British Columbia Hydro and Power Authority

2019/20

SECOND QUARTER REPORT

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three and six months ended September 30, 2019 and should be read in conjunction with the MD&A presented in the 2018/19 Annual Service Plan Report, the 2018/19 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 six months ended September 30, 2019.

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

- The net income for the three months ended September 30, 2019 was $nil, $34 million lower than the same period in the prior fiscal year. The decrease in net income after regulatory account transfers was primarily driven by the elimination of rate smoothing and higher planned dismantling expenses, partially offset by the return of the credit balance in the energy deferral accounts to ratepayers.

- The net income for the six months ended September 30, 2019 was $25 million, $89 million lower than the same period in the prior fiscal year. The decrease in net income after regulatory account transfers was primarily driven by the same reasons discussed above.

- Water inflows to the system during the six months ended September 30, 2019 were below average, slightly lower than that observed in the same period in the prior year. Much of this is associated with below average inflows to the Kootenays, small hydro projects and the Williston (Peace) with the exception of the last two months of second quarter, where inflows at the Williston reservoir were above average. On the other hand, the Kinbasket (Columbia) reservoir was near average for this period. Despite reduced reservoir inflows in spring and early summer 2019, BC Hydro is forecasting normal operating conditions at most of its reservoirs in the fall and winter. Near or above average rain and water inflows over the summer and early fall have resulted in improved conditions.

- Capital expenditures, before contributions in aid of construction, for the three and six months ended September 30, 2019 were $839 million and $1.46 billion, respectively, a $1.15 billion and $1.06 billion, respectively, decrease over the prior fiscal year. The decrease in capital expenditures for the three and six months ended September 30, 2019 compared to the same period in the prior year was primarily due to the completion of the purchase of the remaining two-thirds interest in the Waneta Dam on July 26, 2018. BC Hydro continues to invest significantly in capital projects/programs to upgrade its existing assets and build new infrastructure, including the Site C Project, Peace Region Electricity Supply, Microsoft Enterprise Agreement, Transmission Wood Structure and Framing Replacement, Distribution

Wood Poles Replacements, LNG Canada Load Interconnections, Supply Chain Applications and Mica Replace Units 1-4 Transformers.

CONSOLIDATED RESULTS OF OPERATIONS

($ in millions)	*For the three months ended September 30* **2019**	2018	Change	*For the six months ended September 30* **2019**	2018	Change
Total Revenues	**$ 1,316**	$ 1,536	$ (220)	**$ 2,684**	$ 2,939	$ (255)
Net Income	**$ -**	$ 34	$ (34)	**$ 25**	$ 114	$ (89)
Capital Expenditures	**$ 839**	$ 1,985	$ (1,146)	**$ 1,464**	$ 2,524	$ (1,060)
GWh Sold (Domestic)	**11,598**	13,288	(1,690)	**23,443**	25,921	(2,478)

($ in millions)	***As at September 30, 2019***	*As at March 31, 2019*	Change
Total Assets and Regulatory Balances	**$ 37,514**	$ 36,567	$ 947
Shareholder's Equity	**$ 5,004**	$ 4,946	$ 58
Accrued Payment to the Province	**$ -**	$ 59	$ (59)
Retained Earnings	**$ 4,958**	$ 4,933	$ 25
Debt to Equity	**82 : 18**	82 : 18	n/a
Number of Domestic Customer Accounts	**2,066,251**	2,049,157	17,094

REVENUES

For the three and six months ended September 30, 2019, total revenues of $1.32 billion and $2.68 billion, respectively, were $220 million and $255 million, respectively, lower than the same period in the prior fiscal year. The decrease over the prior fiscal year for the three months ended September 30, 2019 was due to lower trade revenues of $127 million and lower domestic revenues of $93 million. The decrease over the prior fiscal year for the six months ended September 30, 2019 was due to lower trade revenues of $187 million and lower domestic revenues of $68 million.

for the three months ended September 30	*(in millions)* **2019**	2018	*(gigawatt hours)* **2019**	2018	*($ per MWh)* [1] **2019**	2018
Domestic Revenues						
Residential	**$ 400**	$ 401	**3,409**	3,461	**$ 117.34**	$ 115.86
Light industrial and commercial	**472**	460	**4,528**	4,540	**104.24**	101.32
Large industrial	**200**	219	**3,208**	3,550	**62.34**	61.69
Surplus Sales	**-**	111	**(1)**	1,470	**-**	75.51
Other sales	**115**	89	**454**	267	**-**	-
Total Domestic Revenues	**$ 1,187**	$ 1,280	**11,598**	13,288	**$ 102.35**	$ 96.33
Trade Revenues						
Gross electricity and gas	**$ 258**	$ 378	**6,924**	5,790	**$ 42.31**	$ 56.34
Less: forward electricity and gas purchases	**(129)**	(122)	**-**	-	**-**	-
Total Trade Revenues	**$ 129**	$ 256	**6,924**	5,790	**$ 18.63**	$ 44.21
Total Revenues	**$ 1,316**	$ 1,536	**18,522**	19,078	**$ 71.05**	$ 80.51

[1] 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.

for the six months ended September 30	(in millions) 2019	2018	(gigawatt hours) 2019	2018	($ per MWh)[1] 2019	2018
Domestic Revenues						
Residential	**$ 822**	$ 834	**6,975**	7,231	**$ 117.85**	$ 115.34
Light industrial and commercial	**928**	927	**8,901**	9,180	**104.26**	100.98
Large industrial	**407**	411	**6,572**	6,779	**61.93**	60.63
Surplus Sales	**1**	115	**182**	2,230	**5.49**	51.57
Other sales	**226**	165	**813**	501	**-**	-
Total Domestic Revenues	**$ 2,384**	$ 2,452	**23,443**	25,921	**$ 101.69**	$ 94.60
Trade Revenues						
Gross electricity and gas	**$ 488**	$ 653	**13,102**	13,423	**$ 37.86**	$ 28.85
Less: forward electricity and gas purchases	**(188)**	(166)	**-**	-	**-**	-
Total Trade Revenues	**$ 300**	$ 487	**13,102**	13,423	**$ 22.90**	$ 36.28
Total Revenues	**$ 2,684**	$ 2,939	**36,545**	39,344	**$ 73.44**	$ 74.70

[1] 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

For the three months ended September 30, 2019, domestic revenues were $1.19 billion, a decrease of $93 million (or 7 percent), compared to the same period in the prior fiscal year. The decrease over the same period in prior fiscal year was primarily due to lower surplus sales, due to low reservoir levels. Large industrial revenues were also lower, with declines in the pulp and paper and wood sectors caused by curtailments driven by a weak lumber market and fibre supply shortages. These lower revenues were partially offset by higher average customer rates that reflect the 1.76 percent interim average net bill increase as approved by the BCUC effective April 1, 2019, as well as higher other sales, which includes higher revenues related to the sale of two-thirds of the production from the Waneta Dam and Generating Facility which the Company acquired in July 2018.

For the six months ended September 30, 2019, domestic revenues were $2.38 billion, a decrease of $68 million (or 3 per cent), compared to the same period in the prior fiscal year. The decrease was primarily due to the same reasons noted above. In addition, residential revenue was lower, driven by lower average use per account. Large industrial revenue was slightly lower, with the declines in the pulp and paper and wood sectors seen in the second quarter largely offset by the higher revenues from the oil and gas sector in the first quarter.

Trade Revenues

Powerex Corp., a wholly owned subsidiary of the Company, is an energy marketer whose activities include trading wholesale power, environmental products (renewable energy credits or other similar products), carbon products (allowances and other similar products), natural gas, ancillary services, and financial energy 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 Corp.'s trade activities earn income to keep the Company's customer rates low 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 September 30, 2019 were $129 million, a decrease of $127 million (or 50 percent) compared to the same period in the prior fiscal year. The decrease in trade revenue was primarily driven by lower sales prices.

Total trade revenues for the six months ended September 30, 2019 were $300 million, a decrease of $187 million (or 38 percent) compared to the same period in the prior fiscal year. The decrease in trade revenue was primarily driven by lower sales prices.

