4.0 and 3.5 for fiscal 2017 and 2018, while it evaluates the full Revenue Requirements Application.

In October 2016, the BCUC and Interveners submitted 2,180 information requests to BC Hydro about the Application (Round 1), which BC Hydro responded to in November 2016. In December 2016, the BCUC and interveners submitted an additional 1,288 information requests to BC Hydro (Round 2). BC Hydro provided its responses in January 2017.

The BCUC confirmed in January 2017 that a written process would be undertaken to review the Application, rather than an oral hearing. The BCUC accepted intervener evidence in February 2017, with a subsequent round of information requests. BC Hydro filed rebuttal evidence in April 2017, which was followed by a round of information requests on that evidence, and BC Hydro's responses to those requests in May 2017. The proceeding has now transitioned into final argument stage, starting with BC Hydro submitting its Final Argument in May 2017 and will complete with BC Hydro submitting its Reply Argument in July 2017. A decision from the BCUC is expected in late summer or early fall of 2017.

BC Hydro 2015 Rate Design Application

In January 2017, the BCUC issued its decision on Module 1 of the Rate Design Application approving all of BC Hydro's rate design proposals with the exception of the E-Plus rate, which it determined should be phased out over 5 years. In response, the E-Plus Homeowners Group filed an application for reconsideration of the decision. The B.C. Old Age Pensioners' Organization et al has also applied for a reconsideration of the decision as it relates to the BCUC's denial of their proposals. The BCUC will determine whether the applications are to proceed to the next phase of reconsideration.

For Module 2 of the Rate Design Application, in addition to engagement with relevant customer groups, two intervener workshops were held, covering topics such as the scope of the next filing, the transmission extension policy, optional rates (which includes looking at removing disincentives that default rates pose to low-carbon electrification), as well as street lighting and non-integrated area rates. Analysis will continue to refine preferred rate options to bring forward for consultations planned for the summer of 2017. BC Hydro expects to file the Module 2 Rate Design Application in winter 2018.

Inquiry of Expenditures Related to the Adoption of the SAP Platform

BC Hydro filed a Consolidated Information Filing in June 2016 in compliance with BCUC Order G-81-16 providing information pertaining to BC Hydro's investment in the SAP technology platform. The filing included background information on BC Hydro's enterprise resource planning investments from the 1990s to present day, historical and forecast SAP-related expenditures, and a review of SAP-related project oversight and governance.

In October 2016, the BCUC held a procedural conference to hear submissions from BC Hydro and Interveners on further process for the Inquiry. In November 2016, the BCUC issued Order G-168-16 directing that BC Hydro provide witness statements for several current and former employees in January 2017. The BCUC issued Order No. G-26-17 in February 2017 confirming another round of information requests on those statements and BC Hydro provided responses in May 2017. The BCUC will then review those responses and make a determination as to next steps in the process.

Capital Expenditures and Projects Review

In May 2016, the BCUC issued Order No. G-58-16 initiating a review of the regulatory oversight of BC Hydro's capital expenditures and projects. At the request of BCUC Staff, further regulatory process will commence two weeks following the issuance of the final decision in BC Hydro's Revenue Requirements Application proceeding.

Supply Chain Applications Project Application

In December 2016, BC Hydro filed the Supply Chain Applications Project Application under section 44.2 for acceptance of expenditures on a new SAP IT platform to meet BC Hydro's current and future business needs, reduce risk, and provide benefits for supply chain activities throughout BC Hydro. The project's total capital cost is estimated between $60 - $79 million with a committed in service date in the second quarter of fiscal 2020. The BCUC and interveners issued the first round of information requests in February 2017, which BC Hydro responded to in early March 2017. The BCUC and interveners issued a second round of information requests in April 2017 and BC Hydro provided responses in May 2017. In addition, in April 2017, intervener evidence was filed and responses to information requests on the intervener evidence were provided in May 2017. The BCUC decision on the Application is expected in fall 2017.

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 cost of energy, 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 cost of energy 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 44 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 the system.

Domestic Demand for Energy

Electricity demand is generally forecast to increase as B.C.'s population and gross domestic product increases; however, short-term fluctuations in electricity demand can be experienced due to timing of large industrial facility closures or restarts and demand-side management impacts on residential and commercial customers. 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. 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. 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.

Energy Market Prices

The cost of energy, the revenue from trade market activity, and the market opportunities available to Powerex all depend on a combination of system surplus or deficit energy, system flexibility and gas and electricity market fundamentals. When domestic loads are significantly different than forecast, this will contribute to a variance in the net market electricity sales in order to manage the generation within the Province.

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 cost of energy 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.

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, 2017, approximately 14 per cent of existing debt had a maturity of one year or less and is recognized as variable rate debt. BC Hydro has steadily reduced its allocation of variable rate debt over the last few years in response to historically low long-term interest rates and rising debt levels.

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 current low, long-term interest rates, BC Hydro hedged $4.4 billion (approximately 50 per cent) of its forecast long-term future debt issuances over the 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 2017 forecast net income for fiscal 2018 at $698 million which is consistent with Order in Council No. 590 which states that BC Hydro's annual rate of return on deemed equity shall be an amount necessary to yield a net income of $698 million for fiscal 2018.

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 2018 assumes average water inflows (100 per cent of average), domestic sales of 57,552 GWh, average market energy prices of US $25.00/MWh, short-term interest rates of 0.67 per cent, and a US dollar exchange rate of US $0.7702.

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 2018. 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 2017
Customer Load [1]	+/-1%	$30	52,010 GWh	50,992 GWh	51,896 GWh
Interest rates	+/- 100 basis points	$35	1.30% [2]	0.87% [2]	0.91% [2]
Electricity trade margins [3]	+/-10%	$20	$215	$127	$208
Hydro generation [4]	+/-1%	$10	52,115 GWh	41,230 GWh	48,736 GWh
Exchange rates (US/ CDN)	+/- $0.01	$5	$1.00 [5]	$0.76 [5]	$0.76 [5]

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

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

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

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

[5] Exchange rates are the 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, 2017. 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.

Jessica McDonald
President and Chief Executive Officer

Cheryl Yaremko
Executive Vice-President, Finance & Business Services and Chief Financial Officer

Vancouver, Canada
June 7, 2017

INDEPENDENT AUDITORS' REPORT

The Minister of Energy and Mines and Minister Responsible For Core Review, 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, 2017, 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, 2017 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, 2017

AUDITED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

for the years ended March 31 (in millions)		**2017**		2016
Revenues				
Domestic	**$**	**5,199**	$	5,056
Trade		**675**		601
		5,874		5,657
Expenses				
Operating expenses (Note 5)		**4,585**		4,250
Finance charges (Note 6)		**605**		752
Net Income		**684**		655
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)		**(11)**		12
Reclassification to income of derivatives designated as cash flow hedges (Note 19)		**(11)**		(21)
Foreign currency translation gains		**6**		10
Other Comprehensive Income (Loss)		**(16)**		1
Total Comprehensive Income	**$**	**668**	$	656

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

as at March 31 (in millions)		**2017**		2016
ASSETS				
Current Assets				
Cash and cash equivalents (Note 8)	**$**	**49**	$	44
Accounts receivable and accrued revenue (Note 9)		**808**		655
Inventories (Note 10)		**185**		155
Prepaid expenses		**162**		173
Current portion of derivative financial instrument assets (Note 19)		**144**		137
		1,348		1,164
Non-Current Assets				
Property, plant and equipment (Note 11)		**22,998**		21,385
Intangible assets (Note 12)		**601**		609
Regulatory assets (Note 13)		**6,127**		6,324
Derivative financial instrument assets (Note 19)		**215**		92
Other non-current assets (Note 14)		**599**		460
		30,540		28,870
	$	**31,888**	$	30,034
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities (Note 15)	**$**	**1,190**	$	1,725
Current portion of long-term debt (Note 16)		**2,878**		2,376
Current portion of derivative financial instrument liabilities (Note 19)		**60**		143
		4,128		4,244
Non-Current Liabilities				
Long-term debt (Note 16)		**17,146**		15,837
Regulatory liabilities (Note 13)		**530**		416
Derivative financial instrument liabilities (Note 19)		**41**		27
Contributions in aid of construction		**1,765**		1,669
Post-employment benefits (Note 18)		**1,566**		1,657
Other non-current liabilities (Note 20)		**1,803**		1,684
		22,851		21,290
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**4,822**		4,397
Accumulated other comprehensive income		**27**		43
		4,909		4,500
	$	**31,888**	$	30,034

