British Columbia Hydro and Power Authority

2014/15
ANNUAL REPORT

For more information on BC Hydro contact:

333 Dunsmuir Street,

Vancouver, BC

V6B 5R3

Lower Mainland

604 BCHYDRO

(604 224 9376)

Outside Lower Mainland

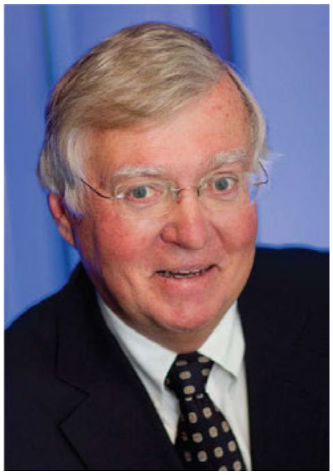
1 800 BCHYDRO

(1 800 224 9376)

bchydro.com

BC Hydro's Annual Report can be found online at:
http://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html

Board Chair's Message and Accountability Statement



Chair's Message

The 2014/15 Annual Report outlines how BC Hydro is meeting the objectives laid out in the Government's Letter of Expectations and is aligning our organization with the Taxpayer Accountability Principles. Our Board members have all signed the addendum that is posted on bchydro.com publicly showing this support.

With prudent reinvestment, careful planning and strong, respectful relationships, BC Hydro is well positioned to deliver clean, reliable, low cost power for the long-term benefit of our growing province.

Accountability Statement

The BC Hydro 2014/15 Annual 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 Annual Report, including what has been included and how it has been reported.

The information presented reflects the actual performance of BC Hydro for the 12 months ended March 31, 2015 in relation to the 2014/15-2016/17 Service Plan. The Board is 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, 2015 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 2014/15-2016/17 Service Plan was released and any significant limitations in the reliability of the information are identified in the report.

The BC Hydro 2014/15 Annual Report compares the corporation's actual results to the expected results identified in the 2014/15- 2016/17 Service Plan. I am accountable for those results as reported.

Steve Bellringer

Stephen Bellringer
Board Chair

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Purpose of the Organization

BC Hydro was created over 50 years ago to generate and deliver clean, reliable and low cost electricity to homes and businesses throughout British Columbia. The electricity generated by our dams and delivered by our transmission and distribution infrastructure has powered B.C.'s economy and quality of life for generations.

As a provincial Crown corporation, the owner and sole shareholder of BC Hydro is the Province of British Columbia. BC Hydro reports to the B.C. 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.

BC Hydro has also created or retained a number of subsidiaries. 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 energy, natural gas, ancillary services, and financial energy products and services. Powertech is internationally recognized as holding expertise providing research and development, testing, technical services, and advanced technology services to the international community including BC Hydro. For more information on Powerex, Powertech, or other active and inactive subsidiaries, see **Appendix A**.

Strategic Direction and Context

Strategic Direction

Guided by the Province's 10 year plan for rates, BC Hydro is continuing to ensure alignment with the Taxpayer Accountability Principles and the objectives outlined in the B.C. Government's Letter of Expectations (GLE).

The B.C. Government's Letter of Expectations describes the relationship between BC Hydro and the Province, and sets out what the Shareholder wishes BC Hydro to achieve. The Province and BC Hydro review the letter annually and update it as required. The objectives for 2014/15 were:

- work to implement the Integrated Resource Plan;
- continued development of the Site C project and supporting it through the environmental assessment process;
- deliver value and maintain competitive rates by efficiently and responsibly managing the business;

- minimize rate increases to consumers and industry by continuing to replace and build hydroelectric and transmission infrastructure; and,
- work with the Columbia Power Corporation (CPC) to report to Government on the progress of the Columbia Power Corporation / BC Hydro Joint Development Committee.

To meet these objectives, BC Hydro has strategies in place to safely and reliably meet the energy needs of British Columbians while also responsibly managing costs and maintaining low rates.

Strategic Context

In November 2013, the Province announced the 10 year plan for electricity rates to create more rate certainty for BC Hydro customers. BC Hydro's operating environment is guided by this plan. With the first year of the plan complete, there is an opportunity to highlight the progress made and the challenges faced over the last year in executing on this plan, while also adhering to the Taxpayer Accountability Principles and delivering on the objectives in the GLE. The following key actions are included in the rates plan:

- rate increases for the first two years set at nine per cent and six per cent;
- invest $1.6 billion in Power Smart programs over the 10 years of the plan;
- rate design review to help industrial customers reduce costs;
- $1.7 billion average annual capital investment (with Site C this annual average is $2.4 billion); and,
- dividend reduced over five years after fiscal 2017, then eliminated until debt/equity ratio reaches 60/40.

Rates for BC Hydro customers increased by nine per cent in April 2014 and six per cent in April 2015. Despite the increases, BC Hydro customers continue to have some of the lowest rates in North America for residential, commercial and industrial customers.

BC Hydro is actively working to refine the conservation programs that help all customer groups reduce electricity consumption, which will reduce their electricity bills. In addition, BC Hydro's investments in Power Smart programs are aligned to achieve the *Clean Energy Act* objective which states that 66 per cent of all new incremental demand must be met through conservation or demand side management (DSM). The Integrated Resource Plan (IRP) analyzes the potential for additional conservation beyond the 66 per cent target through a comprehensive analysis that considers the load forecast, available committed supply, potential DSM savings and supply side resource options, among other factors. With consideration of all those factors, the 2013 IRP included a stretch target to meet 78 per cent of incremental demand by 2021.

BC Hydro is on track to meet the 66 per cent target in the *Clean Energy Act*, but an evaluation of conservation rate structures in fiscal 2015 revealed lower than expected energy savings resulting in BC Hydro falling short in meeting the 78 per cent target in the IRP. The report found that while residential customers are responding reasonably well to the rate design, commercial customers had lower than expected energy savings from the Large and Medium General Service conservation rates.

BC Hydro is engaging with commercial and industrial customers to simplify the rate structure and, in fall 2015, will submit a Rate Design Application to the British Columbia Utilities Commission (BCUC) to make a number of improvements to the conservation rates.

In December 2014, the B.C. Government approved the Site C Clean Energy Project to proceed to construction in summer 2015. The Site C project received federal and provincial environmental approvals in October 2014. When Site C is combined with the $1.7 billion in capital investment outlined in the rates plan, BC Hydro will be investing an average of $2.4 billion per year in the province's electrical system over a 10 year period.

In fiscal 2015, BC Hydro successfully brought the Northwest Transmission Line (NTL) Project, Mica Unit 5, the Iskut Extension Project and the Mica SF_6 Gas Insulated Switchgear Replacement Project into service. While BC Hydro has experienced challenges on some of its capital projects, across all 563 generation, substation and transmission line projects delivered between fiscal 2011 and fiscal 2015, BC Hydro has come in 1.8 per cent under the original budget (less reserve funds) of $3.94 billion overall.

Delivering capital projects on time and on budget is a company-wide priority for BC Hydro and is critical to the rates plan. To achieve that goal, BC Hydro recently reorganized the company to create a new Capital Infrastructure Project Delivery business group consolidating the strengths across the company to provide a strong foundation to deliver the growing capital project portfolio over the next 10 years.

BC Hydro's relationship with First Nations is critical to delivering the capital plan. In many cases, BC Hydro's infrastructure footprint continues to grow within the traditional territories of First Nations where an operating footprint already exists. We are committed to working closely with those First Nations to chart a path forward to a better, more transparent and collaborative relationship where each other's views and interests are integrated into the decisions we make. In fiscal 2015, BC Hydro and West Moberly First Nations (WMFN) signed a relationship agreement to facilitate engagement and discussion on non-project related issues within the First Nation's Treaty rights. It's the first relationship agreement between BC Hydro and any of the Treaty 8 Nations.

BC Hydro is constantly looking for ways to improve its operating environment. BC Hydro is holding operating cost increases to less than the rate of inflation. As part of the 2011 Government Review, BC Hydro has found operating costs savings of $391 million. BC Hydro continues to be mindful of the cost environment and, as part of that recognition, is finding ways to drive down expenses and find efficiencies which was partly achieved through the recent reorganization. Additionally, BC Hydro is taking a hard look at the use of contractors to ensure the right balance between building internal core strengths and retaining external expertise to complement the workforce.

In fiscal 2015, domestic revenues were lower than planned primarily due to lower domestic load as a result of warmer weather in the winter months. In addition, surplus sales were lower than planned due to lower water inflows during the summer months, recorded at 87 per cent of average, and reduced opportunities for exports in the winter due to lower market prices. Surplus sales can occur when BC Hydro has excess water that it can convert into electricity which is in excess of its domestic load requirements and sell to the market. These two issues were the main reasons there were significant additions of $320 million to the Heritage and Non-Heritage regulatory accounts.

Interest rates have been on a steady decline over the last several years. For example, BC Hydro's weighted average interest rate for new long term borrowings has dropped from 4.9 per cent in fiscal 2008 to 3.4 per cent in fiscal 2015. This has had a positive impact on finance charges which have been significantly below the planned amount, contributing to a $120 million addition to the Finance Charges regulatory account this year that will be used to offset future rate increases. Unfortunately, while dropping interest rates have had a positive impact on finance charges, they have contributed to a decline in the discount rate used to calculate our pension liabilities. During the year, this discount rate dropped from 4.37 per cent to 3.51 per cent. However, offsetting this, the pension plan assets posted investment returns of 12.9 per cent, which was above our planned returns of 7.1 per cent, which provided an offset to the negative impact of the lower discount rate. The net impact of these items resulted in an increase in our non-current pension plan cost regulatory account of $317 million. In the prior year, discount rates increased, and we had a $247 million reduction in this regulatory account. The pension plan obligation is a long term liability. Given that long term interest rates are at a historical low, we expect them to rise over the term of this obligation, thus we expect this regulatory account to decrease in the future as interest rates rise.

Risks and Opportunities

BC Hydro strives to manage all the risks it faces on a cost effective basis, taking into account the potential benefits to be gained in return for acceptance of the risk. Selected risks and sample mitigation efforts that BC Hydro manages as part of its risk management plan include the following:

BC Hydro operations may expose people to unsafe conditions
Improving safety performance through implementing BC Hydro's Safety Taskforces' recommendations continues to be a priority area for the organization. In fiscal 2015, an additional five recommendations were implemented, bringing the total number of recommendations in sustainment to 12. All 21 recommendations are expected to be fully implemented and in sustainment by the end of fiscal 2017.

BC Hydro's demand side management efforts may not deliver the desired level of savings
BC Hydro regularly monitors the response to demand side management initiatives and cumulative savings against our demand side management goals and continues to make adjustments to ensure programs, rate structures and codes and standards effectively work together to help all customer groups reduce electricity consumption.

Load/resource balance and energy market prices may increase cost of energy
The amount of generation available influences BC Hydro's financial results through both changing reservoir inflows and the amount of energy we have available (or need to import to meet domestic load), and through changing our ability to take advantage of short-term market price variations. Forecasts assume the average generation from the optimal dispatch of BC Hydro-controlled plants across the most recent 41 years of data in BC Hydro's inflow records.

Weather may impact BC Hydro's system, load and resources
Through prudent system planning, vegetation management, and storm response preparation, BC Hydro has developed a robust system to withstand many weather events, and when necessary, has the flexibility to recover effectively when customers are impacted.

Asset failure
In fiscal 2015, risk management plans and capital upgrades continued to improve dam safety such as the Ruskin Dam right abutment and spillway work, the Spillway Gate Reliability Program, and the Bennett Dam spillway chute resurfacing. Emergency planning preparation continued with the City of Campbell River and residents near Jordan River, including the release of the results of BC Hydro's seismic study in November 2014.

Evolving legal landscape and increasing First Nations expectations
For all its activities BC Hydro must uphold the honour of the Crown in its dealings with First Nations. BC Hydro has a well-established consultation practice focused on understanding the impact of our activities on Aboriginal rights and title in order to mitigate, and where appropriate, accommodate those interests.

BC Hydro's information technology systems may be infiltrated by malicious software
With an increasing reliance on technology to manage data about our customers and employees and accessing our critical operating systems, BC Hydro is increasing its capabilities in electronic security and processes.

Customer impact from planned rate increases
BC Hydro continues to communicate its long-term plan for meeting B.C.'s demand for energy through our Integrated Resource Plan and through communication about our capital projects. We work to build public understanding of our infrastructure programs and conservation and energy efficiency initiatives. The 10 year plan for rates announced in fiscal 2014 provides rate certainty for customers with rate caps set out for fiscal 2017, fiscal 2018 and fiscal 2019.

Changes in debt levels and interest rates may increase BC Hydro's costs.
BC Hydro has steadily reduced the proportion of variable rate debt over the last few years in response to historically low, long-term interest rates and rising debt levels.

Additional information on risks that could significantly impact BC Hydro meeting its objectives are outlined at www.bchydro.com/serviceplan.

Report on Performance

Over the last year, BC Hydro has focussed on the objectives outlined in the GLE and ensuring alignment to the the Taxpayer Accountability Principles. While much of the intent of the Taxpayer Accountability Principles were already in place at BC Hydro, work is underway to further integrate the newly developed Principles into BC Hydro's daily operations. Communication and orientation of the Principles were immediately provided to the Board and Executive Team at BC Hydro. The Ministry has developed a draft strategic engagement plan, and BC Hydro and the Ministry are meeting regularly on key projects, decisions and announcements. Work is also underway to develop an evaluation plan that will include specific efficiency and performance measures against the Taxpayer Accountability Principles.

In response to the GLE, BC Hydro has made significant progress on each of the objectives, completed the federal-provincial environmental assessment process for a Site C decision, executed the capital plan with critical projects coming into service, and developed a collaborative working relationship with Columbia Power Corporation. Challenges were also faced, including the rate design for the commercial customer group and achieving the DSM target in the 2013 Integrated Resource Plan. Both challenges have been identified and proactive planning is underway to find a solution.

A more detailed report on each of the Taxpayer Accountability Principles and Government's Letter of Expectations is described on the next page.

Taxpayer Accountability Principles

BC Hydro is taking ongoing steps to ensure we align with the Taxpayer Accountability Principles. Since the introduction of the Principles in 2014, BC Hydro has implemented the following:

Cost Consciousness
Operating cost increases for fiscal 2015 budget were limited to less than the rate of inflation despite significant cost pressures. BC Hydro has implemented several Lean process reviews to identify efficiencies including Contract Approvals, Business Case / Expenditure Authorization Request (EAR) approvals, Vegetation Management, Customer Build, Terrace Field Office Procurement, and Substations Asbestos Inventory Update Process.

Accountability
BC Hydro's CEO and Chair meet with the Minister and Deputy Minister on a regular basis. We have initiated development of an evaluation plan with the Ministry with specific efficiency and performance measures to evaluate against the Taxpayer Accountability Principles.

Appropriate Compensation
BC Hydro continues to ensure appropriate compensation while maintaining the ability to attract and retain the highly skilled workforce it requires through benchmarking to 50th percentile on a Total Rewards basis with a focus on electric utilities and public sector in benchmarking. Any compensation plans/changes are approved by the Public Sector Employees Council (PSEC).

Service
BC Hydro has developed a customer strategy to improve service to customers. The Customer Service organization has recently been aligned with Transmission and Distribution, bringing together the main touch points with our customers into one business group.

Respect
In fiscal 2015, BC Hydro developed a First Nations strategy to ensure effective long-term relationships with Aboriginal people in B.C. Implementation will begin in fiscal 2016. Since May 2014, BC Hydro has engaged customers in advance of filing the Rate Design Application with the BCUC through formal workshops, customer and stakeholder information sessions, customer focus groups, and individual engagement and consultation with intervener groups. The Ministry has developed a draft strategic engagement plan, and BC Hydro and the Ministry are touching base regularly on key projects, decisions and announcements.

Integrity
As integrity is one of BC Hydro's core values, BC Hydro employs an Ethics Officer, and has developed an Employee Code of Conduct, which provides guidance on the standards of conduct expected of Directors, employees and contractors of BC Hydro. This includes guidelines to ensure decisions and actions are transparent, ethical and free from conflict of interest.

Government Letter of Expectations

In addition to the Taxpayer Accountability Principles, BC Hydro has focussed on the five objectives or directions in the 2014 Government Letter of Expectations letter. In fiscal 2015, BC Hydro completed the work towards these objectives including the following examples:

Work to implement the revised Integrated Resource Plan.
Along with capital investment in our system including Site C, BC Hydro remains focused on conservation and energy efficiency measures. BC Hydro is on track to meet the 66 per cent target in the *Clean Energy Act*, but an evaluation of conservation rate structures in fiscal 2015 revealed lower than expected energy savings resulting in BC Hydro falling short in meeting the 78 per cent target in the IRP.

The DSM forecast is currently tracking approximately 1,300 GWh/yr below the cumulative energy savings target of 7,800 GWh/yr by fiscal 2021. The report found that while residential customers are responding reasonably well to the rate design, commercial customers had lower than expected energy savings from the Large and Medium General Service conservation rates.

BC Hydro is engaging with commercial and industrial customers to simplify the rate structures and, in fall 2015, will file a Rate Design Application with the BCUC to make a number of improvements to the rates.

Continued development of the Site C Project and supporting it through the environmental assessment process.
In October 2014, the Site C project received federal and provincial environmental approvals. In December 2014, the Site C project, a third dam and generating station on the Peace River, was approved by the B.C. Government to proceed to construction. Site C is the most cost-effective way to meet the long-term need for energy and dependable capacity. To prepare for a summer 2015 construction start, BC Hydro is procuring contracts, completing construction planning and continuing to engage Aboriginal groups and communities.

Deliver value and maintain competitive rates by efficiently and responsibly managing the business.
On April 1, 2014, BC Hydro implemented the BCUC approved 9 per cent rate increase as outlined in the 10 year plan for rates. Even with this increase, BC Hydro continued to have the third lowest rates for residential customers and the fourth lowest rates for commercial and industrial customers in North America as stated in the HydroQuebec Comparison of Electricity Prices in Major North American Cities released in August 2014.

