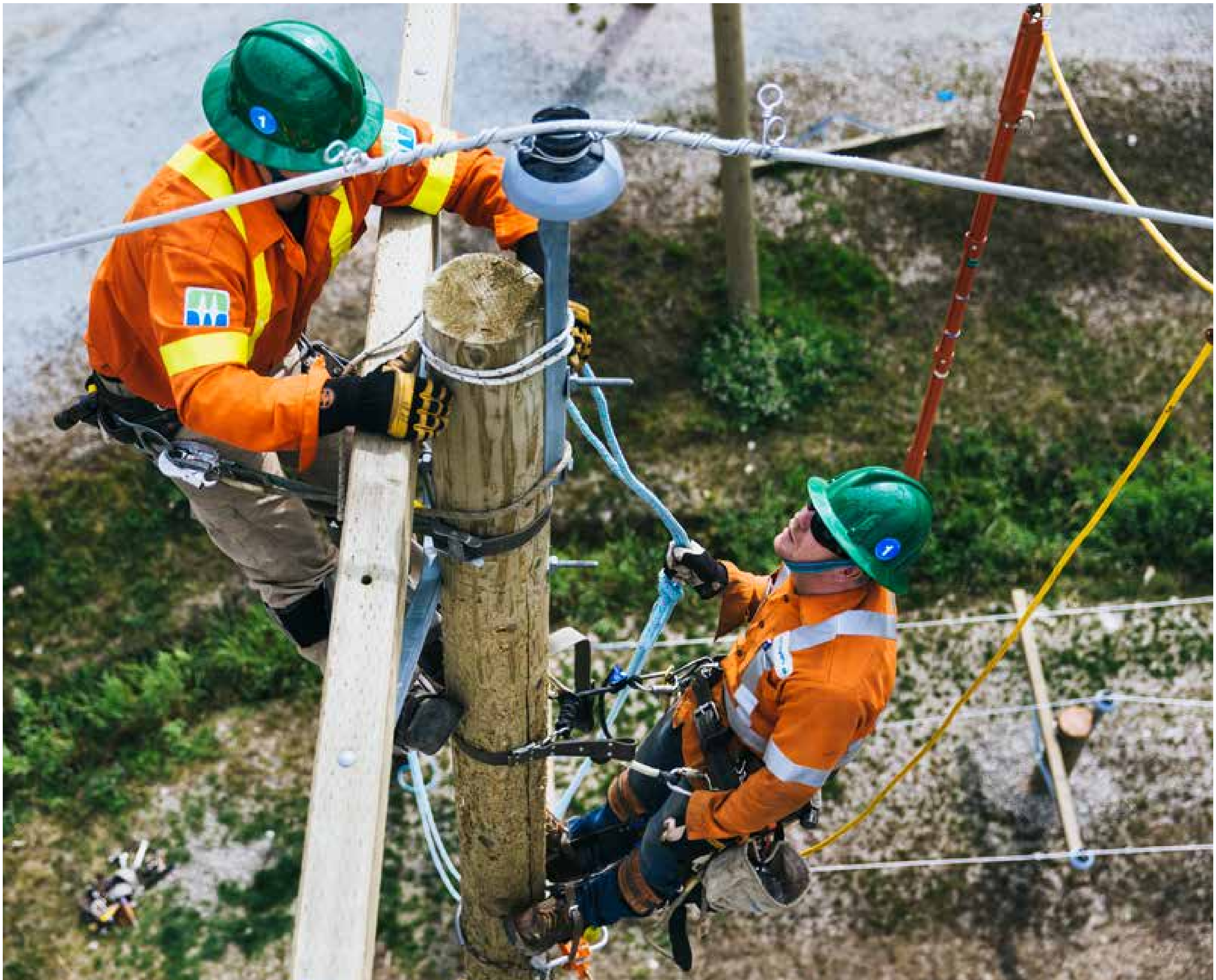

BC HYDRO FIRST QUARTER REPORT FISCAL 2015

BC hydro
FOR GENERATIONS

BRITISH COLUMBIA

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 three months ended June 30, 2014 and should be read in conjunction with the MD&A presented in the 2014 Annual Report, the 2014 Annual Consolidated Financial Statements of the Company, and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three months ended June 30, 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 after regulatory account transfers for the three months ended June 30, 2014 was $93 million, $38 million higher than the same period in the prior fiscal year. 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 and higher electricity and gas purchases.
- The system inflow energy equivalent for the three months ended June 30, 2014 was 99 per cent of average, with Williston and Kinbasket reservoirs at 96 and 102 per cent of average, respectively. The system inflow energy equivalent for the same period in the prior fiscal year was 103 per cent of average (Williston 98 per cent and Kinbasket 114 per cent). Approximately 40 per cent of the system inflow for the fiscal year occurs in the first quarter and is due to a combination of snowmelt and rainfall. Although the fiscal 2015 snowpack was about 1 per cent higher than in fiscal 2014, dry conditions across the province in June resulted in a system inflow energy equivalent for the current quarter at 4 per cent lower than the same period in the prior year. The current system inflow energy for fiscal 2015 is forecast to be 3 per cent below average, compared to the system inflow energy for fiscal 2014 which was 5 per cent below average.
- In October 2013, the Federal Energy Regulatory Commission (FERC) issued an Order approving the settlement between Powerex and 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 into escrow of US$273 million in fiscal 2014 pending the Settlement Effective Date which translated to CDN$287 million on the transaction date and CDN$292 million as at June 30, 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.
- Capital expenditures for the three months ended June 30, 2014 were $439 million. BC Hydro continues to invest significantly to refurbish its ageing infrastructure and build new assets for future growth, including Mica Units 5 & 6, G.M. Shrum Units 1 to 5 Turbine Rehabilitation, Ruskin Dam and Powerhouse Upgrade, Smart Metering and Infrastructure (SMI), Northwest Transmission Line, Interior to Lower Mainland Transmission, and Dawson Creek/Chetwynd Area Transmission.