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

OPERATING EXPENSES

For the three and six months ended September 30, 2019, total operating expenses of $1.23 billion and $2.44 billion, respectively, were $147 million and $211 million, respectively, higher than the same period in the prior fiscal year. The increase over the same period in the prior fiscal year for the three months ended September 30, 2019 was primarily due to higher domestic energy costs of $95 million, higher personnel expenses of $20 million, higher grants, taxes and other costs of $13 million, and higher amortization and depreciation of $9 million. The increase over the same period in prior fiscal year for the six months ended September 30, 2019 was primarily due to higher domestic energy costs of $147 million, higher personnel expenses of $37 million, higher grants, taxes and other costs of $26 million, and higher amortization and depreciation of $24 million. This was partially offset by lower trade energy costs of $29 million.

Energy Costs

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission and other charges. Energy costs are primarily influenced 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 for the three months ended September 30, 2019 were $607 million, $101 million (or 20 percent) higher than the same period in the prior fiscal year. The increase was primarily due to higher domestic energy costs of $95 million.

Total energy costs for the six months ended September 30, 2019 were $1.18 billion, $118 million (or 11 percent) higher than the same period in the prior fiscal year. The increase was primarily due to higher domestic energy costs of $147 million, partially offset by lower trade energy costs of $29 million.

for the three months ended September 30	*(in millions)* **2019**	2018	*(gigawatt hours)* **2019**	2018	*($ per MWh)* [2] **2019**	2018
Domestic Energy Costs						
Water rental payments (hydro generation)[1]	**$ 79**	$ 84	**7,342**	10,197	**$ 10.76**	$ 8.24
Purchases from Independent Power Producers	**377**	346	**4,419**	4,162	**85.31**	83.13
Other electricity purchases - Domestic	**24**	-	**523**	11	**45.89**	-
Gas and transportation for thermal generation	**2**	4	**46**	46	**43.48**	86.96
Transmission charges and other expenses	**(5)**	4	**20**	22	**-**	-
Non-Treaty storage and co-ordination agreements	**6**	(47)	**-**	-	**-**	-
Allocation from (to) trade energy	**6**	3	**184**	(10)	**40.16**	41.15
Total Domestic Energy Costs	**$ 489**	$ 394	**12,534**	14,428	**$ 39.01**	$ 27.31
Trade Energy Costs						
Gross electricity and remarketed gas	**$ 173**	$ 164	**6,482**	5,733	**$ 31.25**	$ 27.67
Less: forward electricity and gas purchases	**(129)**	(122)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**44**	42	**-**	-	**-**	-
Transmission charges and other expenses	**80**	73	**-**	-	**-**	-
Allocation (to) from domestic energy	**(6)**	(3)	**(184)**	10	**40.16**	41.15
Total Trade Energy Costs	**$ 118**	$ 112	**6,298**	5,743	**$ 18.74**	$ 19.50
Total Energy Costs	**$ 607**	$ 506	**18,832**	20,171	**$ 32.23**	$ 25.09

for the six months ended September 30	*(in millions)* **2019**	2018	*(gigawatt hours)* **2019**	2018	*($ per MWh)* [2] **2019**	2018
Domestic Energy Costs						
Water rental payments (hydro generation)[1]	**$ 158**	$ 168	**13,961**	18,916	**$ 11.32**	$ 8.88
Purchases from Independent Power Producers	**702**	671	**8,607**	8,576	**81.56**	78.24
Other electricity purchases - Domestic	**89**	1	**2,432**	51	**36.60**	19.61
Gas and transportation for thermal generation	**3**	8	**75**	71	**40.00**	112.68
Transmission charges and other expenses	**(5)**	8	**41**	47	**-**	-
Non-Treaty storage and co-ordination agreements	**12**	(47)	**-**	-	**-**	-
Allocation from (to) trade energy	**8**	11	**281**	412	**39.54**	30.86
Total Domestic Energy Costs	**$ 967**	$ 820	**25,397**	28,073	**$ 38.08**	$ 29.21
Trade Energy Costs						
Gross electricity and remarketed gas	**$ 250**	$ 264	**13,316**	13,935	**$ 20.95**	$ 18.49
Less: forward electricity and gas purchases	**(188)**	(166)	**-**	-	**-**	-
Net Electricity and Remarketed Gas	**62**	98	**-**	-	**-**	-
Transmission charges and other expenses	**154**	150	**-**	-	**-**	-
Allocation (to) from domestic energy	**(8)**	(11)	**(281)**	(412)	**39.54**	30.86
Total Trade Energy Costs	**$ 208**	$ 237	**13,035**	13,523	**$ 15.96**	$ 17.53
Total Energy Costs	**$ 1,175**	$ 1,057	**38,432**	41,596	**$ 30.57**	$ 25.41

[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 September 30, 2019 were $489 million, $95 million (or 24 percent) higher than the same period in the prior fiscal year. The increase in costs was primarily due to higher costs from net water storage associated with the Non-Treaty storage and co-ordination agreements, higher costs from Independent Power Producers which was largely due to higher generation for a thermal plant to serve domestic load requirements, and higher domestic market purchases required to meet domestic load requirements due to lower water inflows and reservoir storage levels which constrained hydro generation.

Domestic energy costs for the six months ended September 30, 2019 were $967 million, $147 million (or 18 per cent) higher than the same period in the prior fiscal year. The increase in costs was primarily due to the same reasons noted above.

Variances between actual and planned domestic energy costs are transferred to the Heritage Deferral Account (HDA) and Non-Heritage Deferral Account (NHDA). Changes to regulatory account balances are discussed in the *Regulatory Transfers* section.

Trade Energy Costs

Total trade energy costs for the three months ended September 30, 2019 were $118 million, a increase of $6 million (or 5 percent) compared to the same period in the prior fiscal year. The increase in trade energy costs was primarily driven by higher purchase volumes.

Total trade energy costs for the six months ended September 30, 2019 were $208 million, a decrease of $29 million (or 12 percent) compared to the same period in the prior fiscal year. The decrease in trade energy costs was primarily driven by lower purchase prices.

Variances between actual and planned trade costs are transferred to the Trade Income Deferral Account.

Water Inflows and Reservoir Storage

Water inflows to the system for the six months ended September 30, 2019 remain below average, slightly lower than that observed in the same period in the prior year. Much of this is associated with below average inflows to the Kootenays, small hydro projects and the Williston (Peace) with the exception of the last two months of second quarter, where inflows at the Williston reservoir were above average. On the other hand, the Kinbasket (Columbia) reservoir was near average for this period.

System energy storage continues to track below the historic average due to low inflows from the first quarter, but not as low as those observed in second quarter of prior fiscal year.

Personnel Expenses

Personnel expenses include salaries and wages, benefits and post-employment benefits. Personnel expenses for the three and six months ended September 30, 2019 were $156 million and $334 million, respectively, $20 million and $37 million higher than the same period in the prior fiscal year primarily due to higher employee benefits costs (including current pension costs and BC employer health tax) and BC Hydro’s Accenture Repatriation which occurred on May 1, 2018 and the Workforce Optimization program which started in July 2015. Both initiatives have replaced external service providers with internal staff to reduce costs and deliver on our business objectives.

Materials and External Services

Materials and External Services primarily include materials, supplies, and contractor fees. Materials and external services for the three and six months ended September 30, 2019 were $141 million and $280 million, respectively, $4 million and $6 million, respectively, higher than the same period in the prior fiscal year primarily due to higher costs related to operating the Waneta Dam and Generating Facility and the John Hart Generating Station, which was partially offset by lower contractor costs as a result of BC Hydro's Accenture Repatriation and the Workforce Optimization program.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, amortization of intangible assets, and amortization of right-of-use assets. For the three and six months ended September 30, 2019, amortization and depreciation expense was $247 million and $488 million, respectively, $9 million and $24 million, respectively, higher than the same period in the prior fiscal year primarily due to additional property, plant and equipment placed 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. Other costs, net of recoveries, primarily includes gains and losses on the disposal of assets, certain cost recoveries related to operating costs, and dismantling costs. Total grants, taxes and other costs for the three and six months ended September 30, 2019 were $96 million and $197 million, respectively, $13 million and $26 million, respectively, higher than the same period in the prior fiscal year primarily due to higher dismantling costs related to the decommissioning of assets and a higher Polychlorinated Biphenyl removal provision mainly due to a change in discount rates.

