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Capital Power reports solid third quarter 2019 results

Results highlighted by record cash flow generation in the quarter driven by the execution of the Company's growth strategy

EDMONTON, Alberta – October 28, 2019 – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended September 30, 2019.

Third Quarter Highlights

- Achieved excellent operating performance with 96% facility availability
- Generated net cash flows from operating activities of $209 million and adjusted funds from operations of $225 million
- Entered into an agreement to acquire full ownership of Genesee 3 through divestiture of share of Keephills 3
- Purchased and cancelled 1.6 million common shares under the Normal Course Issuer Bid

Net cash flows from operating activities were $209 million in the third quarter of 2019 compared with $65 million in the third quarter of 2018. Adjusted funds from operations (AFFO) were $225 million in the third quarter of 2019, compared to $156 million in the third quarter of 2018.

Net loss attributable to shareholders in the third quarter of 2019 was $226 million and basic loss per share was $2.25, compared with net income attributable to shareholders of $18 million, and basic earnings per share of $0.08, in the comparable period of 2018. Normalized earnings attributable to common shareholders in the third quarter of 2019, after adjusting for non-recurring items (see Significant Events) and fair value adjustments, were $64 million or $0.60 per share compared with $34 million or $0.33 per share in the third quarter of 2018.

Net cash flows from operating activities were $519 million for the nine months ended September 30, 2019 compared with $317 million for the nine months ended September 30, 2018. Adjusted funds from operations were $427 million for the first nine months of 2019, compared to $317 million in the comparable nine month period last year.

For the nine months ended September 30, 2019, net loss attributable to shareholders was $57 million and basic loss per share was $0.90 per share, compared with net income attributable to shareholders of $127 million, and basic earnings per share of $0.93, for the nine months ended September 30, 2018. For the nine months ended September 30, 2019, normalized earnings attributable to common shareholders were $109 million, or $1.05 per share, compared with $84 million or $0.81 per share in the first nine months of 2018.

"Our financial results for the third quarter of 2019 were in line with management's expectations," said Brian Vaasjo, President and CEO of Capital Power. "The third quarter results benefitted from strong operating performance with average facility availability of 96 per cent. The Company captured an averaged realized Alberta power price of $59 per megawatt hour (MWh) in the third quarter that was 26% higher than the average spot power price of $47 per MWh that was impacted by cooler summer temperatures and low natural gas prices. We continue to have a positive outlook for Alberta power prices that is consistent with current forward prices of nearly $60 per MWh for 2020 and 2021."

"With the recent acquisitions of Arlington Valley and Goreway and commercial operations of New Frontier Wind, the Company generated a record quarter of adjusted funds from operations of $225 million in the third quarter and $427 million in the first nine months of 2019. Based on our outlook for the remainder of the year, we continue to be on track to achieve AFFO at the top end of the $485 million to $535 million annual guidance range for 2019," stated Mr. Vaasjo.

"One of the highlights in the third quarter was an agreement to acquire the remaining 50% share of Genesee 3 from TransAlta Corporation in exchange for the divestiture of our 50% share in Keephills 3 and $10 million cash," continued Mr. Vaasjo. "The transaction closed on October 1 allowing us to assume full control of the Genesee site and providing us strategic freedom to make decisions that further optimize value for the Genesee units including accelerating dual-fuel capability to maximize flexibility in using natural gas as fuel. The non-cash net loss on the transaction is expected to be $227 million, including the $401 million impairment of Keephills 3 recorded in the third quarter, and expected offsetting gains in the fourth quarter upon close of the transaction of $174 million."

The Company continued to be active with its Normal Course Issuer Bid (NCIB) by purchasing and cancelling 1.6 million common shares at an average exercise price of $30.40 per share for a total cost of $50 million in the third quarter. In the first nine months of 2019, the Company purchased and cancelled 2.0 million common shares at an average exercise price of $29.66 per share for a total cost of $60 million. Under its TSX approved NCIB, the Company can purchase and cancel up to 9.0 million common shares during the one-year period ending February 2020.

Operational and Financial Highlights [1] (unaudited)	**Three months ended September 30**		**Nine months ended September 30**	
(millions of dollars except per share and operational amounts)	**2019**	**2018**	**2019**	**2018**
Electricity generation (Gigawatt hours)	6,808	5,213	18,090	14,823
Generation facility availability	96%	98%	95%	96%
Revenues and other income [3]	$ 517	$ 395	$ 1,280	$ 1,077
Adjusted EBITDA [2, 3]	$ 284	$ 179	$ 677	$ 565
Net (loss) income [3, 4, 5]	$ (228)	$ 17	$ (62)	$ 122
Net (loss) income attributable to shareholders of the Company [3]	$ (226)	$ 18	$ (57)	$ 127
Basic (loss) earnings per share [3]	$ (2.25)	$ 0.08	$ (0.90)	$ 0.93
Diluted (loss) earnings per share [3]	$ (2.25)	$ 0.08	$ (0.90)	$ 0.93
Normalized earnings attributable to common shareholders [2,3]	$ 64	$ 34	$ 109	$ 84
Normalized earnings per share [2, 3]	$ 0.60	$ 0.33	$ 1.05	$ 0.81
Net cash flows from operating activities	$ 209	$ 65	$ 519	$ 317
Adjusted funds from operations [2]	$ 225	$ 156	$ 427	$ 317
Adjusted funds from operations per share [2]	$ 2.11	$ 1.52	$ 4.11	$ 3.07
Purchase of property, plant and equipment and other assets	$ 193	$ 135	$ 523	$ 241
Dividends per common share, declared	$ 0.4800	$ 0.4475	$ 1.3750	$ 1.2825

1 The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the unaudited condensed interim consolidated financial statements for the nine months ended September 30, 2019.

2 Earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from its joint venture interests, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emissions credits (adjusted EBITDA), normalized earnings attributable to common shareholders, normalized earnings per share, adjusted funds from operations and adjusted funds from operations per share are non-GAAP financial measures and do not have standardized meanings under GAAP and are, therefore, unlikely to be comparable to similar measures used by other enterprises. See Non-GAAP Financial Measures.

3 Prior quarter amounts have been restated to reflect the IAS 8 accounting policy changes resulting from the transition to IFRS 16 – *Leases*.

4 Includes depreciation and amortization for the three months ended September 30, 2019 and 2018 of $135 million and $83 million respectively, and for the nine months ended September 30, 2019 and 2018 of $355 million and $250 million respectively. Forecasted depreciation and amortization for the three months ended December 31, 2019 is $117 million.

5 On June 28, 2019, as a result of the Alberta Government's Bill 3 - Job Creation Tax Cut Act, the Alberta corporate income tax rate was reduced from 12% to 8% over 4 years. Accordingly, the 2019 statutory tax rate is 26.5% and will decrease further to 25% for the 2020 year, to 24% for the 2021 year, and to 23% for the 2022 year. Due to this tax rate decrease, the Canadian deferred tax assets and liabilities were re-measured, resulting in the recognition of a deferred income tax recovery of $51 million within net income.

Significant Events

Genesee 3 and Keephills 3 swap transaction

On August 2, 2019, the Company announced it had entered into an agreement to divest its 50% share of Keephills 3 to TransAlta Corporation (TransAlta), and to acquire TransAlta's 50% share of Genesee 3. The transaction closed on October 1, 2019, with a net cost to Capital Power of $10 million, subject to working capital and other closing adjustments. Previously both facilities had been owned and operated under 50/50 Joint Venture Agreements between Capital Power and TransAlta. Following the close of the transaction, Genesee 3 is fully owned and operated by Capital Power and Keephills 3 is fully owned and operated by TransAlta.

Keephills 3 and Genesee 3 are the only supercritical coal facilities in Alberta, with a net capacity of 463 MW and 466 MW, respectively. The swap of interests in the facilities is aligned with Capital Power's strategic plan to deliver responsible energy for tomorrow. As a result of the transaction, the Company gained full control of the Genesee site, providing strategic freedom and latitude to make decisions that further optimize value for the Genesee units. The transaction is expected to streamline costs and commercial processes and reduce regulatory compliance risk.

The transaction results in an expected pre-tax net loss of approximately $227 million. In the third quarter of 2019, the Company recorded a pre-tax impairment of $401 million on Keephills 3 upon classification as assets held for sale. In the fourth quarter of 2019, the acquisition of the additional 50% of Genesee 3 will be accounted for as a business combination. A gain of approximately $60 million is expected to be recognized on the Company's existing share of Genesee 3 as a result of the remeasurement of the carrying amount of the Company's previously owned portion of Genesee 3. In addition, the net reduction to the carrying amounts of the Company's coal-fired generation assets will result in a one-time adjustment of approximately $114 million to accelerate the recognition of deferred government grant revenue that aligns with the reduction in the new lower carrying amount of coal-fired assets. This relates to the government grant revenue that the Company is receiving over time from the province of Alberta for the 2029 phase-out of coal-fired generation. The Off-coal Agreement is not impacted by the transaction and as a result, compensation will continue to be collected over time and the Company's ongoing obligations pertaining to the Off-coal Agreement are unchanged. The transaction is expected to be neutral to AFFO over the medium term.

Retirement plans announced for Brian Vaasjo, President and CEO

On July 29, 2019, the Company announced that Brian Vaasjo, President and Chief Executive Officer, has advised the Board of Directors of his intention to retire in 2020.

The announcement activated an established CEO succession plan developed by Capital Power's Board of Directors. The Board's search for a new President and Chief Executive Officer is well under way and the Board will announce a successor in due course. Mr. Vaasjo will continue in his current role, leading the Company and serving on the Board of Directors, until his successor assumes the role. For a period thereafter, Mr. Vaasjo will remain with the Company in an advisory role to support the Board, his successor, and the business and ensure a smooth leadership transition.

Dividend increase

On July 26, 2019, the Company's Board of Directors approved an increase of 7.3% in the annual dividend for holders of its common shares, from $1.79 per common share to $1.92 per common share. This increased common share dividend will commence with the third quarter 2019 quarterly dividend payment on October 31, 2019 to shareholders of record at the close of business on September 30, 2019.

Accelerated plan for Genesee natural gas capability

On June 18, 2019, the Company announced that it is proceeding with a project that will maximize the flexibility to utilize natural gas as fuel at Genesee, which previously burned primarily coal. The financial impact of this transformation is highly dependant on carbon cost and natural gas price assumptions and is estimated to increase adjusted funds from operations by approximately $10 million in 2020 and $20 million in 2021.

The total cost of the project to completely transform Genesee 1 and 2 to dual-fuel capability and up to 40% gas capability for Genesee 3 is estimated at $50 million with expenditures of $18 million, $19 million, and $13 million in 2019 to 2021, respectively. The project involves adding new gas pipeline infrastructure within the Genesee site and modifications to the Genesee 1 and 2 boilers. The rated capacity of the units will remain the same.

After the units have been transformed to 100% dual-fuel capability, the units can utilize up to 100% natural gas or coal, or a mix of the two. The amount of coal used at any given time, versus natural gas, will be driven by several factors including natural gas and coal prices and carbon costs.

Based on Genesee 1 and 2 at 100% dual-fuel capability and Genesee 3 at 40% natural gas capability, annual greenhouse gas emissions (GHGs) are expected to be reduced by approximately 20% to 33%, assuming operation of the units is between 50% to 100% of hours on natural gas.

The coal operations at the Genesee facility are currently planned to continue up to December 2029, at which time regulatory requirements will require the Company to discontinue the use of coal. The Genesee facility will continue as a 100% natural gas-fired facility after that time. The Genesee units are already the most efficient coal generating units in Alberta and best performing from an emissions intensity perspective. Under the Genesee Performance Standard program, which commenced in 2016, a 10% improvement in efficiency and performance of the units is targeted by 2021, which improvements will benefit both natural gas and coal operations.

$325 million private placement debt financing

On June 12, 2019, the Company issued $325 million of private placement senior notes which consist of three tranches with 10, 12 and 15-year terms. The 10-year tranche has a principal amount of $210 million that matures in June 2029 with a coupon rate of 4.56%. The 12-year tranche has a $65 million principal amount and matures in June 2031 with a coupon rate of 4.72%. The 15-year tranche has a $50 million principal amount and matures in June 2034 with a coupon rate of 4.96%. The net proceeds from the transaction will primarily be used for refinancing of existing bank indebtedness and for other general corporate purposes.

Acquisition of the Goreway Power Station

On June 4, 2019, the Company completed the acquisition of 100% of the ownership interests in Goreway Power Station Holdings Inc., which owns the Goreway Power Station (Goreway). Goreway is an 875 MW natural gas combined cycle generation facility located in Brampton, Ontario. The purchase price consisted of (i) $410 million of total cash consideration, including working capital and other closing adjustments of $23 million, and (ii) the assumption of $590 million of project level debt.

Financing of the Goreway acquisition consisted of a combination of debt from the Company's existing credit facilities and equity offerings as described below.

Goreway has a 20-year Accelerated Clean Energy Supply Contract expiring in June 2029 with the Ontario Independent Electricity System Operator (credit ratings of A (high)/Aa3 from DBRS and Moody's, respectively). Goreway is strategically located in the Greater Toronto Area load centre making it an important asset in Ontario's electric system and, in combination with the Company's other Ontario natural gas assets, will provide operating and market synergies over time. The acquisition of Goreway supports the Company's growth strategy and fully meets the Company's investment criteria. In addition, the investment contributes to the Company's dividend growth strategy through immediate AFFO accretion supported by contracted cash flows through mid-2029.

Goreway is expected to generate approximately $124 million of adjusted EBITDA and $50 million of AFFO in 2020. For the 2020-2023 period, average annual adjusted EBITDA and AFFO are estimated to be $127 million and $56 million, respectively. The acquisition of Goreway is forecasted to be $0.27 accretive to AFFO per share in 2020 representing growth of approximately 6%.

Preferred share offering

On May 16, 2019, the Company issued 6 million Cumulative Minimum Rate Reset Preference Shares, Series

11 (Series 11 Shares) at a price of $25.00 per share for gross proceeds of $150 million less issue costs of $4 million. The preferred shares will pay fixed cumulative dividends of $1.4375 per share per annum, yielding 5.75% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board of Directors of Capital Power, for the initial period ending June 30, 2024. The dividend rate will be reset on June 30, 2024 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.15%, provided that, in any event, such rate shall not be less than 5.75%. The Series 11 Shares are redeemable by Capital Power, at its option on June 30, 2024 and every five years thereafter at a value of $25.00 per share.

Holders of the Series 11 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 12 (Series 12 Shares), subject to certain conditions, on June 30, 2024 and every five years thereafter. Holders of the Series 12 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 4.15%, as and when declared by the Board of Directors of Capital Power. The Series 12 Shares would be redeemable by Capital Power, at its option, on June 30, 2029 and June 30 of every fifth year thereafter at a value of $25.00 per share. The Series 12 Shares would also be redeemable by Capital Power, at its option, on any date after June 30, 2024 excluding June 30 of every fifth year, at a value of $25.50 per share.

Common share offering

In May of 2019, the Company completed a public offering of 4,945,000 subscription receipts (Subscription Receipts), on a bought deal basis, at an issue price of $30.30 per Subscription Receipt (the Offering Price), for total gross proceeds of $150 million less issue costs of $6 million (inclusive of the full exercise of a 645,000 over-allotment option). On June 4, 2019, upon closing of the Goreway acquisition, each Subscription Receipt was converted for one common share of the Company.

Capital Power increases its equity interest in C2CNT; testing of carbon nanotubes in concrete proceeding

In May 2019, Capital Power committed to increase its equity interest in C2CNT from 5% to 9% by March of 2020. C2CNT has developed an innovative technology that captures and transforms carbon dioxide into a useful and high-value product called carbon nanotubes (CNTs) which can be used as an additive to substantially increase the strength of materials such as concrete, steel and aluminum. Carbon dioxide emissions are avoided by reducing the amount of material required in addition to the carbon dioxide utilized in the production of CNTs.

Capital Power also has the right to provide notice to exercise two tranches of options in 2020 for an additional 31% equity interest in C2CNT. If exercised, Capital Power’s equity ownership of C2CNT would increase to a total of 40%.

The investment supports Capital Power’s pursuit of innovative and leading-edge technology to reduce greenhouse gases. The carbon conversion technology, led by Dr. Stuart Licht, head of the C2CNT team and professor of chemistry at George Washington University, is currently being tested at demonstration scale at the Alberta Carbon Conversion Technology Centre located at the Shepard Energy Centre in Calgary that Capital Power co-owns with ENMAX.

Lehigh Hanson (Lehigh), a subsidiary of HeidelbergCement A.G., a worldwide construction materials company, has agreed to conduct testing for the utilization of CNTs in concrete at their cost. The testing is expected in the fall of 2019 followed by limited marketing of the CNTs in concrete product in the first half of 2020. Lehigh has also made a modest financial contribution to C2CNT development.

Additional information on C2CNT is available on Capital Power’s website at: https://www.capitalpower.com/sustainability/innovation.

Appointments to the Board of Directors

Effective April 26, 2019, Robert Phillips was appointed to the Capital Power Board of Directors.

Effective March 1, 2019, Jane Peverett was appointed to the Capital Power Board of Directors.

Heat rate call option at Arlington Valley

During the first quarter of 2019, the Company entered into a heat rate call option agreement (HRCO) with an investment grade counterparty covering the periods outside of Arlington Valley’s existing summer tolling agreements. The HRCO commenced on April 1, 2019 and terminates December 31, 2025, covering (i) April and November-December 2019 and (ii) January-May and October-December 2020-2025. Pursuant to the HRCO the counterparty has the right to call the plant in exchange for fixed monthly premiums plus reimbursements for fuel at an indexed price, variable operating and maintenance expense and start charges. Adjusted EBITDA and AFFO from the Arlington Valley facility during the period covered by the HRCO is expected to be consistent with the guidance provided at the time the acquisition was announced.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on October 28, 2019 at 9:00 am (MDT) to discuss the third quarter operating and financial results. The conference call dial-in numbers are:

(604) 638-5340 (Vancouver)
(403) 351-0324 (Calgary)
(416) 915-3239 (Toronto)
(514) 375-0364 (Montreal)
(800) 319-4610 (toll-free from Canada and USA)

Interested parties may also access the live webcast on the Company's website at www.capitalpower.com with an archive of the webcast available following the conclusion of the analyst conference call.

Non-GAAP Financial Measures

The Company uses (i) earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from its joint venture interests, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emission credits (adjusted EBITDA), (ii) adjusted funds from operations, (iii) adjusted funds from operations per share (iv) normalized earnings attributable to common shareholders, and (v) normalized earnings per share as financial performance measures.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective.

Adjusted EBITDA

Capital Power uses adjusted EBITDA to measure the operating performance of facilities and categories of facilities from period to period. Management believes that a measure of facility operating performance is more meaningful if results not related to facility operations such as impairments, foreign exchange gains or losses and gains or losses on disposals are excluded from the adjusted EBITDA measure. Commencing with the Company's March 31, 2019 quarter-end, adjusted EBITDA excludes unrealized changes in fair value of commodity derivatives and emission credits which were previously included in adjusted EBITDA. This change was made to better align the Company's measure of adjusted EBITDA with its other non-GAAP measures, as both the adjusted funds from operations and the normalized earnings per share measures exclude the impacts of unrealized changes in fair value of commodity derivatives and emission credits. This change also results in improved period over period comparability of adjusted EBITDA.

Comparative figures have been restated to reflect the above change to the adjusted EBITDA metric.

A reconciliation of adjusted EBITDA to net income is as follows:

(unaudited, $ millions)	Three months ended							
	Sep 30 2019	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**
Revenues and other income [2]	517	366	397	340	395	369	313	267
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(231)	(134)	(167)	(233)	(261)	(152)	(153)	(125)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	(8)	(48)	(34)	53	35	(22)	1	18
Adjusted EBITDA from joint ventures [1]	6	7	6	11	10	12	18	18
Adjusted EBITDA	**284**	**191**	**202**	**171**	**179**	**207**	**179**	**178**
Depreciation and amortization [2]	(135)	(122)	(98)	(85)	(83)	(83)	(84)	(80)
Unrealized changes in fair value of commodity derivatives and emission credits	8	48	34	(53)	(35)	22	(1)	(18)
Impairment	(401)	-	-	-	-	-	-	-
Gain on disposal of joint venture	-	-	-	159	-	-	-	-
Foreign exchange (loss) gain	(1)	-	(4)	6	(2)	3	3	(4)
Net finance expense	(42)	(37)	(36)	(33)	(28)	(29)	(33)	(32)
Finance expense and depreciation expense from joint ventures [1]	(7)	(7)	(8)	(10)	(7)	(8)	(7)	(13)
Income tax recovery (expense) [2]	66	33	(30)	(19)	(7)	(46)	(18)	(45)
Net (loss) income	**(228)**	**106**	**60**	**136**	**17**	**66**	**39**	**(14)**
Net (loss) income attributable to:								
Non-controlling interests	(2)	(2)	(1)	(2)	(1)	(2)	(2)	(3)
Shareholders of the Company [2]	(226)	108	61	138	18	68	41	(11)
Net (loss) income	**(228)**	**106**	**60**	**136**	**17**	**66**	**39**	**(14)**

1 Total income from joint ventures as per the Company's consolidated statements of income (loss). Prior quarters' values include Capital Power's share of K2 Wind up until December 31, 2018 disposal date.

2 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16.

Adjusted funds from operations and adjusted funds from operations per share

The Company uses adjusted funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, debt repayments and common share dividends to the Company's shareholders.

Adjusted funds from operations represents net cash flows from operating activities adjusted to include net finance expense and current income tax expense and exclude changes in operating working capital and distributions received from the Company's joint venture interests. Net finance expense and current income tax expense are included as the timing of cash receipts and payments of interest and income taxes and the resulting cash basis amounts are not comparable from period to period. Changes in operating working capital are excluded from adjusted funds from operations as the timing of cash receipts and payments also affects the period-to-period comparability. Distributions received from the Company's joint venture interests are excluded as the distributions are calculated after the effect of joint venture debt payments, which are not considered operating activities. Adjusted funds from operations is reduced by the tax equity financing project investors' shares of adjusted funds from operations associated with assets under tax equity financing structures to ensure that only the Company's share is reflected in the overall metric. Adjusted funds from operations also excludes the impact of fair value changes in certain unsettled derivative financial instruments that are charged or credited to the Company's bank margin account held with a specific exchange counterparty. Adjusted funds from operations is reduced by sustaining capital expenditures and preferred share dividends and adjusted to include the Company's share of the adjusted funds from operations of its joint venture interests and cash from coal compensation that will be received annually.