Commitments and Contingencies (Notes 11 and 21)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

W. J. Brad Bennett, O.B.C.
Chair, Board of Directors

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 (Loss)	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2015	$ 67	$ (25)	$ 42	$ 60	$ 4,068	$ 4,170
Payment to the Province (Note 17)	-	-	-	-	(326)	(326)
Comprehensive Income (Loss)	10	(9)	1	-	655	656
Balance as at March 31, 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

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

for the years ended March 31 (in millions)	**2017**	2016
Operating Activities		
Net income	**$ 684**	$ 655
Regulatory account transfers (Note 13)	**(129)**	(947)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 13)	**440**	472
Amortization and depreciation expense (Note 7)	**783**	745
Unrealized (gains) losses on mark-to-market	**(204)**	75
Employee benefit plan expenses	**113**	110
Interest accrual	**757**	717
Other items	**114**	69
	2,558	1,896
Changes in:		
Accounts receivable and accrued revenue	**(159)**	(29)
Prepaid expenses	**11**	9
Inventories	**(28)**	(33)
Accounts payable, accrued liabilities and other non-current liabilities	**(367)**	(73)
Contributions in aid of construction	**110**	98
Other non-current assets	**(39)**	(97)
	(472)	(125)
Interest paid	**(759)**	(711)
Cash provided by operating activities	**1,327**	1,060
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(2,513)**	(2,102)
Cash used in investing activities	**(2,513)**	(2,102)
Financing Activities		
Long-term debt:		
Issued (Note 16)	**1,340**	2,641
Retired (Note 16)	**-**	(150)
Receipt of revolving borrowings	**10,046**	7,761
Repayment of revolving borrowings	**(9,583)**	(8,927)
Payment to the Province (Note 17)	**(585)**	(264)
Other items	**(27)**	(14)
Cash provided by financing activities	**1,191**	1,047
Increase in cash and cash equivalents	**5**	5
Cash and cash equivalents, beginning of year	**44**	39
Cash and cash equivalents, end of year	**$ 49**	$ 44

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2017 AND 2016

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. 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* (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 unless recovered in rates in the year the amounts are incurred.

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, 2017.

(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.

NOTE 3: CHANGES IN ACCOUNTING POLICIES

Effective April 1, 2016, the Company adopted the following amendments to IFRS standards, which had no impact on the consolidated financial statements.

- Amendments to IFRS 10, *Consolidated Financial Statements*
- Amendments to IFRS 11, *Joint Arrangements*
- Amendments to IFRS 12, *Disclosure of Interests in Other Entities*
- Amendments to IAS 1, *Presentation of Financial Statements*
- Amendments to IAS 16, *Property, Plant and Equipment*
- Amendments to IAS 38, *Intangible Assets*

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 operates under a cost of service regulation as prescribed by the BCUC. 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, which differs from IFRS, 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 otherwise be included in comprehensive income unless recovered in rates in the year the amounts are incurred. 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. 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.

(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 lives, in years, are as follows:

Software	2 – 10
Other	10 – 20

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 trade obligations for which they have been pledged as security.

(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 (Note 19: Financial Instruments – Fair Value Hierarchy). 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, that have not been recognized, 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, 2017, 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:

- Amendments to IAS 7, *Statement of Cash Flows* (April 1, 2017)
- IFRS 9, *Financial Instruments* (April 1, 2018)
- IFRS 15, *Revenue From Contracts With Customers* (April 1, 2018)
- Amendments to IAS 40, *Investment Property* (April 1, 2018)
- IFRS 16, *Leases* (April 1, 2019)

The Company does not have any plans to early adopt any of the new or amended standards. It is expected that the standards effective for the Company's 2018 fiscal year will not have a material effect on the consolidated financial statements. The Company continues to assess the impact of adopting standards that become effective for the Company's fiscal years commencing April 1, 2018 and later.

NOTE 5: OPERATING EXPENSES

(in millions)		**2017**		2016
Electricity and gas purchases	**$**	**1,576**	$	1,345
Water rentals		**349**		366
Transmission charges		**169**		141
Personnel expenses		**541**		527
Materials and external services		**608**		605
Amortization and depreciation (Note 7)		**1,232**		1,241
Grants and taxes		**234**		220
Other costs, net of recoveries		**55**		8
Less: Capitalized costs		**(179)**		(203)
	$	**4,585**	$	4,250

NOTE 6: FINANCE CHARGES

(in millions)		**2017**		2016
Interest on long-term debt	**$**	**767**	$	771
Interest on finance lease liabilities		**25**		94
Less: Other recoveries		**(94)**		(52)
Capitalized interest		**(93)**		(61)
	$	**605**	$	752

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 $81 million (2016 - $81 million). The effective capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 4.1 per cent (2016 - 4.1 per cent).

NOTE 7: AMORTIZATION AND DEPRECIATION

(in millions)		**2017**		2016
Depreciation of property, plant and equipment	**$**	**705**	$	678
Amortization of intangible assets		**78**		67
Amortization of regulatory accounts		**449**		496
	$	**1,232**	$	1,241

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2017 AND 2016

NOTE 8: CASH AND CASH EQUIVALENTS

(in millions)		**2017**		2016
Cash	**$**	**25**	$	33
Short-term investments		**24**		11
	$	**49**	$	44

NOTE 9: ACCOUNTS RECEIVABLE AND ACCRUED REVENUE

(in millions)		**2017**		2016
Accounts receivable	**$**	**526**	$	390
Accrued revenue		**138**		128
Restricted cash		**28**		62
Other		**116**		75
	$	**808**	$	655

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

NOTE 10: INVENTORIES

(in millions)		**2017**		2016
Materials and supplies	**$**	**145**	$	119
Natural gas trading inventories		**40**		36
	$	**185**	$	155

There were no materials and supplies inventory impairments during the years ended March 31, 2017 and 2016. 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 $84 million (2016 - $30 million).

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NOTE 11: PROPERTY, PLANT AND EQUIPMENT

(in millions)	Generation	Transmission	Distribution	Land & Builidings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at March 31, 2015	$ 6,989	$ 5,640	$ 5,378	$ 578	$ 735	$ 2,905	$ 22,225
Net additions (transfers)	535	1,465	418	72	165	(487)	2,168
Disposals and retirements	(6)	(34)	(31)	-	(34)	(8)	(113)
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
Accumulated Depreciation							
Balance at March 31, 2015	$ (840)	$ (566)	$ (592)	$ (74)	$ (220)	$ -	$ (2,292)
Depreciation expense	(211)	(177)	(171)	(23)	(72)	-	(654)
Disposals and retirements	3	8	8	-	32	-	51
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)
Net carrying amounts							
At March 31, 2016	$ 6,470	$ 6,336	$ 5,010	$ 553	$ 606	$ 2,410	$ 21,385
At March 31, 2017	$ 6,594	$ 6,601	$ 5,217	$ 581	$ 641	$ 3,364	$ 22,998

(i) The Company includes its one-third interest in Waneta with a net book value of $695 million (2016 - $715 million) in Generation assets. Depreciation expense on the Waneta asset for the year ended March 31, 2017 was $20 million (2016 - $20 million).

(ii) Included within Distribution assets are the Company’s portion of utility poles with a net book value of $972 million (2016 - $911 million) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2017 was $25 million (2016 - $23 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 2017 (2016 - $13 million).

(iv) The Company has contractual commitments to spend $3,288 million on major property, plant and equipment projects (on individual projects greater than $50 million) as at March 31, 2017.

Leased assets

Property, plant and equipment under finance leases of $388 million (2016 - $388 million), net of accumulated amortization of $201 million (2016 - $186 million), are included in the total amount of property, plant and equipment above.

