British Columbia Hydro and Power Authority

2017/18

THIRD QUARTER REPORT

BC Hydro
Power smart

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 three and nine months ended December 31, 2017 and should be read in conjunction with the MD&A presented in the 2017 Annual Service Plan Report, the 2017 Audited Consolidated Financial Statements and related notes of the Company, and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three and nine months ended December 31, 2017.

The Company applies accounting standards as prescribed by the Province of British Columbia (the Province) which combine 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 three months ended December 31, 2017 was $233 million, $20 million higher than the same period in the prior fiscal year. Domestic revenues were $91 million higher than the same period in the prior fiscal year primarily due to higher average customer rates reflecting an average interim rate increase as approved by the British Columbia Utilities Commission (BCUC) of 3.5 per cent effective April 1, 2017. This was partially offset by $26 million higher domestic costs of energy mainly due to higher planned purchases from Independent Power Producers, $17 million higher finance charges, and higher materials and external services of $13 million.

- Net income for the nine months ended December 31, 2017 was $357 million, $28 million higher than the same period in the prior fiscal year. Domestic revenues were $224 million higher than the same period in the prior fiscal year primarily due to higher average customer rates reflecting an average interim rate increase as approved by the British Columbia Utilities Commission of 3.5 per cent effective April 1, 2017. This was partially offset by $88 million higher domestic costs of energy mainly due to higher planned purchases from Independent Power Producers, $39 million higher finance charges, $20 million higher grants, taxes, and other costs, $19 million less costs eligible to be capitalized, and higher materials and external services of $18 million.

- Water inflows to the system during the nine months ended December 31, 2017 were 97 per cent of average compared to 100 per cent of average in the same period in the prior fiscal year. The lower water inflows in fiscal 2018 compared to the same period in the prior fiscal year were the result of dry weather in the Peace region, partially offset by higher snowmelt in the Columbia region.

- Capital expenditures, before contributions in aid of construction, for the three and nine months ended December 31, 2017 were $641 million and $1,776 million respectively. This was a $63 million and $25 million increase respectively, over the same periods in the prior fiscal year. BC Hydro continues to invest significantly in capital projects/programs to refurbish its ageing infrastructure and build new assets for future growth, including Site C, John Hart Generating Station Replacement, Ruskin Dam Safety and Powerhouse Upgrade, Distribution Wood Poles Replacements, W.A.C. Bennett Dam Riprap Upgrade, Horne Payne Substation Upgrade, and Kamloops Substation.

CONSOLIDATED RESULTS OF OPERATIONS

	For the three months ended December 31			*For the nine months ended December 31*		
($ in millions)	**2017**	2016	Change	**2017**	2016	Change
Total Revenues	**$ 1,646**	$ 1,564	$ 82	**$ 4,471**	$ 4,202	$ 269
Net Income	**$ 233**	$ 213	$ 20	**$ 357**	$ 329	$ 28
Capital Expenditures	**$ 641**	$ 578	$ 63	**$ 1,776**	$ 1,751	$ 25
GWh Sold (Domestic)	**$ 14,917**	15,016	(99)	**42,684**	41,876	808

($ in millions)	***As at December 31, 2017***	*As at March 31, 2017*	Change
Total Assets	**$ 32,856**	$ 31,888	$ 968
Shareholder's Equity	**$ 5,148**	$ 4,909	$ 239
Accrued Payment to the Province	**$ 159**	$ -	$ 159
Retained Earnings	**$ 5,020**	$ 4,822	$ 198
Debt to Equity	**80 : 20**	80 : 20	n/a
Number of Domestic Customer Accounts	**2,012,753**	1,987,963	24,790
Total Reservoir Storage (GWh)	**19,548**	14,526	5,022

REVENUES

Total revenues after regulatory account transfers for the three months ended December 31, 2017 were $1,646 million, an increase of $82 million or 5 per cent compared to the same period in the prior fiscal year. The increase includes higher domestic revenues of $91 million partially offset by lower trade revenues of $9 million.

Total revenues after regulatory account transfers for the nine months ended December 31, 2017 were $4,471 million, an increase of $269 million or 6 per cent compared to the same period in the prior fiscal year. The increase includes higher domestic revenues of $224 million and higher trade revenues of $45 million. The table below shows revenues before regulatory account transfers, the amount of regulatory account transfers, and total revenues after regulatory account transfers.

for the three months ended December 31	*(in millions)* **2017**	2016	*(gigawatt hours)* **2017**	2016	*($ per MWh)*[2] **2017**	2016
Domestic						
Residential	**$ 620**	$ 598	**5,303**	5,327	**$ 116.91**	$ 112.26
Light industrial and commercial	**492**	457	**4,971**	4,794	**98.97**	95.33
Large industrial	**210**	195	**3,555**	3,375	**59.07**	57.78
Other sales	**96**	92	**1,088**	1,520	**88.24**	60.53
Total Domestic Revenue Before Regulatory Transfers	**1,418**	1,342	**14,917**	15,016	**95.06**	89.37
Rate smoothing and energy deferral regulatory transfers	**54**	39	**-**	-	**-**	-
Total Domestic	**$ 1,472**	$ 1,381	**14,917**	15,016	**$ 98.68**	$ 91.97
Trade						
Gross electricity and gas	**$ 305**	$ 346	**8,590**	9,001	**$ 35.31**	$ 36.66
Less: forward electricity and gas purchases	**(131)**	(163)	**-**	-	**-**	-
Total Trade[1]	**$ 174**	$ 183	**8,590**	9,001	**$ 20.26**	$ 20.33
Total	**$ 1,646**	$ 1,564	**23,507**	24,017	**$ 70.02**	$ 65.12

for the nine months ended December 31	*(in millions)* **2017**	2016	*(gigawatt hours)* **2017**	2016	*($ per MWh)*[2] **2017**	2016
Domestic						
Residential	**$ 1,442**	$ 1,346	**12,561**	12,231	**$ 114.80**	$ 110.05
Light industrial and commercial	**1,389**	1,307	**14,091**	13,779	**98.57**	94.85
Large industrial	**589**	566	**10,045**	9,882	**58.64**	57.28
Other sales	**349**	315	**5,987**	5,984	**58.29**	52.64
Total Domestic Revenue Before Regulatory Transfers	**3,769**	3,534	**42,684**	41,876	**88.30**	84.39
Rate smoothing and energy deferral regulatory transfers	**160**	171	**-**	-	**-**	-
Total Domestic	**$ 3,929**	$ 3,705	**42,684**	41,876	**$ 92.05**	$ 88.48
Trade						
Gross electricity and gas	**$ 965**	$ 951	**25,704**	26,803	**$ 34.55**	$ 31.58
Less: forward electricity and gas purchases	**(423)**	(454)	**-**	-	**-**	-
Total Trade[1]	**$ 542**	$ 497	**25,704**	26,803	**$ 21.09**	$ 18.54
Total	**$ 4,471**	$ 4,202	**68,388**	68,679	**$ 65.38**	$ 61.18

[1] Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer and this is reflected in the cost of energy table.
[2] The Trade $ per MWh represents the gross $ per MWh of physical transactions and does not include financial transactions. The Total Trade $ per MWh is a simple average calculation and does not reflect actual trade energy prices during the period.

