British Columbia Hydro and Power Authority

2016/17

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, 2016 and should be read in conjunction with the MD&A presented in the 2016 Annual Service Plan Report, the 2016 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, 2016.

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

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

HIGHLIGHTS

- Net income for the three months ended December 31, 2016 was $213 million, comparable to the same period in the prior fiscal year. Net income for the nine months ended December 31, 2016 was $329 million, $21 million lower than the same period in the prior fiscal year. Domestic revenues were $95 million higher than the prior year primarily due to higher average customer rates reflecting an average interim rate increase as approved by the British Columbia Utilities Commission (BCUC) of 4 per cent effective April 1, 2016. Finance charges were $107 million lower than the prior year primarily due to lower long-term and short-term interest rates, lower interest charges on electricity purchase agreements accounted for as finance leases, and higher interest during construction which was capitalized. This was offset by $185 million higher domestic energy costs mainly due to higher planned purchases from Independent Power Producers and $50 million higher other costs mainly due to higher asset related costs incurred from asset disposals, retirements, asset removals, and dismantling costs.

- Water inflows to the system during the nine months ended December 31, 2016 were 100 per cent of average, compared to 97 per cent of average in the same period in the prior fiscal year. Observed inflows to Williston and Kinbasket reservoirs were 102 per cent and 105 per cent of average, respectively, compared to 100 per cent and 108 per cent, respectively, in the same period in the prior fiscal year. The average inflows for the nine months ended December 31, 2016 were the result of higher precipitation and snowmelt across the province in the first quarter and higher precipitation in the third quarter, partially offset by drier conditions in the second quarter.

- Capital expenditures, before contributions in aid of construction, for the three and nine months ended December 31, 2016 were $578 million and $1,751 million, respectively. BC Hydro continues to invest significantly in capital projects to refurbish its ageing infrastructure and build new assets for future growth, including Site C Clean Energy project, John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, Distribution Wood Poles Replacements program, W.A.C. Bennett Dam Riprap Upgrade project, Big Bend Substation project, and Horne Payne Substation Upgrade project.

CONSOLIDATED RESULTS OF OPERATIONS

	For the three months ended December 31			*For the nine months ended December 31*		
($ in millions)	**2016**	2015	Change	**2016**	2015	Change
Total Revenues	**$ 1,564**	$ 1,503	$ 61	**$ 4,202**	$ 4,073	$ 129
Net Income	**$ 213**	$ 217	$ (4)	**$ 329**	$ 350	$ (21)
Capital Expenditures	**$ 578**	$ 594	$ (16)	**$ 1,751**	$ 1,567	$ 184
GWh Sold (Domestic)	**15,016**	14,229	787	**41,876**	42,756	(880)

($ in millions)	***As at December 31, 2016***	*As at March 31, 2016*	Change
Total Assets	**$ 31,558**	$ 30,034	$ 1,524
Shareholder's Equity	**$ 4,568**	$ 4,500	$ 68
Accrued Payment to the Province	**$ 259**	$ 326	$ (67)
Retained Earnings	**$ 4,467**	$ 4,397	$ 70
Debt to Equity	**81 : 19**	80 : 20	n/a
Number of Domestic Customer Accounts	**1,981,658**	1,960,555	21,103
Total Reservoir Storage (GWh)	**24,073**	16,518	7,555

REVENUES

Total revenues after regulatory account transfers for the three months ended December 31, 2016 were $1,564 million, an increase of $61 million or 4 per cent compared to the same period in the prior fiscal year. Total revenues after regulatory account transfers for the nine months ended December 31, 2016 were $4,202 million, an increase of $129 million or 3 per cent compared to the same period in the prior fiscal year. The increase was primarily due to higher domestic revenue mainly due to higher average customer rates and higher transfers to the Rate Smoothing regulatory account to smooth the rate impacts of the rate increases in the 10 Year Rates Plan. The tables below show revenues before regulatory account transfers, the amount of regulatory account transfers, and total revenues after regulatory account transfers as follows:

for the three months ended December 31	(in millions) 2016	2015	(gigawatt hours) 2016	2015	($ per MWh)[2] 2016	2015
Domestic						
Residential	**$ 598**	$ 539	**5,327**	5,029	**$ 112.26**	$ 107.18
Light industrial and commercial	**457**	427	**4,794**	4,660	**95.33**	91.63
Large industrial	**195**	190	**3,375**	3,493	**57.78**	54.39
Other energy sales	**92**	91	**1,520**	1,047	**60.53**	86.91
Total Domestic Revenue Before Regulatory Transfers	**1,342**	1,247	**15,016**	14,229	**89.37**	87.64
Rate smoothing and energy deferral regulatory transfers	**39**	105	**-**	-	**-**	-
Total Domestic	**$ 1,381**	$ 1,352	**15,016**	14,229	**$ 91.97**	$ 95.02
Trade						
Gross electricity and gas	**$ 346**	$ 252	**9,001**	7,763	**$ 36.66**	$ 31.93
Less: forward electricity and gas purchases	**(163)**	(101)	**-**	-	**-**	-
Total Trade[1]	**$ 183**	$ 151	**9,001**	7,763	**$ 20.33**	$ 19.45
Total	**$ 1,564**	$ 1,503	**24,017**	21,992	**$ 65.12**	$ 68.34

for the nine months ended December 31	(in millions) 2016	2015	(gigawatt hours) 2016	2015	($ per MWh)[2] 2016	2015
Domestic						
Residential	**$ 1,346**	$ 1,276	**12,231**	12,129	**$ 110.05**	$ 105.20
Light industrial and commercial	**1,307**	1,252	**13,779**	13,669	**94.85**	91.59
Large industrial	**566**	565	**9,882**	10,264	**57.28**	55.05
Other energy sales	**315**	368	**5,984**	6,694	**52.64**	54.97
Total Domestic Revenue Before Regulatory Transfers	**3,534**	3,461	**41,876**	42,756	**84.39**	80.95
Rate smoothing and energy deferral regulatory transfers	**171**	149	**-**	-	**-**	-
Total Domestic	**$ 3,705**	$ 3,610	**41,876**	42,756	**$ 88.48**	$ 84.43
Trade						
Gross electricity and gas	**$ 951**	$ 827	**26,803**	21,976	**$ 31.58**	$ 34.31
Less: forward electricity and gas purchases	**(454)**	(364)	**-**	-	**-**	-
Total Trade[1]	**$ 497**	$ 463	**26,803**	21,976	**$ 18.54**	$ 21.07
Total	**$ 4,202**	$ 4,073	**68,679**	64,732	**$ 61.18**	$ 62.92

[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, 2016 were $1,381 million, an increase of $29 million or 2 per cent compared to the same period in the prior fiscal year. The increase was primarily due to $59 million higher residential revenues, mainly due to higher average customer rates and colder weather than in the prior fiscal year (consumption was 298 GWh or 6 per cent higher). December 2016 was particularly cold and the monthly average temperature across British Columbia was 4.3 degrees Celsius lower than December 2015, which was the primary contributor to the approximately 500 GWh higher load than December 2015. Light industrial and commercial revenues were $30 million higher mainly due to higher average customer rates. This was partially offset by $66 million in lower regulatory account transfers which are discussed in the *Regulatory Transfers* section.