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NOTE 12: INTANGIBLE ASSETS

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at March 31, 2015	$ 198	$ 119	$ 366	$ 31	$ 59	$ 773
Net additions	42	30	73	7	1	153
Disposals and retirements	-	-	(2)	(19)	(2)	(23)
Balance at March 31, 2016	240	149	437	19	58	903
Net additions	5	19	48	7	(7)	72
Disposals and retirements	-	-	(13)	(2)	-	(15)
Balance at March 31, 2017	$ 245	$ 168	$ 472	$ 24	$ 51	$ 960
Accumulated Amortization						
Balance at March 31, 2015	$ -	$ (38)	$ (177)	$ (11)	$ -	$ (226)
Amortization expense	-	(21)	(48)	-	-	(69)
Disposals and retirements	-	(4)	5	-	-	1
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)
Net carrying amounts						
At March 31, 2016	$ 240	$ 86	$ 217	$ 8	$ 58	$ 609
At March 31, 2017	$ 245	$ 81	$ 211	$ 13	$ 51	$ 601

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.

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 unless the Company sought recovery through rates in the year in which they are incurred. For the year ended March 31, 2017, the impact of regulatory accounting has resulted in a net decrease to total comprehensive income of $311 million (2016 - $475 million net increase) which is comprised of a decrease to net income of $108 million (2016 - $403 million increase) and a decrease to other comprehensive income of $203 million (2016 - $72 million increase). 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, unless otherwise recovered through rates. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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comprehensive income.

(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**
Pension Costs	691	(120)	-	(60)	(180)	**511**
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	78	32	2	(17)	17	**95**
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**

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(in millions)	*As at April 1 2015*	*Addition / (Reduction)*	*Interest*	*Amortization*	*Net Change*	*As at March 31 2016*
Regulatory Assets						
Heritage Deferral Account	$ 165	$ (137)	$ 1	$ (29)	$ (165)	$ -
Non-Heritage Deferral Account	524	483	28	(118)	393	917
Trade Income Deferral Account	244	51	9	(55)	5	249
Demand-Side Management	842	145	-	(79)	66	908
First Nations Provisions & Costs	564	14	6	(43)	(23)	541
Pension Costs	564	142	-	(15)	127	691
Site C	419	-	17	-	17	436
CIA Amortization	87	5	-	-	5	92
Environmental Provisions & Costs	382	51	-	(75)	(24)	358
Smart Metering & Infrastructure	283	20	11	(31)	-	283
IFRS Pension	650	-	-	(38)	(38)	612
IFRS Property, Plant & Equipment	758	134	-	(20)	114	872
Rate Smoothing	166	121	-	-	121	287
Other Regulatory Accounts	66	30	1	(19)	12	78
Total Regulatory Assets	5,714	1,059	73	(522)	610	6,324
Regulatory Liabilities						
Heritage Deferral Account	-	15	1	8	24	24
Dismantling Cost	33	-	-	(24)	(24)	9
Foreign Exchange Gains and Losses	71	(3)	-	1	(2)	69
Total Finance Charges	173	158	-	(26)	132	305
Amortization of Capital Additions	4	14	-	(9)	5	9
Total Regulatory Liabilities	281	184	1	(50)	135	416
Net Regulatory Asset	$ 5,433	$ 875	$ 72	$ (472)	$ 475	$ 5,908

RATE REGULATION

In July 2016, BC Hydro filed the Fiscal 2017-2019 Revenue Requirements Application requesting rate increases of 4.0 per cent, 3.5 per cent, and 3.0 per cent for fiscal 2017, 2018, and 2019, respectively, in accordance with Direction No. 7 issued by the Province in March 2014. The BCUC approved interim rate increases of 4.0 per cent for fiscal 2017 and 3.5 per cent for fiscal 2018. The results for the year ended March 31, 2017 reflect the interim approved rate increase of 4.0 per cent for fiscal 2017 and the orders sought by BC Hydro with respect to regulatory accounts as filed in the Application. A decision from the BCUC is expected in late summer or early fall of 2017.

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 the 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

Amounts incurred for Demand-Side Management are deferred and amortized on a straight-line basis over the anticipated 15 year period of benefit of the program. Demand-Side Management programs are designed to reduce the energy requirements on the Company's system. Demand-Side Management costs 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.

In the Fiscal 2017-2019 Revenue Requirements Application, BC Hydro proposed to recover forecast lump sum settlement payments over 10 years starting in the year of payment, forecast annual settlement payments in the year of payment, and that actual annual negotiation costs be recovered from the First Nations Costs Regulatory Account in the year incurred. Variances between forecast and actual lump sum and annual settlement payments in a test period are proposed to be 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).

PENSION COSTS

This account captures the operating service cost variances between forecast and actual service costs and all other variances between forecast and actual costs for post-employment benefit plans including net interest and re-measurements. This account is amortized over the average remaining service life of the employee group (current 12 years).

SITE C

Site C Clean Energy 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 Clean Energy 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. In the Fiscal 2017-2019 Revenue Requirements Application, BC Hydro proposed that forecast environmental and remediation costs be amortized from the accounts each year. Variances between forecast and actual environmental and remediation expenditures are proposed to 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.

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 earnings 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, equal to the fiscal 2012 overhead deferral amount less a ten year phase-in adjustment. The annual deferred amounts are amortized over 40 years beginning the year following the deferral of the expenditures.

RATE SMOOTHING ACCOUNT

As part of the 10 Year Rates Plan and pursuant to Direction No. 7, the Rate Smoothing Regulatory Account was established with the objective of smoothing rate increases over the 2013 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 2013 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. These 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 $40 million include the following: Storm Restoration Costs, Real Property Sales, Capital Project Investigation Costs, Arrow Water Systems Provisions, Arrow Water Systems (Costs), Minimum Reconnection Charges, Dismantling Cost, and Amortization of Capital Additions.

NOTE 14: OTHER NON-CURRENT ASSETS

(in millions)		**2017**		2016
Non-current receivables	**$**	**278**	$	185
Sinking funds		**179**		167
Other		**142**		108
	$	**599**	$	460

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Non-Current Receivables

Included in the non-current receivables balance are $184 million of receivables (2016 - $152 million) attributable to contributions-in-aid and tariff supplemental charges related to a transmission line. The contributions-in-aid will be received in 17 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 $24 million (2016 - $11 million) and has been recorded within accounts receivable and accrued revenue.

Included in the non-current receivables balance is a $68 million (2016 - $8 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 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)	**2017**		2016	
	Carrying Value	**Weighted Average Effective Rate[1]**	Carrying Value	Weighted Average Effective Rate[1]
Province of BC bonds	**$ 114**	**3.5 %**	$ 107	2.9 %
Other provincial government and crown corporation bonds	**65**	**3.5 %**	60	3.1 %
	$ 179		$ 167	

[1] *Rate calculated on market yield to maturity.*

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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NOTE 15: ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in millions)		**2017**		2016
Accounts payable	**$**	**224**	$	256
Accrued liabilities		**792**		957
Current portion of other long-term liabilities (Note 20)		**115**		122
Dividend payable (Note 17)		**-**		326
Other		**59**		64
	$	**1,190**	$	1,725

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, 2017, the outstanding amount under the borrowing program was $2,838 million (2016 - $2,376 million).

For the year ended March 31, 2017, the Company issued bonds for net proceeds of $1,340 million (2016 - $2,641 million) and a par value of $1,350 million (2016 - $2,691 million), a weighted average effective interest rate of 2.4 per cent (2016 - 2.5 per cent) and a weighted average term to maturity of 18.9 years (2016 - 20.2 years).

For the year ended March 31, 2017, there were no bond maturities (2016 - $150 million).