Domestic Revenues

Domestic revenues for the three months ended December 31, 2017 were $1,472 million, an increase of $91 million, or 7 per cent, compared to the same period in the prior fiscal year. The increase before regulatory account transfers was primarily due to higher average customer rates that reflect the 3.5 per cent interim rate increase as approved by the BCUC effective April 1, 2017 and higher consumption in the light industrial and commercial class. Regulatory transfers were $15 million higher than the same period in the prior fiscal year, as discussed in the *Regulatory Transfers* section.

Domestic revenues for the nine months ended December 31, 2017 were $3,929 million, an increase of $224 million or 6 per cent compared to the same period in the prior fiscal year. The increase before regulatory account transfers was primarily due to higher average customer rates that reflect the 3.5 per cent interim rate increase. The increase was also due to higher residential consumption that was primarily driven by colder weather, higher light industrial and commercial consumption due to a higher number of customers in the current period compared to the same period in the prior fiscal year, and higher surplus energy (a component of other sales) sold to the market that was largely driven by higher market prices. This increase was partially offset by $11 million in lower regulatory account transfers which are discussed in the *Regulatory Transfers* section.

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 an active participant in western energy markets, buying and selling wholesale power, natural gas, ancillary services, clean and renewable power, and environmental products.

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

Total trade revenues for the three months ended December 31, 2017 were $174 million, a decrease of $9 million or 5 per cent compared with the same period in the prior fiscal year. The decrease in trade revenues was primarily related to lower average gas sales price compared to the prior period.

Total trade revenues for the nine months ended December 31, 2017 were $542 million, an increase of $45 million or 9 per cent compared with the same period in the prior fiscal year. The increase in trade revenues was primarily related to an increase in the average energy sales price during the first half of the year, driven by increased demand in California due to hot weather and a series of heatwaves resulting in high prices in that region.

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

OPERATING EXPENSES

For the three and nine months ended December 31, 2017, total operating expenses, after regulatory account transfers, of $1,244 million and $3,620 million respectively, were $45 million and $202 million higher than the same period in the prior fiscal year. The increase over the prior fiscal year for the three months ended December 31, 2017 was primarily due to higher costs of energy of $17 million and higher materials and external services of $13 million. The increase over the prior fiscal year for the nine months ended December 31, 2017 was primarily due to higher costs of energy of $133 million, higher grants, taxes and other costs of $20 million, lower costs eligible to be capitalized of $19 million, and higher material and external services of $18 million.

Costs of Energy

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission and other charges. Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand, and environmental and social impacts.

Total energy costs after regulatory transfers for the three months ended December 31, 2017 were $593 million, $17 million or 3 per cent higher than the same period in the prior fiscal year. The increase was primarily due to higher domestic energy costs of $26 million partially offset by lower trade energy costs of $9 million.

Total energy costs after regulatory transfers for the nine months ended December 31, 2017 were $1,722 million, $133 million or 8 per cent higher than the same period in the prior fiscal year. The increase over the prior fiscal year was primarily due to higher domestic energy costs of $88 million and higher trade energy costs of $45 million. The table below shows energy costs before regulatory account transfers, the amount of regulatory account transfers, and total energy costs after regulatory account transfers.

for the three months ended December 31	*(in millions)* **2017**	2016	*(gigawatt hours)* **2017**	2016	*($ per MWh)* [2] **2017**	2016
Domestic						
Water rental payments (hydro generation)[1]	**$ 80**	$ 88	**13,909**	13,258	**$ 5.75**	$ 6.64
Purchases from Independent Power Producers	**346**	319	**3,400**	3,331	**101.76**	95.77
Other electricity purchases - Domestic	**0**	1	**9**	36	**-**	27.78
Gas and transportation for thermal generation	**2**	4	**33**	3	60.61	1,333.33
Transmission charges and other expenses	**4**	8	**32**	36	**-**	-
Columbia River Treaty Related Agreements	**(3)**	5	**-**	-	**-**	-
Allocation from (to) trade energy	**(19)**	(7)	**(881)**	(212)	**25.80**	34.69
Total Domestic Cost of Energy Before Regulatory Transfers	**410**	418	**16,502**	16,452	**24.85**	25.41
Energy deferral regulatory transfers	**57**	23	**-**	-	**-**	-
Total Domestic	**$ 467**	$ 441	**16,502**	16,452	**$ 28.30**	$ 26.81
Trade						
Gross electricity and remarketed gas	**$ 190**	$ 254	**7,734**	8,678	**$ 24.22**	$ 28.75
Less: forward electricity and gas purchases	**(131)**	(163)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**59**	91	**-**	-	**-**	-
Transmission charges and other expenses	**60**	63	**-**	-	**-**	-
Allocation (to) from domestic energy	**19**	7	**881**	212	**25.80**	34.69
Total Trade Cost of Energy Before Regulatory Transfers	**138**	161	**8,615**	8,890	**16.02**	18.11
Trade net margin regulatory transfer	**(12)**	(26)	**-**	-	**-**	-
Total Trade	**$ 126**	$ 135	**8,615**	8,890	**$ 14.63**	$ 15.19
Total Energy Costs	**$ 593**	$ 576	**25,117**	25,342	**$ 23.61**	$ 22.73

for the nine months ended December 31	*(in millions)* **2017**	2016	*(gigawatt hours)* **2017**	2016	*($ per MWh)* [2] **2017**	2016
Domestic						
Water rental payments (hydro generation)[1]	**$ 241**	$ 266	**35,202**	33,932	**$ 6.85**	$ 7.84
Purchases from Independent Power Producers	**1,056**	954	**11,921**	11,220	**88.58**	85.03
Other electricity purchases - Domestic	**1**	2	**41**	62	**24.39**	32.26
Gas and transportation for thermal generation	**7**	16	**34**	74	**205.88**	216.22
Transmission charges and other expenses	**12**	17	**79**	85	**-**	-
Columbia River Treaty Related Agreements	**(32)**	1	**-**	-	**-**	-
Allocation from (to) trade energy	**(17)**	-	**(796)**	(52)	**22.62**	30.31
Total Domestic Cost of Energy Before Regulatory Transfers	**1,268**	1,256	**46,481**	45,321	**27.28**	27.71
Energy deferral regulatory transfers	**54**	(22)	**-**	-	**-**	-
Total Domestic	**$ 1,322**	$ 1,234	**46,481**	45,321	**$ 28.44**	$ 27.23
Trade						
Gross electricity and remarketed gas	**$ 550**	$ 610	**24,950**	26,817	**$ 21.79**	$ 22.43
Less: forward electricity and gas purchases	**(423)**	(454)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**127**	156	**-**	-	**-**	-
Transmission charges and other expenses	**206**	190	**-**	-	**-**	-
Allocation (to) from domestic energy	**17**	-	**796**	52	**22.62**	30.31
Total Trade Cost of Energy Before Regulatory Transfers	**350**	346	**25,746**	26,869	**13.59**	12.88
Trade net margin regulatory transfer	**50**	9	**-**	-	**-**	-
Total Trade	**$ 400**	$ 355	**25,746**	26,869	**$ 15.54**	$ 13.21
Total Energy Costs	**$ 1,722**	$ 1,589	**72,227**	72,190	**$ 23.84**	$ 22.01

[1] Water rental payments are based on the previous calendar year's generation volumes. The volumes in the table are the actual hydro generation during the period. The $ per MWh is a simple average calculation and does not reflect actual water rental rates during the period.