Domestic revenues for the nine months ended December 31, 2016 were $3,705 million, an increase of $95 million or 3 per cent compared to the same period in the prior fiscal year. The increase was primarily due to $70 million higher residential revenues mainly due to colder weather in the third quarter compared to prior year and higher average customer rates, partially offset by warmer weather in the first quarter compared to prior year. Light industrial and commercial revenues were $55 million higher mainly due to higher average customer rates. This was partially offset by $53 million lower other energy sales as a result of less surplus energy sold, a component of other energy sales, into the market as compared to the same period in the prior fiscal year (4,910 GWh for the nine months ended December 31, 2016 compared to 5,603 GWh for the nine months ended December 31, 2015) due to a combination of both lower volumes and lower prices in fiscal 2017. The higher volumes sold in fiscal 2016 were to manage spill risk from higher storage levels built up during previous periods at large reservoirs, as well as to maintain Arrow reservoir levels to support ferry service and facilitate industrial operations on the lake. In addition, there were $22 million higher regulatory account transfers which are discussed in the *Regulatory Transfers* section.

Average customer rates reflect an average interim rate increase as approved by the BCUC of 4 per cent effective April 1, 2016.

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

Trade revenues for the three months ended December 31, 2016 were $183 million, an increase of $32 million or 21 per cent compared with the same period in the prior fiscal year. The increase was primarily due to a 15 per cent increase in the average physical energy sale price and a 16 per cent increase in the volume of physical energy sold. The increase in the average physical energy sale price was reflective of overall higher market prices in Western North America primarily as a result of colder temperatures during the period. The increase in physical volumes sold was primarily due to an outage of a key third party transmission line to California in the prior period which significantly reduced export opportunities relative to the current period.

Trade revenues for the nine months ended December 31, 2016 were $497 million, an increase of $34 million or 7 per cent compared with the same period in the prior fiscal year. The increase in revenues was primarily due to a 22 per cent increase in the volume of physical energy sold. The increase in volume of physical energy sold was primarily due to an outage of a key third party transmission line to California in the prior period.

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, 2016, operating expenses, after regulatory account transfers, of $1,199 million and $3,418 million, respectively, were $100 million and $257 million higher than in the same periods in the prior fiscal year. The increase in both periods, after regulatory account transfers, was primarily due to higher planned purchases from Independent Power Producers and higher asset related costs incurred in the current periods from asset disposals, retirements, asset removals, and dismantling costs.

Cost of Energy

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission charges 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 December 31, 2016 were $576 million, $79 million or 16 per cent higher than the same period in the prior fiscal year. Total energy costs after regulatory account transfers for the nine months ended December 31, 2016 were $1,589 million, $203 million or 15 per cent higher than the same period in the prior fiscal year. The increase in both periods after regulatory account transfers over the prior fiscal year was primarily due to higher planned purchases from Independent Power Producers. The tables below show energy costs before regulatory account transfers, the amount of regulatory account transfers, and total energy costs after regulatory account transfers as follows:

	(in millions)		*(gigawatt hours)*		*($ per MWh)* [3]	
for the three months ended December 31	**2016**	2015	**2016**	2015	**2016**	2015
Domestic						
Water rental payments (hydro generation)[1]	**$ 88**	$ 80	**13,258**	12,212	**$ 6.64**	$ 6.44
Purchases from Independent Power Producers	**319**	340	**3,331**	3,719	**95.77**	91.38
Other electricity purchases - Domestic	**1**	1	**36**	25	**27.78**	33.52
Gas for thermal generation[2]	**4**	7	**3**	62	**1,333.33**	119.88
Transmission charges and other expenses	**8**	10	**36**	31	**-**	-
Columbia River Treaty Related Agreements	**5**	-	**-**	-	**-**	-
Allocation from (to) trade energy	**(7)**	-	**(212)**	(26)	**34.69**	22.90
Total Domestic Cost of Energy Before Regulatory Transfers	**418**	438	**16,452**	16,023	**25.41**	27.31
Energy deferral regulatory transfers	**23**	(63)	**-**	-	**-**	-
Total Domestic	**$ 441**	$ 375	**16,452**	16,023	**$ 26.81**	$ 23.39
Trade						
Gross electricity and remarketed gas	**$ 254**	$ 181	**8,678**	7,760	**$ 28.63**	$ 23.09
Less: forward electricity and gas purchases	**(163)**	(101)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**91**	80	**-**	-	**-**	-
Transmission charges and other expenses	**63**	53	**-**	-	**-**	-
Allocation (to) from domestic energy	**7**	-	**212**	26	**34.69**	22.90
Total Trade Cost of Energy Before Regulatory Transfers	**161**	133	**8,890**	7,786	**18.11**	21.41
Trade net margin regulatory transfer	**(26)**	(11)	**-**	-	**-**	-
Total Trade	**$ 135**	$ 122	**8,890**	7,786	**$ 15.19**	$ 20.04
Total Energy Costs	**$ 576**	$ 497	**25,342**	23,809	**$ 22.73**	$ 22.29

[1] Water rental payments are based on the previous calendar year's generation volumes. The volumes are actual hydro generation during the period. The $ per MWh is a simple average calculation and does not reflect actual water rental rates during the period.
[2] Due to an outage at one thermal generating station, there is minimal output for the three months ended December 31, 2016 which results in a higher unit cost ($ per MWh), since the costs are primarily fixed costs.
[3] 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.