Adjusted funds from operations per share is determined by applying adjusted funds from operations to the weighted average number of common shares used in the calculation of basic, diluted and normalized earnings per share.

A reconciliation of net cash flows from operating activities to adjusted funds from operations is as follows:

(unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2019	**2018**	**2019**	**2018**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**209**	**65**	**519**	**317**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	36	20	83	70
Realized loss on settlement of interest rate derivatives	-	-	19	-
Change in fair value of derivatives reflected as cash settlement	1	4	(36)	(16)
Distributions received from joint ventures	(3)	(5)	(9)	(24)
Miscellaneous financing charges paid [1]	1	1	4	4
Income taxes paid	2	1	4	2
Change in non-cash operating working capital	(3)	68	(26)	62
	34	89	39	98
Net finance expense [2]	(33)	(23)	(90)	(72)
Current income tax expense [3]	(6)	(6)	(7)	(15)
Sustaining capital expenditures [4]	(18)	(13)	(58)	(54)
Preferred share dividends paid	(13)	(10)	(36)	(30)
Cash received from coal compensation	50	50	50	50
Remove tax equity interests' respective shares of adjusted funds from operations	(2)	(1)	(4)	(5)
Adjusted funds from operations from joint ventures	4	5	14	28
Adjusted funds from operations	**225**	**156**	**427**	**317**
Weighted average number of common shares outstanding (millions)	**106.5**	**102.4**	**104.0**	**103.2**
Adjusted funds from operations per share ($)	**2.11**	**1.52**	**4.11**	**3.07**

1 Included in other cash items on the condensed interim consolidated statement of cash flows to reconcile net income to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts, amortization, accretion charges and non-cash implicit interest on tax equity investment structures.

3 Excludes current income tax expense related to the disposal of the Company's interest in K2 Wind joint venture as the amount is considered an investing activity.

4 Includes sustaining capital expenditures net of partner contributions of $2 million and $5 million for the three and nine months ended September 30, 2019, respectively, compared with $1 million and $6 million for the three and nine months ended September 30, 2018.

Normalized earnings attributable to common shareholders and normalized earnings per share

The Company uses normalized earnings attributable to common shareholders and normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings per share is based on earnings (loss) used in the calculation of basic earnings (loss) per share according to GAAP and adjusted for items that are not reflective of performance in the period such as unrealized fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or unusual contracts, and foreign exchange gain or loss on the revaluation of U.S. dollar denominated debt. The adjustments, shown net of tax, consist of unrealized fair value changes on financial instruments that are not necessarily indicative of future actual realized gains or losses, non-recurring gains or losses, or gains or losses reflecting corporate structure decisions.

(unaudited, $ millions except per share amounts and number of common shares)	Three months ended							
	Sep 30 2019	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**
Basic (loss) earnings per share ($)[2]	**(2.25)**	**0.93**	**0.49**	**1.24**	**0.08**	**0.55**	**0.30**	**(0.21)**
Net (loss) income attributable to shareholders of the Company per condensed interim consolidated statements of (loss) income [2]	**(226)**	**108**	**61**	**138**	**18**	**68**	**41**	**(11)**
Preferred share dividends including Part VI.1 tax	(14)	(12)	(11)	(11)	(10)	(11)	(10)	(11)
(Loss) earnings attributable to common shareholders [2]	(240)	96	50	127	8	57	31	(22)
Unrealized changes in fair value of derivatives [1]	(3)	(30)	(20)	35	26	(19)	25	14
Impairment (see Significant Events)	307	-	-	-	-	-	-	-
Alberta tax rate change	-	(51)	-	-	-	-	-	-
Gain on disposal of joint venture	-	-	-	(134)	-	-	-	-
Non-cash tax equity adjustment	-	-	-	-	-	(15)	-	-
Realized foreign exchange gain on settlement of foreign currency derivative instruments	-	-	-	-	-	-	(29)	-
Asset held for sale accounting treatment of K2 Wind	-	-	-	3	-	-	-	-
Income tax adjustments	-	-	-	-	-	(2)	2	-
Unrealized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	-	-	-	-	-	-	(1)
Realized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	-	-	-	-	-	-	(1)
Provision for Line Loss Rule Proceeding	-	-	-	-	-	-	-	7
U.S. tax reform rate decrease	-	-	-	-	-	-	-	31
Success fee received related to development project	-	-	-	-	-	-	-	(3)
Release of tax liability on foreign domiciled investment	-	-	-	-	-	-	-	(1)
Normalized earnings attributable to common shareholders [2]	**64**	**15**	**30**	**31**	**34**	**21**	**29**	**24**
Weighted average number of common shares outstanding (millions)	106.5	103.6	101.8	102.3	102.4	103.1	104.2	104.3
Normalized earnings per share ($)[2]	**0.60**	**0.14**	**0.29**	**0.30**	**0.33**	**0.20**	**0.28**	**0.23**

1 Includes impacts of the interest rate non-hedge held by one of the Company's joint ventures and recorded within income from joint ventures on the Company's statements of income.

2 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16.

Forward-looking Information

Forward-looking information or statements included in this press release are provided to inform the Company's shareholders and potential investors about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this press release is generally identified by words such as will, anticipate, believe, plan, intend, target, and expect or similar words that suggest future outcomes.

Material forward-looking information in this press release includes disclosures regarding: (i) expected expenditures and impacts related to the Genesee dual-fuel project including expected AFFO increases, (ii) expected benefits, including AFFO impacts, related to the swap of interests in the Genesee 3 and Keephills 3 facilities, (iii) expected benefits, including AFFO and AFFO per share increases, related to the acquisition of Goreway, (iv) expected impacts on adjusted EBITDA and AFFO from Arlington Valley driven by the HRCO signed in the year, (v) expected AFFO performance compared to guidance for 2019 and (vi) forecasted depreciation and amortization for the remainder of 2019.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity, other energy and carbon prices, (ii) performance, (iii) status of and impact of policy, legislation and regulations, and (iv) effective tax rates.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are: (i) changes in electricity prices in markets in which the Company operates, (ii) changes in energy commodity market prices and use of derivatives, (iii) regulatory and political environments including changes to environmental, financial reporting, market structure and tax legislation, (iv) generation facility availability and performance including maintenance of equipment, (v) ability to fund current and future capital and working capital needs, (vi) changes in market prices and availability of fuel, and (vii) ability to realize the anticipated benefits of the Goreway acquisition, (viii) limitations inherent in the Company's review of acquired assets, (ix) ability to realize the anticipated benefits of the swap of interests in the Genesee 3 and Keephills 3 facilities, and (x) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's Management's Discussion and Analysis for the year ended December 31, 2018, prepared as of February 15, 2019, for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the specified approval date. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of October 25, 2019, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the nine months ended September 30, 2019, the audited consolidated financial statements and MD&A of Capital Power Corporation for the year ended December 31, 2018, the annual information form of Capital Power Corporation dated February 19, 2019, and the cautionary statements regarding forward-looking information which begin on page 13. In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation together with its subsidiaries.

In this MD&A, financial information for the nine months ended September 30, 2019 and the nine months ended September 30, 2018 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods which were prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors approved this MD&A as of October 25, 2019.

Contents

FORWARD-LOOKING INFORMATION

Forward-looking information or statements included in this MD&A are provided to inform the Company's shareholders and potential investors about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this MD&A is generally identified by words such as will, anticipate, believe, plan, intend, target, and expect or similar words that suggest future outcomes.

Material forward-looking information in this MD&A includes expectations regarding:

- future revenues, expenses, earnings and adjusted funds from operations,
- the future pricing of electricity and market fundamentals in existing and target markets,
- future dividend growth,
- the Company's future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions,
- the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings,
- future growth and emerging opportunities in the Company's target markets including the focus on certain technologies,
- the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions (including phase 1 of the Whitla Wind project and the Cardinal Point Wind project),
- facility availability and planned outages,
- capital expenditures for facility maintenance and other (sustaining capital, future growth projects, Genesee dual-fuel capability project),
- the impact of market designs in the Company's core markets,
- the impact of the transformation of the Genesee units to 100% dual-fuel,
- expectations pertaining to the financial impacts of the acquisition of Goreway (see Significant Events), including the impacts to adjusted funds from operations, adjusted funds from operations per share and adjusted EBITDA,
- expectations pertaining to the financial impacts of the swap of interests in the Genesee 3 and Keephills 3 facilities (see Significant Events), including expectations regarding the impacts to adjusted funds from operations and the expected accounting impacts of the transaction including the pre-tax net loss on the transaction, and
- expectations around the Line Loss Rule Proceeding including timing of retrospective loss factors being finalized, participation in applicable appeal processes, and potential impacts to the Company.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments, and other factors it believes are appropriate including its review of purchased businesses and assets. The material factors and assumptions used to develop these forward-looking statements relate to:

- electricity and other energy prices and carbon prices,
- performance,
- business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects,
- status of and impact of policy, legislation and regulations,
- effective tax rates,
- other matters discussed under the Performance Overview and Outlook sections,
- anticipated performance of the acquired Goreway facility (see Significant Events), and
- the anticipated future performance of the Genesee 3 and Keephills 3 facilities used to assess the financial impacts of the swap of interests (see Significant Events).

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are:

- changes in electricity prices in markets in which the Company operates,
- changes in energy commodity market prices and use of derivatives,
- regulatory and political environments including changes to environmental, financial reporting, market structure and tax legislation,
- generation facility availability and performance including maintenance of equipment,
- ability to fund current and future capital and working capital needs,
- acquisitions and developments including timing and costs of regulatory approvals and construction,
- changes in market prices and availability of fuel,
- ability to realize the anticipated benefits of the Goreway acquisition,
- ability to realize the anticipated benefits of the swap of interests in the Genesee 3 and Keephills 3 facilities,

- limitations inherent in the Company's review of acquired assets, and
- changes in general economic and competitive conditions.

See Risks and Risk Management in the Company's December 31, 2018 annual MD&A for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the specified approval date. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

OVERVIEW OF BUSINESS AND CORPORATE STRUCTURE

Capital Power is a growth-oriented North American power producer headquartered in Edmonton, Alberta. The Company develops, acquires, owns and operates power generation facilities using a variety of energy sources. Capital Power owns nearly 6,000 megawatts (MW) of power generation capacity at 25 facilities across North America. Approximately 900 MW of owned generation capacity is in advanced development in Alberta and Illinois.

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP), Capital Power L.P. Holdings Inc., and Capital Power (US Holdings) Inc., all wholly owned subsidiaries of the Company.

CORPORATE STRATEGY

The Company's corporate strategy remains unchanged from that disclosed in its 2018 annual MD&A.

PERFORMANCE OVERVIEW

The Company measures its performance in relation to its corporate strategy through financial and non-financial targets that are approved by the Board of Directors of Capital Power. The measurement categories include corporate measures and measures specific to certain groups within the Company. The corporate measures are company-wide and include adjusted funds from operations and safety. The group-specific measures include facility operating margin and other operations measures, committed capital, construction and maintenance capital on budget and on schedule, and facility site safety.

Operational excellence

Performance measure	2019 target	Actual results for the nine months ended September 30, 2019
Facility availability average	95% or greater	95%
Sustaining capital expenditures	$80 to 90 million	$58 million [1]

1 Includes sustaining capital expenditures net of joint venture contributions of $5 million.

The Company's facility availability averaged 95% which reflected planned outages at Genesee, Cloverbar Energy Centre, Roxboro, Southport, Decatur Energy, Shepard, Arlington Valley, Joffre, and Goreway. Unplanned outages also occurred at Genesee, Shepard, EnPower, Cloverbar Energy Centre, and Southport.

Sustaining capital expenditures for the nine months ended September 30, 2019 were lower than target for the year to date primarily due to timing of sustaining capital projects which were budgeted in the first nine months of the year but are now expected to occur later in the year. Full year sustaining capital expenditures are expected to be consistent with the target.

Disciplined growth

Performance measure	2019 target	Status as at September 30, 2019
Whitla Wind	Completion of Whitla Wind on budget and on time for commercial operations in December 2019.	Construction expected to be complete in the fourth quarter of 2019. Total project costs are expected to exceed the budget due largely to foreign exchange impacts (see Liquidity and Capital Resources).
Cardinal Point Wind	Progress on the development of Cardinal Point Wind to be on track with budget and the March 2020 completion date.	Construction expected to be complete and on budget in the first quarter of 2020.
Other contracted growth	$500 million of committed capital.	The Company exceeded its target for other contracted growth through the acquisition of Goreway (see Significant Events).

Financial stability and strength

Performance measure	2019 target [1]	Actual results for the nine months ended September 30, 2019
Adjusted funds from operations [2]	$485 million to $535 million	$427 million
Adjusted EBITDA [2]	$870 million to $920 million	$677 million

1 The targets presented at the Company's Investor Day in December 2018 were revised to include the expected impact of the acquisition of Goreway for the periods subsequent to the close of the transaction (see Significant Events).

2 Adjusted funds from operations and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures.

OUTLOOK

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A which identifies the material factors and assumptions used to develop forward-looking information and their material associated risk factors.

At its Investor Day held in December 2018, the Company provided financial guidance for 2019 adjusted funds from operations in the range of $460 million to $510 million and 2019 adjusted EBITDA in the range of $800 million to $850 million (see Non-GAAP Financial Measures). These ranges were subsequently revised as a result of the acquisition of Goreway (see Significant Events) to be $485 million to $535 million for adjusted funds from operations and $870 million to $920 million for adjusted EBITDA, which includes the expected results of the acquired assets subsequent to transaction close. Based on the actual results for the first nine months of 2019 and the Company's forecast for the remainder of 2019, the Company expects adjusted funds from operations for 2019 to be at the top end of the adjusted guidance range.

Priorities for the Company in 2019 include working with provincial and federal governments and relevant agencies on the evolution of energy markets, specifically in Alberta and Ontario, and the design and implementation of climate policy. The Company continues to develop its wind facilities with Whitla Wind and Cardinal Point Wind expected to commence commercial operation in the fourth quarter of 2019 and the first quarter of 2020, respectively. The Company has exceeded its $500 million target for additional committed capital in 2019 with the acquisition of Goreway (see Significant Events). Finalizing the integration of Goreway will be a priority during the remainder of 2019.

In 2019, Capital Power's availability target of 95% reflects major scheduled maintenance outages for Genesee 1, Clover Bar Energy Centre, Joffre, Shepard, and Decatur Energy compared to those scheduled for Genesee 2, Genesee 3, Clover Bar Energy Centre, Joffre, Shepard, East Windsor, and Decatur Energy in 2018.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2020, 2021, and 2022 as at September 30, 2019, were:

Alberta commercial portfolio positions and power prices	Full year 2020	Full year 2021	Full year 2022
Percentage of baseload generation sold forward [1]	53%	2%	10%
Contracted price [2]	Mid-$50	High-$60	Low-$50
Forward Alberta pool prices	$57	$58	$55

1 Based on the Alberta baseload facilities plus a portion of Joffre and the uncontracted portion of Shepard.

2 Forecasted average contracted prices may differ significantly from future average realized prices as future realized prices are driven by a combination of previously contracted prices and settled prices.

The 2019 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. However, they do not include the effects of potential future acquisitions or development activities, or potential market and operational impacts relating to unplanned facility outages including outages at facilities of other market participants, and the related impacts on market power prices.

At its Investor Day held in December 2018, the Company extended the 7% annual dividend growth guidance for one additional year to 2021. Each annual increase is subject to changing circumstances and approval by the Board of Directors of Capital Power at the time of the increase.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding. It is expected that, outside of new growth opportunities, no additional common share equity will be required during the remainder of 2019.

NON-GAAP FINANCIAL MEASURES

The Company uses (i) earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from its joint venture interests, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emission credits (adjusted EBITDA), (ii) adjusted funds from operations, (iii) adjusted funds from operations per share, (iv) normalized earnings attributable to common shareholders, and (v) normalized earnings per share as financial performance measures.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective.

Adjusted EBITDA

Capital Power uses adjusted EBITDA to measure the operating performance of facilities and categories of facilities from period to period. Management believes that a measure of facility operating performance is more meaningful if results not related to facility operations such as impairments, foreign exchange gains or losses and gains or losses on disposals are excluded from the adjusted EBITDA measure. Commencing with the Company's March 31, 2019 quarter-end, adjusted EBITDA excludes unrealized changes in fair value of commodity derivatives and emission credits which were previously included in adjusted EBITDA. This change was made to better align the Company's measure of adjusted EBITDA with its other non-GAAP measures, as both the adjusted funds from operations and the normalized earnings per share measures exclude the impacts of unrealized changes in fair value of commodity derivatives and emission credits. This change also results in improved period over period comparability of adjusted EBITDA.

Comparative figures have been restated to reflect the above change to the adjusted EBITDA metric.

A reconciliation of adjusted EBITDA to net income is as follows:

(unaudited, $ millions)	Three months ended							
	Sep 30 2019	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**
Revenues and other income [2]	517	366	397	340	395	369	313	267
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(231)	(134)	(167)	(233)	(261)	(152)	(153)	(125)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	(8)	(48)	(34)	53	35	(22)	1	18
Adjusted EBITDA from joint ventures [1]	6	7	6	11	10	12	18	18
Adjusted EBITDA	**284**	**191**	**202**	**171**	**179**	**207**	**179**	**178**
Depreciation and amortization [2]	(135)	(122)	(98)	(85)	(83)	(83)	(84)	(80)
Unrealized changes in fair value of commodity derivatives and emission credits	8	48	34	(53)	(35)	22	(1)	(18)
Impairment	(401)	-	-	-	-	-	-	-
Gain on disposal of joint venture	-	-	-	159	-	-	-	-
Foreign exchange (loss) gain	(1)	-	(4)	6	(2)	3	3	(4)
Net finance expense	(42)	(37)	(36)	(33)	(28)	(29)	(33)	(32)
Finance expense and depreciation expense from joint ventures [1]	(7)	(7)	(8)	(10)	(7)	(8)	(7)	(13)
Income tax recovery (expense) [2]	66	33	(30)	(19)	(7)	(46)	(18)	(45)
Net (loss) income	**(228)**	**106**	**60**	**136**	**17**	**66**	**39**	**(14)**
Net (loss) income attributable to:								
Non-controlling interests	(2)	(2)	(1)	(2)	(1)	(2)	(2)	(3)
Shareholders of the Company [2]	(226)	108	61	138	18	68	41	(11)
Net (loss) income	**(228)**	**106**	**60**	**136**	**17**	**66**	**39**	**(14)**

1 Total income from joint ventures as per the Company's consolidated statements of income (loss). Prior quarters' values include Capital Power's share of K2 Wind up until the December 31, 2018 disposal date.

2 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

Adjusted funds from operations and adjusted funds from operations per share

The Company uses adjusted funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, debt repayments and common share dividends to the Company's shareholders.

Adjusted funds from operations represents net cash flows from operating activities adjusted to include net finance expense and current income tax expense and exclude changes in operating working capital and distributions received from the Company's joint venture interests. Net finance expense and current income tax expense are included as the timing of cash receipts and payments of interest and income taxes and the resulting cash basis amounts are not comparable from period to period. Changes in operating working capital are excluded from adjusted funds from operations as the timing of cash receipts and payments also affects the period-to-period comparability. Distributions received from the Company's joint venture interests are excluded as the distributions are calculated after the effect of joint venture debt payments, which are not considered operating activities. Adjusted funds from operations is reduced by the tax equity financing project investors' shares of adjusted funds from operations associated with assets under tax equity financing structures to ensure that only the Company's share is reflected in the overall metric. Adjusted funds from operations also excludes the impact of fair value changes in certain unsettled derivative financial instruments that are charged or credited to the Company's bank margin account held with a specific exchange counterparty. Adjusted funds from operations is reduced by sustaining capital expenditures and preferred share dividends and adjusted to include the Company's share of the adjusted funds from operations of its joint venture interests and cash from coal compensation that will be received annually.

Adjusted funds from operations per share is determined by applying adjusted funds from operations to the weighted average number of common shares used in the calculation of basic, diluted and normalized earnings per share.

A reconciliation of net cash flows from operating activities to adjusted funds from operations is as follows:

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**209**	**65**	**519**	**317**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	36	20	83	70
Realized loss on settlement of interest rate derivatives	-	-	19	-
Change in fair value of derivatives reflected as cash settlement	1	4	(36)	(16)
Distributions received from joint ventures	(3)	(5)	(9)	(24)
Miscellaneous financing charges paid [1]	1	1	4	4
Income taxes paid	2	1	4	2
Change in non-cash operating working capital	(3)	68	(26)	62
	34	89	39	98
Net finance expense [2]	(33)	(23)	(90)	(72)
Current income tax expense [3]	(6)	(6)	(7)	(15)
Sustaining capital expenditures [4]	(18)	(13)	(58)	(54)
Preferred share dividends paid	(13)	(10)	(36)	(30)
Cash received from coal compensation	50	50	50	50
Remove tax equity interests' respective shares of adjusted funds from operations	(2)	(1)	(4)	(5)
Adjusted funds from operations from joint ventures	4	5	14	28
Adjusted funds from operations	**225**	**156**	**427**	**317**
Weighted average number of common shares outstanding (millions)	**106.5**	**102.4**	**104.0**	**103.2**
Adjusted funds from operations per share ($)	**2.11**	**1.52**	**4.11**	**3.07**

1 Included in other cash items on the condensed interim consolidated statements of cash flows to reconcile net income to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts, amortization, accretion charges and non-cash implicit interest on tax equity investment structures.

3 Excludes current income tax expense related to the disposal of the Company's interest in the K2 Wind joint venture as the amount is considered an investing activity.

4 Includes sustaining capital expenditures net of partner contributions of $2 million and $5 million for the three and nine months ended September 30, 2019, respectively, compared with $1 million and $6 million for the three and nine months ended September 30, 2018, respectively.