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

Domestic Energy Costs

Domestic energy costs for the three months ended December 31, 2017 were $467 million, $26 million or 6 per cent higher than the same period in the prior fiscal year. There was a decrease in costs before regulatory account transfers driven by higher allocation to trade energy due to increased net trade export opportunities, lower water rental payments due to the elimination of the higher Tier 3 water rental rate which was being phased out during calendar 2017, and higher recoveries from water transactions associated with the Columbia River Treaty related agreements, offset by an increased number of Independent Power Producers in operation in the current period.

Domestic energy costs for the nine months ended December 31, 2017 were $1,322 million, $88 million or 7 per cent higher than the same period in the prior fiscal year. The increase in costs from the prior fiscal year before regulatory account transfers were primarily due to an increased number of Independent Power Producers in operation in the current period. The increase in costs was partially offset by higher recoveries from water transactions associated with the Columbia River Treaty related agreements, lower water rental payments and higher allocation to trade energy due to increased net trade export opportunities.

In addition, there were $34 million higher regulatory transfers for the three months ended, and $76 million higher regulatory account transfers for the nine months ended December 31, related to the HDA and NHDA. Changes to regulatory account balances are discussed in the *Regulatory Transfers* section. Variances between actual and planned domestic costs 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 December 31, 2017 were $138 million, a decrease of $23 million or 14 per cent compared with the same period in the prior fiscal year. The decrease in trade energy costs was primarily related to a lower average gas purchase price compared to the prior period.

Total trade energy costs before regulatory account transfers for the nine months ended December 31, 2017 were $350 million, an increase of $4 million or 1 per cent compared with the same period in the prior fiscal year. The increase in trade energy costs was primarily driven by higher allocation from domestic energy due to increased net trade export opportunities and an increase in transmission charges and other expenses. This was partly offset by a decrease in the average energy purchase volume and price for the period.

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

Water Inflows and Reservoir Storage

Water inflows to the system during the nine months ended December 31, 2017 were 97 per cent of average compared to 100 per cent of average in the same period in the prior fiscal year. The lower water inflows in fiscal 2018 compared to the same period in the prior fiscal year were the result of dry weather in the Peace region, partially compensated by strong snowmelt in the Columbia region.

Total reservoir storage as at December 31, 2017 was 19,548 GWh, a decrease of 4,525 GWh compared to total reservoir storage as at December 31, 2016 of 24,073 GWh. System energy storage declined below the low end of the 10-year historical range (20,334 to 24,882 GWh between 2007 and 2016) due to strong electricity prices which resulted in more exports, dry weather and a reduction in overall inflows.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three and nine months ended December 31, 2017 were $140 million and $410 million respectively, an increase of $7 million and $12 million respectively, compared to the same period in the prior fiscal year.

Materials and External Services

Materials and External Services primarily includes materials, supplies, and contractor fees. Materials and external services for the three and nine months ended December 31, 2017 were $156 million and $456 million respectively, $13 million and $18 million higher respectively, than the same period in the prior fiscal year. The increase is primarily due to higher planned Independent Power Producers operating costs.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and the amortization of certain regulatory assets and liabilities. For the three and nine months ended December 31, 2017, amortization and depreciation expense was $314 million and $914 million respectively, which are the same for each of the periods in the prior fiscal year. For the three and nine months ended December 31, 2017, the amortization and depreciation expense included $107 million and $292 million respectively (three and nine months ended December 31 2016 - $118 million and $318 million) of amortization of regulatory account balances, which is the regulatory mechanism to recover the regulatory account balances in rates.

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 and nine months ended December 31, 2017 were $79 million and $236 million respectively, $1 million lower and $20 million higher respectively, than the same period in the prior fiscal year.

The increase for the nine months ended December 31, 2017 compared to prior year was primarily due to higher dismantling costs that were expensed as planned in the current period, but drew down the balance in a regulatory account during the same period in the prior fiscal year, and higher grants and taxes.

Capitalized Costs

Capitalized costs consist of overhead costs directly attributable to capital expenditures that are transferred from operating costs to Property, Plant & Equipment. Certain overhead costs not eligible for capitalization under IFRS are transferred from operating costs to the IFRS Property, Plant & Equipment Regulatory Account. These transfers are amortized over 40 years which approximates the composite average life of the Property, Plant & Equipment. In addition, starting in fiscal 2013, the ongoing impact of this change is being included in rates over a 10-year period through transfers to the IFRS Property, Plant & Equipment Regulatory Account as approved by the BCUC. As such, each year, 1/10 more of ineligible costs will be charged to operating costs such that by the end of year ten, all ineligible costs will be charged to operating costs.

Capitalized costs for the three and nine months ended December 31, 2017 were $38 million and $118 million respectively, compared to $47 million and $137 million respectively, in the same period in the prior fiscal year. The decrease in capitalized costs is consistent with the additional ineligible costs being charged to operating costs as noted above.

FINANCE CHARGES

Finance charges for the three and nine months ended December 31, 2017 were $169 million and $494 million respectively, compared to $152 million and $455 million respectively, in the same period in the prior fiscal year. The increase in both periods was primarily due to a higher amount of long-term debt borrowings, higher lease charges, and higher long-term and short-term interest rates. This increase was partially offset by higher interest during construction costs which was capitalized.

REGULATORY TRANSFERS

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

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. The use of regulatory accounts is common amongst regulated utility industries throughout North America. BC Hydro uses various regulatory accounts, in compliance with BCUC orders, to better match costs and benefits for different generations of customers, smooth out the rate impact of large non-recurring costs, and defer to future periods differences between forecast and actual costs or revenues. Regulatory accounts allow the Company to defer certain types of revenues and cost variances through transfers to and from the accounts which are then included in customer rates in future periods, subject to approval by the BCUC and have the effect of adjusting net income.