($ in millions)	For the three months ended June 30 2014	2013	Change
Net Income	$ 93	$ 55	$ 38
Number of Domestic Customers	1,918,776	1,896,896	21,880
GWh Sold (Domestic)	12,049	11,977	72
Total Reservoir Storage (GWh)	23,726	24,848	(1,122)

($ in millions)	As at June 30, 2014	As at March 31, 2014	Change
Total Assets	$ 25,762	$ 25,711	$ 51
Retained Earnings	$ 3,844	$ 3,751	$ 93
Debt to Equity	80 : 20	80 : 20	N/A

CONSOLIDATED RESULTS OF OPERATIONS

These interim statements present the Company's operating results and financial position under the Prescribed Standards. Under the Prescribed Standards, the Company applies the principles of IFRS plus ASC 980 to reflect the rate-regulated environment in which the Company operates. These principles allow for the deferral of costs and recoveries that under IFRS would otherwise be recorded as expenses or income in the current accounting period. 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 British Columbia Utilities Commission (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.

For the three months ended June 30, 2014, transfers resulted in a net addition to regulatory accounts of $21 million, primarily due to additions for the Rate Smoothing regulatory account, demand-side management programs (DSM), deferral of costs for future recovery in rates including Site C and the phasing in of the rate impact of the reduction in the amount of overhead eligible for capitalization under IFRS as compared to Canadian generally accepted accounting principles (CGAAP). These additions were partially offset by a decrease to the Trade Income Deferral Account (TIDA) due to better than plan results in the current quarter and amortization of regulatory accounts.

Net income after regulatory account transfers for the three months ended June 30, 2014 was $93 million, $38 million higher than the same period in the prior fiscal year. 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 and higher electricity and gas purchases.

REVENUES

Total revenues after regulatory account transfers for the three months ended June 30, 2014 was $1,370 million, an increase of $116 million or 9 per cent compared to the same period in the prior fiscal year primarily due to higher domestic revenues resulting from higher average customer rates, partially offset by lower trade revenues resulting from lower net electricity revenues.

	(in millions)		*(gigawatt hours)*		*($ per MWh)*[2]	
For the three months ended June 30	**2014**	2013	**2014**	2013	**2014**	2013
Domestic						
Residential	**$ 376**	$ 341	**3,769**	3,765	**$ 99.76**	$ 90.57
Light industrial and commercial	**383**	355	**4,456**	4,407	**85.95**	80.55
Large industrial	**181**	158	**3,544**	3,319	**51.07**	47.60
Other energy sales	**68**	56	**280**	486	**242.86**	115.23
Total Domestic Revenue Before Regulatory Transfer	**1,008**	910	**12,049**	11,977	**83.66**	75.98
Rate smoothing and load variance regulatory transfer	**76**	37	**-**	-	**-**	-
Total Domestic	**$ 1,084**	$ 947	**12,049**	11,977	**$ 89.97**	$ 79.07
Trade						
Electricity - Gross	**$ 315**	$ 337	**7,709**	8,328	**$ 40.86**	$ 40.47
Less: forward electricity purchases	**(90)**	(71)	**-**	-	**-**	-
Electricity - Net	**225**	266	**-**	-	**-**	-
Gas - Gross	**246**	204	**5,341**	5,025	**46.06**	40.60
Less: forward gas purchases	**(185)**	(163)	**-**	-	**-**	-
Gas - Net	**61**	41	**-**	-	**-**	-
Total Trade[1]	**$ 286**	$ 307	**13,050**	13,353	**$ 21.92**	$ 22.99
Total	**$ 1,370**	$ 1,254	**25,099**	25,330	**$ 54.58**	$ 49.51

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

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

DOMESTIC REVENUES

Total domestic revenues after regulatory account transfers for the three months ended June 30, 2014 were $1,084 million, an increase of $137 million or 14 per cent over the same period in the prior fiscal year. Domestic revenues before regulatory account transfers of $1,008 million were $98 million or 11 per cent higher than in the same period in the prior fiscal year. The increase was primarily due to higher average customer rates and higher load for light industrial and commercial and large industrial customers.

Average customer rates were higher in fiscal 2015 compared to the prior fiscal year, reflecting an average rate increase as approved by the BCUC of 9 per cent effective April 1, 2014.

Increased load for the light industrial and commercial customer class was mainly due to increased activity in the manufacturing, services, and commercial real estate sectors. Higher gigawatt hours sold to the large industrial customer class was mainly due to the start up and expansion of several metal mines. Other energy sales volumes were lower than the prior fiscal year due to lower water inflows and system constraints in the current fiscal year.

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. Exports are made only after ensuring domestic demand requirements can be met.

Total trade revenues for the three months ended June 30, 2014 were $286 million, a decrease of $21 million or 7 per cent compared with the same period in the prior fiscal year. The decrease in total trade revenues was primarily due to a $41 million decrease in net electricity revenue offset by a $20 million increase in net gas revenue. The decrease in net electricity revenue was due to a 7 per cent decrease in the volume of physical electricity sold and an increase in forward electricity purchases. The increase in net gas revenue was primarily due to a 20 per cent increase in average natural gas sales prices which reflect overall higher natural gas prices in North America due to low storage levels. Variances between actual and planned trade income (which includes trade revenues) are deferred to the TIDA.

OPERATING EXPENSES

For the three months ended June 30, 2014, total operating expenses of $1,137 million were $86 million higher than in the same period in the prior fiscal year. The increase over the same period of the prior year was primarily the result of higher amortization and depreciation expense due to higher amortization of regulatory accounts and higher expenditures on 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.

Total energy costs after regulatory account transfers for the three months ended June 30, 2014 were $581 million, $50 million or 9 per cent higher than in the prior fiscal year. The increase over the prior year was due primarily to higher domestic energy purchases mainly due to more Independent Power Producers (IPPs) achieving commercial operations and higher trade net gas purchase costs due to an increase in natural gas prices.