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

(in millions)	**2017**					2016				
	Canadian	**US**	**Euro**	**Total**	**Weighted Average Interest Rate[1]**	Canadian	US	Euro	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:										
2017	$ -	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	-
2018	**40**	-	-	**40**	**4.9**	40	-	-	40	4.8
2019	**1,030**	**267**	-	**1,297**	**4.4**	1,030	259	-	1,289	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**	-	-	-	-	-
1-5 years	**2,871**	**267**	-	**3,138**	**6.1**	2,345	259	-	2,604	5.8
6-10 years	**2,460**	**666**	**376**	**3,502**	**3.9**	2,136	649	390	3,175	4.9
11-15 years	**1,910**	-	-	**1,910**	**4.6**	1,000	-	-	1,000	3.7
16-20 years	-	**400**	**197**	**597**	**5.2**	1,110	-	-	1,110	5.0
21-25 years	**1,250**	-	-	**1,250**	**4.9**	1,250	389	-	1,639	5.5
26-30 years	**4,588**	-	-	**4,588**	**3.9**	4,588	-	-	4,588	3.9
Over 30 years	**2,230**	-	-	**2,230**	**3.4**	1,730	-	-	1,730	3.5
Bonds	**15,309**	**1,333**	**573**	**17,215**	**4.4**	14,159	1,297	390	15,846	4.6
Revolving borrowings	**2,284**	**554**	-	**2,838**	**0.6**	1,605	771	-	2,376	0.6
	17,593	**1,887**	**573**	**20,053**		15,764	2,068	390	18,222	
Adjustments to carrying value resulting from discontinued hedging activities	**20**	**24**	-	**44**		23	24	-	47	
Unamortized premium, discount, and issue costs	**(56)**	**(12)**	**(5)**	**(73)**		(39)	(12)	(5)	(56)	
	17,557	**1,899**	**568**	**20,024**		15,748	2,080	385	18,213	
Less: Current portion	**(2,324)**	**(554)**	-	**(2,878)**		(1,605)	(771)	-	(2,376)	
				-					-	
Long-term debt	**$ 15,233**	**$ 1,345**	**$ 568**	**$ 17,146**		$ 14,143	$ 1,309	$ 385	$ 15,837	

[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, 2017 in a net asset position of $41 million (2016 - $18 million). Such contracts are primarily used to hedge foreign currency long-term debt principal and U.S. commercial paper borrowings.

(in millions)	**2017**	2016
Cross-Currency Swaps		
Euro dollar to Canadian dollar - notional amount[1]	**€ 402**	€ 264
Euro dollar to Canadian dollar - weighted average contract rate	**1.47**	1.48
Weighted remaining term	**11 years**	10 years
Foreign Currency Forwards		
United States dollar to Canadian dollar - notional amount[1]	**US$ 1,241**	US$ 1,450
United States dollar to Canadian dollar - weighted average contract rate	**1.26**	1.28
Weighted remaining term	**6 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, 2017 with a net asset position of $194 million (2016 - $nil, no interest rate contracts). Such contracts are used to lock in interest rates on future Canadian denominated debt issues. The contracts outstanding relate to $3,600 million of planned 10 and 30 year debt to be issued on dates ranging from June 2017 to December 2020.

(in millions)	**2017**	2016
Bond Locks		
Canadian dollar - notional amount[1]	**$ 400**	$ -
Weighted forecast borrowing yields	**2.92%**	-
Weighted remaining term	**< 1 year**	-
Forward Swaps		
Canadian dollar - notional amount[1]	**$ 3,200**	$ -
Weighted forecast borrowing yields	**2.92%**	-
Weighted remaining term	**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.

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, 2017, and March 31, 2016 was as follows:

(in millions)	**2017**	2016
Total debt, net of sinking funds	**$ 19,845**	$ 18,046
Less: Cash and cash equivalents	**(49)**	(44)
Net Debt	**$ 19,796**	$ 18,002
Retained earnings	**$ 4,822**	$ 4,397
Contributed surplus	**60**	60
Accumulated other comprehensive income	**27**	43
Total Equity	**$ 4,909**	$ 4,500
Net Debt to Equity Ratio	**80 : 20**	80 : 20

Payment to the Province

Under a Special Directive from the Province, the Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The Special Directive states that 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 July 2016, the Province issued Order in Council No. 589, which amends the Special Directive and states that BC Hydro must make a Payment to the Province of an amount no less than $259 million by June 30, 2017, as it relates to fiscal 2017. The Company paid the $259 million minimum payment to the Province in March 2017. The Payment to the Province was less than 85 per cent of the Company's net income. The Payment to the Province calculation as at March 31, 2017 determined that no further payment was required due to the debt to equity ratio cap.

During fiscal 2017, the Payment to Province in respect of both fiscal 2016 and 2017 were paid to the Province, resulting in a total payment of $585 million as follows: $326 million in June 2016 related to fiscal 2016 and $259 million in March 2017 related to fiscal 2017. As a result, the Company has accrued $nil at March 31, 2017 (2016 - $326 million) for the Payment to Province, which is included in accounts payable and accrued liabilities.

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 upon retirement of employees. 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, 2017 and 2016 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)	**2017**	2016	**2017**	2016	**2017**	2016
Current service costs charged to personnel operating costs	**$ 88**	$ 97	**$ 16**	$ 16	**$ 104**	$ 113
Net interest costs charged to finance costs	**49**	40	**17**	17	**66**	57
Total post-employment benefit plan expense	**$ 137**	$ 137	**$ 33**	$ 33	**$ 170**	$ 170

Actuarial gains and losses recognized in other comprehensive income are $nil (2016 - $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 Pension Costs regulatory account.

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

	Pension Benefits Plans		**Other Benefits Plans**		**Total**	
(in millions)	**2017**	2016	**2017**	2016	**2017**	2016
Defined benefit obligation of funded plans	**$ (4,431)**	$ (4,228)	**$ -**	$ -	**$ (4,431)**	$ (4,228)
Defined benefit obligation of unfunded plans	**(160)**	(157)	**(435)**	(441)	**(595)**	(598)
Fair value of plan assets	**3,460**	3,169	**-**	-	**3,460**	3,169
Plan deficit	**$ (1,131)**	$ (1,216)	**$ (435)**	$ (441)	**$ (1,566)**	$ (1,657)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2017 and fiscal 2016 in accordance with IFRIC 14, *The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction*.

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

	Pension Benefit Plans		**Other Benefit Plans**	
(in millions)	**2017**	2016	**2017**	2016
Defined benefit obligation				
Opening defined benefit obligation	**$ 4,385**	$ 4,357	**$ 441**	$ 432
Current service cost	**88**	97	**16**	16
Interest cost on benefit obligations	**236**	115	**17**	17
Benefits paid[1]	**(175)**	(171)	**(13)**	(12)
Employee contributions	**35**	28	**-**	-
Actuarial losses (gains)[2]	**22**	(41)	**(26)**	(12)
Defined benefit obligation, end of year	**4,591**	4,385	**435**	441
Fair value of plan assets				
Opening fair value	**3,169**	3,291	n/a	n/a
Interest income on plan assets[3]	**187**	74	n/a	n/a
Employer contributions	**40**	66	n/a	n/a
Employee contributions	**35**	28	n/a	n/a
Benefits paid[1]	**(170)**	(165)	n/a	n/a
Actuarial gains (losses)[2,3]	**199**	(125)	n/a	n/a
Fair value of plan assets, end of year	**3,460**	3,169	-	-
Accrued benefit liability	**$ (1,131)**	$ (1,216)	**$ (435)**	$ (441)

[1] *Benefits paid under Pension Benefit Plans include $14 million (2016 - $13 million) of settlement payments.*

[2] *Actuarial gains/losses are included in the Pension Costs regulatory account and for fiscal 2017 are comprised of $199 million of experience gains on return of plan assets and $4 million of net experience gains on the benefit obligations due to actuarial assumption changes and experience gains, offset by discount rate changes.*

[3] *Actual income on defined benefit plan assets for the year ended March 31, 2017 was $386 million (2016 - $51 million loss).*

(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**	
	2017	2016	**2017**	2016
Discount rate				
Benefit cost	**3.81%**	3.51%	**3.72%**	3.79%
Accrued benefit obligation	**3.68%**	3.81%	**3.92%**	3.72%
Rate of return on plan assets	**3.81%**	3.51%	**n/a**	n/a
Rate of compensation increase				
Benefit cost	**3.35%**	3.35%	**3.35%**	3.35%
Accrued benefit obligation	**3.00%**	3.35%	**3.00%**	3.35%
Health care cost trend rates				
Weighted average health care cost trend rate	**n/a**	n/a	**5.03%**	5.10%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**4.29%**	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 accrued benefit 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**	**2017**	2016
Equities	56%	41%	76%	**61%**	60%
Fixed interest investments	29%	19%	39%	**26%**	30%
Real estate	10%	5%	15%	**8%**	8%
Infrastructure and renewable resources	5%	0%	10%	**5%**	2%

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 2018 is expected to amount to $40 million. The expected benefit payments to be paid in fiscal 2018 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 2017	One percentage point decrease 2017
Effect on current service costs	$ 4	$ (3)
Effect on defined benefit obligation	55	(44)

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

		2017	
($ in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1% increase	$ -482	$ -23
Discount rate	1% decrease	+ 554	+ 28
Longevity	1 year	+/- 144	+/- 2

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 2017 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. 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 $179 million. The maximum credit risk exposure for these U.S. dollar sinking funds as at March 31, 2017 is its fair value of $197 million. The Company manages this risk through Board-approved credit risk management policies which contain limits and procedures related to the selection of counterparties. Exposures to credit risks are monitored on a regular basis. In addition, the Company has credit loss insurance that covers most credit exposures with U.S. counterparties or transactions delivered in the U.S.