Net regulatory account transfers are comprised of the following:

(in millions)	*For the three months ended December 31* **2017**	2016	*For the nine months ended December 31* **2017**	2016
Energy Deferral Accounts				
Heritage Deferral Account	**$ 13**	$ 8	**$ (48)**	$ (17)
Non-Heritage Deferral Account	**(106)**	(48)	**(85)**	60
Trade Income Deferral Account	**9**	22	**(50)**	(13)
	(84)	(18)	**(183)**	30
Forecast Variance Accounts				
Total Finance Charges	**(10)**	(5)	**(22)**	(9)
Rate Smoothing	**78**	56	**199**	150
Pension Costs	**(123)**	3	**(119)**	8
Debt Management	**56**	(299)	**(9)**	(201)
Other	**16**	10	**27**	5
	17	(235)	**76**	(47)
Capital-Like Accounts				
Demand-Side Management	**17**	22	**41**	54
IFRS Property, Plant & Equipment	**22**	28	**67**	84
	39	50	**108**	138
Non-Cash Accounts				
Environmental Provisions & Costs	**4**	(34)	**(2)**	(25)
First Nations Provisions & Costs	**4**	5	**15**	12
Other	**-**	-	**(2)**	-
	8	(29)	**11**	(13)
Amortization of regulatory accounts	**(107)**	(118)	**(292)**	(318)
Interest on regulatory accounts	**16**	19	**49**	58
Net change in regulatory accounts	**$ (111)**	$ (331)	**$ (231)**	$ (152)

For the three and nine months ended December 31, 2017, net reductions to the Company's regulatory accounts after interest and amortization were $111 million and $231 million respectively, compared to $331 million and $152 million respectively, for the same periods in the prior fiscal year. The net regulatory asset balance as at December 31, 2017 was $5,366 million compared to $5,597 million as at March 31, 2017.

Net reductions to the regulatory accounts during the nine months ended December 31, 2017 included:

- $292 million of net amortization which is the regulatory mechanism to recover the regulatory account balances in rates;
- $183 million to the energy deferral accounts, primarily due to lower Independent Power Producers finance lease expenses, higher domestic revenues, higher recoveries from Columbia River Treaty related agreements, and higher trade net income; and
- $119 million to the Pension Costs Regulatory Account, primarily due to a reduction in post-retirement benefit plan liability as a result of the 50% reduction in Medical Service Plan premiums.

These net reductions were partially offset by the following additions:

- $199 million of planned additions to the Rate Smoothing Regulatory Account to smooth the impacts of the rate increases during the 10 Year Rates Plan period;

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

- $49 million of interest on regulatory accounts.

BC Hydro has regulatory mechanisms in place or has applied for regulatory mechanisms in the Fiscal 2017-2019 Revenue Requirements Application (F17-F19 RRA) to collect 24 of 26 regulatory accounts in use or with balances at December 31, 2017 in rates over various periods, which represent approximately 78 per cent of the total net regulatory asset account balance.

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 Special Directive states that for fiscal 2018 and subsequent years, the Payment will be reduced by $100 million per year based on the Payment in the immediate preceding fiscal year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

The fiscal 2017 Payment to the Province was $259 million and was paid in March 2017. Under the Special Directive, the Payment for fiscal 2018 will be $159 million. As a result, the Company has accrued $159 million as at December 31, 2017.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the nine months ended December 31, 2017 was $1,128 million, compared to $661 million in the same period in the prior fiscal year. The increase was mainly due to higher domestic revenues primarily due to higher average customer rates and higher consumption, lower cash flow used from changes in working capital, and higher trade gross margin.

The long-term debt balance net of sinking funds as at December 31, 2017 was $20,234 million compared to $19,845 million as at March 31, 2017. The increase was mainly a result of an increase in long-term bond issuances for net proceeds of $1,156 million ($1,200 million par value). This increase was partially offset by lower revolving borrowings of $678 million, which is a component of the long-term debt balance. Long-term debt increased primarily to fund capital expenditures.

CAPITAL EXPENDITURES

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

(in millions)	*For the three months ended December 31* **2017**	2016	*For the nine months ended December 31* **2017**	2016
Transmission lines and substations replacements and expansion	**$ 170**	$ 115	**$ 384**	$ 346
Generation replacements and expansion	**135**	140	**407**	417
Distribution system improvements and expansion	**123**	109	**372**	338
General, including technology, vehicles and buildings	**46**	49	**131**	160
Site C Project	**167**	165	**482**	490
Total Capital Expenditures[1]	**$ 641**	$ 578	**$ 1,776**	$ 1,751

[1] *Total capital expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the Consolidated Interim Statements of Cash Flows because the expenditures above include accruals.*

Transmission lines and substation capital expenditures includes expenditures on the following projects/programs: Horne Payne Substation Upgrade, Kamloops Substation, South Fraser Transmission Relocation, Transmission Wood Structure and Framing Replacement, Fernie Substation Upgrade, Campbell River Substation Capacity Upgrade, South Surrey Area Reinforcement, Peace Region Electric Supply, Spacer Damper Replacement, Bear Mountain Terminal Load Capacity Increase and Peace Region Load Shedding Remedial Action Scheme.

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

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

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

Site C Project expenditures relate to site preparation, clearing for reservoir and transmission lines, engineering and design, as well as social and land programs in addition to main civil works.

RATE REGULATION

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy, and earn an annual rate of return.

BC Hydro Fiscal 2017-2019 Revenue Requirements Application

In July 2016, BC Hydro filed an F17-F19 RRA to approve its revenue requirements for a three year test period covering fiscal 2017 to fiscal 2019. The Application requested rate increases of 4.0 per cent for fiscal 2017, 3.5 per cent for fiscal 2018, and 3.0 per cent in fiscal 2019 in alignment with the 10 Year Rates Plan.

The Province has since provided BC Hydro with a new Mandate Letter with the expectation that BC Hydro rates will be frozen for fiscal 2019, a comprehensive review of BC Hydro's activities will be conducted, and a refreshed plan to keep electricity rates low and predictable over the long-term will be developed. On November 8, 2017, BC Hydro filed an Application amending the original RRA and requesting a rate freeze for fiscal 2019. BC Hydro expects the BCUC to issue a decision on the F17-F19 RRA (including with respect to the requested rate freeze for fiscal 2019) in February 2018.

Site C Project Review

On August 2, 2017, the Province required the BCUC to conduct an inquiry into the Site C Project. The inquiry began on August 9, 2017, and the BCUC issued its preliminary report on September 20, 2017. On November 1, 2017, the BCUC issued its final report to the Province concluding the inquiry. On December 11, 2017, the British Columbia government announced the Site C Project will be completed.

BC Hydro Waneta Transaction

On October 30, 2017, BC Hydro submitted an Application to the BCUC under section 44.2 of the *Utilities Commission Act* for approval to purchase Teck Resources Limited's (Teck) two-third interest in the Waneta Dam and associated assets for $1.2 billion. The purchase agreement includes a 20 year agreement, at fixed prices, providing Teck with a leasehold interest in the two-thirds portion of Waneta. This will enable Teck to use the electricity generated from its interest in Waneta to continue to serve its Trail smelter. The Waneta dam is located near the mouth of the Pend d'Oreille River near Trail, BC, and has a generating capacity of 2,670 GWh per year. BC Hydro currently retains a one-third interest in the facility.

The BCUC has established a preliminary regulatory process to review the Application, including two rounds of information requests. BC Hydro responded to 958 information requests in the first round, with a second round of information requests to come in February 2018. BC Hydro requires final orders on the Application no later than August 1, 2018, as a condition of the purchase agreement between BC Hydro and Teck.