Normalized earnings attributable to common shareholders and normalized earnings per share

The Company uses normalized earnings attributable to common shareholders and normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings per share is based on earnings (loss) used in the calculation of basic earnings (loss) per share according to GAAP and adjusted for items that are not reflective of performance in the period such as unrealized fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or unusual contracts, and foreign exchange gain or loss on the revaluation of U.S. dollar denominated debt. The adjustments, shown net of tax, consist of unrealized fair value changes on financial instruments that are not necessarily indicative of future actual realized gains or losses, non-recurring gains or losses, or gains or losses reflecting corporate structure decisions.

(unaudited, $ millions except per share amounts and number of common shares)	Three months ended							
	Sep 30 2019	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**
Basic (loss) earnings per share ($)[2]	**(2.25)**	**0.93**	**0.49**	**1.24**	**0.08**	**0.55**	**0.30**	**(0.21)**
Net (loss) income attributable to shareholders of the Company per condensed interim consolidated statements of (loss) income [2]	**(226)**	**108**	**61**	**138**	**18**	**68**	**41**	**(11)**
Preferred share dividends including Part VI.1 tax	(14)	(12)	(11)	(11)	(10)	(11)	(10)	(11)
(Loss) earnings attributable to common shareholders [2]	(240)	96	50	127	8	57	31	(22)
Unrealized changes in fair value of derivatives [1]	(3)	(30)	(20)	35	26	(19)	25	14
Impairment (see Significant Events)	307	-	-	-	-	-	-	-
Alberta tax rate change	-	(51)	-	-	-	-	-	-
Gain on disposal of joint venture	-	-	-	(134)	-	-	-	-
Non-cash tax equity adjustment	-	-	-	-	-	(15)	-	-
Realized foreign exchange gain on settlement of foreign currency derivative instruments	-	-	-	-	-	-	(29)	-
Asset held for sale accounting treatment of K2 Wind	-	-	-	3	-	-	-	-
Income tax adjustments	-	-	-	-	-	(2)	2	-
Unrealized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	-	-	-	-	-	-	(1)
Realized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	-	-	-	-	-	-	(1)
Provision for Line Loss Rule Proceeding	-	-	-	-	-	-	-	7
U.S. tax reform rate decrease	-	-	-	-	-	-	-	31
Success fee received related to development project	-	-	-	-	-	-	-	(3)
Release of tax liability on foreign domiciled investment	-	-	-	-	-	-	-	(1)
Normalized earnings attributable to common shareholders [2]	**64**	**15**	**30**	**31**	**34**	**21**	**29**	**24**
Weighted average number of common shares outstanding (millions)	106.5	103.6	101.8	102.3	102.4	103.1	104.2	104.3
Normalized earnings per share ($)[2]	**0.60**	**0.14**	**0.29**	**0.30**	**0.33**	**0.20**	**0.28**	**0.23**

1 Includes impacts of the interest rate non-hedge held by one of the Company's joint ventures and recorded within income from joint ventures on the Company's statements of income.

2 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

Normalized earnings per share reflects the period-over-period change in normalized earnings attributable to common shareholders and the changes from period to period in the weighted average number of common shares outstanding.

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Revenues and other income [3]	517	395	1,280	1,077
Adjusted EBITDA [1, 3]	284	179	677	565
Net (loss) income [3]	(228)	17	(62)	122
Net (loss) income attributable to shareholders of the Company [3]	(226)	18	(57)	127
Normalized earnings attributable to common shareholders [1, 3]	64	34	109	84
Basic (loss) earnings per share ($) [3]	(2.25)	0.08	(0.90)	0.93
Diluted (loss) earnings per share ($) [2, 3]	(2.25)	0.08	(0.90)	0.93
Normalized earnings per share ($) [1, 3]	0.60	0.33	1.05	0.81
Net cash flows from operating activities	209	65	519	317
Adjusted funds from operations [1]	225	156	427	317
Adjusted funds from operations per share ($) [1]	2.11	1.52	4.11	3.07
Purchase of property, plant and equipment and other assets	193	135	523	241
Dividends per common share, declared ($)	0.4800	0.4475	1.3750	1.2825
Dividends per Series 1 preferred share, declared ($)	0.1913	0.1913	0.5738	0.5739
Dividends per Series 3 preferred share, declared ($)	0.3408	0.2875	1.0224	0.8625
Dividends per Series 5 preferred share, declared ($)	0.3274	0.3274	0.9821	0.8900
Dividends per Series 7 preferred share, declared ($)	0.3750	0.3750	1.1250	1.1250
Dividends per Series 9 preferred share, declared ($)	0.3594	0.3594	1.0781	1.0782
Dividends per Series 11 preferred share, declared ($)	0.3594	-	0.5366	-

	As at	
	September 30, 2019	December 31, 2018
Loans and borrowings including current portion	3,304	2,647
Total assets	8,543	7,569

1 The consolidated financial highlights, except for adjusted EBITDA, normalized earnings attributable to common shareholders, normalized earnings per share, adjusted funds from operations and adjusted funds from operations per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

2 Diluted earnings per share was calculated after giving effect to outstanding share purchase options.

3 The comparative periods' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

See Consolidated Net Income and Results of Operations for discussion of the key drivers of the changes in revenues and other income, adjusted EBITDA, net income and net income attributable to shareholders of the Company.

The changes in basic and diluted earnings per share were driven by the same factors as net income which are discussed in Consolidated Net Income and Results of Operations. The changes in normalized earnings per share and normalized earnings attributable to common shareholders were affected by the same drivers as basic earnings per share, but also the adjustments between earnings per share and normalized earnings per share described under Non-GAAP Financial Measures.

See Liquidity and Capital Resources for discussion of the key drivers of the changes in net cash flows from operating activities. Adjusted funds from operations (AFFO) for the three and nine months ended September 30, 2019 was higher than the comparable periods primarily due to higher adjusted funds from operations from the Alberta facilities driven by favorable pricing and generation, adjusted funds from operations from the new facilities acquired and the commissioning of New Frontier Wind in the fourth quarter of 2018. These increases were partially offset by the impact of higher net finance expense, preferred share dividends, and sustaining capital expenditures in the 2019 periods and the impact of the second quarter Alberta contracted facilities outage as described in Consolidated Net Income and Results of Operations.

The increase in purchases of property, plant and equipment and other assets is discussed in Liquidity and Capital Resources.

SIGNIFICANT EVENTS

Genesee 3 and Keephills 3 swap transaction

On August 2, 2019, the Company announced it had entered into an agreement to divest its 50% share of Keephills 3 to TransAlta Corporation (TransAlta), and to acquire TransAlta's 50% share of Genesee 3. The transaction closed on October 1, 2019, with a net cost to Capital Power of $10 million, subject to working capital and other closing adjustments. Previously both facilities had been owned and operated under 50/50 Joint Venture Agreements between Capital Power and TransAlta. Following the close of the transaction, Genesee 3 is fully owned and operated by Capital Power and Keephills 3 is fully owned and operated by TransAlta.

Keephills 3 and Genesee 3 are the only supercritical coal facilities in Alberta, with a net capacity of 463 MW and 466 MW, respectively. The swap of interests in the facilities is aligned with Capital Power's strategic plan to deliver responsible energy for tomorrow. As a result of the transaction, the Company gained full control of the Genesee site, providing strategic freedom and latitude to make decisions that further optimize value for the Genesee units. The transaction is expected to streamline costs and commercial processes and reduce regulatory compliance risk.

The transaction results in an expected pre-tax net loss of approximately $227 million. In the third quarter of 2019, the Company recorded a pre-tax impairment of $401 million on Keephills 3 upon classification as assets held for sale. In the fourth quarter of 2019, the acquisition of the additional 50% of Genesee 3 will be accounted for as a business combination. A gain of approximately $60 million is expected to be recognized on the Company's existing share of Genesee 3 as a result of the remeasurement of the carrying amount of the Company's previously owned portion of Genesee 3. In addition, the net reduction to the carrying amounts of the Company's coal-fired generation assets will result in a one-time adjustment of approximately $114 million to accelerate the recognition of deferred government grant revenue that aligns with the reduction in the new lower carrying amount of coal-fired assets. This relates to the government grant revenue that the Company is receiving over time from the province of Alberta for the 2029 phase-out of coal-fired generation. The Off-coal Agreement is not impacted by the transaction and as a result, compensation will continue to be collected over time and the Company's ongoing obligations pertaining to the Off-coal Agreement are unchanged. The transaction is expected to be neutral to AFFO over the medium term.

Capital Power announces retirement plans for Brian Vaasjo, President and Chief Executive Officer

On July 29, 2019, the Company announced that Brian Vaasjo, President and Chief Executive Officer, has advised the Board of Directors of his intention to retire in 2020.

The announcement activated an established CEO succession plan developed by Capital Power's Board of Directors. The Board's search for a new President and Chief Executive Officer is well under way and the Board will announce a successor in due course. Mr. Vaasjo will continue in his current role, leading the Company and serving on the Board of Directors, until his successor assumes the role. For a period thereafter, Mr. Vaasjo will remain with the Company in an advisory role to support the Board, his successor, and the business and ensure a smooth leadership transition.

Dividend increase

On July 26, 2019, the Company's Board of Directors approved an increase of 7.3% in the annual dividend for holders of its common shares, from $1.79 per common share to $1.92 per common share. This increased common share dividend will commence with the third quarter 2019 quarterly dividend payment on October 31, 2019 to shareholders of record at the close of business on September 30, 2019.

Accelerated plan for Genesee natural gas capability

On June 18, 2019, the Company announced that it is proceeding with a project that will maximize the flexibility to utilize natural gas as fuel at Genesee, which previously burned primarily coal. The financial impact of this transformation is highly dependant on carbon cost and natural gas price assumptions and is estimated to increase adjusted funds from operations by approximately $10 million in 2020 and $20 million in 2021.

The total cost of the project to completely transform Genesee 1 and 2 to dual-fuel capability and up to 40% gas capability for Genesee 3 is estimated at $50 million with expenditures of $18 million, $19 million, and $13 million in 2019 to 2021, respectively. The project involves adding new gas pipeline infrastructure within the Genesee site and modifications to the Genesee 1 and 2 boilers. The rated capacity of the units will remain the same.

After the units have been transformed to 100% dual-fuel capability, the units can utilize up to 100% natural gas or coal, or a mix of the two. The amount of coal used at any given time, versus natural gas, will be driven by several factors including natural gas and coal prices and carbon costs.

Based on Genesee 1 and 2 at 100% dual-fuel capability and Genesee 3 at 40% natural gas capability, annual greenhouse gas emissions (GHGs) are expected to be reduced by approximately 20% to 33%, assuming operation of the units is between 50% to 100% of hours on natural gas.

The coal operations at the Genesee facility are currently planned to continue up to December 2029, at which time regulatory requirements will require the Company to discontinue the use of coal. The Genesee facility will continue as a 100% natural gas-fired facility after that time. The Genesee units are already the most efficient coal generating units in Alberta and best performing from an emissions intensity perspective. Under the Genesee Performance Standard program, which commenced in 2016, a 10% improvement in efficiency and performance of the units is targeted by 2021, which improvements will benefit both natural gas and coal operations.

$325 million private placement debt financing

On June 12, 2019, the Company issued $325 million of private placement senior notes which consist of three tranches with 10, 12 and 15-year terms. The 10-year tranche has a principal amount of $210 million that matures in June 2029 with a coupon rate of 4.56%. The 12-year tranche has a $65 million principal amount and matures in June 2031 with a coupon rate of 4.72%. The 15-year tranche has a $50 million principal amount and matures in June 2034 with a coupon rate of 4.96%. The net proceeds from the transaction will primarily be used for refinancing of existing bank indebtedness and for other general corporate purposes.

Acquisition of the Goreway Power Station

On June 4, 2019, the Company completed the acquisition of 100% of the ownership interests in Goreway Power Station Holdings Inc., which owns the Goreway Power Station (Goreway). Goreway is an 875 MW natural gas combined cycle generation facility located in Brampton, Ontario. The purchase price consisted of (i) $410 million of total cash consideration, including working capital and other closing adjustments of $23 million, and (ii) the assumption of $590 million of project level debt.

Financing of the Goreway acquisition consisted of a combination of debt from the Company’s existing credit facilities and equity offerings as described below.

Goreway has a 20-year Accelerated Clean Energy Supply Contract expiring in June 2029 with the Ontario Independent Electricity System Operator (credit ratings of A (high)/Aa3 from DBRS and Moody’s, respectively). Goreway is strategically located in the Greater Toronto Area load centre making it an important asset in Ontario’s electric system and, in combination with the Company’s other Ontario natural gas assets, will provide operating and market synergies over time. The acquisition of Goreway supports the Company’s growth strategy and fully meets the Company’s investment criteria. In addition, the investment contributes to the Company’s dividend growth strategy through immediate AFFO accretion supported by contracted cash flows through mid-2029.

Goreway is expected to generate approximately $124 million of adjusted EBITDA and $50 million of AFFO in 2020. For the 2020-2023 period, average annual adjusted EBITDA and AFFO are estimated to be $127 million and $56 million, respectively. The acquisition of Goreway is forecasted to be $0.27 accretive to AFFO per share in 2020 representing growth of approximately 6%.

Preferred share offering

On May 16, 2019, the Company issued 6 million Cumulative Minimum Rate Reset Preference Shares, Series 11 (Series 11 Shares) at a price of $25.00 per share for gross proceeds of $150 million less issue costs of $4 million. The preferred shares will pay fixed cumulative dividends of $1.4375 per share per annum, yielding 5.75% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board of Directors of Capital Power, for the initial period ending June 30, 2024. The dividend rate will be reset on June 30, 2024 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.15%, provided that, in any event, such rate shall not be less than 5.75%. The Series 11 Shares are redeemable by Capital Power, at its option on June 30, 2024 and every five years thereafter at a value of $25.00 per share.

Holders of the Series 11 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 12 (Series 12 Shares), subject to certain conditions, on June 30, 2024 and every five years thereafter. Holders of the Series 12 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 4.15%, as and when declared by the Board of Directors of Capital Power. The Series 12 Shares would be redeemable by Capital Power, at its option, on June 30, 2029 and June 30 of every fifth year thereafter at a value of $25.00 per share. The Series 12 Shares would also be redeemable by Capital Power, at its option, on any date after June 30, 2024 excluding June 30 of every fifth year, at a value of $25.50 per share.

Common share offering

In May of 2019, the Company completed a public offering of 4,945,000 subscription receipts (Subscription Receipts), on a bought deal basis, at an issue price of $30.30 per Subscription Receipt (the Offering Price), for total gross proceeds of $150 million less issue costs of $6 million (inclusive of the full exercise of a 645,000 over-allotment option). On June 4, 2019, upon closing of the Goreway acquisition, each Subscription Receipt was converted for one common share of the Company.

Capital Power increases its equity interest in C2CNT; testing of carbon nanotubes in concrete proceeding

In May 2019, Capital Power committed to increase its equity interest in C2CNT from 5% to 9% by March of 2020. C2CNT has developed an innovative technology that captures and transforms carbon dioxide into a useful and high-value product called carbon nanotubes (CNTs) which can be used as an additive to substantially increase the strength of materials such as concrete, steel and aluminum. Carbon dioxide emissions are avoided by reducing the amount of material required in addition to the carbon dioxide utilized in the production of CNTs.

Capital Power also has the right to provide notice to exercise two tranches of options in 2020 for an additional 31% equity interest in C2CNT. If exercised, Capital Power's equity ownership of C2CNT would increase to a total of 40%.

The investment supports Capital Power's pursuit of innovative and leading-edge technology to reduce greenhouse gases. The carbon conversion technology, led by Dr. Stuart Licht, head of the C2CNT team and professor of chemistry at George Washington University, is currently being tested at demonstration scale at the Alberta Carbon Conversion Technology Centre located at the Shepard Energy Centre in Calgary that Capital Power co-owns with ENMAX.

Lehigh Hanson (Lehigh), a subsidiary of HeidelbergCement A.G., a worldwide construction materials company, has agreed to conduct testing for the utilization of CNTs in concrete at their cost. The testing is expected in the fall of 2019 followed by limited marketing of the CNTs in concrete product in the first half of 2020. Lehigh has also made a modest financial contribution to C2CNT development.

Additional information on C2CNT is available on Capital Power's website at: https://www.capitalpower.com/sustainability/innovation.

Appointments to the Board of Directors

Effective April 26, 2019, Robert Phillips was appointed to the Capital Power Board of Directors.

Effective March 1, 2019, Jane Peverett was appointed to the Capital Power Board of Directors.

Heat rate call option at Arlington Valley

During the first quarter of 2019, the Company entered into a heat rate call option agreement (HRCO) with an investment grade counterparty covering the periods outside of Arlington Valley's existing summer tolling agreements. The HRCO commenced on April 1, 2019 and terminates December 31, 2025, covering (i) April and November-December 2019 and (ii) January-May and October-December 2020-2025. Pursuant to the HRCO the counterparty has the right to call the plant in exchange for fixed monthly premiums plus reimbursements for fuel at an indexed price, variable operating and maintenance expense and start charges. Adjusted EBITDA and AFFO from the Arlington Valley facility during the period covered by the HRCO is expected to be consistent with the guidance provided at the time the acquisition was announced.

CONSOLIDATED NET INCOME (LOSS) AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income (loss) for the three and nine months ended September 30, 2019 compared with the three and nine months ended September 30, 2018 are presented below followed by further discussion of these items.

(unaudited, $ millions)	Three months		Nine months	
Consolidated net income for the periods ended September 30, 2018 [1]		**17**		**122**
Increase (decrease) in adjusted EBITDA:				
Alberta commercial facilities and portfolio optimization	12		61	
Alberta contracted facilities	(5)		(16)	
Ontario and British Columbia contracted facilities	26		14	
U.S. contracted facilities	71		56	
Corporate	1	105	(3)	112
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		43		104
Impairment		(401)		(401)
Increase in depreciation and amortization expense		(52)		(105)
Decrease (increase) in foreign exchange loss		1		(9)
Increase in net finance expense		(14)		(25)
Decrease in income before tax		(318)		(324)
Change in income tax expense or recovery		73		140
Decrease in net income		**(245)**		**(184)**
Consolidated net loss for the periods ended September 30, 2019		**(228)**		**(62)**

[1] The comparative periods' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

Results by facility category and other

	Three months ended September 30							
	2019	2018	2019	2018	2019	2018	2019	2018
	Electricity generation (GWh) [1]		**Facility availability** (%) [2]		**Revenues and other income** (unaudited, $ millions) [11]		**Adjusted EBITDA** (unaudited, $ millions) [3, 11]	
Total electricity generation, average facility availability and facility revenues	6,808	5,213	96	98	416	308		
Alberta commercial facilities [4]								
Genesee 3	492	495	96	98	22	27		
Keephills 3	450	494	93	100	19	27		
Clover Bar Energy Centre 1, 2 and 3	348	217	96	88	18	15		
Joffre	150	154	82	97	10	15		
Shepard Energy Centre	782	789	100	100	34	36		
Halkirk	86	85	95	95	8	7		
Clover Bar Landfill Gas	-	-	-	7	-	-		
Alberta commercial facilities	2,308	2,234	95	96	111	127		
Portfolio optimization	N/A	N/A	N/A	N/A	70	21		
	2,308	2,234	95	96	181	148	72	60
Alberta contracted facilities [4]								
Genesee 1	803	829	96	99				
Genesee 2	795	799	100	100				
	1,598	1,628	98	99	68	70	49	54
Ontario and British Columbia contracted facilities								
Island Generation	379	17	99	100	10	10		
York Energy [5]	3	3	99	100	N/A	N/A		
East Windsor	2	4	99	99	8	8		
Goreway [6]	304	N/A	87	N/A	53	N/A		
K2 Wind [7]	N/A	35	N/A	98	N/A	N/A		
Kingsbridge 1	15	14	98	98	1	1		
Port Dover and Nanticoke	46	43	94	94	7	7		
Quality Wind	73	74	96	94	9	10		
EnPower	3	10	72	100	-	1		
	825	200	92	98	88	37	63	37
U.S. contracted facilities								
Roxboro, North Carolina	88	87	99	100	10	10		
Southport, North Carolina	112	104	84	100	17	15		
Decatur Energy, Alabama	709	784	100	100	36	35		
Arlington Valley, Arizona [8]	878	N/A	100	N/A	61	N/A		
Beaufort Solar, North Carolina	8	8	100	100	1	1		
Bloom Wind, Kansas	176	152	98	97	13	11		
Macho Springs, New Mexico	21	16	97	97	2	2		
New Frontier Wind, North Dakota [9]	85	N/A	97	N/A	9	N/A		
	2,077	1,151	99	99	149	74	115	44
Corporate [10]					15	15	(15)	(16)
Unrealized changes in fair value of commodity derivatives and emission credits					16	51		
Consolidated revenues and other income and adjusted EBITDA					**517**	**395**	**284**	**179**

	Nine months ended September 30							
	2019	2018	2019	2018	2019	2018	2019	2018
	Electricity generation (GWh) [1]		**Facility availability** (%) [2]		**Revenues and other income** (unaudited, $ millions) [11]		**Adjusted EBITDA** (unaudited, $ millions) [3, 11]	
Total electricity generation, average facility availability and facility revenues	18,090	14,823	95	96	1,133	911		
Alberta commercial facilities [4]								
Genesee 3	1,494	1,442	99	98	85	70		
Keephills 3	1,353	1,348	95	97	72	66		
Clover Bar Energy Centre 1, 2 and 3	908	596	95	90	60	44		
Joffre	587	397	94	93	49	38		
Shepard Energy Centre	2,268	2,169	94	89	110	98		
Halkirk	313	320	97	97	32	29		
Clover Bar Landfill Gas	-	-	-	29	-	-		
Alberta commercial facilities	6,923	6,272	95	93	408	345		
Portfolio optimization	N/A	N/A	N/A	N/A	103	92		
	6,923	6,272	95	93	511	437	227	166
Alberta contracted facilities [4]								
Genesee 1	2,196	2,391	89	100				
Genesee 2	2,341	2,109	98	92				
	4,537	4,500	94	96	188	197	134	150
Ontario and British Columbia contracted facilities								
Island Generation	713	27	100	100	29	29		
York Energy [5]	11	8	100	98	N/A	N/A		
East Windsor	7	8	99	99	26	26		
Goreway [6]	380	N/A	90	N/A	69	N/A		
K2 Wind [7]	N/A	152	N/A	99	N/A	N/A		
Kingsbridge 1	71	70	98	98	6	6		
Port Dover and Nanticoke	210	221	97	97	31	33		
Quality Wind	224	250	97	96	29	31		
EnPower	13	35	75	95	1	3		
	1,629	771	96	98	191	128	155	141
U.S. contracted facilities								
Roxboro, North Carolina	238	253	96	96	28	28		
Southport, North Carolina	332	333	88	94	49	46		
Decatur Energy, Alabama	1,489	2,029	93	98	74	74		
Arlington Valley, Arizona [8]	2,022	N/A	94	N/A	116	N/A		
Beaufort Solar, North Carolina	23	22	100	96	2	2		
Bloom Wind, Kansas	520	547	99	97	36	80		
Macho Springs, New Mexico	103	96	98	98	12	11		
New Frontier Wind, North Dakota [9]	274	N/A	96	N/A	29	N/A		
	5,001	3,280	94	97	346	241	207	151
Corporate [10]					47	45	(46)	(43)
Unrealized changes in fair value of commodity derivatives and emission credits					(3)	29		
Consolidated revenues and other income and adjusted EBITDA					**1,280**	**1,077**	**677**	**565**

1 Gigawatt hours (GWh) of electricity generation reflects the Company's share of facility output.

2 Facility availability represents the percentage of time in the period that the facility was available to generate power regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

3 The financial results by facility category, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

4 Based on the nature of future cash flows, the Alberta assets are combined as one CGU for impairment testing purposes. Since the cash flows of Genesee 1 and 2 will remain contracted through 2020, management will continue to present facility results based on the Alberta Commercial and Alberta Contracted groupings through 2020.