During fiscal 2015, BC Hydro piloted a common, structured process improvement framework based on the Lean methodology. Several pilot initiatives were undertaken, which identified a number of process improvements. One such pilot initiative related to Vegetation Management, with benefits achieved through improved processes related to inspections, planning and program overlap. Training of BC Hydro staff is underway to build capacity to apply this methodology to other business and operational processes throughout the company.

BC Hydro continued to execute on its strategy to better meet its supply chain business requirements and to identify productivity and efficiency opportunities through changes in people, process and technology.

BC Hydro also continued to drive efficiencies in how work is performed, from planning through execution. We expanded our capabilities in strategic resource planning and high-level work allocation to better inform decisions on workforce requirements and our contractor strategy. Work allocation and planning considerations were embedded into business planning processes and front line managers have been provided with new enhanced tools to assist them with scheduling and dispatching work. This new scheduling tool provides a more holistic view as opposed to previously having multiple sources.

BC Hydro is also leveraging benefits of our smart meters. The remote disconnect/reconnect functionality has given us the ability to remotely disconnect and/or reconnect services in as little as four seconds, freeing up crews to do higher value-added work.

Minimize rate increases to consumers and industry by continuing to replace and build hydroelectric and transmission infrastructure.
With the addition of the Site C project to the capital plan, BC Hydro is now planning to invest $2.4 billion per year in capital infrastructure over the next 10 years. During fiscal 2015, BC Hydro aligned its project management and delivery resources to help ensure a unified, disciplined and systematic way to bring capital projects into service safely, to a high standard of quality, on time and on budget.

In fiscal 2015, BC Hydro successfully brought the Northwest Transmission Line (NTL) Project, Iskut Extension Project, Mica Unit 5, and Mica SF_6 Gas Insulated Switchgear Replacement Project into service. The Dawson Creek/Chetwynd Area Transmission (DCAT) Project, Interior to Lower Mainland (ILM) Project, Hugh Keenleyside Spillway Gate Reliability Upgrade Project and Mica Unit 6 Project are all nearing completion and expected to be in service in fiscal 2016.

Working with the Columbia Power Corporation to report to government on the progress of the Columbia Power Corporation / BC Hydro Joint Development Committee.
BC Hydro and Columbia Power Corporation agreed to collaborate on the potential redevelopment of small BC Hydro-owned facilities, and have studied two facilities for redevelopment; Duncan Dam and Elko. A new generating facility at Duncan Dam was studied and in April 2013, it was decided not to pursue this project any further, as it was not economically viable. The study of Elko is ongoing on a replacement of the powerhouse and dam with similar sized facility in the existing location.

Goals, Strategies, Measures and Targets
In fiscal 2015, BC Hydro's vision continued to be: Powering B.C. with clean, reliable electricity for generations with six core values essential to our success: accountability, integrity, safety, service, teamwork and ingenuity. In addition, six strategic goals guide our actions each supported by corresponding strategies, performance measures and targets. Each performance measure has a definition and rationale, as well as benchmarking measures that allow a comparison of performance over time. These measures track our progress on delivering key priorities. 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 Report. The vision and its associated values and strategic goals support transparency and accountability as required by Government under the Taxpayer Accountability Principles.

The BC Hydro 2014/15 Annual Report compares the corporation's fiscal 2015 actual results to the expected results identified in the 2014/15- 2016/17 Service Plan. The fiscal 2016 and fiscal 2017 targets presented below are based on the recent 2015/16- 2017/18 Service Plan.

Goal 1: Safely Keep The Lights On

Safely and reliably meet the electricity needs of our customers through integrated planning and technology, and in the operation, maintenance and advancement of our system.

Strategies

Safety

- Continue to implement the recommendations of the Safety Taskforce.
- Develop an integrated safety, health and environment management system that is easy for field workers to use, and embeds a single set of processes in the business. This system will improve safety and environmental performance, and ensure due diligence in meeting compliance with regulation and internal policy, standards, rules and procedures.
- Systematically identify and, where possible, reduce the number of hazards through work-planning activities and work procedure development.
- Increase integration of job-safety planning into daily work for all operational facilities and activities.

Reliability

- Plan regionally to identify opportunities to increase regional transmission capacity and advance work on major transmission projects.
- Improve the reliability of poor performing feeders in the short-and medium-term through focused vegetation management and automated recloser programs.
- To address reliability in the long-term, implement our Distribution Automation strategy. The strategy uses smart meters and other technology to increase automation and flexibility in outage management.
- Invest in technology projects that support safe and reliable operations, such as the Smart Meter and Infrastructure Program; the Distribution Management System; and, the Enterprise Geographic Information System.
- Through our asset management principles, prudently invest in our assets to extend their operating lives, enhance capability, manage risk, and increase efficiency.
- Continue to effectively manage dam safety issues, risks and regulatory requirements.

Performance Measures 1-8[1]

Performance Measures	Actual F2012	Actual F2013	Actual F2014	Target F2015	**Actual F2015**	Target F2016	Target F2017
Safety measures							
Zero Fatality & Serious Injury[2] [Loss of life or the injury has resulted in a permanent disability]	0	2	0	0	**1**[3]	0	0
Severity,[2,4] [Number of calendar days lost due to injury per 200,000 hours worked]	27.4	45.1[5]	28.9	25.0	**23.3**	25.0	25.0
All Injury Frequency [Number of injuries per 200,000 hours, based on actual hours worked]	1.7	2.1	2.0	1.6	**1.9**[6]	NR[7]	NR[7]
Safety Taskforce Recommendation Implementation [Number of recommendations fully implemented and in sustainment (out of 21 total)]	N/A	1	7	12	**12**	NR[8]	NR[8]
Reliability measures							
CAIDI (duration)[9] [average interruption in hours per interrupted customer]	2.27	2.12	2.30	2.25	**2.36**	2.30	2.30
SAIFI (frequency)[9] [Number of sustained disruptions per year] (excluding major events)	1.58	1.29	1.56	1.40	**1.30**	1.40	1.40
CEMI-4 (%)[9] [Customers experiencing four or more outages]	12.50	9.10	12.35	11.00	**9.23**	11.00	11.00
Winter Generation Availability (%)	96.8	98.1	96.8	96.4	**97.4**[10]	96.4	96.4

[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]. This metric did not meet target for the fiscal year as a result of a serious injury from an electrical contact in November 2014. It has been 56 months without a fatality.
[4]The severity targets for fiscal 2016 and fiscal 2017 have been revised to better reflect past performance.
[5] The fiscal 2013 Severity result of 45.1 is unusually high compared to other years. Over 40 per cent of the fiscal 2013 Severity result is due to five injuries resulting in considerable time loss (180 days or more). Traditionally, BC Hydro only experiences one or two injuries in a year with this amount of time loss.
[6] The 12 month rolling AIF of 1.9 was worse than the fiscal 2015 target of 1.6. While the winter hazards reduction program appears to be delivering the anticipated outcomes, injuries from other hazards affected safety performance levels and therefore AIF did not meet the target for the fiscal year.
[7] In the 2015/16-2017/18 Service Plan All Injury Frequency safety measure is being replaced by the Lost Time Injury Frequency safety measure. Focusing on Lost Time Injury Frequency encourages 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.
[8]Safety Taskforce Recommendation Implementation was removed as a metric after fiscal 2016 but will continue to be tracked internally.
[9] 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. Targets for fiscal 2016 and fiscal 2017 have been adjusted to reflect these factors but remain in line with historical performance.
[10] Winter Generation Availability was better than the plan of 96.4 per cent.
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. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

Goal 2: Succeed Through Relationships

Gain support for our work by building trusted relationships with First Nations, customers, suppliers and the communities we serve.

Strategies

- Sustain gold-level certification under the Progressive Aboriginal Relations program by maintaining leading practices in the areas of Aboriginal employment, business development, capacity development and community engagement.
- Increase project and operational certainty by continuing to build collaborative and enduring relationships with First Nations.
- Strengthen BC Hydro's understanding of customers' needs and expectations through the use of enhanced data collection and reporting capabilities.
- Meet the evolving needs of customers by providing choice, increasing self-service and giving timely, easy access to consistent, high-quality information.
- Partner with external organizations and communities, and work with the energy efficiency industry to successfully implement the Demand Side Management (DSM) plan.
- Continue to implement the remaining recommendations from our supplier engagement review to improve the effectiveness of procurement and contract management and how we engage and interact with our suppliers.

.Performance Measure 9 - 12[1]

Performance Measures	Actual F2012	Actual F2013	Actual F2014	Target F2015	**Actual F2015**	Target F2016	Target F2017
CSAT Index [Customer Satisfaction Index: % of customers satisfied or very satisfied]	87.0	86.0	85.0	85.0	**86.0**	85.0	85.0
Billing Accuracy [% of accurate bills]	98.4	98.5	99.1	99.0	**99.5**	99.0	99.0
First Call Resolution[2] [% of customer calls resolved first time]	74.0	68.0	71.0	73.0	**71.0**	71.0	71.0
Progressive Aboriginal Relations Designation[3]	Silver	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] The fiscal 2016 and fiscal 2017 targets were reduced compared to the 2014/15-2016/17 Service Plan due to the movement of a greater number of less complicated calls to the self-serve environment (web and phone) resulting in the call centre handling a greater percentage of complex calls that may not lend themselves to resolution on the first call.

[3] BC Hydro currently holds a gold level designation in the Canadian Council of Aboriginal Business' Progressive Aboriginal Relations Program which was attained in fiscal 2013. BC Hydro's intent is to recertify the standing every three years. In fiscal 2016, BC Hydro will apply for the next certification.

Goal 3: Mind Our Footprint

Create a sustainable energy future in B.C. by carefully managing our impacts on the environment and fostering an energy conservation and efficiency culture.

Strategies

- Implement the Demand-Side Management (DSM) plan recommended in the IRP, including Power Smart programs and conservation rate structures, supporting new energy efficiency regulations, and maintaining an energy conservation and efficiency culture.
- Continue to meet the 93 per cent clean energy objective in the *Clean Energy Act* by managing energy purchased from independent power producers and advancing clean energy capacity resources.
- Continue to meet regulatory requirements related to GHG emissions reporting and verification.
- Contribute to the Province's goal of achieving carbon neutrality in the public sector by reducing GHG emissions from our buildings, vehicles and paper use and by purchasing offsets for our residual emissions. Continue to facilitate the electrification of transportation in B.C.
- Manage the impact on the environment from BC Hydro's new developments and retrofits of existing facilities by incorporating an "avoid, minimize and offset" approach to project design, planning and implementation.
- Continue to implement environmental studies and projects related to water licence requirements under BC Hydro's Water Use Plans, to confirm the suitability of operational controls at hydroelectric generating plants.
- Continue implementing the PCB electrical equipment phase-out strategy, and pursue a long-term strategy for the handling, decontamination and disposal of PCB-contaminated equipment and materials.
- Ensure resources, training and tools are in place at BC Hydro's facilities and throughout our operations to identify risks and prevent environmental incidents; and, to deploy the most effective approaches to minimize impacts when incidents occur.
- Work in partnership with First Nations and communities to understand impacts related to managing BC Hydro's assets and implement compensation programs and other environmental projects reflective of this input.

Performance Measures 13 - 16[1]

Performance Measures	Actual F2012	Actual F2013	Actual F2014	Target F2015	**Actual F2015**	Target F2016	Target F2017
Demand Side Management (DSM) (GWh/year)[2]	3,424	4,460	4,776	5,500	**4,334**[3]	5,000	5,600
Clean Energy (%)[4]	98.1	98.2	97.1	93.0	**97.9**	93.0	93.0
Electricity Production GHG Emissions (kilotonnes CO_2e)[5,6]	560	631	730	740	**667**[7]	1,110	1,120
Carbon Neutral Program Emissions (kilotonnes CO_2e)[5,8]	30.0	28.8	27.0	29.0	**26.6**	28.0	28.0

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.
[2] Target numbers are rounded values presented as cumulative run-rate savings since 2008 and include energy savings from Power Smart programs as well as from codes/standards and rate structures. The energy savings actuals for fiscal 2015 and targets for fiscal 2016, and fiscal 2017 include the impact of the evaluation of the energy savings from conservation rate structures, which have largely contributed to a reduction of the DSM targets relative to the previous Service Plan.
[3] Cumulative energy savings at the end of fiscal 2015 were 1,166 GWh/yr lower than plan primarily due to an adjustment to the Medium General Service and Large General Service Rates savings due to a recent evaluation of these rate structures.
[4] The Clean Energy Target represents the minimum threshold generation target 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 actual resource use and is consistent with previous years.
[5] All actuals, forecast and targets for Electricity Production GHG Emissions and Carbon Neutral Program Emissions are presented on a calendar year basis, not fiscal year. For Electricity Production, this is to ensure consistency with GHG emissions reports filed under *the Canadian Environmental Protection Act, 1999* and the B.C. Reporting Regulation. For Carbon Neutral this is to ensure consistency with the B.C. Carbon Neutral Government Regulation.
[6] The upward revision of the plan from fiscal 2015 to fiscal 2016 and fiscal 2017 compared to previous Service Plan is primarily related to the potential for higher production from existing BC Hydro and independent power producer thermal plants.
[7] The Electricity Production GHG Emissions measure includes emissions from electricity generation, electricity purchased from B.C. IPPs, and fugitive SF_6 releases. The calendar year 2014 Electricity Production GHG emissions were estimated to be 667 kilotonnes CO_2e, which is ten per cent below the plan of 740 kilotonnes CO_2e. Emissions were lower than forecasted for the Burrard Generating Station, which was rarely called upon for system requirements in 2014. Fugitive SF_6 releases were also lower than forecasted, mostly due to a reduction in SF_6 equipment decommissioning in 2014.
[8] The targets are based on emissions from BC Hydro's vehicle fleet, buildings and paper use. The calendar year 2014 emissions were 26.6 kilotonnes which is eight per cent lower than target. The reduction in emissions is mostly attributable to a reduction in building energy use.

Goal 4: Foster Economic Development

Foster economic development opportunities across B.C. through our projects, practices and advancement of the energy efficiency and clean energy sectors.

Strategies

- As outlined in the Integrated Resource Plan, advance a set of actions that support a healthy, diverse clean energy sector and promote clean energy opportunities for First Nations.
- Support the Province's economic development priorities with implementation of such projects as: the Northwest Transmission Line; transmission upgrades required to supply the initial 3,000 gigawatt hours of LNG load and to prepare to meet future LNG requirements; and, clean energy opportunities for First Nations.
- Integrate economic development principles into decision making tools, procurement practices, business cases and corporate policies.
- Ensure appropriate tariff/rate structures are in place to enable business expansion across B.C.
- Help expand and retain current customers by improving the competitiveness of businesses through Power Smart programs and the delivery of clean, reliable energy.

BC Hydro continues to enable economic development and measures performance through reliability, maintaining competitive rates, and through implementing our capital plans.

Goal 5: Maintain Competitive Rates

Deliver value for British Columbia and maintain competitive rates by efficiently and responsibly managing our business.

Strategies

- Continue to focus on management and control of our cost structure in order to realize cost-savings and efficiencies.
- Prudently implement our capital plan and continue to deliver on BC Hydro's capital investment program, including process and procurement improvements.
- Improve operational excellence, safety and reliability in the Transmission & Distribution business group by improving work delivery methods, resourcing strategies, integrated planning, as well as technology platforms.
- Continue to implement category and materials management strategies to deliver improved supply chain operational efficiencies; meet cost control and other business objectives through improved sourcing of products and services; and build strong supplier relationships.
- Manage the cost of energy by: implementing a DSM plan; ensuring new electricity supply is the most cost-effective available; making prudent short-term generate and buy decisions; and, optimizing BC Hydro's ability to use the flexibility of our heritage assets.
- Optimize BC Hydro's balance sheet and cost of capital.

Performance Measures 17 - 19[1]

Performance Measures	Actual F2012	Actual F2013	Actual F2014	Target F2015	**Actual F2015**	Target F2016	Target F2017
Competitive Rates[2]	1st quartile	1st quartile	1st quartile	1st quartile	**1st quartile**	1st quartile	1st quartile
Net Income[3] ($ million)	558	509	549	582	**581**	653	693
Operating Costs[3,4] ($ million)	665	705	702	706	**710**	713	730

[1] Performance Measure definitions, rationales, data sources, and benchmarking information are available at www.bchydro.com/performance.
[2] Based on the annual HydroQuebec Report on Electricity Rates in North America. BC Hydro's residential rates are the third lowest in North America; its small commercial and large commercial rates are fourth and third lowest respectively and its industrial rates are the fourth lowest.
[3] Performance within (+/-) 0.5 per cent is considered acceptable.
[4] Operating Costs are defined as personnel, materials and external services expenses included in income that are incurred in the day-to-day operation of BC Hydro's electric utility, net of recoveries, capitalized costs and reclassification adjustments.

Goal 6: Engage a Safe and Empowered Team

Empower a team that is committed to safety, innovative and prepared for the future.

Strategies

- Address workforce gaps by ensuring that development plans provide a readily available talent pool for critical roles.
- Continue to prudently manage staffing levels.
- Ensure the optimal complement of new recruits; skilled, experienced and high-performing employees; and, contracted or outsourced service providers.
- Provide sustainable total compensation that attracts the best candidates, aligns employees to our key objectives, retains top performers and maintains employee well-being while also keeping rates low for customers.
- Ensure organizational leaders have the training and tools to encourage high performance and engage teams to work together safely and effectively.

Note: *For information on how BC Hydro is working to ensure the safety of employees, contractors and the public see Goal 1.*

Performance Measure 20[1]

Performance Measures	Actual F2012	Actual F2013	Actual F2014	Target F2015	**Actual F2015**	Target F2016	Target F2017
Employee Engagement (%)[2]	NR	78 Index score was 79.	79 Index score was 79.	Meet or exceed Towers Watson's Global Utilities Index	**82** **Index score was 79.**	Meet or exceed Towers Watson's Global Utilities Index	Meet or exceed Towers Watson's Global Utilities Index

[1] Performance Measure definitions, rationales, data sources, and benchmarking information are available at www.bchydro.com/performance.
[2] The target is to meet or exceed the annual Towers Watson Global Utilities Index Score.