Customer Emergency Fund

On July 24, 2017, in response to the BCUC Order No. G-5-17, BC Hydro filed an application for a pilot program called the Customer Emergency Fund. This pilot provides grants of up to $600 per account to eligible residential customers in short-term financial hardship facing the possibility of electricity service disconnection. The pilot will be funded by a 25 cent per month rate rider on residential customer bills.

On November 17, 2017 the BCUC issued Order No. G-166-17 approving the Customer Emergency Fund Rate Rider. This order allows BC Hydro to commence the pilot in June 2018, and to continue it until the earlier of either June 2022, or issuance of a BCUC Order to end the Customer Emergency Fund Pilot.

RISK MANAGEMENT

BC Hydro is exposed to numerous risks, which can result in safety, environmental, financial, reliability and reputational impacts. This section of the MD&A discusses risks that may impact financial performance.

The impact of many financial risks associated with uncontrollable external influences on BC Hydro's net income is mitigated through the use of BCUC-approved regulatory accounts. Regulatory accounts assist in matching costs and benefits for different generations of customers, to smooth the impact of large, non-recurring costs and to defer for future recovery in rates the differences between planned and actual costs or revenues that arise due to uncontrollable events. BC Hydro's approach to the recovery of its regulatory accounts is included in the F17-F19 RRA.

Significant Financial Risks

The largest sources of variability in BC Hydro's financial performance are typically domestic and trade revenues, domestic and trade costs of energy, and finance charges. These are influenced by several elements, which generally fall into the following five categories: energy availability, domestic demand for energy, energy market prices, deliveries from electricity purchase agreement contracts, and interest rates. Neither a high nor a low value of any of these individual drivers is intrinsically positive or negative for BC Hydro's financial results. It is the specific combination of these drivers in any given year which has an impact.

While meeting domestic demand, environmental regulations and treaty obligations, BC Hydro attempts to operate the system to take maximum advantage of market energy prices - buying from the markets when prices are low and selling when prices are high. In doing so, BC Hydro attempts to optimize the combined effects of these elements and reduce the net cost of energy for our customers.

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 Service Plan Report for the year ended March 31, 2017. In addition, information on risks and opportunities that could significantly impact BC Hydro meeting its objectives is outlined at www.bchydro.com/serviceplan.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's updated Service Plan filed in September 2017 forecast net income for fiscal 2018 of $698 million which is consistent with the allowed net income prescribed by Order in Council No. 590.

BC Hydro filed an updated forecast with the Province in January 2018 which is incorporated into the February 2018 Service Plan and forecasts net income of $698 million for fiscal 2018 and $712 million for fiscal 2019.

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, interest rates, and foreign exchange rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The forecast for fiscal 2019 assumes average water inflows (100 per cent of average), domestic sales of 52,664 GWh, average market energy prices of US $21.43/MWh, short-term interest rates of 1.72 per cent, and a Canadian to US dollar exchange rate of US $0.8088.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)		*For the three months ended December 31* **2017**		2016		*For the nine months ended December 31* **2017**		2016
Revenues								
Domestic	**$**	**1,472**	$	1,381	**$**	**3,929**	$	3,705
Trade		**174**		183		**542**		497
		1,646		1,564		**4,471**		4,202
Expenses								
Operating expenses (Note 3)		**1,244**		1,199		**3,620**		3,418
Finance charges (Note 4)		**169**		152		**494**		455
Net Income		**233**		213		**357**		329
OTHER COMPREHENSIVE INCOME								
Items Reclassified Subsequently to Net Income								
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 13)		**12**		(11)		**20**		6
Reclassification to income of derivatives designated as cash flow hedges (Note 13)		**(17)**		(1)		**29**		(16)
Foreign currency translation (losses) gains		**-**		5		**(8)**		8
Other Comprehensive Income (Loss)		**(5)**		(7)		**41**		(2)
Total Comprehensive Income	**$**	**228**	$	206	**$**	**398**	$	327

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(in millions)		***As at December 31 2017***		*As at March 31* 2017
ASSETS				
Current Assets				
Cash and cash equivalents	**$**	**71**	$	49
Accounts receivable and accrued revenue		**835**		808
Inventories (Note 6)		**191**		185
Prepaid expenses		**71**		162
Current portion of derivative financial instrument assets (Note 13)		**157**		144
		1,325		1,348
Non-Current Assets				
Property, plant and equipment (Note 7)		**24,387**		22,998
Intangible assets (Note 7)		**589**		601
Regulatory assets (Note 8)		**5,869**		6,127
Derivative financial instrument assets (Note 13)		**124**		215
Other non-current assets (Note 9)		**562**		599
		31,531		30,540
	$	**32,856**	$	31,888
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities	**$**	**1,270**	$	1,190
Current portion of long-term debt (Note 10)		**3,447**		2,878
Current portion of derivative financial instrument liabilities (Note 13)		**94**		60
		4,811		4,128
Non-Current Liabilities				
Long-term debt (Note 10)		**16,962**		17,146
Regulatory liabilities (Note 8)		**503**		530
Derivative financial instrument liabilities (Note 13)		**18**		41
Contributions in aid of construction		**1,844**		1,765
Post-employment benefits (Note 12)		**1,470**		1,566
Other non-current liabilities (Note 14)		**2,100**		1,803
		22,897		22,851
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**5,020**		4,822
Accumulated other comprehensive income		**68**		27
		5,148		4,909
	$	**32,856**	$	31,888

Commitments (Note 7)

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

Approved on behalf of the Board:

Kenneth G. Peterson
Chair, Board of Directors

Len Boggio, FCPA, FCA, ICD.D
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 as at April 1, 2016	$ 77	$ (34)	$ 43	$ 60	$ 4,397	$ 4,500
Payment to the Province (Note 11)	-	-	-	-	(259)	(259)
Comprehensive Income (Loss)	8	(10)	(2)	-	329	327
Balance as at December 31, 2016	$ 85	$ (44)	$ 41	$ 60	$ 4,467	$ 4,568
Balance as at April 1, 2017	$ 83	$ (56)	$ 27	$ 60	$ 4,822	$ 4,909
Payment to the Province (Note 11)	-	-	-	-	(159)	(159)
Comprehensive Income (Loss)	(8)	49	41	-	357	398
Balance as at December 31, 2017	$ 75	$ (7)	$ 68	$ 60	$ 5,020	$ 5,148

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the nine months ended December 31* **2017**	2016
Operating Activities		
Net income	**$ 357**	$ 329
Regulatory account transfers (Note 8)	**(61)**	(166)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Notes 5 and 8)	**292**	318
Amortization and depreciation expense (Note 5)	**622**	587
Unrealized (gains) losses on mark-to-market of financial instruments	**27**	(217)
Employee benefit plan expenses	**79**	86
Interest accrual	**595**	567
Other items	**76**	95
	1,987	1,599
Changes in:		
Accounts receivable and accrued revenue	**34**	(145)
Prepaid expenses	**66**	109
Inventories	**(8)**	(56)
Accounts payable, accrued liabilities and other non-current liabilities	**(327)**	(253)
Contributions in aid of construction	**93**	80
Other non-current assets	**(9)**	-
	(151)	(265)
Interest paid	**(708)**	(673)
Cash provided by operating activities	**1,128**	661
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(1,610)**	(1,855)
Cash used in investing activities	**(1,610)**	(1,855)
Financing Activities		
Long-term debt:		
Issued (Note 10)	**1,156**	895
Retired (Note 10)	**(40)**	-
Receipt of revolving borrowings	**6,481**	7,584
Repayment of revolving borrowings	**(7,159)**	(6,885)
Payment to the Province (Note 11)	**-**	(326)
Other items	**66**	(30)
Cash provided by financing activities	**504**	1,238
Increase in cash and cash equivalents	**22**	44
Cash and cash equivalents, beginning of period	**49**	44
Cash and cash equivalents, end of period	**$ 71**	$ 88

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

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2017

NOTE 1: REPORTING ENTITY

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia.