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 International Financial Reporting Standards (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 2012/13, 10 per cent (and increasing by 10 percentage points each year over ten years) of the 100 per cent annual ineligible costs overhead costs is being left in operating costs and will continue such that by the end of year ten, 100 per cent of the ineligible IFRS overhead costs will be charged to operating costs in the year and 0 per cent will be deferred into the IFRS Property, Plant & Equipment Regulatory Account. Capitalized costs for the three and six months ended September 30, 2019 were $18 million and $36 million, respectively, which was unchanged compared to the same period in the prior fiscal year.

FINANCE CHARGES

Finance charges for the three and six months ended September 30, 2019 were $397 million and $857 million, respectively, $260 million and $523 million, respectively, higher than the same period in prior fiscal year. The increase was primarily due to unrealized losses on future debt hedges used to economically hedge the interest rates on future debt issuances.

REGULATORY TRANSFERS

In accordance with IFRS 14, the Company separately presents regulatory balances and related net movements on the Condensed Consolidated Interim Statements of Financial Position and the Condensed Consolidated Interim Statements of Comprehensive Income.

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, and to 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:

(in millions)	*For the three months ended September 30* **2019**	2018	*For the six months ended September 30* **2019**	2018
Energy Deferral Accounts				
Heritage Deferral Account	**$ 15**	$ (91)	**$ 23**	$ (95)
Non-Heritage Deferral Account	**38**	(50)	**57**	8
Trade Income Deferral Account	**28**	(94)	**12**	(150)
	81	(235)	**92**	(237)
Forecast Variance Accounts				
Total Finance Charges	**-**	14	**8**	12
Rate Smoothing	**-**	70	**-**	141
Non-Current Pension Costs	**24**	17	**(22)**	34
Debt Management	**184**	(92)	**423**	(102)
Storm Restoration	**(5)**	-	**(9)**	-
Other	**(19)**	5	**(14)**	5
	184	14	**386**	90
Capital-Like Accounts				
Demand-Side Management	**15**	17	**28**	28
IFRS Property, Plant & Equipment	**12**	17	**23**	34
	27	34	**51**	62
Non-Cash Accounts				
Environmental Provisions & Costs	**4**	(6)	**9**	(4)
First Nations Provisions & Costs	**4**	5	**10**	12
Other	**(1)**	(2)	**(2)**	(3)
	7	(3)	**17**	5
Amortization of regulatory accounts	**8**	(104)	**12**	(208)
Interest on regulatory accounts	**3**	11	**8**	24
Net increase in regulatory accounts	**$ 310**	$ (283)	**$ 566**	$ (264)

The Company adopted IFRS 16, *Leases* on April 1, 2019, which resulted in an increase of $64 million to the opening net regulatory asset balance as at April 1, 2018 (the $64 million is not included in the above table). Refer to Note 2 in the Unaudited Condensed Consolidated Interim Financial Statements for more detail on the impact of the adoption of IFRS 16.

For the six months ended September 30, 2019, there was a net addition of $566 million to the Company's regulatory accounts compared to a net reduction of $264 million in the prior fiscal year. The net regulatory asset balance as at September 30, 2019 was $4.82 billion compared to $4.26 billion as at March 31, 2019.

Net additions to the regulatory accounts during the six months ended September 30, 2019 included $423 million of additions to the Debt Management Regulatory Account as a result of losses on interest rate hedges due to a decrease in forward interest rates and $57 million of additions to the Non-Heritage Deferral Account primarily due to lower domestic revenues than planned.

BC Hydro has or has applied for regulatory mechanisms to collect 23 of 25 regulatory accounts in use or with balances at September 30, 2019 in rates over various periods, which represent approximately 90 percent of the net regulatory asset balance.

PAYMENT TO THE PROVINCE

In accordance with Order in Council No. 095/2014 from the Province, for 2017/18 and subsequent years, the payment to the Province was 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 2018/19 Payment to the Province was $59 million and was paid in June 2019. As a result, the Payment for 2019/20 will be $nil.

As at September 30, 2019, the Company's net debt to equity ratio was 82:18.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the six months ended September 30, 2019 was $714 million, compared to $902 million in the same period in the prior fiscal year. The decrease was mainly due lower trade margin, higher domestic cost of energy, and lower domestic revenues, partially offset by higher cash flow received from changes in working capital.

The long-term debt balance net of sinking funds as at September 30, 2019 was $22.88 billion compared to $22.19 billion as at March 31, 2019. The increase was mainly as a result of an increase in net long-term bond issuances (net of redemptions) for net proceeds of $1.01 billion, primarily to fund capital expenditures. This increase was partially offset by lower revolving borrowings of $282 million, and net foreign exchange gains of $29 million.

CAPITAL EXPENDITURES

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

	For the three months ended September 30		*For the six months ended September 30*	
(in millions)	**2019**	2018	**2019**	2018
Transmission lines and substations replacements and expansion	**$ 118**	$ 181	**$ 196**	$ 261
Generation replacements and expansion	**76**	113	**147**	205
Distribution system improvements and expansion	**127**	124	**246**	243
General, including technology, vehicles and buildings	**69**	28	**105**	61
Waneta two-thirds interest acquisition	**-**	1,219	**-**	1,219
Site C	**449**	320	**770**	535
Total Capital Expenditures	**$ 839**	$ 1,985	**$ 1,464**	$ 2,524

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.

The decrease in capital expenditures for the three and six months ended September 30, 2019 compared to the same period in the prior year was primarily due to the completion of the purchase of the remaining two-thirds interest in the Waneta Dam on July 26, 2018.

Transmission lines and substation capital expenditures include expenditures on the following projects/programs: Peace Region Electricity Supply, Transmission Wood Structure and Framing Replacement, LNG Canada Load Interconnection, Fort St. John and Taylor Electric Supply, UBC Load Increase Stage 2, and Vancouver Island Radio System.

Generation capital expenditures include expenditures on the following projects: Mica Replace Units 1-4 Transformers, John Hart Generating Station Replacement, G.M. Shrum Spillway Gate Upgrade, Bridge River 2 Units 7 and 8 Upgrade, Ruskin Dam and Powerhouse Upgrade, G.M. Shrum G1-G10 Control System Upgrade, Cheakamus Recoat Units 1 and 2 Penstock, Cheakamus Unit 1 and Unit 2 Generator Replacement, Mica Modernize Controls (Digital), and Kootenay Canal Powerhouse Crane Upgrade.

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 the Microsoft Enterprise Agreement, Supply Chain Applications project, various building development programs, vehicles, and technology projects.

Site C Project expenditures relate to site preparation, reservoir clearing, transmission lines and substation, engineering and design, highway realignment, main civil works, generating station and spillway, as well as social and land programs.

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.

Capital Expenditures and Projects Review

The BCUC initiated a review in May 2016 to review the regulatory oversight of BC Hydro's capital expenditures and projects. BC Hydro submitted our current proposal in June 2018, which included draft Capital Filing Guidelines. These draft Guidelines expand upon the previous capital project filing guidelines by including the review of capital expenditures and projects in a revenue requirements proceeding, and better aligning capital project regulatory applications with our current capital planning processes. BC Hydro submitted its Final Argument in the proceeding in August 2019, and is now awaiting a Decision from the BCUC.

BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

In February 2019, BC Hydro filed an Application with the BCUC to approve its revenue requirements for a two-year test period covering 2019/20 and 2020/21. In August 2019, BC Hydro provided an Evidentiary Update to its Application, which forecasted a reduction of $122.4 million to our total revenue requirement for the two-year test period. Accordingly, BC Hydro is now requesting a net rate increase of 1.76 percent for fiscal 2020 and a net rate decrease of 0.99 percent for fiscal 2021. After an oral hearing in January 2020, BC Hydro expects a decision in the spring.

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, and to defer for future recovery in rates the differences between planned and actual costs or revenues that often arise due to uncontrollable events. BC Hydro's approach to the recovery of its regulatory accounts is included in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.

Significant Financial Risks

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

While meeting domestic demand, environmental regulations and treaty obligations, BC Hydro seeks 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 seeks 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 2018/19 Annual Service Plan Report for the year ended March 31, 2019. 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 2019 forecast net income for 2019/20 at $712 million which is consistent with the amount required by Order in Council No. 051.

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 Service Plan forecast for 2019/20 assumes average water inflows (100 percent of average), domestic sales of 53,567 GWh, average market energy prices of US $25.88/MWh, short-term interest rates of 2.37 percent, and a Canadian to US dollar exchange rate of US $0.7910.