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, 2015 (fiscal 2015) and should be read in conjunction with the Audited Consolidated Financial Statements and related notes of the Company for the years ended March 31, 2015 and 2014.

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, 2015 was $581 million, $32 million higher than the prior fiscal year net income of $549 million. The increase from the prior year was primarily due to higher domestic revenues resulting from higher average customer rates, partially offset by higher amortization and depreciation expenses primarily due to an increase in assets in service and higher amortization of regulatory accounts.

- Inflows to the system during fiscal 2015 were 102 per cent of average, compared to 95 per cent of average for the prior fiscal year. Actual inflows to Williston and Kinbasket reservoirs were 93 per cent and 112 per cent, respectively. The higher inflows in fiscal 2015 were due in large part to warmer and wetter conditions in the fall and winter months after a very dry summer that resulted in above average runoff across the system.

- Capital expenditures for the year ended March 31, 2015 were $2,169 million, a $133 million increase over the prior fiscal year, which is consistent with the 10 year plan. BC Hydro continues to invest significantly in capital projects to refurbish its ageing infrastructure and build new assets for future growth, including the Interior to Lower Mainland Transmission Project, Iskut Extension Project, Dawson Creek/Chetwynd Area Transmission Project, John Hart Generating Station Replacement, Upper Columbia Capacity Additions at Mica – Units 5 & 6, Ruskin Dam Safety and Powerhouse Upgrade, and Northwest Transmission Line Project.

- In December 2014, the Site C Clean Energy project (Site C) was approved by the Provincial Government to proceed to construction in summer 2015. 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 will provide clean, renewable and cost-effective power in B.C. for more than 100 years.

CONSOLIDATED RESULTS OF OPERATIONS

for the years ended March 31 ($ in millions)		**2015**		2014		Change
Total Revenues	**$**	**5,748**	$	5,392	$	356
Net Income	**$**	**581**	$	549	$	32
Capital Expenditures	**$**	**2,169**	$	2,036	$	133
GWh Sold (Domestic)		**51,213**		53,018		(1,805)

as at March 31 ($ in millions)		**2015**		2014		Change
Total Assets	**$**	**27,753**	$	25,711	$	2,042
Shareholder's Equity	**$**	**4,170**	$	3,865	$	305
Accrued Payment to the Province	**$**	**264**	$	167	$	97
Retained Earnings	**$**	**4,068**	$	3,751	$	317
Debt to Equity		**80 : 20**		80 : 20		n/a
Number of Domestic Customers		**1,935,068**		1,914,549		20,519
Total Reservoir Storage (GWh)		**19,565**		12,855		6,710

REVENUES

Total revenues for the year ended March 31, 2015 were $5,748 million, an increase of $356 million or 7 per cent compared to the prior fiscal year primarily due to higher domestic revenues resulting from higher average customer rates, partially offset by lower trade revenues primarily due to decreases in volumes of physical gas and electricity sold.

		(in millions)			*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31		**2015**		2014	**2015**	2014	**2015**	2014
Domestic								
Residential	**$**	**1,712**	$	1,663	**17,047**	17,965	**$100.43**	$ 92.57
Light industrial and commercial		**1,597**		1,489	**18,564**	18,501	**86.03**	80.48
Large industrial		**748**		687	**14,020**	13,994	**53.35**	49.09
Other energy sales		**280**		275	**1,582**	2,558	**176.99**	107.51
Total Domestic Revenue Before Regulatory Transfer		**4,337**		4,114	**51,213**	53,018	**84.69**	77.60
Rate smoothing and load variance regulatory transfer		**492**		205	-	-	-	-
Total Domestic	**$**	**4,829**	$	4,319	**51,213**	53,018	**$ 94.29**	$ 81.46
Trade								
Electricity - Gross	**$**	**989**	$	1,147	**21,928**	23,806	**$ 45.10**	$ 48.18
Less: forward electricity purchases		**(214)**		(281)	-	-	-	-
Electricity - Net		**775**		866	-	-	-	-
Gas - Gross		**886**		1,144	**21,637**	26,276	**40.95**	43.54
Less: forward gas purchases		**(742)**		(937)	-	-	-	-
Gas - Net		**144**		207	-	-	-	-
Total Trade[1]	**$**	**919**	$	1,073	**43,565**	50,082	**$ 21.09**	$ 21.42
Total Revenues	**$**	**5,748**	$	5,392	**94,778**	103,100	**$ 60.65**	$ 52.30

[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 $/MWh figures are based on total gross sales which includes physical and financial transactions whereas the volumes only include physical transactions.*

Domestic Revenues

Domestic revenues after regulatory account transfers for the year ended March 31, 2015 were $4,829 million, an increase of $510 million or 12 per cent compared to the prior fiscal year. Domestic revenues before regulatory account transfers of $4,337 million were $223 million or 5 per cent higher than the prior fiscal year. The increase was primarily due to higher average customer rates, partially offset by lower overall consumption. Average customer rates were higher in fiscal 2015, reflecting an average rate increase as approved by the British Columbia Utilities Commission (BCUC) of 9 per cent effective April 1, 2014.

Lower consumption was primarily driven by lower residential demand and lower other energy sales. The lower residential demand was due to warmer weather conditions during the winter months. The lower other energy sales were primarily due to lower surplus sales as a result of lower water inflows in the summer months and reduced opportunities for exports in the winter due to lower market prices.

Variances between actual and planned load are deferred to the Non-Heritage Deferral Account (NHDA) and variances between actual and planned other energy sales are deferred to the Heritage Deferral Account (HDA) and NHDA.

Trade Revenues

Powerex, a wholly owned subsidiary of the Company, is a key participant in energy markets across North America, buying and supplying wholesale power, natural gas, ancillary services, financial energy products, and environmental products with an expanding list of trade partners.

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 help the Company 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. Electricity is also traded based on market opportunities. Exports are made only after ensuring domestic demand requirements can be met.

Trade revenues for the year ended March 31, 2015 were $919 million, a decrease of $154 million or 14 per cent compared to the prior fiscal year. The decrease in revenue was primarily due to an 18 per cent decrease in the volume of physical gas sold and an 8 per cent decrease in the volume of physical electricity sold. The decrease in the volume of physical gas sold was primarily due to a decrease in physical gas sales in Eastern North America as a result of lower physical gas prices. Physical gas prices decreased by 6 per cent compared to the prior fiscal year. The decrease in the volume of physical electricity sold was primarily due to lower sales in Alberta.

Variances between actual and planned trade income (which includes trade revenues) are deferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the year ended March 31, 2015, total operating expenses of $4,535 million were $290 million higher than the prior fiscal year. The increase over the prior fiscal year was primarily due to higher amortization and depreciation expenses and higher expenditures on domestic electricity and gas purchases.

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.

Energy costs for the year ended March 31, 2015 were $2,203 million, $57 million or 3 per cent higher than the prior fiscal year. The increase over the prior fiscal year was primarily due to higher domestic energy costs mainly due to more Independent Power Producers (IPPs) achieving commercial operations, partially offset by lower trade electricity and gas purchases.

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [2]	
for the years ended March 31	**2015**	2014	**2015**	2014	**2015**	2014
Domestic						
Water rental payments (hydro generation)[1]	**$ 334**	$ 372	**41,318**	45,225	**$ 8.11**	$ 8.42
Purchases from Independent Power Producers	**1,064**	825	**13,377**	11,025	**79.54**	74.82
Other electricity purchases - Domestic	**6**	42	**207**	918	**28.76**	45.60
Gas for thermal generation	**34**	43	**213**	268	**157.36**	161.89
Transmission charges and other expenses	**2**	11	**115**	117	**-**	-
Non-treaty storage / Libby Coordination Agreement	**14**	(15)	**-**	-	**-**	-
Allocation from trade energy	**16**	29	**512**	1,365	**33.51**	32.30
Total Domestic Cost of Energy Before Regulatory Transfers	**1,470**	1,307	**55,742**	58,918	**26.37**	22.18
Domestic cost of energy regulatory transfers	**(12)**	(55)	**-**	-	**-**	-
Total Domestic	**$ 1,458**	$ 1,252	**55,742**	58,918	**$ 26.15**	$ 21.25
Trade						
Electricity - Gross	**$ 617**	$ 792	**22,397**	25,013	**$ 27.55**	$ 31.66
Less: forward electricity purchases	**(214)**	(281)	**-**	-	**-**	-
Electricity - Net	**403**	511	**-**	-	**-**	-
Remarketed gas - Gross	**842**	1,086	**21,812**	26,754	**38.60**	40.59
Less: forward gas purchases	**(742)**	(937)	**-**	-	**-**	-
Remarketed gas - Net	**100**	149	**-**	-	**-**	-
Transmission charges and other expenses	**248**	227	**-**	-	**-**	-
Allocation to domestic energy	**(16)**	(29)	**(512)**	(1,365)	**33.51**	32.30
Total Trade Cost of Energy Before Regulatory Transfers	**735**	858	**43,697**	50,402	**21.73**	20.97
Trade net margin regulatory transfer	**10**	36	**-**	-	**-**	-
Total Trade	**$ 745**	$ 894	**43,697**	50,402	**$ 21.96**	$ 21.68
Total Energy Costs	**$ 2,203**	$ 2,146	**99,439**	109,320	**$ 24.31**	$ 21.45

[1] *Total GWh is net of storage exchange.*

[2] *Total cost per MWh includes other electricity purchases at gross cost.*

Domestic Energy Costs

Domestic energy costs after regulatory account transfers for the year ended March 31, 2015 were $1,458 million, $206 million or 16 per cent higher than the prior fiscal year. Domestic energy costs before regulatory account transfers of $1,470 million for the year ended March 31, 2015 were $163 million or 12 per cent higher than the prior fiscal year primarily due to higher IPP costs. IPP costs were higher due to a higher volume of electricity purchased as a result of more IPPs achieving commercial operations, fewer IPP outages due to maintenance, and higher deliveries from hydro IPPs due to higher inflows. Energy costs were also higher from water transactions related to the Non-Treaty Storage Agreement and Libby Coordination Agreement, partially offset by lower water rental payments, a reduction in domestic purchases and fewer net trade energy imports (lower allocation from trade energy). Hydro generation was lower than the prior fiscal year despite higher inflows due to lower domestic load, lower surplus sales due to low market prices and higher IPP deliveries.

Water rental payments are based on the prior year's generation and current year's rates. During fiscal 2014, there was less hydro generated than fiscal 2013 resulting in lower water rental payments in the current year. Water rental rates are indexed each calendar year based on the annual percentage change in British Columbia's consumer price index.

Variances between actual and planned domestic cost of energy are transferred to the HDA and NHDA.

Trade Energy Costs

Trade energy costs after regulatory account transfers for the year ended March 31, 2015 were $745 million, a decrease of $149 million or 17 per cent compared with the prior fiscal year. Trade energy costs before regulatory account transfers for the year ended March 31, 2015 were $735 million, a decrease of $123 million or 14 per cent compared to the prior fiscal year. The decrease in trade energy costs was primarily due to an 18 per cent decrease in the volume of physical gas purchased and a 10 per cent decrease in the volume of physical electricity purchased, consistent with the decrease in physical gas volumes and physical electricity volumes sold, respectively.

Variances between actual and planned trade income (which includes trade energy costs) are deferred to the TIDA.

Water Inflows

Inflows to the system during fiscal 2015 were 102 per cent of average, compared to 95 per cent of average for the prior fiscal year. Actual inflows to Williston and Kinbasket reservoirs were 93 per cent and 112 per cent, respectively. The higher inflows in fiscal 2015 were due in large part to warmer and wetter conditions in the fall and winter months after a very dry summer that resulted in above average runoff across the system.

The Williston and Kinbasket reservoirs have been managed such that system energy storage on March 31, 2015 was 17,800 GWh, or 5,300 GWh above the 10 year historic average. This was 6,200 GWh higher than the system energy storage of 11,600 GWh recorded one year earlier. The Williston and Kinbasket reservoir energy contents were 11,200 GWh (1,900 GWh above the 10 year historic average) and 6,600 GWh (3,400 GWh above the 10 year historic average), respectively, with Williston 2,700 GWh higher than the prior fiscal year and Kinbasket 3,500 GWh higher than the prior fiscal year. The high levels of system storage at the end of the fiscal year are a culmination of reduced domestic demand (mild temperatures and lower than forecast industrial load), higher than average inflows during the fourth quarter ended March 31, 2015, and reduced opportunities for market exports (mild temperatures and increased generation in the Pacific Northwest).

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the year ended March 31, 2015 were $534 million, $4 million lower than the prior fiscal year, primarily due to workforce reductions and lower current service pension costs.

Materials and External Services

Expenditures on materials and external services for the year ended March 31, 2015 were $593 million, $14 million higher than the prior fiscal year, primarily due to increased expenditures on distribution maintenance and work programs and generation operations.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment (PP&E), intangible assets, and the amortization of certain regulatory assets and liabilities. For the year ended March 31, 2015, amortization and depreciation expense was $1,205 million, $210 million or 21 per cent higher than the prior fiscal year primarily due to an increase in assets in service and higher amortization of regulatory accounts. Included in the amortization of regulatory accounts were six regulatory accounts with total amortization of $110 million, which commenced amortization in fiscal 2015.

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, 2015 were $209 million, comparable to total grants and taxes of $203 million in the prior fiscal year.

Capitalized Costs

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to property, plant and equipment. Overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS PP&E regulatory account. The annual transfers to the IFRS PP&E regulatory account are amortized over 40 years which approximates the composite average life of the PP&E. In addition, the ongoing impact of this change is being smoothed into rates over a 10 year period through transfers to the IFRS PP&E regulatory account. As such, each year, 1/10 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 to either PP&E or the associated regulatory accounts for the year ended March 31, 2015 were $224 million, $20 million lower than capitalized costs of $244 million in the prior fiscal year. The reduction in capitalized costs was primarily due to the annual reduction of the transfer of operating costs to the IFRS PP&E account.

Other Costs, Net of Recoveries

Other costs, net of recoveries primarily include gains and losses on the disposal of assets and certain cost recoveries classified as operating costs. For the year ended March 31, 2015, other costs net of recoveries were $15 million, $13 million lower than the prior fiscal year primarily due to a third party settlement received in the current year, and lower provisions recorded in the current year.

FINANCE CHARGES

Finance charges for the year ended March 31, 2015 were $632 million, $34 million or 6 per cent higher than the prior fiscal year. The increase was primarily due to lower planned capitalized interest during construction and higher planned lease charges relating to Electricity Purchase Agreements (EPAs) accounted for as finance leases. The increase was partially offset by lower planned short term and long term interest rates and lower interest expense on pension plan liabilities resulting from a lower discount rate.

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 would otherwise be included in the determination of comprehensive income in the year the amounts are incurred. The deferred amounts are either recovered or refunded through future rate adjustments.

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 would otherwise be included in net income or other comprehensive income, unless otherwise recovered through rates. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC.

Net regulatory account transfers are comprised of the following:

for the years ended March 31 (in millions)		**2015**		2014
Energy Accounts				
Heritage Deferral Account	**$**	**82**	$	50
Non-Heritage Deferral Account		**238**		(3)
Trade Income Deferral Account		**(10)**		171
		310		218
Forecast Variance Accounts				
Finance Charges		**(120)**		(80)
Rate Smoothing Account		**166**		111
Non-Current Pension Cost		**317**		(247)
Other		**25**		14
		388		(202)
Capital-Like Accounts				
Demand-Side Management (DSM)		**125**		118
Site C		**65**		67
Smart Metering and Infrastructure (SMI)		**26**		75
IFRS Property, Plant and Equipment		**157**		179
		373		439
Non-Cash Accounts				
Environmental Provisions & Costs		**69**		22
First Nations Costs & First Nations Provisions		**12**		42
Other		**6**		8
		87		72
Amortization of regulatory accounts		**(491)**		(319)
Interest on regulatory accounts		**67**		57
Net change in regulatory accounts	**$**	**734**	$	265

For the year ended March 31, 2015, net additions to the Company's regulatory accounts after amortization were $734 million compared to prior year net additions of $265 million. The net asset balance in the regulatory asset and liability accounts as at March 31, 2015 was an asset of $5,433 million compared to an asset of $4,699 million as at March 31, 2014.

Net additions to the regulatory accounts during the year ended March 31, 2015 included:

- Transfers to the Non-Current Pension Cost regulatory account for variances that arise between forecast and actual non-current pension and other post employment benefit costs, which would otherwise be included in operating expenses as well as actuarial gains and losses. The increase was primarily due to the transfer of net actuarial losses on post-employment defined benefit plans as a result of the decrease in the discount rate, partially offset by higher rate of return on plan assets. The decrease in the prior year was a result of an increase in the discount rate and a higher rate of return on plan assets;

- Increases to the energy deferral accounts were primarily due to lower revenues as a result of lower domestic load. In addition, there were lower surplus sales due to lower water inflows in the summer months and reduced opportunities for exports in the winter due to lower market prices;

- Increases to the Rate Smoothing regulatory account for smoothing the rate impacts of the rate increases in the 10 year rate plan;

- Transfers to the IFRS Property, Plant and 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;

- Planned expenditures on DSM projects, which support energy conservation; and

- Transfers to the Environmental Provisions regulatory account which reflect increases required to asbestos and polychlorinated biphenyls (PCBs) contamination provisions.

These net additions were partially offset by:

- An increase in net amortization of the regulatory accounts; and

- Transfers to the Finance Charges regulatory liability account due to favourable variances to the forecast.