(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 price risk, such as changes in commodity prices and equity values. The Company monitors its exposure to market fluctuations and may use derivative contracts to manage these risks, as it considers appropriate. Other than in its energy trading subsidiary, Powerex, the Company does not use derivative contracts for trading or speculative purposes.

(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. During the year, the Company issued a European currency denominated bond and simultaneously entered into a cross-currency swap hedging the principal and interest payments of the bond against movements in the Euro, thereby effectively converting it into a Canadian bond.

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 number of Board-approved policy documents. The Company uses cross-currency swaps and forward foreign exchange purchase contracts to achieve and maintain the Board-approved 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's Board-approved debt management strategies include maintaining a percentage of variable interest rate debt within a certain range. The Company may enter into interest rate swaps to achieve and maintain the target range of variable interest rate debt. In addition, the Company may enter into bond locks and forward swaps 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.

The Company enters into derivative contracts to manage commodity price risk. 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. Risks are managed within defined limits that are regularly reviewed by the Board of Directors.

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, 2017 and 2016.

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at March 31, 2017 and 2016. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

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	2017		2016		**2017**	2016
(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	**$ 24**	**$ 24**	$ 11	$ 11	**$ -**	$ 1
Loans and Receivables:						
Accounts receivable and accrued revenue	**808**	**808**	655	655	**-**	-
Non-current receivables	**278**	**282**	185	185	**12**	7
Cash	**25**	**25**	33	33	**-**	-
Held to Maturity:						
Sinking funds – US	**179**	**197**	167	194	**8**	8
Other Financial Liabilities:						
Accounts payable and accrued liabilities	**(1,190)**	**(1,190)**	(1,725)	(1,725)	**-**	-
Revolving borrowings - CAD	**(2,284)**	**(2,284)**	(1,605)	(1,605)	**(11)**	(14)
Revolving borrowings - US	**(554)**	**(554)**	(771)	(771)	**(5)**	(2)
Long-term debt (including current portion due in one year)	**(17,186)**	**(19,601)**	(15,837)	(18,684)	**(742)**	(701)
First Nations liabilities (non-current portion)	**(394)**	**(549)**	(378)	(547)	**(17)**	(17)
Finance lease obligations (non-current portion)	**(197)**	**(197)**	(219)	(219)	**(19)**	(21)
Other liabilities	**(336)**	**(342)**	(238)	(244)	**-**	-

The carrying value of cash equivalents, loans and receivables, and accounts payable and accrued liabilities 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)	**2017 Fair Value**	2016 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ 68**	$ 57
Foreign currency contracts (cash flow hedges for €EURO denominated long-term debt)	**(27)**	(5)
	41	52
Non-Designated Derivative Instruments:		
Interest rate contracts	**194**	-
Foreign currency contracts	**-**	(34)
Commodity derivatives	**23**	41
	217	7
Net asset	**$ 258**	$ 59

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)	**2017**	2016
Current portion of derivative financial instrument assets	**$ 144**	$ 137
Current portion of derivative financial instrument liabilities	**(60)**	(143)
Derivative financial instrument assets, non-current	**215**	92
Derivative financial instrument liabilities, non-current	**(41)**	(27)
Net asset	**$ 258**	$ 59

For designated cash flow hedges for the year ended March 31, 2017, a loss of $11 million (2016 - gain of $12 million) was recognized in other comprehensive income. For the year ended March 31, 2017, $11 million (2016 - $21 million) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange losses (2016 - losses) recorded in the year.

For interest rate contracts not designated as hedges with an aggregate notional principal of $3.6 billion, used to economically hedge the interest rates on future debt issuances, there was a $194 million increase (2016 - $nil, no interest rate contracts) in the fair value of these contracts. For the interest rate contracts with an aggregate notional principal of $800 million for debt issued to date, there was a $7 million realized loss (2016 - $nil, no interest rate contracts) in the fair value of these contracts. The change in fair value of $194 million on the remaining $3.6 billion of interest rate contracts and the settlement loss of $7 million on $800 million of interest rate contracts realized was recognized in finance charges and then transferred to the Debt Management regulatory account which had a balance of $187 million as at March 31, 2017.

For foreign currency contracts not designated as hedges for the year ended March 31, 2017, a gain of $1 million (2016 - gain of $2 million) was recognized in finance charges with respect to foreign currency contracts for cash management purposes. For the foreign currency contracts for U.S. revolving borrowings for the year ended March 31, 2017, a gain of $18 million (2016 - gain of $58 million) was recognized in finance charges. These economic hedges offset $17 million of foreign exchange revaluation losses (2016 - loss of $61 million) recorded with respect to U.S. revolving borrowings for the year ended March 31, 2017.

For commodity derivatives not designated as hedges, a net loss of $1 million (2016 - gain of $9 million) was recorded in trade revenue for the year ended March 31, 2017.

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Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)		**2017**		2016
Deferred inception loss, beginning of the year	**$**	**48**	$	70
New transactions		**(12)**		(14)
Amortization		**(1)**		(10)
Foreign currency translation loss		**1**		2
Deferred inception loss, end of the year	**$**	**36**	$	48

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, call centre agents ensure accounts are secured either by a credit bureau check, a cash security deposit, or a credit reference letter.

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

Domestic and Trade Accounts Receivable Net of Allowance for Doubtful Accounts

(in millions)		**2017**		2016
Current	**$**	**494**	$	362
Past due (30-59 days)		**31**		27
Past due (60-89 days)		**7**		6
Past due (More than 90 days)		**3**		3
		535		398
Less: Allowance for doubtful accounts		**(9)**		(8)
	$	**526**	$	390

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 transactions under International Swaps and Derivatives Association (ISDA) and Western Systems Power Pool (WSPP) or similar master netting agreements and presents these transactions on a gross basis under derivative commodity assets/liabilities in the statement of financial position. These master netting agreements do not meet the criteria for offsetting as the Company does not have the legally enforceable right to offset recognized amounts. The right to offset is enforceable only on the occurrence of future events such as a credit default.

Under the Company's trading agreements, the amounts owed by each counterparty that are due on a single day in respect of all transactions outstanding in the same currency under the same agreement are aggregated into a single net amount being payable by one party to the other. Such receivable or payable amounts meet the criteria for offsetting and are presented as such on the Company's 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, 2017			
Derivative commodity assets	$ 90	$ 1	$ 89
Derivative commodity liabilities	67	1	66
As at March 31, 2016			
Derivative commodity assets	$ 165	$ 5	$ 160
Derivative commodity liabilities	124	5	119

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.

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

As at March 31, 2017	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	87	5	8	100
Assets from trading activities	100	0	0	100

As at March 31, 2016	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	92	2	6	100
Assets from trading activities	100	0	0	100

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2017 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, 2017. In respect of the cash flows in foreign currencies, the exchange rate as at March 31, 2017 has been used.