for the nine months ended December 31	*(in millions)* **2016**	2015	*(gigawatt hours)* **2016**	2015	*($ per MWh)[2]* **2016**	2015
Domestic						
Water rental payments (hydro generation)[1]	**$ 266**	$ 235	**33,932**	35,651	**$ 7.84**	$ 6.43
Purchases from Independent Power Producers	**954**	939	**11,220**	11,359	**85.03**	82.65
Other electricity purchases - Domestic	**2**	1	**62**	32	**32.26**	26.22
Gas for thermal generation	**16**	21	**74**	153	**216.22**	140.10
Transmission charges and other expenses	**17**	20	**85**	77	**-**	-
Columbia River Treaty Related Agreements	**1**	-	**-**	-	**-**	-
Allocation from (to) trade energy	**-**	(6)	**(52)**	(262)	**30.31**	26.80
Total Domestic Cost of Energy Before Regulatory Transfers	**1,256**	1,210	**45,321**	47,010	**27.71**	25.73
Energy deferral regulatory transfers	**(22)**	(161)	**-**	-	**-**	-
Total Domestic	**$ 1,234**	$ 1,049	**45,321**	47,010	**$ 27.23**	$ 22.30
Trade						
Gross electricity and remarketed gas	**$ 610**	$ 556	**26,817**	21,784	**$ 22.34**	$ 25.02
Less: forward electricity and gas purchases	**(454)**	(364)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**156**	192	**-**	-	**-**	-
Transmission charges and other expenses	**190**	153	**-**	-	**-**	-
Allocation (to) from domestic energy	**-**	6	**52**	262	**30.31**	26.80
Total Trade Cost of Energy Before Regulatory Transfers	**346**	351	**26,869**	22,046	**12.88**	22.74
Trade net margin regulatory transfer	**9**	(14)	**-**	-	**-**	-
Total Trade	**$ 355**	$ 337	**26,869**	22,046	**$ 13.21**	$ 22.11
Total Energy Costs	**$ 1,589**	$ 1,386	**72,190**	69,056	**$ 22.01**	$ 22.24

[1] Water rental payments are based on the previous calendar year's generation volumes. The volumes are actual hydro generation during the period. The $ per MWh is a simple average calculation and does not reflect actual water rental rates during the period.
[2] The $ per MWh represents the gross unit cost per physical electricity and gas transaction. The Total Trade $ per MWh is a simple average calculation and does not reflect actual trade energy prices during the period.

Domestic Energy Costs

Domestic energy costs for the three months ended December 31, 2016 were $441 million, $66 million or 18 per cent higher than the same period in the prior fiscal year. The significant variances from the prior fiscal year before regulatory account transfers were primarily due to $21 million lower purchases from Independent Power Producers driven by lower deliveries from one large hydro Independent Power Producer in the current period, partially offset by higher volumes due to an increased number of Independent Power Producers in operation in the current period. The decrease in IPP purchases was offset by $86 million lower regulatory account transfers which are discussed in the *Regulatory Transfers* section.

Domestic energy costs for the nine months ended December 31, 2016 were $1,234 million, $185 million or 18 per cent higher than the same period in the prior fiscal year. The significant variances from the prior fiscal year before regulatory account transfers were primarily due to $31 million higher water rental payments in the current year. Water rental payments are based on the previous calendar year's generation volumes and in calendar year 2015 there was more hydro generated than in calendar year 2014. The increase was also due to $15 million higher Independent Power Producer costs mainly due to an increased number of Independent Power Producers in operation in the current period and an increase in the average unit cost, partially offset by lower volumes in the current period. In addition, there were $139 million lower regulatory account transfers which are discussed in the *Regulatory Transfers* section.

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

Trade Energy Costs

Trade energy costs before regulatory account transfers for the three months ended December 31, 2016 were $161 million, an increase of $28 million or 21 per cent compared with the same period in the prior fiscal year. The increase was primarily due to a 24 per cent increase in the average physical energy purchase price and a 12 per cent increase in the volume of physical energy purchased. The increase in the average physical energy purchase price was reflective of overall higher market prices in Western North America primarily as a result of colder temperatures during the period. The increase in physical volumes purchased was primarily due to an outage of a key third party transmission line to California in the prior period.

Trade energy costs before regulatory account transfers for the nine months ended December 31, 2016 were $346 million, which was comparable with trade energy costs for the same period in the prior fiscal year.

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

Water Inflows

Water inflows (energy equivalent) to BC Hydro's system during the nine months ended December 31, 2016 were 100 per cent of average, compared to 97 per cent of average in the same period in the prior fiscal year. Observed inflows to Williston and Kinbasket reservoirs were 102 per cent and 105 per cent of average, respectively, compared to 100 per cent and 108 per cent, respectively, in the same period in the prior fiscal year. The average inflows for the nine months ended December 31, 2016 were the result of higher precipitation and snowmelt across the province in the first quarter and higher precipitation in the third quarter, partially offset by drier conditions in the second quarter.

The Williston and Kinbasket reservoirs have been managed such that system energy storage on December 31, 2016 was 22,100 GWh, or 1,600 GWh above the 10 year historic average. This was 200 GWh higher than the system energy storage of 21,900 GWh recorded one year earlier. The Williston and Kinbasket reservoir energy contents were 13,900 GWh (300 GWh above the 10 year historic average) and 8,200 GWh (1,300 GWh above the 10 year historic average), respectively, with Williston 1,500 GWh lower than the prior fiscal year and Kinbasket 1,700 GWh higher than the prior fiscal year. The higher than average system energy storage at December 31, 2016 was a carry-over from the above average energy content at the start of the fiscal year.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three and nine months ended December 31, 2016 were $133 million and $398 million, respectively, comparable to personnel expenses of $130 million and $393 million, respectively, in the same period in the prior fiscal year.

Materials and External Services

Expenditures on materials and external services for the three and nine months ended December 31, 2016 were $143 million and $438 million, respectively, comparable to expenditures on materials and external services of $153 million and $448 million, respectively, in the same period in the prior fiscal year.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment (PP&E), amortization of intangible assets, and the amortization of certain regulatory assets and liabilities. Amortization and depreciation expense for the three months ended December 31, 2016, was comparable to the same period in the prior fiscal year. Amortization and depreciation expense for the nine months ended December 31, 2016 were $914 million, $9 million lower than the same period in the prior fiscal year primarily due to lower amortization of regulatory accounts, partially offset by higher depreciation of property, plant and equipment due to an increase in assets in service.

Grants, 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, 2016 were $80 million and $216 million, respectively, $24 million and $50 million higher, respectively, than the same periods in the prior fiscal year. The increase was primarily due to higher asset related costs incurred from asset disposals, retirements, asset removals, and dismantling costs. The increase in dismantling costs was a result of a change in how dismantling costs are being accounted for this year. Previously, when dismantling costs were incurred, the Dismantling Cost regulatory account (formerly the Future Removal & Site Restoration Costs regulatory account) would be drawn down. At the end of the first quarter in fiscal 2017, the regulatory account was fully drawn down and these costs are now expensed.

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 smoothed into rates over a 10-year period through transfers to the IFRS Property, Plant & Equipment regulatory account as approved by the BCUC. As such, each year, 1/10th more of ineligible costs will be charged to operating costs such that by the end of year ten, all ineligible costs will be charged to operating costs.