Net regulatory account balances are as follows:

as at March 31 (in millions)	**2015**	2014
Energy Accounts		
Heritage Deferral Account	**$ 165**	$ 105
Non-Heritage Deferral Account	**524**	362
Trade Income Deferral Account	**244**	324
	933	791
Capital-Like Accounts		
Demand-Side Management (DSM)	**842**	788
Site C	**419**	338
Capital Project Investigation Costs	**30**	35
Smart Metering and Infrastructure (SMI)	**283**	277
IFRS Property, Plant and Equipment	**758**	617
	2,332	2,055
Forecast Variance Accounts		
Rate Smoothing Account	**166**	-
Non-Current Pension Cost	**564**	280
Foreign Exchange Gains and Losses	**(71)**	(89)
CIA Amortization	**87**	81
Finance Charges	**(173)**	(79)
Other Forecast Variance Accounts	**32**	56
	605	249
Non-Cash Accounts		
First Nations Costs & First Nations Provisions	**564**	589
Environmental Provisions & Costs	**382**	383
Future Removal and Site Restoration Costs	**(33)**	(56)
IFRS Pension & Other Post-Employment Benefits	**650**	688
	1,563	1,604
Total Regulatory Account Balance	**$ 5,433**	$ 4,699

BC Hydro has regulatory mechanisms in place to collect 26 of 28 regulatory accounts, which represent approximately 90 per cent of the total net regulatory account balance, in rates over various periods including six regulatory accounts which commenced amortization in fiscal 2015 and resulted in an additional $110 million of amortization expense for the year ended March 31, 2015 compared to the prior fiscal year.

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 2014/15-2016/17 was filed in February 2014 and forecast net income for fiscal 2015 at $582 million.

The table below provides an overview of BC Hydro's fiscal 2015 financial performance results, relative to its February 2014 Service Plan forecast. The results and forecasts form the basis upon which key financial performance targets are set.

Consolidated Statement of Operations

(in millions)	Actual		February 2014 Service Plan	Variance to Feb 2014 Service Plan	Forecast [3]		
	2014	2015	2015 [1]		2016	2017 [1]	2018
Revenues							
Domestic	$ 4,319	$ 4,829	$ 4,830	$ (1)	$ 5,057	$ 5,403	$ 5,604
Trade	1,073	919	999	(80)	1,029	1,024	1,012
	5,392	5,748	5,829	(81)	6,086	6,427	6,616
Expenses							
Operating Costs							
Cost of energy	2,146	2,203	2,283	80	2,280	2,525	2,590
Other operating expenses							
Personnel expenses, materials & external services [2]	848	868	867	(1)	900	963	1,006
Amortization	995	1,205	1,204	(1)	1,254	1,253	1,246
Finance charges	598	632	633	1	751	733	796
Grants and taxes	203	209	214	5	218	229	238
Other	53	50	46	(4)	30	31	33
	4,843	5,167	5,246	80	5,433	5,735	5,909
Net Income	$ 549	$ 581	$ 582	$ (1)	$ 653	$ 693	$ 707

[1] *Columns may not add due to minor rounding.*
[2] *These amounts are net of capitalized costs and recoveries.*
[3] *BC Hydro Service Plan 2015/16 - 2017/18.*

Trade revenue and Trade cost of energy amounts were both lower than the forecast by $80 million; however, the Trade gross margin was on Plan. Variances to the February 2014 Service Plan for Trade revenue and Trade cost of energy are both deferred through the TIDA.

Overall, domestic revenues and expenses and net income were comparable to the Service Plan forecast.

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 Payment accrued for the year ended March 31, 2015 is $264 million which is below 85 per cent of the Company's net income due to the 80:20 cap.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the year ended March 31, 2015 was $1,018 million, compared with cash flow provided by operating activities of $788 million in the prior fiscal year. The increase was primarily due to the cash transfer to funds held in trust in the prior fiscal year for the California legal settlement.

The long-term debt balance net of sinking funds at March 31, 2015 was $16,721 million, compared with $15,568 million at March 31, 2014. The increase was mainly as a result of an increase in long-term bond issues totaling $1,565 million ($1,665 million par value) to fund capital expenditures and net foreign exchange revaluation losses of $145 million. These increases were partially offset by long-term bond redemptions totaling $325 million par value and a decrease in revolving borrowings of $215 million.

CAPITAL EXPENDITURES

Capital expenditures, which include property, plant and equipment and intangible assets, were as follows:

for the years ended March 31 (in millions)		**2015**		2014
Transmission lines and substation replacements & expansion	**$**	**1,003**	$	912
Generation replacements and expansion		**526**		496
Distribution system improvements and expansion		**399**		422
General, including technology, vehicles and buildings		**216**		206
Site C		**25**		-
Total Capital Expenditures	**$**	**2,169**	$	2,036

Total capital expenditures presented in this table are different from the expenditures in the Consolidated Statements of Cash Flows due to the effect of accruals related to these expenditures.

Transmission lines and substation capital expenditures includes expenditures on the Interior to Lower Mainland Transmission Line, Iskut Extension, Dawson Creek/Chetwynd Area Transmission, Northwest Transmission Line, Surrey Area substation, Merritt Area Transmission, and Shell Groundbirch Interconnection projects.

Generation capital expenditures include expenditures for John Hart Generating Station Replacement, Upper Columbia Capacity Additions at Mica – Units 5 & 6, Ruskin Dam Safety and Powerhouse Upgrade, G.M. Shrum Units 1 to 5 Turbine Rehabilitation, Hugh Keenleyside Spillway Gate Upgrade, and Mica Gas Insulated Switchgear projects.

Distribution capital expenditures include expenditures on customer driven work, end of life asset replacements, system expansion and improvements, and the Smart Metering and Infrastructure project.

General capital expenditures include expenditures on various technology projects and building development programs.

Site C

In December 2014, the Site C project was approved by the Provincial Government. 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 will provide clean, renewable and cost-effective power in B.C. for more than 100 years. Site C expenditures incurred after the Provincial Government's positive investment decision in December 2014 are recorded as property, plant and equipment and include expenditures on engineering and procurement support in preparation for the start of construction in summer 2015.

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 achieve an annual rate of return on deemed equity (ROE).

BC Hydro 10 Year Rate Plan

In November 2013, the Government announced a 10 year rate plan for BC Hydro. On March 6, 2014, the Government issued Directions No. 6 and 7 to the BCUC to implement the 10 year rate plan. Direction No. 6 sets BC Hydro's rate increase at 9 per cent for fiscal 2015 and 6 per cent for fiscal 2016 and also specifies the amounts to be amortized from BC Hydro's regulatory accounts in those years. Direction No. 7 caps BC Hydro's rate increases for fiscal 2017, fiscal 2018 and fiscal 2019 at 4.0 per cent, 3.5 per cent and 3.0 per cent, respectively, subject to a BCUC review. The BCUC will also set the rates for the final five years of the plan. In addition, Direction No. 7 sets the ROE at 11.84 per cent for fiscal 2015, fiscal 2016 and fiscal 2017. Furthermore, the Deferral Account Rate Rider will remain at 5 per cent for fiscal 2015 and future years. Starting in fiscal 2018, the annual payment to the Province will be reduced over five years and then be restricted if the payment would result in a debt to equity ratio exceeding 60:40. Allowed net income for fiscal 2018 and future years will increase by inflation.

BC Hydro F2015-F2016 Revenue Requirements Rate Application (F15-F16 RRRA)

The F15-F16 RRRA requested rate increases for fiscal 2015 and fiscal 2016 at 9 per cent and 6 per cent, respectively, and also requested specific amounts to be amortized from BC Hydro's regulatory accounts. In addition, the F15-F16 RRRA requested the approval of two new regulatory accounts; a) the Rate Smoothing Regulatory Account (to smooth out rate increases over the 10 year period of the 10 year plan) and b) the Real Property Sales Regulatory Account to capture the variance between forecast and actual net gains from real property sales. The BCUC issued Order No. G-48-14 on March 24, 2014, approving the application as filed. On April 1, 2015, BC Hydro's rates increased by 6 per cent as approved by the BCUC order.

Rate Design Application (RDA)

BC Hydro is preparing its next RDA, which is expected to be filed with the BCUC in September 2015. Among other things, the 2015 RDA will consider and update many of the underlying drivers, analysis and assumptions that impact BC Hydro's rates for residential, commercial and industrial customers. Government policy, BC Hydro's load resource balance and energy surplus, conservation results and customer experience with the rates will be considered, and may result in amendments or updates to the rates. Rate design changes are designed to be revenue neutral to the utility. BC Hydro will also consider the relevant Industrial Electricity Policy Review recommendations, as well as changes to BC Hydro's long run marginal cost which is used in rate design.

Available Transfer Capacity (ATC) Rule

On December 5, 2011, the Alberta Electric System Operator (AESO) filed a proposed rule with the Alberta Utilities Commission (AUC) to allocate ATC between the existing BC - Alberta intertie and new interties when the Alberta system is constrained and cannot accommodate the total ATC of all interties. BC Hydro opposed the proposed rule because of the harm it would cause to the Company and its ratepayers. The AUC issued its decision on February 1, 2013 approving the rule as filed. BC Hydro and Powerex were granted leave to appeal to the Alberta Court of Appeal and filed Notice of Appeals on May 15, 2014. The appeal was heard on January 15, 2015 with a decision expected by the end of the second quarter of fiscal 2016.

BCUC Review Task Force

In April 2014, the Province announced the establishment of a Task Force to review the operations of the BCUC. The Task Force review process took place over the summer and early fall of 2014, and involved extensive input from utilities and their stakeholders. In February 2015, the Government released the Independent Review of the B.C. Utilities Commission Report. The report contains 35 recommendations to improve the governance, processes and performance of the Commission. In April 2015, the BCUC began consultations with utilities in connection with the recommendations concerning compliance and reporting and performance measures.

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 impacted financial performance in the year. Risks that impact non-financial organizational performance are discussed in the Risks and Opportunities section of this Annual Report.

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of 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 has a documented plan for the recovery of its regulatory accounts which it filed with the F15-F16 RRRA.

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 and cost of energy. Both revenues and cost of energy are influenced by several elements, which generally fall into the following four categories:

- Generation available from BC Hydro-dispatched hydro plants;
- Domestic demand for electricity;
- Energy market prices; and,
- Deliveries from EPA contracts.

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.

Generation Availability

The amount of generation available influences BC Hydro's financial results through both changing the amount of energy we have available to export (or need to import to meet domestic load) and through changing 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. The range of historic inflows is significant, with over 15,000 GWh (or approximately 25 per cent of current domestic demand) separating the wettest years from the driest in the most recent 40 years of data 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 IPP generating assets and by BC Hydro's operation of the system.

The financial forecast in the Service Plan assumes that inflows into BC Hydro-dispatched plants will be the average of the most recent 40 years of data in BC Hydro's records. The final system inflow energy for fiscal 2015 was 102 per cent of average, whereas the system inflow energy for fiscal 2014 was 95 per cent of average. In fiscal 2015, the timing of the inflows had a negative impact on net income before regulatory account transfers. In particular, at the beginning of October 2014, system storage was slightly below the long term average, due in part to below average (at that time, forecast to be 95 per cent of average) inflows in fiscal 2015. However, due to a wetter and warmer than average winter, inflows were materially above average and fiscal 2015 came in at 102 per cent or 3,500 GWh higher. Unfortunately, the expected value of this energy, which is now in storage, is less than what would have been achieved had BC Hydro known that inflows would be higher and therefore had more of the energy been sold during the higher-priced winter period. The previous Domestic Revenues and Domestic Energy Costs discussions contain more information on the impact on fiscal 2015 financial performance.

Domestic Demand For Energy

Electricity demand is generally increasing as B.C.'s population increases. However, this demand can be variable for large industrial customers due to variability in export markets and world commodity prices. Weather is a significant driver of residential load, with colder years resulting in higher demand for electrical heating. The timing and ultimate impact of demand side management programs is also difficult to predict and can cause variations between expected and actual load. Both the amount of electricity used by BC Hydro's customers and the time at which it is used influence the amount and timing of BC Hydro's market energy purchases and sales. To the extent there is a mismatch between the amount of available generation and domestic demand BC Hydro will be either a net importer or net exporter of energy in a given year. However, even in high inflow years, BC Hydro may need to make some purchases during periods of the year when generation availability is low because of either water management requirements or maintenance outages (generally late fall, winter, and early spring). Similarly, even in low water years, electricity sales may be advantageous during certain periods either to minimize spill from large reservoirs or to take advantage of market price fluctuations. The value of all of these transactions is subject to market price risk.

In fiscal 2015, wetter and warmer than average winter weather, as well as reduced industrial loads, resulted in winter (October 2014 to March 2015) loads that were about 1,800 GWh below forecast. The energy that would have gone to serving load will now be sold to the market, at prices that are between 10 and 50 per cent of what would have been received had it been sold to domestic customers. More information can be found in the discussion on Domestic Revenues.

Energy Market Prices

The cost of energy purchases, the value of trade energy sales and the trade opportunities available to Powerex all depend on a combination of system surplus or deficit energy, system flexibility and neighbouring market fundamentals. Both domestic loads and market prices in fiscal 2015 were materially lower than forecast in the Service Plan, resulting in a change from a net export to a small net import position.

Deliveries From EPA Contracts

Energy delivered under EPA 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 EPA contract energy changes BC Hydro's average cost of energy changes. BC Hydro's portfolio of EPA contracts includes a significant portion of hydro resources and the amount of generation under these contracts is driven by hydrology, which may vary significantly from year to year. In fiscal 2015, there was greater than forecast energy delivered from hydro IPPs due to high water inflows. However, the impact of high water flows was more than offset by lower than forecast deliveries for several IPPs due to delays in achieving their commercial operations date.

Finance Charges

Interest expense on borrowings is a significant component of Finance Charges. 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. 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. BC Hydro accepts this variability in return for the savings obtained from normally lower short term rates.

As of March 31, 2015, approximately 22 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. The majority of BC Hydro's USD denominated debt is hedged with long term foreign exchange derivative contracts and as a result is not a significant risk variable.

The actual fiscal 2015 financial results compared to the Service Plan can be found in the previous Comparison with Service Plan discussion.

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 2015 forecasted net income for fiscal 2016 at $653 million.

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, domestic sales load, market prices for electricity and natural gas, weather, temperatures, 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 2016 assumes average water inflows (100 per cent of average), domestic sales of 55,379 GWh, average market energy prices of US $32.22/MWh, short-term interest rates of 1.32 per cent and a US dollar exchange rate of US $0.8561.

EARNINGS SENSITIVITY

The following table shows the 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 2016. 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 2015
Hydro generation [1]	1,000 GWh	25	52,114 GWh	39,303 GWh	41,226 GWh
Electricity trade margins	+/-10%	15	n/a	n/a	n/a
Interest rates	+/- 100 basis points	50	1.30% [2]	1.10% [2]	1.22% [2]
Exchange rates (US/ CDN)	+/- $0.01	5	$1.01 [3]	$0.88 [3]	$0.88 [3]
Weather	1°C change in average temperature	25	1.6°C [4]	-0.7 °C [4]	1.6 °C [4]

[1] Assumes change in hydro generation is offset by corresponding change in energy imports (i.e. increase in hydro generation is offset by decrease in energy imports).

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

[3] Exchange rates are the annual daily average US Dollar noon rates.

[4] Weather high and low numbers represents the variance in degrees Celsius from the normal temperatures over the winter months November to March from 2010/11 to 2014/15. (-0.7 degrees lower than normal to 1.6 degrees higher than normal – normal is the 10 year rolling average).

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 3, 2015. 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 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 & Supply Chain and Chief Financial Officer

Vancouver, Canada
June 3, 2015

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, 2015, 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, 2015 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 Accountants
Vancouver, Canada
June 3, 2015

AUDITED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

for the years ended March 31 (in millions)	**2015**	2014
Revenues		
Domestic	**$ 4,829**	$ 4,319
Trade	**919**	1,073
	5,748	5,392
Expenses		
Operating expenses (Note 5)	**4,535**	4,245
Finance charges (Note 6)	**632**	598
Net Income	**581**	549
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)	**81**	37
Reclassification to income on derivatives designated as cash flow hedges (Note 19)	**(127)**	(70)
Foreign currency translation gains	**34**	16
Other Comprehensive Loss	**(12)**	(17)
Total Comprehensive Income	**$ 569**	$ 532

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

as at March 31 (in millions)	**2015**	2014
ASSETS		
Current Assets		
Cash and cash equivalents (Note 8)	**$ 39**	$ 107
Restricted cash (Notes 8 and 15)	**31**	355
Accounts receivable and accrued revenue (Note 9)	**596**	718
Inventories (Note 10)	**122**	114
Prepaid expenses	**211**	203
Current portion of derivative financial instrument assets (Note 19)	**152**	96
	1,151	1,593
Non-Current Assets		
Property, plant and equipment (Note 11)	**19,933**	18,525
Intangible assets (Note 12)	**547**	509
Regulatory assets (Note 13)	**5,714**	4,928
Derivative financial instrument assets (Note 19)	**97**	27
Other non-current assets (Note 14)	**311**	129
	26,602	24,118
	$ 27,753	$ 25,711
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Notes 15 and 20)	**$ 1,708**	$ 1,886
Current portion of long-term debt (Note 16)	**3,698**	4,087
Current portion of derivative financial instrument liabilities (Note 19)	**85**	76
	5,491	6,049
Non-Current Liabilities		
Long-term debt (Note 16)	**13,178**	11,610
Regulatory liabilities (Note 13)	**281**	229
Derivative financial instrument liabilities (Note 19)	**38**	55
Contributions in aid of construction	**1,583**	1,291
Post-employment benefits (Note 18)	**1,498**	1,173
Other non-current liabilities (Note 20)	**1,514**	1,439
	18,092	15,797
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**4,068**	3,751
Accumulated other comprehensive income	**42**	54
	4,170	3,865
	$ 27,753	$ 25,711

Commitments and Contingencies (Note 21)

See accompanying Notes to the Consolidated Financial Statements.