BC Hydro filed an updated forecast with the Province in November 2019. The updated forecast net income for 2019/20 is $707 million and assumes domestic sales of 53,365 GWh, average market energy prices of U.S. $25.07/MWh, short-term interest rates of 1.63 percent and a Canadian to US dollar exchange rate of US $0.7638. BC Hydro is forecasting normal operating conditions at most of its reservoirs in the fall and winter despite reduced reservoir inflows in spring and early summer 2019 as near or above average rain and water inflows over the summer and early fall have resulted in improved conditions.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

	For the three months ended September 30		For the six months ended September 30	
(in millions)	**2019**	2018 (Note 18)	**2019**	2018 (Note 18)
Revenues (Note 3)				
Domestic	**$ 1,187**	$ 1,280	**$ 2,384**	$ 2,452
Trade	**129**	256	**300**	487
	1,316	1,536	**2,684**	2,939
Expenses				
Operating expenses (Note 4)	**1,229**	1,082	**2,438**	2,227
Finance charges (Note 5)	**397**	137	**857**	334
Net Income (Loss) Before Movement in Regulatory Balances	**(310)**	317	**(611)**	378
Net movement in regulatory balances (Note 9)	**310**	(283)	**636**	(264)
Net Income	**-**	34	**25**	114
OTHER COMPREHENSIVE INCOME				
Items Reclassified Subsequently to Net Income				
Effective portion of changes in fair value of derivatives designated as cash flow hedges (Note 14)	**(2)**	(16)	**7**	(23)
Reclassification to income of derivatives designated as cash flow hedges (Note 14)	**9**	28	**28**	34
Foreign currency translation gains (losses)	**1**	(2)	**(2)**	-
Items That Will Not Be Reclassified to Net Income				
Actuarial gain on post employment benefits	**-**	-	**70**	-
Other Comprehensive Income before movement in regulatory balances	**8**	10	**103**	11
Net movements in regulatory balances (Note 9)	**-**	-	**(70)**	-
Other Comprehensive Income	**8**	10	**33**	11
Total Comprehensive Income	**$ 8**	$ 44	**$ 58**	$ 125

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(in millions)		***As at September 30* 2019**		*As at March 31* 2019 (Note 18)
ASSETS				
Current Assets				
Cash and cash equivalents	**$**	**82**	$	84
Restricted cash		**15**		109
Accounts receivable and accrued revenue		**585**		912
Inventories (Note 7)		**200**		168
Prepaid expenses		**213**		159
Current portion of derivative financial instrument assets (Note 14)		**59**		79
		1,154		1,511
Non-Current Assets				
Property, plant and equipment (Note 8)		**28,288**		27,334
Right-of-use assets		**1,430**		1,466
Intangible assets (Note 8)		**648**		602
Derivative financial instrument assets (Note 14)		**48**		49
Other non-current assets (Note 10)		**617**		598
		31,031		30,049
Total Assets		**32,185**		31,560
Regulatory Balances (Note 9)		**5,329**		5,007
Total Assets and Regulatory Balances	**$**	**37,514**	$	36,567
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities	**$**	**1,558**	$	1,546
Current portion of long-term debt (Note 11)		**3,265**		3,121
Current portion of unearned revenues and contributions in aid		**91**		87
Current portion of derivative financial instrument liabilities (Note 14)		**170**		89
		5,084		4,843
Non-Current Liabilities				
Long-term debt (Note 11)		**19,813**		19,261
Lease liabilities		**1,445**		1,470
Derivative financial instrument liabilities (Note 14)		**562**		294
Unearned revenues and contributions in aid		**2,010**		1,905
Post-employment benefits (Note 13)		**1,744**		1,752
Other non-current liabilities (Note 15)		**1,346**		1,346
		26,920		26,028
Total Liabilities		**32,004**		30,871
Regulatory Balances (Note 9)		**506**		750
Shareholder's Equity				
Contributed surplus		**60**		60
Retained earnings		**4,958**		4,933
Accumulated other comprehensive loss		**(14)**		(47)
		5,004		4,946
Total Liabilities, Shareholder's Equity and Regulatory Balances	**$**	**37,514**	$	36,567

Commitments (Note 8)

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve (Note 18)	Unrealized Gains (Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Loss (Note 18)	Contributed Surplus	Retained Earnings (Note 18)	Total
Balance as at April 1, 2018	$ (5)	$ (29)	$ (34)	$ 60	$ 5,420	$ 5,446
Payment to the Province (Note 12)	-	-	-	-	(59)	(59)
Comprehensive Income	-	11	11	-	114	125
Balance as at September 30, 2018	$ (5)	$ (18)	$ (23)	$ 60	$ 5,475	$ 5,512
Balance as at April 1, 2019	$ (2)	$ (45)	$ (47)	$ 60	$ 4,933	$ 4,946
Comprehensive Income (Loss)	(2)	35	33	-	25	58
Balance as at September 30, 2019	$ (4)	$ (10)	$ (14)	$ 60	$ 4,958	$ 5,004

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

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the six months ended September 30* **2019**	2018 (Note 18)
Operating Activities		
Net income	**$ 25**	$ 114
Regulatory account transfers (Note 9)	**(566)**	264
Adjustments for non-cash items:		
Amortization and depreciation expense (Note 6)	**488**	464
Unrealized losses on derivative financial instruments	**427**	(80)
Post-employee benefit plan expenses	**66**	52
Interest accrual	**432**	421
Other items	**87**	(19)
	959	1,216
Changes in working capital and other assets and liabilities (Note 17)	**186**	94
Interest paid	**(431)**	(408)
Cash provided by operating activities	**714**	902
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(1,272)**	(2,570)
Cash used in investing activities	**(1,272)**	(2,570)
Financing Activities		
Long-term debt issued (Note 11)	**1,186**	2,418
Long-term debt retired (Note 11)	**(175)**	(457)
Receipt of revolving borrowings	**5,150**	3,702
Repayment of revolving borrowings	**(5,427)**	(3,709)
Payment to the Province (Note 12)	**(59)**	(159)
Other items	**(119)**	3
Cash provided by financing activities	**556**	1,798
Increase (Decrease) in cash and cash equivalents	**(2)**	130
Cash and cash equivalents, beginning of period	**84**	42
Cash and cash equivalents, end of period	**$ 82**	$ 172

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

NOTE 1: REPORTING ENTITY

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

The condensed consolidated interim financial statements (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). All intercompany transactions and balances are eliminated on consolidation. On July 26, 2018, the Company completed the purchase of the remaining two-thirds interest of Waneta Dam and Generating Facility (Waneta). Prior to this transaction, the Company accounted for its one-third interest in Waneta as a joint operation.

NOTE 2: BASIS OF PRESENTATION

Basis of Accounting

These interim financial statements have been prepared by management in accordance with principles of IAS 34, *Interim Financial Reporting* and were prepared using the same accounting policies as described in BC Hydro's 2018/19 Annual Service Plan Report, except for changes as a result of the adoption of IFRS 16, *Leases* (IFRS 16). These interim financial statements should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2018/19 Annual Service Plan Report.

Certain amounts in the prior year's comparative figures have been reclassified to conform to the current year's presentation.

These interim financial statements were approved on behalf of the Board of Directors on November 6, 2019.

BC Hydro's significant accounting policy regarding leases was amended for the adoption of IFRS 16.

IFRS 16 - Leases

Effective April 1, 2019, the Company adopted IFRS 16, *Leases*, which replaces the existing standards IAS 17, *Leases* and IFRIC 4, *Determining Whether an Arrangement Contains a Lease*. The Company applied the standard on a full retrospective basis in accordance with IAS 8, *Accounting Policies, Changes in Accounting Estimates and Errors*, under which the comparative periods are restated.

At inception of a contract, the Company assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether the contract involves the use of an identified asset, whether the Company has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use, and has the right to direct the use of the asset. At inception or on reassessment of a contract that contains a lease component, consideration is allocated to each lease component within the contract on the basis of its relative stand-alone prices.

As a lessee, the Company recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any decommissioning and restoration costs, less any lease incentives received.

The right-of-use asset is subsequently depreciated from the commencement date to the earlier of the end of the lease term, or the end of the useful life of the asset. In addition, the right-of-use asset may be reduced due to impairment losses, if any, and adjusted for remeasurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the incremental borrowing rate.