For the three months ended June 30	(in millions) 2014	2013	(gigawatt hours) 2014	2013	($ per MWh) 2014[2]	2013[2]
Domestic						
Water rental payments (hydro generation)[1]	**$ 85**	$ 96	**8,836**	9,578	**$ 9.95**	$ 10.41
Purchases from Independent Power Producers	**224**	198	**3,251**	2,939	**68.82**	67.51
Other electricity purchases - Domestic	**1**	1	**36**	43	**32.89**	30.90
Gas for thermal generation	**9**	10	**56**	39	**162.54**	251.17
Transmission charges and other expenses	**-**	2	**27**	25	**-**	-
Allocation from trade energy	**21**	10	**631**	426	**28.94**	24.30
Total Domestic Cost of Energy Before Regulatory Transfers	**340**	317	**12,837**	13,050	**26.48**	24.30
Domestic cost of energy regulatory transfers	**(2)**	(49)	**-**	-	**-**	-
Total Domestic	**$ 338**	$ 268	**12,837**	13,050	**$ 26.33**	$ 20.53
Trade						
Electricity - Gross	**$ 192**	$ 207	**8,329**	8,687	**$ 23.05**	$ 23.83
Less: forward electricity purchases	**(90)**	(71)	**-**	-	**-**	-
Electricity - Net	**102**	136	**-**	-	**-**	-
Remarketed gas - Gross	**243**	191	**5,455**	5,055	**44.54**	37.78
Less: forward gas purchases	**(185)**	(163)	**-**	-	**-**	-
Remarketed gas - Net	**58**	28	**-**	-	**-**	-
Transmission charges and other expenses	**72**	63	**-**	-	**-**	-
Allocation to domestic energy	**(21)**	(10)	**(631)**	(426)	**28.94**	24.30
Total Trade Cost of Energy Before Regulatory Transfers	**211**	217	**13,153**	13,316	**22.87**	21.13
Trade net margin regulatory transfer	**32**	46	**-**	-	**-**	-
Total Trade	**$ 243**	$ 263	**13,153**	13,316	**$ 25.34**	$ 24.59
Total Energy Costs	**$ 581**	$ 531	**25,990**	26,366	**$ 25.83**	$ 22.58

[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 transfers for the three months ended June 30, 2014 were $338 million, $70 million or 26 per cent higher than the same period in the prior fiscal year. Domestic energy costs before regulatory transfers of $340 million for the three months ended June 30, 2014 were $23 million or 7 per cent higher than the same period in the prior fiscal year primarily due to more IPPs achieving commercial operations. In addition, due to lower water inflows and system constraints in the current fiscal year, there was less hydro generation resulting in increased net trade energy imports (higher allocation from trade energy). This was partially offset by lower water rental payments.

Water rental payments are based on the prior year's generation and current year's rates. In the prior fiscal year, less hydro was generated 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

Total trade energy costs before regulatory account transfers for the three months ended June 30, 2014 were $211 million, a decrease of $6 million or 3 per cent compared with the same period in the prior fiscal year. The decrease in total trade energy costs was primarily due to a $34 million decrease in net electricity purchase costs partially offset by a $30 million increase in net gas purchase costs. The decrease in net electricity purchases was due to a 4 per cent decrease in the volume of physical electricity purchased and an increase in forward electricity purchases. Forward electricity purchases are reclassified to revenues in accordance with the Prescribed Standards. The increase in net gas purchase costs was primarily due to an 18 per cent increase in the average gas purchase price reflecting increases in natural gas prices in North America due to low storage levels. Variances between actual and planned trade income (which includes trade energy costs) are deferred to the TIDA.

Water Inflows

The system inflow energy equivalent for the three months ended June 30, 2014 was 99 per cent of average, with Williston and Kinbasket reservoirs at 96 and 102 per cent of average, respectively. The system inflow energy equivalent for the same period in the prior fiscal year was 103 per cent of average (Williston 98 per cent and Kinbasket 114 per cent). Approximately 40 per cent of the system inflow for the fiscal year occurs in the first quarter and is due to a combination of snowmelt and rainfall. Although the fiscal 2015 snowpack was about 1 per cent higher than in fiscal 2014, dry conditions across the province in June resulted in a system inflow energy equivalent for the current quarter at 4 per cent lower than the same period in the prior year. The current system inflow energy for fiscal 2015 is forecast to be 3 per cent below average, compared to the system inflow energy for fiscal 2014 which was 5 per cent below average.

The Company's reservoirs have been managed such that system energy storage on June 30, 2014 was 21,700 GWh, or 600 GWh below the 10 year historic average. This was 1,000 GWh lower than the system energy storage of 22,700 GWh recorded one year earlier. The Williston and Kinbasket reservoir energy contents were 14,500 GWh (1,000 GWh below the 10 year historic average) and 7,200 GWh (400 GWh above the 10 year historic average), respectively, with Williston 1,000 GWh lower than the prior year and Kinbasket the same as the prior year.

PERSONNEL EXPENSES

Personnel expenses include labour, benefits and post-employment benefits. Personnel costs of $137 million for the three months ended June 30, 2014 were $3 million lower than the same period in the prior fiscal year primarily due to a reduction in labour costs.

MATERIALS AND EXTERNAL SERVICES

Expenditures on materials and external services for the three months ended June 30, 2014 of $135 million were $6 million lower than the same period in the prior fiscal year primarily due to decreased services and other operational activities.

AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, and the amortization of certain regulatory assets and liabilities. For the three months ended June 30, 2014, amortization and depreciation expense was $290 million, $46 million or 19 per cent higher than the same period in the prior fiscal year. The increase was primarily due to higher amortization of regulatory accounts.

GRANTS, TAXES AND OTHER COSTS

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, taxes and other costs for the three months ended June 30, 2014 were $51 million, comparable with $53 million in the same period in the prior fiscal year.