Approved on behalf of the Board:

Stephen Bellringer
Chair, Board of Directors

James Brown
Chair, Audit & Finance Committee

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized Gains/(Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income	Contributed Surplus	Retained Earnings	Total
Balance, April 1, 2013	$ 17	$ 54	$ 71	$ 60	$ 3,369	$ 3,500
Payment to the Province	-	-	-	-	(167)	(167)
Comprehensive Income (Loss)	16	(33)	(17)	-	549	532
Balance, March 31, 2014	33	21	54	60	3,751	3,865
Payment to the Province	-	-	-	-	(264)	(264)
Comprehensive Income (Loss)	34	(46)	(12)	-	581	569
Balance, March 31, 2015	$ 67	$ (25)	$ 42	$ 60	$ 4,068	$ 4,170

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

for the years ended March 31 (in millions)	**2015**	2014
Operating Activities		
Net income	**$ 581**	$ 549
Regulatory account transfers (Note 13)	**(1,225)**	(584)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 13)	**491**	319
Amortization and depreciation expense	**691**	643
Unrealized gains on mark-to-market	**(53)**	(39)
Employee benefit plan expenses	**84**	94
Interest accrual	**670**	640
Other items	**96**	54
	1,335	1,676
Changes in:		
Restricted cash	**324**	(285)
Accounts receivable, accrued revenue and prepaid expenses	**141**	(38)
Inventories	**1**	64
Accounts payable, accrued liabilities and other non-current liabilities	**(202)**	(95)
Contributions in aid of construction	**89**	113
	353	(241)
Interest paid	**(670)**	(647)
Cash provided by operating activities	**1,018**	788
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(1,928)**	(1,916)
Cash used in investing activities	**(1,928)**	(1,916)
Financing Activities		
Long-term debt:		
Issued	**1,565**	1,011
Retired	**(325)**	(706)
Receipt of revolving borrowings	**8,112**	8,409
Repayment of revolving borrowings	**(8,326)**	(7,224)
Payment to the Province (Note 17)	**(167)**	(215)
Settlement of hedging derivatives	**-**	(84)
Other items	**(17)**	(16)
Cash provided by financing activities	**842**	1,175
Increase (decrease) in cash and cash equivalents	**(68)**	47
Cash and cash equivalents, beginning of year	**107**	60
Cash and cash equivalents, end of year	**$ 39**	$ 107

See accompanying Notes to the Consolidated Financial Statements.

NOTE 1: REPORTING ENTITY

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown corporation of the 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 3, 2015.

(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

Except for the changes noted below, the Company has consistently applied the accounting policies set out in Note 4 to all periods presented in these consolidated financial statements.
Standards that have been adopted effective April 1, 2014 that have little or no impact on the consolidated financial statements include:

- Amendments to IFRS 10, *Consolidated Financial Statements*
- Amendments to IFRS 12, *Disclosure of Interests in Other Entities*
- Amendments to IAS 27, *Consolidated and Separate Financial Statements*
- Amendments to IAS 32, *Financial Instruments: Presentation*
- Amendments to IAS 36*, Impairment of Assets*
- Amendments to IAS 39, *Financial Instruments: Recognition and Measurement*
- IFRIC 21, *Levies*

Effective April 1, 2014, the Company elected to change its accounting policy for measurement of natural gas inventory held in storage for trading purposes from the lower of weighted average cost and net realizable value to fair value less costs to sell and included in Level 2 of the fair value hierarchy (Note 19: Financial Instruments – Fair Value Hierarchy). Changes in fair value are recognized in trade revenues. Management believes fair value less costs to sell provides a more relevant measure of performance in natural gas trading activities. The change in accounting policy has no material impact on initial adoption or in the comparative period.

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. Restricted cash also includes funds held in trust.

(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. 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
Held to maturity	US dollar sinking funds
Loans and receivables	Cash Restricted cash Accounts receivable and other receivables
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 these circumstances, the unrealized inception gain or loss is recognized in income only if the gain or loss on the instrument is evidenced by a quoted market price in an active market or if the valuation technique or model uses only observable market data as inputs. Where these criteria are not met, the unrealized inception gain or loss is deferred and amortized into income over the period until all data inputs become observable in the market, or, when data inputs are not expected to become observable in the future, over the full term of the underlying financial instrument. Additional information on deferred inception gains and losses is disclosed in Note 19, Financial Instruments.

(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 market-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) Deferred Revenue – Skagit River Agreement

Deferred 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 80-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.

(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, Commitments and Contingencies.

(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, 2015, 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 19, *Employee Benefits* (effective April 1, 2015)
- Amendments to IFRS 10, *Consolidated Financial Statements* (April 1, 2016)
- Amendments to IFRS 11, *Joint Arrangements* (April 1, 2016)
- Amendments to IFRS 12, *Disclosure of Interests in Other Entities* (April 1, 2016)
- Amendments to IAS 1, *Presentation of Financial Statements* (April 1, 2016)
- Amendments to IAS 16, *Property, Plant and Equipment* (April 1, 2016)
- Amendments to IAS 27, *Separate Financial Statements* (April 1, 2016)
- Amendments to IAS 28, *Investments in Associates and Joint Ventures* (April 1, 2016)
- Amendments to IAS 38, *Intangible Assets* (April 1, 2016)
- IFRS 15, *Revenue From Contracts With Customers* (April 1, 2017)
- IFRS 9, *Financial Instruments* (effective April 1, 2018)

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 2016 fiscal year will not have a material effect on the consolidated financial statements.

IFRS 14, *Regulatory Deferral Accounts*, effective for fiscal years beginning on or after January 1, 2016, has been issued; however, the Company currently does not intend to adopt IFRS 14 as it has adopted the Prescribed Standards, not IFRS, and accounts for its regulatory accounts in accordance with ASC 980.

NOTE 5: OPERATING EXPENSES

(in millions)		**2015**		2014
Electricity and gas purchases	**$**	**1,707**	$	1,607
Water rentals		**358**		361
Transmission charges		**138**		178
Personnel expenses		**534**		538
Materials and external services		**593**		579
Amortization and depreciation (Note 7)		**1,205**		995
Grants and taxes		**209**		203
Capitalized costs		**(224)**		(244)
Other costs, net of recoveries		**15**		28
	$	**4,535**	$	4,245

NOTE 6: FINANCE CHARGES

(in millions)		**2015**		2014
Interest on long-term debt	**$**	**685**	$	731
Interest on finance lease liabilities		**77**		46
Net interest expense on net defined benefit liability		**3**		14
Less: capitalized interest		**(69)**		(106)
Total finance costs		**696**		685
Other recoveries		**(64)**		(87)
	$	**632**	$	598

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 $89 million (2014 - $89 million). The effective capitalization rate used to determine the amount of borrowing costs eligible for capitalization was 4.1 per cent (2014 - 4.3 per cent).

NOTE 7: AMORTIZATION AND DEPRECIATION

(in millions)		**2015**		2014
Depreciation of property, plant and equipment	**$**	**626**	$	581
Amortization of intangible assets		**65**		62
Amortization of regulatory accounts		**514**		352
	$	**1,205**	$	995

NOTE 8: CASH AND CASH EQUIVALENTS AND RESTRICTED CASH

Cash and Cash Equivalents

(in millions)		**2015**		2014
Cash	**$**	**28**	$	74
Short-term investments		**11**		33
	$	**39**	$	107

Restricted Cash

(in millions)		**2015**		2014
Funds held in trust (Note 15)	**$**	**-**	$	302
Other		**31**		53
	$	**31**	$	355

NOTE 9: ACCOUNTS RECEIVABLE AND ACCRUED REVENUE

(in millions)		**2015**		2014
Accounts receivable	**$**	**411**	$	512
Accrued revenue		**89**		92
Other		**96**		114
	$	**596**	$	718

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

NOTE 10: INVENTORIES

(in millions)		**2015**		2014
Materials and supplies	**$**	**110**	$	111
Natural gas in storage		**12**		3
	$	**122**	$	114

There were no materials and supplies inventory impairments during the years ended March 31, 2015 and 2014. 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 $69 million (2014 - $106 million).

NOTE 11: PROPERTY, PLANT AND EQUIPMENT

(in millions)	Generation	Transmission	Distribution	Land & Builidings	Equipment & Other	Unfinished Construction	Total
Cost							
Balance at March 31, 2013	$ 6,251	$ 4,103	$ 4,743	$ 441	$ 577	$ 2,269	$ 18,384
Net additions	269	462	338	65	96	681	1,911
Disposals and retirements	(4)	(13)	(24)	(2)	(12)	(10)	(65)
Balance at March 31, 2014	6,516	4,552	5,057	504	661	2,940	20,230
Net additions	479	1,096	349	77	85	(9)	2,077
Disposals and retirements	(6)	(8)	(28)	(3)	(11)	(26)	(82)
Balance at March 31, 2015	$ 6,989	$ 5,640	$ 5,378	$ 578	$ 735	$ 2,905	$ 22,225
Accumulated Depreciation							
Balance at March 31, 2013	$ (459)	$ (270)	$ (283)	$ (33)	$ (113)	$ -	$ (1,158)
Depreciation expense	(188)	(146)	(156)	(18)	(62)	-	(570)
Disposals and retirements	2	5	6	-	10	-	23
Balance at March 31, 2014	(645)	(411)	(433)	(51)	(165)	-	(1,705)
Depreciation expense	(198)	(161)	(165)	(24)	(64)	-	(612)
Disposals and retirements	3	6	6	1	9	-	25
Balance at March 31, 2015	$ (840)	$ (566)	$ (592)	$ (74)	$ (220)	$ -	$ (2,292)
Net carrying amounts							
At March 31, 2014	$ 5,871	$ 4,141	$ 4,624	$ 453	$ 496	$ 2,940	$ 18,525
At March 31, 2015	$ 6,149	$ 5,074	$ 4,786	$ 504	$ 515	$ 2,905	$ 19,933

(i) As at March 31, 2015, the Company has included its one-third interest in Waneta with a net book value of $735 million (2014 - $755 million) in Generation assets. Depreciation expense on the Waneta asset for the year ended March 31, 2015 was $20 million (2014 - $22 million).

(ii) Included within Distribution assets are the Company’s portion of utility poles with a net book value of $842 million (2014 - $781 million) that are jointly owned with a third party. Depreciation expense on jointly owned utility poles for the year ended March 31, 2015 was $21 million (2014 - $20 million).

(iii) The Company received government grants 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, during fiscal 2014, the Company received government grants of $94 million 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 2015.

(iv) The Company has contractual commitments to spend $1,184 million on major property, plant and equipment projects (individual projects greater than $50 million) as at March 31, 2015.

Leased assets

Property, plant and equipment under finance leases of $388 million (2014 - $388 million), net of accumulated amortization of $173 million (2014 - $159 million), are included in the total amount of property, plant and equipment above.

NOTE 12: INTANGIBLE ASSETS

(in millions)	Land Rights	Internally Developed Software	Purchased Software	Other	Work in Progress	Total
Cost						
Balance at March 31, 2013	$ 182	$ 48	$ 280	$ 11	$ 27	$ 548
Net additions	1	37	68	8	19	133
Retirements	-	-	(14)	-	-	(14)
Balance at March 31, 2014	183	85	334	19	46	667
Net additions	15	34	32	21	17	119
Disposals and retirements	-	-	-	(9)	(4)	(13)
Balance at March 31, 2015	$ 198	$ 119	$ 366	$ 31	$ 59	$ 773
Accumulated Amortization						
Balance at March 31, 2013	$ -	$ (9)	$ (96)	$ (5)	$ -	$ (110)
Amortization expense	-	(12)	(47)	(3)	-	(62)
Retirements	-	-	14	-	-	14
Balance at March 31, 2014	-	(21)	(129)	(8)	-	(158)
Amortization expense	-	(17)	(48)	(3)	-	(68)
Disposals and retirements	-	-	-	-	-	-
Balance at March 31, 2015	$ -	$ (38)	$ (177)	$ (11)	$ -	$ (226)
Net carrying amounts						
At March 31, 2014	$ 183	$ 64	$ 205	$ 11	$ 46	$ 509
At March 31, 2015	$ 198	$ 81	$ 189	$ 20	$ 59	$ 547

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 following regulatory assets and liabilities have been established through rate regulation. In the absence of rate regulation, these amounts would be reflected in comprehensive income unless the Company sought recovery through rates in the year in which they are incurred. For the year ended March 31, 2015, the impact of regulatory accounting has resulted in a net increase to total comprehensive income of $734 million (2014 - $265 million) which is comprised of an increase to net income of $470 million (2014 - $557 million) and an increase to other comprehensive income of $264 million (2014 – $292 million decrease). For each regulatory account, the amount reflected in the Net Change column in the following regulatory tables represents the impact on comprehensive income for the applicable year, 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 comprehensive income.

(in millions)	*April 1 2014*	*Addition (Reduction)*	*Amortization*	*Net Change*	*March 31 2015*
Regulatory Assets					
Heritage Deferral Account	$ 105	$ 86	$ (26)	$ 60	$ 165
Non-Heritage Deferral Account	362	253	(91)	162	524
Trade Income Deferral Account	324	1	(81)	(80)	244
Demand-Side Management Programs	788	125	(71)	54	842
First Nations Costs & First Nations Provisions	589	19	(44)	(25)	564
Non-Current Pension Cost	280	317	(33)	284	564
Site C	338	81	-	81	419
CIA Amortization	81	6	-	6	87
Environmental Provisions & Costs	383	72	(73)	(1)	382
Smart Metering and Infrastructure (SMI)	277	37	(31)	6	283
IFRS Pension & Other Post-Employment Benefits	688	-	(38)	(38)	650
IFRS Property, Plant and Equipment	617	157	(16)	141	758
Rate Smoothing Account	-	166	-	166	166
Other Regulatory Accounts	96	16	(46)	(30)	66
Total Regulatory Assets	4,928	1,336	(550)	786	5,714
Regulatory Liabilities					
Future Removal and Site Restoration Costs	56	-	(23)	(23)	33
Foreign Exchange Gains and Losses	89	(18)	-	(18)	71
Finance Charges	79	120	(26)	94	173
Other Regulatory Accounts	5	9	(10)	(1)	4
Total Regulatory Liabilities	229	111	(59)	52	281
Net Regulatory Asset	$ 4,699	$ 1,225	$ (491)	$ 734	$ 5,433

(in millions)	*April 1 2013*	*Addition (Reduction)*	*Amortization*	*Net change*	*March 31 2014*
Regulatory Assets					
Heritage Deferral Account	$ 70	$ 53	$ (18)	$ 35	$ 105
Non-Heritage Deferral Account	467	15	(120)	(105)	362
Trade Income Deferral Account	190	183	(49)	134	324
Demand-Side Management Programs	733	118	(63)	55	788
First Nations Costs & First Nations Provisions	553	42	(6)	36	589
Non-Current Pension Cost	544	(247)	(17)	(264)	280
Site C	258	80	-	80	338
CIA Amortization Variance	75	6	-	6	81
Environmental Provisions & Costs	367	24	(8)	16	383
Smart Metering and Infrastructure	192	85	-	85	277
Finance Charges	1	(1)	-	(1)	-
IFRS Pension & Other Post-Employment Benefits	723	-	(35)	(35)	688
IFRS Property, Plant and Equipment	447	179	(9)	170	617
Other Regulatory Accounts	121	2	(27)	(25)	96
Total Regulatory Assets	4,741	539	(352)	187	4,928
Regulatory Liabilities					
Future Removal and Site Restoration Costs	88	-	(32)	(32)	56
Rate Smoothing	111	(111)	-	(111)	-
Foreign Exchange Gains and Losses	100	(10)	(1)	(11)	89
Finance Charges	-	79	-	79	79
Other Regulatory Accounts	8	(3)	-	(3)	5
Total Regulatory Liabilities	307	(45)	(33)	(78)	229
Net Regulatory Asset	$ 4,434	$ 584	$ (319)	$ 265	$ 4,699

RATE REGULATION

On March 6, 2014 the Province issued Directions No. 6 and 7 to the BCUC that, among other things, requires the Company to amortize specific amounts prescribed for a majority of BC Hydro's regulatory accounts, in each of fiscal 2015 and fiscal 2016.

HERITAGE DEFERRAL ACCOUNT (HDA)

Under a Special Direction issued by the Province, the BCUC was directed to authorize the Company to establish the HDA. This account is intended to mitigate the impact of certain variances between the forecasted costs in a revenue requirements application and actual costs of service associated with the Company's hydroelectric and thermal generating facilities by adjustment of net income. These deferred variances are recovered in rates through the rate rider.

NON-HERITAGE DEFERRAL ACCOUNT (NHDA)

Under a Special Direction issued by the Province, the BCUC approved the establishment of the NHDA, which is intended to mitigate the impact of certain cost variances between the forecasted costs in a revenue requirements application and actual costs related to energy acquisition and maintenance of the Company's distribution assets by adjustment of net income. These deferred variances are recovered in rates through the rate rider.

As part of the 10 year rate plan, the Province announced the permanent closure of the Burrard Thermal generating station by 2016, except for its transmission support role. Certain costs incurred by the Company in fiscal 2014 and later years arising from the decommissioning of the parts of Burrard Thermal Generating Station that are not required for transmission support services are to be deferred to the NHDA pursuant to Direction No. 7.

TRADE INCOME DEFERRAL ACCOUNT

Established under a Special Directive issued by the Province, 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 the revenue requirements application and actual Trade Income. These deferred variances are recovered in rates through the rate rider.

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. The difference between the Trade Income forecast and actual Trade Income is deferred except for amounts arising from a net loss in Trade Income.

In March 2014, the Province issued Direction No. 7 to the BCUC which contained a provision that requires the BCUC to remove the "floor" of $nil in the definition of Trade income for fiscal 2014 only. As a result, Powerex's net loss for fiscal 2014 was deferred to the TIDA. For fiscal 2015 and future years, the floor was reinstated.

DEMAND-SIDE MANAGEMENT ACTIVITIES (DSM)

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

FIRST NATIONS COSTS & FIRST NATIONS PROVISIONS REGULATORY ACCOUNTS

The First Nations Costs 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. Annual settlement costs paid pursuant to these settlements are transferred to the First Nations Costs regulatory account. In addition, annual negotiation costs and current year interest costs are deferred to the First Nations Costs regulatory account.

Also, pursuant to the Company's F2015-F2016 Revenue Requirements Rate Application, lump sum settlement payments are to be amortized over 10 years and, in fiscal 2015 and fiscal 2016, annual negotiation costs, annual settlement payments, and current year interest will be expensed from the First Nations Costs regulatory account in the year incurred.