These condensed consolidated interim financial statements (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) and 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. The interim 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 interim financial statements have been prepared in accordance with the 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 these interim 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.

The impact of the application of ASC 980 on these interim financial statements with respect to BC Hydro's regulatory accounts is described in Note 8.

These interim financial statements have been prepared by management in accordance with 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 2017 Annual Service Plan Report. Effective April 1, 2017, BC Hydro adopted amendments to various accounting standards that did not have a significant impact on these interim financial statements. These interim financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2017 Annual Service Plan Report.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2017

These interim financial statements were approved on behalf of the Board of Directors on February 5, 2018.

NOTE 3: OPERATING EXPENSES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2017**	2016	**2017**	2016
Electricity and gas purchases	**$ 472**	$ 444	**$ 1,353**	$ 1,192
Water rentals	**79**	90	**238**	270
Transmission charges	**42**	42	**131**	127
Personnel expenses	**140**	133	**410**	398
Materials and external services	**156**	143	**456**	438
Amortization and depreciation (Note 5)	**314**	314	**914**	914
Grants, taxes and other costs	**79**	80	**236**	216
Less: Capitalized costs	**(38)**	(47)	**(118)**	(137)
	$ 1,244	$ 1,199	**$ 3,620**	$ 3,418

NOTE 4: FINANCE CHARGES

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2017**	2016	**2017**	2016
Interest on long-term debt	**$ 210**	$ 195	**$ 618**	$ 575
Interest on finance lease liabilities	**12**	5	**34**	15
Less: Other recoveries	**(20)**	(23)	**(61)**	(69)
Capitalized interest	**(33)**	(25)	**(97)**	(66)
	$ 169	$ 152	**$ 494**	$ 455

NOTE 5: AMORTIZATION AND DEPRECIATION

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2017**	2016	**2017**	2016
Depreciation of property, plant and equipment	**$ 186**	$ 175	**$ 559**	$ 529
Amortization of intangible assets	**21**	21	**63**	58
Amortization of regulatory accounts (Note 8)	**107**	118	**292**	327
	$ 314	$ 314	**$ 914**	$ 914

NOTE 6: INVENTORIES

(in millions)	***As at December 31 2017***		*As at March 31 2017*	
Materials and supplies	**$**	**145**	$	145
Natural gas trading inventories		**46**		40
	$	**191**	$	185

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

NOTE 7: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset expenditures, before contributions in aid of construction, for the three and nine months ended December 31, 2017 were $641 million and $1,776 million, respectively (2016 - $578 million and $1,751 million, respectively).

As of December 31, 2017, the Company has contractual commitments to spend $4,210 million on major property, plant and equipment projects (for individual projects greater than $50 million), which includes $1.2 billion relating to the purchase of the remaining two-thirds share of the Waneta Dam and Generating Station (Waneta) from Teck Resources Limited (Teck).

On August 1, 2017, BC Hydro agreed to exercise its option to purchase the remaining two-thirds interest of Waneta from Teck for $1.2 billion. The purchase agreement includes a 20 year agreement, at fixed prices, providing Teck with a leasehold interest in the two-thirds portion of Waneta. This will enable Teck to use the electricity generated from its interest in Waneta to continue to serve its Trail smelter. Teck has an option to extend the agreement for a further 10 years. Completion of the purchase is subject to a number of conditions, including approval by the BCUC. BC Hydro currently owns the other one-third interest in Waneta.

On December 4, 2017 the commercial operation date for the Fort St. James Green Energy electricity purchase agreement (EPA) was reached. BC Hydro recognized the EPA as a $235 million finance lease resulting in a non-cash increase to property, plant and equipment and other non-current liabilities. The facility is a 40 megawatt biomass power plant located near Fort St. James, British Columbia.

NOTE 8: RATE REGULATION

In July 2016, BC Hydro filed the Fiscal 2017-2019 Revenue Requirements Application (F17-F19 RRA) requesting rate increases of 4.0 per cent, 3.5 per cent, and 3.0 per cent for fiscal 2017, 2018, and 2019, respectively, in accordance with Direction No. 7 issued by the Province in March 2014. The BCUC approved interim rate increases of 4.0 per cent for fiscal 2017 and 3.5 per cent for fiscal 2018. The results for the three and nine months ended December 31, 2017 reflect the interim approved rates and the orders sought by BC Hydro with respect to regulatory accounts as filed in the F17-F19 RRA. On November 8, 2017, pursuant to the Government Mandate Letter dated August 24, 2017 and announcement by the

Minister on November 8, 2017, BC Hydro filed an application to amend its requested rate increase for fiscal 2019 from 3.0 per cent to 0 per cent. A decision from the BCUC on the F17-F19 RRA is expected in the fourth quarter of fiscal 2018.

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 total comprehensive income unless the Company sought recovery through rates. For the three and nine months ended December 31, 2017, the impact of regulatory accounting has resulted in a net decrease to total comprehensive income of $111 million and $231 million, respectively (2016 – decrease of $331 million and $152 million, respectively). For the three and nine months ended December 31, 2017, the impact on comprehensive income is comprised of an increase and decrease to net income of $29 million and $60 million, respectively (2016 - decrease of $313 million and $98 million, respectively) and a decrease to other comprehensive income of $140 million and $171 million, respectively (2016 – decrease of $18 million and $54 million, respectively). 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 year to date, 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.