CAPITALIZED COSTS

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to property, plant and equipment. Overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS Property, Plant and Equipment regulatory account. Capitalized costs for the three months ended June 30, 2014 of $57 million were comparable to capitalized costs of $58 million in the same period in the prior fiscal year.

FINANCE CHARGES

Finance charges after net regulatory transfers for the three months ended June 30, 2014 of $140 million were $8 million or 5 per cent lower than in the same period in the prior fiscal year. The decrease is primarily due to lower planned short term and long term interest rates, and lower planned lease charges. The decrease was partially offset by lower planned capitalized interest during construction.

REGULATORY ACCOUNT TRANSFERS

The Company has established various regulatory accounts with the approval of the BCUC. Regulatory accounts allow the Company to defer certain types of revenue and cost variances through transfers to and from the accounts which have the effect of adjusting net income. 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:

(in millions)	For the three months ended June 30 2014	2013
Energy Accounts		
Heritage Deferral	$ (2)	$ 9
Non-Heritage Deferral	41	28
Trade Income Deferral	(31)	166
	8	203
Forecast Variance Accounts		
Finance Charges	(5)	(23)
Rate Smoothing Account	38	25
Other	(10)	(3)
	23	(1)
Capital-Like Accounts		
Demand Side Management (DSM)	18	21
Site C	19	13
Smart Metering and Infrastructure (SMI)	3	20
IFRS Property, Plant and Equipment	39	45
	79	99
Non-Cash Accounts		
Environmental Provisions	6	(12)
First Nations	4	10
Other	2	1
	12	(1)
Amortization of regulatory accounts	(117)	(71)
Interest on regulatory accounts	16	10
Net change in regulatory accounts	$ 21	$ 239

For the three months ended June 30, 2014, net increases to the Company's regulatory accounts were $21 million, $218 million lower than the same period in the prior fiscal year. The decrease over the prior fiscal year was due primarily to the deferral of the Powerex California legal settlement in the prior year. The net asset balance in the regulatory asset and liability accounts as at June 30, 2014 was an asset of $4,720 million compared to an asset of $4,699 million as at March 31, 2014.

Net additions to the regulatory accounts during the three months ended June 30, 2014 included:

- Increase to the energy deferral accounts primarily due to lower than plan domestic revenues partially offset by higher than plan trade income;
- Increase to the Rate Smoothing regulatory account for smoothing the rate impact of the F2015-F2016 Revenue Requirements Rate Application;
- Planned expenditures on DSM projects, which support energy conservation, and the Site C project; and
- Transfers to the IFRS Property, Plant and Equipment regulatory account for smoothing the rate impact of overhead costs eligible for capitalization under CGAAP but not eligible under IFRS as they are not considered directly attributable to the construction of capital assets.

These net additions were partially offset primarily by the net amortization of the regulatory accounts.

For fiscal 2015, 27 of 29 regulatory accounts, representing approximately 80 per cent of the total regulatory account balance, are being collected in rates over various periods. Six additional regulatory accounts commenced amortization in fiscal 2015. This resulted in an additional $27 million amortization expense in the three months ended June 30, 2014 compared to the same period in the prior fiscal year.

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. No Payment has been accrued as at June 30, 2014 for fiscal 2015 as the Company's debt to equity ratio is at the 80:20 cap prior to the calculation of the Payment.

LEGAL PROCEEDINGS

CALIFORNIA SETTLEMENT

In October 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 into escrow of US$273 million in fiscal 2014 pending the Settlement Effective Date which translated to CDN$287 million on the transaction date and CDN$292 million as at June 30, 2014, which is recorded as restricted cash in the Statement of Financial Position.

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.

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 PLAN

In November 2013, the Government announced a 10 year plan for BC Hydro. On March 6, 2014, the Government issued Directions No. 6 and 7 to the BCUC to implement the 10 year 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.

BC HYDRO F2015-F2016 REVENUE REQUIREMENTS RATE APPLICATION (F15-F16 RRRA)

The F15-F16 RRRA sets rates 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 26, 2014, approving the application as filed.

AVAILABLE TRANSFER CAPACITY (ATC) RULE

In December 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 participated in the hearing opposing the proposed rule. The AUC issued its decision on February 1, 2013 approving the rule as filed. The impact to BC Hydro of the approval of the ATC rule is a reduction in the effective transmission transfer capability between the provinces, which in turn reduces the ability of transmission customers, including Powerex, to sell energy into Alberta. On March 4, 2013, BC Hydro and Powerex filed a motion for leave to appeal the AUC decision with the Alberta Court of Appeal. BC Hydro and Powerex also filed a request for Review and Variance with the AUC on April 2, 2013. On August 16, 2013, the AUC issued its decision denying the request for Review and Variance. The motions for leave to appeal were heard on November 19, 2013 and on April 10, 2014, the Alberta Court of Appeal granted leave. BC Hydro and Powerex filed a Notice of Appeal on May 15, 2014 and the appeal will be heard on January 15, 2015 with a decision expected by end of fiscal 2015.

NEW POWER PURCHASE AGREEMENT WITH FORTISBC

In May 2013, BC Hydro filed an application with the BCUC for approval of a new 20 year Power Purchase Agreement (PPA) with FortisBC. BC Hydro's current PPA with FortisBC has been in place since 1993 and expired on September 30, 2013. The BCUC extended the term of the PPA beyond September 30, 2013, until such time as the decision on the application was issued. On May 6, 2014, the BCUC issued Order No. G-60-14 and approved the new PPA effective July 1, 2014, for a 20 year period.

BCUC REVIEW TASK FORCE

On April 28, 2014, the Province announced the establishment of a Task Force to review the operations of the BCUC. Terms of Reference were issued the same day and focus on providing recommendations to make the BCUC more effective and efficient. BC Hydro will be providing input to the Task Force as determined by the schedule established by the Task Force for its review. The Terms of Reference for the Task Force require that its report be completed by November 17, 2014.