Lease payments included in the measurement of the lease liability are comprised of:

i) Fixed payments, including in-substance fixed payments, less any lease incentives receivable;

ii) Variable lease payments that depend on an index or a rate, initially measured using the index or rate as at the commencement date;

iii) Amounts expected to be payable under a residual value guarantee;

iv) Exercise prices of purchase options if reasonably certain the option will be exercised; and

v) Payments of penalties for terminating the lease, if the lease term reflects the lessee exercising an option to terminate the lease.

The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in our estimate or assessment of the amount expected to be payable under a residual value guarantee, purchase, extension or termination option.

When the lease liability is remeasured, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

Variable lease payments not included in the initial measurement of the lease liability are charged directly to the consolidated statement of comprehensive income as an expense.

The impact of the adoption of IFRS 16 on these condensed interim consolidated financial statements is disclosed in Note 18 - Explanation of Adoption of IFRS 16 and Restatement of Previously Reported Figures.

Key Assumptions and Significant Judgments

In the situation where the implicit interest rate in the lease is not readily determined, the Company uses judgment to estimate the incremental borrowing rate for discounting the lease payments. The Company's incremental borrowing rate generally reflects the interest rate that the Company would have to pay to borrow a similar amount at a similar term and with similar security. The Company estimates the lease term by considering the facts and circumstances that create an economic incentive to exercise an extension or termination option. Certain qualitative and quantitative assumptions are used when evaluating these options.

Practical Expedients Used as Permitted by IFRS 16

(i) The Company has elected not to separate non-lease components and account for the lease and non-lease components as a single lease component for leases pertaining to generating equipment.

(ii) The Company has elected not to recognise right-of-use assets and lease liabilities for short-term leases that have a lease term of 12 months or less and leases of low-value assets, including office equipment.

NOTE 3: REVENUES

The Company disaggregates revenue by revenue type and customer class, which are considered to be the most relevant revenue information for management to consider in allocating resources and evaluating performance.

	For the three months ended September 30		*For the six months ended September 30*	
(in millions)	**2019**	2018	**2019**	2018
Domestic				
Residential	**$ 400**	$ 401	**$ 822**	$ 834
Light industrial and commercial	**472**	460	**928**	927
Large industrial	**200**	219	**407**	411
Surplus sales	**-**	111	**1**	115
Other sales	**115**	89	**226**	165
Total Domestic	**1,187**	1,280	**2,384**	2,452
Total Trade[1]	**129**	256	**300**	487
Total Revenue	**$ 1,316**	$ 1,536	**$ 2,684**	$ 2,939

[1] Includes mark-to-market gains (losses) from derivatives.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2019

NOTE 4: OPERATING EXPENSES

	For the three months ended September 30		For the six months ended September 30	
(in millions)	**2019**	2018	**2019**	2018
Electricity and gas purchases	**$ 476**	$ 368	**$ 919**	$ 783
Water rentals	**79**	84	**158**	168
Transmission charges	**52**	54	**98**	106
Personnel expenses	**156**	136	**334**	297
Materials and external services	**141**	137	**280**	274
Amortization and depreciation (Note 6)	**247**	238	**488**	464
Grants, taxes and other costs	**96**	83	**197**	171
Capitalized costs	**(18)**	(18)	**(36)**	(36)
	$ 1,229	$ 1,082	**$ 2,438**	$ 2,227

NOTE 5: FINANCE CHARGES

	For the three months ended September 30		For the six months ended September 30	
(in millions)	**2019**	2018	**2019**	2018
Interest on long-term debt	**$ 217**	$ 216	**$ 432**	$ 421
Interest on lease liabilities	**11**	15	**26**	27
Interest on defined benefit plan obligations	**15**	14	**31**	28
Mark-to-market losses (gains) on derivative financial instruments	**181**	(91)	**420**	(103)
Capitalized interest	**(41)**	(30)	**(78)**	(61)
Other	**14**	13	**26**	22
	$ 397	$ 137	**$ 857**	$ 334

NOTE 6: AMORTIZATION AND DEPRECIATION

	For the three months ended September 30		For the six months ended September 30	
(in millions)	**2019**	2018	**2019**	2018
Depreciation of property, plant and equipment	**$ 203**	$ 194	**$ 403**	$ 376
Depreciation of right-of-use assets	**24**	23	**46**	46
Amortization of intangible assets	**20**	21	**39**	42
	$ 247	$ 238	**$ 488**	$ 464

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2019

NOTE 7: INVENTORIES

(in millions)	***As at September 30* 2019**	*As at March 31* 2019
Materials and supplies	**$ 164**	$ 161
Natural gas trading inventories	**36**	7
	$ 200	$ 168

NOTE 8: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset additions, before contributions in aid of construction, for the three and six months ended September 30, 2019 were $839 million and $1.46 billion, respectively (2018/19 - $1.99 billion and $2.52 billion, respectively).

As of September 30, 2019, the Company has contractual commitments to spend $2.96 billion on major property, plant and equipment projects (for individual projects greater than $50 million).

NOTE 9: RATE REGULATION

In February 2019, BC Hydro filed an Application with the British Columbia Utilities Commission (BCUC) to approve its revenue requirements for a two year test period covering 2019/20 and 2020/21. Subsequently, BC Hydro submitted an Evidentiary Update in August 2019. The financial impact of the Evidentiary Update has been incorporated in these financial statements in accordance with the Company's rate regulation accounting policy, whereby BC Hydro defers amounts in advance of a final decision on the application by the BCUC based on management's estimate on the probability of acceptance and recovery in future rates.

Regulatory Accounts

The Company has established various regulatory accounts through rate regulation and with the approval of the BCUC. In the absence of rate regulation, these amounts would be reflected in total comprehensive income. The net movement in regulatory balances related to total comprehensive income is as follows:

(in millions)	*For the three months ended September 30* **2019**	2018	*For the six months ended September 30* **2019**	2018
Net increase (decrease) in regulatory balances related to net income	**$ 310**	$ (283)	**$ 636**	$ (264)
Net increase (decrease) in regulatory balances related to OCI	**-**	-	**(70)**	-
	$ 310	$ (283)	**$ 566**	$ (264)

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. 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.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
FOR THE THREE AND SIX MONTHS ENDED SEPTEMBER 30, 2019

(in millions)	*As at April 1 2019*	*Addition (Reduction)*	*Interest [1]*	*Amortization*	*Net Change [2]*	***As at September 30 2019***
Regulatory Assets						
Non-Heritage Deferral Account[3]	$ 141	$ 57	$ 3	$ (21)	$ 39	**$ 180**
Demand-Side Management	915	28	-	(52)	(24)	**891**
Debt Management	163	423	-	6	429	**592**
First Nations Provisions & Costs	505	10	2	(16)	(4)	**501**
Non-Current Pension Costs	486	(22)	-	(28)	(50)	**436**
Site C	491	-	9	-	9	**500**
CIA Amortization	83	(2)	-	-	(2)	**81**
Environmental Provisions & Costs	227	9	(1)	(10)	(2)	**225**
Smart Metering & Infrastructure	217	-	4	(15)	(11)	**206**
IFRS Pension	497	-	-	(19)	(19)	**478**
IFRS Property, Plant & Equipment	1,064	23	-	(15)	8	**1,072**
Storm Restoration Costs	58	(9)	1	(15)	(23)	**35**
Total Finance Charges	20	8	-	(5)	3	**23**
Real Property Sales	49	1	1	-	2	**51**
Other Regulatory Accounts	91	(13)	1	(21)	(33)	**58**
Total Regulatory Assets	5,007	513	20	(211)	322	**5,329**
Regulatory Liabilities						
Heritage Deferral Account	485	(23)	8	(140)	(155)	**330**
Trade Income Deferral Account[3]	261	(12)	4	(83)	(91)	**170**
Other Regulatory Accounts	4	2	-	-	2	**6**
Total Regulatory Liabilities	750	(33)	12	(223)	(244)	**506**
Net Regulatory Asset	$ 4,257	$ 546	$ 8	$ 12	$ 566	**$ 4,823**

[1]As permitted by the BCUC, interest charges were accrued to certain regulatory balances at a rate of 3.8 per cent for the six months ended September 30, 2019 (2018/19 – 4.0 per cent) at the Company's weighted average cost of debt.