NON-CURRENT PENSION COST

Variances that arise between forecast and actual non-current pension and other post employment benefit costs are deferred. In the absence of rate regulation and the application of ASC 980, these cost variances would be included in operating results. In addition, actuarial gains and losses related to post employment benefit plans are also deferred. In the absence of rate regulation, these actuarial gains and losses would be included in other comprehensive income in the year in which they are incurred. The account is amortized over the average remaining service life of the employee group.

SITE C

Site C expenditures incurred in fiscal 2007 through the third quarter of fiscal 2015 have been deferred. In December 2014, the Site C project was approved by the Provincial Government, resulting in expenditures being capitalized in property, plant and equipment starting in the fourth quarter of fiscal 2015.

CONTRIBUTIONS IN AID OF CONSTRUCTION (CIA) AMORTIZATION VARIANCE

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 AND 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. The regulatory asset for PCB remediation is amortized based on actual expenditures incurred during the year.

Balances related to non-PCB environmental regulatory provisions are not amortized – amounts are transferred to environmental cost regulatory assets based on actual expenditures incurred attributable to the provision. Environmental cost regulatory assets are amortized over the term covered by the

Company's next revenue requirements filing.

SMART METERING AND INFRASTRUCTURE (SMI)

Net operating costs incurred by the Company with respect to the SMI program are being deferred. Costs relating to identifiable tangible and intangible assets that meet the capitalization criteria are being recorded as property, plant and equipment or intangible assets respectively. The SMI net operating costs incurred prior to fiscal 2015, amortization of capital assets, and finance charges have been deferred and commenced amortization, based on the fiscal 2014 ending balance, over 15 years starting in fiscal 2015. Furthermore, per Direction 6, net operating costs incurred in fiscal 2015 and fiscal 2016 are being deferred. The Company will seek approval to recover these costs commencing in fiscal 2017. Pursuant to Direction 7 to the BCUC, the BCUC may not disallow recovery in rates of the costs deferred to the SMI regulatory account.

IFRS PENSION & OTHER POST-EMPLOYMENT BENEFITS

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

As part of the 10 year rate plan, the Rate Smoothing regulatory account was established with the objective of smoothing rate increases so that there is less volatility from year to year. It functions in a fashion similar to the F2012-F2014 Rate Smoothing Account, which was fully amortized at the end of fiscal 2014. The account balance will be fully amortized by the end of the 10 year rate plan.

FUTURE REMOVAL AND SITE RESTORATION COSTS

This account was established by a one-time transfer of $251 million from retained earnings for liabilities previously recorded in excess of amounts required as decommissioning obligations. The costs of dismantling and disposal of property, plant and equipment may be applied to this regulatory liability if they do not otherwise relate to an asset retirement obligation. This account is estimated to be depleted by the end of fiscal 2016.

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.

FINANCE CHARGES

This account is intended to mitigate the impact of certain variances that arise between the forecasted costs in a revenue requirements application and actual finance charges incurred. Variances incurred during the current test period are recovered over the next test period. A test period refers to the period covered by a revenue requirements application filing (the current test period is fiscal 2015 and fiscal 2016).

OTHER REGULATORY ACCOUNTS

Other regulatory asset and liability accounts with individual balances less than $30 million include the following: Arrow Water Systems, Capital Project Investigation Costs, Home Purchase Option Plan, Asbestos Remediation, Storm Damage, Real Property Sales and Amortization of Capital Additions.

In fiscal 2015, the Real Property Sales regulatory account was established pursuant to Direction 7. Per Direction 6, the BCUC was required to approve a forecast of $10 million of real property net gains in fiscal 2015 and fiscal 2016. Per Direction 7, variances between the Company's actual real property gain/loss and the $10 million forecast each year, are deferred to the Real Property Sales regulatory account.

NOTE 14: OTHER NON-CURRENT ASSETS

(in millions)		**2015**		2014
Sinking funds	**$**	**155**	$	129
Non-current receivable		**156**		-
	$	**311**	$	129

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)	**2015**		2014	
	Carrying Value	**Weighted Average**	Carrying Value	Weighted Average
Province of BC bonds	**$ 100**	**3.0 %**	$ 85	3.9 %
Other provincial government and crown corporation bonds	**55**	**3.1 %**	44	4.0 %
	$ 155		$ 129	

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

Effective December 2005, all sinking fund payment requirements on all new and outstanding debt were removed.

Non-Current Receivable

In July 2014, the Company recorded a receivable, at fair value, of $162 million ($10 million included in accounts receivable and accrued revenue and $152 million in other non-current assets) for contributions in aid of the construction of the Northwest Transmission Line. The contributions will be received in 19 annual payments of approximately $10 million, adjusted for inflation. The fair value of the receivable was measured using an estimated inflation rate and 4.6 per cent discount rate.

NOTE 15: ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in millions)		**2015**		2014
Accounts payable	**$**	**294**	$	386
Accrued liabilities		**945**		819
Legal settlement		**-**		302
Current portion of other long-term liabilities (Note 20)		**129**		120
Dividend payable (Note 17)		**264**		167
Other		**76**		92
	$	**1,708**	$	1,886

Legal Settlement

On October 4, 2013, the Federal Energy Regulatory Commission (FERC) issued an Order approving the settlement between Powerex and Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, the California Attorney General, and the California Public Utilities Commission (the California Parties) arising from events and transactions in the California power market during the 2000 and 2001 period.

As part of the settlement, Powerex made a net cash payment of US$273 million into escrow in fiscal 2014 which translated to CDN$302 million as at March 31, 2014. Notice of the Settlement Effective Date of July 11, 2014 was filed by the parties at FERC and the cash was released from escrow on July 25, 2014.

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 $4.5 billion, and is included in revolving borrowings. At March 31, 2015, the outstanding amount under the borrowing program was $3,547 million (2014 - $3,762 million).

During fiscal 2015, the Company issued bonds with a par value of $1,665 million (2014 – $1,150 million) a weighted average effective interest rate of 3.4 per cent (2014 – 3.9 per cent) and a weighted average term to maturity of 26.4 years (2014 – 29.9 years).

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

($ amounts in millions of Canadian dollars)	**2015**				2014			
	Canadian	**US**	**Total**	**Weighted Average Interest Rate**[1]	Canadian	US	Total	Weighted Average Interest Rate[1]
Maturing in fiscal:								
2015	**$ -**	**$ -**	**$ -**	**-**	$ 325	$ -	$ 325	5.5
2016	**150**	**-**	**150**	**5.2**	150	-	150	5.2
2017	**-**	**-**	**-**	**-**	-	-	-	-
2018	**40**	**-**	**40**	**4.8**	40	-	40	4.8
2019	**1,030**	**254**	**1,284**	**4.6**	1,030	221	1,251	4.6
2020	**175**	**-**	**175**	**5.3**	-	-	-	-
1-5 years	**1,395**	**254**	**1,649**	**4.7**	1,545	221	1,766	4.8
6-10 years	**2,336**	**-**	**2,336**	**7.3**	2,500	-	2,500	7.2
11-15 years	**800**	**634**	**1,434**	**5.2**	10	553	563	6.6
16-20 years	**1,110**	**-**	**1,110**	**5.0**	1,610	-	1,610	5.0
21-25 years	**-**	**380**	**380**	**7.4**	-	332	332	7.4
26-30 years	**5,838**	**-**	**5,838**	**4.1**	3,273	-	3,273	4.3
Over 30 years	**530**	**-**	**530**	**4.4**	1,730	-	1,730	4.0
Bonds	**12,009**	**1,268**	**13,277**	**5.0**	10,668	1,106	11,774	5.2
Revolving borrowings	**2,623**	**924**	**3,547**	**0.7**	3,504	258	3,762	1.0
	14,632	**2,192**	**16,824**		14,172	1,364	15,536	
Adjustments to carrying value resulting from hedge accounting	**27**	**25**	**52**		31	22	53	
Unamortized premium, discount, and issue costs	**13**	**(13)**	**-**		120	(12)	108	
	$ 14,672	**$ 2,204**	**$ 16,876**		$ 14,323	$ 1,374	$ 15,697	
Less: Current portion	**(2,774)**	**(924)**	**(3,698)**		(3,829)	(258)	(4,087)	
Long-term debt	**$ 11,898**	**$ 1,280**	**$ 13,178**		$ 10,494	$ 1,116	$ 11,610	

[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, 2015 in an asset position of $76 million (2014 – liability of $31 million). Such contracts are primarily used to hedge U.S. dollar long-term debt principal and U.S. commercial paper borrowings.

($ amounts in millions)	**2015**	2014
Foreign Currency Forwards		
United States dollar to Canadian dollar - notional amount[1]	**US$ 1,542**	US$ 1,091
United States dollar to Canadian dollar - weighted average contract rate	**1.22**	1.17
Weighted remaining term	**6 years**	10 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 and a limit on the Payment to the Province if it would cause the debt to equity ratio to exceed 80:20.

The Company monitors its capital structure on the basis of its debt to equity ratio. 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.

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

The debt to equity ratio at March 31, 2015, and March 31, 2014 was as follows:

(in millions)	**2015**	2014
Total debt, net of sinking funds	**$ 16,721**	$ 15,568
Less: Cash and cash equivalents	**(39)**	(107)
Net Debt	**$ 16,682**	$ 15,461
Retained earnings	**$ 4,068**	$ 3,751
Contributed surplus	**60**	60
Accumulated other comprehensive income	**42**	54
Total Equity	**$ 4,170**	$ 3,865
Net Debt to Equity Ratio	**80 : 20**	80 : 20

Payment to 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 Province, 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 Payment accrued at March 31, 2015 is $264 million (March 31, 2014 - $167 million), which is included in accounts payable and accrued liabilities and is less than 85 per cent of the net income due to the 80:20 cap.

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 basic and indexing contributions to the plan funds based on a percentage of current pensionable earnings. The Company contributes 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, 2012. The next scheduled funding valuation is as at December 31, 2015.

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, 2015 and 2014 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**	
(in millions)	**2015**	2014	**2015**	2014
Current service costs charged to personnel operating costs	**$ 77**	$ 80	**$ 13**	$ 14
Net interest costs charged to finance costs	**38**	44	**17**	15
Total post-employment benefit plan expense	**$ 115**	$ 124	**$ 30**	$ 29

Actual return on defined benefit plan assets for the year ended March 31, 2015 was $382 million (2014 - $388 million).

Actuarial gains and losses recognized in other comprehensive income are nil (2014 – nil). As per Note 13, in accordance with Prescribed Standards and as approved by the BCUC, actuarial gains and losses, as summarized in Note 18(c) below, are deferred to the Non-Current Pension Cost regulatory account.

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

(in millions)	Pension Benefits Plans **2015**	Pension Benefits Plans 2014	Other Benefits Plans **2015**	Other Benefits Plans 2014
Defined benefit obligation of funded plans	**$ (4,202)**	$ (3,648)	**$ -**	$ -
Defined benefit obligation of unfunded plans	**(155)**	(136)	**(432)**	(374)
Fair value of plan assets	**3,291**	2,985	**-**	-
Plan deficit	**$ (1,066)**	$ (799)	**$ (432)**	$ (374)

The Company determined that there was no minimum funding requirement adjustment required in fiscal 2015 and fiscal 2014 in accordance with IFRIC 14, The Limit on Defined Benefit Asset, Minimum Funding Requirements and Their Interaction.

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

(in millions)	Pension Benefit Plans **2015**	Pension Benefit Plans 2014	Other Benefit Plans **2015**	Other Benefit Plans 2014
Defined benefit obligation				
Opening defined benefit obligation	**$ 3,784**	$ 3,702	**$ 374**	$ 361
Current service cost	**77**	80	**13**	14
Interest cost on benefit obligations	**230**	218	**17**	15
Benefits paid[1]	**(175)**	(169)	**(12)**	(12)
Employee contributions	**27**	28	**-**	-
Actuarial (gains) losses[2]	**414**	(75)	**40**	(4)
Defined benefit obligation, end of year	**4,357**	3,784	**432**	374
Fair value of plan assets				
Opening fair value	**2,985**	2,667	n/a	n/a
Interest income on plan assets	**192**	174	n/a	n/a
Employer contributions	**66**	65	n/a	n/a
Employee contributions	**27**	28	n/a	n/a
Benefits paid[1]	**(169)**	(163)	n/a	n/a
Actuarial gains[2]	**190**	214	n/a	n/a
Fair value of plan assets, end of year	**3,291**	2,985	-	-
Accrued benefit liability	**$ (1,066)**	$ (799)	**$ (432)**	$ (374)

[1] *Benefits paid under Pension Benefit Plans include $20 million (2014 - $16 million) of settlement payments.*

[2] *Actuarial gains/losses are included in the Non-Current Pension Cost regulatory account and for fiscal 2015 are comprised of experience gains on return of plan assets of $190 million, and changes in discount rate and experience losses on the benefit obligations of $454 million.*

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

	Pension Benefit Plans		Other Benefit Plans	
	2015	2014	**2015**	2014
Discount rate				
Benefit cost	**4.37%**	4.00%	**4.59%**	4.20%
Accrued benefit obligation	**3.51%**	4.37%	**3.79%**	4.59%
Expected long term rate of return on plan assets	**4.37%**	4.00%	**n/a**	n/a
Rate of compensation increase				
Benefit cost	**3.35%**	3.35%	**n/a**	n/a
Accrued benefit obligation	**3.35%**	3.35%	**n/a**	n/a
Health care cost trend rates				
Weighted average health care cost trend rate	**n/a**	n/a	**5.47%**	5.79%
Weighted average ultimate health care cost trend rate	**n/a**	n/a	**4.39%**	4.42%
Year ultimate health care cost trend rate will be achieved	**n/a**	n/a	**2026**	2027

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**	**2015**	2014
Equities	58%	41%	77%	**62%**	64%
Fixed interest investment	29%	19%	39%	**28%**	27%
Real estate	10%	5%	15%	**9%**	9%
Infrastructure	3%	0%	10%	**1%**	0%

Plan assets are re-balanced within ranges around target applications. The 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 contributions to be paid to its funded defined benefit plan in fiscal 2016 is expected to amount to $62 million. The expected benefit payments to be paid in fiscal 2016 in respect to the unfunded defined benefit plan is $19 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 2015	One percentage point decrease 2015
Effect on current service costs	$ 3	$ (2)
Effect on defined benefit obligation	51	(41)

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

		2015	
($ in millions)	Increase/ decrease in assumption	Effect on accrued benefit obligation	Effect on current service costs
Discount rate	1%	$ +/- 531	$ +/- 21
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 period.

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 2015 Annual 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 $155 million. The maximum credit risk exposure for these U.S. dollar sinking funds as at March 31, 2015 is its fair value of $184 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 (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. 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. 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 U.S. dollar 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.

(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 a variety of 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 table are prior to the application of regulatory accounting for the years ended March 31, 2015 and 2014.

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at March 31, 2015 and 2014. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

(in millions)	**2015 Carrying Value**	**2015 Fair Value**	2014 Carrying Value	2014 Fair Value	**Interest Income (Expense) recognized in Finance Charges 2015**	Interest Income (Expense) recognized in Finance Charges 2014
Financial Assets and Liabilities at Fair Value Through Profit or Loss						
Short-term investments	**$ 11**	**$ 11**	$ 33	$ 33	**$ 1**	$ 2
Loans and Receivables:						
Accounts receivable and accrued revenue	**596**	**596**	718	718	-	-
Non-current receivable (long-term portion)	**156**	**162**	-	-	**5**	-
Restricted cash	**31**	**31**	355	355	-	-
Cash	**28**	**28**	74	74	-	-
Held to Maturity						
Sinking funds – US	**155**	**184**	129	143	**7**	6
Other Financial Liabilities:						
Accounts payable and accrued liabilities	**(1,708)**	**(1,708)**	(1,886)	(1,886)	-	-
Revolving borrowings - CAD	**(2,623)**	**(2,623)**	(3,504)	(3,504)	**(33)**	(24)
Revolving borrowings - US	**(924)**	**(924)**	(258)	(258)	-	(1)
Long-term debt (including current portion due in one year)	**(13,329)**	**(16,799)**	(11,935)	(13,405)	**(638)**	(614)
First Nations liability (long-term portion)	**(391)**	**(758)**	(385)	(725)	**(9)**	(21)
Finance lease obligation (long-term portion)	**(240)**	**(240)**	(259)	(259)	**(23)**	(24)
Other liabilities	**(81)**	**(86)**	(28)	(28)	-	-

For non-derivative financial assets and liabilities classified as financial assets and liabilities at fair value through profit or loss, $nil (2014 - $12 million gain) has been recognized in net income for the year relating to changes in fair value. For short-term investments, loans and receivables, and accounts payable and accrued liabilities, the carrying value 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)	**2015 Fair Value**	2014 Fair Value
Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ 45**	$ (36)
Non-Designated Derivative Instruments:		
Foreign currency contracts	**31**	5
Commodity derivatives	**50**	23
	81	28
Net asset (liability)	**$ 126**	$ (8)

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)	**2015**	2014
Current portion of derivative financial instrument assets	**$ 152**	$ 96
Current portion of derivative financial instrument liabilities	**(85)**	(76)
Derivative financial instrument assets, long-term	**97**	27
Derivative financial instrument liabilities, long-term	**(38)**	(55)
Net asset (liability)	**$ 126**	$ (8)

For designated cash flow hedges for the year ended March 31, 2015, a gain of $81 million (2014 - $37 million gain) was recognized in other comprehensive income. For the year ended March 31, 2015, $127 million (2014 - $70 million) was removed from other comprehensive income and reported in net income, offsetting foreign exchange losses (2014 – losses) recorded in the year.