5 York Energy is accounted for under the equity method. Capital Power's share of the facility's net income is included in income from joint ventures on the Company's condensed interim consolidated statements of income. Capital Power's share of the facility's adjusted EBITDA is included in adjusted EBITDA above. The equivalent of Capital Power's share of the facility's revenue was $7 million and $23 million for three and nine months ended September 30, 2019, respectively, compared with $7 million and $22 million for the three and nine months ended September 30, 2018. The facility's revenues are not included in the above results.

6 Goreway was acquired on June 4, 2019.

7 Capital Power's share of K2 Wind was disposed of effective December 31, 2018.

8 Arlington Valley was acquired on November 30, 2018.

9 New Frontier Wind was commissioned on December 21, 2018.

10 Corporate revenues were offset by interplant category eliminations.

11 The prior periods' amounts for the Ontario and British Columbia contracted facilities, as appropriate, have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

Energy prices and hedged positions

		Three months ended September 30		Nine months ended September 30		Year ended December
Alberta	**Unit**	**2019**	**2018**	**2019**	**2018**	**31, 2018**
Hedged position [1]	Percentage sold forward at beginning of period (%)	100	100	80	90	87
Spot power price average	$ per MWh	47	55	58	49	50
Realized power price [2]	$ per MWh	59	54	58	50	51
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	0.99	1.15	1.73	1.42	1.46

1 Hedged position is for the Alberta baseload facilities as well as a portion of Joffre and the uncontracted portion of Shepard.

2 Realized power price is the average price realized as a result of the Company's commercial contracted sales and portfolio optimization activities.

3 AECO refers to the historical virtual trading hub located in Alberta and known as the Nova Inventory Transfer system operated by TransCanada PipeLines Limited.

Alberta commercial facilities and portfolio optimization

The Alberta spot price averaged $47 per MWh and $58 per MWh for the three and nine months ended September 30, 2019, compared with $55 per MWh and $49 per MWh, respectively, for the corresponding periods in 2018. Lower pricing in the third quarter of 2019 reflected lower temperatures during the summer months of 2019, the impact of lower natural gas pricing, and fewer baseload facility outages. Higher pricing for the nine months ended September 30, 2019, reflected cooler temperatures during the first two quarters of 2019, higher natural gas pricing, lower wind generation and a higher volume of power exports.

Generation was higher for the three and nine months ended September 30, 2019 driven most notably by higher dispatch at Clover Bar Energy Centre and Joffre, offset partly by a planned outage at Joffre in the three months ended September 30, 2019 and forced outages at Keephills 3 in the third quarter of 2019 with none in the comparable period of 2018. Higher generation for the nine months ended September 30, 2019 was also driven by a shorter planned outage and higher dispatch at Shepard Energy Centre in 2019 compared with 2018. Availability for the three months ended September 30, 2019 was consistent with the comparable period in 2018, while availability for the nine months ended September 30, 2019 was higher than the comparable period in 2018, primarily due to the noted shorter planned outage at Shepard Energy Centre and fewer outage hours at Clover Bar Energy Centre partially offset by more forced outages at Keephills 3 in 2019 compared with 2018.

Revenues and other income for the three and nine months ended September 30, 2019 increased compared with the corresponding periods in 2018 primarily due to higher realized power prices and increased generation as described above.

Adjusted EBITDA for the three and nine months ended September 30, 2019 increased compared to the corresponding periods in 2018 driven by the revenues and other income drivers noted above. For the nine months ended September 30, 2019, the increases were also driven by favourable margins earned on export activity, partially offset by the impact of higher natural gas pricing, and lower ancillary services revenues as compared to 2018.

Alberta contracted facilities

Availability for the three months ended September 30, 2019 was lower compared with the corresponding period in 2018 primarily due to a longer unplanned outage in 2019 compared with 2018. Availability for the nine months ended September 30, 2019 was lower compared with the corresponding period in 2018 primarily due to the length of the Genesee 1 planned maintenance outage in 2019 which was four days longer than the Genesee 2 planned outage in 2018.

Generation for the three and nine months ended September 30, 2019 was consistent with the corresponding periods in 2018. Despite the length and timing of the 2019 planned outage, generation for the nine months ended September 30, 2019 was consistent with 2018 partially due to lower dispatch by the PPA buyer in 2018, compared with 2019.

Revenues and other income were lower in the three months ended September 30, 2019 compared with the corresponding period in 2018 primarily due to lower availability incentives as a result of lower Alberta pool prices in the third quarter of 2019, compared with 2018. Revenues and other income were lower in the nine months ended September 30, 2019 compared with the corresponding period in 2018 primarily due to the noted planned outage length as the 2019 results reflect higher net availability penalties which were magnified by higher Alberta power pool prices during the outage period in 2019. The nine months ended September 30, 2019 also reflected higher excess energy payments driven by higher generation and higher running energy payments on higher pricing, partially offset by lower capacity revenues compared with 2018.

Adjusted EBITDA for the three and nine months ended September 30, 2019 was lower than the corresponding periods in 2018 primarily due to the noted factors affecting revenues and other income as well as higher coal costs in 2019. These unfavourable variances are partially offset by higher environmental compliance incentive recoveries in 2019 compared with 2018.

Ontario and British Columbia contracted facilities

Generation for the three and nine months ended September 30, 2019 was higher than the comparable periods in 2018 primarily due to the acquisition of Goreway (see Significant Events) in the second quarter of 2019 and higher dispatch at Island Generation in 2019, partially offset by the sale of K2 Wind in the fourth quarter of 2018. Availability in 2019 was lower than 2018 primarily due to forced outages at the EnPower facilities as well as the impact on overall availability of a Goreway planned outage in the third quarter of 2019.

Revenues and other income were higher for the three and nine months ended September 30, 2019 compared with the corresponding periods in 2018 primarily due to the acquisition of Goreway in the second quarter of 2019. Adjusted EBITDA for the three and nine months ended September 30, 2019 was higher than the corresponding period in 2018 primarily due to the acquisition of Goreway in 2019, partially offset by the disposal of K2 Wind in the fourth quarter of 2018. Revenues and other income do not include K2 Wind and York Energy, which are accounted for under the equity method.

U.S. contracted facilities

Generation increased in the three and nine months ended September 30, 2019 compared with the corresponding periods in 2018 primarily due to the addition of Arlington Valley and the commencement of commercial operations at New Frontier Wind in the fourth quarter of 2018, partially offset by lower dispatch at Decatur Energy.

Availability for the three months ended September 30, 2019 was consistent with the corresponding period in 2018 due to the noted additions of Arlington Valley and New Frontier which had strong availability in the third quarter of 2019, offset by numerous forced outages at Southport in 2019 compared with no outages in 2018. Availability decreased in the nine months ended September 30, 2019 compared with the corresponding period in 2018 primarily due to a longer planned outage at Decatur in 2019 compared with 2018 and more frequent forced outages at Southport in 2019 compared with 2018.

Revenues and other income for the three and nine months ended September 30, 2019 are higher than the corresponding periods in 2018 primarily due to the addition of Arlington Valley and the commencement of commercial operations at New Frontier Wind in the fourth quarter of 2018. The increase in revenue and other income for the nine months ended September 30, 2019 compared to the corresponding period in 2018 was partially offset by the impacts of the updated Bloom Wind tax equity investor agreement signed during the second quarter of 2018.

Adjusted EBITDA for the three and nine months ended September 30, 2019 are higher than the corresponding periods in 2018 primarily due to the impacts noted above. The increase in adjusted EBITDA for the nine months ended September 30, 2019 compared to the corresponding period in 2018 was partially offset by higher planned outage costs at Decatur in 2019 compared with 2018.

Corporate

Corporate results include (i) revenues for cost recoveries and other income related to coal compensation from the Province of Alberta, (ii) costs of support services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management, and environment, health and safety, and (iii) business development expenses. Note that cost recovery revenues are primarily intercompany revenues that are offset by interplant category transactions.

Revenues are slightly higher for the nine months ended September 30, 2019 due largely to the recognition of coal compensation revenues being amortized through 2029 beginning in 2019, as compared to an ending year of 2030 for recognition in 2018 as a result of federal regulation shortening the life of coal generation assets by one year.

Net corporate expenditures within adjusted EBITDA for the three months ended September 30, 2019 were lower than the corresponding period in 2018 primarily as a result of lower long-term incentive costs due to lower payout factors for 2019 accrued costs. For the nine months ended September 30, 2019, net corporate expenditures were higher primarily driven by the write-off of wind development projects no longer being developed and higher business development expenses resulting from higher acquisition costs related to Goreway, partially offset by the lower long-term incentive costs due to lower payout factors.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Three months ended September 30			
	2019	2018	2019	2018
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Income before tax**	
Unrealized gains (losses) on Alberta energy derivatives	22	95	(4)	-
Unrealized losses on U.S. energy derivatives	(6)	(42)	(6)	(42)
Unrealized (losses) gains on natural gas derivatives	(3)	(3)	11	7
Unrealized gains on emission derivatives	3	1	3	1
Unrealized gains (losses) on emission credits held for trading	-	-	4	(1)
	16	**51**	**8**	**(35)**

(unaudited, $ millions)	Nine months ended September 30			
	2019	2018	2019	2018
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Income before tax**	
Unrealized (losses) gains on Alberta energy derivatives	(38)	51	27	(3)
Unrealized gains (losses) on U.S. energy derivatives	35	(18)	35	(18)
Unrealized (losses) gains on natural gas derivatives	(2)	(13)	28	4
Unrealized gains on emission derivatives	2	9	2	9
Unrealized losses on emission credits held for trading	-	-	(2)	(6)
	(3)	**29**	**90**	**(14)**

The Company's revenues and other income and adjusted EBITDA relating to its Alberta commercial facilities and portfolio optimization and U.S. wind facilities include realized changes in the fair value of commodity derivatives and emission credits. Unrealized changes in the fair value of commodity derivatives and emission credits are excluded from revenues and other income relating to the Alberta commercial facilities and portfolio optimization and U.S. wind facilities and are also excluded from the Company's adjusted EBITDA metric.

When a derivative instrument settles, the unrealized fair value changes recorded in prior periods for that instrument are reversed from this category. The gain or loss realized upon settlement is then reflected in adjusted EBITDA for the applicable facility category.

During the three months ended September 30, 2019 the Alberta energy portfolio recognized unrealized losses of $4 million, primarily due to the reversal of prior period unrealized net gains on forward sales contracts that settled during the quarter. During the nine months ended September 30, 2019, the Alberta energy portfolio recognized unrealized gains of $27 million compared to unrealized losses of $3 million in 2018. The 2019 gains were primarily due to the impact of increasing forward power prices on net forward purchase contracts while the 2018 losses were due to the reversal of prior period unrealized net gains on forward sales contracts that settled in the third quarter of 2018.

During the three months ended September 30, 2019 and the three and nine months ended September 30, 2018, the Company recorded unrealized losses of $6 million, $42 million and $18 million respectively, on U.S. energy derivatives, primarily as a result of increasing forward prices on forward sales contracts in the respective periods. During the nine months ended September 30, 2019, the Company recorded unrealized gains of $35 million on U.S. energy derivatives, primarily as a result of decreasing forward prices on forward sales contracts in the period.

During the three and nine months ended September 30, 2019 the Company recorded unrealized gains of $11 million and $28 million on natural gas derivatives respectively. These were attributable to net forward purchase contracts being valued against increasing forward natural gas prices, and the reversal of prior periods' unrealized losses on positions that settled in 2019. Unrealized gains on natural gas derivatives for the three and nine months ended September 30, 2018 were attributable to net forward purchase contracts valued against increasing forward natural gas prices, as well as the reversal of prior period unrealized losses on positions that settled in 2018.

Unrealized gains on emissions derivatives for the three and nine months ended September 30, 2019 and 2018 were due to net forward purchase contracts being valued against increasing forward prices and the impact of the reversal of previously unrealized net losses on positions that settled during the respective periods.

During the three months ended September 30, 2019 the Company recorded unrealized gains on emission credits held for trading, primarily due to the impact of increasing market prices on portfolio holdings. During the nine months ended September 30, 2019 and 2018 the Company recorded unrealized losses of $2 million and $6 million respectively. These losses were due mainly to the reversal of prior period unrealized net gains on emission credits sold during those periods.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Interest on borrowings less capitalized interest	(35)	(26)	(97)	(82)
Realized losses on the settlement of interest rate derivatives	(1)	-	(2)	-
Other net finance expense – interest on coal compensation from the Province of Alberta, sundry interest, guarantee and other fees	1	3	3	8
	(35)	(23)	(96)	(74)
Unrealized gains representing changes in the fair value of interest rate derivatives	-	2	-	2
Other net finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta	(7)	(7)	(19)	(18)
Total net finance expense	(42)	(28)	(115)	(90)
Impairment	(401)	-	(401)	-
Depreciation and amortization	(135)	(83)	(355)	(250)
Foreign exchange (loss) gain	(1)	(2)	(5)	4
Finance expense and depreciation expense from joint ventures	(7)	(7)	(22)	(22)
Income tax recovery (expense)	66	(7)	69	(71)
Net loss attributable to non-controlling interests	2	1	5	5

Net finance expense

Higher net finance expense for the three and nine months ended September 30, 2019 compared with the corresponding periods in the prior year was primarily due to higher loans and borrowings outstanding as a result of the acquisition of Arlington Valley in the fourth quarter of 2018, and the financing related to the acquisition of Goreway in the second quarter of 2019 (see Significant Events).

Impairment

During the three and nine months ended September 30, 2019, the Company recognized a pre-tax impairment of $401 million related to the classification of Keephills 3 as an asset held for sale (see Significant Events).

Depreciation and amortization

Depreciation and amortization for the three and nine months ended September 30, 2019 increased compared with the corresponding periods in the prior year primarily due to the acquisition of Arlington Valley and New Frontier Wind commencing commercial operation in the last quarter of 2018, and the acquisition of Goreway in the second quarter of 2019 (see Significant Events). In addition to this, starting in the first quarter of 2019, Capital Power adjusted the useful lives of assets related to coal to reflect new expected end of life dates resulting from federal regulation changes, including the assets that would be used in a coal-to-gas conversion, to the new estimated life as set out by the federal government. Slightly offsetting these impacts was lower depreciation for Keephills 3 for which depreciation was no longer recorded following the classification of Keephills 3 as an asset held for sale, effective August 2, 2019.

Foreign exchange (loss) gain

For the three months ended September 30, 2019, the exchange rate of the Canadian dollar relative to the U.S. dollar weakened resulting in an unrealized gain on foreign currency purchase contracts mostly offset by unrealized losses on foreign currency sell contracts. For the nine months ended September 30, 2019, the unrealized loss is mostly attributable to net outstanding foreign currency purchase contracts in the first quarter of 2019, during which the Canadian dollar strengthened against the U.S. dollar.

As at September 30, 2018, the Company had outstanding foreign currency purchase contracts totalling US$117 million. For the three months ended September 30, 2018, the exchange rate of the Canadian dollar relative to the U.S. dollar strengthened resulting in an unrealized loss in the period. For the nine months ended September 30, 2018, the exchange rate of the Canadian dollar relative to the U.S. dollar weakened resulting in an unrealized gain.

Finance expense and depreciation expense from joint ventures

Finance expense and depreciation expense from joint ventures includes Capital Power's share of finance expense and depreciation expense of York Energy and K2 Wind (through to the December 31, 2018 disposal date), which are accounted for under the equity method.

Income tax recovery (expense)

For the three and nine months ended September 30, 2019 income tax recovery was $66 million and $69 million, respectively, compared to income tax expense of $7 million and $71 million in the corresponding periods of 2018. The increase in income tax recovery was primarily due to the recognition of a deferred income tax recovery on the impairment of Keephills 3 in the third quarter of 2019 (see Significant Events), the decrease in the Alberta corporate income tax rate in the second quarter of 2019, which reduced deferred tax liabilities on the statement of financial position, and lower amounts attributable to tax-equity interests driven by the updated Bloom Wind tax equity investor agreement signed in the second quarter of 2018.

With the introduction of the Bill 3 – Job Creation Tax Act on June 28, 2019, the Alberta corporate income tax rate was reduced from 12% to 8% over four years. Since the Canadian deferred tax assets and liabilities were re-measured, a deferred income tax recovery of $51 million was recognized during the second quarter of 2019.

Non-controlling interests

Non-controlling interests mostly consist of the Coal Mine partner's share of the consolidated depreciation expense of the Coal Mine.

COMPREHENSIVE (LOSS) INCOME

(unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2019	**2018**	**2019**	**2018**
Net (loss) income	(228)	17	(62)	122
Other comprehensive income (loss):				
Net unrealized gains (losses) on derivatives designated as cash flow hedges	19	32	(53)	13
Net unrealized gains on derivatives designated as cash flows hedges – joint ventures	-	2	-	3
Net realized (gains) losses on derivatives designated as cash flow hedges reclassified to net income	(6)	7	14	8
Net realized losses on derivatives designated as cash flow hedges reclassified to net income – joint ventures	-	1	-	2
Unrealized foreign exchange gains (losses) on the translation of foreign operations	11	(8)	(22)	12
Total other comprehensive income (loss), net of tax	24	34	(61)	38
Comprehensive (loss) income	**(204)**	**51**	**(123)**	**160**

Other comprehensive income (loss) includes fair value adjustments on financial instruments held by the Company to hedge market risks and which meet the requirements of hedges for accounting purposes. To the extent that such hedges are ineffective, any related gains or losses are recognized in net (loss) income. Other unrealized fair value changes on derivative instruments designated as cash flow hedges and foreign currency translation gains or losses are subsequently recognized in net (loss) income when the hedged transactions are completed and the foreign operations are disposed of or otherwise terminated.

FINANCIAL POSITION

The significant changes in the consolidated statements of financial position from December 31, 2018 to September 30, 2019 were as follows:

(unaudited, $ millions)	As at September 30, 2019	As at December 31, 2018	Increase (decrease)	IFRS 16 impact (see Accounting Changes)	Impact of business combination and swap transaction[2]	Other	Primary other changes
Trade and other receivables [1]	315	438	(123)	(2)	12	(133)	Lower receivables are driven by the receipt of the remaining proceeds on disposal of K2 Wind and timing of collection of generation receivables.
Right-of-use assets	93	-	93	86	-	7	Reclassification from property, plant and equipment.
Intangible assets	790	473	317	-	419	(102)	Decrease due to depreciation and emission credits used for compliance and transferred to inventory.
Property, plant and equipment [1]	5,802	5,356	446	-	198	248	Increase due to capital additions, including Whitla Wind and Cardinal Point Wind, partly offset by depreciation.
Assets net of liabilities held for sale	301	-	301	-	301	-	
Net derivative financial instruments liabilities	134	45	89	-	105	(16)	Impacts of increasing forward natural gas prices on forward purchase contracts and the settlement of interest rate hedge derivatives and natural gas non-hedge contracts, partially offset by the settlement of foreign exchange non-hedge contracts and the impact of increasing forward power prices on forward power sales contracts.
Loans and borrowings (including current portion)	3,304	2,647	657	-	590	67	Increase primarily due to issuance of private placement senior notes (see Significant Events) and medium-term note, partly offset by net repayment of credit facilities.

(unaudited, $ millions)	As at September 30, 2019	As at December 31, 2018	Increase (decrease)	IFRS 16 impact (see Accounting Changes)	Impact of business combination and swap transaction[2]	Other	Primary other changes
Lease liabilities (including current portion)	109	18	91	96	-	(5)	Decrease primarily due to lease payments.
Net deferred tax liabilities [1]	429	351	78	(2)	114	(34)	Decrease primarily due to the impact of the reduced Alberta statutory income tax rate and the reclass of tax on the disposal of K2 Wind from deferred tax liability to current tax liability, which was offset by the utilization of non-capital loss carry forwards.

[1] Balance as at December 31, 2018 has been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

[2] Includes the impacts of assets and liabilities acquired through the Goreway acquisition (see Significant Events) and the impairment and classification of Keephills 3 as held for sale (see Significant Events).

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Nine months ended September 30		
Cash inflows (outflows)	**2019**	**2018**	**Change**
Operating activities	519	317	202
Investing activities	(738)	(168)	(570)
Financing activities	175	(161)	336

Operating activities

Cash flows from operating activities for the nine months ended September 30, 2019 increased compared with the same period in 2018 primarily due to cash flows from the acquisitions of Arlington Valley and Goreway (see Significant Events) in the fourth quarter of 2018 and second quarter of 2019, respectively, and the commencement of commercial operations of New Frontier Wind in the fourth quarter of 2018. Cash flows from the Alberta assets were higher in the nine months ended September 30, 2019 when compared to the same period in the previous year driven by increased generation and Alberta power prices. Partially offsetting these increases were a decrease in distributions received from joint ventures and net realized cash losses on certain interest rate derivatives settled during the nine months ended September 30, 2019.