Capitalized costs for the three and nine months ended December 31, 2016 were $47 million and $137 million, respectively, $7 million and $18 million lower, respectively, than the same periods in the prior fiscal year. The reduction in capitalized costs was primarily due to the annual reduction of the transfer of operating costs to the IFRS PP&E account as discussed above.

FINANCE CHARGES

Finance charges for the three months ended December 31, 2016 were $152 million, $35 million or 19 per cent lower than the same period in the prior fiscal year. Finance charges for the nine months ended December 31, 2016 were $455 million, $107 million or 19 per cent lower than the same period in the prior fiscal year. The decrease in both periods was primarily due to lower long-term and short-term interest rates, lower interest charges on electricity purchase agreements accounted for as finance leases, and higher interest during construction which was capitalized. This decrease was partially offset by higher volume of long-term debt borrowings and higher US dollar interest expense.

REGULATORY TRANSFERS

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 combined with ASC 980 to reflect the rate-regulated environment in which the Company operates. These Prescribed Standards allow for the deferral of costs and recoveries that under IFRS would otherwise be included in the determination of total comprehensive income in the year the amounts are incurred or would be reflected in rates. The deferred amounts are either recovered or refunded through future rate adjustments.

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

Net regulatory account transfers are comprised of the following:

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2016**	2015	**2016**	2015
Energy Deferral Accounts				
Heritage Deferral Account	**$ 8**	$ 5	**$ (17)**	$ (112)
Non-Heritage Deferral Account	**(48)**	127	**60**	319
Trade Income Deferral Account	**22**	11	**(13)**	18
	(18)	143	**30**	225
Forecast Variance Accounts				
Total Finance Charges	**(5)**	(40)	**(9)**	(129)
Rate Smoothing	**56**	32	**150**	86
Pension Costs	**3**	-	**8**	-
Debt Management	**(299)**	-	**(201)**	-
Other	**10**	13	**5**	25
	(235)	5	**(47)**	(18)
Capital-Like Accounts				
Demand-Side Management	**22**	45	**54**	96
Smart Metering & Infrastructure	**-**	4	**-**	10
IFRS Property, Plant & Equipment	**28**	34	**84**	101
	50	83	**138**	207
Non-Cash Accounts				
Environmental Provisions & Costs	**(34)**	-	**(25)**	(4)
First Nations Provisions & Costs	**5**	8	**12**	13
Other	**-**	2	**-**	4
	(29)	10	**(13)**	13
Amortization of regulatory accounts	**(118)**	(128)	**(318)**	(350)
Interest on regulatory accounts	**19**	18	**58**	54
Net change in regulatory accounts	**$ (331)**	$ 131	**$ (152)**	$ 131

For the three and nine months ended December 31, 2016, net reductions to the Company's regulatory accounts after interest and amortization were $331 million and $152 million, respectively, compared to net additions of $131 million and $131 million, respectively, for the same periods in the prior fiscal year. The net regulatory asset balance as at December 31, 2016 was $5,756 million compared to $5,908 million as at March 31, 2016.

Net reductions to the regulatory accounts during the nine months ended December 31, 2016 included:

- Net amortization of $318 million which is the regulatory mechanism to recover the regulatory account balances in rates; and
- Decreases of $201 million to the Debt Management regulatory account as a result of an increase in interest rates since BC Hydro's initial interest rate hedges on future debt issuances were executed.

These net reductions were partially offset by:

- Increases of $150 million to the Rate Smoothing account to smooth the rate impacts over the 10 Year Rates Plan;
- Transfers of $84 million 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;
- Interest on regulatory accounts of $58 million;
- Expenditures of $54 million on planned Demand-Side Management projects, which support energy conservation; and
- Increases of $30 million to the energy deferral accounts primarily due to lower domestic revenues as a result of lower domestic load, higher purchases from Independent Power Producers, partially offset by higher surplus sales.

BC Hydro has regulatory mechanisms in place or has applied for regulatory mechanisms in the Fiscal 2017-2019 Revenue Requirements Application to collect 25 of 27 regulatory accounts in use or with balances at December 31, 2016 in rates over various periods, which represent approximately 85 per cent of the total net regulatory 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 Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The Special Directive states that for fiscal 2018 and subsequent years, the payment to the Province will be reduced by $100 million per year based on the payment in the immediate preceding fiscal year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

On July 28, 2016, the Province issued Order in Council No. 589, which amended the Special Directive. This amendment states that BC Hydro must make a payment to the Province of an amount no less than $259 million by June 30, 2017, as it relates to fiscal 2017. As a result, the Company has accrued the $259 million minimum amount as at December 31, 2016 even though the Company's debt to equity ratio exceeded the 80:20 cap prior to the calculation of the Payment.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the nine months ended December 31, 2016 was $661 million, compared with cash flow provided by operating activities of $634 million in the same period in the prior fiscal year.

The long-term debt balance net of sinking funds at December 31, 2016 was $19,646 million, compared with $18,046 million at March 31, 2016. The increase was mainly a result of an increase in long-term bond issuances totaling $895 million ($900 million par value) and revolving borrowings of $699 million. Long-term debt increased to fund capital expenditures.

CAPITAL EXPENDITURES

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

(in millions)	*For the three months ended December 31* **2016**	2015	*For the nine months ended December 31* **2016**	2015
Transmission lines and substations replacements and expansion	**$ 115**	$ 133	**$ 346**	$ 493
Generation replacements and expansion	**140**	127	**417**	373
Distribution system improvements and expansion	**109**	124	**338**	343
General, including technology, vehicles and buildings	**49**	42	**160**	120
Site C Clean Energy project	**165**	168	**490**	238
Total Capital Expenditures	**$ 578**	$ 594	**$ 1,751**	$ 1,567

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 Big Bend Substation project, the Transmission Wood Structure and Framing Replacement program, Horne Payne Substation Upgrade project, Spacer Damper Replacement program, 500kV Oil-Filled Current Transformers Replacement program, Campbell River Substation Capacity Upgrade, and Meikle Wind Energy interconnection project. Transmission lines and substation capital expenditures for the three and nine months ended December 31, 2016 were lower than the same periods in the prior fiscal year primarily due to the following large projects being completed in the latter part of fiscal 2016: Interior to Lower Mainland Transmission Line project, Dawson Creek/Chetwynd Area Transmission project, and Surrey Area Substation project.

Generation capital expenditures include expenditures for John Hart Generating Station Replacement project, Ruskin Dam Safety and Powerhouse Upgrade project, W.A.C. Bennett Dam Riprap Upgrade project, and GMS Spillway Chute Interim Upgrade project.