[2] Net Change includes a net increase to net income of $636 million (2018/19 – a net decrease to net income of $264 million) and net decrease to other comprehensive income of $70 million (2018/19 – $nil).

[3] As a result of the adoption of IFRS 16, the opening balances as at April 1, 2019 included a $65 million adjustment to the Non-Heritage Deferral Account and a $2 million adjustment to the Trade Income Deferral Account. Refer to Note 18 - Explanation of Adoption of IFRS 16 and Restatement of Previously Reported Figures for more details.

There were no significant changes to the remaining recovery/reversal periods for the six months ended September 30, 2019. Refer to Note 14 – Rate Regulation in the Company's 2018/19 Annual Service Plan Report.

NOTE 10: OTHER NON-CURRENT ASSETS

(in millions)	***As at September 30* 2019**	*As at March 31* 2019
Non-current receivables	**$ 132**	$ 148
Sinking funds	**200**	197
Non-current Site C prepaid expenses	**283**	250
Other	**2**	3
	$ 617	$ 598

Included in the non-current receivables balance were $127 million of receivables (March 31, 2019 - $135 million) attributable to contributions.

NOTE 11: LONG-TERM DEBT AND DEBT MANAGEMENT

The Company's 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 $4.50 billion. At September 30, 2019, the outstanding amount under the borrowing program was $2.66 billion (March 31, 2019 - $2.95 billion), and is recorded as revolving borrowings.

For the three months ended September 30, 2019, the Company issued bonds for net proceeds of $596 million (2018/19 - $1.54 billion) and a par value of $525 million (2018/19 - $1.55 billion), a weighted average effective interest rate of 2.3 per cent (2018/19 - 2.9 per cent) and a weighted average term to maturity of 30.3 years (2018/19 - 19.0 years). For the six months ended September 30, 2019, the Company issued bonds for net proceeds of $1.19 billion (2018/19 - $2.42 billion) and a par value of $1.08 billion (2018/19 - $2.45 billion), a weighted average effective interest rate of 2.3 per cent (2018/19 - 3.0 per cent) and a weighted average term to maturity of 24.4 years (2018/19 - 19.8 years).

For the three months ended September 30, 2019, there were no bond maturities (2018/19 – no bond maturities). For the six months ended September 30, 2019, the Company redeemed bonds with par value of $175 million (2018/19 - $457 million).

NOTE 12: 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 loss, and contributed surplus. The Company monitors its capital structure on the basis of its debt to equity ratio.

During the three and six months ended September 30, 2019, there were no changes in the approach to capital management.

The debt to equity ratio at September 30, 2019, and March 31, 2019 was as follows:

(in millions)	***As at September 30* 2019**	*As at March 31* 2019
Total debt, net of sinking funds	**$ 22,878**	$ 22,185
Less: Cash and cash equivalents	**(82)**	(84)
Net Debt	**$ 22,796**	$ 22,101
Retained earnings	**$ 4,958**	$ 4,933
Contributed surplus	**60**	60
Accumulated other comprehensive loss	**(14)**	(46)
Total Equity	**$ 5,004**	$ 4,947
Net Debt to Equity Ratio	**82 : 18**	82 : 18

Payment to the Province

In accordance with Order in Council No. 095/2014 from the Province, for 2017/18 and subsequent years, the payment to the Province was 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 2018/19 Payment to the Province was $59 million and was paid in June 2019. As a result, the Payment for 2019/20 will be $nil.

NOTE 13: 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 for the three and six months ended September 30, 2019 was $48 million and $96 million, respectively (2018/19 - $41 million and $82 million).

Company contributions to the registered defined benefit pension plans for the three and six months ended September 30, 2019 were $11 million and $22 million, respectively (2018/19 - $11 million and $22 million, respectively).

In the absence of a plan amendment, curtailment or settlement, the Company recognizes plan re-measurements due to market fluctuations from changes in the market rate of return on plan assets and liability discount rates at year end.

NOTE 14: FINANCIAL INSTRUMENTS

Categories of Financial Instruments

The following table provides a comparison of carrying values and fair values for non-derivative financial instruments as at September 30, 2019, and March 31, 2019.

(in millions)	**September 30, 2019 Carrying Value**	**September 30, 2019 Fair Value**	March 31, 2019 Carrying Value	March 31, 2019 Fair Value
Fair Value Through Profit or Loss				
Cash equivalents - short-term investments	**$ 22**	**$ 22**	$ 50	$ 50
Amortized Cost:				
Cash	**60**	**60**	34	34
Restricted cash	**15**	**15**	109	109
Accounts receivable and accrued revenue	**585**	**585**	912	912
Non-current receivables	**132**	**149**	148	159
Sinking funds	**200**	**232**	197	220
Accounts payable and accrued liabilities	**(1,558)**	**(1,558)**	(1,546)	(1,546)
Revolving borrowings	**(2,663)**	**(2,663)**	(2,945)	(2,945)
Long-term debt (including current portion due in one year)	**(20,415)**	**(24,443)**	(19,437)	(22,480)
First Nations liabilities (non-current portion)	**(390)**	**(736)**	(391)	(640)
Lease liabilities (non-current portion)	**(1,445)**	**(1,445)**	(1,470)	(1,470)
Other liabilities	**(426)**	**(448)**	(419)	(434)

The fair values of non-derivative financial instruments, where the carrying value differs from fair value, are classified as Level 2 of the fair value hierarchy. The carrying value of cash equivalents, restricted cash, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and revolving borrowings approximates fair value due to the short duration of these financial instruments.

Hedges

The following foreign currency contracts under hedge accounting were in place at September 30, 2019 in a net asset position of $31 million (March 31, 2019 – net asset $22 million). Such contracts are used to hedge the principal on $US denominated long-term debt and the principal and coupon payments on Euro denominated long-term debt for which hedge accounting has been applied. The hedging instruments are effective in offsetting changes in the cash flows of the hedged item attributed to the hedged risk. The main source of hedge ineffectiveness in these hedges is credit risk.

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($ amounts in millions)		**September 30, 2019**		March 31, 2019
Cross-Currency Hedging Swaps				
Euro dollar to Canadian dollar - notional amount[1]	**€**	**402**	€	402
Euro dollar to Canadian dollar - weighted average contract rate		**1.47**		1.47
Weighted remaining term		**8 years**		9 years
Foreign Currency Hedging Forwards				
United States dollar to Canadian dollar - notional amount[1]	**US$**	**573**	US$	573
United States dollar to Canadian dollar - weighted average contract rate		**1.25**		1.25
Weighted remaining term		**11 years**		11 years

[1] *Notional amount for a derivative instrument is defined as the contractual amount on which payments are calculated.*

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

(in millions)		**September 30, 2019 Fair Value**		March 31, 2019 Fair Value
Designated Derivative Instruments Used to Hedge Risk Associated with Long-term Debt				
Foreign currency contract assets (cash flow hedges for $US denominated long-term debt)	**$**	**21**	$	10
Foreign currency contract assets (cash flow hedges for €EURO denominated long-term debt)		**10**		12
		31		22
Non-Designated Derivative Instruments				
Interest rate contract assets		**-**		25
Interest rate contract liabilities		**(658)**		(310)
Foreign currency contract assets (liabilities)		**(1)**		2
Commodity derivative assets		**74**		78
Commodity derivative liabilities		**(71)**		(72)
		(656)		(277)
Net liability	**$**	**(625)**	$	(255)

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)	**September 30, 2019**	March 31, 2019
Current portion of derivative financial instrument assets	**$ 59**	$ 79
Current portion of derivative financial instrument liabilities	**(170)**	(89)
Derivative financial instrument assets, non-current	**48**	49
Derivative financial instrument liabilities, non-current	**(562)**	(294)
Net liability	**$ (625)**	$ (255)

Designated cash flow hedges for the three and six months ended September 30, 2019, had a gain of $nil and a gain of $9 million, respectively (2018/19 - loss of $16 million and $23 million, respectively). The effective portion was recognized in other comprehensive income and the ineffective portion was recognized in finance charges. For the three and six months ended September 30, 2019, $9 million and $28 million, respectively (2018/19 - $28 million and $34 million, respectively) was reclassified from other comprehensive income and reported in net income, offsetting net foreign exchange gains (2018/19 - gains) recorded in the period.