Investing activities

Cash flows used in investing activities for the nine months ended September 30, 2019 increased compared with the same period in 2018 primarily due to the acquisition of Goreway (see Significant Events) in the second quarter of 2019 combined with higher year-to-date spending on the Company's wind development projects in 2019 compared to 2018. Partially offsetting these increases were cash inflows from the collection of outstanding receivables from the disposal of K2 Wind in the first quarter of 2019.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2019 Actual	Nine months ended September 30, 2019 Actual	Balance of 2019 Estimated [1, 2]	Actual or Projected Total [2]	Timing
Genesee 4 and 5 [3,4]	18	-	-	700	Targeted completion currently being reassessed by management
New Frontier Wind [5]	174	2	-	176	Completed in December 2018
Whitla Wind [6]	71	226	36	340	Targeted completion in the fourth quarter of 2019
Cardinal Point Wind [7]	28	183	53	295	Targeted completion in March of 2020
Commercial initiatives [8]	-	44	23	98	
Development sites and projects	15	2	-		
Subtotal growth projects		**457**	**112**		
Sustaining – facility maintenance excluding Genesee mine		55			
Sustaining – Genesee mine maintenance and lands		8			
Total capital expenditures [9]		**520**			
Emission credits held for compliance		11			
Capitalized interest		(8)			
Purchase of property, plant and equipment and other assets		**523**			

1 The Company's 2019 estimated capital expenditures include only expenditures for previously announced growth projects and exclude other potential new development projects.

2 Projected capital expenditures to be incurred over the life of the projects for Genesee 4 and 5, New Frontier Wind, Whitla Wind and Cardinal Point Wind are based on management's estimates. Projected capital expenditures for development sites are not reflected beyond the current period until specific projects reach the advanced development stages and projected capital expenditures for commercial initiatives are not reflected beyond the current period.

3 Excludes interest to fund construction and refundable transmission system contribution payments.

4 Continuation and timing of the Genesee 4 and 5 project will be considered once sufficient Alberta market certainty exists and new generation is required in Alberta to balance supply and demand.

5 New Frontier Wind began commercial operations in December 2018. The finalization of construction activities is occurring during 2019. Projected total cost excludes a $19 million (US$15 million) developer fee paid to a subsidiary of the Company.

6 The original projected total construction cost for Whitla Wind was expected to be in the range of $315 million to $325 million. Actual project costs are now expected to exceed that range primarily driven by foreign exchange impacts on U.S. dollar costs. These amounts are partially economically hedged by forward U.S. currency purchases which have a fair value of $1 million at September 30, 2019 (recorded within current derivative instruments assets as foreign exchange non-hedges) as well as realized foreign exchange gains on forward currency purchases settled in the nine months ended September 30, 2019 of $7 million recorded in net income. The remaining foreign exchange differential is driven by movements in the U.S dollar to Canadian dollar foreign exchange rate between the bid date of Whitla Wind into the initial Alberta REP and the date that Whitla Wind was awarded the contract, which were not hedged.

7 The projected total cost for Cardinal Point Wind reflects the midpoint of the expected range of construction costs of $289 million to $301 million (US$236 million to US$246 million).

8 Commercial initiatives include the combustion turbine upgrade project for Decatur Energy with capital expenditures incurred of $24 million (US$18 million). This project will result in an additional 30MW of generation and was completed in the second quarter of 2019. Commercial Initiatives also includes expected spending on the Company's Genesee dual-fuel project (see Significant Events) and the Genesee Performance Standard project as well as various other projects designed to either increase the capacity or efficiency of their respective facilities or to reduce emissions.

9 Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the consolidated statements of cash flows as purchase of property, plant and equipment and other assets.

Financing activities

The cash flows from financing activities for the nine months ended September 30, 2019 primarily reflected the net issuance of loans and borrowings, issuance of common and preferred shares (see Significant Events), repurchase of common shares and payment of common and preferred share dividends.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at September 30, 2019			As at December 31, 2018		
	Maturity timing	Total facilities	Credit facility utilization	Available	Total facilities	Credit facility utilization	Available
Committed credit facilities	2020/2024	1,250			1,150		
Letters of credit outstanding			101			99	
Bankers' acceptances outstanding			250			396	
Bank loans outstanding [1]			149			218	
		1,250	500	750	1,150	713	437
Bilateral demand credit facilities	N/A	326			200		
Letters of credit outstanding			143			172	
		326	143	183	200	172	28
Demand credit facilities	N/A	25	-	25	25	-	25
		1,601	**643**	**958**	**1,375**	**885**	**490**

1 U.S. dollar denominated bank loans outstanding totaling US$112 million (December 31, 2018 – US$160 million).

As at September 30, 2019, the committed credit facility utilization decreased $213 million compared with the utilization as at December 31, 2018, due to decreased bankers' acceptances and U.S. dollar bank loans. In the fourth quarter of 2018 the Company secured a committed non-revolving $150 million credit facility for a period of up to 12 months, which was fully repaid and closed in June 2019. In the second quarter of 2019, the $1.0 billion of committed credit facilities were extended 1-year to mature in July 2024, and the Company secured a committed non-revolving $250 million credit facility for a period of up to 12 months, or June 2020. The available credit facilities provide the Company with adequate funding for ongoing development projects.

The Company has a corporate credit rating of BBB- with a stable outlook from Standard & Poor's (S&P). The BBB rating category assigned by S&P is the fourth highest rating of S&P's ten rating categories for long-term debt obligations. According to S&P, a BBB corporate credit rating exhibits adequate capacity to meet financial commitments, however, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.

The Company has a corporate credit rating of BBB (low) with a stable outlook from DBRS Limited (DBRS). The BBB rating category assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality and the capacity of the payment of financial obligations is considered acceptable but the entity is vulnerable to future events.

The above credit ratings from S&P and DBRS are investment grade credit ratings which enhance Capital Power's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

Future cash requirements

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's expected cash requirements for 2019 include:

(unaudited, $ millions)	Nine months ended September 30, 2019 actual	Balance of 2019 estimated	Total 2019 expected cash requirements
Repayment of debt payable [1]	286	14	300
Capital expenditures – sustaining	58	23	81
Capital expenditures – ongoing growth projects	457	112	569
Common share dividends [2]	139	51	190
Preferred share dividends	36	12	48
	976	**212**	**1,188**

1 Excludes repayment of credit facilities.

2 Includes 7.3% annual dividend growth (see Significant Events).

The Company uses a short-form base shelf prospectus to provide it with the ability, market conditions permitting, to obtain new debt and equity capital from external markets when required. Under the short-form base shelf prospectus, Capital Power may raise up to $3 billion by issuing common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities. This prospectus expires in June 2020.

If the Canadian and U.S. financial markets become unstable, Capital Power's ability to raise new capital to meet its financial requirements, and to refinance indebtedness under existing credit facilities and debt agreements may be adversely affected. Capital Power has credit exposure relating to various agreements, particularly with respect to its PPA, energy supply contract, trading and supplier counterparties. While Capital Power continues to monitor its exposure to its significant counterparties, there can be no assurance that all counterparties will be able to meet their commitments.

Off-statement of financial position arrangements

As at September 30, 2019, the Company has $244 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements and to satisfy legislated reclamation requirements. If the Company were to terminate these off-statement of financial position arrangements, the penalties or obligations would not have a material impact on the Company's financial condition, results of operations, liquidity, capital expenditures or resources.

Capital resources

(unaudited, $ millions)	As at	
	September 30, 2019	**December 31, 2018**
Loans and borrowings	3,304	2,647
Lease liabilities [1]	109	18
Less cash and cash equivalents	(133)	(182)
Net debt	3,280	2,483
Share capital	3,450	3,200
Deficit and other reserves	(496)	(190)
Non-controlling interests	38	43
Total equity	2,992	3,053
Total capital	**6,272**	**5,536**

[1] Includes the current portion disclosed within deferred revenue and other liabilities.

CONTINGENT LIABILITIES AND PROVISIONS

Contingent liabilities

The Company and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

Line Loss Rule Proceeding provision

Capital Power participated in the Line Loss Rule (LLR) Proceeding before the Alberta Utilities Commission (AUC) regarding loss factors that form the basis for certain transmission charges paid by Alberta generators, including Capital Power. The LLR Proceeding addressed the replacement of the non-compliant LLR as well as the possible correction of line loss charges and credits for the years 2006 up to (but not including) 2017.

The Company is participating in legal or regulatory processes rendering the final outcome of the LLR Proceeding still unknown. However, based on current AUC decisions, Capital Power would incur additional charges related to transmission amounts of historical periods and, as such, recorded a current provision of $9 million during the fourth quarter of 2017 pertaining to the estimated net liability for its currently held Alberta assets. The recorded provision reflects the Company's estimated net liability. However, it is expected that the invoicing process will result in gross billings to Capital Power of which those amounts not attributable to Capital Power will then be recovered from the appropriate parties. The Alberta Electric System Operator has indicated invoicing for the line loss adjustments will not occur until 2021. As a result, the estimated net liability was reclassified from current to non-current provisions in the third quarter of 2019. Upon closing of the acquisition of the additional 50% interest in Genesee 3 and divesture of the Company's interest in Keephills 3 (see Significant Events) on October 1, 2019, the Company recorded a $6 million increase to the provision in the fourth quarter of 2019, which brings the total estimated net liability to $15 million.

RISKS AND RISK MANAGEMENT

There have been no material changes in the nine months ended September 30, 2019 to the Company's business and operational risks as described in the Company's December 31, 2018 MD&A. Additional information pertaining to climate-related risks and opportunities can be found on the Company's website within its Climate Change Disclosure report dated February 19, 2019.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $361 million as at September 30, 2019 ($259 million as at December 31, 2018) for its generation facilities and the Genesee Coal Mine as it is obliged to remove the facilities at the end of their useful lives and restore the facility and mine sites to their original condition. Decommissioning provisions for the Genesee Coal Mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation. The timing of reclamation activities could vary and the amount of decommissioning provisions could change depending on potential future changes in environmental regulations and the timing of any facility fuel conversions.

The Company has forward contracts to purchase environmental credits totaling $617 million and forward contracts to sell environmental credits totaling $572 million in future years. Included within these forward purchases and sales are net purchase amounts which will be used by the Company to comply with applicable environmental regulations and net sales amounts related to other emissions trading activities.

REGULATORY MATTERS

Ontario's Independent Electric System Operator (the "IESO") unexpectedly announced in July 2019 that it was cancelling further work on a broad capacity market framework. In reviewing its long-term planning outlook, the IESO advised that it expects sufficient capacity to exist in the market for the next ten-year period particularly if resources are re-acquired when their existing contracts expire. The process to recontract assets, including those owned by the Company, is expected to commence late 2019 or early 2020 and is likely to include a combination of bilateral contract extensions and competitive processes.

On October 31, 2018, the Government of Ontario passed Bill 4, the *Cap and Trade Cancellation Act, 2018*. Bill 4 repealed the *Climate Change Mitigation and Low-carbon Economy Act, 2016*, and set out the legal framework for a wind-down of the Cap and Trade program. The Federal Government Greenhouse Gas Pollution Pricing Act (GGPPA) imposes a carbon pricing system on Ontario and other provinces that do not have an equivalent system in place to meet targeted Greenhouse Gas (GHG) reduction levels. On July 4, 2019, the Government of Ontario published the final Greenhouse Gas Emissions Performance Standards (Ontario Regulation 241/19) and the regulation also came into effect on the day it was filed. However, the first compliance period is not until the Federal Government removes Ontario from Part 2 of Schedule 1 of the Federal GGPPA. As such, the GGPPA will remain in effect in Ontario until 2022. The PPAs for York Energy, East Windsor and Goreway have a provision that triggers a contractual amendment, the effect of which will enable recovery of any imposed federal carbon compliance costs. Accordingly, the Company does not believe the implementation of a federal carbon pricing system or any potential provincial GHG system will have a material adverse effect on its financial condition and results of operations.

On April 16, 2019, the Province of Alberta held an election resulting in the United Conservative Party (UCP) forming a majority government to replace the previous New Democratic Party majority government. Premier Jason Kenney has appointed a Cabinet and the new Government has initiated consultations and action on a number of items that had been identified in the UCP platform. On July 24, the Government of Alberta announced its decision to maintain the energy-only market and advised that it will table the necessary legislation and amend regulations to stop the implementation of the capacity market as soon as possible. Capital Power remains well positioned to compete in Alberta's energy-only market through our market and commodity management expertise, our young, diverse and efficient fleet of assets, and our pipeline of development projects for which regulatory approvals have already been received. In July, the Government initiated its process to develop the new Technology Innovation and Emissions Reduction (TIER) framework, which will replace the current Carbon Competitiveness and Incentive Regulation (CCIR) as the carbon management framework for large emitters. Capital Power participated in the TIER consultation process, and Management's understanding continues to be that the carbon framework governing the electricity sector will continue to establish carbon compliance obligations for emissions from electricity generation relative to a "best natural gas" emissions intensity standard similar to the existing CCIR. The TIER legislation will be introduced for consideration by the Legislature in the Fall Session and is expected to be effective January 1, 2020.

USE OF JUDGMENTS AND ESTIMATES

In preparing the condensed interim consolidated financial statements, management made judgments, estimates and assumptions that affect the application of the Company's accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ from these estimates. There have been no significant changes to the Company's use of judgments and estimates as described in the Company's December 31, 2018 MD&A, other than those judgments made as a part of the adoption of new accounting standards in the first quarter of 2019, as described under Accounting Changes.

ACCOUNTING CHANGES

Effective January 1, 2019

The Company adopted one new accounting standard as issued by the International Accounting Standards Board (IASB). The standard and impact to Capital Power were:

Standard	Description	Impact to Capital Power and current implementation status	Effective Date
Leases (IFRS 16)	The new standard which replaced IAS 17 – Leases addresses the recognition, measurement, presentation and disclosure of leases. IFRS 16 provides a single lessee accounting model requiring lessees to recognize right-of-use assets and lease liabilities for all leases previously classified as operating leases, including but not limited to, office space leases and land leases. There are no changes to lessor accounting under the new standard. However, the criteria for assessing whether a contract contains a lease have changed.	The Company elected not to grandfather lease assessments, as previously assessed under IAS 17 and IFRIC 4 – Determining Whether an Arrangement Contains a Lease. Management reviewed all contracts and existing lease arrangements to determine the impact of the IFRS 16 adoption. For contracts determined to contain leases with the Company as the lessee under IFRS 16, the Company elected to apply the modified retrospective approach where the lessee does not restate comparative figures and the cumulative effect of initial application of the standard is recognized in the opening deficit balance. The Company recognized right-of-use assets for the underlying assets and lease liabilities for future lease payments. Management determined that certain PPAs and energy supply contracts that were previously considered to be finance leases with the Company as the lessor are no longer considered leases under IFRS 16, but rather are now accounted for under IFRS 15 – Revenue from Contracts with Customers. The transition impact for the former finance leases was accounted for retrospectively in accordance with IAS 8 - Accounting Policies, Changes in Accounting Estimates and Errors and treated as a change in accounting policy.	Effective for annual periods beginning on or after January 1, 2019.

The adjustments to the impacted financial statement categories within the consolidated statements of financial position as a result of changes described in the IFRS 16 discussion above are as follows:

	Previously stated at January 1, 2018	IAS 8	Restated as at January 1, 2018	Previously stated at December 31, 2018	IAS 8	Restated as at December 31, 2018	IFRS 16	As at January 1, 2019
Assets [1]	$ 6,898	$ (79)	$ 6,819	$ 7,660	$ (91)	$ 7,569	$ 84	$ 7,653
Liabilities [2]	3,836	(22)	3,814	4,541	(25)	4,516	90	4,606
Equity [2]	$ 3,062	$ (57)	$ 3,005	$ 3,119	$ (66)	$ 3,053	$ (6)	$ 3,047

1 Under IFRS 16, assets related to leases as the lessee represent right-of-use assets and assets related to leases as the lessor represent property, plant and equipment.

2 The opening deficit adjustments above reflect increase to the opening deficit balances, net of deferred tax impacts at a rate of 27% which also impacts the liabilities amounts as reductions to deferred tax liabilities.

The adjustments to the impacted line items within the consolidated statements of income pertaining to the IAS 8 accounting policy change related to the former finance leases where Capital Power was the lessor were:

	Three months ended September 30, 2019			Three months ended September 30, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	478	484	6	367	373	6
Depreciation and amortization	(126)	(135)	(9)	(74)	(83)	(9)
Income tax recovery (expense)	65	66	1	(8)	(7)	1
Net (loss) income impact			(2)			(2)

	Nine months ended September 30, 2019			Nine months ended September 30, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	1,165	1,183	18	943	961	18
Depreciation and amortization	(328)	(355)	(27)	(223)	(250)	(27)
Income tax recovery (expense)	66	69	3	(74)	(71)	3
Net (loss) income impact			(6)			(6)

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at September 30, 2019 and December 31, 2018 were as follows:

(unaudited, $ millions)		September 30, 2019		December 31, 2018	
	Fair value hierarchy level [1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	133	133	182	182
Trade and other receivables [2]	N/A	262	262	385	385
Government grant receivable [3]	Level 2	473	430	511	505
Fair value through income or loss					
Derivative financial instruments assets – current and non-current	See below	189	189	148	148
Fair value through other comprehensive income					
Derivative financial instruments assets – current and non-current	See below	1	1	11	11
Financial liabilities:					
Other financial liabilities					
Trade and other payables	N/A	314	314	244	244
Loans and borrowings [3]	Level 2	3,304	3,352	2,647	2,645
Fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See below	191	191	186	186
Fair value through other comprehensive income					
Derivative financial instruments liabilities – current and non-current	See below	133	133	18	18

1 Fair values for Level 1 financial assets and liabilities are based on unadjusted quoted prices in active markets for identical instruments while fair values for Level 2 financial assets and liabilities are generally based on indirectly observable prices. The determination of fair values for Level 3 financial assets and liabilities is prepared by appropriate subject matter experts and reviewed by the Company's commodity risk group and by management.

2 Excludes current portion of government grant receivable.

3 Includes current portion.

Risk management and hedging activities

There have been no material changes in the nine months ended September 30, 2019 to the Company's risk management and hedging activities as described in the Company's December 31, 2018 MD&A.

The derivative financial instruments assets and liabilities held at September 30, 2019 compared with December 31, 2018 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at September 30, 2019				
	Fair value hierarchy level	Commodity cash flow hedges	Commodity non-hedges	Interest rate cash flow hedges	Foreign exchange non-hedges	Total
Derivative financial instruments assets	Level 2	1	164	-	1	166
	Level 3	-	24	-	-	24
		1	188	-	1	190
Derivative financial instruments liabilities	Level 2	(34)	(175)	(99)	(1)	(309)
	Level 3	-	(15)	-	-	(15)
		(34)	(190)	(99)	(1)	(324)
Net derivative financial instruments (liabilities) assets		**(33)**	**(2)**	**(99)**	**-**	**(134)**

(unaudited, $ millions)		As at December 31, 2018				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Foreign exchange non-hedges**	**Total**
Derivative financial instruments assets	Level 2	11	120	-	12	143
	Level 3	-	16	-	-	16
		11	136	-	12	159
Derivative financial instruments liabilities	Level 2	(11)	(141)	(7)	(1)	(160)
	Level 3	-	(44)	-	-	(44)
		(11)	(185)	(7)	(1)	(204)
Net derivative financial instruments (liabilities) assets		**-**	**(49)**	**(7)**	**11**	**(45)**

Commodity, interest rate and foreign exchange derivatives designated as accounting hedges

Unrealized gains and losses for fair value changes on commodity, interest rate and foreign exchange derivatives that qualify for hedge accounting are recorded in other comprehensive income (loss) and, when realized, are reclassified to net (loss) income as revenues, energy purchases and fuel, finance expense or foreign exchange gains and losses as appropriate. When interest rate derivatives are used to hedge the interest rate on a future debt issuance, realized gains or losses are deferred within accumulated other comprehensive loss and recognized within finance expense over the life of the debt, consistent with the interest expense on the hedged debt.

Commodity, interest rate and foreign exchange derivatives not designated as accounting hedges

The change in fair values of commodity derivatives not designated as hedges is primarily due to changes in forward Alberta power and natural gas prices and their impact on the Alberta portfolio as well as the change in pricing on U.S. trading relating to the swap arrangements on the Company's U.S. wind generation. Unrealized and realized gains and losses for fair value changes on commodity derivatives that do not qualify for hedge accounting are recorded in net income as revenues or energy purchases and fuel.

Unrealized and realized gains and losses on foreign exchange derivatives and interest rate derivatives that are not designated as hedges for accounting purposes are recorded in net income as foreign exchange gains or losses and net finance expense, respectively.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no significant changes in the Company's disclosure controls and procedures and internal controls over financial reporting that occurred during the nine months ended September 30, 2019 that have materially affected or are reasonably likely to materially affect the Company's disclosures of required information and internal control over financial reporting.