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(in millions)	Carrying Value	Fiscal 2018	Fiscal 2019	Fiscal 2020	Fiscal 2021	Fiscal 2022	Fiscal 2023 *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)	$ 952	$ (952)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	20,225	(3,645)	(2,047)	(871)	(1,759)	(1,115)	(22,467)
Lease obligations	219	(40)	(21)	(21)	(21)	(21)	(291)
Other long-term liabilities	745	(103)	(58)	(54)	(52)	(54)	(1,782)
Total Non-Derivative Financial Liabilities	22,141	(4,740)	(2,126)	(946)	(1,832)	(1,190)	(24,540)
Derivative Financial Liabilities							
Cross currency swaps used for hedging	27						
Cash outflow		(14)	(14)	(14)	(14)	(14)	(679)
Cash inflow		5	5	5	5	5	602
Forward foreign exchange contracts used for hedging	4						
Cash outflow		-	-	-	-	-	(337)
Cash inflow		-	-	-	-	-	346
Other forward foreign exchange contracts designated at fair value	3						
Cash outflow		(397)	-	-	-	-	-
Cash inflow		395	-	-	-	-	-
Financially settled commodity derivative liabilities designated at fair value	52	(46)	(5)	(1)	-	-	-
Physically settled commodity derivative liabilities designated at fair value	15	(42)	(4)	-	-	-	-
Total Derivative Financial Liabilities	101	(99)	(18)	(10)	(9)	(9)	(68)
Total Financial Liabilities	22,242	(4,839)	(2,144)	(956)	(1,841)	(1,199)	(24,608)
Derivative Financial Assets							
Forward foreign exchange contracts used for hedging	(72)						
Cash outflow		-	(204)	-	-	-	(382)
Cash inflow		-	266	-	-	-	417
Other forward foreign exchange contracts designated at fair value	(3)						
Cash outflow		(226)	-	-	-	-	-
Cash inflow		229	-	-	-	-	-
Interest rate swaps used for hedging	(194)	71	55	26	47	-	-
Financially settled commodity derivative assets designated at fair value	(55)	35	4	-	-	-	-
Physically settled commodity derivative assets designated at fair value	(35)	103	19	11	-	-	-
Total Derivative Financial Assets	(359)	212	140	37	47	-	35
Net Financial Liabilities[1]	**$ 21,883**	**$ (4,627)**	**$(2,004)**	**$ (919)**	**$ (1,794)**	**$ (1,199)**	**$ (24,573)**

[1] *The Company believes that the liquidity risk associated with commodity derivative financial liabilities needs to be considered in conjunction with the profile of payments or receipts arising from commodity derivative financial assets. It should be noted that cash flows associated with future energy sales and commodity contracts which are not considered financial instruments under IAS 39 are not included in this analysis, which is prepared in accordance with IFRS 7.*

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MARKET RISKS

(a) Currency Risk

Sensitivity Analysis
A $0.01 strengthening (weakening) of the U.S. dollar against the Canadian dollar at March 31, 2017 would have a negative (positive) impact of $3 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, 2017 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, 2017 would have a negative (positive) impact on net income of $33 million 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 foreign exchange rates, remain constant.

For the interest rate contracts, an increase of 100-basis points in interest rates at March 31, 2017 would have a positive impact on net income of $344 million and a decrease of 100 basis points in interest rates at March 31, 2017 would have a negative impact on net income of $405 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, 2017 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 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 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 $8 million at March 31, 2017 (2016 - $10 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2017 AND 2016

The following tables present the financial instruments measured at fair value for each hierarchy level as at March 31, 2017 and 2016:

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)

As at March 31, 2016 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 11	$ -	$ -	$ 11
Derivatives designated as hedges	-	62	-	62
Derivatives not designated as hedges	75	30	62	167
	$ 86	$ 92	$ 62	$ 240

As at March 31, 2016 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (10)	$ -	$ (10)
Derivatives not designated as hedges	(108)	(46)	(6)	(160)
	$ (108)	$ (56)	$ (6)	$ (170)

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. For the year ended March 31, 2016, energy derivatives with a carrying amount of $14 million were transferred from Level 2 to Level 1 as the Company now uses published price quotations in an active market.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED MARCH 31, 2017 AND 2016

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, 2017 and 2016:

(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**

(in millions)		
Balance as at April 1, 2015	**$**	**39**
Net gain recognized		21
New transactions		(4)
Balance as at March 31, 2016	**$**	**56**

During the period, energy derivatives with a carrying amount of $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, 2017, unrealized gains of $8 million (2016 - gains of $22 million) were recognized on Level 3 derivative commodity assets held at March 31, 2017. During the year ended March 31, 2017, unrealized gains of $1 million (2016 - gains of $3 million) were recognized on Level 3 derivative commodity liabilities held at March 31, 2017. 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)		**2017**		2016
Provisions				
Environmental liabilities	**$**	**339**	$	390
Decommissioning obligations		**52**		56
Other		**12**		10
		403		456
First Nations liabilities		**409**		409
Finance lease obligations		**219**		240
Unearned revenue		**551**		463
Other liabilities		**336**		238
		1,918		1,806
Less: Current portion, included in accounts payable and accrued liabilities		**(115)**		(122)
	$	**1,803**	$	1,684

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**

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 2018 and 2045, is approximately $398 million and was determined based on current cost estimates. A range of discount rates between 0.6 per cent to 2.4 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 (2016 - $85 million), which will be settled between fiscal 2018 and 2054. The undiscounted cash flows are then discounted by a range of discount rates between 0.6 per cent to 2.4 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 7.9 per cent to 9.3 per cent with contract terms of 25 years expiring from 2018 until 2036. Finance lease liabilities are payable as follows:

	Future minimum lease payments	**Interest**	**Present value of minimum lease payments**	Future minimum lease payments	Interest	Present value of minimum lease payments
(in millions)	**2017**	**2017**	**2017**	2016	2016	2016
Less than one year	**$ 40**	**$ 18**	**$ 22**	$ 40	$ 20	$ 20
Between one and five years	**84**	**60**	**24**	103	63	40
More than five years	**291**	**118**	**173**	312	132	180
Total minimum lease payments	**$ 415**	**$ 196**	**$ 219**	$ 455	$ 215	$ 240

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 $53,042 million of which approximately $93 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 $415 million accounted for as obligations under capital leases. The total BC Hydro combined payments are estimated to be approximately $1,488 million for less than one year, $6,137 million between one and five years, and $45,417 million for more than five years and up to 54 years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $1,629 million extending to 2034. The total Powerex energy purchase commitments are estimated to be approximately $503 million for less than one year, $761 million between one and five years, and $365 million for more than five years. Powerex has energy sales commitments of $539 million extending to 2027 with estimated amounts of $361 million for less than one year, $170 million between one and five years, and $8 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 $1,011 million. Payments are $97 million for less than 1 year, $158 million between one and five years, and $756 million for more than five years.

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) A contractor has filed a Notice to Arbitrate a claim against BC Hydro. BC Hydro has filed a counterclaim. The arbitration process is currently ongoing and the outcome of the claims are not determinable at this time and no amount has been recognized in these consolidated financial statements.

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

d) The Company and its subsidiaries have outstanding letters of credit totaling $1,124 million (2016 - $1,065 million), of which there is US $21 million (2016 - US $30 million).

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 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)	**2017**	2016
Consolidated Statement of Financial Position		
Accounts receivable	**$ 93**	$ 103
Accounts payable and accrued liabilities	**57**	381
Amounts incurred/accrued during the year include:		
Water rental fees	**346**	327
Cost of energy sales	**111**	116
Taxes	**140**	132
Interest	**760**	720
Payment to the Province	**259**	326

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, 2017, the aggregate exposure under this indemnity totaled approximately $268 million (2016 - $62 million). The Company has not experienced any losses to date under this indemnity.

The Company and British Columbia Investment Management Corporation (bcIMC) are related parties and are both wholly owned by the Province. The Company has responsibility for administration of the British Columbia Hydro and Power Authority Pension Plan and uses internal and external service providers for this purpose. It has engaged bcIMC to manage investments on behalf of the plan. bcIMC uses internal and external investment managers for this purpose. Refer to Note 18 for the Company contributions to the pension plan for 2017 and 2016.

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)	**2017**	2016
Short-term employee benefits	**$ 4**	$ 4
Post-employment benefits	**1**	1

Capital Plan and Major 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. *Appendix D: Capital Project Descriptions* provides further details on each $50 million project.