RATE DESIGN APPLICATION (RDA)

BC Hydro is beginning the preparation of its next RDA, which is expected to be filed with the BCUC at the end of June 2015. Among other things, the 2015 RDA will consider and update many of the underlying drivers, analysis and assumptions that impact BC Hydro's conservation 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. BC Hydro will also consider the Industrial Electricity Policy Review recommendations with respect to the transmission stepped rate and transmission Time of Use rates, as well as changes to BC Hydro's long run marginal cost which is used in the pricing of step (tier) 2 energy blocks for the conservation rates.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the three months ended June 30, 2014 was $124 million, compared with cash flow provided by operating activities of $46 million in the prior fiscal year. The increase was primarily due to an increase in cash flows from net income before regulatory transfers due to higher revenues, partially offset by higher energy costs. The increase in cash flows was partially offset by changes in working capital.

The long-term debt balance net of sinking funds at June 30, 2014 was $15,894 million, compared with $15,568 million at March 31, 2014. The increase was mainly as a result of an increase in net long-term bond issues totaling $694 million ($765 million par value). This increase was partially offset by long-term bond redemptions totaling $325 million par value, net foreign exchange revaluation gains of $34 million, and a decrease in revolving borrowings of $6 million. Long-term debt increased primarily to fund capital expenditures.

CAPITAL EXPENDITURES

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

	For the three months ended June 30	
(in millions)	**2014**	2013
Distribution system improvements and expansion	**$ 103**	$ 90
Generation replacements and expansion	**103**	101
Transmission lines and substation replacements & expansion	**203**	176
General, including technology, vehicles and buildings	**30**	35
Total Capital Expenditures	**$ 439**	$ 402

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

Distribution capital expenditures for the three months ended June 30, 2014 were $103 million, which includes expenditures on customer driven work, end of life asset replacement, system expansion and improvement, and Smart Metering and Infrastructure project.

Generation capital expenditures for the three months ended June 30, 2014 were $103 million, which includes expenditures for John Hart Replacement, Mica Units 5 & 6 Installation, Ruskin Dam and Powerhouse Upgrade, G.M. Shrum Units 1 to 5 Turbine Rehabilitation and Hugh Keenleyside Spillway Gate Upgrade projects.

Transmission lines and substations capital expenditures for the three months ended June 30, 2014 were $203 million, which includes expenditures on the Northwest Transmission Line, Dawson Creek/Chetwynd Area Transmission, Interior to Lower Mainland Transmission Line, Iskut Extension, Merritt Area Transmission, Surrey Area and Big Bend substation projects. The Northwest Transmission Line Project was put into service on July 15, 2014.

General capital expenditures for the three months ended June 30, 2014 were $30 million which primarily included expenditures on various technology projects and building development programs.

RISK MANAGEMENT

BC Hydro is exposed to numerous risks, which can result in safety, environmental, financial, reliability and reputational impacts. 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.

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 Electricity Purchase Agreement (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.

This section should be read in conjunction with the risks disclosed in the Risk Management section in the Management's Discussion and Analysis presented in the Annual Report for the year ended March 31, 2014.

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 2014 forecasted net income for fiscal 2015 at $582 million, which is consistent with the 10 year plan announced by the Government in November 2013.

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 and interest rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The Service Plan forecast for fiscal 2015 assumed average water inflows (100 per cent of average), domestic tariff sales of 53,130 GWh, average market energy prices of U.S. $31.85/MWh, short-term interest rates of 1.28 per cent, an allowed return on equity of 11.84 per cent, and an approved rate increase of 9 per cent for fiscal 2015.

BC Hydro filed an updated forecast with the Province in August 2014. The significant changes from the Service Plan for fiscal 2015, which has no net income impact after regulatory account transfers, include:

- An increase in domestic tariff sales of 345 GWh. Forecast sales in the large industrial and commercial sector has increased largely as a result of an improved economic recovery especially in the pulp and paper sector and this is partly offset by lower consumption per account in the residential sector.
- A decrease in surplus sales mainly as a result of lower market purchases and an increase in domestic tariff sales.
- A decrease in short term interest rates by 0.19 to 1.09 per cent.

The impact of the changes above flow through BCUC approved regulatory accounts and have the effect of reducing future rate increases in comparison to the original 10 year plan.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

	For the three months ended June 30	
(in millions)	**2014**	2013
Revenues		
Domestic	**$ 1,084**	$ 947
Trade	**286**	307
	1,370	1,254
Expenses		
Operating Expenses (Note 4)	**1,137**	1,051
Finance Charges (Note 5)	**140**	148
Net Income	**93**	55
OTHER COMPREHENSIVE INCOME		
Items Reclassified Subsequently to Net Income		
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 16)	**(16)**	17
Reclassification to income on derivatives designated as cash flow hedges (Note 16)	**29**	(27)
Foreign currency translation gains (losses)	**(5)**	5
Other Comprehensive Income (Loss)	**8**	(5)
Total Comprehensive Income	**$ 101**	$ 50