SUMMARY OF QUARTERLY RESULTS

(GWh)	Three months ended							
Electricity generation	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**
Total electricity generation	6,808	5,500	5,782	5,406	5,213	4,584	5,026	4,839
Alberta commercial facilities								
Genesee 3	492	502	500	372	495	468	479	511
Keephills 3	450	433	470	483	494	434	420	362
Clover Bar Energy Centre 1, 2 and 3	348	264	296	264	217	204	175	92
Joffre	150	205	232	212	154	115	128	119
Shepard Energy Centre	782	679	807	769	789	585	795	694
Halkirk	86	107	120	130	85	103	132	168
Clover Bar Landfill Gas	-	-	-	-	-	-	-	2
	2,308	2,190	2,425	2,230	2,234	1,909	2,129	1,948
Alberta contracted facilities								
Genesee 1	803	556	837	877	829	751	811	860
Genesee 2	795	698	848	850	799	647	663	864
	1,598	1,254	1,685	1,727	1,628	1,398	1,474	1,724
Ontario and British Columbia contracted facilities								
Island Generation	379	166	168	-	17	-	10	3
York Energy	3	4	4	2	3	3	2	2
East Windsor	2	3	2	1	4	2	2	1
Goreway	304	76	N/A	N/A	N/A	N/A	N/A	N/A
K2 Wind	N/A	N/A	N/A	70	35	41	76	57
Kingsbridge 1	15	20	36	33	14	20	36	37
Port Dover and Nanticoke	46	65	99	78	43	70	108	84
Quality Wind	73	77	74	112	74	98	78	117
EnPower	3	5	5	3	10	11	14	13
	825	416	388	299	200	245	326	314
U.S. contracted facilities								
Roxboro, North Carolina	88	88	62	74	87	90	76	86
Southport, North Carolina	112	121	99	106	104	118	111	120
Decatur Energy, Alabama	709	372	408	674	784	576	669	425
Arlington Valley, Arizona	878	750	394	87	N/A	N/A	N/A	N/A
Beaufort Solar, North Carolina	8	9	6	5	8	8	6	6
Bloom Wind, Kansas	176	169	175	164	152	197	198	190
Macho Springs, New Mexico	21	43	39	31	16	43	37	26
New Frontier Wind, North Dakota	85	88	101	9	N/A	N/A	N/A	N/A
	2,077	1,640	1,284	1,150	1,151	1,032	1,097	853

(%)	Three months ended							
Facility availability	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**
Total average facility availability	96	92	96	94	98	93	96	95
Alberta commercial facilities								
Genesee 3	96	100	100	74	98	98	97	100
Keephills 3	93	92	99	100	100	100	92	75
Clover Bar Energy Centre 1, 2 and 3	96	91	97	85	88	90	93	97
Joffre	82	100	100	100	97	90	93	100
Shepard Energy Centre	100	86	97	100	100	68	100	94
Halkirk	95	98	98	98	95	98	98	97
Clover Bar Landfill Gas	-	-	-	-	7	78	-	45
	95	93	98	93	96	87	96	93
Alberta contracted facilities								
Genesee 1	96	72	100	100	99	100	100	100
Genesee 2	100	95	100	98	100	93	83	100
	98	83	100	99	99	97	92	100
Ontario and British Columbia contracted facilities								
Island Generation	99	100	100	100	100	100	100	100
York Energy	99	100	100	100	100	94	100	100
East Windsor	99	99	99	99	99	99	99	97
Goreway	87	99	N/A	N/A	N/A	N/A	N/A	N/A
K2 Wind	N/A	N/A	N/A	99	98	100	98	98
Kingsbridge 1	98	97	98	99	98	98	98	98
Port Dover and Nanticoke	94	100	99	98	94	99	100	96
Quality Wind	96	98	96	95	94	97	97	96
EnPower	72	97	55	97	100	86	97	96
	92	99	98	99	98	98	99	98
U.S. contracted facilities								
Roxboro, North Carolina	99	100	88	97	100	99	88	100
Southport, North Carolina	84	90	91	83	100	95	89	99
Decatur Energy, Alabama	100	81	98	85	100	94	100	89
Arlington Valley, Arizona	100	100	81	94	N/A	N/A	N/A	N/A
Beaufort Solar, North Carolina	100	100	100	97	100	98	93	97
Bloom Wind, Kansas	98	98	99	100	97	96	98	98
Macho Springs, New Mexico	97	99	98	99	97	98	97	98
New Frontier Wind, North Dakota	97	95	96	98	N/A	N/A	N/A	N/A
	99	91	92	89	99	95	98	92

Financial results

(unaudited, $ millions)	Three months ended							
	Sep 30 2019	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**
Revenues and other income								
Alberta commercial facilities and portfolio optimization	181	150	180	150	148	116	173	190
Alberta contracted facilities	68	46	74	71	70	66	61	64
Ontario and British Columbia contracted facilities [3]	88	56	47	52	37	41	50	54
U.S. contracted facilities	149	102	95	63	74	102	65	58
Corporate [1]	15	17	15	13	15	15	15	19
Unrealized changes in fair value of commodity derivatives and emission credits	16	(5)	(14)	(9)	51	29	(51)	(118)
	517	**366**	**397**	**340**	**395**	**369**	**313**	**267**
Adjusted EBITDA								
Alberta commercial facilities and portfolio optimization	72	71	84	62	60	51	55	60
Alberta contracted facilities	49	32	53	53	54	51	45	47
Ontario and British Columbia contracted facilities [2, 3]	63	48	44	52	37	45	59	60
U.S. contracted facilities	115	54	38	25	44	72	35	30
Corporate	(15)	(14)	(17)	(21)	(16)	(12)	(15)	(19)
	284	**191**	**202**	**171**	**179**	**207**	**179**	**178**

1 Revenues are offset by interplant category revenue eliminations.

2 The reported Ontario and British Columbia contracted facilities' adjusted EBITDA includes the adjusted EBITDA from the York Energy joint venture. Prior quarters' values include Capital Power's share of K2 Wind which was disposed of effective December 31, 2018.

3 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

Quarterly revenues, net income and cash flows from operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, planned and unplanned facility outages and items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's power, natural gas, interest rate and foreign exchange derivative contracts.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Sep 30 2019	Jun 30 2019	Mar 31 2019	Dec 31 2018	Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017
Revenues and other income [4]	517	366	397	340	395	369	313	267
Adjusted EBITDA [1, 2, 3, 4]	284	191	202	171	179	207	179	178
Net (loss) income [4]	(228)	106	60	136	17	66	39	(14)
Net (loss) income attributable to shareholders of the Company [4]	(226)	108	61	138	18	68	41	(11)
Basic (loss) earnings per share ($) [4]	(2.25)	0.93	0.49	1.24	0.08	0.55	0.30	(0.21)
Normalized earnings per share ($) [1, 4]	0.60	0.14	0.29	0.30	0.33	0.20	0.28	0.23
Net cash flows from operating activities	209	114	286	133	65	109	143	75
Adjusted funds from operations [1]	225	85	117	80	156	76	85	94
Adjusted funds from operations per share ($) [1]	2.11	0.82	1.15	0.78	1.52	0.74	0.82	0.90
Purchase of property, plant and equipment and other assets	193	279	51	114	135	66	40	42

1 The consolidated financial highlights, except for adjusted EBITDA, normalized earnings per share, adjusted funds from operations and adjusted funds from operations per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

2 The reported Ontario and British Columbia contracted facilities' adjusted EBITDA includes the adjusted EBITDA from the York Energy joint venture. Prior quarters' values include Capital Power's share of K2 Wind which was disposed of effective December 31, 2018.

3 Commencing with the Company's March 31, 2019 quarter-end, adjusted EBITDA excludes unrealized changes in fair value of commodity derivatives and emission credits which were previously included in adjusted EBITDA. This change was made to better align the Company's measure of adjusted EBITDA with its other non-GAAP measures, as both the adjusted funds from operations and the normalized earnings per share measures exclude the impacts of unrealized changes in fair value of commodity derivatives and emission credits. Comparative figures have been restated to reflect the above change to the adjusted EBITDA metric.

4 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

	Three months ended							
Spot price averages	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**
Alberta power ($ per MWh)	47	57	69	56	55	56	35	22
Alberta natural gas (AECO) ($ per Gj)	0.99	1.17	2.62	1.59	1.15	1.10	1.99	1.73
Capital Power's Alberta portfolio average realized power price ($ per MWh)	59	55	58	52	54	51	47	46

Factors impacting results for the previous quarters

Significant events and items which affected results for the previous quarters were as follows:

For the quarter ended June 30, 2019, the Company recorded net income attributable to shareholders of $108 million compared to net income attributable to shareholders of $68 million for the quarter ended June 30, 2018. The increase mainly resulted from an income tax recovery of $33 million in the second quarter of 2019 compared to income tax expense of $46 million in the second quarter of 2018 primarily due to a reduction in the Alberta corporate income tax rate enacted in the second quarter of 2019. Further contributing to the increase were unrealized gains on commodity derivatives and emission credits which were $26 million higher in the second quarter of 2019 compared to the second quarter of 2018. These variances were partially offset by higher depreciation and amortization due to New Frontier Wind commencing commercial operation in the last quarter of 2018 and the acquisitions of Arlington Valley and Goreway in the last quarter of 2018 and second quarter of 2019, respectively. In addition, adjusted EBITDA was lower in the second quarter of 2019 compared to the second quarter of 2018, largely due to the timing and length of planned outages and the impact of the Bloom Wind tax equity agreement renegotiation in the second quarter of 2018, offset partially by higher margins earned on the sale of emission credits in the second quarter of 2019.

For the quarter ended March 31, 2019, the Company recorded net income attributable to shareholders of $61 million compared to net income attributable to shareholders of $41 million for the quarter ended March 31, 2018. The increase compared to the prior quarter mainly resulted from an increase in adjusted EBITDA most notably due to the higher Alberta power pricing averaging $69 per MWh in the first quarter of 2019 compared to $35 per MWh in the first quarter of 2018, offset partially by lower adjusted EBITDA from joint ventures due to the disposal of K2 Wind in December 2018. Other notable impacts included higher unrealized gains on commodity derivatives and emission credits in 2019 which were higher by $35 million, largely offset by higher depreciation and amortization due to the acquisition of Arlington Valley and New Frontier Wind commencing commercial operation in the last quarter of 2018, and increased income tax expense primarily due to higher consolidated income before tax.

For the quarter ended December 31, 2018, the Company recorded net income attributable to shareholders of $138 million compared to net loss attributable to shareholders of $11 million for the quarter ended December 31, 2017. The increase compared to the prior quarter mainly resulted from the $159 million gain on disposal of the Company's minority owned interest in K2 Wind. In addition, tax expenses were lower by $26 million in the fourth quarter of 2018 as compared to 2017 driven by U.S. federal tax rate decreases in the fourth quarter of 2017 and the resulting reduction in deferred tax assets. These impacts were partially offset by higher unrealized losses on commodity derivatives and emission credits in 2018 which were higher by $35 million.

For the quarter ended September 30, 2018, the Company recorded net income attributable to shareholders of $18 million compared to net loss attributable to shareholders of $7 million for the quarter ended September 30, 2017. Higher net income reflects the recognition of non-cash impairment losses in the third quarter of 2017 totalling $83 million (pre-tax) related to the Company's Southport, Roxboro and Decatur Energy facilities. The Company did not record an impairment loss in 2018. Favourable net income attributed to shareholders was partially offset by a foreign exchange loss of $2 million in the third quarter of 2018 compared to a foreign exchange gain of $21 million in the third quarter of 2017 reflecting a gain on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes, and income tax expense of $7 million in the third quarter of 2018 compared to income tax recovery of $9 million in the third quarter of 2017. Adjusted EBITDA was higher in the third quarter of 2018 compared to the third quarter of 2017 primarily due to the impact of higher Alberta power prices in 2018 compared with 2017 on the Alberta contracted assets. Losses related to unrealized changes in the fair value of commodity derivatives and emission credits were higher in the third quarter of 2018 compared to the third quarter of 2017 largely as a result of the 2018 impact of increasing forward prices on forward sales contracts relating to U.S. energy derivatives.

For the quarter ended June 30, 2018, the Company recorded net income attributable to shareholders of $68 million compared to $107 million for the quarter ended June 30, 2017. Lower net income reflected the reversal of a previous write-down of deferred tax assets related to the tax benefit associated with the Company's U.S. income tax loss carryforwards as a result of the acquisition of Decatur Energy and the commissioning of Bloom Wind in the second quarter of 2017. Further contributing to the decrease were higher net finance expenses and depreciation and amortization due to the acquisition of the thermal facilities and Decatur Energy and the receipt of Bloom Wind Project financing in the second quarter of 2017. These variances were partially offset by higher adjusted EBITDA in the second quarter of 2018 compared to the second quarter of 2017 primarily due to the impact of higher Alberta power prices in 2018 compared with 2017 on the Alberta contracted assets, a full quarter of results from the assets acquired in the second quarter of 2017, and higher Bloom Wind revenue due to the renegotiation of the commercial terms within the Bloom Wind tax equity agreement. Non-cash after tax net income related to Bloom Wind increased $15 million driven by tax rate differences while the $44 million increase in adjusted EBITDA was related to timing.

For the quarter ended March 31, 2018, the Company recorded net income attributable to shareholders of $41 million compared to $46 million for the quarter ended March 31, 2017. The financial results reflected higher unrealized gains on Alberta energy derivatives in the first quarter of 2017 that resulted from the impact of decreasing forward Alberta power prices on net forward sales contracts, partially offset by the reversal of prior year unrealized net gains on forward sales contracts that settled during the first quarter of 2017. Further contributing to the decrease were higher net finance expenses and depreciation and amortization due to the acquisition of the thermal facilities and Decatur Energy and the receipt of Bloom Wind Project financing in the second quarter of 2017. Adjusted EBITDA was higher in the first quarter of 2018 compared to the first quarter of 2017 primarily due to Bloom Wind commencing operations and acquisition of the thermal facilities and Decatur Energy in the second quarter of 2017.

For the quarter ended December 31, 2017, the Company recorded net loss attributable to shareholders of $11 million compared to net income attributable to shareholders of $27 million for the quarter ended December 31, 2016. The decrease compared to the prior quarter mainly resulted from lower average realized prices on the Alberta portfolio and unrealized losses on the Alberta power portfolio that were primarily due to the reversal of prior period unrealized net gains on forward sales contracts that settled during the period. Adjusted EBITDA was higher quarter over quarter mostly due to the impact of the acquired thermal facilities and Decatur Energy in the second quarter of 2017 and other income related to coal compensation from the Province of Alberta. During the fourth quarter of 2017, the U.S. federal income tax rate decreased as part of the U.S. tax reform and the Company's U.S. deferred tax assets and liabilities were re-measured. As a result of the re-measurement, the Company recognized $31 million in deferred income tax expense. In the fourth quarter of 2017, the Company also recorded a current provision of $9 million related to the LLR proceeding based on current Module C conclusions.

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

The Company's common shares are listed on the TSX under the symbol CPX and began trading on June 26, 2009.

	Three months ended							
	Sep 30 2019	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**
Share price ($/common share)								
High	31.43	32.25	32.44	29.79	29.45	26.00	25.14	25.59
Low	29.31	29.60	26.22	25.33	25.12	23.42	22.15	23.26
Close	30.68	30.15	31.30	26.59	28.51	25.23	24.24	24.49
Volume of shares traded (millions)	18.2	19.6	18.0	25.5	14.8	11.1	14.0	16.9

Outstanding share and partnership unit data

As at October 23, 2019, the Company had 105.170 million common shares, 5 million Cumulative Rate Reset Preference Shares (Series 1), 6 million Cumulative Rate Reset Preference Shares (Series 3), 8 million Cumulative Rate Reset Preference Shares (Series 5), 8 million Cumulative Minimum Rate Reset Preference Shares (Series 7), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 9), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 11), and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares as at October 23, 2019 were 108.559 million. The outstanding special limited voting share is held by EPCOR.

As at October 23, 2019, CPLP had 24.040 million general partnership units outstanding and 89.473 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

ADDITIONAL INFORMATION

Additional information relating to Capital Power Corporation, including the Company's annual information form and other continuous disclosure documents, is available on SEDAR at www.sedar.com.

Condensed Interim Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(Unaudited, in millions of Canadian dollars)
Nine months ended September 30, 2019 and 2018

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Nine months ended September 30, 2019 and 2018

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Income (Loss)
(Unaudited, in millions of Canadian dollars, except per share amounts)

	Three months ended September 30, 2019	Three months ended September 30, 2018 (note 3)	Nine months ended September 30, 2019	Nine months ended September 30, 2018 (note 3)
Revenues	$ 484	$ 373	$ 1,183	$ 961
Other income	33	22	97	116
Energy purchases and fuel	(126)	(173)	(221)	(300)
Gross margin	391	222	1,059	777
Other raw materials and operating charges	(37)	(27)	(106)	(91)
Staff costs and employee benefits expense	(41)	(39)	(121)	(107)
Depreciation and amortization	(135)	(83)	(355)	(250)
Impairment (note 5)	(401)	-	(401)	-
Other administrative expense	(27)	(22)	(84)	(68)
Foreign exchange (loss) gain	(1)	(2)	(5)	4
Operating (loss) income	(251)	49	(13)	265
Net finance expense	(42)	(28)	(115)	(90)
(Loss) income from joint ventures	(1)	3	(3)	18
(Loss) income before tax	(294)	24	(131)	193
Income tax recovery (expense) (note 6)	66	(7)	69	(71)
Net (loss) income	$ (228)	$ 17	$ (62)	$ 122
Attributable to:				
Non-controlling interests	$ (2)	$ (1)	$ (5)	$ (5)
Shareholders of the Company	$ (226)	$ 18	$ (57)	$ 127
Earnings (loss) per share (attributable to common shareholders of the Company):				
Basic (note 7)	$ (2.25)	$ 0.08	$ (0.90)	$ 0.93
Diluted (note 7)	$ (2.25)	$ 0.08	$ (0.90)	$ 0.93

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Comprehensive Income (Loss)
(Unaudited, in millions of Canadian dollars)

	Three months ended September 30, 2019	Three months ended September 30, 2018 (note 3)	Nine months ended September 30, 2019	Nine months ended September 30, 2018 (note 3)
Net (loss) income	$ (228)	$ 17	$ (62)	$ 122
Other comprehensive income (loss):				
Items that are or may be reclassified subsequently to net (loss) income:				
Cash flow hedges:				
Unrealized gains (losses) on derivative instruments[1]	19	32	(53)	13
Unrealized gains on derivative instruments – joint ventures[2]	-	2	-	3
Reclassification of (gains) losses on derivative instruments to net (loss) income for the period[3]	(6)	7	14	8
Reclassification of losses on derivative instruments to net (loss) income for the period – joint ventures[4]	-	1	-	2
Net investment in foreign subsidiaries:				
Unrealized gains (losses) [5]	11	(8)	(22)	12
Total items that are or may be reclassified subsequently to net (loss) income, net of tax	24	34	(61)	38
Total other comprehensive income (loss), net of tax	24	34	(61)	38
Total comprehensive (loss) income	$ (204)	$ 51	$ (123)	$ 160
Attributable to:				
Non-controlling interests	$ (2)	$ (1)	$ (5)	$ (5)
Shareholders of the Company	$ (202)	$ 52	$ (118)	$ 165

[1] For the three and nine months ended September 30, 2019, net of income tax expense of $5 million and income tax recovery of $16 million, respectively. For the three and nine months ended September 30, 2018, net of income tax expense of $14 million and $7 million, respectively.

[2] For the three and nine months ended September 30, 2019, net of income tax expense of nil and for the three and nine months ended September 30, 2018, net of income tax expense of $1 million.

[3] For the three and nine months ended September 30, 2019, net of reclassification of income tax expense of $2 million and reclassification of income tax recovery of $4 million, respectively. For the three and nine months ended September 30, 2018, net of reclassification of income tax recovery of $2 million and $3 million, respectively.

[4] For the three and nine months ended September 30, 2019, net of reclassification of income tax recovery of nil. For the three and nine months ended September 30, 2018, net of reclassification of income tax recovery of $1 million.

[5] For the three and nine months ended September 30, 2019 and September 30, 2018, net of income tax expense of nil.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Financial Position
(Unaudited, in millions of Canadian dollars)

	September 30, 2019	December 31, 2018 (note 3)
Assets		
Current assets:		
Cash and cash equivalents	$ 133	$ 182
Trade and other receivables	315	438
Inventories	225	200
Derivative financial instruments assets (note 8)	72	77
Assets held for sale (note 5)	324	-
	1,069	897
Non-current assets:		
Other assets	54	66
Derivative financial instruments assets (note 8)	118	82
Government grant receivable	420	459
Deferred tax assets	32	59
Equity-accounted investments	130	142
Right-of-use assets (note 9)	93	-
Intangible assets	790	473
Property, plant and equipment	5,802	5,356
Goodwill	35	35
Total assets	$ 8,543	$ 7,569
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 314	$ 244
Derivative financial instruments liabilities (note 8)	190	90
Loans and borrowings (note 10)	870	456
Deferred revenue and other liabilities	71	62
Provisions	35	54
Liabilities related to assets held for sale (note 5)	23	-
	1,503	906
Non-current liabilities:		
Derivative financial instruments liabilities (note 8)	134	114
Loans and borrowings (note 10)	2,434	2,191
Lease liabilities (note 9)	103	17
Deferred revenue and other liabilities	529	587
Deferred tax liabilities	461	410
Provisions	387	291
	4,048	3,610
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 11)	3,450	3,200
Deficit	(467)	(222)
Other reserves	(29)	32
Deficit and other reserves	(496)	(190)
	2,954	3,010
Non-controlling interests	38	43
Total equity	2,992	3,053
Total liabilities and equity	$ 8,543	$ 7,569

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share Capital (note 11)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2019 (note 3)	$ 3,200	$ 7	$ 23	$ (9)	$ 11	$ (222)	$ 3,010	$ 43	$ 3,053
Accounting policy changes:									
Impact of IFRS 16 (note 3)	-	-	-	-	-	(8)	(8)	-	(8)
Tax impact of IFRS 16 (note 3)	-	-	-	-	-	2	2	-	2
Adjusted equity as at January 1, 2019	$ 3,200	$ 7	$ 23	$ (9)	$ 11	$ (228)	$ 3,004	$ 43	$ 3,047
Net loss	-	-	-	-	-	(57)	(57)	(5)	(62)
Other comprehensive loss:									
Cash flow derivative hedge losses	-	(69)	-	-	-	-	(69)	-	(69)
Reclassification of losses to net loss	-	18	-	-	-	-	18	-	18
Unrealized loss on foreign currency translation	-	-	(22)	-	-	-	(22)	-	(22)
Tax on items recognized directly in equity	-	12	-	-	-	-	12	-	12
Other comprehensive loss	$ -	$ (39)	$ (22)	$ -	$ -	$ -	$ (61)	**$** -	$ (61)
Total comprehensive loss	-	(39)	(22)	-	-	(57)	(118)	(5)	(123)
Common share dividends (note 11)	-	-	-	-	-	(145)	(145)	-	(145)
Preferred share dividends (note 11)	-	-	-	-	-	(36)	(36)	-	(36)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Issue of share capital	300	-	-	-	-	-	300	-	300
Share issue costs	(11)	-	-	-	-	-	(11)	-	(11)
Deferred taxes on share issue costs	1	-	-	-	-	-	1	-	1
Common shares purchased	(60)	-	-	-	-	-	(60)	-	(60)
Share-based payments	-	-	-	-	1	-	1	-	1
Share options exercised	20	-	-	-	(1)	-	19	-	19
Equity as at September 30, 2019	$ 3,450	$ (32)	$ 1	$ (9)	$ 11	$ (467)	$ 2,954	$ 38	$ 2,992