For derivative instruments not designated as hedges, a gain of $8 million (2014 - $2 million gain) was recognized in finance charges for the year ended March 31, 2015 with respect to foreign currency contracts for cash management purposes. For the year ended March 31, 2015, a gain of $22 million (2014 - $63 million gain) was recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $24 million of foreign exchange revaluation losses (2014 - $69 million loss) recorded with respect to U.S. short-term borrowings for the year ended March 31, 2015. A net gain of $43 million (2014 - $9 million gain) was recorded in trade revenue for the year ended March 31, 2015 with respect to commodity derivatives.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)		**2015**		2014
Deferred inception loss, beginning of the year	**$**	**50**	$	58
New transactions		**22**		(1)
Amortization		**(2)**		(7)
Deferred inception loss, end of the year	**$**	**70**	$	50

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 center 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)		**2015**		2014
Current	**$**	**381**	$	472
Past due (30-59 days)		**26**		32
Past due (60-89 days)		**6**		9
Past due (More than 90 days)		**6**		7
		419		520
Allowance for doubtful accounts		**(8)**		(8)
Total	**$**	**411**	$	512

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 legal 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 that are subject to the above agreements:

As at March 31, 2015	Gross Derivative Instruments Presented in Statement of Financial Position	Related Instruments That Are Not Offset	Net Amount
Derivative commodity assets	$ 165	1	$ 164
Derivative commodity liabilities	115	1	114

As at March 31, 2014	Gross Derivative Instruments Presented in Statement of Financial Position	Related Instruments That Are Not Offset	Net Amount
Derivative commodity assets	$ 99	2	$ 97
Derivative commodity liabilities	76	2	74

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

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

As at March 31, 2015	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	86	1	13	100
Assets from trading activities	100	0	0	100

As at March 31, 2014	Investment Grade %	Unrated %	Non-Investment Grade %	Total %
Accounts receivable	88	1	11	100
Assets from trading activities	100	0	0	100

The outstanding amount of collateral received from customers at March 31, 2015 was $nil (2014 - $7 million).

LIQUIDITY RISK

The following table details the remaining contractual maturities at March 31, 2015 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, 2015. In respect of the cash flows in U.S. dollars, the exchange rate as at March 31, 2015 has been used.

(in millions)	Carrying Value	Fiscal 2016	Fiscal 2017	Fiscal 2018	Fiscal 2019	Fiscal 2020	Fiscal 2021 *and thereafter*
Non-Derivative Financial Liabilities							
Total accounts payable and other payables (excluding interest accruals and current portion of lease obligations and other long-term liabilities)	$ 1,497	$ (1,497)	$ -	$ -	$ -	$ -	$ -
Long-term debt (including interest payments)	17,045	(4,376)	(663)	(702)	(1,934)	(771)	(19,558)
Lease obligations	259	(83)	(86)	(88)	(42)	(43)	(827)
Other long-term liabilities	495	(13)	(16)	(12)	(20)	(25)	(1,226)
Total Non-Derivative Financial Liabilities		(5,969)	(765)	(802)	(1,996)	(839)	(21,611)
Derivative Financial Liabilities							
Forward foreign exchange contracts used for hedging	8						
Cash outflow		-	-	-	-	-	(337)
Cash inflow		-	-	-	-	-	330
Financially settled commodity derivative liabilities designated at fair value	98	(72)	(22)	(6)	(1)	-	-
Physically settled commodity derivative liabilities designated at fair value	17	(36)	10	-	-	-	-
Total Derivative Financial Liabilities	123	(108)	(12)	(6)	(1)	-	(7)
Total Financial Liabilities		(6,077)	(777)	(808)	(1,997)	(839)	(21,618)
Derivative Financial Assets							
Forward foreign exchange contracts used for hedging	(53)						
Cash outflow		-	-	-	(204)	-	(382)
Cash inflow		-	-	-	254	-	397
Other forward foreign exchange contracts designated at fair value	(31)						
Cash outflow		(946)	-	-	-	-	-
Cash inflow		976	-	-	-	-	-
Financially settled commodity derivative liabilities designated at fair value	(110)	83	11	3	1	-	-
Physically settled commodity derivative liabilities designated at fair value	(55)	94	42	22	8	4	-
Total Derivative Financial Assets	(249)	207	53	25	59	4	15
Net Financial Liabilities[1]		**$ (5,870)**	**$ (724)**	**$ (783)**	**$(1,938)**	**$ (835)**	**$ (21,603)**

[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.*

MARKET RISKS

(a) Currency Risk

Sensitivity Analysis
A $0.01 strengthening (weakening) of the U.S. dollar against the Canadian dollar at March 31, 2015 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 and would have an immaterial impact on other comprehensive income. The 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, 2015 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, 2015 would have a negative (positive) impact on net income of $40 million but as a result of regulatory accounting would have no impact on net income and would have an immaterial impact on other comprehensive income. The 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.

This sensitivity analysis has been determined assuming that the change in interest rates had occurred at March 31, 2015 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 commodity prices for commodities Powerex trades, including electricity, natural gas and associated derivative products. Prices for these 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 the 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 $5 million at March 31, 2015 (2014 - $9 million).

Fair Value Hierarchy

The following provides an analysis of financial instruments that are measured subsequent to initial recognition at fair value, grouped based on the lowest level of input that is significant to that fair value measurement.

The inputs used in determining fair value are characterized by using a hierarchy that prioritizes inputs based on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 - values are quoted prices (unadjusted) in active markets for identical assets and liabilities.
- Level 2 - inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, as of the reporting date.
- Level 3 - inputs are those that are not based on observable market data.

The following tables present the financial instruments measured at fair value for each hierarchy level as at March 31, 2015 and 2014:

As at March 31, 2015 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 11	$ -	$ -	$ 11
Derivatives designated as hedges	-	53	-	53
Derivatives not designated as hedges	72	77	47	196
Total financial assets carried at fair value	$ 83	$ 130	$ 47	$ 260
Derivatives designated as hedges	$ -	$ (8)	$ -	$ (8)
Derivatives not designated as hedges	(76)	(31)	(8)	(115)
Total financial liabilities carried at fair value	$ (76)	$ (39)	$ (8)	$ (123)

As at March 31, 2014 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 33	$ -	$ -	$ 33
Derivatives designated as hedges	-	18	-	18
Derivatives not designated as hedges	21	35	49	105
Total financial assets carried at fair value	$ 54	$ 53	$ 49	$ 156
Derivatives designated as hedges	$ -	$ (54)	$ -	$ (54)
Derivatives not designated as hedges	(22)	(49)	(6)	(77)
Total financial liabilities carried at fair value	$ (22)	$ (103)	$ (6)	$ (131)

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 Levels 1 and 2 during the period.

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.

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, 2015 and 2014:

(in millions)		
Balance at March 31, 2013	**$**	**34**
Cumulative impact of net gain recognized		9
New transactions		3
Existing transactions settled		(3)
Balance at March 31, 2014		**43**
Cumulative impact of net gain recognized		38
New transactions		(3)
Existing transactions settled		(39)
Balance at March 31, 2015	**$**	**39**

Level 3 fair values for energy derivatives are determined using inputs that are not observable. 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.

During the year, unrealized gains of $42 million (2014 - $29 million gain) were recognized on Level 3 derivative commodity assets still on hand at year end. During the year, unrealized losses of $8 million (2014 - $14 million loss) were recognized on Level 3 derivative commodity liabilities still on hand at year end. 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 Policy 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)		**2015**		2014
Provisions				
Environmental liabilities	**$**	**368**	$	333
Decommissioning obligations		**53**		50
Other		**27**		22
Total Provisions		**448**		405
First Nations liabilities		**414**		417
Finance lease obligations		**259**		276
Other liabilities		**81**		28
Deferred revenue - Skagit River Agreement		**441**		433
		1,643		1,559
Less: Current portion, included in accounts payable and accrued liabilities		**(129)**		(120)
	$	**1,514**	$	1,439

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

		Environmental		Decommissioning		Other		Total
Balance at March 31, 2014	$	333	$	50	$	22	$	405
Made during the period		50		-		7		57
Used during the period		(35)		(2)		(5)		(42)
Changes in estimate		14		4		3		21
Accretion		6		1		-		7
Balance at March 31, 2015	$	368	$	53	$	27	$	448

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 2016 and 2045, is approximately $435 million and was determined based on current cost estimates. A range of discount rates between 0.5 to 2.0 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 $84 million (2014 – $87 million), which will be settled between fiscal 2015 and 2054. The undiscounted cash flows are then discounted by a range of discount rates between 0.5 to 2.0 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:

(in millions)	**Future minimum lease payments 2015**	**Interest 2015**	**Present value of minimum lease payments 2015**	Future minimum lease payments 2014	Interest 2014	Present value of minimum lease payments 2014
Less than one year	**$ 40**	**$ 21**	**$ 19**	$ 40	$ 23	$ 17
Between one and five years	**143**	**83**	**60**	162	89	73
More than five years	**312**	**132**	**180**	333	147	186
Total minimum lease payments	**$ 495**	**$ 236**	**$ 259**	$ 535	$ 259	$ 276

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 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 $53,817 million of which approximately $171 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 $495 million accounted for as obligations under capital leases. The total BC Hydro combined payments are estimated to be approximately $1,446 million for less than one year, $6,217 million between one and five years, and $46,154 million for more than five years and up to 56 years.

Powerex has energy purchase commitments with an estimated minimum payment obligation of $2,389 million extending to 2034. The total Powerex energy purchase commitments are estimated to be approximately $536 million for less than one year, $1,021 million between one and five years, and $832 million for more than five years. Powerex has energy sales commitments of $655 million extending to 2027 with estimated amounts of $372 million for less than one year, $258 million between one and five years, and $25 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 $819 million. Payments are $123 million for less than 1 year, $188 million between one and five years, and $508 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) Due to the size, complexity and nature of the Company's operations, various other legal matters are pending. It is not possible at this time to predict with any certainty the outcome of such litigation. Management believes that any settlements related to these matters will not have a material effect on the Company's consolidated financial position or results of operations.

c) The Company and its subsidiaries have outstanding letters of credit totaling $822 million (2014 - $913 million), of which there is US $44 million (2014 – US $106 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 involved in the marketing and trading of power and gas 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)	**2015**	2014
Balance Sheet		
Accounts receivable	**$ 91**	$ 96
Accounts payable and accrued liabilities	**320**	227
Amounts incurred/accrued during the year include:		
Water rental fees	**334**	372
Cost of energy sales	**130**	170
Taxes	**125**	125
Interest	**674**	644
Payment to the Province	**264**	167

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. At March 31, 2015, the aggregate exposure under this indemnity totaled approximately $74 million (2014 - $22 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 2015 and 2014.

Key Management Personnel and Board Compensation

Key management personnel and board compensation includes compensation to the Company's executive officers, executive vice presidents, senior vice presidents and board of directors.

(in millions)	**2015**	2014
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 C provides further details on each $50 million project.

Capital Project (Project descriptions can be found in Appendix C)	**Targeted Final In-Service Date (calendar year)**	**Total Cost ($ millions)**	**Life to Date (LTD) Cost** as of March 31, 2015 **($ millions)**
P3rojects Recently Put Into Service			
Vancouver City Central Transmission	March 2014, In-Service	$172	$171
Northwest Transmission Line Project	July 2014, In-Service	$716	$680
Mica SF_6 Gas Insulated Switchgear Replacement Project	August 2014, In-Service	$199	$178
Iskut Extension Project*	December 2014, In-Service	$169	$164
**The total cost represents the gross costs of the project and has not been netted to reflect the contribution from the customer towards the construction of the transmission line. The total cost decreased from $209M to $169M to reflect lower costs of constructing the Tatogga Lake Substation and upgrading an existing substation. BC Hydro purchased the transmission line upon completion by the customer at a fixed cost.*			
Ongoing and Planned			
Merritt Area Transmission Project	2015 Targeted In-Service	$65	$44
G.M. Shrum Units 1 to 5 Turbine Replacement	2015 Targeted In-Service	$272	$154
Long Beach Area Reinforcement	2015 Targeted In-Service	$56	$26
Surrey Area Substation Project	2015 Targeted In-Service	$94	$45
Interior to Lower Mainland Transmission Line Project	2015 Targeted In-Service	$725	$616
Smart Metering & Infrastructure Program*	2015 Targeted In-Service	$930	$728
**Smart Metering & Infrastructure Program amount includes both capital costs and operating expenditures subject to regulatory deferral.*			
Hugh Keenleyside Spillway Gate Reliability Upgrade	2015 Targeted In-Service	$123	$91
Upper Columbia Capacity Additions at Mica – Units 5 & 6	2015 Targeted In-Service	$714	$518
Dawson Creek/Chetwynd Area Transmission Project	2016 Targeted In-Service	$296	$221

Big Bend Substation	2017 Targeted In-Service	$56	$19
Ruskin Dam Safety and Powerhouse Upgrade	2017 Targeted In-Service	$748	$310
John Hart Generating Station Replacement	2019 Targeted In-Service	$1,093	$281
Cheakamus Unit 1 and Unit 2 Generator Replacement	2019 Targeted In-Service	$74	$5
Site C Clean Energy Project	2024* Targeted In-Service	$8,335**	$ 444**

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

***Site C forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral. 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.*

Contemplated Projects over $50 million

BC Hydro is contemplating the following projects over $50 million to commence during fiscal 2016-fiscal 2018, listed in alphabetical order. These projects are in the initial project phases; scope, final cost and benefit assessment, and completion dates are still to be determined. These projects are not yet approved by the Board of Directors.

Capital Project (Project descriptions can be found in Appendix C)	
Bridge River 2 Units 5 and 6 Upgrade	Peace Region Electric Supply
Bridge River 2 Units 7 and 8 Upgrade	Prince George to Terrace Capacitors
Clowhom Unit Upgrade	Revelstoke Left Bank Slope Stability
Downtown Vancouver Electricity Supply Plan	Revelstoke Unit 6 Installation
G.M. Shrum G1-G10 Control System Upgrade	Seven Mile Unit 1-3 Turbines Overhaul
Horne Payne Substation Upgrade	Strathcona Dam Discharge Upgrade
John Hart Dam Seismic Upgrade	Strathcona Dam Spillway Upgrade
Ladore Dam Spillway Gates Upgrade	Terrace – Kitimat Transmission Project
Metro North System Supply Reinforcement	W.A.C. Bennett Dam Rip-Rap Upgrade
Northwest Substation Upgrades Project	West Kelowna Transmission Project

Appendix A: Subsidiaries and Operating Segments

Active Subsidiaries

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

Powerex Corp.

Powerex Corp. (Powerex) is a wholly-owned subsidiary of BC Hydro and a key participant in energy markets across North America, buying and supplying wholesale power, renewable energy, natural gas, ancillary services, and financial energy products and services. Established in 1988, its export, marketing and trade activities help manage 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 required in addition to meeting its own trade commitments. Powerex also markets, on behalf of 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 through the Chair of Powerex and works closely with the President & CEO of BC Hydro as a member of the Executive Team. The Chair of the Powerex Board, the Powerex CEO and BC Hydro's Chief Executive Officer (who is also a member of the Powerex Board), ensure the Board of BC Hydro is informed of Powerex's key strategies and business activities.

Powerex operates in complex and volatile energy-markets, which can cause net income in any given year to vary significantly. Market and economic conditions, reduced BC Hydro system flexibility, income timing differences and the strength of the Canadian dollar can materially impact Powerex net income. Over the previous five years, Powerex income has ranged from approximately $8 to $142 million (fiscal 2010 to fiscal 2014). In fiscal 2015, Powerex's net income was $119 million. For more information, visit powerex.com.

Powertech Labs Inc.

Powertech Labs Inc. (Powertech), operating in Surrey since its inception in 1988, is a wholly-owned subsidiary of BC Hydro. Powertech is internationally recognized as holding expertise in providing research and development, testing, technical services and advanced technology services to the international energy community including BC Hydro.

Powertech's revenue in fiscal 2014 was $30 million with a net income of $3.8 million. The revenue for fiscal 2015 was $30 million with a net income of $4.2 million. In fiscal 2015, capital investment was $4.9 million with the focus split between service expansion and sustainment. 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, 2015, these other subsidiaries consisted of the following:

1. BCH Services Asset Corp.
2. British Columbia Hydro International Limited
3. British Columbia Power Exchange Corporation
4. British Columbia Power Export Corporation
5. British Columbia Transmission Corporation
6. Columbia Estate Company Limited*
7. Edgewood Water Corporation*
8. Edmonds Centre Developments Limited*
9. Fauquier Water and Sewage Corporation*
10. Hydro Monitoring (Alberta) Inc.*
11. Victoria Gas Company Limited
12. Waneta Holdings (US) Inc.*

Appendix B: Additional Information

Organizational Overview

BC Hydro has offices in more than 100 communities throughout British Columbia and our employees operate in some of the most difficult terrain in the world. Our transmission system connects with transmission systems in Alberta and Washington State, which improves overall reliability of the system and provides opportunities for trade. Our largest offices are located in Burnaby, Cranbrook, Kamloops, Nanaimo, Prince George, Revelstoke, Surrey, Vancouver, Vernon and Victoria.

Information about BC Hydro's organization and operating environment can be found at: http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information regarding:

- About BC Hydro: Organizational Overview and Our System
- Mandate and Legislation
- Risks and Opportunities
- Performance Measures Data Analysis, Benchmarking and Rationale

Corporate Governance

BC Hydro is governed by a Board of Directors that is responsible 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 our web page at http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information regarding:

- Board of Directors
- Executive Team
- Code of Conduct

BC Hydro has an Ethics Officer, and an Employee Code of Conduct which provides guidance on the standards of conduct expected of Directors, Employees and Contractors of BC Hydro. This is in addition to an independent Code Advisor for Directors and senior members of the executive. This includes guidelines on conflict of interest to ensure decisions and actions are transparent, ethical and free from conflict of interest.

Contact Information

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

Appendix C: Capital Project Descriptions

Projects Recently Put Into Service

Vancouver City Central Transmission

Built an enclosed 230/12 kV substation in the Mt. Pleasant area of Vancouver and two new underground 230 kV transmission lines connecting the new substation to the existing transmission network to serve growing loads in the Mt. Pleasant/False Creek area and maintain a reliable supply of electricity to other areas of Vancouver.

Northwest Transmission Line Project

Constructed an approximately 340 km, 287 kV transmission line between Skeena Substation near Terrace and a new substation near Bob Quinn Lake to ensure a reliable supply of clean power to potential industrial developments in the area, and provide a secure interconnection point for clean generation projects. The total cost decrease from $746M to $716M is due to lower than estimated costs for line construction, clearing work, overhead and interest during construction.