Major Capital Projects (Project descriptions can be found in Appendix D)	**Targeted Completion Date (calendar year)**	**Approved Anticipated Total Cost of Project ($ millions)**	**Project Cost to March 31,2017 ($ millions)**
Projects Recently Put Into Service			
Big Bend Substation	2017 In-Service	$72	$63
Major Capital Projects (Project descriptions can be found in Appendix D)	**Targeted Completion Date (calendar year)**	**Approved Anticipated Total Cost of Project ($ millions)**	**Project Cost to March 31, 2017 ($ millions)**
Ongoing and Planned			
Ruskin Dam Safety and Powerhouse Upgrade	2017 Targeted In-Service	$748	$525
Horne Payne Substation Upgrade Project	2018 Targeted In-Service	$93	$23
John Hart Generating Station Replacement	2019 Targeted In-Service	$1,093	$679
Cheakamus Unit 1 and Unit 2 Generator Replacement	2019 Targeted In-Service	$74	$17
Fort St. John and Taylor Electric Supply	2019 Targeted In-Service	$53	$1
W.A.C. Bennett Dam Riprap Upgrade Project	2019 Targeted In-Service	$170	$62
South Fraser Transmission Relocation Project	2019 Targeted In-Service	$76	$9

Major Capital Projects (Project descriptions can be found in Appendix D)	**Targeted Completion Date (calendar year)**	**Approved Anticipated Total Cost of Project ($ millions)**	**Project Cost to March 31, 2017 ($ millions)**
Ongoing and Planned Continued			
Bridge River 2 Units 5 and 6 Upgrade Project*	2019 Targeted In-Service	$86	$10
G.M. Shrum G1-G10 Control System Upgrade	2021 Targeted In-Service	$60 (Partial Implemen-tation Funding)	$14
Site C Clean Energy Project	2024** Targeted In-Service	$8,335***	$1,631

**Bridge River 2 Units 5 and 6 Upgrade Project was not reflected in the 2017/18 – 2019/20 Service Plan as the project was approved after the filing of the Service Plan.*

***Planned in-service date for all units. This timeline reflects the project's current schedule and is subject to change based on a review of the construction schedule.*

****Site C total cost excludes the Project Reserve of $440 million (established by the British Columbia Government to account for events outside of BC Hydro's control that could occur during construction) which is held by the Treasury Board.*

Appendix A - 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 Board of Directors, the Chair of the Powerex Board and the Powerex CEO ensure the Board of BC Hydro is informed of Powerex's key strategies and business activities. The Powerex CEO also works closely with the BC Hydro CEO and Executive Team and informs the BC Hydro CEO and Executive Team of Powerex's 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 (2012/13 to 2016/17). The 2017/18 to 2019/20 Service Plan forecast includes annual net income from Powerex of approximately $120 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 various fields including: research and development, testing, technical services and advanced technology services to the international energy community including BC Hydro.

The Powertech Chief Executive Officer (CEO) reports to the BC Hydro President and CEO. The Powertech Board is chaired by BC Hydro's President and CEO and its Directors include senior Executive of BC Hydro.

Over the last five years Powertech's revenue has ranged from $29 million to $37 million (2012/13 to 2016/17) with a net income in the range of $2 million to $4 million. The 2017/18 to 2019/20 Service Plan forecast includes annual net income from Powertech ranging from $4 million to $5 million. 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, 2017, these other subsidiaries consisted of the following:

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

Appendix B - Additional Information

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.

Corporate Governance

BC Hydro is governed by a Board of Directors that is accountable to the Minister Responsible for the implementation of government direction. The Board's direction is implemented by management, who carries out the day-to-day operations of the Corporation under the supervision of the Chief Executive Officer. For more information on Corporate Governance, please refer to: 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.

Contact Information

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

Appendix C - Crown Corporations Mandate and Actions Summary

In the 2016/17 Mandate Letter from the minister responsible, BC Hydro received direction on strategic priorities for the 2016/17 fiscal year. These priorities and the Crown Corporation's resulting actions are summarized below:

Mandate Letter Direction	Crown Corporation's Action
1. Continue to implement the 10-Year Plan to keep electricity rates low and predictable by optimizing resources and advancing its Revenue Requirements and Rate Design Applications.	BC Hydro's Fiscal 2017 – Fiscal 2019 Revenue Requirements Application is currently before the British Columbia Utilities Commission (BCUC) for review. BC Hydro submitted the application to the BCUC in July 2016 in alignment with the 10 Year Rates Plan. The BCUC approved interim, refundable rate increases of 4 per cent effective April 1, 2016 and 3.5 per cent effective April 1, 2017. BC Hydro's 2015 Rate Design Application was reviewed by the BCUC through an oral hearing in summer 2016. In January 2017, a Decision was issued that approved all of the key changes to residential, commercial and industrial rate designs.
2. Develop the overall capital plan portfolio on time and on budget to maintain the reliability of the system, support British Columbia's economic growth and meets the needs of customers.	From fiscal 2013 to 2017, BC Hydro completed 540 capital projects at a total cost of $6.4 billion which is 0.94 per cent under budget overall. Capital expenditures for 2016/17 were $2.4 billion and capital in-service additions were $1.5 billion. The list of projects above $50 million which came into service in 2016/17 is included in the Financial section of this Annual Service Plan Report.

Mandate Letter Direction	Crown Corporation's Action
3. Deliver the Site C project on time and on budget and ensure First Nations and local communities have the ability to participate in economic development opportunities arising from the construction of the project.	Site preparation commenced in July 2015 and was substantially completed this year. As of March 31, 2017, 2,470 hectares of land were cleared, 10 million cubic metres of material were excavated, the temporary construction bridge was put into service, a 1,600-person worker accommodation facility was constructed, the temporary construction power and substation were installed, and public and on-site access roads were built and improved. The Main Civil Works Contractor began work on North Bank Excavation, the Right Bank Drainage Tunnel and the Right Bank Cofferdam, and completed the Moberly River Construction Bridge and the Roller-Compacted Concrete Batch Plant. Procurement activities have resulted in the award of many small and large contracts with commitments totaling approximately $4.0 billion as at March 31, 2017. The number of on-site workers reached 2,252 by March 2017, of which 1,814 or 81 per cent, were from British Columbia. Specific to aboriginal business opportunities and employment, by the end of fiscal 2017, $150 million in procurement commitments have been made to First Nations companies, and joint ventures including First Nations companies, and approximately 200 First Nations employees and contractors were working on the project. BC Hydro has reached project impact agreements with a number of First Nations, including Doig River First Nation, Halfway River First Nation, McLeod Lake Indian Band and Dene Tha' First Nation.
4. Work with Clean Energy BC to identify further opportunities for clean energy producers in British Columbia.	BC Hydro has initiated an optimization process for the Standing Offer Program and Micro-Standing Offer Program to reflect future system needs, consider recent advancements in technology and align with the 2013 10 Year Rates Plan. In January 2017, the BC Utilities Commission approved BC Hydro's renewal of two electricity purchase agreements. The renewal of run-of-river Electricity Purchase Agreements was contemplated in the 2013 Integrated Resource Plan.

Mandate Letter Direction	Crown Corporation's Action
5. Improve customer satisfaction by providing timely and responsive service and exploring innovative energy conservation solutions such as load curtailment rates.	In fiscal 2017, BC Hydro improved customer access to critical billing information through functional upgrades to MyHydro, launched a 'pay now' self-service option for customers receiving electronic bill notices, and implemented a Winter Payment Plan program to help customers defer larger than expected bills resulting from an unseasonably cold winter. Customer-focused training was prioritized for new employees and call centre staff. BC Hydro is continuing to pilot a number of innovative conservation solutions to understand how they can help meet long-term energy and capacity needs. In fiscal 2017, BC Hydro implemented the second year of its industrial load curtailment pilot program and continued with trials of residential and commercial demand response initiatives.
6. Implement the five-year safety plan to ensure the safety of your workforce and the public	Completed year two of the five year safety plan. Key activities completed include: The Life Saving Rules 1-4 Training and Qualification Project; the Job Planning, Identification of Critical Hazards and use of Multiple Barriers Project; the SafeStart Project; the Knife Injury Reduction Project; the Class Zero Rubber Gloves Requirements and Rules Clarification Project; the Fire Resistant Clothing and Eye Protection Standards Upgrade project; the Field Ergonomics Project for Material Management and Fleet Services; the Streamlining of Investigation and Corrective Actions for Safety Incidents Project; Phase 1 for the Improvement to Field Access to Safety Information Project (SafeHub); Phase 1 of the Contractor Safety Management Program; and Implementing tools to provide in-depth Safety Analytics.

Appendix D - Capital Project Descriptions

Projects Recently Put Into Service

Big Bend Substation

The South Burnaby, Big Bend area required a new, 100 MVA, 69/12 kV substation to meet local residential and commercial load growth.

Ongoing and Planned

Ruskin Dam Safety and Powerhouse Upgrade

Improve seismically deficient dam and rehabilitation/replacement of powerhouse equipment that was brought into service between 1930 and 1950. The project includes: 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 unsatisfactory condition.

Horne Payne Substation Upgrade Project

Expand the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated (GIS) 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.