[1] Accumulated other comprehensive loss. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive loss and the employee benefits reserve.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share Capital (note 11)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit (note 3)	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2018	$ 3,262	$ (39)	$ (27)	$ (11)	$ 10	$ (181)	$ 3,014	$ 48	$ 3,062
Accounting policy changes:									
Impact of IAS 8 (note 3)	-	-	-	-	-	(79)	(79)	-	(79)
Impact of IFRS 15	-	-	-	-	-	(44)	(44)	-	(44)
Tax impact of IAS 8 (note 3)	-	-	-	-	-	22	22	-	22
Tax impact of IFRS 15	-	-	-	-	-	11	11	-	11
Adjusted equity as at January 1, 2018	$ 3,262	$ (39)	$ (27)	$ (11)	$ 10	$ (271)	$ 2,924	$ 48	$ 2,972
Net income	-	-	-	-	-	127	127	(5)	122
Other comprehensive income:									
Cash flow derivative hedge gains	-	20	-	-	-	-	20	-	20
Cash flow derivative hedge gains – joint ventures	-	4	-	-	-	-	4	-	4
Reclassification of losses to net income	-	11	-	-	-	-	11	-	11
Reclassification of losses to net income – joint ventures	-	3	-	-	-	-	3	-	3
Unrealized gain on foreign currency translation	-	-	12	-	-	-	12	-	12
Tax on items recognized directly in equity	-	(12)	-	-	-	-	(12)	-	(12)
Other comprehensive income	$ -	$ 26	$ 12	$ -	$ -	$ -	$ 38	**$** -	$ 38
Total comprehensive income	-	26	12	-	-	127	165	(5)	160
Common share dividends (note 11)	-	-	-	-	-	(132)	(132)	-	(132)
Preferred share dividends (note 11)	-	-	-	-	-	(30)	(30)	-	(30)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Common shares purchased	(55)	-	-	-	-	-	(55)	-	(55)
Share-based payments	-	-	-	-	1	-	1	-	1
Share options exercised	9	-	-	-	-	-	9	-	9
Equity as at September 30, 2018	$ 3,216	$ (13)	$ (15)	$ (11)	$ 11	$ (307)	$ 2,881	$ 43	$ 2,924

[1] Accumulated other comprehensive loss. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive loss and the employee benefits reserve.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Cash Flows
(Unaudited, in millions of Canadian dollars)

	Nine months ended September 30, 2019	2018 (note 3)
Cash flows from operating activities:		
Net (loss) income	$ (62)	$ 122
Non-cash adjustments to reconcile net (loss) income to net cash flows from operating activities:		
Impairment (note 5)	401	-
Depreciation and amortization	355	250
Net finance expense	115	90
Fair value changes on commodity derivative instruments and emission credits held for trading	(90)	14
Foreign exchange losses (gains)	5	(4)
Income tax (recovery) expense	(69)	71
Loss (income) from joint ventures	3	(18)
Recognition of government grant deferred revenue	(41)	(38)
Tax equity attributes	(45)	(70)
Other items	8	9
Change in fair value of derivative instruments reflected as cash settlement	36	16
Distributions received from joint ventures	9	24
Interest paid	(83)	(70)
Other cash items	(49)	(17)
Change in non-cash operating working capital	26	(62)
Net cash flows from operating activities	519	317
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(523)	(241)
Business acquisition, net of acquired cash (note 4)	(390)	-
Government grant received	50	50
Other cash flows from investing activities	7	6
Realized gain on foreign currency derivative instruments	7	-
Change in non-cash investing working capital	111	17
Net cash flows used in investing activities	(738)	(168)
Cash flows from (used in) financing activities:		
Proceeds from issue of loans and borrowings	875	224
Repayment of loans and borrowings	(747)	(192)
Realized gain on foreign currency derivative instruments	-	33
Issue of share capital (note 11)	300	-
Share issue costs	(11)	-
Proceeds from exercise of share options	19	9
Common shares purchased (note 11)	(60)	(55)
Dividends paid (note 11)	(175)	(160)
Capitalized interest paid	(8)	(3)
Income taxes paid on preferred share dividends	(15)	(15)
Other cash flows used in financing activities	(3)	(2)
Net cash flows from (used in) financing activities	175	(161)
Foreign exchange (loss) gain on cash held in a foreign currency	(5)	1
Net decrease in cash and cash equivalents	(49)	(11)
Cash and cash equivalents at beginning of period	182	52
Cash and cash equivalents at end of period	$ 133	$ 41

See accompanying notes to the condensed interim consolidated financial statements

1. Reporting entity:

Capital Power Corporation (the Company or Capital Power) develops, acquires, owns and operates power generating facilities and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities.

The registered and head office of the Company is located at 10423 101 Street, Edmonton, Alberta, Canada, T5H 0E9. The common shares of the Company are traded on the Toronto Stock Exchange under the symbol “CPX”.

Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and changes in energy prices. Consequently, interim results are not necessarily indicative of annual results.

2. Basis of presentation:

These condensed interim consolidated financial statements have been prepared by management in accordance with International Accounting Standards (IAS) 34, Interim Financial Reporting. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company’s 2018 annual consolidated financial statements prepared in accordance with International Financial Reporting Standards (IFRS).

These condensed interim consolidated financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent annual consolidated financial statements, except as outlined in note 3, and have been prepared under the historical cost basis, except for the Company’s derivative instruments, emission credits held for trading, defined benefit pension assets and cash-settled share based payments, which are stated at fair value.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on October 25, 2019.

3. Changes in significant accounting policies:

Effective January 1, 2019 (date of initial application), the Company adopted IFRS 16 – *Leases*. The objective of this standard is to provide a foundation for users of financial statements to evaluate the amount, timing and uncertainty of cash flows arising from leases. To meet this objective, the new standard introduces a single lessee accounting model requiring lessees to recognize right-of-use assets and lease liabilities for all leases previously classified as operating leases. There are no changes to lessor accounting under the new standard, however the criteria for assessing whether a contract contains a lease have changed. These assessments now focus on whether the customer controls the use of the identified asset throughout the period of use. As such, certain electricity and natural gas supply contracts where the Company was the lessor are no longer considered a lease under IFRS 16 and the energy revenue is now accounted for under IFRS 15 – *Revenue from Contracts with Customers*.

The Company has elected not to grandfather lease assessments, as previously assessed under IAS 17 - *Leases* and IFRIC 4 – *Determining Whether an Arrangement Contains a Lease*. Management reviewed all contracts and existing lease arrangements in determining the impact of adopting this standard.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

3. Changes in significant accounting policies, continued:

Impact on transition to IFRS 16 - Leases as the lessee

The Company is the lessee in various office, equipment and land leases that were previously accounted for as operating leases. The Company has elected to apply the modified retrospective approach where the lessee will not restate comparative figures and the cumulative effect of initial application of the standard will be recognized in the opening deficit balance at January 1, 2019.

The Company is also the lessee in a sale-and-leaseback transaction for the Beaufort Solar facility. The lease was accounted for as a finance lease under IAS 17 and remains unchanged under the new standard. The carrying amount of the right-of-use asset and lease liability at January 1, 2019 was determined based on the carrying amount of the lease asset and liability under IAS 17 immediately before that date.

On initial application, the Company recognized a lease liability of $96 million for future lease payments and a right-of-use asset of $86 million for the underlying asset with the difference recognized in the opening deficit balance. IFRS 16 transition impacts are presented in the tables below.

Measurement:

- Right-of-use assets are measured retrospectively, as if this standard had been applied since the commencement date of each lease, discounted using the Company's incremental borrowing rate at the date of initial application.
- Lease liabilities are measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rate at January 1, 2019. The weighted-average incremental borrowing rate was 5.72%.

Practical expedients applied:

- The Company grouped leases with reasonably similar characteristics into portfolios and applied appropriate discount rates to each of these portfolios of leases.
- The Company relied on its assessment of whether leases are onerous by applying IAS 37 – *Provisions, Contingent Liabilities and Contingent* Assets immediately before the date of initial application as an alternative to performing an impairment review. No leases were determined to be onerous.
- Management excluded initial direct costs from the measurement of the right-of-use assets at the date of initial application.

The following table reconciles the Company's operating lease obligations at December 31, 2018, as previously disclosed in the Company's consolidated financial statements, to the lease liabilities recognized on initial application of IFRS 16 at January 1, 2019.

Operating lease commitments at December 31, 2018	$	142
Discounted using the incremental borrowing rate at January 1, 2019		(65)
Add: Equipment lease contracts		19
Add: Finance lease obligation as at December 31, 2018 [1]		18
Lease liabilities recognized at January 1, 2019 [1]	$	114

[1] At December 31, 2018, $1 million of current finance lease obligations were reclassified from trade and other payables to deferred revenue and other liabilities to conform to the current period's presentation.

Impact on transition to IFRS 16 - Leases as the lessor

Finance leases:

- Management has determined that power purchase arrangements (PPAs) and energy supply contracts for Kingsbridge 1, Port Dover and Nanticoke and Quality Wind that were previously considered finance leases with the Company as the lessor are no longer considered leases upon adoption of this standard, but rather will be accounted for under IFRS 15 – Revenue from Contracts with Customers. The transition impact for the former finance leases will be treated as a change in accounting policy and accounted for retrospectively in accordance with IAS 8 - Accounting Policies, Changes in Accounting Estimates and Errors.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

3. Changes in significant accounting policies, continued:

Impact on transition to IFRS 16 - Leases as the lessor, continued

Operating leases:

- The Company is the lessor in various PPAs where it operates the facilities under PPAs that convey the right to the holder of the agreement to use the related property, plant and equipment. As such, the Genesee units 1 and 2, Island Generation, Decatur Energy and Arlington Valley power generation facilities continue to be accounted for as assets under operating leases as this classification remains unchanged under the new standard. Management determined that the East Windsor, EnPower and Roxboro PPAs no longer contain a lease under IFRS 16 and the energy revenues will be accounted for under IFRS 15. This change has no impact on the Company's financial statement balances, but will result in additional revenues from contracts with customers within the Company's segment information in note 13.

For further disclosure on the Company's leases, see note 9.

Summarized impacts of IFRS 16 adoption and resulting IAS 8 accounting policy change

The impacts of adopting IFRS 16 on the consolidated statements of financial position as at January 1, 2019 and 2018, inclusive of the related IAS 8 accounting policy changes, were:

	Previously stated at January 1, 2018	IAS 8	Restated as at January 1, 2018	Previously stated at December 31, 2018	IAS 8	Restated as at December 31, 2018	IFRS 16	As at January 1, 2019
Assets								
Current Assets:								
Cash and cash equivalents	$ 52	$ -	$ 52	$ 182	$ -	$ 182	$ -	$ 182
Trade and other receivables	278	(23)	255	462	(24)	438	(2)	436
Inventories	120	-	120	200	-	200	-	200
Derivative financial instruments assets	92	-	92	77	-	77	-	77
	542	(23)	519	921	(24)	897	(2)	895
Non-current Assets:								
Other assets	68	-	68	66	-	66	-	66
Derivative financial instruments assets	79	-	79	82	-	82	-	82
Finance lease receivables	644	(644)	-	620	(620)	-	-	-
Government grant receivable	493	-	493	459	-	459	-	459
Deferred tax assets	74	-	74	59	-	59	-	59
Equity-accounted investments in joint ventures	184	-	184	142	-	142	-	142
Right-of-use assets	-	-	-	-	-	-	86	86
Intangible assets	401	-	401	473	-	473	-	473
Property, plant and equipment	4,378	588	4,966	4,803	553	5,356	-	5,356
Goodwill	35	-	35	35	-	35	-	35
Total Assets	$ 6,898	$ (79)	$ 6,819	$ 7,660	$ (91)	$ 7,569	$ 84	$ 7,653

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

3. Changes in significant accounting policies, continued:

Summarized impacts of IFRS 16 adoption and resulting IAS 8 accounting policy change, continued

	Previously stated at January 1, 2018	IAS 8	Restated as at January 1, 2018	Previously stated at December 31, 2018	IAS 8	Restated as at December 31, 2018	IFRS 16	As at January 1, 2019
Liabilities and equity								
Current liabilities:								
Trade and other payables [1]	$ 216	$ -	$ 216	$ 245	$ (1)	$ 244	$ -	$ 244
Derivative financial instruments liabilities	86	-	86	90	-	90	-	90
Loans and borrowings	239	-	239	456	-	456	-	456
Deferred revenue and other liabilities [1]	58	-	58	61	1	62	5	67
Provisions	37	-	37	54	-	54	-	54
	636	-	636	906	-	906	5	911
Non-current liabilities:								
Derivative financial instruments liabilities	56	-	56	114	-	114	-	114
Loans and borrowings	1,907	-	1,907	2,191	-	2,191	-	2,191
Finance lease obligations [1]	17	-	17	17	(17)	-	-	-
Lease liabilities [1]	-	-	-	-	17	17	91	108
Deferred revenue and other liabilities	581	-	581	587	-	587	(4)	583
Deferred tax liabilities	374	(22)	352	435	(25)	410	(2)	408
Provisions	265	-	265	291	-	291	-	291
	3,200	(22)	3,178	3,635	(25)	3,610	85	3,695
Equity:								
Share capital	3,262	-	3,262	3,200	-	3,200	-	3,200
Deficit [1]	(181)	(57)	(238)	(156)	(66)	(222)	(6)	(228)
Other reserves	(67)	-	(67)	32	-	32	-	32
Deficit and other reserves	(248)	(57)	(305)	(124)	(66)	(190)	(6)	(196)
	3,014	(57)	2,957	3,076	(66)	3,010	(6)	3,004
Non-controlling interests	48	-	48	43	-	43	-	43
Total equity	3,062	(57)	3,005	3,119	(66)	3,053	(6)	3,047
Total liabilities and equity	$ 6,898	$ (79)	$ 6,819	$ 7,660	$ (91)	$ 7,569	$ 84	$ 7,653

[1] Comparative figures have been reclassified to conform to the current year's presentation.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

3. Changes in significant accounting policies, continued:

IAS 8 accounting policy change – impacts on consolidated statements of income

The adjustments to the impacted line items within the consolidated statements of income (loss) pertaining to the IAS 8 accounting policy change related to the former finance leases where the Company was the lessor were:

	Three months ended September 30, 2019			Three months ended September 30, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	478	484	6	367	373	6
Depreciation and amortization	(126)	(135)	(9)	(74)	(83)	(9)
Income tax recovery (expense)	65	66	1	(8)	(7)	1
Net income (loss) impact			(2)			(2)

	Nine months ended September 30, 2019			Nine months ended September 30, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	1,165	1,183	18	943	961	18
Depreciation and amortization	(328)	(355)	(27)	(223)	(250)	(27)
Income tax recovery (expense)	66	69	3	(74)	(71)	3
Net income (loss) impact			(6)			(6)

4. Acquisition of the Goreway Power Station:

On June 4, 2019, a subsidiary of the Company acquired all of the equity interests in Goreway Power Station Holdings Inc., which owns the Goreway Power Station (Goreway). Goreway is an 875-megawatt natural gas combined cycle generation facility located in Brampton, Ontario. The purchase price consisted of (i) $410 million of total cash consideration, including working capital and other closing adjustments of $23 million, and (ii) the assumption of $590 million of asset level debt.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

4. Acquisition of the Goreway Power Station, continued:

The preliminary allocation of the purchase price to the assets acquired and liabilities assumed based on their estimated fair values is as follows:

		June 4, 2019
Cash and cash equivalents	$	20
Trade and other receivables		22
Inventories		9
Property, plant and equipment		821
Intangible assets		500
Trade and other payables		(19)
Loans and borrowings		(590)
Derivative financial instrument liabilities[1]		(105)
Provisions		(40)
Deferred tax liabilities		(208)
Fair value of net assets acquired	$	410

[1] Interest rate swap agreements to hedge the interest on the assumed debt.

The purchase price allocation is preliminary, subject to the finalization of the allocation between property, plant and equipment and intangible assets, which is expected to occur during the fourth quarter of 2019.

Goreway has a 20-year Accelerated Clean Energy Supply Contract expiring in June 2029 with the Ontario Independent Electricity System Operator. Goreway is strategically located in the Greater Toronto Area load centre making it an important asset in Ontario's electric system and, in combination with the Company's other Ontario natural gas assets, will provide operating and market synergies over time. The acquisition of Goreway supports the Company's growth strategy, fully meets the Company's investment criteria and contributes to the Company's dividend growth strategy through increased contracted cash flows through mid-2029.

The amount allocated to trade and other receivables for the acquisition represents both the estimated fair value and the gross contractual amounts receivable. As at September 30, 2019, all of the contractual cash flows pertaining to the acquired trade and other receivables have been collected.

The asset level debt assumed related to Goreway is a floating-rate bank facility based on prevailing market interest rates repayable quarterly with principal payments amortizing to 2029. The interest rate risk on this bank facility has been largely hedged through 2029 by interest rate swaps assumed as part of the acquisition covering 85% of the debt principal amount. The Company has elected to apply hedge accounting on these interest rate swaps. These swaps result in an effective fixed interest rate, on that portion of the assumed debt, of 7.4% (including a 1.4% stamping rate) per annum. The balance of the debt is subject to an interest rate based on the Canadian Dollar Offered Rate. The assumed bank facility matures in September 2020 at which time the hedging instruments also have a mandatory settlement. Management expects to extend both the credit facility and the hedging instruments before the maturity and mandatory settlement in September of 2020.

The results of operations of Goreway are included in the Company's consolidated statements of income (loss) and statements of changes in equity from the date of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statements of financial position. Since the acquisition date, the following revenues and net income are included in the consolidated statements of income (loss) for the three and nine months ended September 30, 2019:

	Three months ended September 30, 2019	Nine months ended September 30, 2019
Revenues	$ 53	$ 69
Net income	10	13

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

4. Acquisition of the Goreway Power Station, continued:

The consolidated revenues and net loss of the Company including Goreway, had the acquisition occurred at January 1, 2019, would have been as follows:

	Three months ended September 30, 2019	Nine months ended September 30, 2019
Revenues	$ 484	$ 1,276
Net loss	(228)	(40)

In conjunction with the acquisition of Goreway, for the three and nine months ended September 30, 2019, the Company incurred $2 million in acquisition costs which have been recorded on the Company's consolidated statements of income as other administrative expenses.

5. Genesee 3 and Keephills 3 swap transaction:

Genesee 3 (G3) and Keephills 3 (K3) are coal and natural gas co-fired generating units in Alberta with a net capacity of 466 megawatts ("MW") and 463 MW, respectively. Previously, both generating units were owned and operated under 50/50 Joint Venture Agreements between Capital Power and TransAlta Corporation (TransAlta).

In August 2019, the Company entered into an agreement to divest its 50% share of K3 to TransAlta, and to acquire TransAlta's 50% share of G3 for cash consideration, paid by Capital Power, of $10 million, subject to working capital and other closing adjustments. Accordingly, the K3 net assets are classified as assets held for sale for the period ended September 30, 2019. The consideration to be paid approximates the difference in fair value between the exchanged interests on the date of the transaction.

The transaction closed on October 1, 2019 at an expected pre-tax net loss of approximately $227 million, with components of the net loss being recognized in the third and fourth quarters of 2019 as disclosed in the table below.

Recorded during September 2019		
Impairment of K3 upon classification as assets held for sale		$ (401)
		(401)
To be recorded in the fourth quarter of 2019		
Gain to be recognized upon remeasurement of CPC's existing share of G3 net assets[1]		60
Accelerated recognition of coal compensation into income [2]		114
		$ 174
Total net loss on the transaction	$	(227)

[1] The acquisition of the additional 50% of G3 will be accounted for as a business combination. A gain is expected to be recognized on the Company's existing share of G3 as a result of the remeasurement of the carrying amount to its estimated fair value upon close of the business combination.

[2] Currently, the Company is receiving coal compensation from the province of Alberta related to the 2029 phase out of coal-fired generation that was determined by reference to the carrying amount of these assets. The coal compensation is being recognized annually through 2029 on a systematic basis that aligns with the depreciation expense related to coal-fired assets. The net reduction to the carrying amounts of the Company's coal-fired generation assets upon close of the transaction will result in a one-time adjustment to accelerate the recognition of deferred government grant revenue that aligns with the reduction to the new lower carrying amount of coal-fired assets.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

5. Genesee 3 and Keephills 3 swap transaction, continued:

Assets held for sale – Keephills 3

The Company records assets held for sale at the lower of their fair value less costs to sell and their carrying amount. Comparing the carrying amount of the K3 disposal group to the estimated fair value of the proceeds to be received, the Company recorded pre-tax impairments of $401 million within the Alberta cash-generating unit in the three months ended September 30, 2019. The impairment was applied to the carrying amounts of the intangible assets and property, plant and equipment of the K3 disposal group.

For purposes of calculating the above impairment, the Company used the fair value less costs to sell of K3 as the recoverable amount of the assets. The fair value less costs to sell was established by the transaction agreement described above based on the fair value of G3, net of the $10 million payment made by the Company, less the Company's estimate of the directly attributable incremental costs related to the disposal. The determination of the G3 fair value is disclosed below.

At September 30, 2019, the K3 disposal group consisted of assets and liabilities, net of the impairment, as follows:

	September 30, 2019
Assets held for sale	
Trade and other receivables	$ 10
Inventories	9
Other assets	2
Intangible assets	34
Property, plant and equipment	269
	$ 324
Liabilities related to assets held for sale	
Trade and other payables	$ 3
Deferred revenues and other liabilities (current and non-current)	5
Provisions (non-current)	15
	$ 23

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

5. Genesee 3 and Keephills 3 swap transaction, continued:

Acquisition of Genesee 3

On October 1, 2019, the Company acquired an additional 50% interest in G3 increasing its total ownership to 100%. The purchase price consisted of (i) $10 million of total cash consideration, (ii) the exchange of Capital Power's 50% interest in K3 of $301 million, and nominal preliminary working capital and other closing adjustments. The preliminary allocation of the purchase price to the assets acquired and liabilities assumed on acquisition of the additional 50% share of G3 based on their estimated fair values is as follows:

		October 1, 2019
Cash and cash equivalents	$	3
Trade and other receivables		1
Inventories		8
Property, plant and equipment		276
Increased share of Genesee site shared property, plant and equipment [3]		23
Fair value of net assets acquired	$	311

[3] Relates to shared assets of the Genesee site for which capital contributions were previously made by TransAlta.