For outstanding interest rate contracts not designated as hedges with an aggregate notional principal of $5.43 billion (March 31, 2019 – $6.05 billion), used to economically hedge the interest rates on future debt issuances, there was a $178 million and $395 million decrease, respectively (2018/19 - $85 million and $88 million increase, respectively) in the fair value of these contracts for the three and six months ended September 30, 2019. For interest rate contracts associated with debt issued, there was a $6 million and $28 million decrease, respectively (2018/19 - $7 million and $14 million increase, respectively) in the fair value of contracts that settled during the three and six months ended September 30, 2019. The net decrease for the six months ended September 30, 2019 of $423 million in the fair value of these interest rate contracts was transferred to the Debt Management Regulatory Account which had a net asset balance of $592 million as at September 30, 2019.

Foreign currency contracts for cash management purposes not designated as hedges, for the three and six months ended September 30, 2019, had a loss of $nil and $nil, respectively (2018/19 – a loss of $1 million and a gain of $1 million, respectively) recognized in finance charges. Foreign currency contracts associated with U.S. revolving borrowings not designated as hedges, for the three and six months ended September 30, 2019, had gains of $3 million and losses of $3 million, respectively (2018/19 - loss of $1 million and $1 million, respectively) recognized in finance charges. These economic hedges offset $2 million of foreign exchange revaluation losses and $4 million of foreign exchange revaluation gains, respectively (2018/19 - gains of $1 million and $1 million, respectively) recorded in finance charges with respect to U.S. revolving borrowings for the three and six months ended September 30, 2019.

For commodity derivatives not designated as hedges, a net gain of $49 million and $133 million, respectively (2018/19 – net loss of $4 million and a net gain of $13 million, respectively) was recorded in trade revenue for the three and six months ended September 30, 2019.

Inception Gains and Losses

Changes in deferred inception gains and losses are as follows:

(in millions)	*For the three months ended September 30* **2019**	2018	*For the six months ended September 30* **2019**	2018
Deferred inception gain, beginning of the period	**$ 13**	$ (1)	**$ 15**	$ 23
New transactions	**3**	10	**11**	21
Amortization	**(9)**	(6)	**(19)**	(41)
Deferred inception gain, end of the period	**$ 7**	$ 3	**$ 7**	$ 3

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition, as defined by its transaction price, and the fair value calculated by a valuation technique or model (inception gain or loss). In addition, the Company's inception gain or loss on a contract may arise as a result of embedded derivatives which are recorded at fair value, with the remainder of the contract recorded on an accrual basis. In these circumstances, the unrealized inception gain or loss is deferred and amortized into income over the full term of the underlying financial instrument.

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.

  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 commodity 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.

- Level 3 - inputs are those that are not based on observable market data. Level 3 fair values for commodity 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.

The following tables present the financial instruments measured at fair value for each hierarchy level as at September 30, 2019 and March 31, 2019:

As at September 30, 2019 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value				
Short-term investments	$ 22	$ -	$ -	$ 22
Derivatives designated as hedges	-	31	-	31
Derivatives not designated as hedges	47	5	24	76
	$ 69	$ 36	$ 24	$ 129
Total financial liabilities carried at fair value				
Derivatives not designated as hedges	$ (36)	$ (670)	$ (26)	$ (732)
	$ (36)	$ (670)	$ (26)	$ (732)

As at March 31, 2019 *(in millions)*	Level 1	Level 2	Level 3	Total
Total financial assets carried at fair value				
Short-term investments	$ 50	$ -	$ -	$ 50
Derivatives designated as hedges	-	22	-	22
Derivatives not designated as hedges	64	38	4	106
	$ 114	$ 60	$ 4	$ 178
Total financial liabilities carried at fair value				
Derivatives not designated as hedges	$ (47)	$ (325)	$ (11)	$ (383)
	$ (47)	$ (325)	$ (11)	$ (383)

The Company’s policy is to recognize level transfers at the end of each period during which the change occurred. There were no transfers between Level 1 and 2 during the period.

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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 six months ended September 30, 2019 and 2018:

(in millions)		
Balance as at April 1, 2019	**$**	**(7)**
Net gain recognized		27
New transactions		(12)
Existing transactions settled		(10)
Balance as at September 30, 2019	**$**	**(2)**

(in millions)		
Balance as at April 1, 2018	**$**	**2**
Net loss recognized		(20)
New transactions		6
Existing transactions settled		13
Balance as at September 30, 2018	**$**	**1**

There were no transfers between Level 3 and 2 during the period.

During the three and six months ended September 30, 2019, unrealized losses of $11 million and unrealized gains of $13 million, respectively (2018/19 - $11 million and $3 million loss, respectively) were recognized on Level 3 derivative commodity instruments still on hand. These gains and losses were recognized in trade revenues.

Methodologies and procedures regarding commodity trading Level 3 fair value measurements are determined by the Company's risk management group. Level 3 fair values are calculated within the Company's risk management policies for trading activities based on underlying contractual data as well as observable and non-observable inputs. To ensure reasonability, Level 3 fair value measurements are reviewed and validated by risk management and finance departments on a regular basis.

The key unobservable inputs in the valuation of certain Level 3 financial instruments includes components of forward commodity prices and delivery or receipt volumes. A sensitivity analysis was prepared using the Company's assessment of a reasonably possible change in various components of forward prices and volumes of 10 percent. Forward commodity prices used in determining Level 3 base fair value at September 30, 2019 are $3-$89 per MwH and a 10 percent increase/decrease in certain components of these prices would not significantly decrease/increase fair value. A 10 percent change in estimated volumes used in determining Level 3 fair value would increase/decrease fair value by $13 million.

NOTE 15: OTHER NON-CURRENT LIABILITIES

(in millions)		***As at September 30* 2019**		*As at March 31* 2019
Provisions				
Environmental liabilities	**$**	**277**	$	284
Decommissioning obligations		**54**		53
Other		**68**		30
		399		367
First Nations liabilities		**403**		410
Other contributions		**236**		238
Other liabilities		**426**		419
		1,464		1,434
Less: Current portion, included in accounts payable and accrued liabilities		**(118)**		(88)
	$	**1,346**	$	1,346

A contractor made claims against BC Hydro alleging delays and disruptions impacting work completed to-date and expected to be performed in future periods. BC Hydro continues to assess the validity of the claim amounts. Additional details of the claims are not being disclosed as they could seriously prejudice BC Hydro's legal and commercial interests in relation to the dispute.

NOTE 16: 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 17: SUPPLEMENTARY INFORMATION TO CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

The supplementary information to the Condensed Consolidated Interim Statements of Cash Flows was as follows:

Change in Working Capital and Other Assets and Liabilities

(in millions)	*For the six months ended September 30* **2019**	2018
Restricted Cash	**$ 94**	$ 49
Accounts receivable and accrued revenue	**350**	157
Inventories	**(32)**	(60)
Prepaid expenses	**(58)**	(88)
Other non-current assets	**(34)**	8
Accounts payable and accrued liabilities	**(152)**	-
Unearned revenues and contributions in aid	**100**	68
Post-employment benefits	**(66)**	(18)
Other non-current liabilities	**(16)**	(22)
	$ 186	$ 94

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
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NOTE 18: EXPLANATION OF ADOPTION OF IFRS 16 AND RESTATEMENT TO PREVIOUSLY REPORTED FIGURES