Transfers to the regulatory accounts for the nine months ended December 31, 2017 are based on the F17-F19 RRA, which remains subject to approval by the BCUC.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2017

(in millions)	*As at April 1 2017*	*Addition (Reduction)*	*Interest*	*Amortization*	*Net Change*	*As at December 31 2017*
Regulatory Assets						
Non-Heritage Deferral Account	$ 756	$ (85)	$ 21	$ (141)	$ (205)	$ 551
Trade Income Deferral Account	194	(50)	4	(36)	(82)	112
Demand-Side Management	916	41	-	(72)	(31)	885
First Nations Provisions & Costs	532	15	4	(29)	(10)	522
Pension Costs	511	(119)	-	(24)	(143)	368
Site C	453	-	14	-	14	467
CIA Amortization	91	(2)	-	-	(2)	89
Environmental Provisions & Costs	294	(2)	(1)	(24)	(27)	267
Smart Metering & Infrastructure	261	-	8	(24)	(16)	245
IFRS Pension	574	-	-	(29)	(29)	545
IFRS Property, Plant & Equipment	962	67	-	(19)	48	1,010
Rate Smoothing	488	199	-	-	199	687
Other Regulatory Accounts	95	36	2	(12)	26	121
Total Regulatory Assets	6,127	100	52	(410)	(258)	5,869
Regulatory Liabilities						
Heritage Deferral Account	53	48	3	(10)	41	94
Foreign Exchange Gains and Losses	66	7	-	(29)	(22)	44
Debt Management	187	9	-	-	9	196
Total Finance Charges	215	22	-	(76)	(54)	161
Other Regulatory Accounts	9	2	-	(3)	(1)	8
Total Regulatory Liabilities	530	88	3	(118)	(27)	503
Net Regulatory Asset	$ 5,597	$ 12	$ 49	$ (292)	$ (231)	$ 5,366

NOTE 9: OTHER NON-CURRENT ASSETS

(in millions)	***As at December 31 2017***	*As at March 31* 2017
Non-current receivables	**$ 223**	$ 278
Sinking funds	**175**	179
Other	**164**	142
	$ 562	$ 599

Included in the non-current receivables balance are $166 million of receivables (March 31, 2017 - $184 million) attributable to contributions in aid of construction and tariff supplemental charges related to a transmission line and $34 million of receivables (March 31, 2017 - $68 million) from mining customers participating in the Mining Customer Payment Plan that was established in February 2016 as a result of a direction from the Province.

NOTE 10: LONG-TERM DEBT AND DEBT MANAGEMENT

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

The Company has a commercial paper borrowing program with the Province which is limited to $4,500 million, and is included in revolving borrowings. At December 31, 2017, the outstanding amount under the borrowing program was $2,162 million (March 31, 2017 - $2,838 million).

For the three months ended December 31, 2017, the Company issued bonds with net proceeds of $587 million (2016 - $189 million) and a par value of $600 million (2016 - $200 million), a weighted average effective interest rate of 2.8 per cent (2016 - 3.1 per cent) and a weighted average term to maturity of 9.7 years (2016 - 31.6 years). For the nine months ended December 31, 2017, the Company issued bonds with net proceeds of $1,156 million (2016 - $895 million) and a par value of $1,200 million (2016 - $900 million), a weighted average effective interest rate of 2.9 per cent (2016 - 2.6 per cent) and a weighted average term to maturity of 20.3 years (2016 - 23.4 years).

For the three months ended December 31, 2017, there were no bond maturities (2016 - $nil). For the nine months ended December 31, 2017, there were $40 million par value in bond maturities (2016 - $nil).

NOTE 11: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining the Company's equity for regulatory purposes, as well as the annual Payment to the Province (see below). Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province. For this purpose, the applicable Order in Council defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity comprises retained earnings, accumulated other comprehensive income, and contributed surplus. The Company monitors its capital structure on the basis of its debt to equity ratio.

During the nine months ended December 31, 2017, there were no changes in the approach to capital management.

The debt to equity ratio at December 31, 2017, and March 31, 2017 was as follows:

(in millions)	***As at December 31*** **2017**	*As at March 31* 2017
Total debt, net of sinking funds	**$ 20,234**	$ 19,845
Less: Cash and cash equivalents	**(71)**	(49)
Net Debt	**$ 20,163**	$ 19,796
Retained earnings	**$ 5,020**	$ 4,822
Contributed surplus	**60**	60
Accumulated other comprehensive income	**68**	27
Total Equity	**$ 5,148**	$ 4,909
Net Debt to Equity Ratio	**80 : 20**	80 : 20

Payment to the Province

Under a Special Directive from the Province, the Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Special Directive states that for fiscal 2018 and subsequent years, the Payment will be reduced by $100 million per year based on the Payment in the immediate preceding fiscal year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

The fiscal 2017 Payment to the Province was $259 million and was paid in March 2017. Under the Special Directive, the Payment for fiscal 2018 will be $159 million. As a result, the Company has accrued $159 million as at December 31, 2017 (2016 - $259 million).

NOTE 12: POST-EMPLOYMENT BENEFITS

During the quarter, the Company reduced the Medical Services Plan (MSP) portion of its non-pension post-employment benefits obligations by $125 million. The September 2017 BC Provincial Budget announced a 50% reduction in MSP premiums for all BC residents effective January 1, 2018. This change was passed by legislation during the quarter ended December 31, 2017. The reduction in liability was credited to the Pension Costs Regulatory Account.

The expense recognized 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 and nine months ended December 31, 2017 was $41 million and $122 million, respectively (2016 - $42 million and $127 million, respectively).

Company contributions to the registered defined benefit pension plans for the three and nine months ended December 31, 2017 were $10 million and $30 million, respectively (2016 - $14 million and $43 million, respectively).

NOTE 13: 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 and nine months ended December 31, 2017 and 2016 (except where noted).

Categories of Financial Instruments

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

(in millions)	**December 31, 2017 Carrying Value**	**December 31, 2017 Fair Value**	March 31, 2017 Carrying Value	March 31, 2017 Fair Value
Financial Assets and Liabilities at Fair Value Through Profit or Loss:				
Cash equivalents - short-term investments	**$ 52**	**$ 52**	$ 24	$ 24
Loans and Receivables:				
Accounts receivable and accrued revenue	**835**	**835**	808	808
Non-current receivables	**223**	**226**	278	282
Cash	**19**	**19**	25	25
Held to Maturity:				
Sinking funds – US	**175**	**195**	179	197
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**(1,270)**	**(1,270)**	(1,190)	(1,190)
Revolving borrowings	**(2,162)**	**(2,162)**	(2,838)	(2,838)
Long-term debt (including current portion due in one year)	**(18,247)**	**(20,960)**	(17,186)	(19,601)
First Nations liabilities (non-current portion)	**(395)**	**(651)**	(394)	(549)
Finance lease obligations (non-current portion)	**(425)**	**(425)**	(197)	(197)
Other liabilities	**(385)**	**(393)**	(336)	(342)

The carrying value of cash, cash equivalents, loans and receivables, accounts payable and accrued liabilities, and revolving borrowings approximates fair value due to the short duration of these financial instruments.

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

(in millions)	**December 31, 2017 Fair Value**	March 31, 2017 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ 42**	$ 68
Foreign currency contracts (cash flow hedges for €EURO denominated long-term debt)	**20**	(27)
	62	41
Non-Designated Derivative Instruments:		
Interest rate contracts	**121**	194
Foreign currency contracts	**(4)**	-
Commodity derivatives	**(10)**	23
	107	217
Net asset	**$ 169**	$ 258

The carrying value of derivative instruments designated and not designated as hedges was the same as the fair value.