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(in millions)	*As at June 30 2014*	*As at March 31 2014*
ASSETS		
Current Assets		
Cash and cash equivalents (Note 7)	**$ 5**	$ 107
Restricted cash (Note 7 and 11)	**312**	355
Accounts receivable and accrued revenue	**599**	718
Inventories (Note 8)	**166**	114
Prepaid expenses	**227**	211
Current portion of derivative financial instrument assets (Note 16)	**63**	96
	1,372	1,601
Non-Current Assets		
Property, plant and equipment (Note 9)	**18,800**	18,525
Intangible assets (Note 9)	**494**	501
Regulatory assets (Note 10)	**4,946**	4,928
Sinking funds	**126**	129
Derivative financial instrument assets (Note 16)	**24**	27
	24,390	24,110
	$ 25,762	$ 25,711
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Notes 11 and 15)	**$ 1,507**	$ 1,886
Current portion of long-term debt (Note 12)	**3,756**	4,087
Current portion of derivative financial instrument liabilities (Note 16)	**58**	76
	5,321	6,049
Non-Current Liabilities		
Long-term debt (Note 12)	**12,264**	11,610
Regulatory liabilities (Note 10)	**226**	229
Derivative financial instrument liabilities (Note 16)	**64**	55
Contributions in aid of construction	**1,309**	1,291
Post-employment benefits	**1,177**	1,173
Other long-term liabilities (Note 15)	**1,435**	1,439
	16,475	15,797
Shareholder's Equity		
Contributed surplus	**60**	60
Retained earnings	**3,844**	3,751
Accumulated other comprehensive income	**62**	54
	3,966	3,865
	$ 25,762	$ 25,711

Commitments (Note 9)

Subsequent event (Note 11)

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Approved on Behalf of the Board:

Stephen Bellringer
Chair, Board of Directors

Tracey L. McVicar
Chair, Audit & Finance Committee

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS 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
Comprehensive Income (Loss)	5	(10)	(5)	-	55	50
Balance, June 30, 2013	$ 22	$ 44	$ 66	$ 60	$ 3,424	$ 3,550
Balance, April 1, 2014	$ 33	$ 21	$ 54	$ 60	$ 3,751	$ 3,865
Comprehensive Income (Loss)	(5)	13	8	-	93	101
Balance, June 30, 2014	$ 28	$ 34	$ 62	$ 60	$ 3,844	$ 3,966

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the three months ended June 30* 2014	2013
Operating Activities		
Net income	**$ 93**	$ 55
Regulatory account transfers (Note 10)	**(138)**	(310)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 10)	**117**	71
Amortization and depreciation expense (Note 6)	**167**	162
Unrealized gains on mark-to-market	**12**	(70)
Interest accrual	**162**	159
Other items	**17**	26
	430	93
Changes in:		
Restricted cash	**43**	43
Accounts receivable and accrued revenue	**104**	13
Prepaid expenses	**(18)**	(5)
Inventories	**(53)**	(7)
Accounts payable, accrued liabilities and other long-term liabilities	**(163)**	85
Contributions in aid of construction	**27**	61
	(60)	190
Interest paid	**(246)**	(237)
Cash provided by operating activities	**124**	46
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(418)**	(376)
Cash used in investing activities	**(418)**	(376)
Financing Activities		
Long-term debt:		
Issued (Note 12)	**694**	325
Retired	**(325)**	(356)
Receipt of revolving borrowings	**2,036**	2,182
Repayment of revolving borrowings	**(2,042)**	(1,544)
Payment to the Province (Note 13)	**(167)**	(215)
Settlement of hedging derivatives	**-**	(84)
Other items	**(4)**	(4)
Cash provided by financing activities	**192**	304
Decrease in cash and cash equivalents	**(102)**	(26)
Cash and cash equivalents, beginning of period	**107**	60
Cash and cash equivalents, end of period	**$ 5**	$ 34

See accompanying Notes to the Unaudited Condensed Consolidated Interim 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 condensed consolidated interim 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 upon consolidation.

The Company accounts for its one third interest in Waneta as a joint operation. 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

BASIS OF ACCOUNTING

These condensed consolidated interim financial statements have been prepared in accordance with significant accounting policies that 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 its 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 periods the amounts are incurred.

The impact of the application of ASC 980 on these condensed consolidated interim financial statements with respect to BC Hydro's regulatory accounts is described in Note 10.

These condensed consolidated interim statements have been prepared by management in accordance with the principles of IAS 34, *Interim Financial Reporting* and the Prescribed Standards and were prepared using the same accounting policies as described in BC Hydro's 2014 Annual Report except as described in Note 3. These interim condensed consolidated financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2014 Annual Report.

These condensed consolidated interim financial statements were approved by the Board of Directors on August 14, 2014.

NOTE 3: CHANGE IN ACCOUNTING POLICIES

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 using the one-month forward price of natural gas and included in Level 2 (Note 16: Financial Instruments – Fair Value Hierarchy) of the fair value hierarchy. Changes in fair value are recognized in trade revenues. Management believes fair value less costs to sell provides a more relevant measurement for valuing natural gas inventory. The change in accounting policy has no material impact on initial adoption or in the comparative period.

NOTE 4: OPERATING EXPENSES

	For the three months ended June 30	
(in millions)	**2014**	2013
Electricity and gas purchases	**$ 457**	$ 418
Water rentals	**89**	77
Transmission charges	**35**	36
Personnel expenses	**137**	140
Materials and external services	**135**	141
Amortization and depreciation (Note 6)	**290**	244
Grants, taxes and other costs	**51**	53
Capitalized costs	**(57)**	(58)
Total	**$ 1,137**	$ 1,051

NOTE 5: FINANCE CHARGES

(in millions)	*For the three months ended June 30* **2014**	2013
Interest on long-term debt	**$ 166**	$ 181
Interest on finance lease liabilities	**6**	12
Net interest expense on net defined benefit liability	**1**	3
Less: capitalized interest	**(17)**	(26)
Total finance costs	**156**	170
Other recoveries	**(16)**	(22)
Total	**$ 140**	$ 148

NOTE 6: AMORTIZATION AND DEPRECIATION

(in millions)	*For the three months ended June 30* **2014**	2013
Depreciation of property, plant and equipment	**$ 151**	$ 147
Amortization of intangible assets	**16**	15
Amortization of regulatory accounts	**123**	82
Total	**$ 290**	$ 244

NOTE 7: CASH AND CASH EQUIVALENTS AND RESTRICTED CASH

CASH AND CASH EQUIVALENTS

(in millions)	***As at June 30*** **2014**	*As at March 31* 2014
Cash	**$ 1**	$ 74
Short-term investments	**4**	33
Total	**$ 5**	$ 107

RESTRICTED CASH

(in millions)	***As at June 30* 2014**	*As at March 31* 2014
Funds held in trust (Note 11)	**$ 292**	$ 302
Other	**20**	53
Total	**$ 312**	$ 355

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

NOTE 8: INVENTORIES

(in millions)	***As at June 30* 2014**	*As at March 31* 2014
Materials and supplies	**$ 120**	$ 111
Natural gas trading inventories	**46**	3
Total	**$ 166**	$ 114

No natural gas trading inventories are pledged as security for liabilities.