Measurement of fair values

The fair value measurement of the additional 50% share of G3 is categorized in Level 3 of the fair value hierarchy based on inputs used in the discounted cash flow model. The Company's cash flow projections incorporate estimates of annual plant revenues, expenses and capital expenditures to the end of G3's useful life in 2039 which assumes a full conversion to natural gas.

These estimates reflect past experience and the Company's current view of future generating capacity, fuel sources and fuel pricing. Consideration is given to externally available information related to future electricity and fuel pricing inputs when developing assumptions and such external information is used to validate the Company's current view of future pricing assumptions. These external sources of information include information from third party advisory and research firms serving the industry. Alberta power pricing and natural gas pricing assumptions used in the modelling above are classified in Level 3 of the fair value hierarchy. The table below presents ranges for the Level 3 inputs over the useful life of G3:

Alberta power prices ($/MWh)	$ 57.80 to $ 85.30
Natural gas prices ($/GJ)	$ 1.53 to $ 4.02

Fair value of pre-existing interest in G3

The remeasurement to fair value of the Company's existing 50% of G3 resulted in a gain of $60 million which will be recorded in net income (loss) in the fourth quarter of 2019.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

6. Income tax:

Income tax differs from the amount that would be computed by applying the federal and provincial income tax rates as follows:

	Three months ended September 30, 2019	Three months ended September 30, 2018 (note 3)	Nine months ended September 30, 2019	Nine months ended September 30, 2018 (note 3)
Income before tax	$ (294)	$ 24	$ (131)	$ 193
Income tax at the statutory rate of 26.5%[1] (2018 – 27.0%)	(78)	7	(35)	52
Increase (decrease) resulting from:				
Amounts attributable to non-controlling interests and tax-equity interests[2]	5	4	14	27
Change in unrecognized tax benefits	-	-	1	-
Non-taxable amounts	(1)	(2)	(4)	(10)
Statutory and other rate differences[1]	8	(1)	(45)	2
Other	-	(1)	-	-
Income tax (recovery) expense	$ (66)	$ 7	$ (69)	$ 71

[1] On June 28, 2019, as a result of the Alberta Government's Bill 3 - Job Creation Tax Cut Act, the Alberta corporate income tax rate was reduced from 12% to 8% over 4 years. Accordingly, the 2019 statutory tax rate is 26.5% and will decrease further to 25% for the 2020 year, to 24% for the 2021 year, and to 23% for the 2022 year. Due to this tax rate decrease, the Canadian deferred tax assets and liabilities were re-measured, resulting in the recognition of a deferred income tax recovery of $51 million during the three months ended June 30, 2019.

[2] During the nine months ended September 30, 2018, the Company recorded a non-taxable, non-cash, one-time amount attributable to tax-equity interests in Bloom Wind of $15 million (US$11 million) relating to the renegotiation of certain commercial terms within the Bloom Wind tax equity agreement. This renegotiation resulted from the reduction of the U.S. Federal corporate tax rate which was effective January 1, 2018. The total amount recorded reflects an increase in other income of $44 million (US$33 million) net of an increase in income tax expense of $29 million (US$22 million).

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

7. Earnings (loss) per share:

Basic earnings (loss) per share

The earnings (loss) and weighted average number of common shares used in the calculation of basic earnings (loss) per share are as follows:

	Three months ended September 30, 2019	Three months ended September 30, 2018 (note 3)	Nine months ended September 30, 2019	Nine months ended September 30, 2018 (note 3)
Income (loss) for the period attributable to shareholders of the Company	$ (226)	$ 18	$ (57)	$ 127
Preferred share dividends of the Company[1]	(14)	(10)	(37)	(31)
Earnings (loss) used in the calculation of basic earnings (loss) per share	$ (240)	$ 8	$ (94)	$ 96

[1] Includes preferred share dividends and related taxes in respect of the three and nine months ended September 30, 2019 and 2018 respectively.

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	106,465,965	102,374,301	103,975,042	103,219,849

Diluted earnings (loss) per share

The earnings (loss) used in the calculation of diluted earnings (loss) per share do not differ from the earnings (loss) used in the calculation of basic earnings (loss) per share for the three and nine months ended September 30, 2019 and 2018. The weighted average number of common shares for the purposes of diluted earnings (loss) per share reconciles to the weighted average number of common shares used in the calculation of basic earnings (loss) per share as follows:

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	106,465,965	102,374,301	103,975,042	103,219,849
Effect of dilutive share purchase options[2]	-	384,161	-	297,697
Weighted average number of common shares used in the calculation of diluted earnings (loss) per share	106,465,965	102,758,462	103,975,042	103,517,546

[2] For the three and nine months ended September 30, 2019, the average market price of the Company's common shares exceeded the exercise price of certain granted share purchase options, but were not included in the calculation of diluted earnings (loss) per share as they were anti-dilutive. For the three and nine months ended September 30, 2018, the average market price of the Company's common shares exceeded the exercise price of certain granted share purchase options, but had a neutral effect on earnings (loss) per share.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Derivative financial instruments and hedge accounting:

Derivative financial and non-financial instruments are held for the purposes of energy purchases, merchant trading or financial risk management.

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

	September 30, 2019				
	Energy and emission allowances		Interest rate	Foreign exchange	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 1	$ 70	$ -	$ 1	$ 72
Non-current	-	118	-	-	118
Derivative instruments liabilities:					
Current	(16)	(78)	(95)	(1)	(190)
Non-current	(18)	(112)	(4)	-	(134)
Net fair value	$ (33)	$ (2)	$ (99)	$ -	$ (134)
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(7)	(14)			
Gigajoules of natural gas		344			
Metric tons of emission allowances		3			
Number of renewable energy credits		(1)			
Interest rate swaps (note 4)			$ 863		
Forward currency sells (U.S. dollars)				$ (70)	
Range of remaining contract terms in years	0.1 to 4.3	0.1 to 13.3	1.0 to 1.2	0.1 to 0.2	

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Derivative financial instruments and hedge accounting, continued:

	December 31, 2018				
	Energy and emission allowances		Interest rate	Foreign exchange	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 5	$ 60	$ -	$ 12	$ 77
Non-current	6	76	-	-	82
Derivative instruments liabilities:					
Current	(9)	(73)	(7)	(1)	(90)
Non-current	(2)	(112)	-	-	(114)
Net fair value	$ -	$ (49)	$ (7)	$ 11	$ (45)
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(7)	(14)			
Gigajoules of natural gas		138			
Metric tons of emission allowances		4			
Number of renewable energy credits		(14)			
Bond forwards			$ 250		
Interest rate swaps			$ 200		
Forward currency buys (U.S. dollars)				$ 117	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 14.0	0.1 to 0.9	0.7 to 0.9	

Fair values of derivative instruments are determined using valuation techniques, inputs, and assumptions as described in the Company's 2018 annual consolidated financial statements. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Unrealized and realized pre-tax gains and losses on derivative instruments recognized in other comprehensive income (loss) and net (loss) income are:

	Three months ended September 30, 2019		Three months ended September 30, 2018	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized (losses) gains
Energy cash flow hedges	$ 14	$ 8	$ 56	$ (9)
Energy and emission allowances non-hedges	4	22	(34)	13
Interest rate cash flow hedges	2	(1)	8	-
Interest rate non-hedges	-	-	2	(1)
Foreign exchange cash flow hedges	-	-	(9)	-
Foreign exchange non-hedges	(2)	1	(2)	-

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Derivative financial instruments and hedge accounting, continued:

	Nine months ended September 30, 2019		Nine months ended September 30, 2018	
	Unrealized (losses) gains	Realized (losses) gains	Unrealized gains (losses)	Realized (losses) gains
Energy cash flow hedges	$ (41)	$ (18)	$ 30	$ (11)
Energy and emission allowances non-hedges	92	37	(8)	45
Interest rate cash flow hedges[1]	(10)	(2)	10	-
Interest rate non-hedges	-	-	2	(1)
Foreign exchange cash flow hedges	-	-	(9)	-
Foreign exchange non-hedges	(11)	7	(29)	33

[1] Interest rate cash flow hedges of $450 million were settled in the nine months ended September 30, 2019 for a total loss of $18 million which includes $17 million deferred within accumulated other comprehensive (loss) income to be reclassified to net (loss) income in future periods within the associated net finance expense pertaining to the hedged note offering.

Realized and unrealized gains and losses relate only to derivative financial instruments. The following realized and unrealized gains (losses) are included in the Company's consolidated statements of income (loss) for the three and nine months ended September 30, 2019 and 2018:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Revenues	$ 64	$ 55	$ (12)	$ 69
Energy purchases and fuel	(30)	(85)	123	(43)
Foreign exchange (loss) gain	(1)	(2)	(4)	4
Net finance expense	(1)	1	(2)	1

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices and interest rate risk relating to future borrowings. For the three and nine months ended September 30, 2019, nil and $1 million of losses, respectively, were realized within net finance expense pertaining to the ineffective portion of hedging derivatives (three and nine months ended September 30, 2018 – nil).

Net after tax gains and losses related to derivative instruments designated as energy cash flow hedges and interest rate hedges are expected to settle and be reclassified to net (loss) income in the following periods:

	September 30, 2019
Within one year	$ (19)
Between 1 – 5 years	(14)
After more than 5 years	-
	$ (33)

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

9. Leases:

Right-of-use assets

	Land	Offices	Equipment	Total
Balance, January 1, 2019	$ 51	$ 28	$ 20	$ 99
Depreciation	(3)	(2)	(1)	(6)
Balance, September 30, 2019	$ 48	$ 26	$ 19	$ 93

Lease liabilities

Contractual undiscounted cash flows for lease liabilities:

As at September 30	2019
Within one year	$ 10
Between one and five years	35
More than five years	107
Total	$ 152

The following table presents amounts recognized in the consolidated statements of income (loss):

	Three months ended September 30, 2019	Nine months ended September 30, 2019
Interest on lease liabilities	$ 1	$ 4
Variable lease payments not included in the measurement of lease liabilities	2	4

As at September 30, 2019, income from sub-leasing right-of-use assets and expenses related to short-term and low-value leases was nil.

Facilities under operating leases

The Genesee units 1 and 2, Island Generation, Decatur Energy and Arlington Valley power generation facilities are accounted for as assets under operating leases.

As at September 30, 2019, the cost of such property, plant and equipment was $2,049 million (December 31, 2018 - $2,006 million), less accumulated depreciation of $501 million (December 31, 2018 - $433 million).

The minimum future rental payments to be received on these PPAs are:

As at September 30	2019
2019	$ 32
2020	170
2021	127
2022	119
2023	47
Thereafter	98
Total	$ 593

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

10. Financing:

On June 12, 2019, the Company completed a $325 million private placement of senior notes consisting of three tranches with 10, 12 and 15-year terms. The 10-year tranche has a principal amount of $210 million that matures in June 2029 with a coupon rate of 4.56%. The 12-year tranche has a $65 million principal amount and matures in June 2031 with a coupon rate of 4.72%. The 15-year tranche has a $50 million principal amount and matures in June 2034 with a coupon rate of 4.96%.

11. Share capital:

	Dividends declared							
	For the three months ended September 30,				For the nine months ended September 30,			
	2019		2018		2019		2018	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[1]	$ 0.4800	$ 51	$ 0.4475	$ 46	$ 1.3750	$ 145	$ 1.2825	$ 132
Preference								
Series 1	0.1913	1	0.1913	1	0.5738	3	0.5739	3
Series 3	0.3408	2	0.2875	1	1.0224	6	0.8625	5
Series 5	0.3274	3	0.3274	3	0.9821	9	0.8900	7
Series 7	0.3750	3	0.3750	3	1.1250	9	1.1250	9
Series 9	0.3594	2	0.3594	2	1.0781	6	1.0782	6
Series 11	0.3594	2	-	-	0.5366	3	-	-

[1] On July 26, 2019, the Company's Board of Directors approved an increase of 7.3% to $1.92 in the annual dividend per common share effective for the third quarter of 2019.

	Dividends paid[2]							
	For the three months ended September 30,				For the nine months ended September 30,			
	2019		2018		2019		2018	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.4475	$ 48	$ 0.4175	$ 43	$ 1.3425	$139	$ 1.2525	$ 130

[2] Preference Shares dividends are declared and paid in the same period.

During the three and nine months ended September 30, 2019, the Company purchased and cancelled 1,635,538 and 2,018,950 of its outstanding common shares at an average exercise price of $30.40 and $29.66 per share for $50 million and $60 million, respectively (three and nine months ended September 30, 2018 – 504,318 and 2,231,256 for $13 million and $55 million, respectively) under its Toronto Stock Exchange approved normal course issuer bid.

On May 8, 2019, the Company completed a public offering of 4,945,000 subscription receipts (Subscription Receipts), on a bought deal basis, at an issue price of $30.30 per Subscription Receipt (the Offering Price), for total gross proceeds of $150 million less issue costs of $6 million (inclusive of the full exercise of a 645,000 over-allotment option). On June 4, 2019, upon closing of the Goreway acquisition, each Subscription Receipt was converted for one common share of the Company.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

11. Share capital, continued:

On May 16, 2019, the Company issued 6 million Cumulative Minimum Rate Reset Preference Shares, Series 11 (Series 11 Shares) at a price of $25.00 per share for gross proceeds of $150 million less issue costs of $4 million. The Series 11 Shares will pay fixed cumulative dividends of $1.4375 per share per annum, yielding 5.75% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board of Directors of Capital Power, for the initial period ending June 30, 2024. The dividend rate will be reset on June 30, 2024 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.15%, provided that, in any event, such rate shall not be less than 5.75%. The Series 11 Shares are redeemable by Capital Power, at its option on June 30, 2024 and every five years thereafter at a value of $25.00 per share.

Holders of the Series 11 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 12 (Series 12 Shares), subject to certain conditions, on June 30, 2024 and every five years thereafter. Holders of the Series 12 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 4.15%, as and when declared by the Board of Directors of Capital Power. The Series 12 Shares would be redeemable by Capital Power, at its option, on June 30, 2029 and June 30 of every fifth year thereafter at a value of $25.00 per share. The Series 12 Shares would also be redeemable by Capital Power, at its option, on any date after June 30, 2024 excluding June 30 of every fifth year, at a value of $25.50 per share.

12. Financial instruments:

Fair values

Details of the fair values of the Company's derivative instruments are described in note 8.

The Company's other short-term financial instruments are classified and measured at amortized cost, consistent with the methodologies described in the Company's 2018 annual consolidated financial statements. Due to the short-term nature of the financial instruments, the fair values are not materially different from their carrying amounts.

The fair values of the Company's other long-term financial instruments are determined using the same valuation techniques, inputs, and assumptions as described in the Company's 2018 annual consolidated financial statements. The carrying amount and fair value of the Company's other financial instruments, which are all classified and subsequently measured at amortized cost, are summarized as follows:

		September 30, 2019		December 31, 2018	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Government grant receivable[1]	Level 2	473	430	511	505
Loans and borrowings[1]	Level 2	3,304	3,352	2,647	2,645

[1] Includes current portion.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Financial instruments, continued:

Fair value hierarchy

Fair value represents the Company's estimate of the price at which a financial instrument could be exchanged between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated statements of financial position are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The valuation techniques used by the Company in determining the fair value of its financial instruments are the same as those used as at December 31, 2018.

The fair value measurement of a financial instrument is included in only one of the three levels described in the Company's 2018 annual consolidated financial statements, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment which will affect the placement within the fair value hierarchy levels.

The Company's policy is to recognize transfers between levels as of the date of the event of change in circumstances that caused the transfer. The transfers between levels in the fair value hierarchy for the three and nine months ended September 30, 2019 and the year ended December 31, 2018 are disclosed below within the continuity of Level 3 balances.

The table below presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated statements of financial position, classified using the fair value hierarchy described in the Company's 2018 annual consolidated financial statements.

	September 30, 2019			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 166	$ 24	$ 190
Derivative financial instruments liabilities	-	(309)	(15)	(324)

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 143	$ 16	$ 159
Derivative financial instruments liabilities	-	(160)	(44)	(204)

Valuation techniques used in determination of fair values within Level 3

The Company has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, their fair values are derived using forecasts based on internal modelling and as a result, are classified within Level 3 of the hierarchy.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Financial instruments, continued:

Fair value hierarchy, continued

Valuation techniques used in determination of fair values within Level 3, continued

In addition, as at September 30, 2019 and December 31, 2018, the Company holds contracts for the sale of renewable energy credits (RECs) for which pricing beyond two years is not readily observable and the contracts are therefore classified in Level 3 of the hierarchy.

The fair values of the Company's commodity derivatives included within Level 3 are determined by applying a mark-to-forecast model. The table below presents ranges for the Company's Level 3 inputs:

	September 30, 2019	December 31, 2018
REC pricing (per certificate) – Thermal	$0.91	$1.09
REC pricing (per certificate) – Solar	$215.10 to $413.72	$221.55 to $395.64
Power pricing (per MWh) – Wind	$13.84 to $61.35	$15.48 to $70.68

Valuation process applied to Level 3

The valuation models used to calculate the fair values of the derivative financial instruments assets and liabilities within Level 3 are prepared by appropriate internal subject matter experts and reviewed by the Company's commodity risk group and by management. The valuation technique and the associated inputs are assessed on a regular basis for ongoing reasonability.

The table below presents the impact to fair value of Level 3 derivative instruments based on reasonably possible alternative assumptions:

	September 30, 2019	December 31, 2018
REC pricing – Thermal[2]	$ -	$ -
REC pricing – Solar[2]	-	-
Power pricing – Wind[2]	18	17

[2] Reflects the increase or decrease to fair value calculated using a $1 per unit decrease or increase in the input.

Continuity of Level 3 balances

The Company classifies financial instruments in Level 3 of the fair value hierarchy when there is reliance on at least one significant unobservable input to the valuation model used to determine fair value. In addition to these unobservable inputs, the valuation model for Level 3 instruments also relies on a number of inputs that are observable either directly or indirectly. Accordingly, the unrealized gains and losses shown below include changes in the fair value related to both observable and unobservable inputs. The following table summarizes the changes in the fair value of financial instruments classified in Level 3:

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Financial instruments, continued:

Fair value hierarchy, continued

Continuity of Level 3 balances, continued

	Nine months ended September 30, 2019	Year ended December 31, 2018
As at January 1[3]	$ (28)	$ 30
Unrealized and realized gains (losses) included in net (loss) income[4]	36	(55)
Transfers[5]	-	(5)
Foreign exchange gain	1	2
As at end of period	$ 9	$ (28)
Total unrealized gains (losses) for the period included in net (loss) income[4]	$ 36	$ (55)

[3] The fair value of derivative instruments assets and liabilities are presented on a net basis.

[4] Recorded in revenues.

[5] Relates to transfer from Level 3 to Level 2 when pricing inputs became readily observable.

All instruments classified as Level 3 are derivative type instruments. Gains and losses associated with Level 3 balances may not necessarily reflect the underlying exposures of the Company. As a result, unrealized gains and losses from Level 3 financial instruments are often offset by unrealized gains and losses on financial instruments that are classified in Levels 1 or 2.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation facilities within Canada (Alberta, British Columbia and Ontario) and in the U.S. (North Carolina, New Mexico, Kansas, Alabama, Arizona and North Dakota), as this is how management assesses performance and determines resource allocations. The Company also holds a portfolio of wind and solar development sites in the U.S., including Cardinal Point Wind which is under development in Illinois.

The Company's results from operations within each geographic area are:

	Three months ended September 30, 2019				Three months ended September 30, 2018 (note 3)			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 350	$ 134	$ -	$ 484	$ 340	$ 33	$ -	$ 373
Revenues - inter-area	-	4	(4)	-	5	8	(13)	-
Other income	19	14	-	33	16	6	-	22
Total revenues and other income	$ 369	$ 152	$ (4)	$ 517	$ 361	$ 47	$ (13)	$ 395

	Nine months ended September 30, 2019				Nine months ended September 30, 2018 (note 3)			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 819	$ 364	$ -	$1,183	$ 789	$ 172	$ -	$ 961
Revenues - inter-area	20	10	(30)	-	9	24	(33)	-
Other income	52	45	-	97	46	70	-	116
Total revenues and other income	$ 891	$ 419	$ (30)	$1,280	$ 844	$ 266	$ (33)	$ 1,077

	As at September 30, 2019			As at December 31, 2018 (note 3)		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 4,282	$ 1,520	$ 5,802	$ 3,947	$ 1,409	$ 5,356
Right-of-use assets (note 9)	57	36	93	-	-	-
Intangible assets	632	158	790	249	224	473
Goodwill	35	-	35	35	-	35
Other assets	54	-	54	65	1	66
	$ 5,060	$ 1,714	$ 6,774	$ 4,296	$ 1,634	$ 5,930

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Segment information, continued:

The Company's revenues and other income from contracts with customers are disaggregated by major type of revenues and operational groupings of revenues:

	Three months ended September 30, 2019						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 125	$ 2	$ 78	$ 31	$ 236	$ 234	$ 470
Emission credit revenues	5	-	-	2	7	7	14
Total revenues[1]	$ 130	$ 2	$ 78	$ 33	$ 243	$ 241	$ 484

	Nine months ended September 30, 2019						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 461	$ 5	$ 162	$ 119	$ 747	$ 396	$ 1,143
Emission credit revenues	17	-	-	6	23	17	40
Total revenues[1]	$ 478	$ 5	$ 162	$ 125	$ 770	$ 413	$ 1,183

[1] Included within trade and other receivables, as at September 30, 2019, were amounts related to contracts with customers of $104 million.

	Three months ended September 30, 2018 (note 3)						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 140	$ 2	$ 27	$ 28	$ 197	$ 166	$ 363
Emission credit revenues	4	-	-	2	6	4	10
Total revenues[2]	$ 144	$ 2	$ 27	$ 30	$ 203	$ 170	$ 373

	Nine months ended September 30, 2018 (note 3)						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 384	$ 6	$ 98	$ 86	$ 574	$ 344	$ 918
Emission credit revenues	17	-	-	6	23	20	43
Total revenues[2]	$ 401	$ 6	$ 98	$ 92	$ 597	$ 364	$ 961

[2] Included within trade and other receivables, as at September 30, 2018, were amounts related to contracts with customers of $175 million.

14. Comparative figures:

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