John Hart Generating Station Replacement

Replace the existing six-unit 126 MW generating station (in operation since 1947), add integrated emergency bypass capability to ensure reliable long-term generation, and mitigate earthquake risk and environmental risk to fish and fish habitat.

Cheakamus Unit 1 and Unit 2 Generator Replacement

Replace the two generators at Cheakamus generating station (in operation since 1957) to address the poor condition and known deficiencies which will increase the capacity of each unit from 70 MW to 90 MW.

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 1L360 and 1L374 at the new Site C switchyard.

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.

South Fraser Transmission Relocation Project

In September 2013, the Province of B.C. announced that the George Massey Tunnel will be replaced with a new bridge. The construction of the new bridge, modifications to Highway 99 and the decommissioning of the George Massey tunnel will 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.

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.

G.M. Shrum G1-G10 Control System Upgrade

The condition of the legacy controls for 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, cause operating problems and increase 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.

Site C Clean Energy 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.

Appendix E - Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	**2017**	2016	2015	2014	2013
Revenues					
Domestic	**$ 5,199**	$ 5,056	$ 4,829	$ 4,319	$ 4,038
Trade	**675**	601	919	1,073	860
Expenses					
Domestic energy costs	**1,608**	1,425	1,458	1,252	1,123
Trade energy costs	**486**	427	745	894	683
Other operating expenses [1]	**1,025**	937	918	901	894
Amortization and depreciation	**1,232**	1,241	1,205	995	953
Grants and taxes	**234**	220	209	203	196
Finance charges	**605**	752	632	598	540
	5,190	5,002	5,167	4,843	4,389
Net Income	**$ 684**	$ 655	$ 581	$ 549	$ 509
Property, Plant and Equipment & Intangible Assets					
At cost	**$ 27,468**	$ 25,183	$ 22,998	$ 20,897	$ 18,932
Less: Accumulated depreciation	**3,869**	3,189	2,518	1,863	1,268
Net Book Value	**$ 23,599**	$ 21,994	$ 20,480	$ 19,034	$ 17,664
Property, Plant & Equipment and Intangible Asset Expenditures					
Sustaining	**$ 1,158**	$ 1,136	$ 1,005	$ 979	$ 1,009
Growth	**1,286**	1,170	1,164	1,057	920
Total Property, Plant & Equipment and Intangible Asset Expenditures [2]	**$ 2,444**	$ 2,306	$ 2,169	$ 2,036	$ 1,929
Net Long-Term Debt [3]	**$ 19,796**	$ 18,002	$ 16,682	$ 15,461	$ 13,962
Retained Earnings	**$ 4,822**	$ 4,397	$ 4,068	$ 3,751	$ 3,369
Debt to Equity Ratio	**80 : 20**	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	**2017**	2016	2015	2014	2013
Generating Capacity (megawatts)					
Hydroelectric	**11,870**	11,869	11,379	10,927	10,927
Thermal	**183**	175	1,120	1,120	1,120
Total	**12,053**	12,044	12,499	12,047	12,047
Peak One-Hour Integrated System Demand (megawatts)	**10,194**	9,602	9,441	10,072	9,345
Number of Customer Accounts					
Residential	**1,776,503**	1,751,296	1,727,945	1,709,071	1,689,050
Light industrial and commercial	**207,802**	205,615	203,466	201,812	199,981
Large industrial	**191**	185	183	177	172
Other	**3,467**	3,459	3,474	3,489	3,482
Trade	**204**	214	226	239	249
Total	**1,988,167**	1,960,769	1,935,294	1,914,788	1,892,934
Domestic Electricity Sold (gigawatt-hours)					
Residential	**18,068**	17,331	17,047	17,965	17,703
Light industrial and commercial	**18,968**	18,421	18,564	18,501	18,384
Large industrial	**13,177**	13,669	14,020	13,994	13,508
Other	**7,439**	7,879	1,582	2,558	7,417
Total	**57,652**	57,300	51,213	53,018	57,012
Revenues (in millions)					
Residential	**$ 2,012**	$ 1,842	$ 1,712	$ 1,663	$ 1,612
Light industrial and commercial	**1,800**	1,685	1,597	1,489	1,436
Large industrial	**770**	766	748	687	642
Other	**428**	464	280	275	322
Total Domestic Revenue Before Regulatory Transfers	**5,010**	4,757	4,337	4,114	4,012
Regulatory transfers	**189**	299	492	205	26
Total Domestic	**5,199**	5,056	4,829	4,319	4,038
Trade - electricity and gas	**675**	601	919	1,073	860
Total	**$ 5,874**	$ 5,657	$ 5,748	$ 5,392	$ 4,898
Average Revenue (per kilowatt-hour) [1]					
Residential	**11.1¢**	10.6¢	10.0¢	9.3¢	9.1¢
Light industrial and commercial	**9.5**	9.1	8.6	8.0	7.8
Large industrial	**5.8**	5.6	5.3	4.9	4.8
Average Annual Kilowatt-Hour Use Per Residential Customer Account	**10,241**	9,958	9,919	10,571	10,534
Lines In Service					
Distribution (kilometres)	**59,078**	58,765	58,518	58,317	58,115
Transmission (circuit kilometres)	**20,278**	20,176	19,792	19,322	19,163

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

TOTAL REQUIREMENTS FOR ELECTRICITY, SOURCES OF SUPPLY AND WATER INFLOWS

for the years ended March 31	**2017**			2016			2015			2014			2013		
	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	**12,053**	**57,652**	**72.7**	12,044	57,300	73.7	12,499	51,213	66.0	12,047	53,018	65.0	12,047	50,992	58.5
Electricity trade		**16,740**	**21.1**		14,732	18.9		21,928	28.2		23,806	29.2		30,975	35.6
		74,392	**93.8**		72,032	92.6		73,141	94.2		76,824	94.2		81,967	94.1
Line loss and system use		**4,927**	**6.2**		5,713	7.4		4,486	5.8		4,733	5.8		5,159	5.9
		79,319	**100.0**		77,745	100.0		77,627	100.0		81,557	100.0		87,126	100.0
Sources of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,730**	**15,910**	**20.1**	2,730	14,274	18.4	2,730	10,801	13.9	2,730	13,650	16.7	2,730	15,878	18.2
Revelstoke	**2,480**	**8,264**	**10.4**	2,480	9,805	12.6	2,480	7,297	9.4	2,480	8,121	10.0	2,480	9,760	11.2
Mica	**2,746**	**7,397**	**9.3**	2,747	9,451	12.2	2,257	6,028	7.8	1,805	7,030	8.6	1,805	7,873	9.0
Kootenay Canal	**583**	**3,330**	**4.2**	583	2,837	3.6	583	3,304	4.4	583	2,935	3.6	583	3,595	4.1
Peace Canyon	**694**	**3,887**	**4.9**	694	3,470	4.5	694	2,678	3.4	694	3,423	4.2	694	3,902	4.5
Seven Mile	**805**	**3,326**	**4.2**	805	2,666	3.4	805	3,907	5.0	805	3,183	3.9	805	3,176	3.6
Bridge River	**478**	**2,504**	**3.2**	478	2,582	3.3	478	2,093	2.7	478	2,397	2.9	478	2,626	3.0
Other	**1,354**	**4,118**	**5.1**	1,352	4,267	5.5	1,352	5,122	6.6	1,352	4,589	5.6	1,352	5,304	6.1
	11,870	**48,736**	**61.4**	11,869	49,352	63.5	11,379	41,230	53.2	10,927	45,328	55.5	10,927	52,115	59.8
Thermal generation															
Burrard	**0**	**0**	**0.0**	0	24	0.0	950	26	0.0	950	84	0.1	950	25	0.0
Other	**183**	**74**	**0.1**	175	191	0.2	170	187	0.2	170	184	0.2	170	97	0.1
Purchases under long-term commitments		**17,753**	**22.4**		18,441	23.7		17,510	22.6		15,300	18.8		15,003	17.2
Purchases under short-term commitments		**13,009**	**16.4**		10,713	13.8		18,586	23.9		20,764	25.5		19,858	22.8
Other		**(253)**	**(0.3)**		(976)	(1.2)		88	0.1		(103)	(0.1)		28	0.0
	12,053	**79,319**	**100.0**	12,044	77,745	100.0	12,499	77,627	100.0	12,047	81,557	100.0	12,047	87,126	100.0
Water inflows (% of average)			**101**			97			102			95			109