NOTE 9: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset expenditures for the three months ended June 30, 2014 were $439 million (2013 - $402 million).

As of June 30, 2014, the Company has contractual commitments to spend $1,895 million on major property, plant and equipment projects (for individual projects greater than $50 million).

NOTE 10: 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 period which they are incurred. For the three month period ended June 30, 2014, the impact of regulatory accounting has resulted in a net increase of $21 million to comprehensive income (June 30, 2013 - $239 million increase). For each regulatory account, the amount reflected in the Net Change column in the following regulatory table represents the impact on comprehensive income for the applicable period, 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*	*June 30 2014*
Regulatory Assets					
Heritage Deferral Account	$ 105	$ (1)	$ (6)	$ (7)	$ 98
Non-Heritage Deferral Account	362	44	(21)	23	385
Trade Income Deferral Account	324	(28)	(18)	(46)	278
Demand-Side Management Programs	788	18	(18)	-	788
First Nation Negotiations, Litigation & Settlement Costs	589	6	(11)	(5)	584
Non-Current Pension Cost	280	(2)	(8)	(10)	270
Site C	338	23	-	23	361
CIA Amortization Variance	81	2	-	2	83
Environmental Provisions	383	6	(17)	(11)	372
Smart Metering and Infrastructure	277	6	(8)	(2)	275
IFRS Pension & Other Post-Employment Benefits	688	-	(10)	(10)	678
IFRS Property, Plant and Equipment	617	39	(4)	35	652
Rate Smoothing	-	38	-	38	38
Other Regulatory Accounts	96	-	(12)	(12)	84
Total Regulatory Assets	4,928	151	(133)	18	4,946
Regulatory Liabilities					
Future Removal and Site Restoration Costs	56	-	(6)	(6)	50
Foreign Exchange Gains and Losses	89	4	-	4	93
Finance Charges	79	5	(7)	(2)	77
Other Regulatory Accounts	5	4	(3)	1	6
Total Regulatory Liabilities	229	13	(16)	(3)	226
Net Regulatory Asset	$ 4,699	$ 138	$ (117)	$ 21	$ 4,720

As part of the 10 year plan announced by Government, the Rate Smoothing Regulatory Account was established under Direction No. 7 to defer, for recovery in future years, those portions of BC Hydro's revenue requirement in a particular fiscal year, that are not recovered in rates in that particular fiscal year.

OTHER REGULATORY ACCOUNTS

Other regulatory asset and liability accounts with individual balances less than $40 million include the following: Arrow Water Systems Divestiture, Capital Project Investigation Costs, Home Purchase Option Program, Return on Equity (ROE) Adjustment, Waneta Rate Smoothing, Asbestos Remediation, Amortization of Capital Additions, and Storm Damage.

NOTE 11: ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(in millions)	*As at June 30* **2014**	*As at March 31* 2014
Accounts payable	**$ 336**	$ 386
Accrued liabilities	**679**	819
Legal settlement	**292**	302
Current portion of other long-term liabilities (Note 15)	**113**	120
Dividend payable	**-**	167
Other	**87**	92
Total	**$ 1,507**	$ 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 into escrow of US$273 million in fiscal 2014 which translated to CDN$287 million on the transaction date and CDN$292 million as at June 30, 2014, which is recorded as restricted cash in the condensed consolidated interim statement of financial position.

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 12: LONG-TERM DEBT AND DEBT MANAGEMENT

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

In the three month period ended June 30, 2014, the Company issued bonds with net proceeds of $694 million and par value of $765 million (2013 - net proceeds of $325 million and par value of $350 million), a weighted average effective interest rate of 3.7 per cent (2013 - 3.6 per cent) and a weighted average term to maturity of 30.1 years (2013 - 33.6 years).

NOTE 13: 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 three months ended June 30, 2014, there were no changes in the approach to capital management.

The debt to equity ratio at June 30, 2014 and March 31, 2014 was as follows:

(in millions)	***As at June 30* 2014**	*As at March 31* 2014
Total debt, net of sinking funds	**$ 15,894**	$ 15,568
Less: Cash and cash equivalents	**(5)**	(107)
Net Debt	**$ 15,889**	$ 15,461
Retained earnings	**$ 3,844**	$ 3,751
Contributed surplus	**60**	60
Accumulated other comprehensive income	**62**	54
Total Equity	**$ 3,966**	$ 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. No Payment has been accrued as at June 30, 2014 (March 31, 2014 - $167 million, included in accounts payable and accrued liabilities) as the Company's debt to equity ratio is at the 80:20 cap prior to the calculation of the Payment.

NOTE 14: POST-EMPLOYMENT BENEFITS

The expense recognized in the statement of comprehensive income for the Company's defined benefit plans 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 for the three months ended June 30, 2014 was $36 million (2013 - $39 million).

Contributions to the registered defined benefit pension plans for the three months ended June 30, 2014 were $16 million (2013 - $12 million).