Distribution capital expenditures include expenditures on customer driven work, end of life asset replacements such as the Distribution Wood Poles Replacements program, and system expansion and improvements.

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

Site C Clean Energy project expenditures relate to site preparation, clearing, and construction of worker accommodation and main civil works.

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.

10 Year Rates Plan

In November 2013, the Government announced a 10 Year Rates Plan for BC Hydro. In March 2014, the Government issued Directions No. 6 and 7 to the BCUC to implement the 10 Year Rates Plan. BC Hydro rate increases for fiscal 2017, fiscal 2018, and fiscal 2019 are subject to BCUC review but are capped at 4.0 per cent, 3.5 per cent, and 3.0 per cent, respectively, pursuant to Direction No. 7. The BCUC will also set the rates for the final five years of the plan. Furthermore, the Deferral Account Rate Rider will remain at 5 per cent for fiscal 2016 and future years.

Fiscal 2017-2019 Revenue Requirements Application

In July 2016, BC Hydro filed an Application to approve its revenue requirements for a three year test period covering fiscal 2017 to fiscal 2019. The Application requested rate increases of 4.0 per cent for fiscal 2017, 3.5 per cent for fiscal 2018, and 3.0 per cent in fiscal 2019. BC Hydro had filed an Application with the BCUC in February 2016 for an interim rate increase of 4.0 per cent for fiscal 2017 which was approved.

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

A procedural conference was held in November 2016 to determine whether an oral or written proceeding would be undertaken and the scope of any proceeding. In January 2017, BC Hydro provided its comments and submitted that it is prepared to have the application reviewed by either an oral or written process. In January 2017, the BCUC determined a written proceeding would be undertaken.

2015 Rate Design Application

In September 2015, BC Hydro filed Module 1 of its 2015 Rate Design Application with the BCUC. Among the various approvals sought in Module 1 of the 2015 Rate Design Application, BC Hydro was seeking approval to simplify its commercial rates and retain the inclining block structure for residential customers. Changes in rate design are designed to be revenue neutral to BC Hydro.

In August 2016, the Commission held an Oral Hearing on Module 1, which included testimony by three separate BC Hydro witness panels. BC Hydro filed its Final Argument to the Commission in September 2016. Interveners filed their Final Arguments in October 2016. In January 2017, the Commission issued a decision on Module 1 approving all of BC Hydro's Rate Design proposals with the exception of E-Plus rates, which BC Hydro is currently in the process of filing a proposal.

Preparations for engagement on Module 2 of the Rate Design Application are underway. Module 2 will include looking at residential and commercial rate options that support low carbon electrification, distribution and transmission extension policies, Non-Integrated Area rates, as well as a review of BC Hydro's Farm and Irrigation rates. Engagement activities began in the fall of 2016, and included consultation with First Nations in regions such as Haida Gwaii.

Inquiry of Expenditures Related to the Adoption of the SAP Platform

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

In October 2016, the Commission held a procedural conference to hear submissions from BC Hydro and Interveners on further process for the Inquiry. In November 2016, the Commission issued Order G-168-16 directing that witness statements be provided by BC Hydro for several current and former employees. BC Hydro wrote to the Commission in December 2016 stating that it would provide witness statements for current employees but that it would not be obtaining witness statements from former employees as they could be viewed with an apprehension of partiality. Witness statements were provided to the Commission in January 2017, after which the Commission will again seek submissions on further process from BC Hydro and Interveners, due in February 2017.

Capital Expenditures and Projects Review

In May 2016, the BCUC issued Order No. G-58-16 initiating a review of the regulatory oversight of BC Hydro's capital expenditures and projects. BC Hydro presented its position on the proposed scope, outcome, process, and timetable for the review prior to the Procedural Conference held in November 2016. The Commission issued Order No. G-174-16 further to the Procedural Conference submissions. BC Hydro's position on the outcome and process were accepted with minor adjustments to accommodate interveners. Per interveners request, the scope will remain open and flexible at this time to include any issues that arise from the Fiscal 2017-2019 Revenue Requirements Application and SAP Inquiry proceedings. At the request of Commission Staff, further regulatory process will commence two weeks following the issuance of the final decision in BC Hydro's Revenue Requirements Application proceeding.

Supply Chain Applications Project Application

In December 2016, BC Hydro filed the Supply Chain Applications Project Application under section 44.2 for acceptance of expenditures on a new SAP IT platform to meet BC Hydro's current and future business needs, reduce risk, and provide benefits for supply chain activities used throughout BC Hydro. The project's total capital cost is between $60 - $79 million with a committed in service date in the second quarter of fiscal 2020. The application filed is Phase One of a two-phase regulatory process and is seeking an order accepting the Definition phase capital costs. At the end of the Definition phase, BC Hydro will file a verification report with updated cost, benefit, scope, and schedule information. At that time, BC Hydro will initiate Phase Two by seeking acceptance of an updated range of Implementation phase costs for the project. In January 2017, the Commission issued its order setting out a regulatory timetable. Information requests will be received by BC Hydro in February 2017. A Procedural Conference to determine further process will be held in March 2017.

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's Fiscal 2017-2019 Revenue Requirements Application includes information regarding existing and proposed recovery mechanisms regarding its regulatory accounts.

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 agreements. 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, 2016. 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 Service Plan filed in February 2016 forecast net income for fiscal 2017 at $692 million.

The Company's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, domestic sales load, market prices for electricity and natural gas, weather, temperatures and interest rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The forecast for fiscal 2018 assumes average water inflows (100 per cent of average), domestic sales load of 57,552 GWh, average market energy prices of US $25.00/MWh, short-term interest rates of 0.67 per cent and a U.S. dollar exchange rate of US$0.7702.

In July 2016, the Government issued Order in Council No. 590, which amends Direction No. 7 to the BCUC. This amendment states that BC Hydro’s annual rate of return on deemed equity shall be an amount necessary to yield a net income of $684 million for fiscal 2017, $698 million for fiscal 2018, and $712 million for fiscal 2019 and subsequent fiscal years.