The derivatives are represented on the statement of financial position as follows:

(in millions)	**December 31, 2017**	March 31, 2017
Current portion of derivative financial instrument assets	**$ 157**	$ 144
Current portion of derivative financial instrument liabilities	**(94)**	(60)
Derivative financial instrument assets, non-current	**124**	215
Derivative financial instrument liabilities, non-current	**(18)**	(41)
Net asset	**$ 169**	$ 258

For designated cash flow hedges for the three and nine months ended December 31, 2017, a gain of $12 million and a gain of $20 million, respectively (2016 - $11 million loss and $6 million gain, respectively) were recognized in other comprehensive income. For the three and nine months ended December 31, 2017, $17 million and $29 million, respectively (2016 - $1 million and $16 million, respectively) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange losses and gains, respectively (2016 - losses) recorded in the period.

For interest rate contracts not designated as hedges with an aggregate notional principal of $3.9 billion (2016 - $3.9 billion), used to economically hedge the interest rates on future debt issuances, there was a $56 million and $3 million decrease, respectively, in the fair value of these contracts for the three and nine months ended December 31, 2017 (2016 - $290 million and $217 million increase, respectively). For the interest rate contracts with an aggregate notional principal of $1.8 billion (2016 - $500 million) associated with debt issued to date, there was an $nil and a $12 million increase, respectively, in the fair value of contracts that settled during the period for the three and nine months ended December 31, 2017 (2016 - $9 million increase and $16 million decrease, respectively). The net increase for the nine months ended December 31, 2017 of $9 million in the fair value of these interest rate contracts were transferred to the Debt Management Regulatory Account which had a balance of $196 million as at December 31, 2017.

For foreign currency contracts not designated as hedges for the three and nine months ended December 31, 2017, a gain of $1 million and a loss of $3 million, respectively, (2016 - gains of $2 million and $2 million, respectively) were recognized in finance charges with respect to foreign currency contracts for cash management purposes. For foreign currency contracts not designated as hedges, primarily relating to foreign currency contracts for U.S. revolving borrowings, for the three and nine months ended December 31, 2017, such contracts had a gain of $6 million and a loss of $55 million, respectively, (2016 - gains of $25 million and $38 million, respectively) which was recognized in finance charges. These economic hedges offset $5 million of foreign exchange revaluation losses and $58 million of foreign exchange revaluation gains, respectively, (2016 - losses of $24 million and $37 million, respectively) recognized in finance charges with respect to U.S. revolving borrowings for the three and nine months ended December 31, 2017.

For commodity derivatives not designated as hedges, a net loss of $9 million and $47 million, respectively (2016 - net loss of $14 million and net loss of $32 million, respectively) was recognized in trade revenue for the three and nine months ended December 31, 2017.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

	For the three months ended December 31				*For the nine months ended December 31*			
(in millions)		**2017**		2016		**2017**		2016
Deferred inception loss, beginning of the period	**$**	**18**	$	39	**$**	**36**	$	48
New transactions		**9**		(2)		**1**		(9)
Amortization		**3**		2		**(5)**		-
Foreign currency translation (gain) loss		**-**		1		**(2)**		1
Deferred inception loss, end of the period	**$**	**30**	$	40	**$**	**30**	$	40

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 December 31, 2017 and March 31, 2017:

As at December 31, 2017 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	**$ 52**	**$ -**	**$ -**	**$ 52**
Derivatives designated as hedges	**-**	**72**	**-**	**72**
Derivatives not designated as hedges	**23**	**176**	**10**	**209**
	$ 75	**$ 248**	**$ 10**	**$ 333**

As at December 31, 2017 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	**$ -**	**$ (10)**	**$ -**	**$ (10)**
Derivatives not designated as hedges	**(42)**	**(58)**	**(2)**	**(102)**
	$ (42)	**$ (68)**	**$ (2)**	**$ (112)**

As at March 31, 2017 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 24	$ -	$ -	$ 24
Derivatives designated as hedges	-	72	-	72
Derivatives not designated as hedges	39	207	41	287
	$ 63	$ 279	$ 41	$ 383

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

The Company determines Level 2 fair values for debt securities and derivatives using discounted cash flow techniques, which use contractual cash flows and market-related discount rates.

Level 2 fair values for energy derivatives are determined using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices). Level 2 includes bilateral and over-the-counter contracts valued using interpolation from observable forward curves or broker quotes from active markets for similar instruments and other publicly available data, and options valued using industry-standard and accepted models incorporating only observable data inputs.

There were no transfers between Level 1 and 2 during the period.

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 nine months ended December 31, 2017 and 2016:

(in millions)		
Balance as at April 1, 2017	**$**	**37**
Net loss recognized		**(37)**
New transactions		**3**
Transfer from Level 3 to Level 2		**(7)**
Existing transactions settled		**12**
Balance as at December 31, 2017	**$**	**8**

(in millions)		
Balance as at April 1, 2016	$	56
Net loss recognized		(32)
New transactions		7
Transfer from Level 3 to Level 2		(2)
Existing transactions settled		(5)
Balance as at December 31, 2016	$	24

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

Level 3 fair values for energy derivatives are determined using inputs that are based on unobservable inputs. Level 3 includes instruments valued using observable prices adjusted for unobservable basis differentials such as delivery location and product quality, instruments which are valued by extrapolation of observable market information into periods for which observable market information is not yet available, and instruments valued using internally developed or non-standard valuation models.

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

During the three and nine months ended December 31, 2017, unrealized losses of $3 million and $19 million, respectively, (2016 - $7 million gain and $19 million loss, respectively) were recognized on Level 3 derivative commodity assets held at December 31, 2017. During the three and nine months ended December 31, 2017, unrealized losses of $3 million and $5 million, respectively (2016 - losses of $4 million and $nil, respectively) were recognized on Level 3 derivative commodity liabilities held at December 31, 2017. These gains and losses are recognized in trade revenues.

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

NOTE 14: OTHER NON-CURRENT LIABILITIES

(in millions)	***As at December 31* 2017**	*As at March 31* 2017
Provisions		
Environmental liabilities	**$ 320**	$ 339
Decommissioning obligations	**52**	52
Other	**14**	12
	386	403
First Nations liabilities	**411**	409
Finance lease obligations	**437**	219
Unearned revenue	**576**	551
Other liabilities	**385**	336
	2,195	1,918
Less: Current portion, included in accounts payable and accrued liabilities	**(95)**	(115)
	$ 2,100	$ 1,803

NOTE 15: 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.

NOTE 16: CONTINGENCIES

BC Hydro is involved in various legal claims and actions in the course of the Company's operations. Although outcome of these claims cannot be predicted with certainty, the Company does not expect these matters to have a material adverse effect on BC Hydro's financial position, cash flows or results of operations. If an unfavourable outcome were to occur, there exists the possibility of a material adverse impact on the Company's financial position. Accruals for litigation and claims are recognized if the Company determines that the loss is probable and the amount can be reasonably estimated. The Company believes it has made adequate provision for such claims. Management has not disclosed ranges of expected outcomes due to the potentially adverse effect on the settlement of the claims.