NOTE 15: OTHER LONG-TERM LIABILITIES

(in millions)	***As at June 30*** **2014**	*As at March 31* 2014
Provisions		
Environmental liabilities	**$ 331**	$ 333
Decommissioning obligations	**51**	50
Other	**20**	22
Total Provisions	**402**	405
First Nations liabilities	**408**	417
Finance lease obligations	**272**	276
Other liabilities	**37**	28
Deferred revenue - Skagit River Agreement	**429**	433
	1,548	1,559
Less: Current portion, included in accounts payable and accrued liabilities	**(113)**	(120)
Total	**$ 1,435**	$ 1,439

NOTE 16: FINANCIAL INSTRUMENTS

Finance charges, including interest income and expenses, for financial instruments disclosed in this note are prior to the application of regulatory accounting for the three months ended June 30, 2014 and 2013.

CATEGORIES OF FINANCIAL INSTRUMENTS

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at June 30, 2014 and March 31, 2014. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

	June 30, 2014		March 31, 2014	
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Financial Assets and Liabilities at Fair Value Through Profit or Loss:				
Short-term investments	**$ 4**	**$ 4**	$ 33	$ 33
Loans and Receivables:				
Accounts receivable and accrued revenue	**599**	**599**	718	718
Restricted cash	**312**	**312**	355	355
Cash	**1**	**1**	74	74
Held to Maturity:				
Sinking funds – US	**126**	**140**	129	143
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**(1,507)**	**(1,507)**	(1,886)	(1,886)
Revolving borrowings - CAD	**(3,597)**	**(3,597)**	(3,504)	(3,504)
Revolving borrowings - US	**(159)**	**(159)**	(258)	(258)
Long-term debt (including current portion due in one year)	**(12,264)**	**(14,124)**	(11,935)	(13,405)
First Nations liability (long-term portion only)	**(376)**	**(818)**	(385)	(725)
Finance Lease Obligation (long-term portion only)	**(254)**	**(254)**	(259)	(259)

For non-derivative financial assets and liabilities classified as financial assets and liabilities at fair value through profit or loss, $nil (2013 - $8 million gain) has been recognized in net income for the three months ended June 30, 2014 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)	**June 30 2014 Fair Value**	March 31 2014 Fair Value
Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ (52)**	$ (36)
Non-Designated Derivative Instruments:		
Foreign currency contracts	**(7)**	5
Commodity derivatives	**24**	23
	17	28
Net liability	**$ (35)**	$ (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)		**June 30 2014**		March 31 2014
Current portion of derivative financial instrument assets	$	**63**	$	96
Current portion of derivative financial instrument liabilities		**(58)**		(76)
Derivative financial instrument assets, long-term		**24**		27
Derivative financial instrument liabilities, long-term		**(64)**		(55)
Net liability	$	**(35)**	$	(8)

For designated cash flow hedges for the three months ended June 30, 2014, a loss of $16 million (2013 - $17 million gain) was recognized in other comprehensive income. For the three months ended June 30, 2014, $29 million (2013 - $27 million) was removed from other comprehensive income and reported in net income, offsetting foreign exchange gains (2013 – losses) recorded in the period.

For derivative instruments not designated as hedges, a loss of $3 million (2013 - $2 million gain) was recognized in finance charges for the three months ended June 30, 2014 with respect to foreign currency contracts for cash management purposes. For the three months ended June 30, 2014, a loss of $7 million (2013 - $41 million gain) was recognized in finance charges with respect to foreign currency contracts for U.S. short-term borrowings. These economic hedges offset $7 million of foreign exchange revaluation gains (2013 - $43 million loss) recorded with respect to U.S. short-term borrowings for the three months ended June 30, 2014. A net gain of $15 million (2013 - $10 million gain) was recorded in trade revenue for the three months ended June 30, 2014 with respect to commodity derivatives.

INCEPTION GAINS AND LOSSES

Changes in deferred inception gains and losses arising from the determination of fair value of derivative financial instruments which are not supported by observable current market transactions or valuation models using only observable market data are as follows:

		For the three months ended June 30		
(in millions)		**2014**		2013
Unamortized gain at beginning of period	$	**(50)**	$	(58)
New transactions		**(3)**		(1)
Amortization		**5**		4
Unamortized gain at end of period	$	**(48)**	$	(55)

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 table presents the financial assets and financial liabilities measured at fair value for each hierarchy level as at June 30, 2014 and March 31, 2014:

As at June 30, 2014 *(in millions)*	Level 1	Level 2	Level 3	Total
Short-term investments	$ 4	$ -	$ -	$ 4
Derivatives designated as hedges	-	11	-	11
Derivatives not designated as hedges	17	31	28	76
Total financial assets carried at fair value	$ 21	$ 42	$ 28	$ 91
Derivatives designated as hedges	$ -	$ (63)	$ -	$ (63)
Derivatives not designated as hedges	(20)	(35)	(4)	(59)
Total financial liabilities carried at fair value	$ (20)	$ (98)	$ (4)	$ (122)

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 uses 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.

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 three months ended June 30, 2014 and 2013:

(in millions)		
Balance at April 1, 2014	**$**	**43**
Cumulative impact of net gain recognized		18
New transactions		(6)
Existing transactions settled		(31)
Balance at June 30, 2014	**$**	**24**

(in millions)		
Balance at April 1, 2013	**$**	**34**
Cumulative impact of net gain recognized		8
New transactions		(3)
Existing transactions settled		(7)
Balance at June 30, 2013	**$**	**32**

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.

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.

A net gain of $10 million (2013 - $9 million gain) recognized in net income during the three months ended June 30, 2014 relates to Level 3 financial instruments held at June 30, 2014. The net gain is recognized in trade revenue.

The Company believes that the use of reasonable alternative valuation input assumptions in the calculation of Level 3 fair values would not result in significantly different fair values. Methodologies and procedures regarding Powerex's energy trading Level 3 fair value measurements are determined by Powerex's Risk Management group. Level 3 Powerex 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 quarterly basis.

NOTE 17: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of the Company's operations, the condensed consolidated interim statement of comprehensive income is not indicative of operations on an annual basis. Seasonal impacts of weather, including its impact on water inflows, energy consumption within the region and market prices of energy, can have a significant impact on the Company's operating results.