BC Hydro prepared an updated forecast in January 2017 which is incorporated into its February 2017 Service Plan and forecasts net income of $684 million for fiscal 2017, $698 million for fiscal 2018, $712 million for fiscal 2019, and $712 million for fiscal 2020, which match the amounts set forth in the Government issued Order in Council No. 590 and also align with the net income forecasts included in the Fiscal 2017-2019 Revenue Requirements Application filed with the BCUC in July 2016.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	*For the three months ended December 31* **2016**	2015	*For the nine months ended December 31* **2016**	2015
Revenues				
Domestic	**$ 1,381**	$ 1,352	**$ 3,705**	$ 3,610
Trade	**183**	151	**497**	463
	1,564	1,503	**4,202**	4,073
Expenses				
Operating expenses (Note 3)	**1,199**	1,099	**3,418**	3,161
Finance charges (Note 4)	**152**	187	**455**	562
Net Income	**213**	217	**329**	350
OTHER COMPREHENSIVE INCOME (LOSS)				
Items Reclassified Subsequently to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 13)	**(11)**	18	**6**	54
Reclassification to income of derivatives designated as cash flow hedges (Note 13)	**(1)**	(40)	**(16)**	(96)
Foreign currency translation gains	**5**	8	**8**	24
Other Comprehensive Loss	**(7)**	(14)	**(2)**	(18)
Total Comprehensive Income	**$ 206**	$ 203	**$ 327**	$ 332

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*** **2016**		*As at March 31* 2016
ASSETS				
Current Assets				
Cash and cash equivalents	**$**	**88**	$	44
Accounts receivable and accrued revenue		**776**		669
Inventories (Note 6)		**214**		155
Prepaid expenses		**93**		202
Current portion of derivative financial instrument assets (Note 13)		**173**		137
		1,344		1,207
Non-Current Assets				
Property, plant and equipment (Note 7)		**22,516**		21,385
Intangible assets (Note 7)		**609**		609
Regulatory assets (Note 8)		**6,316**		6,324
Derivative financial instrument assets (Note 13)		**234**		92
Other non-current assets (Note 9)		**539**		417
		30,214		28,827
	$	**31,558**	$	30,034
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities	**$**	**1,335**	$	1,816
Current portion of long-term debt (Note 10)		**3,114**		2,376
Current portion of derivative financial instrument liabilities (Note 13)		**78**		143
		4,527		4,335
Non-Current Liabilities				
Long-term debt (Note 10)		**16,711**		15,837
Regulatory liabilities (Note 8)		**560**		416
Derivative financial instrument liabilities (Note 13)		**32**		27
Contributions in aid of construction		**1,748**		1,669
Post-employment benefits (Note 12)		**1,686**		1,657
Other non-current liabilities (Note 14)		**1,726**		1,593
		22,463		21,199
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**4,467**		4,397
Accumulated other comprehensive income		**41**		43
		4,568		4,500
	$	**31,558**	$	30,034

Commitments (Note 7)

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

Approved on behalf of the Board:

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

Len Boggio, FCPA, FCA, ICD.D
Chair, Audit & Finance Committee

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 (Loss)	Contributed Surplus	Retained Earnings	Total
Balance as at April 1, 2015	**$ 67**	**$ (25)**	**$ 42**	**$ 60**	**$ 4,068**	**$ 4,170**
Payment to the Province (Note 11)	-	-	-	-	(32)	(32)
Comprehensive Income (Loss)	24	(42)	(18)	-	350	332
Balance as at December 31, 2015	**$ 91**	**$ (67)**	**$ 24**	**$ 60**	**$ 4,386**	**$ 4,470**
Balance as at April 1, 2016	**$ 77**	**$ (34)**	**$ 43**	**$ 60**	**$ 4,397**	**$ 4,500**
Payment to the Province (Note 11)	-	-	-	-	(259)	(259)
Comprehensive Income	8	(10)	(2)	-	329	327
Balance as at December 31, 2016	**$ 85**	**$ (44)**	**$ 41**	**$ 60**	**$ 4,467**	**$ 4,568**

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* **2016**	2015
Operating Activities		
Net income	**$ 329**	$ 350
Regulatory account transfers (Note 8)	**(166)**	(481)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 8)	**318**	350
Amortization and depreciation expense (Note 5)	**587**	557
Unrealized gains on mark-to-market	**(217)**	(26)
Employee benefit plan expenses	**86**	83
Interest accrual	**567**	534
Other items	**95**	63
	1,599	1,430
Changes in:		
Accounts receivable and accrued revenue	**(145)**	(57)
Prepaid expenses	**109**	112
Inventories	**(56)**	(58)
Accounts payable, accrued liabilities and other non-current liabilities	**(253)**	(241)
Contributions in aid of construction	**80**	75
	(265)	(169)
Interest paid	**(673)**	(627)
Cash provided by operating activities	**661**	634
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(1,855)**	(1,472)
Cash used in investing activities	**(1,855)**	(1,472)
Financing Activities		
Long-term debt:		
Issued (Note 10)	**895**	1,864
Retired	**-**	(150)
Receipt of revolving borrowings	**7,584**	6,198
Repayment of revolving borrowings	**(6,885)**	(6,709)
Payment to the Province (Note 11)	**(326)**	(264)
Other items	**(30)**	(9)
Cash provided by financing activities	**1,238**	930
Increase in cash and cash equivalents	**44**	92
Cash and cash equivalents, beginning of period	**44**	39
Cash and cash equivalents, end of period	**$ 88**	$ 131

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, 2016

NOTE 1: REPORTING ENTITY

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

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

The Company accounts for its one third interest in Waneta as a joint operation. 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 2016 Annual Service Plan Report. Effective April 1, 2016, 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 2016 Annual Service Plan Report.

These interim financial statements were approved on behalf of the Board of Directors on February 6, 2017.

NOTE 3: OPERATING EXPENSES

(in millions)	*For the three months ended December 31* **2016**	2015	*For the nine months ended December 31* **2016**	2015
Electricity and gas purchases	**$ 444**	$ 370	**$ 1,192**	$ 1,005
Water rentals	**90**	91	**270**	274
Transmission charges	**42**	36	**127**	107
Personnel expenses	**133**	130	**398**	393
Materials and external services	**143**	153	**438**	448
Amortization and depreciation (Note 5)	**314**	317	**914**	923
Grants, taxes and other costs	**80**	56	**216**	166
Less: Capitalized costs	**(47)**	(54)	**(137)**	(155)
	$ 1,199	$ 1,099	**$ 3,418**	$ 3,161

NOTE 4: FINANCE CHARGES

(in millions)	*For the three months ended December 31* **2016**	2015	*For the nine months ended December 31* **2016**	2015
Interest on long-term debt	**$ 195**	$ 192	**$ 575**	$ 578
Interest on finance lease liabilities	**5**	24	**15**	71
Less: Other recoveries	**(23)**	(14)	**(69)**	(41)
Capitalized interest	**(25)**	(15)	**(66)**	(46)
	$ 152	$ 187	**$ 455**	$ 562

NOTE 5: AMORTIZATION AND DEPRECIATION

(in millions)	*For the three months ended December 31* **2016**	2015	*For the nine months ended December 31* **2016**	2015
Depreciation of property, plant and equipment	**$ 175**	$ 171	**$ 529**	$ 507
Amortization of intangible assets	**21**	17	**58**	50
Amortization of regulatory accounts	**118**	129	**327**	366
	$ 314	$ 317	**$ 914**	$ 923

NOTE 6: INVENTORIES

(in millions)	***As at December 31*** **2016**	*As at March 31* 2016
Materials and supplies	**$ 140**	$ 119
Natural gas trading inventories	**74**	36
	$ 214	$ 155

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, 2016 were $578 million and $1,751 million, respectively (2015 - $594 million and $1,567 million, respectively).