Total cost represents the gross cost of the project and has not been netted for contributions, which total $220 million from the Federal Government and a customer prior to the in-service date. Additional annual payments will be received from a customer for 20 years after the in-service date.

Mica SF6 Gas Insulated Switchgear Replacement Project

Replaced the switchgear system at the Mica Generating Station and installed additional switchgear capacity to accommodate the future Units 5 and 6 additions to ensure the reliability of this key generating station and reduce SF6 (a greenhouse gas) leakage. The switchgear system, energized at 500 kV, conducts energy from the Mica underground powerhouse to the surface, where it transitions to transmission lines.

Iskut Extension Project

The project includes construction of a customer-built 287 kV transmission line extension from Bob Quinn Substation to the customer’s mine, via a new BC Hydro-built substation at Tatogga Lake. In addition, BC Hydro has built a 16 km distribution line from Tatogga Lake Substation to the community of Iskut. The total cost represents the gross costs of the project and has not been netted to reflect the contribution from the customer towards the construction of the transmission line. BC Hydro purchased the transmission line upon completion by the customer at a fixed cost. The total cost decreased from $209M to $169M to reflect lower costs of constructing the Tatogga Lake Substation and upgrading an existing substation.

Ongoing and Planned

Merritt Area Transmission Project

Construct a new 138 kV transmission line between the Merritt and Highland substations, add a new Merritt Substation and new equipment at the Highland Substation to meet the increased demand for power in the Merritt area.

G.M. Shrum Units 1 to 5 Turbine Replacement

Replace the Units 1 to 5 turbine runners to reduce the risk of runner failure, decrease maintenance costs and improve operating efficiency.

Long Beach Area Reinforcement

Expansion of Long Beach and Great Central Lake substations with two new transformers at each and capacitor banks at Long Beach to support the load growth and provide voltage support in the area.

Surrey Area Substation Project

Construct a new 200 MVA 230/25 kV substation in the Fleetwood area of Surrey. The station will be supplied from the adjacent 230 kV transmission line and will allow for future expansion to 400 MVA to service high load growth in the Fraser Valley West area. Construction of this new Fleetwood Substation will also allow for the decommissioning of four ageing substations in the Surrey/Langley area.

Interior to Lower Mainland Transmission Line Project

Construct a new 500 kV transmission line, approximately 247 km in length, between the Nicola Substation near Merritt and the Meridian Substation in Coquitlam and build a new series capacitor station at Ruby Creek near Agassiz to help meet domestic load growth in the Lower Mainland.

Smart Metering and Infrastructure Program

The Smart Metering and Infrastructure Program includes the installation of 1.9 million smart meters in homes and businesses across the province, an advanced telecommunications infrastructure to support electricity system management and customer applications, and information technology to support customer billing, load forecasting and outage management systems.

Hugh Keenleyside Spillway Gate Reliability Upgrade

Upgrade the spillway gates at the Hugh Keenleyside Dam to increase public and employee safety by ensuring the gates meet flood discharge reliability requirements.

Spillway gates control the amount of water that can be discharged from the reservoir. They are generally used in times of flood to pass high inflows.

Upper Columbia Capacity Additions at Mica – Units 5 & 6

Install two additional 500 MW generating units into existing unit bays at the Mica Generating Station. The new units are similar to the four existing units, but with more efficient turbines.

Dawson Creek/Chetwynd Area Transmission Project

The project will expand the Peace Region 230 kV transmission system to the Dawson Creek/Chetwynd Area to supply the area’s load growth. The solution will include the construction of new 230 kV lines between Dawson Creek Area Substation and Bear Mountain Terminal, and from Bear Mountain Terminal to a new substation called Sundance Lake Substation, located approximately 19 km east of Chetwynd. Due to construction delays, the target in-service has shifted by five months from 2015 to 2016.

Big Bend Substation

The South Burnaby, Big Bend area requires a new, 100 MVA, 60/12 kV substation to meet local residential and commercial load growth.

Ruskin Dam 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 replace major generating equipment, which is in poor or unsatisfactory condition.

John Hart Generating Station Replacement

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

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.

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.

Contemplated Projects over $50 million

Bridge River 2 Units 5 and 6 Upgrade

The Bridge River 2 generating Units 5 and 6 are rated as unsatisfactory and have been de-rated from 71 MW to 48 MW. This project will restore the capacity and reliability of the Unit 5 and 6 generators as well as the reliability of other major components.

Bridge River 2 Units 7 and 8 Upgrade

The Bridge River 2 generating Units 7 and 8 are rated as unsatisfactory and have been de-rated from 71 MW to 62 MW. This project will restore the capacity and reliability of the Unit 7 and 8 generators as well as the reliability of other major components.

Clowhom Unit Upgrade

Major components of the Clowhom generating unit are in unsatisfactory or poor condition. This project will address issues with the generating unit in order to maintain reliability and reduce the risk of forced outages at the Clowhom facility.

Downtown Vancouver Electricity Supply Plan

Upgrade and expand the transmission and distribution network serving downtown Vancouver over the next 20 to 30 years to improve reliability and seismic resiliency. Several projects will be identified in the plan including the addition of a new transmission cable coming into the downtown core, the construction of new substations, and the refurbishment and/ or replacement of the existing substations. The project also includes converting the existing distribution system from a 12 kV dual radial system to a 25 kV open-loop system.

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 centre and rectify deficiencies in the current system.

Horne Payne Substation Upgrade

Expand the Horne Payne Substation with the addition of two 230/25 kV, 150 MVA transformers, gas-insulated feeder sections, and a new control building. This project will increase the firm capacity of the substation, add needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12 kV to 25 kV, and allow for the implementation of an open-loop distribution system.

John Hart Dam Seismic Upgrade

Upgrade the John Hart Dam to reliably withstand seismic loadings and meet operations criteria post-earthquake. The project will include upgrades to the earthfill structures (middle and north earthfill dams and intake structure), upgrades to the concrete dam and spillway gates system, and a passive spillway and permanent flood risk mitigation upgrade.

Ladore Dam Spillway Gates Upgrade

Reduce the risk of failure of the spillway gates due to a seismic event. Improve post-seismic operability in order to prevent the subsequent uncontrolled release of water into the downstream John Hart Reservoir and maintain reservoir control in the system.

Metro North System Supply Reinforcement

Add new 230 kV transmission line(s) between Coquitlam and Vancouver to address load growth in the Metro Vancouver area and to strengthen the reliability of the network.

Northwest Substation Upgrades Project

Carry out modifications, upgrades and additions to five substations in the northwest (Williston, Glenannan, Telkwa, Skeena and Minette) to accommodate the interconnection of industrial loads in the northwest, including a liquefied natural gas facility expected to come on line in early 2020.

Peace Region Electric Supply

Increase transmission capacity to the South Peace area by providing a second 230 kV supply to Dawson Creek in response to the significant load growth in the area, mainly from the gas production industry.

Prince George to Terrace Capacitors

Increase the capacity of the 500 kV circuit supplying the north coast areas. This will increase the transfer capacity by up to approximately 60 per cent through the addition of reactive compensation. This additional capacity is required to provide capacity for industrial loads expected to interconnect to in the northwest, including a liquefied natural gas plant that is scheduled for early 2020.

Revelstoke Left Bank Slope Stability

This project will improve the stability of the left bank slope, adjacent to the dam and powerhouse, to reduce the potential for slides or rock fall to impact the penstocks and powerhouse.

Revelstoke Unit 6 Installation

Supply and install a 500 MW unit in the existing empty Unit 6 bay at Revelstoke Generating station to add capacity to the BC Hydro system. Revelstoke Unit 6 is identified as a contingency resource in BC Hydro's 2013 Integrated Resource Plan (IRP).

Seven Mile Unit 1-3 Turbines Overhaul

This project will perform a major overhaul of the Unit 1-3 turbines, installed in 1979 and 1980, in order to address condition issues and extend the life of the turbines.

Strathcona Dam Discharge Upgrade

This project will provide deep reservoir drawdown capability, as a first line of defense against uncontrolled release of the reservoir, resulting from damage to the dam caused by an earthquake or other dam safety events such as increased seepage through the earth fill dam. The project will also facilitate a future dam upgrade project, and power generating station replacement project, and it will result in the decommissioning of the existing low level outlet beneath the dam.

Strathcona Dam Spillway Upgrade

Upgrades to the Strathcona Dam spillway will provide reservoir retention and post-seismic operability; as well as improved reliability of the spillway gates for flood passage capability.

Terrace – Kitimat Transmission Project

Replace the existing transmission line serving the Kitimat area that has reached the end of its serviceable life. This project would replace the 60 km transmission line that runs between Skeena and Minette substations and the 3 km transmission line that runs between Minette and Kitimat substations with new lines on a new right of way. Both of these lines have been de-rated due to defects and deficiencies, and cannot supply current and forecast load demands.

W.A.C. Bennett Dam Rip-Rap Upgrade

The W.A.C. Bennett Dam rip-rap has degraded since its completion in 1967. The project will restore rip-rap over critical eroded zones of the upstream slope to ensure there is adequate protection of the embankment dam against wind generated waves.

West Kelowna Transmission Project

Westbank Substation is presently supplied by a single, radial 138 kV transmission line from Nicola Substation located approximately 85 km west of the Westbank Substation in the Nicola Valley. A new, second transmission line will provide added redundancy to the system, ensuring continued, reliable power in the event of an outage on the existing line.

Appendix D: Financial and Operating Statistics

FINANCIAL STATISTICS

for the years ended or as at March 31 (in millions)	**2015**	2014	2013	2012 [5]	2011 [5]
Revenues	**$ 5,748**	$ 5,392	$ 4,898	$ 4,730	$ 4,016
Expenses					
Energy costs	**2,203**	2,146	1,806	1,876	1,415
Other operating expenses [1]	**918**	901	894	820	860
Amortization	**1,205**	995	953	793	533
Taxes	**209**	203	196	184	184
Finance charges	**632**	598	540	499	435
	5,167	4,843	4,389	4,172	3,427
Net Income	**$ 581**	$ 549	$ 509	$ 558	$ 589
Property, Plant and Equipment & Intangible Assets					
At cost [2]	**$ 22,998**	$ 20,897	$ 18,932	$ 17,161	$ 23,334
Less: Accumulated depreciation [2]	**2,518**	1,863	1,268	758	7,788
Net Book Value	**$ 20,480**	$ 19,034	$ 17,664	$ 16,403	$ 15,546
Property, Plant & Equipment and Intangible Asset Expenditures					
Sustaining	**$ 1,005**	$ 979	$ 1,009	$ 956	$ 865
Growth	**1,164**	1,057	920	747	654
Total Property, Plant & Equipment and Intangible Asset Expenditures [3]	**$ 2,169**	$ 2,036	$ 1,929	$ 1,703	$ 1,519
Net Long-Term Debt [4]	**$ 16,682**	$ 15,461	$ 13,962	$ 12,833	$ 11,520
Retained Earnings	**$ 4,068**	$ 3,751	$ 3,369	$ 3,075	$ 2,747
Debt to Equity Ratio	**80 : 20**	80 : 20	80 : 20	80 : 20	80 : 20

1 *Personnel, materials & external services, capitalized costs and other costs, as per the operating expenses note in the consolidated financial statements.*

2 *F2012 to F2015 information was prepared in accordance with the Prescribed Standards. Arising on transition from Canadian Generally Accepted Accounting Principles (GAAP) to the Prescribed Standards and with the application of the deemed cost exemption, the net book value of property, plant and equipment and intangible assets for BC Hydro entities subject to rate regulation at April 1, 2011 have become the opening cost of property, plant and equipment and intangible assets under the Prescribed Standards except for finance leases.*

3 *Total property, plant and equipment and intangible asset expenditures include non-cash items.*

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

5 *F2012 to F2015 information was prepared in accordance with the Prescribed Standards. Financial information for F2011 was prepared in accordance with Canadian GAAP.*

OPERATING STATISTICS

for the years ended or as at March 31	**2015**	2014	2013	2012	2011
Generating Capacity (megawatts)					
Hydroelectric[1]	**11,379**	10,927	10,927	10,923	10,923
Thermal	**1,120**	1,120	1,120	1,117	1,096
Total	**12,499**	12,047	12,047	12,040	12,019
Peak One-Hour Demand					
Integrated System (megawatts)	**9,441**	10,072	9,345	9,929	9,790
Customers					
Residential	**1,727,945**	1,709,071	1,689,050	1,671,412	1,654,079
Light industrial and commercial	**203,466**	201,812	199,981	197,821	195,402
Large industrial	**183**	177	172	168	166
Other	**3,474**	3,489	3,482	3,490	3,490
Trade	**226**	239	249	264	269
Total	**1,935,294**	1,914,788	1,892,934	1,873,155	1,853,406
Average number of customers per full time equivalent [2]	**340**	330	330	317	317
Electricity Sold (gigawatt-hours)					
Residential	**17,047**	17,965	17,703	18,395	17,797
Light industrial and commercial	**18,564**	18,501	18,384	18,005	18,052
Large industrial	**14,020**	13,994	13,508	13,522	13,164
Other	**1,582**	2,558	7,417	2,275	1,647
Total	**51,213**	53,018	57,012	52,197	50,660
Total electricity sold per full time equivalent (gigawatt-hours) [2]	**9.05**	9.20	10.00	8.88	8.73
Revenues (in millions)					
Residential	**$ 1,712**	$ 1,663	$ 1,612	$ 1,581	$ 1,398
Light industrial and commercial	**1,597**	1,489	1,436	1,327	1,237
Large industrial	**748**	687	642	598	539
Other energy sales	**280**	275	322	236	229
Total Domestic Revenue Before Regulatory Transfer	**4,337**	4,114	4,012	3,742	3,403
Regulatory transfer	**492**	205	26	6	35
Total Domestic	**4,829**	4,319	4,038	3,748	3,438
Total Trade	**919**	1,073	860	982	578
Total Revenues	**$ 5,748**	$ 5,392	$ 4,898	$ 4,730	$ 4,016

[1] *Maximum sustained generating capacity.*

[2] *Regular full time equivalents (FTEs) (actual regular hours worked during the year divided by expected regular working hours during the year) for BC Hydro, excluding subsidiaries.*

OPERATING STATISTICS (CONTINUED)

for the years ended or as at March 31	**2015**	2014	2013	2012	2011
Average Revenue (per kilowatt-hour) [1]					
Residential	**10.0¢**	9.3¢	9.1¢	8.6¢	7.9¢
Light industrial and commercial	**8.6**	8.0	7.8	7.4	6.9
Large industrial	**5.3**	4.9	4.8	4.4	4.1
Other	**17.7**	10.8	4.3	10.4	13.9
Average Annual Kilowatt-Hour Use Per Residential Customer	**9,919**	10,571	10,534	11,067	10,818
Lines In Service					
Distribution (kilometres)	**58,518**	58,317	58,115	57,914	57,648
Transmission (circuit kilometres)	**19,792**	19,322	19,163	18,864	18,764

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

TOTAL REQUIREMENTS FOR ELECTRICITY, SOURCES OF SUPPLY AND WATER INFLOWS

for the years ended March 31	**2015**			2014			2013			2012			2011		
	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	%
Requirements															
Domestic	**12,499**	**51,213**	66.0	12,047	53,018	65.0	12,047	50,992	58.5	12,040	52,197	62.2	12,019	50,660	62.1
Electricity trade		**21,928**	28.2		23,806	29.2		30,975	35.6		26,908	32.1		26,253	32.2
		73,141	94.2		76,824	94.2		81,967	94.1		79,105	94.3		76,913	94.3
Line loss and system use		**4,486**	5.8		4,733	5.8		5,159	5.9		4,783	5.7		4,648	5.7
		77,627	100.0		81,557	100.0		87,126	100.0		83,888	100.0		81,561	100.0
Sources Of Supply															
Hydroelectric generation															
Gordon M. Shrum	**2,730**	**10,801**	13.9	2,730	13,650	16.7	2,730	15,878	18.2	2,730	14,447	17.2	2,730	10,015	12.3
Revelstoke	**2,480**	**7,297**	9.4	2,480	8,121	10.0	2,480	9,760	11.2	2,480	8,756	10.4	2,480	7,155	8.8
Mica	**2,257**	**6,028**	7.8	1,805	7,030	8.6	1,805	7,873	9.0	1,805	7,943	9.5	1,805	6,294	7.7
Kootenay Canal	**583**	**3,304**	4.4	583	2,935	3.6	583	3,595	4.1	583	3,108	3.7	583	2,924	3.6
Peace Canyon	**694**	**2,678**	3.4	694	3,423	4.2	694	3,902	4.5	694	3,613	4.3	694	2,591	3.2
Seven Mile	**805**	**3,907**	5.0	805	3,183	3.9	805	3,176	3.6	805	3,491	4.2	805	3,210	3.9
Bridge River	**478**	**2,093**	2.7	478	2,397	2.9	478	2,626	3.0	478	2,732	3.3	478	2,631	3.2
Other	**1,352**	**5,122**	6.6	1,352	4,589	5.6	1,352	5,304	6.1	1,348	5,743	6.9	1,348	4,483	5.5
	11,379	**41,230**	53.2	10,927	45,328	55.5	10,927	52,115	59.8	10,923	49,833	59.5	10,923	39,303	48.2
Thermal generation															
Burrard	**950**	**26**	0.0	950	84	0.1	950	25	0.0	950	19	0.0	950	58	0.1
Other	**170**	**187**	0.2	170	184	0.2	170	97	0.1	167	124	0.1	146	193	0.2
Purchases under long-term commitments		**17,510**	22.6		15,300	18.8		15,003	17.2		15,317	18.3		15,427	18.9
Purchases under short-term commitments		**18,586**	23.9		20,764	25.5		19,858	22.8		18,640	22.2		26,208	32.1
Other		**88**	0.1		(103)	(0.1)		28	0.0		(45)	(0.1)		372	0.4
	12,499	**77,627**	100.0	12,047	81,557	100.0	12,047	87,126	100.0	12,040	83,888	100.0	12,019	81,561	100.0
Water inflows (% of average)			**102**			95			109			108			86