Reconciliation of Consolidated Statement of Financial Position

(in millions)	As at September 30, 2018 Pre-policy change	IFRS 16 Adjustment	**Post-policy change**
ASSETS			
Current Assets			
Cash and cash equivalents	$ 172	$ -	**$ 172**
Restricted cash	28	-	**28**
Accounts receivable and accrued revenue	612	-	**612**
Inventories	204	-	**204**
Prepaid expenses	220	(4)	**216**
Current portion of derivative financial instrument assets	66	(1)	**65**
	1,302	(5)	**1,297**
Non-Current Assets			
Property, plant and equipment	27,156	(629)	**26,527**
Right-of-use assets	-	1,495	**1,495**
Intangible assets	587	-	**587**
Derivative financial instrument assets	157	-	**157**
Other non-current assets	621	(15)	**606**
	28,521	851	**29,372**
Total Assets	29,823	846	**30,669**
Regulatory Balances	5,769	66	**5,835**
Total Assets and Regulatory Balances	$ 35,592	$ 912	**$ 36,504**
LIABILITIES AND EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities	$ 1,431	$ 51	**$ 1,482**
Current portion of long-term debt	3,056	-	**3,056**
Current portion of unearned revenues and contributions in aid	88	-	**88**
Current portion of derivative financial instrument liabilities	42	(1)	**41**
	4,617	50	**4,667**
Non-Current Liabilities			
Long-term debt	19,227	-	**19,227**
Lease liabilities	648	863	**1,511**
Derivative financial instrument liabilities	18	1	**19**
Unearned revenues and contributions in aid of construction	1,813	-	**1,813**
Post-employment benefits	1,529	-	**1,529**
Other non-current liabilities	1,331	-	**1,331**
	24,566	864	**25,430**
Total Liabilities	29,183	914	**30,097**
Regulatory Balances	896	(1)	**895**
Shareholder's Equity			
Contributed surplus	60	-	**60**
Retained earnings	5,476	(1)	**5,475**
Accumulated other comprehensive income (loss)	(23)	-	**(23)**
	5,513	(1)	**5,512**
Total Liabilities, Shareholder's Equity and Regulatory Balances	$ 35,592	$ 912	**$ 36,504**

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
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Refer to Note 17 – Explanation of Adoption of IFRS 16 and Restatement to Previously Reported Figures to IFRS in the condensed consolidated interim financial statements for the three months ended June 30, 2019 for a reconciliation of the consolidated statement of financial position as at March 31, 2019.

Reconciliation of Consolidated Statement of Comprehensive Income

	For the three months ended September 30, 2018			For the six months ended September 30, 2018		
(in millions)	Pre-policy change	IFRS 16 Adjustment	**Post-policy change**	Pre-policy change	IFRS 16 Adjustment	**Post-policy change**
Revenues						
Domestic	$ 1,280	$ -	**$ 1,280**	$ 2,452	$ -	**$ 2,452**
Trade	256	-	**256**	487	-	**487**
	1,536	-	**1,536**	2,939	-	**2,939**
Expenses						
Operating expenses	1,097	(15)	**1,082**	2,230	(3)	**2,227**
Finance charges	133	4	**137**	328	6	**334**
Net Income Before Movement in Regulatory Balances	306	11	**317**	381	(3)	**378**
Net movement in regulatory balances	(272)	(11)	**(283)**	(267)	3	**(264)**
Net Income (Loss)	34	-	**34**	114	-	**114**
OTHER COMPREHENSIVE INCOME (LOSS)						
Items That Will Be Reclassified to Net Income						
Effective portion of changes in fair value of derivatives designated as cash flow hedges	(16)	-	**(16)**	(23)	-	**(23)**
Reclassification to income of derivatives designated as cash flow hedges	28	-	**28**	34	-	**34**
Foreign currency translation gains (losses)	(2)	-	**(2)**	-	-	**-**
Items That Will Not Be Reclassified to Net Income						
Actuarial gain (loss)	-	-	**-**	-	-	**-**
Other Comprehensive Income (Loss) before movement in regulatory balances	10	-	**10**	11	-	**11**
Net movements in regulatory balances	-	-	**-**	-	-	**-**
Other Comprehensive Income (Loss)	10	-	**10**	11	-	**11**
Total Comprehensive Income (Loss)	$ 44	-	**$ 44**	$ 125	-	**$ 125**

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
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Reconciliation of Consolidated Statement of Cash Flows

(in millions)	For the six months ended September 30, 2018 Pre-policy change	IFRS 16 Adjustment	**Post-policy change**
Operating Activities			
Net income	$ 114	-	**$ 114**
Regulatory account transfers	93	(37)	**56**
Adjustments for non-cash items:			
Amortization of regulatory accounts	208	-	**208**
Amortization and depreciation expense	430	34	**464**
Unrealized losses on derivative financial instruments	(80)	-	**(80)**
Post-employment benefits expense	52	-	**52**
Interest accrual	421	-	**421**
Other items	(23)	4	**(19)**
	1,215	1	**1,216**
Changes in working capital and other assets and liabilities	60	34	**94**
Interest paid	(408)	-	**(408)**
Cash provided by operating activities	867	35	**902**
Investing Activities			
Property, plant and equipment and intangible asset expenditures	(2,570)	-	**(2,570)**
Cash used in investing activities	(2,570)	-	**(2,570)**
Financing Activities			
Long-term debt issued	2,418	-	**2,418**
Long-term debt retired	(457)	-	**(457)**
Receipt of revolving borrowings	3,702	-	**3,702**
Repayment of revolving borrowings	(3,709)	-	**(3,709)**
Payment to the Province	(159)	-	**(159)**
Other items	38	(35)	**3**
Cash provided by financing activities	1,833	(35)	**1,798**
Increase (decrease) in cash and cash equivalents	130	-	**130**
Cash and cash equivalents, beginning of year	42	-	**42**
Cash and cash equivalents, end of year	$ 172	-	**172**

a) Leases

The Company previously recognized three long-term energy purchase agreements as finance leases. Under IFRS 16, these three long-term energy purchase agreements no longer meet the definition of a lease as the contract does not convey the right to control the use of the identified asset. In addition, the Company recognized certain long-term energy purchase agreements, office property agreements, and generating equipment agreements as a lease upon adoption of IFRS 16.

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The following table summarizes the impact of the adjustments to the following periods:

	Incremental Increase (Decrease)		
(in millions)	As at April 1, 2018	For the three months ended September 30, 2018	For the six months ended September 30, 2018
Prepaid expenses	$ (3)	$ (1)	$ (1)
Current portion of derivative financial instrument assets	-	(1)	(1)
Property, plant and equipment	(640)	6	11
Right-of-use assets	1,526	(10)	(31)
Derivative financial instrument assets	-	(1)	-
Other non-current assets	(18)	2	3
Regulatory balances (regulatory assets)	63	(11)	3
Accounts payable and accrued liabilities	62	(13)	(11)
Current portion of derivative financial instrument liabilities	2	(3)	(3)
Lease liabilities	867	(1)	(4)
Derivative financial instrument liabilities	(1)	1	2
Regulatory balances (regulatory liabilities)	(1)	-	-
Retained earnings	(1)	-	-
Operating expenses	-	(15)	(3)
Finance charges	-	4	6
Net movement in regulatory balances in net income	-	(11)	3

b) Restatement of Previously Reported Figures

As noted in the 2018/19 Annual Service Plan Report, the Company transitioned to IFRS during the year ended March 31, 2019. As a result, previously reported figures in the consolidated statement of financial position as at September 30, 2018 and in the consolidated statement of comprehensive income and consolidated statement of cash flows for the three and six months ended September 30, 2018 presented above under pre-policy change columns were restated. Refer to Note 24 – Explanation of Transition to IFRS in the BC Hydro's 2018/19 Annual Service Plan Report for a detailed explanation of adjustments and reclassifications made on transition to IFRS.

The net impact to shareholder's equity as at September 30, 2018 on the transition to IFRS was a net decrease of $9 million, which included a decrease to accumulated other comprehensive income of $83 million and an increase to retained earnings of $74 million. The transition to IFRS resulted in reclassifications within certain line items but had no net impact on the consolidated statement of comprehensive income for the three and six months ended September 30, 2018 or consolidated statement of cash flows for the six months ended September 30, 2018.

NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
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The following table summarizes the impact of the adjustments to the following periods:

	Incremental Increase (Decrease)		
(in millions)	As at September 30, 2018	For the three months ended September 30, 2018	For the six months ended September 30, 2018
Accounts receivable and accrued revenues	$ (5)	$ -	$ -
Property, plant and equipment	(4)	-	-
Regulatory balances (regulatory assets)	34	-	-
Accounts payable and accrued liabilities	(37)	-	-
Current portion of unearned revenues and contributions in aid	88	-	-
Unearned revenue and contributions in aid	(122)	-	-
Post-employment benefits	34	-	-
Other non-current liabilities	71	-	-
Retained earnings	74	-	-
Accumulated other comprehensive income (loss)	(83)	-	-
Domestic revenues	-	(6)	(124)
Operating expenses	-	(233)	(370)
Finance charges	-	(45)	(21)
Net movement in regulatory balances in net income	-	(272)	(267)