As of December 31, 2016, the Company has contractual commitments to spend $3,365 million on major property, plant and equipment projects (for individual projects greater than $50 million).

NOTE 8: RATE REGULATION

On July 28, 2016, BC Hydro filed an Application to approve its revenue requirements for a three year test period covering fiscal 2017 to fiscal 2019. The Application requested rate increases of 4.0 per cent for fiscal 2017, 3.5 per cent for fiscal 2018, and 3.0 per cent for fiscal 2019. BC Hydro filed an Application with the BCUC in February 2016 for an interim rate increase of 4.0 per cent for fiscal 2017 which was approved.

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 in the year in which they are incurred. For the three and nine months ended December 31, 2016, the impact of regulatory accounting has resulted in net decreases to total comprehensive income of $331 million and $152 million, respectively (2015 – net increases of $131 million and $131 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 applicable year, unless otherwise recovered through rates. Under rate regulated accounting, a net decrease in a regulatory asset or a net increase in a regulatory liability results in a decrease to comprehensive income.

Transfers to the regulatory accounts for the nine months ended December 31, 2016 are based on the F2017-2019 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, 2016

(in millions)	*As at April 1 2016*	*Addition (Reduction)*	*Interest*	*Amortization*	*Net Change*	***As at December 31 2016***
Regulatory Assets						
Non-Heritage Deferral Account	$ 917	$ 60	$ 28	$ (126)	$ (38)	**$ 879**
Trade Income Deferral Account	249	(13)	7	(34)	(40)	**209**
Demand-Side Management	908	54	-	(67)	(13)	**895**
First Nations Provisions & Costs	541	12	5	(24)	(7)	**534**
Pension Costs	691	8	-	(45)	(37)	**654**
Site C	436	-	13	-	13	**449**
CIA Amortization	92	-	-	-	-	**92**
Environmental Provisions & Costs	358	(25)	(1)	(29)	(55)	**303**
Smart Metering & Infrastructure	283	-	7	(24)	(17)	**266**
IFRS Pension	612	-	-	(29)	(29)	**583**
IFRS Property, Plant & Equipment	872	84	-	(16)	68	**940**
Rate Smoothing	287	150	-	-	150	**437**
Other Regulatory Accounts	78	9	1	(13)	(3)	**75**
Total Regulatory Assets	6,324	339	60	(407)	(8)	**6,316**
Regulatory Liabilities						
Heritage Deferral Account	24	17	2	(4)	15	**39**
Dismantling Cost	9	1	-	(9)	(8)	**1**
Foreign Exchange Gains and Losses	69	(4)	-	-	(4)	**65**
Debt Management	-	201	-	-	201	**201**
Total Finance Charges	305	9	-	(75)	(66)	**239**
Amortization of Capital Additions	9	7	-	(1)	6	**15**
Total Regulatory Liabilities	416	231	2	(89)	144	**560**
Net Regulatory Asset	$ 5,908	$ 108	$ 58	$ (318)	$ (152)	**$ 5,756**

NOTE 9: OTHER NON-CURRENT ASSETS

(in millions)	***As at December 31 2016***	*As at March 31* 2016
Non-current receivables	**$ 279**	$ 171
Sinking funds	**179**	167
Other	**81**	79
	$ 539	$ 417

Included in the non-current receivables balance are $185 million of receivables (March 31, 2016 - $152 million) attributable to contributions in aid and tariff supplemental charges related to a transmission line and $72 million of receivables (March 31, 2016 - $8 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, 2016, the outstanding amount under the borrowing program was $3,074 million (March 31, 2016 - $2,376 million).

For the three months ended December 31, 2016, the Company issued bonds with net proceeds of $189 million (2015 - $695 million) and a par value of $200 million (2015 - $691 million), a weighted average effective interest rate of 3.1 per cent (2015 - 2.5 per cent) and a weighted average term to maturity of 31.6 years (2015 - 9.8 years). For the nine months ended December 31, 2016, the Company issued bonds with net proceeds of $895 million (2015 - $1,864 million) and a par value of $900 million (2015 - $1,891 million), a weighted average effective interest rate of 2.6 per cent (2015 - 2.7 per cent) and a weighted average term of maturity of 23.4 years (2015 - 20.9 years).

For the three months and nine months ended December 31, 2016, there were no bond maturities (2015 - $150 million and $150 million, respectively).

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, 2016, there were no changes in the approach to capital management.

The debt to equity ratio at December 31, 2016, and March 31, 2016 was as follows:

(in millions)	***As at December 31*** **2016**	*As at March 31* 2016
Total debt, net of sinking funds	**$ 19,646**	$ 18,046
Less: Cash and cash equivalents	**(88)**	(44)
Net Debt	**$ 19,558**	$ 18,002
Retained earnings	**$ 4,467**	$ 4,397
Contributed surplus	**60**	60
Accumulated other comprehensive income	**41**	43
Total Equity	**$ 4,568**	$ 4,500
Net Debt to Equity Ratio	**81 : 19**	80 : 20

Payment to the Province

Under a Special Directive from the Province, the Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The Special Directive states that for fiscal 2018 and subsequent years, the payment to the Province will be reduced by $100 million per year based on the payment in the immediate preceding fiscal year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

On July 28, 2016, the Province issued Order in Council No. 589, which amends the Special Directive and states that BC Hydro must make a Payment to the Province of an amount no less than $259 million by June 30, 2017, as it relates to fiscal 2017. As a result, the Company has accrued the $259 million minimum amount as at December 31, 2016 even though the Company's debt to equity ratio exceeded the 80:20 cap prior to the calculation of the Payment.

NOTE 12: POST-EMPLOYMENT BENEFITS

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, 2016 was $42 million and $127 million, respectively (2015 - $43 million and $128 million, respectively).

Company contributions to the registered defined benefit pension plans for the three and nine months ended December 31, 2016 were $14 million and $43 million, respectively (2015 - $16 million and $48 million, respectively).

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FOR THE THREE AND NINE MONTHS ENDED DECEMBER 31, 2016

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, 2016 and 2015.

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, 2016 and March 31, 2016. The non-derivative financial instruments, where carrying value differs from fair value, would be classified as Level 2 of the fair value hierarchy.

	December 31, 2016		March 31, 2016	
(in millions)	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Financial Assets and Liabilities at Fair Value Through Profit or Loss:				
Cash equivalents - short-term investments	**$ 47**	**$ 47**	$ 11	$ 11
Loans and Receivables:				
Accounts receivable and accrued revenue	**776**	**776**	669	669
Non-current receivables	**279**	**280**	171	171
Cash	**41**	**41**	33	33
Held to Maturity:				
Sinking funds – US	**179**	**194**	167	194
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**(1,335)**	**(1,335)**	(1,816)	(1,816)
Revolving borrowings - CAD	**(1,890)**	**(1,890)**	(1,605)	(1,605)
Revolving borrowings - US	**(1,184)**	**(1,184)**	(771)	(771)
Long-term debt (including current portion due in one year)	**(16,751)**	**(19,260)**	(15,837)	(18,684)
First Nations liabilities (non-current portion)	**(390)**	**(627)**	(378)	(547)
Finance lease obligations (non-current portion)	**(203)**	**(203)**	(219)	(219)
Other liabilities	**(237)**	**(262)**	(147)	(153)

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

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

(in millions)	**December 31, 2016 Fair Value**	March 31, 2016 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt:		
Foreign currency contracts (cash flow hedges for $US denominated long-term debt)	**$ 75**	$ 57
Foreign currency contracts (cash flow hedges for €EURO denominated long-term debt)	**(17)**	(5)
	58	52
Non-Designated Derivative Instruments:		
Interest rate contracts	**217**	-
Foreign currency contracts	**10**	(34)
Commodity derivatives	**12**	41
	239	7
Net asset	**$ 297**	$ 59

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

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

(in millions)	**December 31, 2016**	March 31, 2016
Current portion of derivative financial instrument assets	**$ 173**	$ 137
Current portion of derivative financial instrument liabilities	**(78)**	(143)
Derivative financial instrument assets, non-current	**234**	92
Derivative financial instrument liabilities, non-current	**(32)**	(27)
Net asset	**$ 297**	$ 59

For designated cash flow hedges for the three and nine months ended December 31, 2016, losses of $11 million and gains of $6 million, respectively, (2015 - gains of $18 million and $54 million, respectively) were recognized in other comprehensive income. For the three and nine months ended December 31, 2016, $1 million and $16 million, respectively, (2015 - $40 million and $96 million, respectively) were reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange losses (2015 - losses) recorded in the year.

For interest rate contracts not designated as hedges with an aggregate notional principal of $3.9 billion, used to economically hedge the interest rates on future debt issuances, for the three and nine months ended December 31, 2016, there was a $290 million and $217 million increase, respectively, (2015 - $nil, no interest rate contracts) in the fair value of these contracts. For the interest rate contracts with an aggregate notional principal of $500 million for debt issued to date under the future hedge program, for the three and nine months ended December 31, 2016, there was a $9 million increase and a $16 million decrease, respectively, (2015 - $nil, no interest rate contracts) in the fair value of these contracts. The change in fair value of $217 million on the remaining $3.9 billion of interest rate contracts and the settlement loss of $16 million on $500 million of interest rate contracts realized was recognized in finance charges and then transferred to the Debt Management regulatory account which had a balance of $201 million as at December 31, 2016.

For foreign currency contracts not designated as hedges for the three and nine months ended December 31, 2016, gains of $2 million and $2 million, respectively, (2015 - gains of $2 million and $7 million, respectively) were recognized in finance charges with respect to foreign currency contracts for cash management purposes. For the foreign currency contracts for U.S. short-term borrowings for the three and nine months ended December 31, 2016, gains of $25 million and $38 million, respectively, (2015 - gains of $30 million and $100 million, respectively) were recognized in finance charges. These economic hedges offset $24 million and $37 million of foreign exchange revaluation losses (2015 - losses of $31 million and $103 million, respectively) recorded with respect to U.S. short-term borrowings for the three and nine months ended December 31, 2016, respectively.

For commodity derivatives not designated as hedges, net losses of $14 million and $32 million, respectively (2015 - gains of $3 million and $5 million, respectively) were recorded in trade revenue for the three and nine months ended December 31, 2016.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)	*For the three months ended December 31* **2016**	2015	*For the nine months ended December 31* **2016**	2015
Deferred inception loss, beginning of the period	**$ 39**	$ 64	**$ 48**	$ 70
New transactions	**(2)**	(9)	**(9)**	(7)
Amortization	**3**	5	**1**	(3)
Deferred inception loss, end of the period	**$ 40**	$ 60	**$ 40**	$ 60

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, 2016 and March 31, 2016:

As at December 31, 2016 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value:				
Short-term investments	$ 47	$ -	$ -	$ 47
Derivatives designated as hedges	-	76	-	76
Derivatives not designated as hedges	43	260	28	331
	$ 90	$ 336	$ 28	$ 454

As at December 31, 2016 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial liabilities carried at fair value:				
Derivatives designated as hedges	$ -	$ (18)	$ -	$ (18)
Derivatives not designated as hedges	(55)	(33)	(4)	(92)
	$ (55)	$ (51)	$ (4)	$ (110)

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

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

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

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

There were no transfers between 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 nine months ended December 31, 2016 and 2015:

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

(in millions)		
Balance at April 1, 2015	**$**	**39**
Net gain recognized		(5)
New transactions		6
Existing transactions settled		7
Balance at December 31, 2015	**$**	**47**

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

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

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

During the three and nine months ended December 31, 2016, unrealized gains of $7 million and losses of $19 million, respectively, (2015 - $1 million loss and $4 million loss, respectively) were recognized on Level 3 derivative commodity assets held at December 31, 2016. During the three and nine months ended December 31, 2016, unrealized losses of $4 million and $nil, respectively, (2015 - $8 million loss and $2 million gain, respectively) were recognized on Level 3 derivative commodity liabilities held at December 31, 2016. 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* 2016**	*As at March 31* 2016
Provisions		
Environmental liabilities	**$ 344**	$ 390
Decommissioning obligations	**53**	56
Other	**11**	10
	408	456
First Nations liabilities	**405**	409
Finance lease obligations	**224**	240
Unearned revenue	**551**	463
Other liabilities	**237**	147
	1,825	1,715
Less: Current portion, included in accounts payable and accrued liabilities	**(99)**	(122)
	$ 1,726	$ 1,593

NOTE 15: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of the Company's operations, the condensed consolidated interim statements of comprehensive income are 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.